PtX Competitiveness Analysis

Renewable Hydrogen Market Potential and Value Chain

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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

ACRONYMS

AN	Ammonium Nitrate
ASTM	American Society for Testing Materials
ATJ	Alcohol-to-Jet
BCCS	Bioenergy with Carbon Capture and Storage
BECCU	Bioenergy with Carbon Capture and Utilisation
BF	Blast Furnace
BOF	Basic Oxygen Furnace
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
CCU	Carbon Capture and Utilisation
CCUS	Carbon Capture, Usage and Storage
CTL	Coal-to-Liquids
DAC	Direct Air Capture
DAFF	Department of Agriculture, Forestry and Fisheries
DC	Development Corporation
DFFE	Department of Forestry, Fisheries and the Environment
DME	Direct Dimethyl Ether
DMRE	Department of Mineral Resources and Energy
DNA	Economic and development consulting firm in South Africa
DRI	Direct Reduced Iron
EAF	Electric Arc Furnace
EC	European Commission
EOR	Enhanced Oil Recovery
EPRS	European Parliamentary Research Service
ETS	Emissions Trading Systems
EU	European Union
FT	Fischer-Tropsch
GHCS	Green Hydrogen Commercialisation
GHG	Greenhouse Gas
GIZ	German Agency for International Cooperation
GJ	Gigajoule
GTL	Gas-to-liquids
HEFA	Hydroprocessed Esters and Fatty Acids
HFC	Hydrogen Fuel Cell
HHV	Higher Heating Value
HSRM	Hydrogen Society Roadmap
HTS	High Temperature Shift
HVO	Hydrotreated Vegetable Oil
IATA	International Air Transport Association
IDC	Industrial Development Corporation
IEA	International Energy Agency
IEAGHG	International Energy Agency Greenhouse Gas Programme
IMF	International Monetary Fund
IPCC	Intergovernmental Panel on Climate Changes
IRENA	International Renewable Energy Agency
ISI	Iron and Steel Institute
KW	Kilowatt
LCOA	Levelised Cost of Ammonia
LCOH	Levelised Cost of Hydrogen
LCOX	Levelised Cost of PtX
LHV	Low Heating Value

LPG	Liquefied Petroleum Gas
LTS	Low Temperature Shift
MW	Megawatt
NDC	Nationally Determined Contributions
NPK	Nitrogen, Phosphorus, and Potassium
NYSERDA	New York State Energy Research and Development Authority
OPEX	Operating Expenditures
PEM	Proton Exchange Membrane
PMR	Partnership for Market Readiness
PSA	Pressure Swing Absorption
PV	Solar Photovoltaic
RE	Renewable Energy
SAF	Sustainable Aviation Fuel
SAIIA	South African Institute of International Affairs
SAISI	South African Iron and Steel Institute
SAWEA	South Africa Wind Energy Association
SMR	Steam Methane Reforming
SNG	Synthetic Natural Gas
SOEC	Solid Oxide Electrolysis Cells
USD	US Dollar
WACC	Weighted Average Cost of Capital
WGS	Water Gas Shift
WP	Work Package

EXECUTIVE SUMMARY

South Africa relies heavily on fossil fuels, particularly coal, to drive its economy, which makes the country the 16th largest emitter of greenhouse gases (GHG) in the world as of 2020 (Climate Watch 2023). Green Hydrogen (GH_2) and its derivatives (PtX) can help South Africa defossilise its economy and take advantage of the growing global GH_2 market; and the country has all it takes to play a significant role in the global hydrogen (H_2) economy. South Africa's competitive advantages include its endowment in one of the world's best renewable energy (RE) resources, vast land availability, expertise and experience in liquid hydrocarbon production as well as existence of relevant GH_2- and chemical-related infrastructure.

Since GH_2 will be competing with fossil- and non-fossil-fuel-based alternatives, a price gap analysis was conducted on four H_2 products (green ammonia, GH_2, green methanol and sustainable aviation fuels, (SAF)) covering five most feasible applications (ammonia for export, green fertiliser, marine bunkering, aviation, and green steel). The analysis covered the period up to 2050, assuming the first production in 2025.

Ammonia for export

The estimated cost gap between GH_2- and natural-gas-derived ammonia is at USD 380/tonne in 2025 and USD 78/tonne in 2040. On the other hand, the estimated cost gap between GH_2 and coal-derived ammonia is USD 220/tonne in 2025, which declines gradually to USD 22.5/tonne in 2035. In comparison with coal-derived ammonia, GH_2 cost parity is expected from 2040 onwards, while with natural-gas-derived ammonia the parity is expected from 2045. These estimates are exclusive of carbon tax.

Ammonia based fertilisers

The main used fertilisers in South Africa are Ammonium Nitrate (AN) and urea that, for their production, require ammonia (for both fertilisers) and CO_2 (for urea only). The estimated cost gap between GH_2-derived urea (with an assumed sustainable CO_2 cost of USD 50/tonne) and natural-gas-derived urea in 2025 is USD 252.6/tonne compared to USD 161.8/tonne for coal-derived urea. These gaps are expected to decrease and reach about USD 81/tonne for natural-gas-derived ammonia and zero for coal-derived ammonia by 2040.

In the case of AN, the cost gap in 2025 is estimated at USD 163/tonne between GH_2- and natural-gas-derived AN and USD 95/tonne between GH_2- and coal-derived AN. Like the urea's case, these differences are expected to decline to USD 34/tonne and zero by 2040 for natural gas- and coal-derived AN respectively.

Green Steel

In order to compute the production cost that would occur when using H_2, the H_2 costs associated with three different steel production routes were differentiated. These routes are the Blast Furnace-Basic Oxygen Furnace (BF-BOF), natural-gas-based Direct Reduced Iron-Electric Arc Furnace (DRI-EAF), and GH_2-based DRI-EAF. Assuming no carbon tax, the calculated levelised cost of producing one tonne of steel (energy component only) in 2025 is USD 147/tonne, USD 191/tonne, and USD 366/tonne for the BF-BOF, natural gas-based DRI-EAF, and H_2-based DRI-EAF routes, respectively. The cost is projected to decrease with the reduction in the GH_2 production cost. For example, the cost is estimated to decline to USD 254/tonne by 2040 and to USD 203/tonne by 2050. This shows that with no carbon tax, the cost parity cannot be expected before 2050.

Green methanol for marine bunkering

Green methanol (or e-methanol) is produced using GH_2 and sustainable CO_2, where the production of one tonne of methanol requires approximately 0.188 tonnes of H_2 and 1.373 tonnes of CO_2 (IRENA and MI 2021). The calculated cost of e-methanol in 2025 is USD 1,130/tonne when the carbon cost is USD 300/tonne of CO_2 (obtained from a direct air capture), and USD 786/tonne when the carbon cost is USD 50/tonne CO_2 (from other sources). In both cases, the cost parity is not expected before 2050 without a considerable carbon tax on fossil-fuel-based methanol.

Sustainable aviation fuels

The estimated production cost for SAF in 2025 is approximately USD 2,000/tonne. Compared to the historical jet fuel prices of USD 280-720/tonne for the 2014-2021 period, today's price gap between SAF and fossil-based jet fuel is around USD 1,300 to 1,800/tonne. Though the cost of producing SAF shows a decreasing trend, the price parity is not expected before 2050, unless considerable carbon tax and other incentives are introduced.

Synopsis

The modelling results show that some applications have very little cost gap and can achieve cost parity without the introduction of a carbon tax, while others show huge gaps as presented in the below table.

APPLICATION	2025	2030	2035	2040	2045	2050
Ammonia for export	220-380	115-265	20-100	0-80	0	0
Ammonia for fertiliser (average urea & AN)	128-207	81-144	40-90	16-42	0-18	0
Green steel	175-219	174-129	88-135	52-100	20-68	0-42
Methanol	385-686	269-596	166-466	74-374	0-292	0-170
SAF	1330-1,770	1,023-1,463	716-1,156	481-921	283-723	0-425

As can be seen in the above table, green ammonia (for fertilisers and export) and green steel are the most promising applications that South Africa can focus on in the medium and long term.

As part of the analysis, various alternatives to GH_2/PtX were evaluated for their suitability in different applications such as blue[1] H_2 and batteries. The results revealed that none of these alternatives pose any significant threat to GH_2/PtX in South Africa. While blue H_2 may be relatively cheaper than GH_2 in the short term, GH_2 becomes more competitive in the long run thanks to the expected reduction in its cost. Additionally, the maturity of carbon capture and storage (CCS) technology in the country is still uncertain, making it unsuitable for South Africa at present.

While batteries are often used for mobility, their low energy density makes them unsuitable for long distances. As an alternative, biofuels have been considered. However, they also face significant challenges. A major hurdle is the fact that South Africa is a water-stressed country and producing biofuels on marginal land would require significant amounts of fresh water, which would compete with food crops.

To bridge the existing cost gap between GH_2 products and their fossil-based alternatives, a combination of various mechanisms can be implemented. Key among these include:

- Enforcement of carbon tax on fossil-based products.

[1] Hydrogen produced from SMR or coal gasification with carbon capture and storage (CCS).

- Provision of incentives such as grants, concessional loans, tax credits, loan guarantees, reduced fee to access relevant infrastructure such as transmission lines, gas pipelines, storage facilities.
- Setting up of binding CO_2 reduction targets in key end-use applications, particularly in those applications that are expected to become cost-competitive in the short-run, such as fertiliser and steel production.
- Undertaking of a detailed suitability analysis between GH_2 products and their renewable alternatives beyond the cost gap assessed in this study.

1 INTRODUCTION

South Africa heavily depends on fossil fuels (mainly coal) to fuel its economy, which makes the country the 16th largest emitter of greenhouse gases (GHG) in the world, as of 2020 (Climate Watch 2023). At the national level, Sasol is the second-highest GHG emitter, after Eskom, with its Secunda plant the highest single point source in the world (Centre for Environmental Rights 2019).

Green Hydrogen (GH_2) offers South Africa opportunities to defossilise its economy and benefit from the growing global GH_2 demand by leveraging the country's competitive advantages. South Africa's renewable energy (RE) resources are among the best, and there is land availability as well as the know-how and experience in gas-to-liquids (GTL) and coal-to-liquids (CTL) technologies and infrastructure.

This report is one of several deliverables produced as part of a project entitled "Renewable H_2 market potential and value chain analysis" commissioned by the Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) and implemented by GFA Consulting Group and DNA Economics.

Work Package (WP) 1 of the project seeks to achieve three objectives:

(i) Identify and select South Africa's most feasible applications of GH_2 and PtX.

(ii) Develop a dynamic levelised cost of PtX (LCOX) tool to monitor the development of GH_2/PtX costs.

(iii) Estimate the market potential and value for the selected applications in the medium and long term.

This report provides the results of the competitiveness analysis between GH_2/PtX and their (fossil-fuel-based and renewable) alternatives using the developed LCOX tool.

1.1 Hydrogen production in South Africa

Currently, H_2 is assigned a colour depending on the types of energy sources and technology used to manufacture it. The most common reported colours are black/brown, grey, blue, turquoise, and green. Black and brown H_2 are respectively H_2 produced from the gasification of black and brown coal, while grey H_2 is produced from natural gas via the Steam Methane Reforming (SMR) process – all of which entail the release of carbon dioxide (CO_2) into the atmosphere. When CO_2 from coal gasification or SMR is captured and stored, the resulting H_2 is attributed a blue colour. H_2 is given a turquoise colour if it is produced through methane pyrolysis via a thermal process, whereas a green colour is attributed to H_2 produced via electrolysis of water, using RE.

The production of H_2 in South Africa is estimated between 2-2.4 million tonnes (Mt) per year, equivalent to approximately 2% of global demand (dtic 2022) (GSA 2022). Almost all of this production is used by Sasol in its Fischer-Tropsch (FT) CTL-fuel process that produces synthetic hydrocarbons like methane, diesel, and jet fuel that combines H_2 with CO_2. The Sasol Secunda plant also produces ammonia and other fertilisers.

Black H_2 is produced at Sasol through coal gasification as synthetic gas (syngas), which contains 30-60% CO, 25-30% H_2, 0-5% CH_4, and 5-15% CO_2. The company also produces grey H_2 through SMR of natural gas at its Sasolburg plant. A part of the produced H_2 is used on site and some is sold to a third party. The syngas serves as the feedstock for the FT process (Imasiku, et al. 2021).

Sasol reports that the Secunda plants consumes 33 Mt of coal per year (i.e., 23 million tonnes of oil equivalent, Mtoe), while Sasolburg consumes 1 Mt (i.e., 0.7 Mtoe). Concerning natural gas yearly needs, both plants consume between 100 to 110 billion standard cubic feet (bscf) equivalent to 2.6-2.86 Mtoe per year. About 90% of syngas requirements at Secunda is produced from low-grade coal while the remaining 10% is produced from natural gas. While the low-grade coal is acquired from local mines, the natural gas used as feedstock for both fuels and chemicals manufacturing, as well as for electricity generation, is produced and processed in Mozambique and transported to Secunda via a pipeline (Sasol 2021).

In addition to Sasol, the Petroleum Oil and Gas Corporation of South Africa produces H_2 from natural gas at the company's GTL plant located at Mossel Bay in the Western Cape province. Syngas is created through the SMR method and is further utilised to produce liquid fuels and other hydrocarbon products.

1.2 Climate impact of grey hydrogen production

The production of black and grey H_2 in South Africa generates enormous quantities of GHG emissions, which increase the country's CO_2 footprint. For instance, the production of grey H_2 releases 10 tCO_{2eq}/tH_2 on average, while black/brown H_2 produces about 19 tCO_{2eq}/tH_2 (IEA 2019). With the 2 to 2.4 Mt of H_2 produced in South Africa per year (approx. 90% brown and 10% grey), annual GHG emissions related to H_2 production can be estimated at 36.2-43.4 Mt of CO_{2eq}. These emissions represent about 8-10% of the 442.12 Mt of CO_{2eq} emitted in South Africa in 2020, and 10.4-12.5% of the 348 Mt of CO_{2eq} from combustion activities in the energy sector (DFFE 2022). South Africa has set a target of decreasing its emissions to between 350-420 Mt of CO_{2eq} by 2030 (DSI 2022), and the substitution of black/grey H_2 by GH_2 is viewed as one of viable solutions to meet the country's defossilisation goals.

1.3 Initiatives and future plans

South Africa has already developed plans of action for different sectors to promote the GH_2 economy in the country. According to the Hydrogen Society Roadmap (HSRM), for instance, transport as well as energy intensive and power sectors are targeted for national defossilisation, while GH_2 export and local manufacturing of GH_2 and fuel-cell-related equipment and components are being promoted to strengthen defossilisation (DSI 2022).

In line with the efforts to reduce GHG emissions in the mobility sector, initial interventions are targeting road transport as it is responsible for most of the transport sector emissions. Here, the use of GH_2 to fuel heavy-duty vehicles and buses might play a considerable role (dtic 2022). The mobility sector presents numerous other GH_2 opportunities, such as its use in mining trucks, forklifts in port areas, public buses in metropolitan areas, as well as in port berthing activities.

The petrochemicals and chemicals sector, mining, manufacturing, construction, minerals, and metals production, contribute roughly 25% of South Africa's total GHG emissions. More than half of these emissions come from the petrochemicals and chemicals sector (dtic 2022). GH_2/PtX could potentially contribute to the defossilisation of this sector (which is responsible for 13% of GHG emissions) by substituting black/grey H_2 with GH_2 in different industrial processes, including FT processes, ammonia production and desulphurisation of oil products in oil refineries. By doing so, South Africa could become one of the leading producers of green fuels and green chemicals, for both domestic and export markets. The HSRM recommends an initial focus on the steel, mining, chemicals, refineries, and cement sectors, as collectively they are major industrial energy consumers.

To kickstart the GH_2 economy, several promising pilot projects have been identified in the industrial sector, particularly in ammonia and chemicals. These include initiatives such as Sasol's plan to produce green ammonia. Additionally, the production of green steel is a top priority for the country, with a potential opportunity to pilot this at Arcelor Mittal's Saldanha Bay site. Furthermore, the government is keen to decrease emissions in the paper and pulp sector by switching from natural gas to RE and GH_2-based fuels.

Electricity production in South Africa is responsible for approximately 40% of the total GHG emissions (Centre for Environmental Rights 2019). However, GH_2 may potentially contribute to a more sustainable and efficient power sector by offering RE storage and green power to the primary electricity grid, which can enhance overall grid stability. Moreover, H_2 can be used in micro grids to provide backup power, to power information and communication applications, and to supply electricity and heat to commercial and public buildings and residential areas, including remote locations and islands (both on and off grid).

Although H_2 can technically be used in all the above-mentioned applications, it does not suit all of them everywhere. Due to round-trip efficiency of GH_2/PtX and resulting costs, for instance, it may be relevant to use green ammonia in coal-fired power plants in one country (e.g., PtX importing countries) and not in another (e.g., PtX producing countries). Similarly, battery energy storage systems may be the most cost-effective power backup option compared to H_2 storage. Electric heaters may also compete with GH_2, and the choice of one option over the other depends on various factors, including existing infrastructure, available RE resources as well as the overall supply cost. Therefore, the relevance of GH_2/PtX use for each application should be evaluated on a case-by-case basis by considering available and possible alternatives.

2 GREEN HYDROGEN APPLICATIONS IN SOUTH AFRICA

H_2 can be used as energy carrier and industrial feedstock in a range of applications across all sectors of economy, including heavy and light industry, the power sector, mobility, and buildings, and to cover the end-use energy needs and process feedstocks.

To identify the most relevant PtX applications in South Africa, four consecutive steps were followed, as illustrated in the figure below.

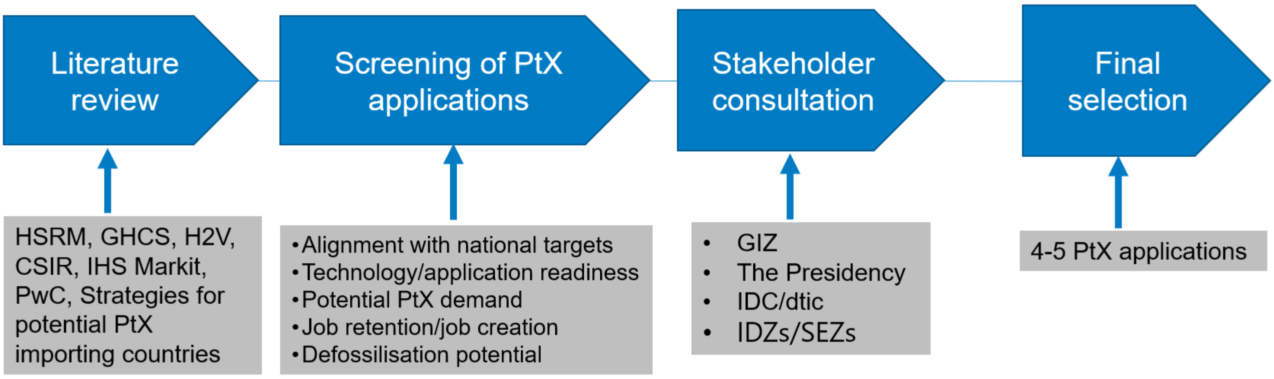


Figure 1: Selection process of the most feasible PtX applications in South Africa

2.1 Literature review and data collection

The first step was to conduct a desktop literature review of publicly available research and documentation related to South Africa's GH_2 economy, both for local applications and export.

Key reviewed documents include:

- Hydrogen Society Roadmap (HSRM)
- South Africa Hydrogen Valley (H_2V)
- Green Hydrogen Commercialisation Strategy (GHCS)
- Powerfuels and GH_2 study
- A Super H_2igh Road Scenario for South Africa
- Unlocking South Africa's Hydrogen Potential
- Country strategies of identified PtX importing countries, namely EU, Germany, Japan

The review of the above documents identified several PtX industrial opportunities for South Africa, and the below table presents the main applications for the three identified markets: domestic, border[2] and export.

[2] Border market: refueling aviation and shipping at the country's borders.

Table 1: Potential GH_2/PtX applications in South Africa

PTX PRODUCT	APPLICATION		USE	MARKET
Ammonia	1	Energy carrier	Energy carrier	Export
	2	Fertiliser production	Feedstock	Domestic
	3	Marine bunkering	Fuel	Border market
Hydrogen	4	Cement	Fuel	Domestic
	5	Green steel	Feedstock	Domestic
	6	HFC*-powered long-haul trucks	Fuel	Domestic
	7	HFC-powered mining trucks	Fuel	Domestic
	8	HFC-powered urban bus	Fuel	Domestic
	9	Power-to-power	Fuel	Domestic
	10	Refineries	Feedstock	Domestic
	11	Production of food & beverages	Feedstock	Domestic
	12	Heating	Fuel	Domestic
Jet fuels (SAF**)	13	Aviation	Fuel	Domestic, border and export
Methanol	14	Energy carrier	Energy carrier	Export
	15	Marine bunkering	Fuel	Border market

*HFC: hydrogen fuel cell; **SAF: sustainable aviation fuel

The literature review also benefited from a "Project Mapping" activity conducted in the framework of the "Renewable H_2 market potential and value chain analysis", which identified over 100 PtX-related projects and initiatives at different stages of development, including initiatives (40), proposal seeking funding (39), early stages (9), fully funded, awaiting kick-off (4), in construction (6), and in operation(22).

These projects and initiatives cover multiple PtX applications (aviation, maritime, mining, steel, stationary power generation, transport, chemicals, etc.) across the PtX value chain, including equipment manufacturing (mainly electrolysers and fuel cells), RE generation (including electricity grid and infrastructure), GH_2 production, compression, conversion and storage, transport and logistics, and end-use markets.

