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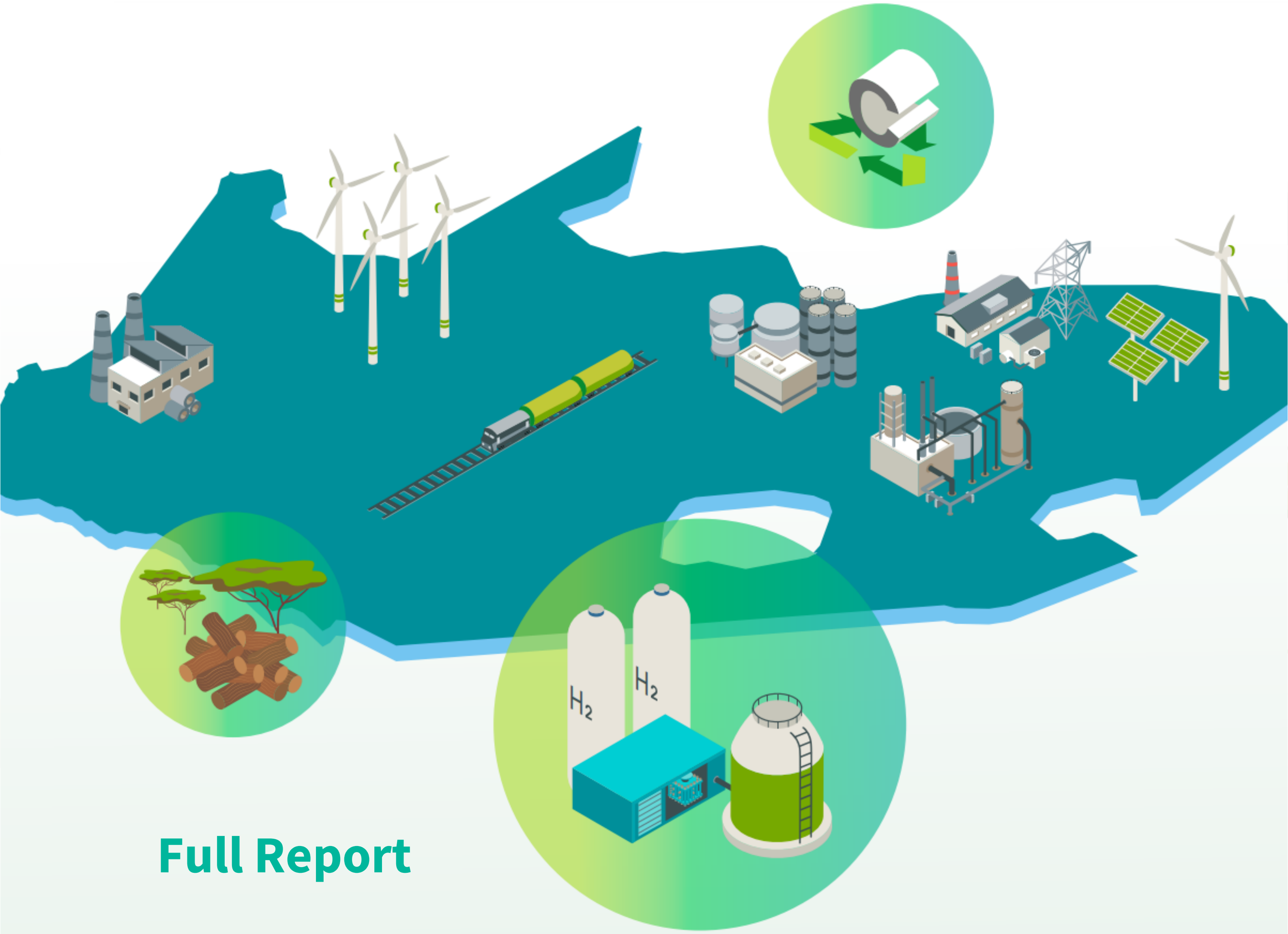
Carbon Sources for PtX Products and Synthetic Fuels in South Africa



Full Report

IMPRINT

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Registered offices:
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International PtX Hub
Potsdamer Platz 10
10785 Berlin, Germany
T +49 61 96 79-0
F +49 61 96 79-11 15

E info@ptx-hub.org
I www.ptx-hub.org

Responsible:
Alexander Mahler, Johannes Arndt (GIZ)

Researcher:
Dr. George Vourliotakis, Dr. Gerhardus Human,
Dr. Petra Behrens, Dr. Dimitris Sarantaridis,
Dr. Sotirios Karellas, Mr. Odysseas Platsakis

EXERGIA Climate Change Consultants S.A.
15 Voukourestiou Str.
10671 Athens, Greece