2.2 Screening of the most relevant PtX applications

South Africa's energy-intensive industrial and manufacturing base, coupled with its high potential to develop an export market, means that the country is spoilt for choice when it comes to the number of PtX applications (see Table 1). Since this study could not assess all the identified potential applications, five of them were prioritised through a screening process, which applied the following criteria.

2.2.1 Alignment with the national targets

This criterion evaluated the country's ambitions and strategic targets, as stipulated in the HSRM and GHCS.

The HRSM defines six priority GH_2 focus areas:

- Defossilisation of transport sectors.
- Defossilisation of energy-intensive industry.
- Creation of an export market for South African hydrogen.
- Centre of excellence in manufacturing for H_2 products and fuel cell components.
- Green and enhanced power sector.
- Hydrogen generation, storage and distribution.

Building on the HSRM, the GHCS formulates six key elements necessary for the successful development of GH_2 in South Africa:

- Export Markets – to secure long-term global market share and competitive trade position.
- Domestic Markets – to stimulate and increase domestic GH_2 demand.
- Investment and Finance – to encourage foreign direct investment and low-cost green finance.
- Economic and socio-economic development – to ensure South Africa's defossilisation targets.
- Local industrial capability and participation – to promote localisation.
- Ensuring a Just Transition – to minimise socioeconomic benefits and minimise negative impacts.

2.2.2 Technology/application readiness in South Africa

While some PtX producers and/or users will need to modify or completely change parts of their production/consumption chains, various applications such as ammonia production, steel making, oil refineries, etc. could switch to PtX products with considerably less effort and cost. These applications could be early PtX adopters and can serve as examples for new applications. For instance, different GTL and CTL synfuel facilities have been in operation for decades in South Africa and, they could be repurposed to produce PtX.

2.2.3 Potential PtX demand

Every application must provide economic and social benefits to South Africa, and this can only be realised if there is a market (domestic and/or border and/or export) for such application. Achieving the required economies of scale will further reduce production costs and ensure South Africa achieves a leading position. In addition to the national demand, several potential importing countries/regions (e.g., Germany, Japan and the EU) are willing to pay "green" premiums for PtX products to support the market ramp-up for PtX products and to achieve their defossilisation strategies and targets.

2.2.4 Potential job retention and job creation

Job retention is a high priority of the energy transition. It is, therefore, a fundamental requirement that, in addition to creating more jobs, the selected applications have the potential to retain/shift jobs by either directly employing the same personnel from the replaced technology or by re-skilling them to qualify for the new technology.

2.2.5 Defossilisation potential

While direct electrification with RE sources can significantly support the energy transition, some sectors and industries such as steel, cement, chemicals, long-haul road transport, maritime shipping, aviation, chemical feedstock and mining (referred to as "hard-to-defossilise sectors") cannot easily make the switch to RE or use battery storage. This criterion looks into the capability of the application to defossilise such sectors, which in return would allow South Africa to achieve it emission reduction targets.

Based on the five selection criteria described above, the highest ranked applications are ammonia for export, green steel, green fertiliser, SAF and mining trucks.

2.3 Stakeholder consultation

To ensure that the proposed applications reflect the goals, expectations, and priorities of the affected actors, the selected applications were presented to relevant stakeholders. The presentation was done via an online MS Teams meeting held on 3 April 2023. It involved over 40 participants from various institutions, including ArcellorMittal, Bus Manufacturing (BusMark), the Department of Mineral Resources and Energy (DMRE), the Department of Science and Innovation (DSI), Engie, Freeport Saldanha, German Energy Solutions, GIZ Hydrox Holdings, Industrial Development Corporation (IDC), Juniper Globe, Liabele Energy, Mainstream Energy, NRGeneration, South Africa Wind Energy Association (SAWEA), Thyssen Krupp, Isithelo (mining), and the University of Cape Town.

Participants endorsed four of the five proposed applications (i.e., ammonia for export and marine bunkering, aviation, green fertiliser, and green steel), and recommended to substitute "mining trucks" with green methanol. This was due to the fact that South Africa has all the inputs to develop large quantities of methanol competitively and it also has the world's largest pure carbon source (Secunda), which should meet international requirements at least by 2036 in accordance with Annex I of Directive 2003/87/EC (EC 2003).

A short description of the selected applications is provided below.

Aviation fuels

The demand for SAF is rising worldwide and South Africa's world leading FT technology and expertise provide the country with a competitive advantage in the production of liquid fuels based on the H_2-production route, along with its existing CTL and GTL infrastructure.

Green ammonia for export

Ammonia is the most promising H_2 carrier, with a much higher energy density per unit volume than compressed and liquid H_2, which makes it the most appropriate carrier for GH_2 export. Ammonia is already a well-established internationally traded commodity, and entities like Germany, Japan, and the EU have expressed their interest to import ammonia. This presents huge opportunities for South Africa, in general, and the country's enterprises, in particular.

Green fertiliser

Ammonia is the main source of nitrogen-based fertilisers, including urea, AN and ammonium sulphate. To manufacture ammonia in South Africa, H_2 is obtained by coal gasification and SMR. GH_2 can replace this fossil-fuel-based H_2 thereby reducing GHG emissions from the agricultural sector and increasing the competitiveness of South African agricultural products on the international market.

Green steel

Steelmaking operations that use iron ore and blast furnace technology (the coal-based technology) can be replaced by GH_2 to defossilise the product. Since ArcelorMittal SSA accounts for over 75% of domestic steel production and 100% of the virgin iron ore production (SAIIA 2022), the defossilisation of this industry relies within the hands of ArcelorMittal.

Methanol

The chemical industry relies heavily on methanol as a primary product for creating other chemicals like formaldehyde, acetic acid, and plastics. Today's methanol supply is primarily sourced from fossil fuels such as natural gas or coal. However, there is a growing interest in developing renewable methanol to combat climate change, by reducing or eliminating CO_2 emissions. Methanol with lower emissions could prove beneficial in defossilising certain industries, particularly as a feedstock in chemical production or as fuel for road and marine transportation.

Apart from the above five applications, power-to-power (including gas turbines) and H_2 applications in refineries are also relevant applications (low hanging fruit); however, these two applications face a number of barriers. Concerning refineries, the current legislation in South Africa limits sulphur content in diesel to 500 ppm (0.05% sulphur content), meaning that South African refineries can easily meet this requirement without the use of GH_2 compared to the European standard "Euro 5", which limits sulphur content in diesel to 10 ppm or 0.001 % sulphur content (Roos, et al. 2022). As for the power-to-power application, the round-trip efficiency is still a limiting factor for uptake, and the use of GH_2 as a means to store curtailed/surplus RE cannot be expected before 2030 (DTIC 2022). Other promising applications include power-to-mobility (long-haul trucks, mining trucks, and powered urban buses). All these applications were not analysed in the framework of the study since they were not regarded by the stakeholders as the Top 5 most feasible GH_2/PtX applications in South Africa.

3 ANALYSIS OF FOSSIL-FUEL-BASED HYDROGEN

Over 62% of today's supplied H_2 is produced from natural gas, 19% from coal, and 18% as a by-product obtained in facilities designed primarily for other products (mainly refineries); whilst only 1% is shared between blue H_2 and H_2 from water electrolysis (IEA 2022). The most commonly used method to produce H_2 from natural gas is through natural gas reforming.

3.1 Analysis of Steam Methane Reforming technology

SMR involves using water as an oxidant to extract H_2 from natural gas, as well as from liquefied petroleum gas (LPG) and naphtha, albeit less frequently. In SMR, a synthesis gas, made mostly of carbon monoxide (CO) and H_2, is formed and then converted to H_2 and CO_2 (IEA 2019).

The SMR process consists of the following two steps:

1. The process of transforming natural gas that involves the reaction of methane with steam (water gas shift process) at temperatures between 750-800°C that gives a gas mixture known as synthesis gas, or syngas. This mixture mainly comprises of H_2 and CO (NYSERDA 2019) according to the following equation.

$$CH_4 + H_2O \text{ (+ heat)} \rightarrow CO + 3H_2$$

2. In the second step, referred to as the (WGS) reaction, the CO produced in the previous step reacts with steam, using a catalyst to produce H_2 and CO_2. This process takes place in two stages: the high temperature shift (HTS) at 350ºC and the low temperature shift (LTS) at 190-210ºC (NYSERDA 2019).

$$CO + H_2O \rightarrow CO_2 + H_2 \text{ (+ small amount of heat)}$$

When H_2 is produced through the SMR process, it may contain impurities such as CO, CO_2, and H_2 sulphide (H_2S). To ensure its quality, the H_2 may require further purification. The purification process involves two primary steps: feedstock purification and product purification. The former removes poisons, such as sulphur and chloride, to prolong the life of downstream steam reforming and other catalysts. The latter involves removing CO_2 through a liquid absorption system and using a methanation step to eliminate residual traces of CO_2. More advanced SMR plants use a pressure swing absorption (PSA) unit to produce 99.99% pure H_2 (NYSERDA 2019).

The industrial practice of SMR of natural gas is prevalent nowadays. H_2 is produced through the SMR process in massive centralised industrial plants, serving various purposes such as chemical manufacturing and petroleum refining. Though only a handful of vendors presently provide small-scale SMR technologies, these are essential for decentralised H_2 production and delivery infrastructure.

The process of SMR of natural gas is highly efficient, cost-effective and widely utilised for H_2 production, thus ensuring energy security in the short and medium term. This method also emits less pollution compared to coal gasification. Currently, steam reforming has one of the highest production efficiencies, which range from 65% to 87% among commercially available methods. Natural gas, with its high H_2-to-carbon ratio, is a convenient and easy-to-handle feedstock for H_2 production (IEAGHG 2007).

3.2 Grey hydrogen production cost in South Africa

The cost of grey H_2 production varies from one region to another and is influenced by various technical and economic factors, with gas prices and capital expenditure (CAPEX) being the two most important (IEA 2019) variables. As shown in the figure below, the fuel costs are the largest cost component in all regions and account for between 45% and 75% of production costs.

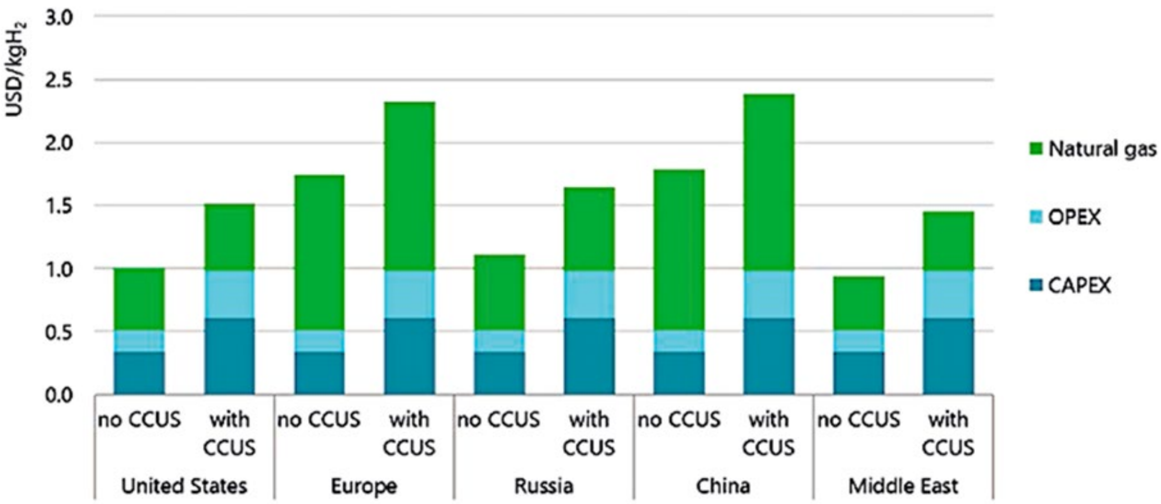


Figure 2: Hydrogen production costs using natural gas in different regions

To estimate H_2 production cost of SMR-produced H_2 known as the "levelised cost of H_2 (LCOH)," [3] it is essential to consider three primary cost components: CAPEX, operating expenditures (OPEX), and fuel costs. In this, the fuel cost, which is the cost of natural gas used for producing grey H_2 through SMR technology, is a crucial element.

The cost of grey H_2 production depends primarily on the volume of natural gas consumed and its price. In order to estimate the LCOH, a high-level computation tool was developed in excel to calculate LCOH for black, grey and green H_2 as well as for the levelised cost of ammonia, methanol and SAS based on the below general equation.

$$LCOH = \frac{C_o * CRF + O}{8760 * C_f} + f * h + V = \frac{C_o * \frac{i * (1+i)^n}{(1+i)^n - 1} + O}{8760 * C_f} + f * h + V$$

Where:

- C_o is the overnight capital cost
- CRT is the capital recovery factor
- O is the fixed operating cost
- f is the fuel cost
- h is the heat rate
- C_f is the capacity factor (or load factor)
- V is the variable operating cost$i$ is the interest/discount rate
- n is the number of payments made to repay capital (usually assumed equal to the project lifetime).

[3] LCOH is the average cost per kg (in discounted real terms) of building and operating H_2 generation assets over the project lifetime.

The term $C.(1+i)^n$ expresses the future cost of the plant based on an assumed discount rate, while the term $\frac{i}{(1+i)^n-1}$ subdivides the future cost into equal annual costs over the lifetime of the plant.

Most of the input data and assumptions used for the calculation of the LCOH for grey H_2 (see the below table) were taken from the IEA's report "IEA G20 Hydrogen report: Assumptions" (IEA 2020b) complemented with additional information on South Africa.

Table 2: Assumption for grey hydrogen production costs

PARAMETER	UNIT	ASSUMPTION
CAPEX	USD/kW_{H2}	910
OPEX	% of CAPEX	4.7
Efficiency	%	76
Lifetime	Years	25
Plant load factor	%	95
Natural gas (NG) cost	USD/GJ (Gigajoule)	3.09
Discount rate	%	8
Carbon Emission Factor	kg_{CO2}/kg_{H2}	9

Figure 3 shows different LCOH cost components for grey H_2 in South Africa, where the fuel cost makes up 48% of the total LCOH, followed by CAPEX which accounts for 35% of the cost, and OPEX which accounts for 17%. It is important to note that no carbon cost was factored into this calculation, as the effective carbon cost level will be determined later in the report.

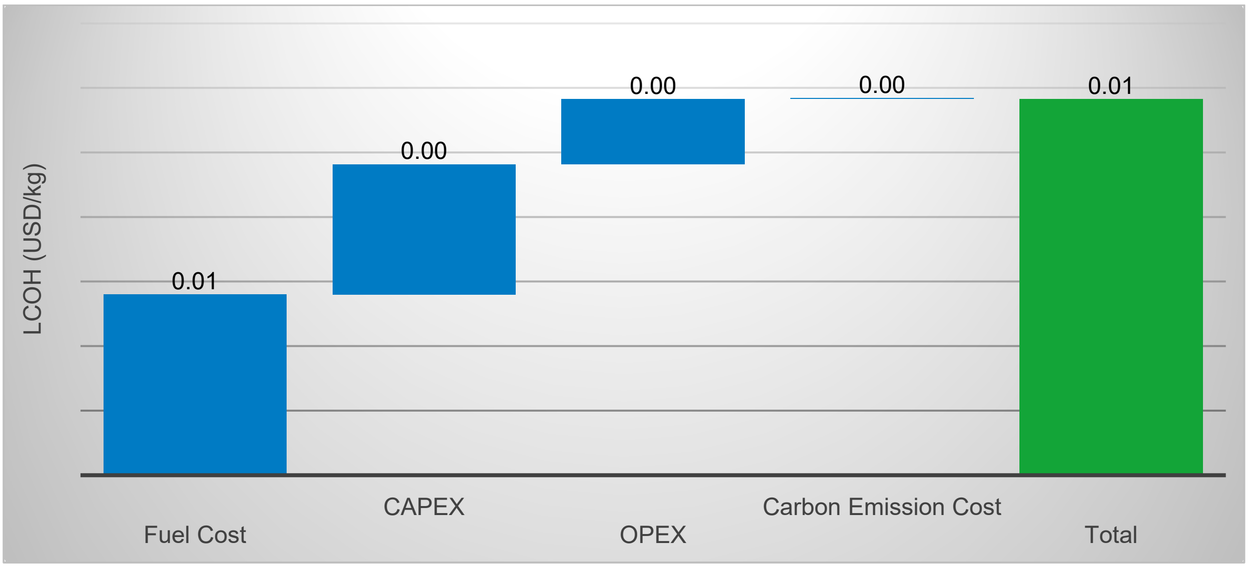


Figure 3: LCOH cost elements for grey H_2 in South Africa

3.3 Analysis of coal gasification technology

Gasification is a fundamental technology that converts coal into various forms besides electricity, and it has the potential to be cost-effective in that sector as well. Gasification plays a vital role in transforming coal into H_2, synthetic natural gas (SNG), liquid fuels, etc.

The process of producing H_2 through the gasification of coal has been a long-standing and widely used technology in the chemical and fertiliser industries. This method, particularly prevalent in China, has led to the operation of approximately 130 coal gasification plants globally, with over 80% of them located in China. It is worth noting that H_2 production through coal gasification results in CO_2 emissions of about 19-20 tCO_2/tH_2, which is almost twice as much as the emissions produced by SMR technology (IEA 2019).

Gasification is a technology that transforms carbon-containing materials, such as coal, into synthesis gas. This process involves the reaction of carbon with steam and oxygen at high pressure (usually over 30 bar) and temperatures of up to 1,500 K. The result is a raw synthesis gas, or syngas, composed mainly of CO and H_2, with some minor by-products (Breault 2010). The by-products are eliminated to produce a clean syngas that can be utilised as a fuel for generating electricity or steam, as a fundamental chemical building block for numerous applications in the petrochemical and refining industries, and for the production of H_2. Gasification is an effective way to add value to low- or negative-value feedstocks by transforming them into valuable fuels and products There are more than 10 major gasifier concepts that are offered by various supplier (e.g., GE, Shell, Siemens, etc.). Each gasifier has different configurations, such as refractory lined, slurry fired, etc (Breault 2010).

3.4 Cost of hydrogen from coal gasification

Similar to SMR, three cost components determine the cost of H_2 produced from coal gasification. However, CAPEX in coal gasification is the largest contributor to the total LCOH (IEA 2019). The coal gasification plant has several ancillary systems such as a coal grinding system, gasifier coal injection system, and gasifier slag/ash removal system. All of these systems drive up the capital cost. To calculate the LCOH for black H_2, the same model mentioned earlier was used and the main input data and assumptions (see the below table) were extracted from IIEA (2020b).

Table 3: Assumption for black hydrogen production costs

PARAMETER	UNIT	ASSUMPTION
CAPEX	USD/kW_{H2}	2,670
OPEX	% of CAPEX	5
Efficiency (HHV)	%	60
Lifetime	Years	25
Plant Load factor	%	95
coal cost	USD/tonne	20
Coal heating value	kWh/kg	5.6
Weighted average cost of capital (WACC)	%	8
Carbon Emission Factor	kg_{CO2}/kg_{H2}	20

These assumptions were cross checked with other literature, and no significant discrepancies were found.

As show in Figure 4, the coal gasification LCOH is estimated at USD 2.05/kg H_2 with CAPEX representing more than 50% of the total costs followed by OPEX and then fuel cost.

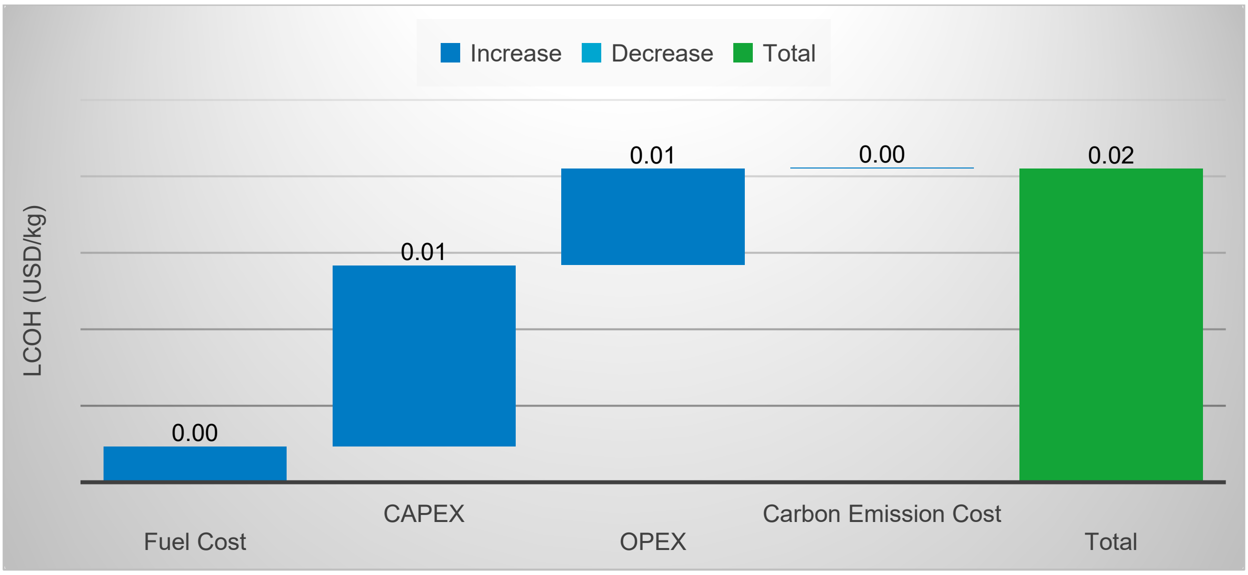


Figure 4: Cost components for hydrogen production from coal

4 GREEN HYDROGEN PRODUCTION COST

In the previous chapter, the production cost of H_2 from natural gas using SMR and coal gasification technologies were estimated. This chapter estimates the LCOH for H_2 produced from water electrolysis.

4.1 Hydrogen production from water electrolysis

Water electrolysis is the process used to produce H_2 by splitting water into H_2 and oxygen (O_2). Several types of electrolysers are available on the market, of which the main electrolyser technologies include alkaline, Proton Exchange Membrane (PEM), and Solid Oxide electrolysis cells (SOECs). Several technical and economic factors influence water electrolysis LCOH, and these include plant CAPEX and efficiency, RE cost, and annual capacity factor or operating hours.

To compute water electrolysis LCOH, the model mentioned in the previous section was used. Input data and assumptions were collected from various sources such the International Renewable Energy Agency (IRENA), IEA, interviews, and scientific papers. The table below shows the most critical assumptions and the assumption source with justification if applied.

Table 4: Assumptions used in green hydrogen model

PARAMETER	UNIT	VALUE	SOURCE/NOTES
Technology Used		Alkaline	Lower cost, longer service life
System efficiency (HHV)	%	70%	IRENA 2020
System efficiency decline	%/year	0.50%	Manufacturer data sheet
Capacity factor	%	60%	Thomas H. Roos 2021, estimated for hybrid PV/Wind
Stack Lifetime	Hours	70,000	IEA 2019
Hydrogen HHV	kWh/Kg	39.4	
Electricity cost	USD/MWh	35.71	Thomas H. Roos 2021
Hydrogen Production System CAPEX	USD/KW	700	IEA 2019 & IRENA 2020
Annual Hydrogen plant OPEX	% of CAPEX	1.50%	IEA 2019
Electrolyser Stack cost percentage from CAPEX	%	45%	IRENA 2020
Discount rate	%	8%	Estimated

For future LCOH estimates, three main factors are expected to drive the LCOH, mainly the electrolyser stack efficiency which is expected to reach over 80% in the long term (by 2050), the system CAPEX that is expected to plummet down under USD 200/kW_{el}, and the RE cost that is expected to decrease as a result of the advancements in technology (IRENA 2020).

The following table summarises the assumptions used to calculate the LCOH in 2030, 2040, and 2050. The assumptions were collected from different sources.

Table 5: Assumption to calculate GH_2

PARAMETER	2030	2040	2050
Electricity (USD/MWh)	33.0	24.0	22.0
CAPEX (USD/kW)	700	600	400
Efficiency (%)	70%	76%	82%

4.2 Simulation results

Based on the above data and assumptions, the analysis of the simulation results reveals that today's LCOH is estimated at USD 3.27/kg H_2, which is comparable to existing studies such as the study "*The cost of production and storage of renewable hydrogen in South Africa and transport to Japan and EU up to 2050 under different scenarios*" by Ross (2021).

As shown in Figure 5, electricity cost represents 63% of the total LCOH, followed by CAPEX with 19%, the financing with 9%, and maintenance with 7%. As expected, water cost represents a minor contribution with 2%.

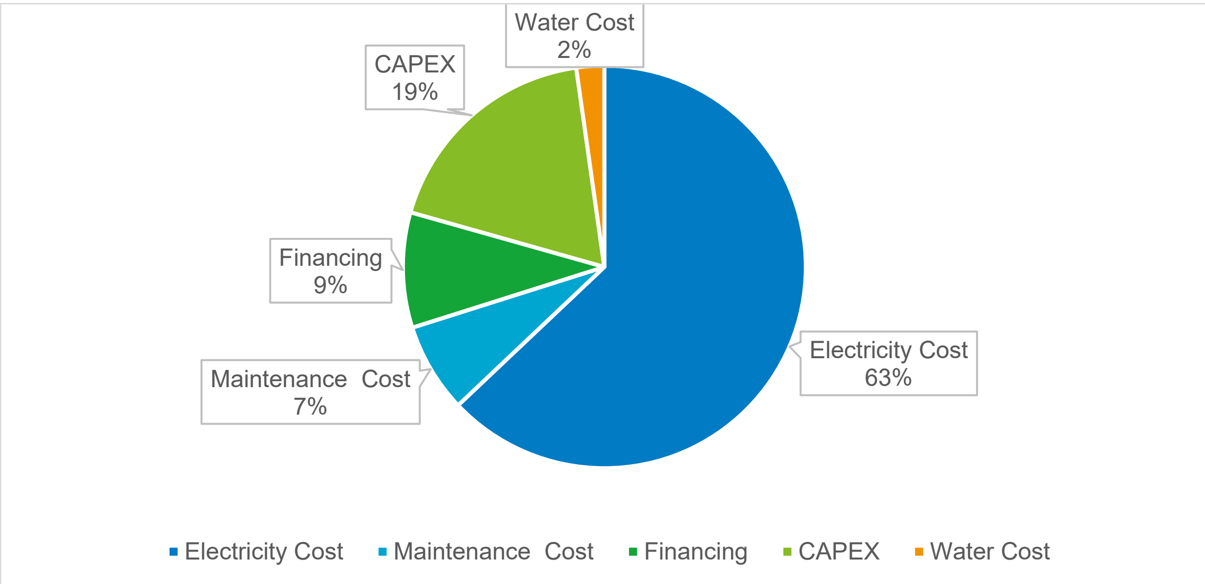


Figure 5: Production costs components for green hydrogen

LCOH is expected to drop to USD 2.7/kgH_2 by 2030, to USD 1.79/kgH_2 by 2040 and to USD 0.83/kgH_2 by 2050. These results indicates that in 2030, the LCOH of GH_2 will be nearly equal to the LCOH of black H_2 produced in South Africa without taking into account the carbon emission tax.

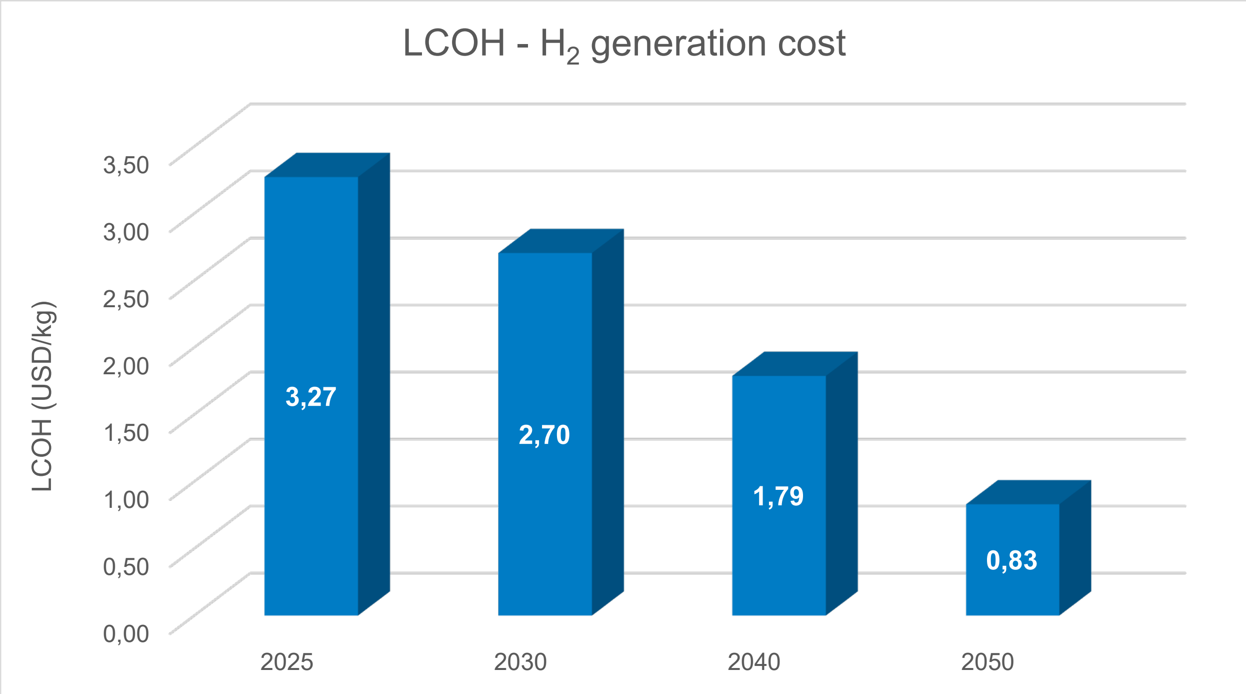


Figure 6: Expected production costs in 2030, 2040 and 2050

5 COMPETITIVENESS ANALYSIS

This chapter assesses the competitiveness (cost gap) between GH_2/PtX and their fossil fuel-based counterparts since the offtake GH_2 and PtX will be driven by their supply costs.

5.1 Ammonia for export

Thanks to the Haber-Bosch process developed by Fritz Haber and Carl Bosch in 1909, ammonia can be produced on a large scale and used in the manufacture of fertilisers. Nowadays, conventional Haber Bosch plants produce ammonia using natural gas (50%), oil (31%), and coal (19%) as feedstock (Smith, K. Hill and Torrente-Murciano 2020). The Haber Bosch process is essential to the future of the chemical industry, but sustainability requires the fossil-fuel-based ammonia to be substituted by green or renewable ammonia. To synthetise green ammonia, GH_2 is combined with nitrogen (N_2) using a Haber-Bosch process, where the ammonia plant and the air separation unit (ASU) supplying nitrogen are both powered by a RE source.

To calculate the cost gap between black/grey and green ammonia, the model used to estimate LCOH was extended to also estimate the levelised cost of Ammonia (LCOA). The input data in the below table was used to calculate the LCOA.

Table 6: Assumption for LCOA calculation

PARAMETER	UNIT	VALUE	NOTES/REFERENCE
Electricity consumption	MWh/t_{NH3}	11	(IEA 2020b)
Capacity factor	%	90%	Estimated
CAPEX	USD/t_{NH3}	2360	(IEA 2020b)
OPEX	% of CAPEX	3%	(IEA 2020b)
Electricity cost	USD/MWh	35.71 in 2025 and 10 in 2050	Thomas H. Roos 2021
H_2 weight % in Ammonia	%	11%	

The cost gap between green and grey ammonia, and black and green ammonia are respectively shown in Figure 7 and Figure 8 below.

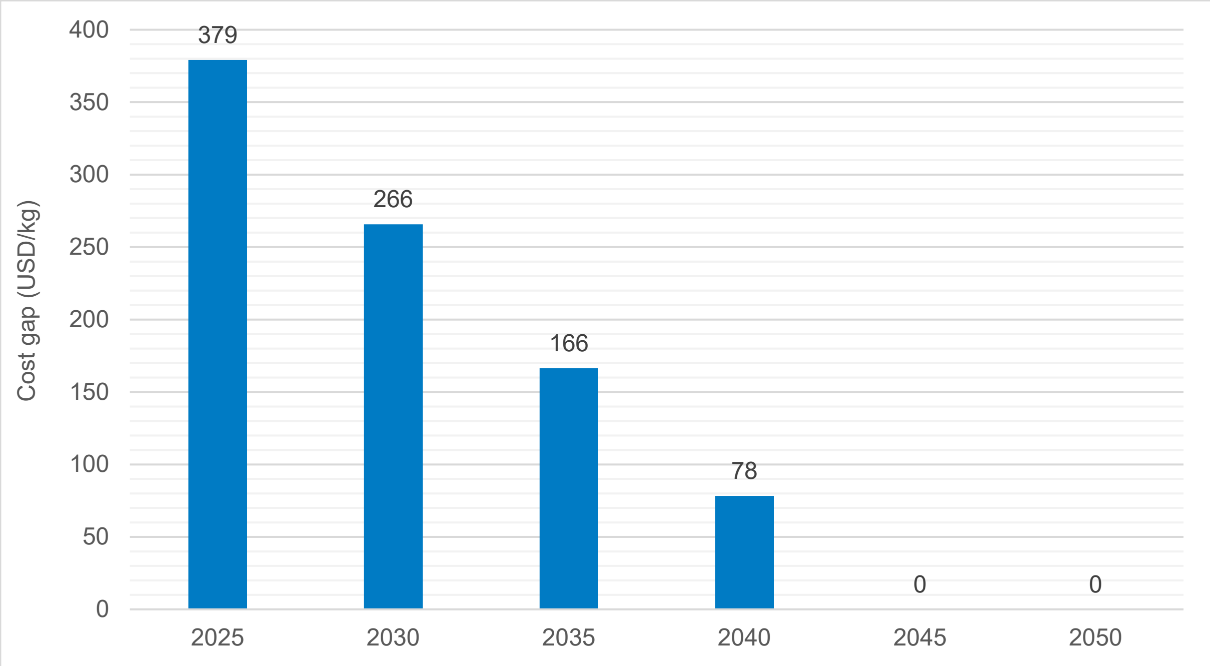


Figure 7: Cost gap for green ammonia vs grey ammonia

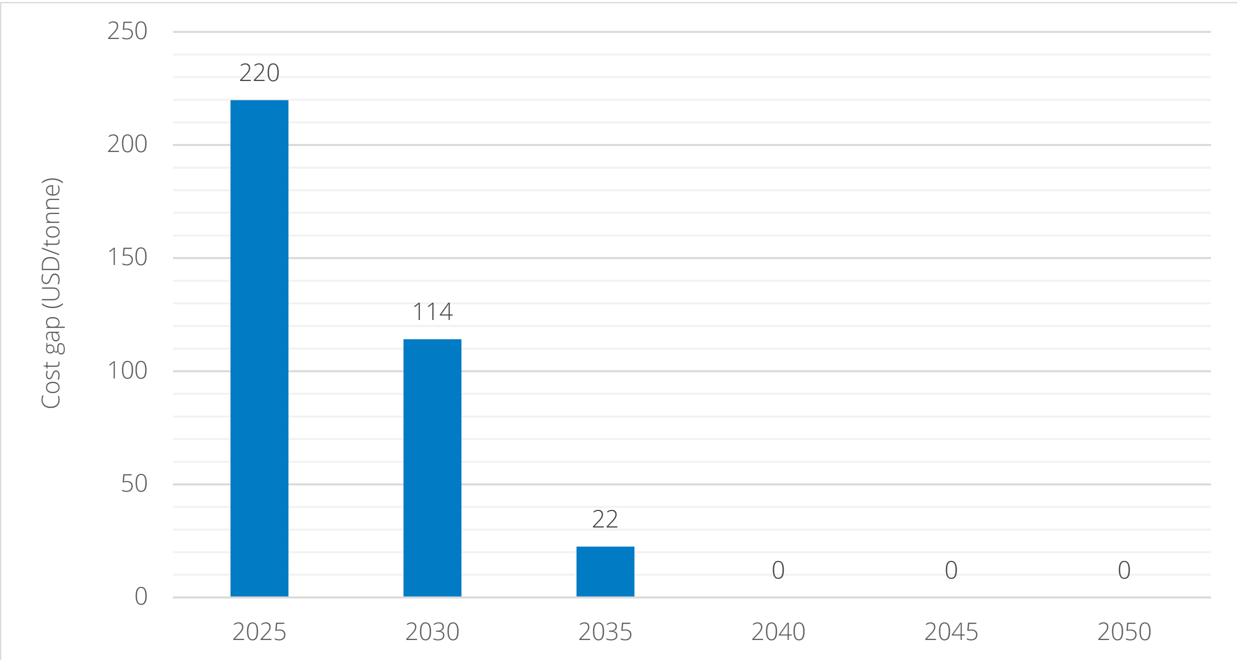


Figure 8: Cost gap for green ammonia vs brown ammonia

As shown in Figure 7, the price gap between green and grey ammonia is estimated at USD 380/tonne in 2025 and USD 78/tonne in 2040. For green and brown ammonia, the cost gap is estimated at USD 220/tonne in 2025 and 22.5 in 2035 (see Figure 8). These ammonia production costs are exclusive of carbon tax.

Under this assumption, the cost parity is projected to be achieve from 2045 onwards for green vs grey (Figure 7) and from 2040 onwards for green vs brown ammonia (Figure 8). The cost gap could be reduced, and the price parity could be achieved earlier if a carbon tax is considered, as discussed in Chapter 6.

5.2 Ammonia for fertiliser production

In South Africa, the use of fertilisers only accounts for 0.5% of the global total (DAFF 2020). The evolution of the usage of fertilisers in the country between 2010-2019 is shown in Figure 9.

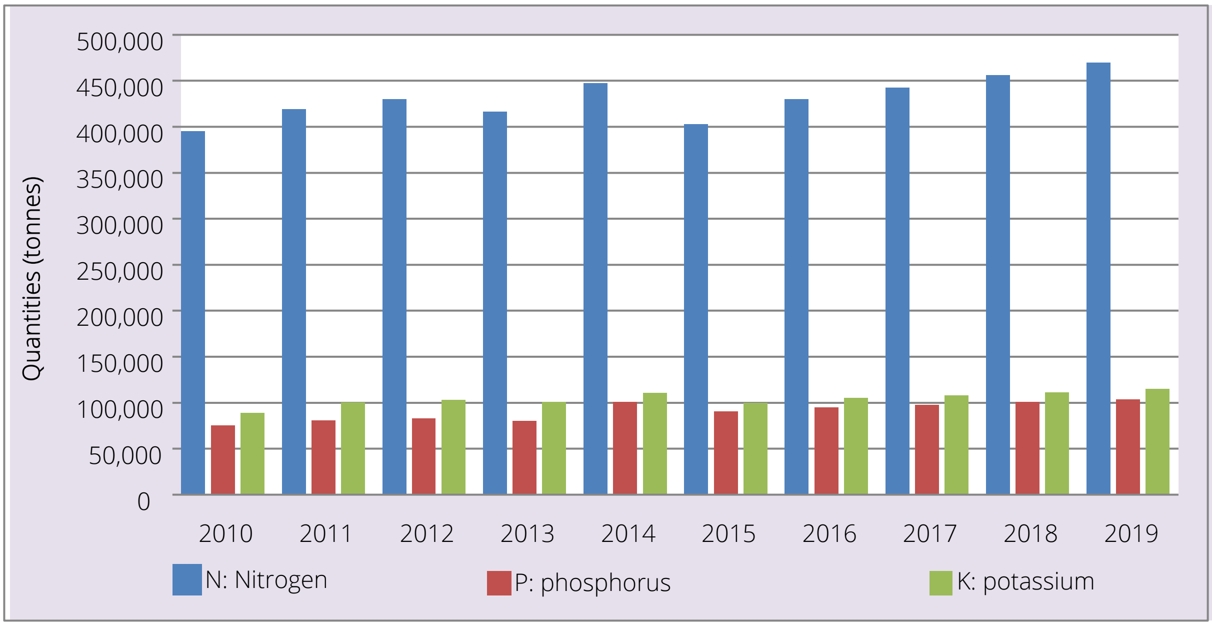
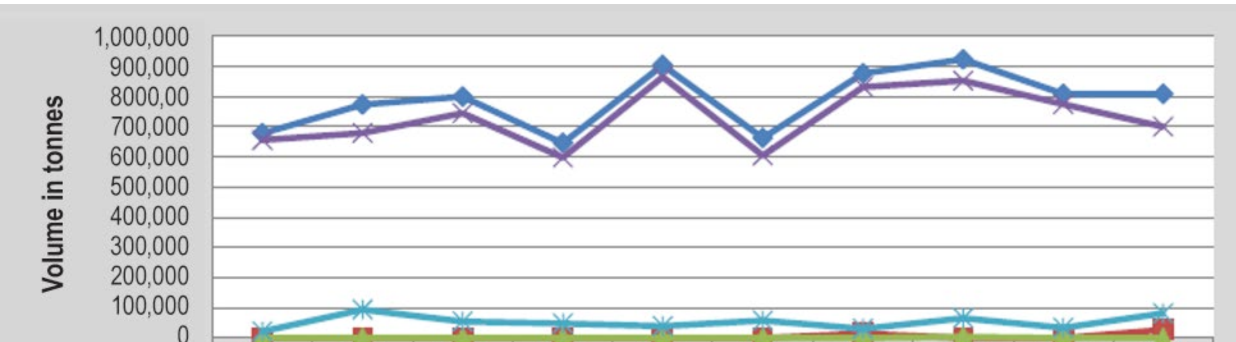


Figure 9: Fertiliser consumption in South Africa during the period 2010-2019

Source: DAFF (2020)

The above figure shows that nitrogen-based fertilisers were consistently the most utilised throughout the period, followed by potassium and phosphorus. It also shows that the consumption of fertilisers in South Africa remained relatively stable during the 10-year time period. Domestic demand for phosphorus and potassium fertilisers was low, averaging 100,000 tonnes per year. However, during the 2019 season, there was a slight increase in the consumption of nitrogen, phosphorus, and potassium (NPK) fertilisers, with all NPK fertilisers seeing a 3% rise in consumption compared to the 2018 season (DAFF 2020).