Layout:
peppermint werbung berlin gmbh, Berlin

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March 2024

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Abbreviations

AEL	Alkaline electrolysis
AFID	Alternative Fuels Infrastructure Directive
AFIR	Alternative Fuels Infrastructure Regulation
BECCS	Bioenergy with carbon capture and storage
CAPEX	Capital expenditure
CBAM	Carbon Border Adjustment Mechanism
CCDR	Country Climate and Development Reports (WB diagnostic reports)
CCS	Carbon Capture and Storage
CCU	Carbon Capture Utilisation
CCUS	Carbon Capture, Utilisation and Storage
CDR	Carbon Dioxide Removal
CEN	European Committee for Standardization
CENELEC	European Committee for Electrotechnical Standardization
CESNI	European committee for drawing up standards in the field of inland navigation
CLC	Chemical Looping Combustion
CORSIA	Carbon Offsetting and Reduction Scheme for International Aviation
CSIR	Council for Scientific and Industrial Research (South Africa)
CTL	Coal-to-Liquid
DAC	Direct Air Capture
DMRE	Department of Mineral Resources and Energy (South Africa)
DRI	Direct Reduction of Iron
EOR	Enhanced Oil Recovery
ETS	(EU) Emissions Trading System
FOLU	Forestry and other land use
ICAO	International Civil Aviation Organisation
IEA	International Energy Agency
IMO	International Maritime Organisation
IPPU	Industrial Processes and Product Use
IRP	Integrated Resource Plan
LCA	Life Cycle Assessment
LOHC	Liquid Organic Hydrogen Carriers
MEA	Mono Ethanol Amine
MTBE	Methyl Tert-Butyl Ether
NDC	Nationally Determined Contributions
OPEX	Operational expenditure
PPA	Power Purchase Agreement
PSA	Pressure Swing Adsorption
RED	Renewable Energy Directive
RFG	Recycled Flue Gas
RFNBO	Renewable Liquid and Gaseous Fuels Of Non-Biological Origin
RLF	Low-Carbon Fuels
RRF	Recovery and Resilience Facility
RWGS	Reverse Water-Gas-Shift Reaction
SAF	Sustainable Aviation Fuels
TRL	Technology Readiness Level
TSA	Temperature Swing Adsorption
VPSA	Vacuum Pressure Swing Adsorption

EXECUTIVE SUMMARY

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Executive summary

Overall framework

The scope of the present study is to primarily **investigate South Africa's potential for producing PtX products**, in order to determine whether the country can afford exporting these products instead of only using them domestically for achieving its own climate change mitigation goals and for being aligned with the global defossilization and decarbonization trends. The report discusses the existing CO2 point sources in South Africa and assesses the technical possibilities of Carbon Capture (CC) technologies for extracting CO2 from these sources.

The **overall methodological approach** of the study follows a demand and supply analysis:

- **Demand for CO2 as a feedstock for PtX product**, is quantified through estimation of the domestic demand for PtX products in South Africa, based on relevant national planning documents, and also potential demand by foreign markets (EU, ICAO, IMO), focusing on set targets and sustainability requirements;
- **Supply of CO2 as a feedstock for PtX product**, is determined on the basis of the estimation of the available CO2 that could be potentially captured, considering mostly the industrial point sources in the country. The potential expected quantities of **CO2 from the power, petrochemical, cement and steel sectors in South Africa** are analysed and estimated, considering the announced plans for the development of the sectors towards 2030 and 2050.

Considering the above, **exports can be approached as the difference between the potentially captured CO2 from the industrial point sources and the domestic demand for CO2 as a feedstock**. The sustainability dimension as a key factor determining the eligibility of the capture CO2 in the exporting countries is also touched upon, although the study primarily aims at providing a more theoretical analysis that will set the basis for future targeted investigation.

South Africa's carbon supply potential

South Africa is one of the largest greenhouse gas (GHG) emitters on the African continent. The country's power and industrial sectors are the primary sources of its GHG emissions, with coal-fired power plants and heavy industries, such as iron & steel, cement and petrochemicals, being the major emitters.

The evolution of South Africa's power sector emissions can be estimated through a combination of factors such as current emission levels, future energy demand projections, and policy and regulatory frameworks. The government's Integrated Resource Plan of 2019, which outlines the country's energy mix and electricity generation capacity, provides a basis for **estimating future emissions from the power sector, considering the expected fuel mix by 2030 and 2050 and a mean emissions factor**. Subsequently, carbon capture is assumed to take place via a post combustion capture process using MDEA (methyldiethanolamine) as solvent.