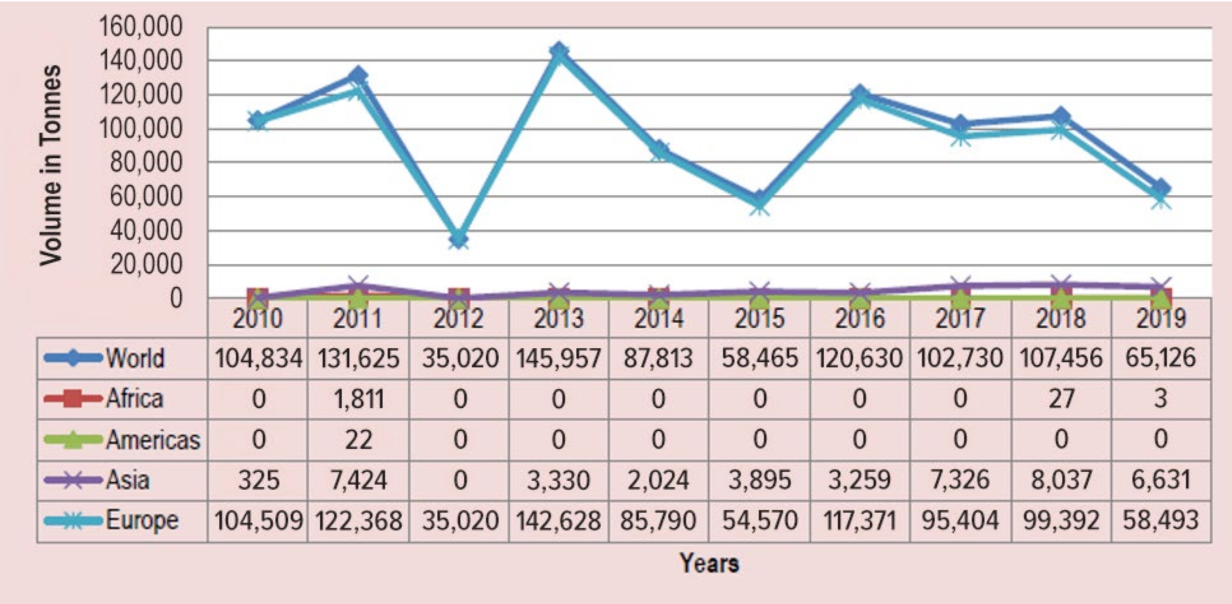
Nitrogen fertilisers are essential for South Africa's agriculture, with urea and AN being the most important among them. In 2019, South Africa imported 809,067 tonnes of urea and 65,126 tonnes for AN. However, the imports for AN have fluctuated between 2010-2019, with the highest peak being 145,957 in 2013. **Error! Reference source not found.** and **Error! Reference source not found.** depict the imports of urea and AN in South Africa between 2010-2019.



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
World	678,981	773,938	800,821	646,071	905,000	662,789	877,638	923,762	808,632	809,067
Africa	144	63	65	0	32	151	15,015	0	1	27,233
Americas	152	95	125	174	18	36	42	4,063	39	14
Asia	656,694	679,573	745,813	598,290	865,600	604,431	831,759	853,454	775,219	700,137
Europe	21,951	94,207	54,818	47,606	39,308	58,170	30,822	66,246	33,337	81,683

Figure 10: Urea imports into South Africa

Source: DAFF (2020).



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
World	104,834	131,625	35,020	145,957	87,813	58,465	120,630	102,730	107,456	65,126
Africa	0	1,811	0	0	0	0	0	0	27	3
Americas	0	22	0	0	0	0	0	0	0	0
Asia	325	7,424	0	3,330	2,024	3,895	3,259	7,326	8,037	6,631
Europe	104,509	122,368	35,020	142,628	85,790	54,570	117,371	95,404	99,392	58,493

Figure 11: Ammonium Nitrate (AN) imports into South Africa

Source: DAFF (2020)

The production of urea and AN relies heavily on ammonia in the case of AN and ammonia and CO_2 in the case of urea. Thus, the cost of CO_2 and H_2 determine the overall cost of the fertilisers. To produce one tonne of urea, 0.73 tonnes of CO_2 is required (Khan, Al-Awadi and Al-Rashidi 2016), which justifies the influence of CO_2 in the overall urea production cost. Ammonia represents 57% of urea and 43% of AN (Systemiq 2022). By multiplying these percentages with the cost gap for ammonia, the cost gap for fertiliser could be obtained. Today, the cost gap for urea with the estimation of CO_2 price at level of USD 50/tonne is USD 252.6/tonne, and USD 161.8/tonne for H_2 produced from natural gas and coal, respectively. These gaps are expected to decline and reach about USD 81/tonne and zero in 2040 for H_2 produced from natural gas and coal, respectively, as shown in the figure below.

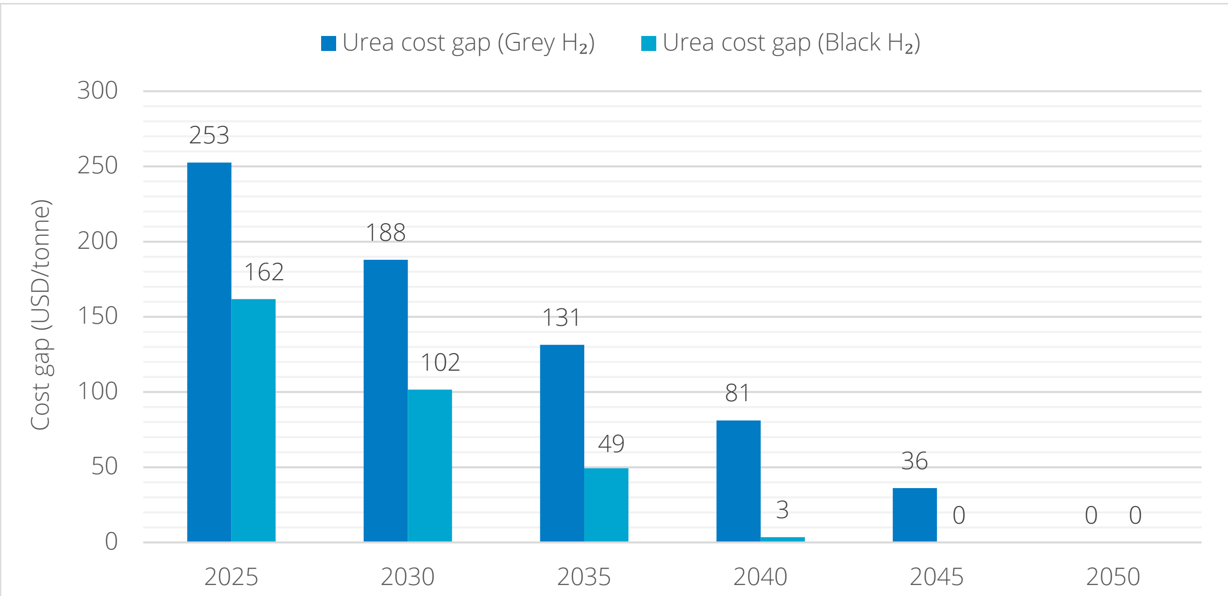


Figure 12: Urea cost gap

Regarding AN, the cost gap is estimated at USD 163/tonne and USD 95/tonne, for grey and black H_2. Similar to the urea case, these gaps are anticipated to decline and reach about USD 34/tonne and zero in 2040 for H_2

produced from natural gas and coal, respectively, as shown in the below figure. The cost parity on both fertilisers is achieved after 2040.

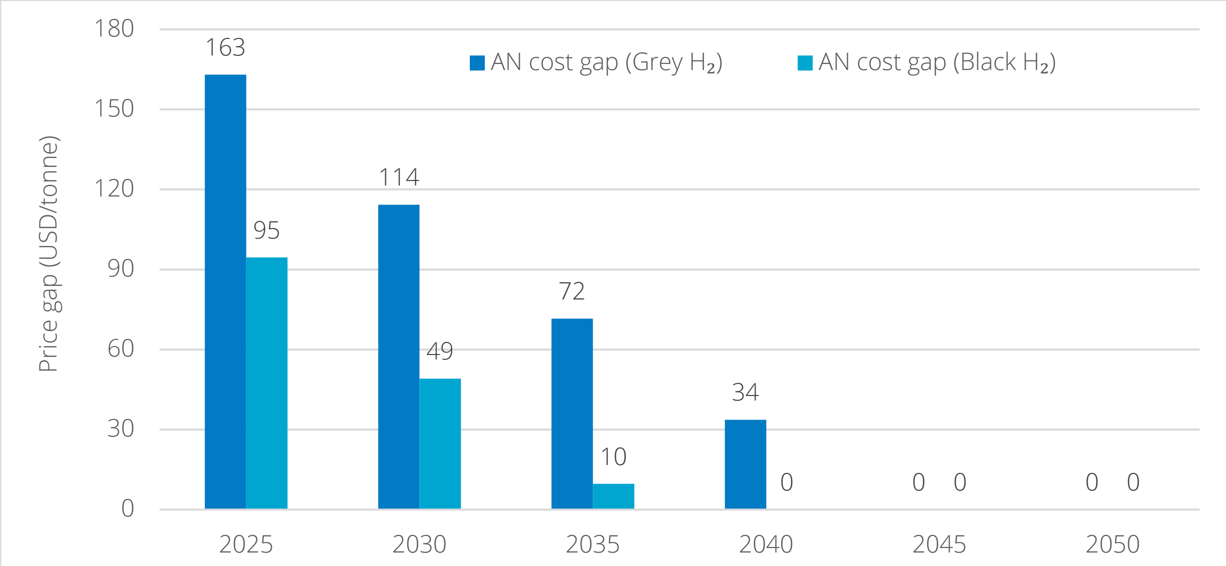


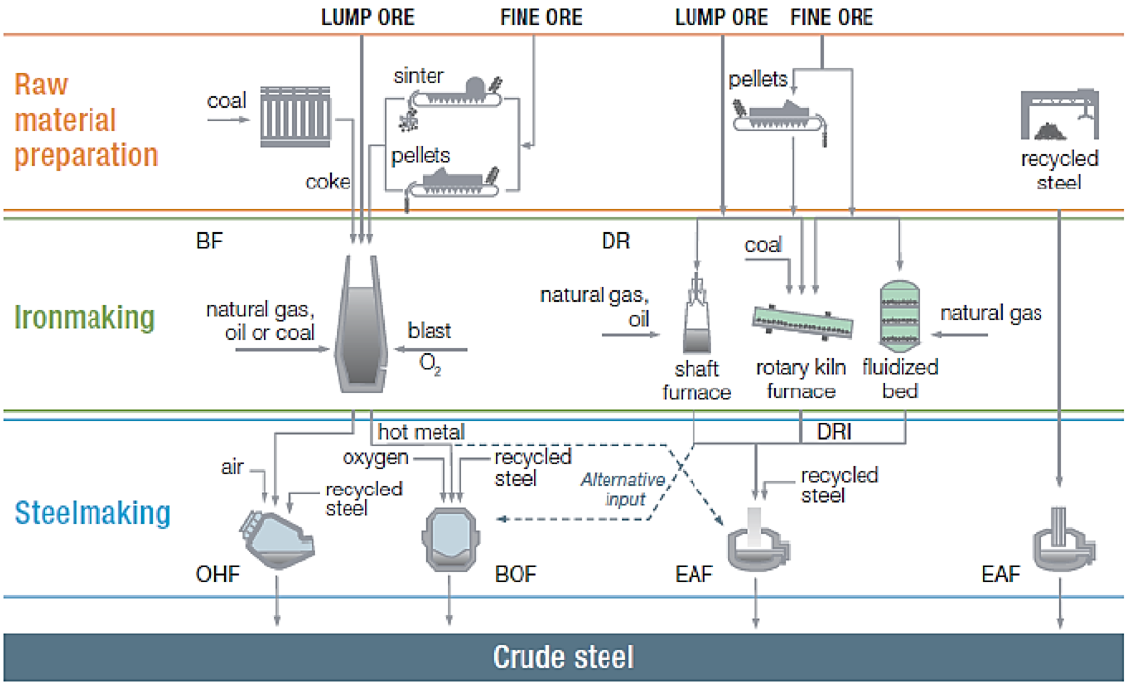
Figure 13: Ammonium Nitrate (AN) cost gap

5.3 Green steel

The steel industry could benefit from the H_2 revolution to help reduce emissions in this hard-to-defossilise sector. In 2019, South Africa was ranked the 27th largest producer of crude steel in the world. Members of the South African Iron and Steel Institute (SAISI) reported that the total amount of crude steel produced in the country was approximately 5.666 Mt in 2019, which corresponds to a 10.5% decrease compared to the 6.328 million tonnes produced in 2018 (SAISI 2021). The production of iron and steel is an energy intensive industrial activity.

Despite the fact that the stock of steel in advanced economies is already saturated, the demand for steel is projected to increase to support the growing population and economic well-being, especially in emerging economies. However, steel production is a major contributor to the struggle to meet climate goals. On average, the direct and indirect CO_2 emissions resulting from the production of one tonne of crude steel are respectively estimated at 1.4 and 0.6 tonnes on a sectoral basis (IEA 2020). According to the defossilisation roadmap, the 2018 emission baseline was 2.90 tCO_{2eq} per tonne of crude steel (ArcelorMittal 2023). This means that the steel sector emitted 16.4 million tonnes of CO_2 in 2019.

The main inputs used in the process of steel making are iron ore; energy sources like coal, natural gas, and electricity; limestone; and steel scrap. The production of crude steel involves three critical stages: raw material preparation, ironmaking, and steelmaking, as shown in Error! Reference source not found..



Source: World steel association, 2019.

Note: BF = Blast Furnace, BOF = Blast Oven Furnace, DR = Direct Reduction, DRI = Direct Reduction Iron, EAF = Electric Arc Furnace, OHF = Open-Hearth furnace, ORE = Iron ore

Figure 14: Steel manufacturing routes

The most commonly used method for producing steel is the Blast Furnace-Basic Oxygen Furnace (BF-BOF) route, which accounts for the majority of global steel production. The process involves feeding coke and iron ore into a blast furnace from the top, while hot air, pulverised coal or natural gas is injected in the lower part of the furnace. To produce one tonne of liquid steel via the BF-BOF route, around 15 GJ of final energy input is required. Lime fluxes and other additives are also used in the blast furnace in varying quantities to control impurities and temperature. The blast furnace produces molten iron ("hot metal") at temperatures up to 1,400-1,500°C. The hot metal is then fed to the BOF, sometimes with some scrap, where oxygen is injected to lower the carbon content from around 4-5% to the desired level of carbon for the steel grade produced (IEA 2020).

Another primary method of producing steel is through the Direct Reduced Iron-Electric Arc Furnace (DRI-EAF) route. This process involves using high-quality DRI pellets. In the DRI furnace, the iron ore is reduced in a solid state (as opposed to the liquid phase in the blast furnace) and then melted in the EAF, sometimes with the addition of scrap. H_2 and CO are the main reduction agents in the DRI-EAF pathway, and they play more balanced roles. DRI-EAF facilities primarily use natural gas to produce reducing syngas (H_2 and CO), but they can also use coal. To produce one tonne of steel through the DRI-EAF route, about 18 GJ to 30 GJ of final energy is required. Natural-gas-based production is generally more efficient than coal-based gasification arrangements (IEA 2020).

In the process of making steel, emissions are produced through the burning of fossil fuels and chemical reactions. There are multiple sources of CO_2 emissions during this process, each with their own level of impact. The coal-DRI/EAF route has the highest carbon footprint, estimated at 2.4 $\text{tonne}_{CO2}/\text{tonne}_{steel}$. Comparatively, the BF-BOF route produces 2 $\text{tonne}_{CO2}/\text{tonne}_{steel}$, while natural gas based DRI/EAF and Scrap steel EAF produce 1.4 $\text{tonne}_{CO2}/\text{tonne}_{steel}$ and 0.4 $\text{tonne}_{CO2}/\text{tonne}_{steel}$, respectively (EPRS 2021).

The basic idea behind the H_2 reduction route (H-DRI) – also called green steel – is to use H_2 as a reducing agent to directly obtain reduced iron instead of using a mixture of H_2 and carbon in the BF. In a DR plant, H_2 can be utilised in two different ways. Firstly, some amount of H_2 can be added to a natural-gas-based plant as a substitute for a portion of the natural gas. Alternatively, a DR plant can be based entirely on 100% H_2. In the case of H_2 addition, about one-third of the required natural gas can be replaced. For instance, in a 2 million tonne per year plant, 60,000 Nm³/h of H_2 can substitute for roughly 20,000 Nm³/h of natural gas, which is approximately 30% of the total natural gas consumption. This substitution can be made in an existing or new plant (MIDREX 2017).

Based on initial modelling and laboratory experiments, it is possible to use almost pure H_2 to make DRI. In practice, the reducing gas H_2 content is about 90%, with the balance of CO, CO_2, water and methane. These constituents result from the addition of natural gas for temperature control and carbon addition (MIDREX 2017).

To calculate the production cost gap when using H_2, the same high-level model mentioned earlier was used. The model calculates energy costs in the three routes BF-BOF, natural gas based DRI-EAF, and H_2 based DRI-EAF. The data were collected from several sources and the main data are summarised in the Annex.

With the assumptions that there is no carbon tax, the levelised cost of producing one tonne of steel was estimated at USD 147/tonne, USD 191/tonne, and USD 366/tonne for the routes BF-BOF, natural-gas-based DRI-EAF, and H_2-based DRI-EAF, respectively. However, the cost will be decreased with the reduction of GH_2 production costs. In 2040, for instance, the cost is estimated to be USD 254/tonne and will decrease further to USD 203/tonne by 2050.

The below figure presents the estimated levelised cost of steel production (energy component only) between 2025-2050, with green steel becoming cost competitive (without carbon tax) in 2045.

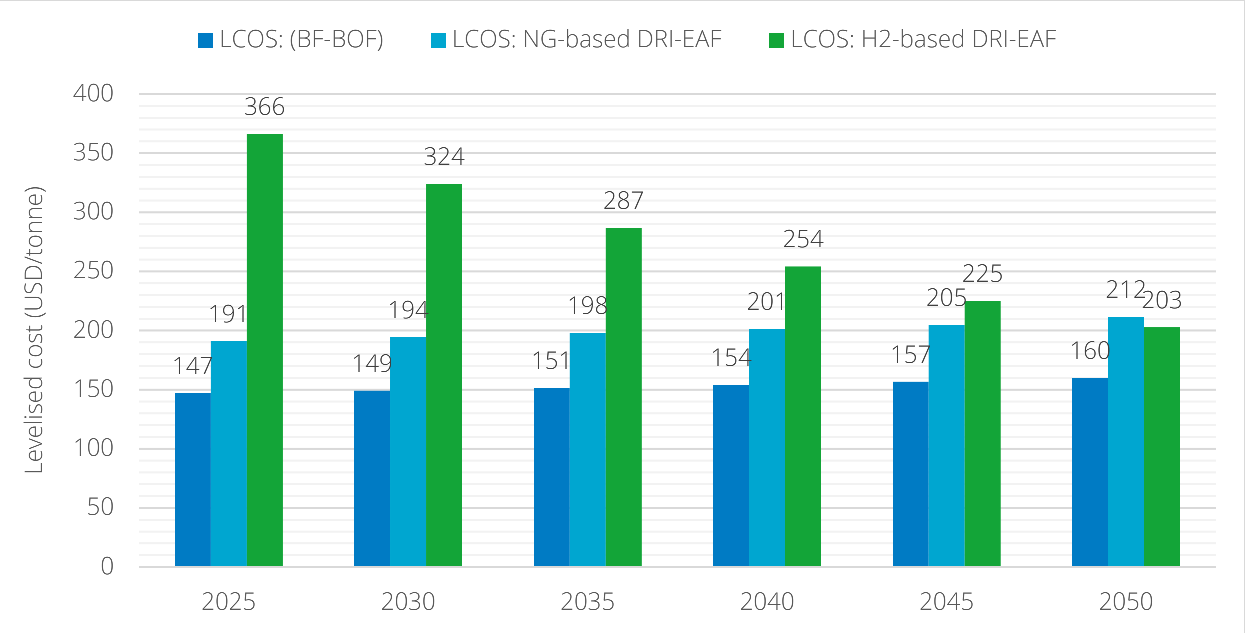


Figure 15: Levelised cost of steel production (energy component only) 2025-2050

5.4 Methanol

Methanol is an important product in the chemical industry, primarily used for producing other chemicals like formaldehyde, acetic acid, and plastics. The figure below summarises key methanol applications worldwide.

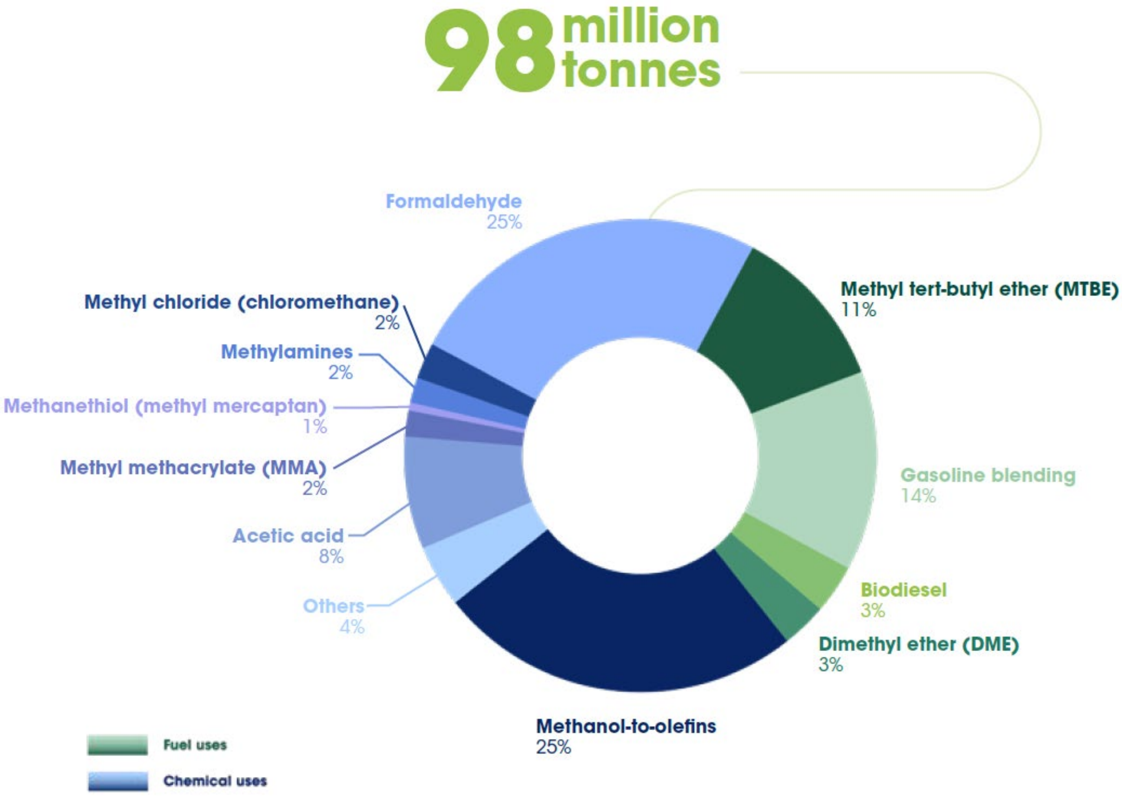


Figure 16: Methanol applications

Source: (IRENA and MI 2021)

The annual production of methanol is approximately 98 Mt, and almost all of it is made from fossil fuels such as natural gas or coal. Over the past decade, methanol production has increased almost twofold, with a considerable portion of the growth occurring in China. Presently, the life-cycle emissions from methanol production and use amount to roughly 0.3 gigatons (Gt) of CO_2 per year, which equates to about 10% of the total chemical sector emissions. If current trends persist, the production of methanol could reach 500 Mt per year by 2050, resulting in the release of 1.5 billion tonnes of CO_2 per year if fossil fuels are the sole source of production (IRENA and MI 2021).

There are various methods for producing methanol, but the most commonly used method involves synthesising methanol from natural gas after producing synthesis gas. Other materials like coal, residual oils, oil, cellulose, or waste masses can also be used in place of natural gas. Another way to produce methanol is through the synthesis of CO_2 and H_2. This approach enables the multiple use of CO_2, which can be extracted from industrial gases (Höhlein, Grube and Biedermann 2003).

Methanol can be produced from renewable sources like forestry and agricultural waste, biogas, sewage, and black liquor from the pulp and paper industry. This type of methanol is known as bio-methanol. Another type of renewable methanol, known as e-methanol, is produced from CO_2 and GH_2 obtained through renewable electricity. Both bio-methanol and e-methanol are chemically identical to fossil-fuel-based methanol, but they emit significantly lower GHG emissions throughout their life cycle. Also, using renewable methanol can reduce reliance on fossil fuel imports and promote local economies.

The figure shows the production methods of methanol and the associated carbon intensity.

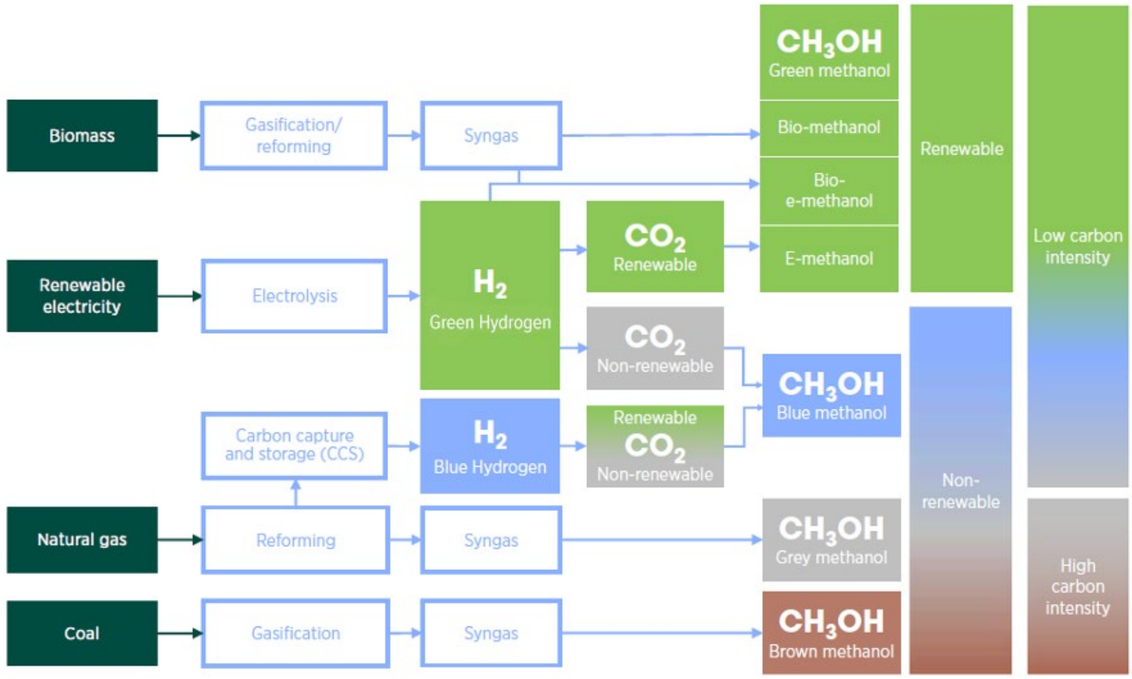


Figure 17: Methanol production routes

Source: (IRENA and MI 2021)

It is possible to estimate the cost of e-methanol by considering the cost of H_2 and CO_2, as these are the main expenses in large e-methanol plants. Once both CO_2 and GH_2 are available, producing methanol in one step and distilling it is a well-established technology. Producing 1 tonne of methanol requires 0.188 tonnes of H_2 and 1.373 tonnes of CO_2 (IRENA and MI 2021).

Estimating the cost of CO_2 depends greatly on its source and the amount of effort required to purify and compress it to the pressure needed for the synthesis of methanol. The below table presents data input used to estimate CO_2 cost (IRENA and MI 2021).

Table 7: CO_2 sources and costs

SOURCE OR TECHNOLOGY	CO_2 CONCENTRATION IN EXHAUST (%)	ESTIMATED COST OF CO_2 (USD/TONNE CO_2)	
		Today	2050
Fossil carbon			
Coal power plant	12-14	43-97	46-55
Coal power plant with oxy-combustion	Close to 100	52-75	52
Natural gas power plant	3-5	80-89	43
Iron and steel	20-30	55-77	40-65
Cement	15-30	35-125	20-103
Natural gas purification	2-65	15-25	20
Ammonia synthesis	Up to 1,000	20-25	24
Renewable carbon			

Biomass to ethanol plant	Up to 1,000	12-22	20
Biogas	40-50	-30	-30
Direct air capture (DAC)	0.042 in air concentrated to close to 100	300-600	50-150
BECCS/BECCU[4]	Close to 100	20-400	---

Source: (IRENA and MI 2021)

In the model developed to estimate the cost gap, the price of e-methanol is USD 786/tonne assuming a carbon cost of USD 50/tonne CO_2 (today's average cost of fossil carbon) and USD 1,130/tonne when assuming a carbon cost of USD 300/tonne CO_2 (today's cost for DAC sourced carbon).[5] **Error! Reference source not found.** and **Error! Reference source not found.** show the cost of methanol compared to the current methanol production costs (grey shaded areas) in both cases.

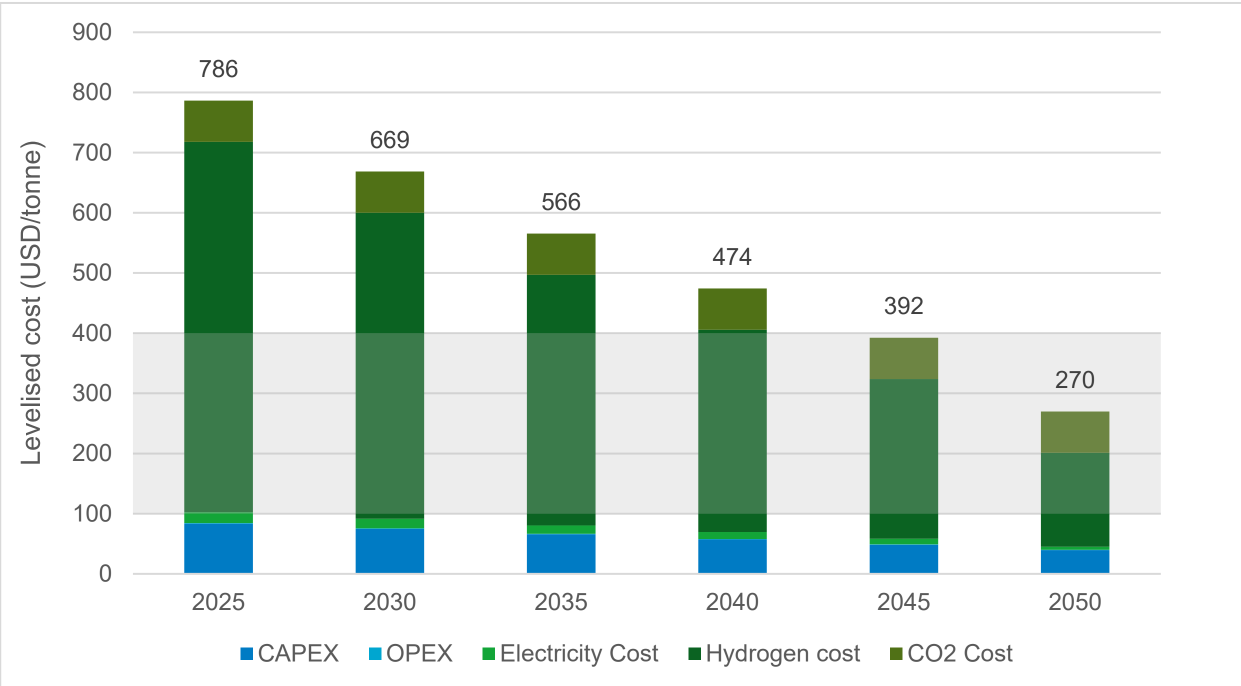


Figure 18: Methanol production cost (CO_2 = USD 50/tonne)

[4] BECCU: Bioenergy with carbon capture and utilisation; BECCS: Bioenergy with carbon capture and storage

[5] The green hydrogen cost is USD 3.27/kGH_2.

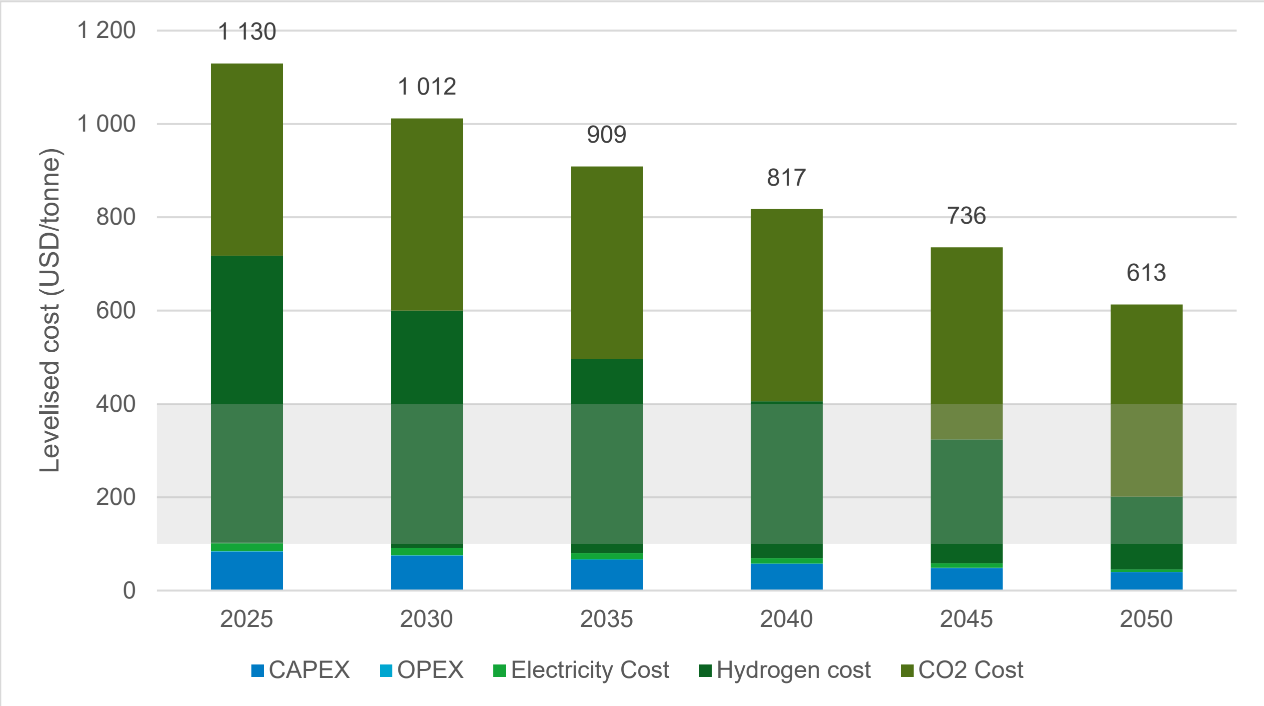


Figure 19: Methanol production cost (CO_2 = USD 300/tonne)

From the above two figures it could be noticed that the main cost driver of e-methanol is H_2cost followed by CO_2. Even in the case where the CO_2 cost is zero, the cost parity will not be reached before 2040. However, if the cost of CO_2 is too high, the cost parity will never be reached as shown in Figure 22.

The results shown in the above two figures are in agreement with other studies as depicted in the IRENA and MI (2021) report that collected the production costs from more than 15 studies as indicated in the below figure.

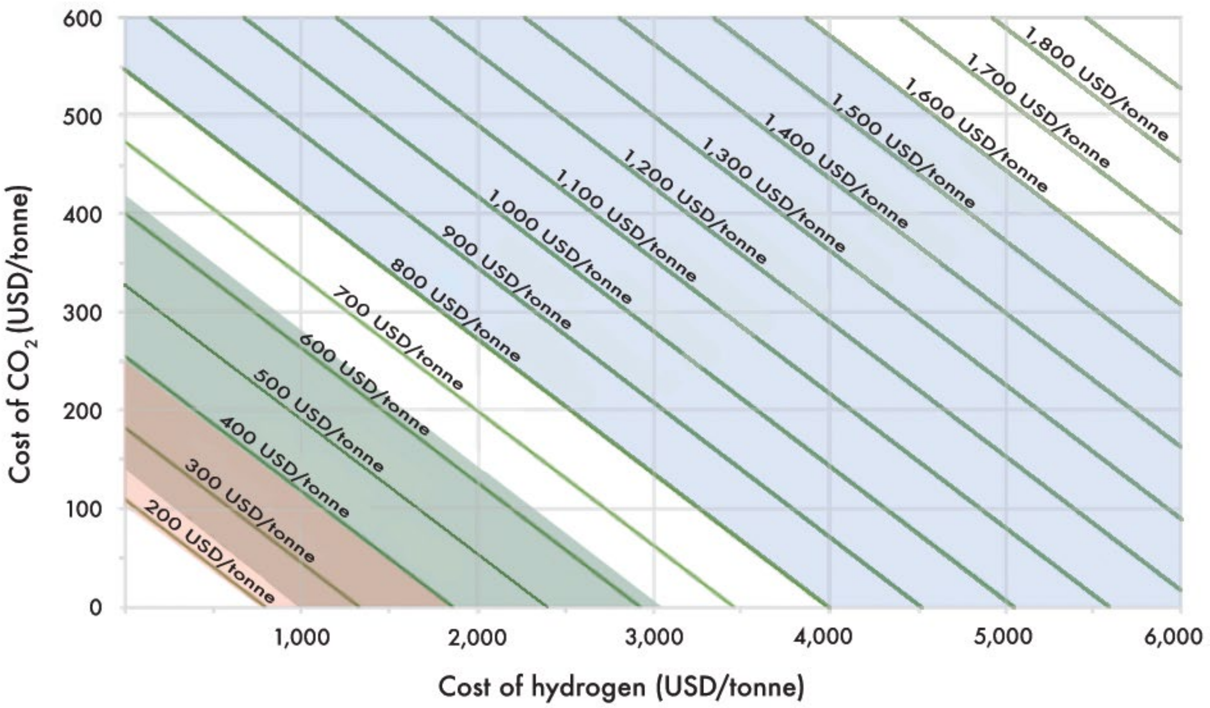


Figure 20: Production cost of methanol as a function of H_2 and CO_2

Source: IRENA and MI (2021)

Although the production cost of e-methanol is still high compared to its alternative fossil-fuel-based methanol, the uptake of e-methanol will probably be driven by regulations rather than its price. For instance, the maritime shipping targets are to reduce its GHG emissions, compared to 2008 levels, by 30% by 2030, 80% by 2040, and reach net zero emissions by 2050 (Smith and Shaw 2023). This requires member countries of the International Maritime Organisation to provide the mentioned amount of sustainable shipping fuels at their border, regardless of the price.

5.5 Sustainable aviation fuel

Back in 2009, the International Air Transport Association (IATA) put forth a goal for the aviation industry to achieve a net decrease in carbon emissions of 50% by the year 2050, in comparison to the levels recorded in 2005. However, this target only gives the industry a time frame of 35 years to achieve it, despite the fact that aircraft programmes can last for over 50 years. In the future, innovative or potentially disruptive aviation propulsion systems could be significant. However, a renewable fuel option that can be easily integrated and emits almost no GHGs is crucial for achieving significant reductions in aviation's GHG emissions (Schmidt and Weindorf 2016).

PTL is a method of producing liquid hydrocarbons using electric energy, water, and CO_2. The process involves three main steps: producing GH_2, providing and converting renewable CO_2, and synthesising the liquid hydrocarbons, which are then refined into fuels (see Error! Reference source not found.).

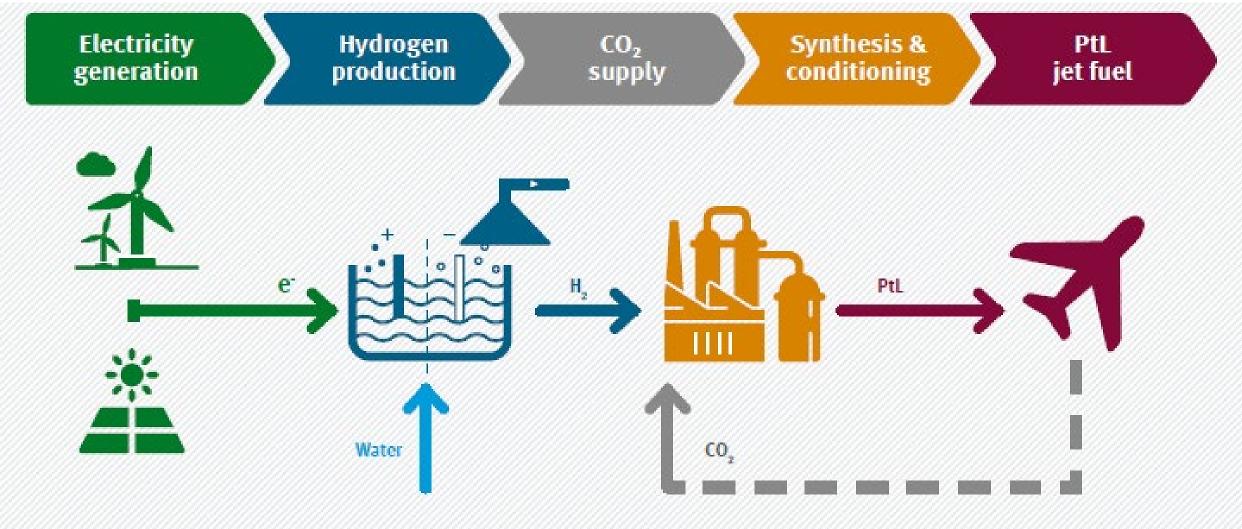


Figure 21: PTL process

Source: Schmidt and Weindorf (2016)

During the PTL production process, a mixture of gasoline, kerosene, diesel, and other fuel products are produced, with the potential to shift toward at least a 50% share of jet fuel components (Schmidt and Weindorf 2016). Two main pathways exist for producing renewable PTL jet fuel: FT synthesis and upgrading, and methanol synthesis and conversion (Schmidt and Weindorf 2016).

The FT pathway is a common method used in producing synthetic jet fuel from different sources like biomass-to-liquid (BTL), GTL and CTL processes. However, instead of using biomass, natural gas, and coal, GH_2 is utilised. To carry out the FT synthesis, CO is required. In processes such as BTL and CTL, CO is obtained from the gasification of biomass and coal, respectively. In the FT-PTL process, CO_2 from concentrated sources or extracted from the air is used, much like in the case of e-methanol. The CO_2 is transformed into CO through an inverse CO-shift reaction using the reverse water gas shift process (Schmidt and Weindorf 2016).

To turn FT-derived crude products into jet fuel and other hydrocarbons, several process steps are required, such as hydrocracking, isomerisation, and distillation. These processes are widely used in crude oil refineries, as well as in CTL and GTL plants. About 50-60% of the products from the FT synthesis can be used for jet fuel (by energy). The light olefins (C3 and C4) fractions from FT synthesis can be processed using oligomerisation to increase the share of liquid hydrocarbons, meeting Jet A-1 specifications. FT synthetic paraffinic kerosene is allowed for up to 50% of jet fuel blends by the American Society for Testing Materials (ASTM) standard (Schmidt and Weindorf 2016).

It is possible to create liquid hydrocarbons, such as jet fuel, using a different method that involves using methanol as an intermediate product. This method builds on existing industrial processes that have been used for many years in large-scale applications, such as natural gas reforming and methanol synthesis (which can also be used to convert methanol into gasoline in some cases). The synthesis reaction for methanol can use both CO and CO_2, meaning that a reverse water gas shift process or co-electrolysis of steam and CO_2 is not necessary, unlike with the FT pathway. The process of converting and upgrading methanol into jet fuel and other hydrocarbons involves several steps, including direct dimethyl ether (DME) synthesis, olefin synthesis, oligomerisation, and hydrotreating. However, while this pathway has promising potential, it has not yet been approved for technical use in creating jet fuel in accordance with ASTM standards (Schmidt and Weindorf 2016).