Besides power, **process emissions of South Africa's core industries in the 2030 and 2050 horizon are estimated on the basis of relevant analysis and projections** reported in the literature for the industrial emissions of the entire African continent (McKinsey, Africa's green manufacturing crossroads report, 2021). The analysis is based on the IEA's decarbonization scenarios framework, namely (a) a base case, where African countries comply with their current NDC commitments and Industry does not make any specific decarbonization efforts beyond the set NDC requirements, and (b) a global NDC-guided case, that aligns Africa's NDC with the global average and the industry undertakes mainly relatively inexpensive brownfield improvements (e.g., use of biofuels). Only the unavoidable portion of the Industrial process emissions, is considered to be available for the carbon capture process, which refers to the emissions that are inherent in certain industrial processes for which mitigation is not currently feasible.

Table 1 provides an **overview of the estimated potential for captured CO2 from the analysed sectors in South Africa**, considering applicable technologies and assuming that carbon capture is applied to unavoidable industrial emissions. Reported quantities should be considered at the theoretical maximum ones and the exact determination of the techno-economical feasible captured CO2 utilization is subject to further detailed studies.

In terms of sustainability criteria, sectors with highest share of unavoidable emissions should be prioritized for carbon capture. Starting from the cement sector which has the highest share of unavoidable emissions (most sustainable) and moving up to the power sector which has the lowest share (least sustainable), the estimated amount of captured CO2 per point source is presented in the following graphs for the years 2030, 2040 and 2050. With respect to the readiness for implementing CC in each sector, it should be mentioned that alternative processes/technologies for steelmaking are already available and can be implemented in the 2030's, while the petrochemical sector would need more time for its transition (based on the publicly available Sasol's sustainability plan). Further, according to the country's NDC, defossilisation of the power sector will not take place before 2050.

The following two figures (Figure 1 and Figure 2) present the lowest and highest amounts of captured CO2 respectively, as derived from the base case and Global NDC-guided scenarios. The maximum amounts of captured CO2 ranges between 210-220 MtCO2 for 2030, 140-170 MtCO2 for 2040 and 170-206 MtCO2 for 2050, which would allow, assuming that renewable hydrogen will be available at scale, to sustainably produce at least 81 million litres of synthetic kerosene in 2030 and 65 million litres in 2050.

Table 1 Overview of captured CO2 from each sector, considering applicable technologies and assuming that CC is applied to unavoidable emissions

Sector	Process emissions share (unavoidable emissions)	2030 MtCO2	2040 MtCO2	2050 MtCO2
Mineral (cement / lime)	65%	6,0-6,9	3,8-9,6	3,3-13,7
Petrochemical (CTL/petr. refining)	50%	29,9-38,7	11,4-36,0	7,1-34,6
Iron and steel	12%	1,1-1,3	0,9-1,4	0,5-1,6
Power	0%	170,9	126,2	155,4

Figure 1 Potential for captured CO2 ordered according to sustainability criteria – Global NDC ambitions scenario

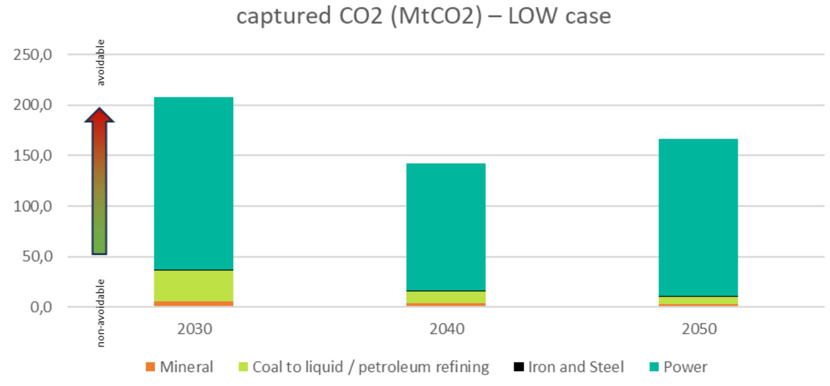

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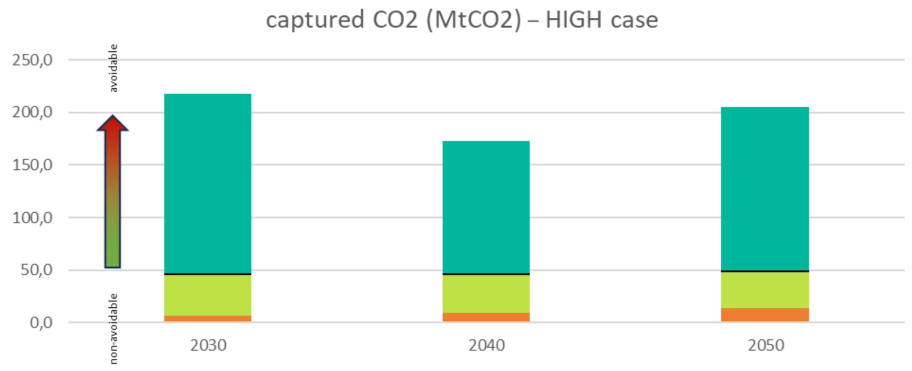
Figure 2 Potential for captured CO2 ordered according to sustainability criteria – Existing African NDC scenario



South Africa's carbon domestic demand

The potential carbon domestic demand, with respect to utilizing emitted CO2 for the production of synthetic fuels or other derivatives, is approached through the **analysis of the published scenarios for the evolution of the liquid fuel demand for transport applications up to 2050** (National Business Institute -NBI- publication series 'Just Transition and Climate Pathways Study for South Africa' – Chapter 2: Decarbonising South Africa's Petrochemicals and Chemicals Sector). The scenarios assume liquid fossil fuels will still play a major role in the mix, but the gradual penetration of hydrogen (H2), Sustainable Aviation Fuel (SAF) and electricity (i.e. for Electric vehicles -EVs-) is also foreseen. Based on these scenarios, **three scenarios for the degree of CO2 exploitation that could be aimed for have been interpolated**, namely:

- **Max CO2 Exploitation**: all the projected liquid fossil fuel is substituted by green synthetic fuel. SAF production as per NBI scenario
- **Medium CO2 Exploitation**: half of the projected liquid fossil fuel is substituted by green synthetic fuel. SAF production as per NBI scenario.
- **Min CO2 Exploitation**: no liquid fossil fuel is substituted. SAF production as per NBI scenario.

The next step of the analysis is to **translate the energy demand for fossil fuels into CO2 demand for the production of PtX of equivalent energy**. To that end, we assumed that the fossil fuel in the developed scenarios is replaced by synthetic fuels, produced by the Reverse Water Gas Shift Fischer Tropsch (RWGS FT) process, and SAF is produced by direct methanol synthesis, followed by e-methanol-to-kerosene conversion. The respective estimates are shown in Table 2.

Table 2 CO2 demand estimations for the different scenarios considered

Matrix of liquid fuel demand and green synthetic fuel exploitation scenarios, including respective CO2 demand				Max Exploitation All liquid fuel demand covered by green fuels		Medium Exploitation Half of liquid fuel demand covered by green fuels		Min Exploitation Only SAF projected demand is met	
	Year	Liquid fossil fuels (PJ)	SAF (PJ)	CO2 (Mt) for e-diesel	CO2 (Mt) for SAF	CO2 (Mt) for e-diesel	CO2 (Mt) for SAF	CO2 (Mt) for e-diesel	CO2 (Mt) for SAF
Reference Technology Scenario	2030	791	1	67.7	0.1	33.9	0.1	-	0.1
	2040	668	30	57.2	2.2	28.6	2.2	-	2.2
	2050	500	80	42.8	5.9	21.4	5.9	-	5.9
Sustainable Development Scenario	2030	709	5	60.7	0.4	30.4	0.4	-	0.4
	2040	554	35	47.4	2.6	23.7	2.6	-	2.6
	2050	388	73	33.2	5.4	16.6	5.4	-	5.4
Global net-zero Scenario	2030	689	5	59.0	0.4	29.5	0.4	-	0.4
	2040	368	33	31.5	2.4	15.8	2.4	-	2.4
	2050	124	81	10.6	6.0	5.3	6.0	-	6.0

Estimated carbon exports potential

Overall, and following the methodology employed in this work, Table 3 provides an overview of:

- The estimated captured CO2 from the point sources examined in the present work (i.e. power sector, iron and steel, cement and petrochemical industries), following the two scenarios considered (base case and global-guided NDC case): Results are presented considering the quantities coming from the power sector, as well as considering only CO2 from process emissions (i.e. only the unavoidable emissions);
- The estimated quantities of CO2 needed for the production of synthetic fuels to cover domestic needs in South Africa;
- The estimated exports potential, determined by subtracting the domestic CO2 demand from the overall produced CO2: Results are presented considering the quantities coming from the power sector, as well as considering only CO2 from process emissions (i.e. only the unavoidable emissions)

It is noted that the reported values represent the theoretical upper limit of captured carbon – practical and market considerations in operating plants can reduce the expected captured carbon to as low as 20-60% of the theoretical values.