The gate-to-gate[6] efficiency for both methods are comparable. In the FT pathway, the efficiency ranges between 37% to 42% while in methanol pathway the efficiency ranges from 41% to 45%[7] (Batteiger, et al. 2022). In our model, we selected the FT pathway as it is ASTM approved. The main assumption was collected from a study carried out by Deutsche Energie-Agentur GmbH (dena) for aviation fuels (dena 2022).

The estimated production cost is around USD 2,000/tonne. According to IATA, the historical jet fuel prices in the period 2014 to 2021 are in the range of USD 280-720/tonne (dena 2022). This will lead to an estimated cost gap between USD 1,300 to 1,800/tonne.

The below figure depicts the estimated production costs during the period of 2025 to 2050 with the estimation of carbon cost level of USD 50/tonne and H_2 cost of USD 3.27/kg. The figure shows the production cost of SAF using GH_2 has a decreasing trend. However, the production cost will be competitive only in the long term towards 2050.

[6] Gate-to-gate here means from electricity input to fuel output.

[7] With the assumption that the CO_2 source is from air.

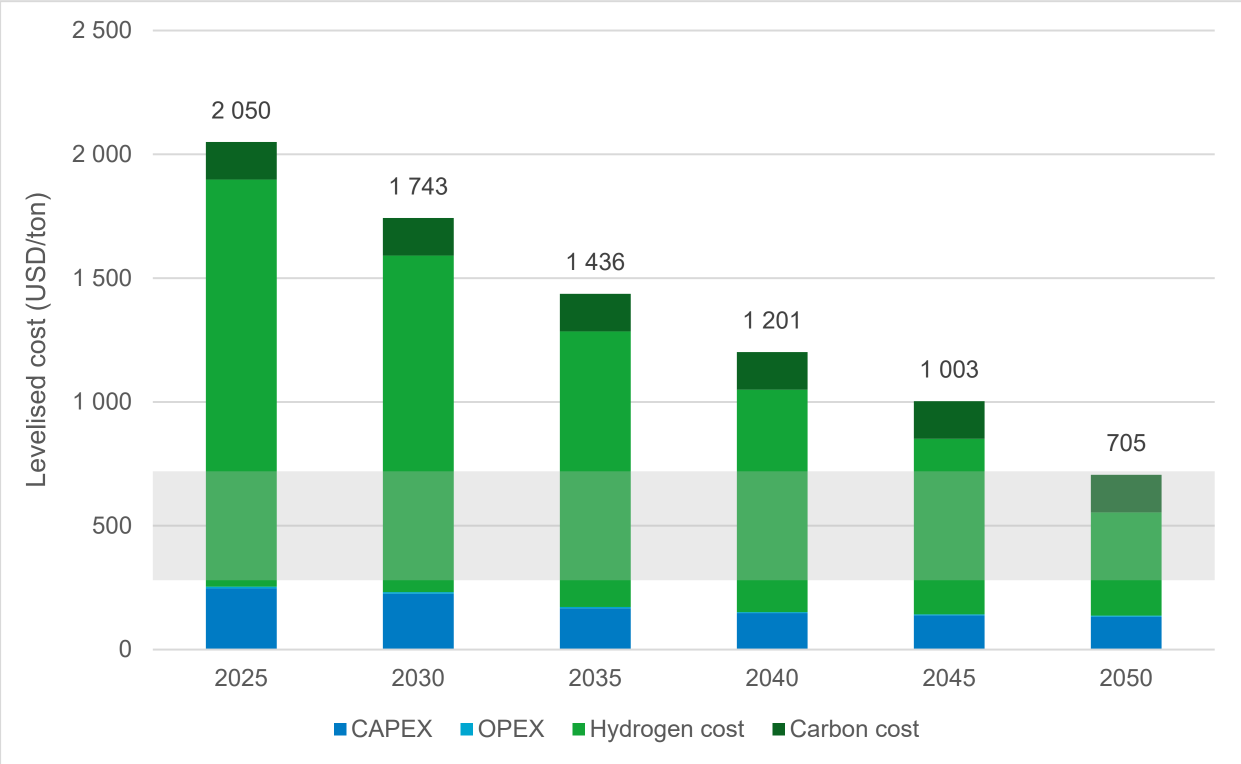


Figure 22: SAF production costs during the period 2025 to 2050

The literature is full of price estimations for the production cost of e-kerosene. The estimation of production costs using DAC as carbon source in 2020 was in the range of EUR 109-551/$MWh_{th,LHV}$ while the result from the current analysis is estimated at USD 234.8/$MWh_{th,LHV}$. By 2050, the range was from EUR 51-321/$MWh_{th,LHV}$ and the current study estimates is USD 122.3/$MWh_{th,LHV}$ (dena 2022).

The figure below shows the cost range from the literature, where red dots represent the results simulated under the current study assuming a carbon price of USD 300/tonne.

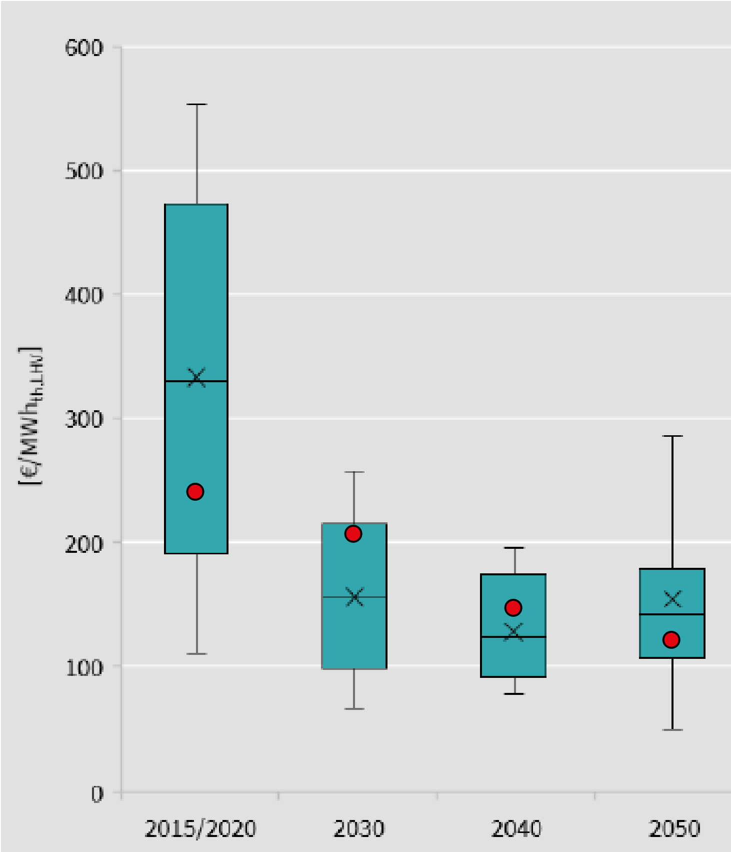


Figure 23: SAF production cost ranges

Source: adjusted by the Author from dena (2022)

Though SAF seems to not be competitive compared to its alternative fossil-fuel-based kerosene, policies and regulations are expected to drive the uptake of SAF rather than economics. For instance, in September 2023, the European Parliament adopted new rules on binding targets for airlines in Europe to increase their use of SAF. The new rules oblige EU airports and fuel suppliers to ensure that, starting from 2025, at least 2% of aviation fuels will be green, with this share increasing every five years: 6% in 2030, 20% in 2035, 34% in 2040, 42% in 2045 and 70% in 2050 (European Parliament 2023).

6 CARBON TAX CONSIDERATIONS

The results presented in the previous chapters were exclusive of any emission taxes. However, CO_2 tax is one of the most efficient and effective tools to control GHG emissions and encourage the industry to develop more climate-friendly solutions.

6.1 Role of the carbon tax

Various solutions are available for countries to achieve their Nationally Determined Contributions (NDCs) goals. A range of policies have been implemented by developed and developing countries to tackle climate change. Each policy is tailored to fit the jurisdiction's emissions profile, political, economic and legal contexts. After the Paris agreement, there is more emphasis on creating policies that can bring about long-term emission reductions on a large scale. Carbon pricing is becoming increasingly popular among jurisdictions, with many using Emissions Trading Systems (ETSs) or carbon taxes to achieve this objective.

Carbon taxes are a way to put a price on GHG emissions, which is done by taxing goods or activities based on the number of emissions they produce. As a result, taxpayers have a financial incentive to reduce their emissions and lower their tax obligations. For industries, a carbon tax could encourage investment in cleaner technology or more efficient practices. Consumers may be motivated to invest in energy efficiency, change their lifestyle habits, or switch to cleaner forms of energy. In energy markets where additional costs are passed on to consumers, carbon taxes may also lead to increased demand for RE from both consumers and industries, which could help promote investments in renewable options. Furthermore, carbon taxes can generate revenue, which can be used to increase government spending or reduce other taxes (PMR 2017).

Carbon prices are a specific policy tool used to combat climate change by placing a direct cost on GHG emissions. Unlike general energy taxes, carbon prices focus solely on mitigating emissions. Unlike other carbon pricing measures, such as ETS, carbon taxes set a fixed cost on each unit of emissions. This is achieved by taxing fossil fuels based on their carbon content or by taxing goods based on the quantity of emissions produced during their production.

It has been observed that South Africa is currently the largest GHG emitter in Africa. From 1990 to 2019, its total GHG emissions (excluding forestry and other land use) increased significantly by over 67%. The energy sector is the main contributor to this, accounting for almost 86% of the total emissions in 2019. Moreover, this sector has been the cause of almost 91% of the GHG emissions increase in the last three decades. This emission profile can be attributed to the country's carbon-intensive electricity generation, which relies heavily on coal-fired power plants (IMF 2023).

In June 2019, the carbon tax was put in place as a crucial tool for the country's efforts to mitigate climate change. It operates under the principle that polluters should pay and is imposed on fuel inputs using emission factors and procedures in accordance with the Intergovernmental Panel on Climate Change's (IPCC) published standards. The tax applies to approximately 90% of the country's total GHG emissions, with the only exclusions being agriculture, forestry, land use, and waste (IMF 2023).

Nonetheless, transitional tax-free thresholds, allowances, and carbon offsets were introduced during the transition phase of the carbon tax. As a result, there is a basic tax-free allowance ranging between 60-75% of emissions across sectors, with additional allowances and offsets potentially adding up to 95% depending on the sector, except for those that have been completely excluded (IMF 2023).

Due to the generous tax-free thresholds and allowances in South Africa, the effective carbon tax rate was relatively low. Initially, the official carbon tax rate was set at ZAR 120 (equivalent to approximately USD 7)/tonne of CO_{2eq}, which then increased to ZAR 134 (or about USD 8) by the end of 2022. However, based on the revenue collected from the carbon tax, it is estimated that the effective rate was less than ZAR 7/tonne of CO_{2e} during the financial year 2021-22. With the transition phase of the carbon tax having been extended to the end of 2025, the effective carbon tax rate is still expected to remain low, despite the planned increase in the official rate in the coming years (IMF 2023).

Producing GH_2 has been difficult to achieve commercially without substantial government assistance and the reduction of costs over time. However, a solution has been proposed that involves a combination of carbon pricing (in the form of a carbon tax with the correct tax level) and H_2 production subsidies. This approach has the potential to increase the use of GH_2 technology and make it a more viable option.

6.2 Estimated cost gap with carbon tax

This section estimates the impacts of carbon tax on PtX production costs based on the International Monetary Fund (IMF) report published in June 2023. According to the IMF report, the government of South Africa proposes to strengthen the carbon tax policy by progressively raising the carbon tax rates between 2023 and 2030, as well as providing a long-term carbon tax trajectory up to 2050 and beyond. After the transition phase of the carbon tax that will end in 2025, the government plans to raise the carbon tax rate to at least USD 20/tCO_2 by 2026, to USD 30/tCO2 by 2030, and accelerate to higher levels up to USD 120/tCO_2 beyond 2050 (IMF 2023).

This study used the above indicated numbers for carbon tax in 2025, 2030, and 2050, while tax levels between 2030 and 2050 were obtained by interpolation. The resulted tax values are USD 52.5, 75, 97.5/tCO_2 for the years 2035, 2040, and 2045, respectively.

Error! Reference source not found. and 25 show the cost gap for grey and black hydrogen production. It can be seen from these figures that by applying carbon tax, black hydrogen will reach cost parity with GH_2 by 2030, while grey hydrogen will reach cost parity in 2040. The reason GH_2 reaches cost parity with black hydrogen earlier than grey hydrogen is due the fact that black hydrogen emits more than twice the CO_2 emissions than grey hydrogen.

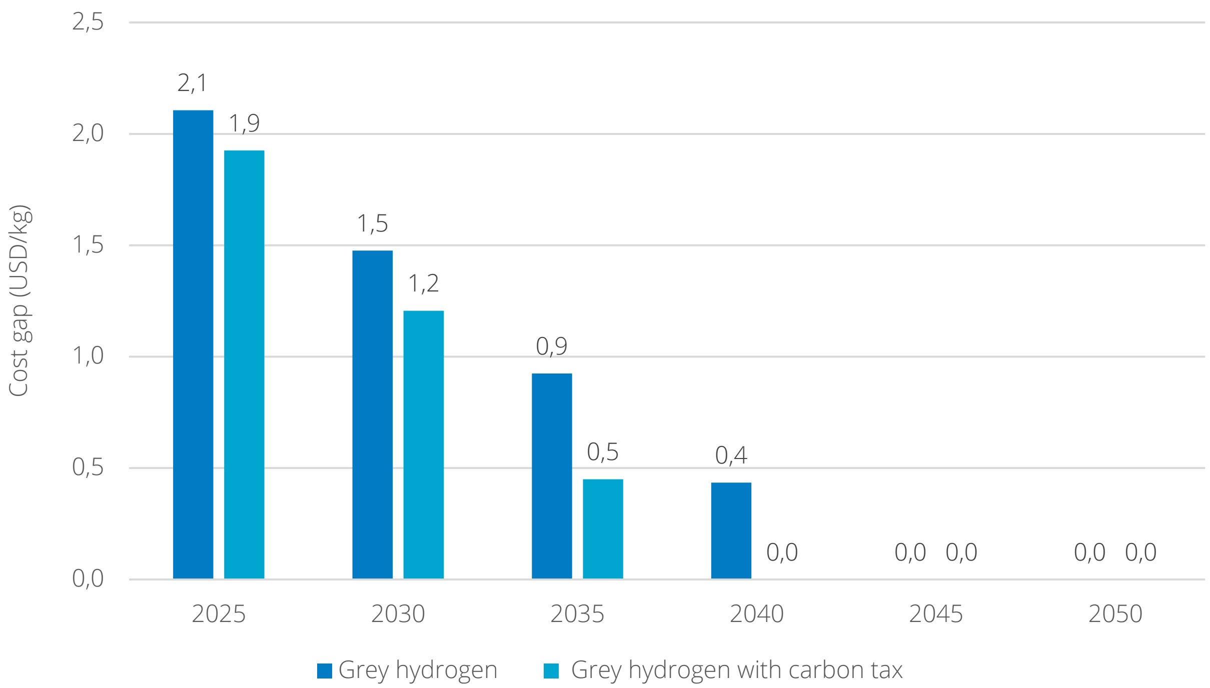


Figure 24: Cost gap with and without carbon tax for grey hydrogen

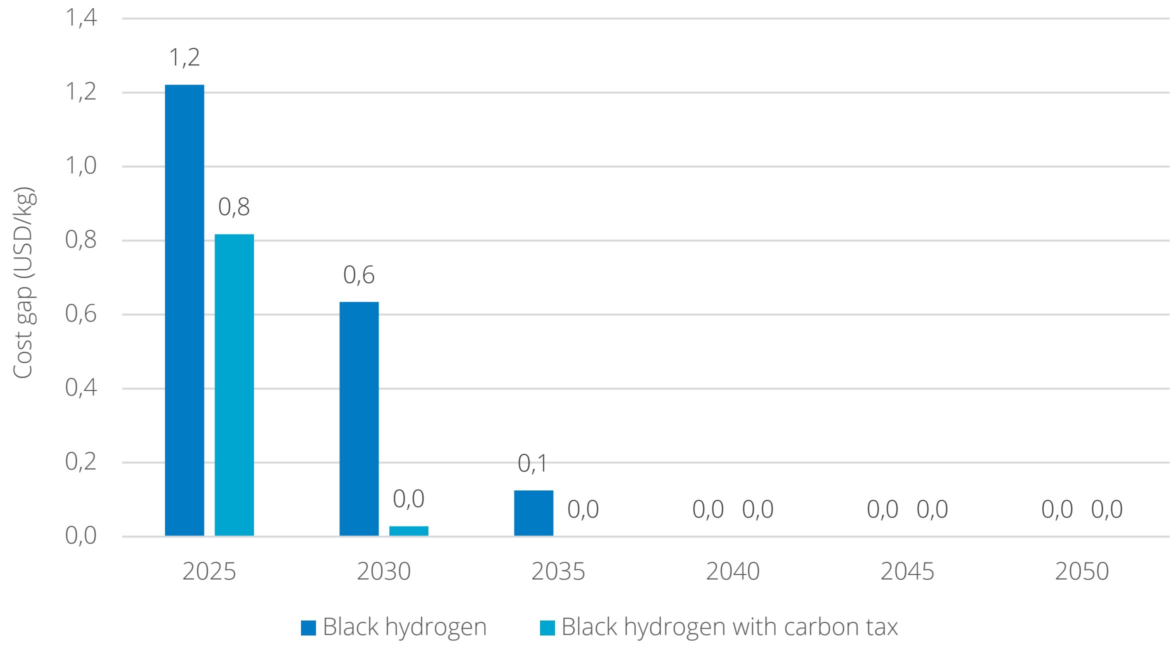


Figure 25: Cost gap with and without carbon tax for black hydrogen

As for ammonia, carbon tax will reduce the cost gap between green and grey ammonia from USD 379/tonne to USD 347/tonne in 2025, and the cost parity will be reached in 2040 (Figure 26). For black ammonia, the cost gap will be reduced from USD 220/tonne to USD 147/tonne in 2025, and the cost parity will be reached in 2030 (Figure 27).

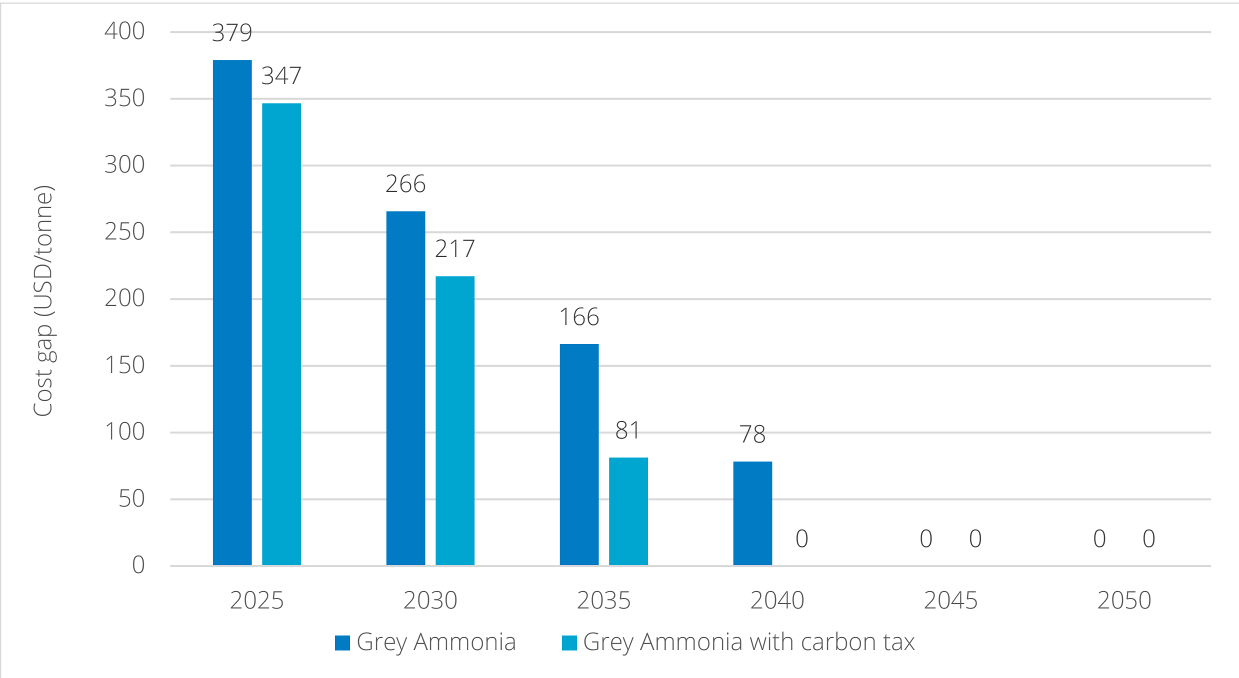


Figure 26: Cost gap between grey ammonia with and without carbon tax

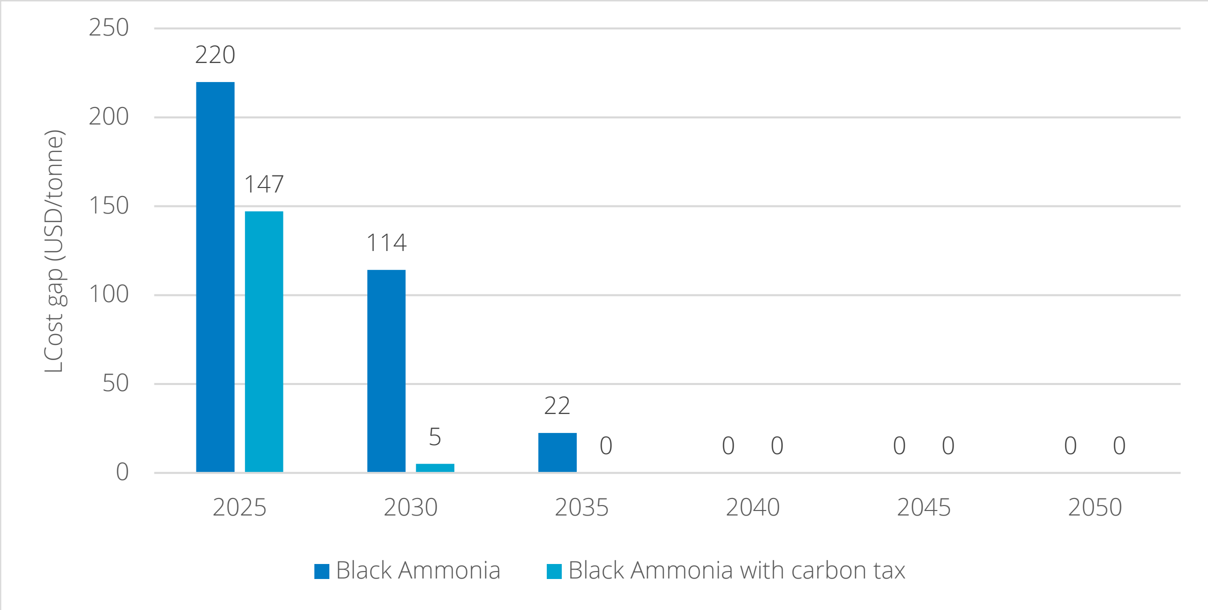


Figure 27: Cost gap between green and black ammonia with and without carbon tax

For fertilisers, the cost parity between green and grey urea is projected to be reached shortly after 2040 (

Figure 28), while in comparison with black urea, the cost parity is expected earlier in 2035 (

Figure 29).