Table 3 Overview of estimated captured CO2 from point sources, estimated CO2 quantities of CO2 to cover domestic needs, and estimated available CO2 for exports

CO2 quantities (MtCO2)	2030	2040	2050
Captured CO2 – incl. power sector	207.9 – 217.8	142.3 – 173.1	166.3 – 205.3
Captured CO2 – without power sector	37.0 – 46.9	16.1 – 46.9	10.9 – 49.9
Domestic CO2 demand	29.9 – 67.8	18.2 – 59.4	11.3 – 48.7
CO2 available for export – incl. power sector	137.5 – 187.9	79.4 – 155	107.8 – 194
CO2 available for export – without power sector	0 – 17.0	0 – 28.7	0 – 38.6

Based on the results, it can be concluded that if South Africa were to substitute all projected fossil fuel consumption with locally produced synthetic fuel, **there would be potentially enough captured CO2 from its point sources to meet that 'domestic' demand**. Further, there is also **significant CO2 surplus that could be utilised for exports**. However, **sustainability considerations would limit the available quantities that can in principle be eligible for exports to international markets**, since unavoidable emissions are a relatively small portion of the total emissions, which are dominated by coal power production. For the EU market, CO2 from the power sector would only be eligible until 2036, according to the Renewable Energy Directive (RED), while CO2 from other sectors, such as petrochemicals, will be eligible until 2041. It is noted that sustainability criteria should be met in any case. Thus, defining the amortisation period of the above-mentioned point sources constitutes one of the key next steps for determining in a accurate quantitative manner the eligible CO2 for the various export markets, according to the relevant policies. In the case CO2 from the power sector is not considered, the estimated export potential for CO2 is drastically reduced, and depending on the defossilisation scenarios for domestic demand and degree of achievement of the global climate ambition, captured CO2 from industrial processes might not even been sufficient to cover the expected domestic demand of transport liquid fuels.

Figure 3 and Figure 4 schematically present the results of the present evaluation of the potential of South Africa for available CO2 for exports up to 2050, both when CO2 captured from the power sector in accounted for and when it is not. For each case, a range is presented, considering different scenarios with respect to the degree of defossilisation of the liquid transport fuels sector in South Africa. The presented potential for available CO2 for exports from South Africa does not consider specific sustainability requirements from the receiving markets; such a consideration would limit the available quantities and would even set them to zero after a certain period of time, as for example is the case of Europe with the previsions of RED.

Figure 3 Potential for available CO2 for exports, including CO2 captured from the power sector (MtCO2)

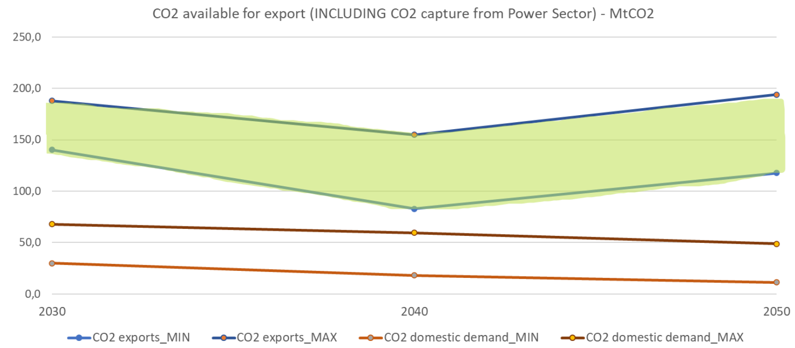
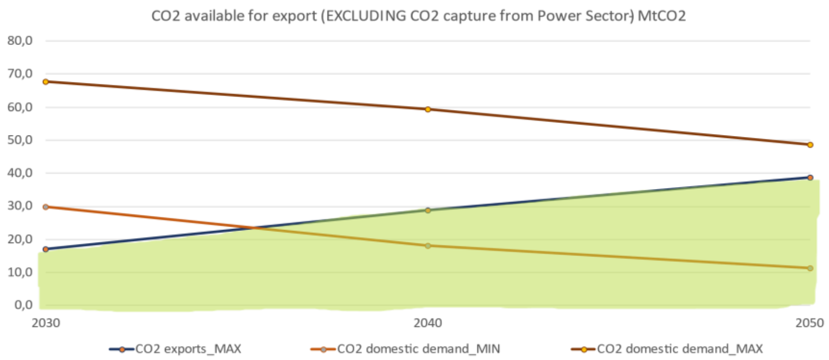


Figure 4 Potential for available CO2 for exports, excluding CO2 captured from the power sector (MtCO2)



Recommendations and Future Work

Power-to-X (PtX) fuels (and products) can provide a crucial solution that can replace fossil fuel consumption in the hard to abate sectors, mainly in industry and transport (including heavy-duty vehicles, shipping and aviation). Both hydrogen and carbon are needed for the synthesis process of a PtX product, and the way these two elements can be secured largely determine the technical, economic and sustainability potential for the finally produced synthetic fuel. The particular characteristics of South Africa's energy system, as well as its key geopolitical position in the southern part of Africa, well located for the global trade routes and with significant national trade history, have an important influence on the development of the PtX value chain. Below, **key recommendations to unlock the PtX products potential of South Africa are provided**:

- Recognise synthetic and PtX fuels as a key component of the energy mix for 2030 and 2050; this is an important prerequisite to set the foundations for the production and use of PtX fuels and allow for the development of the required value chain. Benefits (environmental, economic, energy security, technological, social) deriving from the creation of the PtX value chain both as a whole and at each individual stage.
- Create a long-term national energy strategy taking PtX fuels into account; a strategy will essentially provide a clear signal for the development of the relevant market, by identifying specific targets for the introduction of PtX fuels in the energy mix, on the basis of a least cost approach within a frame of decarbonization of the national economy and ensuring security of energy supply.
- Align the national regulatory frame with the relevant international best practices; Alongside the specific regulatory framework for PtX, any possible need to amend the regulatory framework in other energy sectors, notably electricity and renewables, should be considered. The aim is to establish a framework for regulation, design, and support that enables the coordination of different segments of the energy market to enable the development and use of the necessary PtX infrastructure.
- Promote technologies and demonstrate feasibility; performance of feasibility studies on identified CCU cases to allow for an accurate determination of the realistic potential in the key industrial sectors is needed, also considering the related environmental issues and the public acceptance of such projects.

Key next steps towards the determination of the 'marketable' exports potential of PtX products produced in South Africa would include the following:

- Consideration of biogenic carbon sources and quantification of their potential as carbon feed in the PtX process;
- Consideration of PtX products other than fuels, such as chemicals to be used as feedstock in the relevant industry;
- Determination of the real potential for implementation of carbon capture in the industrial point sources in South Africa.

1 INTRODUCTION

GREEN HYDROGEN SOUTH AFRICA

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Introduction

South Africa has set targets for developing a low-carbon, climate-resilient, and inclusive economy and the energy sector is arguably on the focus of national efforts. The country's coal-based power fleet is one of the most polluting globally and a key reason for the resulting carbon intensity of 8.0 t CO_2e per capita in 2020 (Republic of South Africa Department of Forestry, Fisheries and the Environment, 2022), while the high carbon intensity is also expected to reduce its competitiveness in international markets.

At the same time, South Africa has a significant potential for renewable energy, with solar and wind energy being the two most promising renewable energy sources. The outstanding renewable energy potential, together with the existing synthetic fuel production facilities, which have already played a significant role in the country's industrial development, provide essentially an opportunity for the country to position itself as a major supplier of renewable PtX products, providing that both renewable electricity and sustainably sourced carbon will be used.

The scope of the present study is to primarily investigate South Africa's potential for producing PtX products, in order to determine whether the country can afford exporting these products instead of only using them domestically for achieving its own defossilisation goals and for being aligned with the relevant global trends. The report discusses the existing CO_2 sources and assesses the technical possibilities of Carbon Capturing (CC) technologies for extracting CO_2 from these sources.

The **structure of the report** is the following:

- **Chapter 2** makes an **analysis of relevant international policies** that largely determine the demand for synthetic fuels and CO_2. Focus is given on the relevant EU framework, while other international such as the international aviation and maritime markets are considered due to the potentially favourable conditions, that they offer with respect to the required sustainability criteria.
- An estimation of the South African domestic **demand for carbon** is made in **Chapter 3**. This is based on an analysis of the expected demand for synthetic fuels in the country according to the stated policies and the announced national strategies. A 2050 horizon is considered, building on published works and plausible set of assumptions. Demand for CO_2 is directly derived considering the prevailing synthetic production paths.
- **Chapter 4** deals with the determination of South Africa's **carbon supply potential**. First, domestic industries that can provide CO_2 are identified and an estimation of their carbon production potential is made. Key sectors are: power generation and industry (petrochemicals, iron and steel, cement). A projection of SA's carbon sources volume until 2050 is made, and based on the results of Chapter 4, the **carbon export potential** is estimated. A high-level discussion on the classification of carbon sources by technological / economic / sustainability parameters is also provided.
- Building on Chapters 4 and 5, scenarios of carbon supply for the production of synthetic fuels in South Africa are discussed in **Chapter 5**.
- **Chapter 6** presents a **case study of applying carbon capture to a typical coal-fired power plant** and utilization of carbon for the production of synthetic methanol. Synthetic methanol is considered as a promising future alternative fuel for maritime, which is a potentially important sector for South Africa within the emerging relevant internal IMO market.
- Finally, **Chapter 7** provides **recommendations** regarding the potential for PtX products valorisation in South Africa and presents **directions for future work.**

2

INTERNATIONAL POLICIES DETERMINING DEMAND FOR SYNTHETIC FUELS AND CO2

This chapter provides an analysis of the current policy and legislative framework within the context of EU, and International Maritime and Aviation Organisations, with respect to the eligibility of synthetic fuels to count against the obligatory set targets in each jurisdiction. This includes a review of the demand drivers for exports of PtX fuels from South Africa to Europe and whether these imports comply with the requirements outlined in the European policy and the said international frameworks.

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International policies determining demand for synthetic fuels and CO2

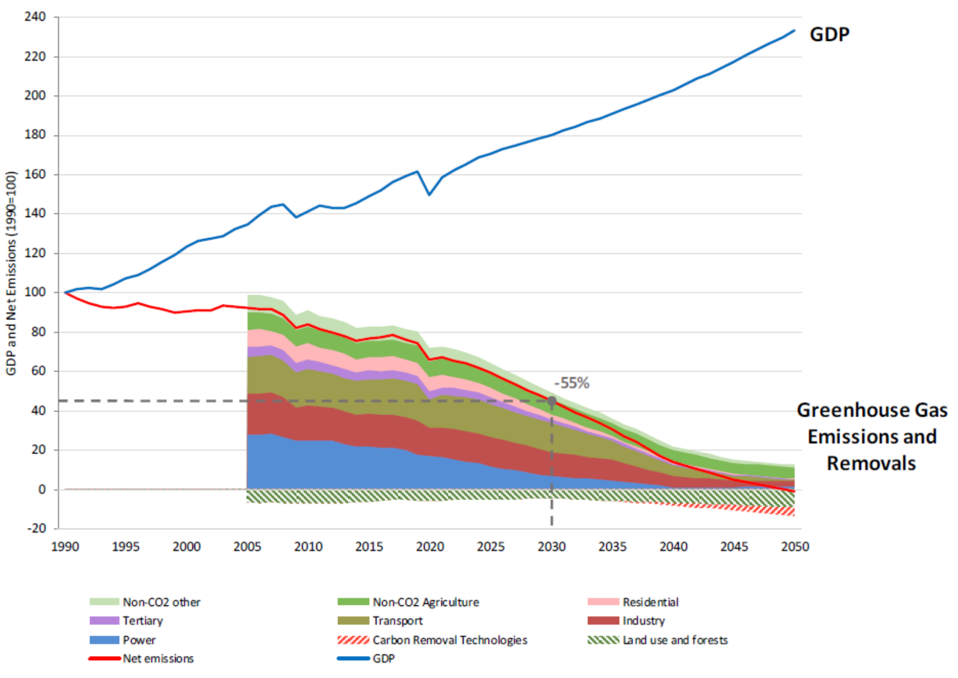
Background

The ongoing climate crisis requires urgent and sustained actions to achieve climate neutrality by 2050. The EU needs to decarbonise the energy it consumes in all sectors to reduce greenhouse gas emissions by at least 55% by 2030 and become climate-neutral by 2050 (EC, 2021). The transport sector contributes significantly to total emissions and is responsible for 25% of greenhouse gas emissions in the EU, mainly from roads (71%), aviation (14.4%) and ships (13.5%).

The sector has a low uptake of renewables that needs to be improved by an increased deployment of electric vehicles and clean hydrogen to decarbonise the heavy-duty transport sector. Hydrogen and its derivatives will be crucial for the decarbonization of the transport sector including the scale up production and usage of synthetic fuels used in the aviation and maritime sectors, that currently depend on high energy density fuels and is difficult to decarbonize.

Figure 5 shows the anticipated pathway in Europe to become climate-neutral by 2050 and the significance to include net zero emission solutions for all sectors. To decarbonise the transport sector, the use of green synthetic fuels (or PtX), incorporating the use of green hydrogen and CO2, which is of particular interest in this study, and the associated legislation/regulation context is analysed next.

Figure 5 EU pathway towards net zero Greenhouse gas emissions (EC, 2020).



EU policies and regulations linked to demand for synthetic fuels and CO2

EU hydrogen strategy (EC, 2020)

The EU strategy on hydrogen (COM/2020/301) was adopted in 2020 and suggested policy action points in 5 areas: investment support; support production and demand; creating a hydrogen market and infrastructure; research and cooperation and international cooperation.

Hydrogen is essential to support the EU's commitment to reach carbon neutrality by 2050 and for the implementation of the Paris Agreement while working towards zero pollution.

Currently, hydrogen represents a modest fraction of the energy mix. In 2022, hydrogen accounted for less than 2% of Europe's energy consumption, and most of it was not derived from renewables - 96% of this hydrogen was produced from natural gas (EC, 2022).

From 2020 to 2024 (**Phase 1** of the strategy), the objective is to install at least **6 GW of electrolysers** in the EU and produce up to **1 million tonnes of renewable hydrogen** aiming at decarbonizing existing hydrogen production in the chemical sector and facilitating take up of hydrogen in new end-use applications (industrial processes, heavy-duty transport etc.)

During **Phase 2** of the strategy, from **2025 to 2030**, hydrogen will become an intrinsic part of an integrated energy system with a strategic objective to install at least **40 GW of electrolysers** by 2030 and produce of up to **10 million tonnes of renewable hydrogen** in the EU29 (EC, 2020). Renewable hydrogen is expected to gradually become cost-competitive with other forms of hydrogen production, but dedicated demand side policies will be needed for industrial demand to gradually include new applications, such as steel-making, trucks, rail and other transport modes.