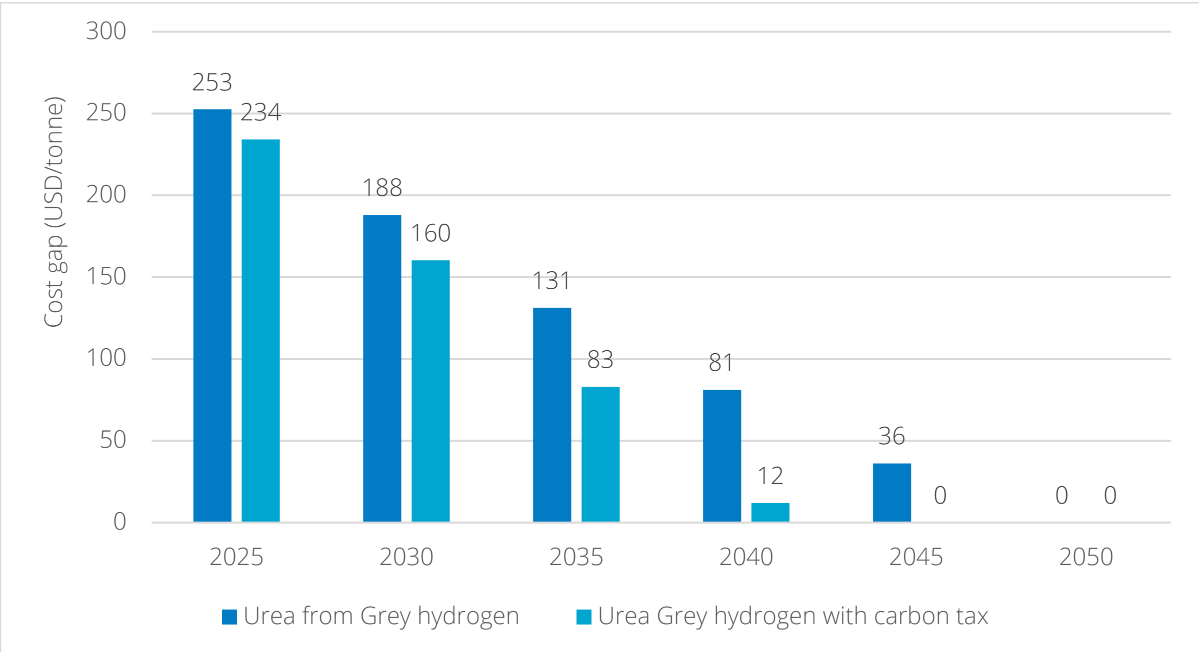


Figure 28: Cost gap between green and natural-gas-based urea with and without carbon tax

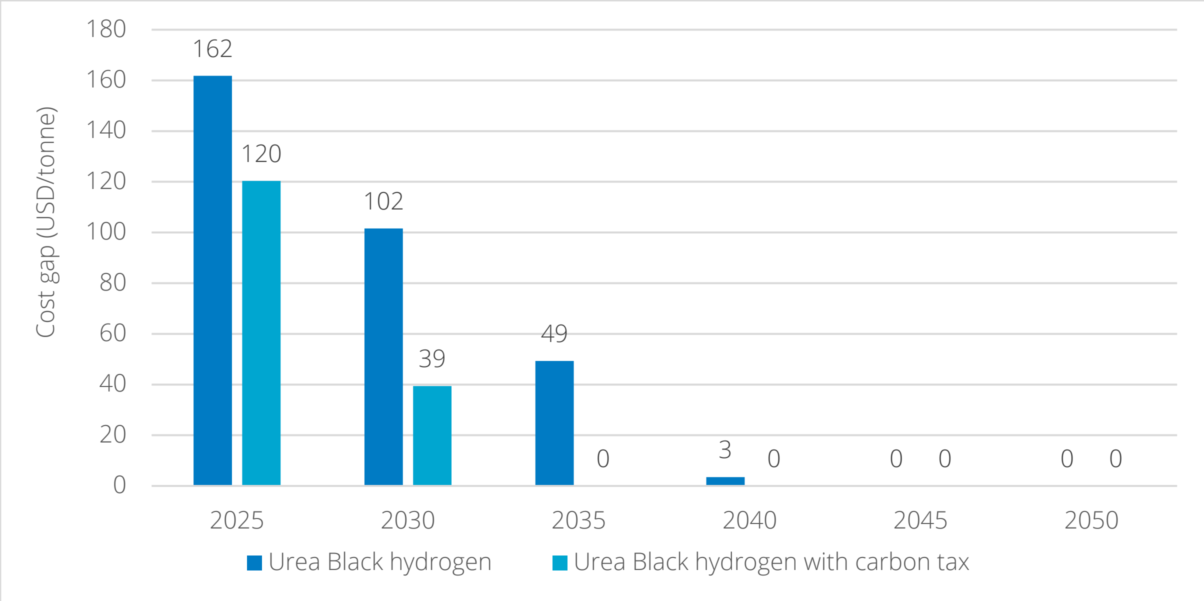


Figure 29: Cost gap between green and coal-based urea with and without carbon tax

For AN fertiliser, the cost parity between green and grey AN is expected in 2040 (

Figure 30), while for black, the cost parity will be reached earlier in 2030 (

Figure 31).

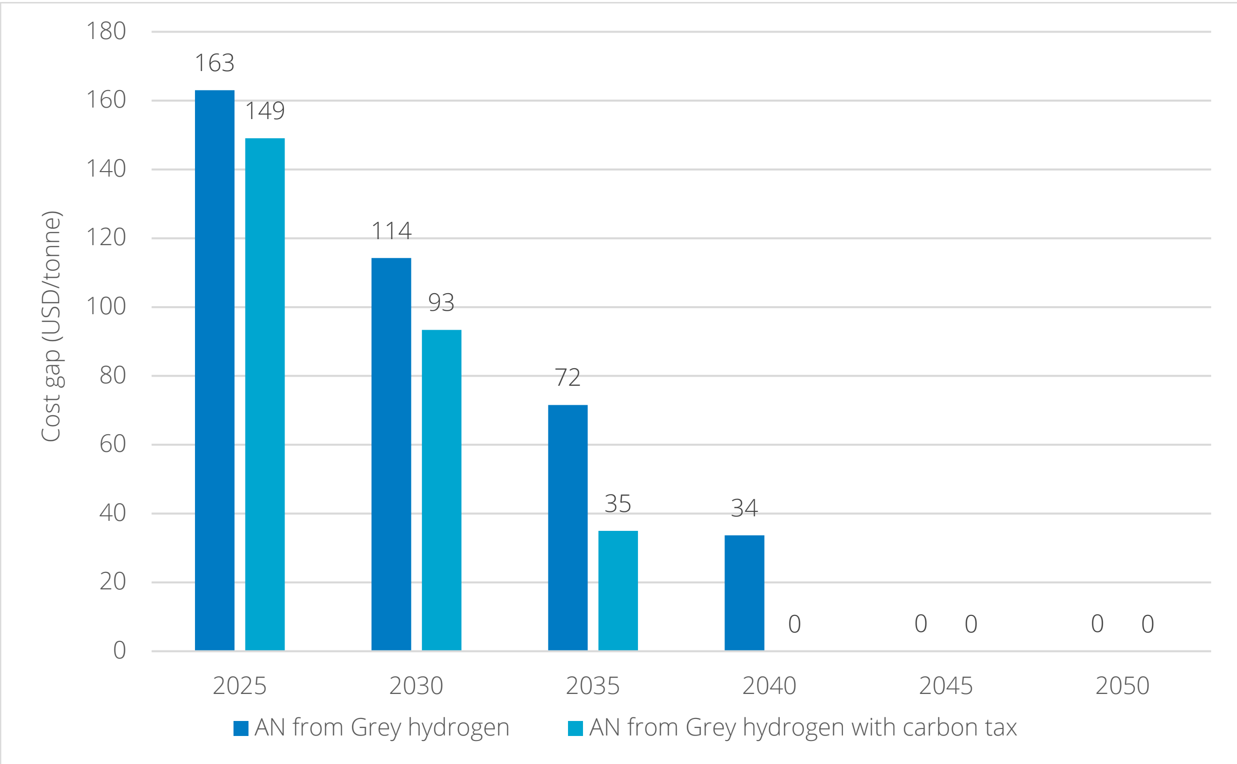


Figure 30: Cost gap between green and natural-gas-based AN with and without carbon tax

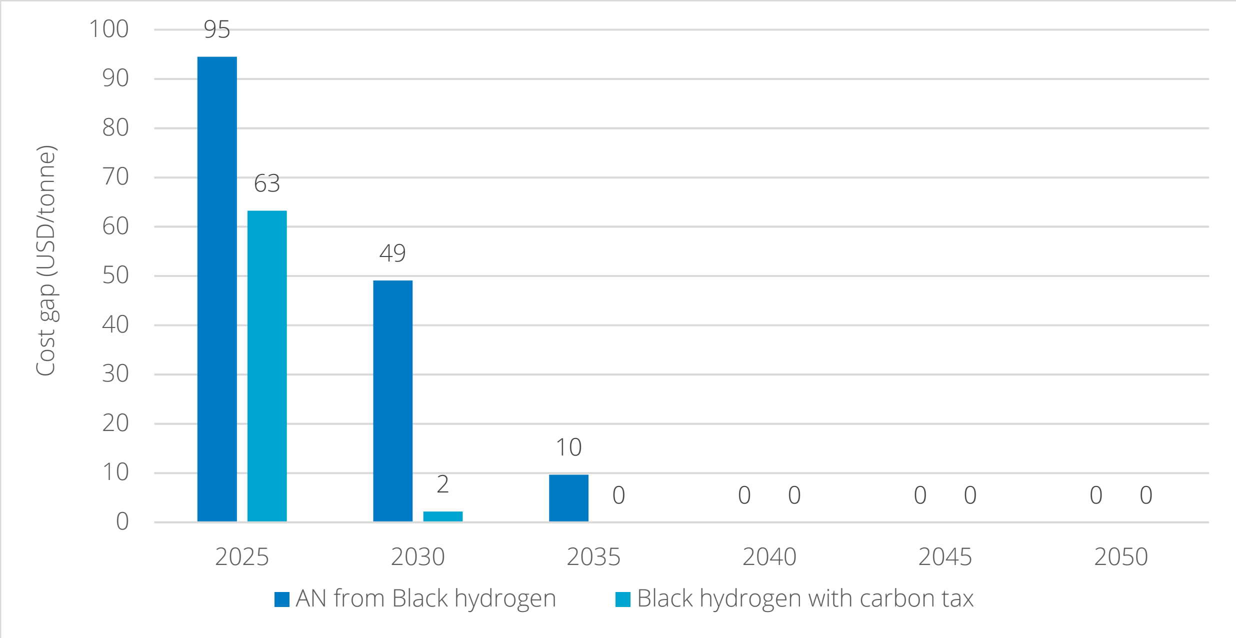


Figure 31: Cost gap between green and coal-based AN with and without carbon tax

For methanol, the cost gap between green and grey methanol will slightly decrease from USD 646/tonne to USD 630/tonne in 2025, and the cost parity is not expected before 2050 (

Figure 32). For coal-based methanol, the cost parity is expected in 2045 (

Figure 33). All these results depend on the purchasing price of carbon required to synthetise methanol. In this analysis, a price of USD 50/tonne was applied.

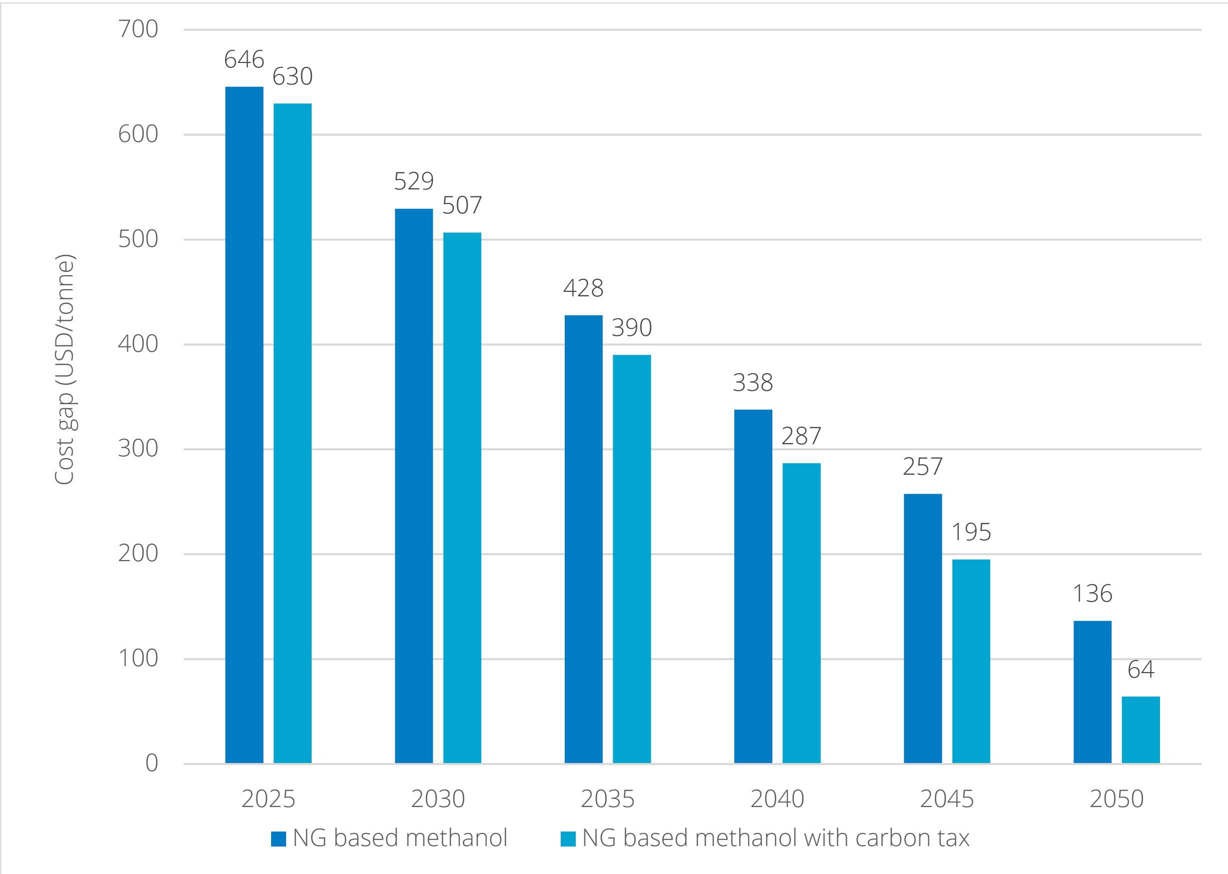


Figure 32: Cost gap between green and natural-gas-based methanol with and without carbon tax

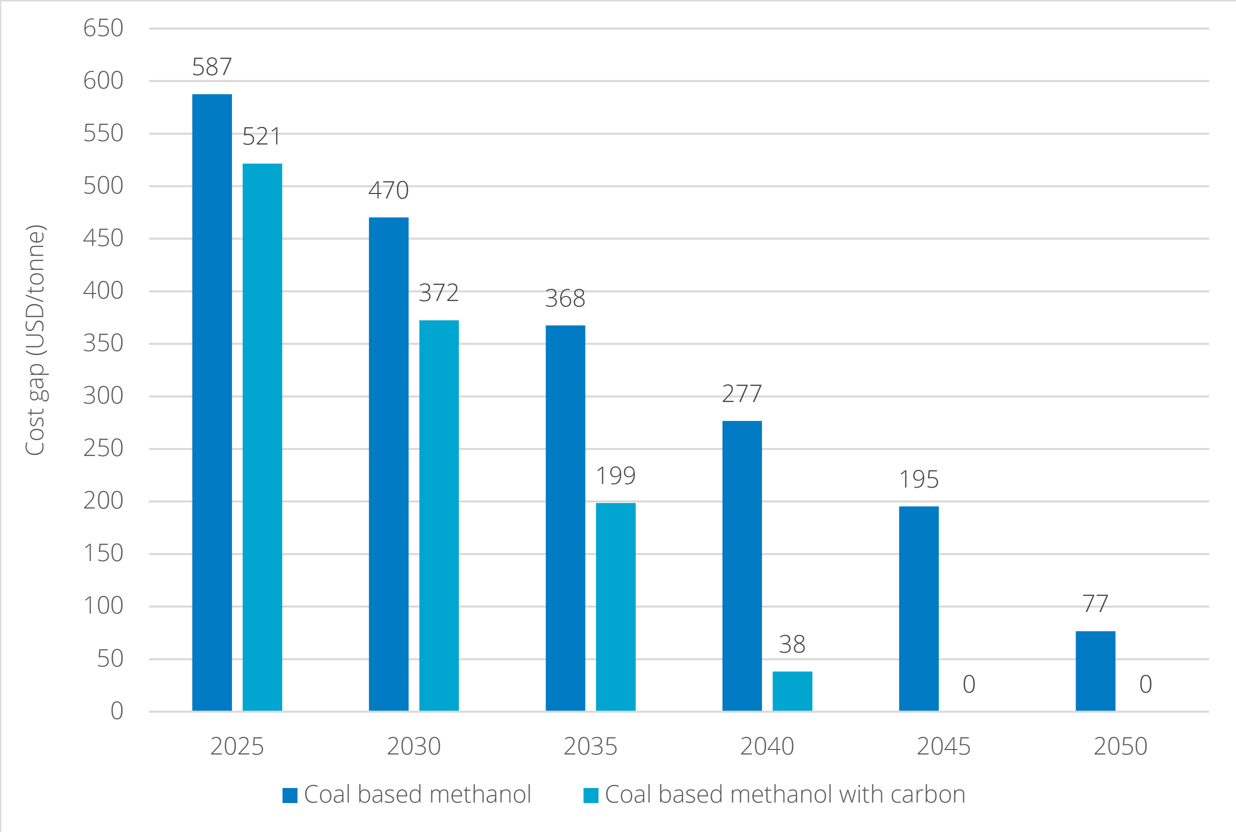


Figure 33: Cost gap between green and coal-based methanol with and without carbon tax

For steel, the cost gap between green and grey steel (energy component only) is projected to decline from USD 175/tonne to USD 147/tonne in 2025, and the cost parity will be reached shortly after 2035.

Figure 34 shows the cost gap for natural-gas-based steel with and without carbon tax.

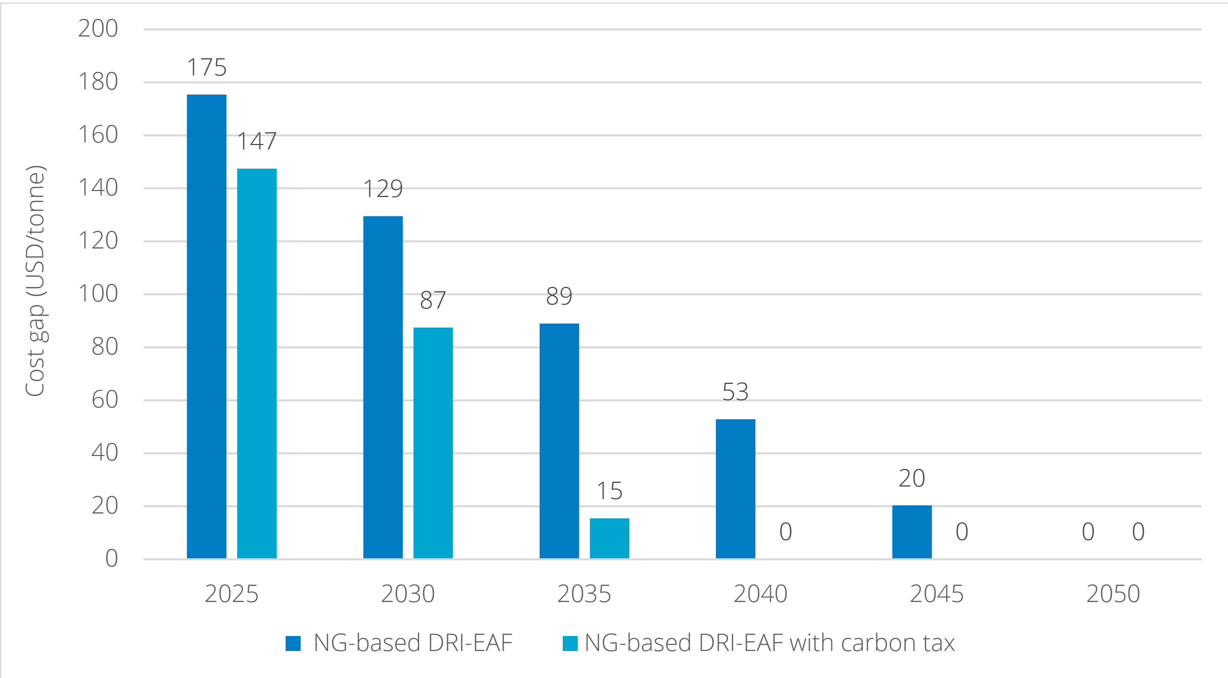


Figure 34: Cost gap between green and natural-gas-based steel with and without carbon tax

7 OTHER RENEWABLE ALTERNATIVES

Several alternatives to GH_2/PtX are emerging, and most of them are based on three technologies: CCS, batteries, and biofuels as presented in the table below.

Table 8: Alternatives for green hydrogen applications

PRODUCT	APPLICATION	ALTERNATIVE
Green ammonia	Export, fertiliser	CCS (blue ammonia)
Green ammonia	Transportation	Batteries, biofuels
Green Steel	Industry	CCS
Methanol	Transportation	Batteries, biofuels
SAF	Transportation	Batteries, biofuels

This section analyses these alternatives in order to identify any threats they may exert on GH_2/PtX counterparts.

7.1 Carbon Capture and Storage

H_2 has become more important as a way to reduce GHG emissions and to enable the achievement of the carbon neutral. Many countries and regions have developed H_2 strategies, where some of these only consider GH_2, while others also consider blue H_2 on top of GH_2 (Riemer and Duscha 2022).

Currently, the majority (about 98%) of H_2 production comes from reforming methane or coal gasification and other fossil-fuel-based materials. A small fraction (less than 0.4%) of H_2 is produced by using RE to electrolyse water. CCS is only used in about 1% of H_2 production from fossil fuels. Unfortunately, the emissions from global H_2 production are significant, with around 830 million tonnes of CO_2 being emitted annually (IEA 2019).

CCS is one of the options considered by some jurisdictions to limit GHG emissions, at least for a transitional period. CCS involves using a variety of technologies to capture CO_2 from large sources such as power plants or factories that use fossil fuels or biomass. CO_2 can also be taken directly from the atmosphere. Once captured, the CO_2 is compressed and transported via pipelines, ships, trains, or trucks for use in different applications or stored permanently in geological formations like depleted oil and gas reservoirs or saline formations. Figure 33 shows the value chain of CCS.

The overall reduction of CO_2 emissions depends on the amount of CO_2 captured and how it is used (IEA 2020). Different terminology is often adopted when discussing carbon capture, utilisation and storage (CCUS) technologies and summarised below (IEA 2020):

- CCS: includes applications where the CO2 is captured and permanently stored.
- Carbon capture and utilisation (CCU) or CO2 use: implies the use of CO2, in the production of fuels and chemicals, for example, methanol and kerosene production
- CCUS: combines CCU and CCS, for example, in enhanced oil recovery (EOR) or in building materials, where the use results in some or all of the CO2 being permanently stored.

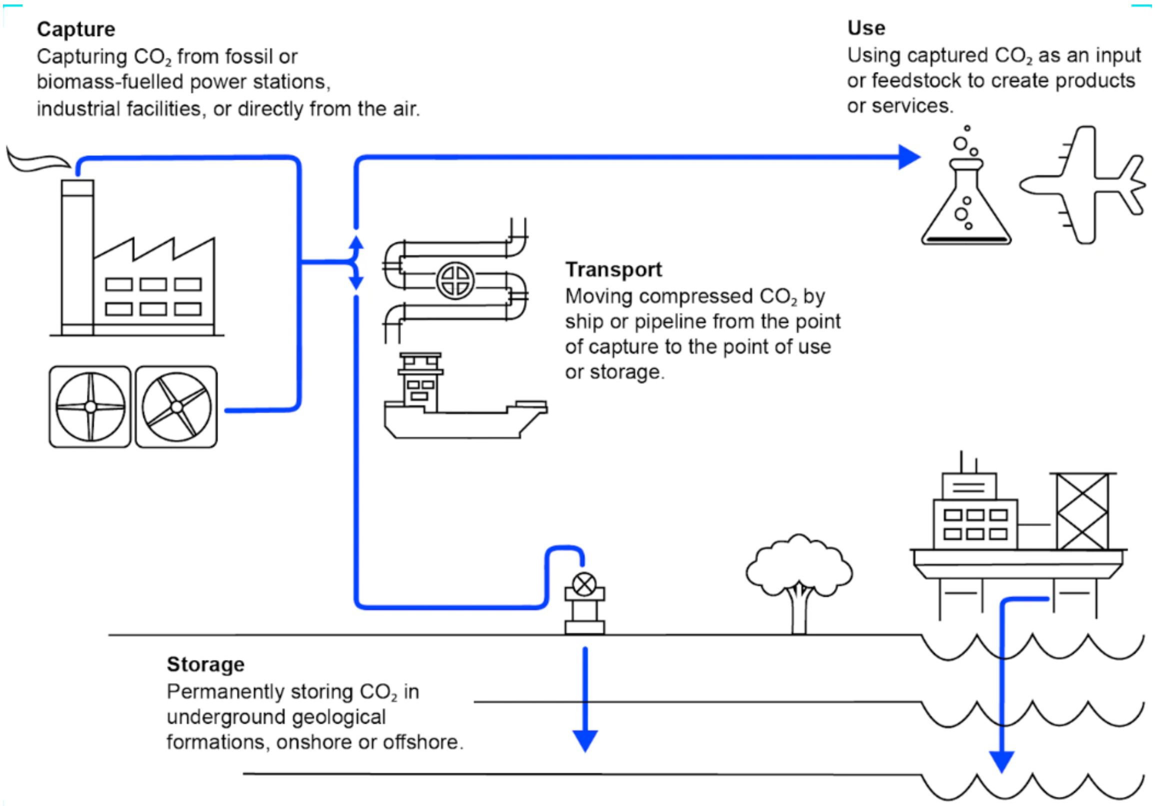


Figure 35: CCS value chain

Source: IEA (2020)

The use of CCS technology may compromise the offtake of GH_2 if blue H_2 can be produced at a lower cost compared to GH_2. The cost of producing blue H_2 can vary depending on the fuel costs in different locations. Implementing CCUS in SMR plants typically results in a 50% increase in CAPEX and a 10% increase in fuel costs, although the exact amounts depend on the specific design. Additionally, OPEX is likely to double due to the added expenses of CO_2 transportation and storage (IEA 2019).

The production cost of blue H_2 in South Africa was estimated through modelling, where an increase in LCOH varies from USD 1.17 to 1.74/kgH_2 in the case of natural gas with CCS and USD 2.05 to 2.13/kgH_2 in the case of coal gasification with CCS.

This leads to a decreased cost gap for ammonia from USD 379 to 276/tonne for natural-gas-based ammonia and from USD 219 to 204/tonne for coal-based ammonia. For fertiliser in the case of urea, for instance, the cost gap decreases from USD 216 to 157/tonne and from USD 125 to 116/tonne for natural-gas- and coal-based production, respectively. The last case is AN, where the production cost gap declines from USD 163 to 118/tonne and from USD 94.5 to 88/tonne for natural-gas- and coal-based production, respectively.

However, it must be noted that in CCS and CCU, all produced CO_2 is not captured completely. A 90% capture rate was estimated. In the case of CCS and CCU, carbon tax can therefore be applied to the remaining 10% emission not captured. Moreover, the above cost does not include the cost of transportation and storage of CO_2.

Expenses associated with transporting and storing CO_2 can affect the overall cost. For instance, the production of 1 kg of H_2 using CCS technology results into 8 kg of CO_2 if natural gas is used and 22 kg of CO_2 in the case of coal. All these CO_2 quantities must be transported and stored, which means that the cost of blue H_2 from coal with CCS is more impacted by CO_2 transport and storage costs compared to gas (Global CCS Institute 2021).

However, a limiting factor that could make blue H_2 less attractive or less feasible to South Africa is that the geological storge capacity is limited and with low confidence[8] (Global CCS Institute 2021). Confidence is a measure of the maturity of storage resource appraisal.

The below figure shows the estimated geological storage capacity in billions of tonnes.

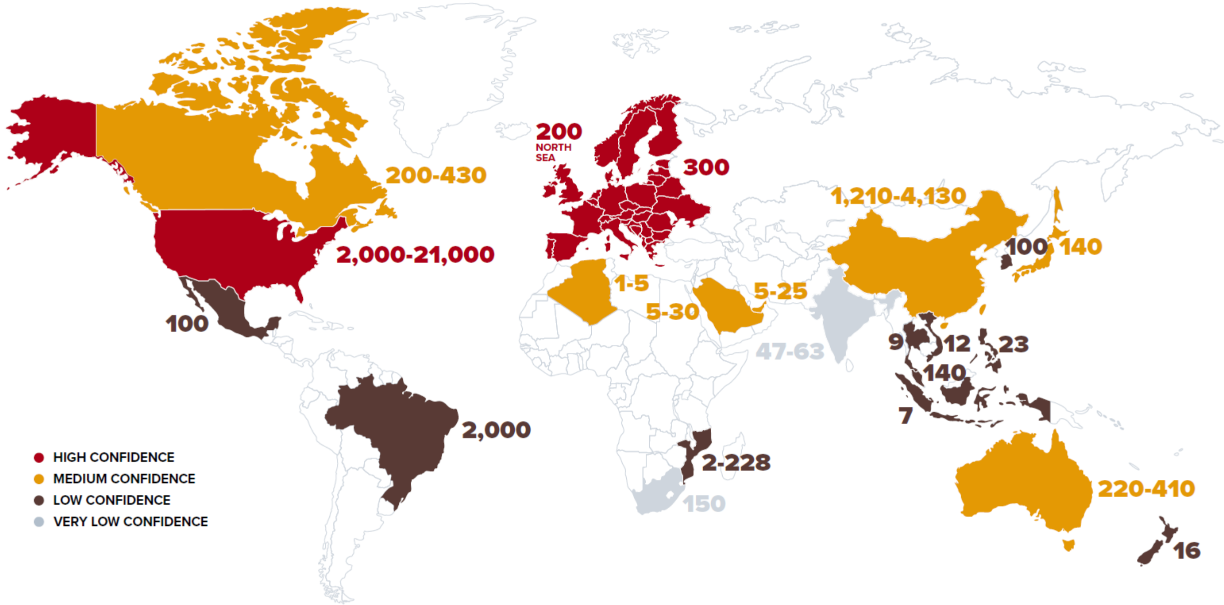


Figure 36: Estimate of Global CO_2 Geological Storage Capacity

Source: Global CCS Institute (2021).

For iron and steel, it is very hard to estimate the cost impact. Wide ranges have been estimated due to the multiple points of emissions in the manufacturing process and the range of expected emissions reduction. The estimated costs range from USD 10-116/tonne CO_2, and the emissions reduction ranges from 8-55% (Leeson, et al. 2014) .

7.2 Batteries

The shipping industry has shown growing interest in lithium-ion (Li-ion) batteries over the past few years. This can be attributed to various reasons, but the most significant one is the considerable drop in prices. The advancements made in the automotive industry have contributed to the technology and production scale. Furthermore, certain regions have implemented regulations requiring low-emission or emission-free operations. Norwegian ports and fjords have become a focal point, and electric or hybrid operations are now the preferred option for new ferries in some areas. With the gradual improvement of charging infrastructure, batteries are poised to become an even more appealing option (DNV 2019).

With regard to electric and hybrid vessels, the initial investment can be high due to the cost of batteries, power systems, and charging infrastructure. However, the long-term benefits include lower energy and maintenance costs. Electric motors are simpler and cleaner to operate than combustion engines, which lower operational costs depending on oil and electricity prices. For instance, the Ampere, the world's first all-electric ferry, has been operating between Norwegian ports since 2015 and saves 60% on average in fuel costs while reducing annual CO_2 emissions by 2,680 tonnes (DNV 2019).

[8] Confidence is a measure of the maturity of storage resource appraisal.

In terms of competition (see Error! Reference source not found.), PTG and PTL products have higher energy densities in terms of both weight and volume compared to Li-ion batteries, which makes them more attractive for long-hall transport (Dieterich, et al. 2020).

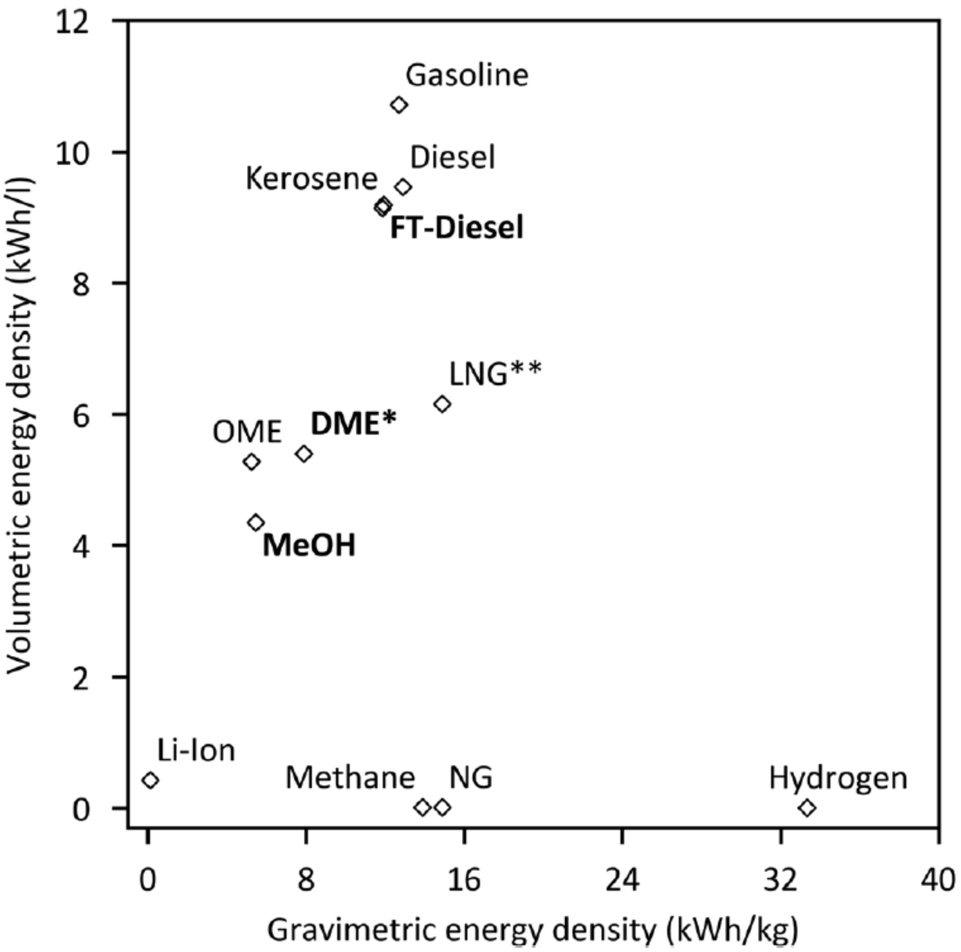


Figure 37: Li-ion batteries energy density vs different types of fuels

Source: Dieterich, et al. 2020

Currently, batteries are mainly used in cars and passenger ferries, with offshore vessels, cruise ships, and fishing boats following suit. Tugs have also adopted this technology, and it is spreading rapidly. Furthermore, deep-sea vessels are starting to utilise batteries to optimise their power management, reducing fuel consumption and maintenance costs for both propulsion and auxiliary power usage. Hybrid power systems, particularly in the ferry and short-sea sectors, are likely to see more batteries being incorporated. Additionally, larger vessels will gradually begin to integrate batteries, most likely as a plug-in option for emission-free port navigation and in-port operations (DNV 2019).

Batteries are being considered as one of the viable solutions to achieve carbon-neutral or zero-emissions shipping. Although batteries alone may not be sufficient for powering large ships, they are still a feasible option for smaller vessels. Furthermore, combining batteries with alternative fuels can be an effective strategy to reduce emissions.

7.3 Biofuels

Biofuels can contribute to reducing GHG emissions in the transport sector. These fuels can be used in existing engines with minimal modifications. In 2022, demand for biofuels reached a high record of 4.3 exajoules (170,000 million litres), exceeding pre-Covid-19 levels seen in 2019 (IEA 2023).

There are several pathways for producing biofuels that have achieved commercial status, including ethanol from corn and sugarcane, fatty acid methyl ester (FAME) biodiesel (the generic chemical term for biodiesel derived from renewable sources), hydrotreated vegetable oil (HVO) as a renewable diesel from vegetable and waste oil, and hydroprocessed esters and fatty Acids (HEFA) bio jet kerosene from vegetable and waste oils. Some other pathways are expected to become commercially viable soon. These include the alcohol-to-jet (ATJ) route from ethanol production, which is projected to be available by the end of 2023. Moreover, some companies are exploring new oilseed crops that do not compete with arable land (IEA 2023).

Producing biofuels can be a costly process. One method, the HEFA/HVO route for aviation, can result in fuels that are three to six times more expensive than traditional jet fuel. The cost depends on the current price of petroleum jet fuel and the type of lipid feedstock used to create the bio jet. As of September 2020, the price of HEFA was USD 2,124/tonne, based on the Argus Media index. This translates to approximately USD 272 per barrel or USD 1.7 per litre (IRENA 2021).

The production of biofuels currently depends mainly on traditional sources such as sugar cane, corn, and soybeans (IEA 2023), which presents certain difficulties. For biofuels to be sustainable, these crops must also meet several other requirements, such as not harming soil quality or biodiversity, causing soil erosion, or emitting pollutants into the air or water. Moreover, energy crops can also be grown, preferably on land that is not used for food or other crops, such as contaminated and marginal land. Therefore, it is crucial to explore advanced feedstocks to reduce the negative effects on land use, food and feed prices, and the environment.

8 CONCLUSION

South Africa is well-positioned to become a major player in the GH_2 economy thanks to its abundant RE resources, experience in the petrochemical industry, and commitment to promoting the technology. The country's H_2 ambitions are driven by a desire to achieve its defossilisation goals while also supporting economic growth and exports. The country has developed the HSRM and the GHCS to guide its vision for the future.

This study analysed the cost gap between green products (ammonia for export and fertiliser production, green steel, green methanol, and SAF) with their fossil-fuel-based counterparts and well as renewable-based alternatives.

The results of the analysis reveal that that some applications have a small cost gap (e.g., fertiliser), while the gap is large for others (e.g., SAF). The calculated cost gaps show the promising applications that South Africa can focus on in the medium- and long-run.

As summarised in the below table, green ammonia and green steel are the most promising applications that could lead the H_2 revolution in South Africa. The cost gap can be filled by carbon tax or provision of subsidies.

Table 9: Summary of cost gaps for the selected applications

APPLICATION	2025	2030	2035	2040	2045	2050
Ammonia for export	220-380	115-265	20-100	0-80	0	0
Ammonia for fertiliser (average for urea and AN)	128-207	81-144	40-90	16-42	0-18	0
Green steel	175-219	174-129	88-135	52-100	20-68	0-42
Methanol	385-686	269-596	166-466	74-374	0-292	0-170
SAF	1,330-1,770	1,023-1,463	716-1,156	481-921	283-723	0-425

This analysis also examined different alternatives to GH_2/PtX in the chosen applications, mainly blue H_2, batteries, and CCS/CCU. The analysis reveals these alternatives do not pose significant threats to GH_2/PtX in South Africa. Blue H_2, for instance, might be relatively cheaper (compared to GH_2) in the short term; however, in the long term, GH_2 becomes competitive. Moreover, it is not confirmed yet if CCS is suitable for South Africa due to a very low confidence in the maturity of the technology in the country.

On the other hand, batteries are considered to be useful in mobility; however, due to their low energy density, they are not suitable for long distances. Biofuels are considered one of the alternatives, and while they have several advantages, they also face several challenges. The most significant challenge is that South Africa is a water-stressed country, and producing biofuels would consume fresh water, which would result in competition with food crops.

The analysis yields several recommendations, which are summarised below:

- Carbon tax and subsidies: could be used to decrease the cost gap between GH_2/PtX and fossil fuel-based H_2.
- Mandatory GH_2/PtX targets in some applications, especially those applications that are expected to become cost competitive in the short-run (e.g., fertiliser steel production).

- Considering renewable alternatives as a supplement to GH_2/PtX and not a rival: GH_2/PtX do not fit all the applications and usages. There are cases where GH_2/PtX are the most suitable and instances where the alternatives (e.g., batteries) are most suitable. This should be evaluated case by case.

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