During **Phase 3** of the strategy, from 2030 to 2050, **renewable hydrogen technologies should reach maturity and be deployed at large scale** to reach all hard-to-decarbonize sectors.

So **hydrogen, and its derivatives**, play a pivotal role according to the above strategy in the pathway towards carbon neutrality and in the efforts to **decarbonise hard- to-abate industrial sectors and transport**.

Fit-for-55 (EC, 2023)

To translate the hydrogen strategy into a concrete European hydrogen policy framework, the Fit-for-55 package was introduced in July 2021. The **Fit-for-55 is the European legislative package proposal for reducing EU greenhouse gas (GHG) emissions by 55% by 2030, compared to a 1990 baseline and reach carbon neutrality by 2050**. The legislative proposals span all sectors of the economy, including shipping and the industry's upstream suppliers. The legislative package includes carbon pricing to discourage the use of carbon-based fuels, rules to ensure the production and uptake of alternative fuels and targets and common principles. **It includes a wide range of regulations and directives and has also highlighted the role of renewable hydrogen and synthetic fuels**. The following section provide an **overview** of the Fit-for-55 measures **relating to e-fuels.**

Alternative fuels infrastructure

The Alternative Fuels Infrastructure Directive (AFID) is being revised as part of the Fit-for-55 proposed measures and revamped as a regulation (AFIR) to **ensure that the adoption of renewable and low-carbon fuels** (RLF) **is not constrained by a lack of recharging and refuelling infrastructure**. The target is to ensure that there is the required infrastructure with coverage across the EU for cars, trucks, ships and planes to (re) charge or (re) fuel with alternative fuels, such as hydrogen and liquefied methane.

Emissions trading system (ETS)

ETS is the key tool for reducing greenhouse gas emissions and one of the world's largest carbon markets. The ETS covers around 40% of total EU emissions, including companies, electricity and heat generation, energy intensive industries (oil refineries, steel, cement, glass and paper industries) and commercial aviation. A new reduction goal is set to 62% emissions reduction by 2030 (up from the 41% achieved since it was first introduced in 2005). In March

2023 the Council adopted a separate amending decision for the ETS. It aims to address the surplus of emission allowances that have built up in the EU ETS since 2009 and to improve the system's resilience to major shocks by adjusting the supply of allowances to be auctioned. The decision prolongs beyond 2023 the increased annual intake rate of allowances (24%). In addition, further changes to the market stability reserve will be adopted as part of the revision of the EU ETS expected to be adopted soon (EC, 2023).

Carbon border adjustment mechanism (CBAM)

CBAM is a new regulation **creating incentives for non-EU producers to reduce emissions**. The CBAM entered into force on 17 May 2023 and will be implemented gradually. It will initially apply only to a selected number of goods at high risk of carbon leakage: cement, iron and steel, aluminium, fertilisers, electricity, hydrogen, as well as some precursors and downstream products made from cement, iron, steel, and aluminium. During the transitional period from 1 October 2023 to 31 January 2026, the burden will be administrative rather than financial, and importers will only report direct GHG emissions embedded in their imports. After the transitional period, importers will have to declare each year the quantity of imports to the EU in the preceding year and their embedded GHG emissions. They will subsequently have to purchase digital CBAM certificates, at a price to be calculated based on the weekly average auction price of EU ETS allowance expressed in €/tonne of CO2 emitted.

Only importers that have met the CBAM requirements will be permitted to import products which fall within the scope of the CBAM. In the case of SA, the CBAM is expected to have a negative impact on its exports. The iron and steel and aluminium sectors are particularly at high risk. This is primarily due to the use of coal-powered electricity and coal as feedstock in these sectors. As the EU plans to further expand the sectors covered by the CBAM, other industries are likely to be at risk too. In the short term, plastics and organic chemicals are expected to be included in the CBAM post assessments by the European Commission after the transitioning phase. South Africa's governmental and industrial stakeholders are concerned, that these developments will make carbon intensive exports increasingly costly and trade more difficult for South Africa if it does not decarbonise its energy and its carbon-intensive industries (Trade & Industrial Policy Strategies, 2023).

REfuelEU aviation and fuelEU maritime.

The aviation and maritime transport sectors account for 14.4% and 13.5% respectively of EU transport emissions (EC, 2023) (EC, 2015). In order to reduce emissions in these sectors, the ***proposed regulations*** *of* ***RefuelEU aviation*** *and* ***FuelEU maritime*** *aim to* ***increase the use of sustainable fuels by aircrafts and ships*** *and have set overall targets. Aircraft fuel suppliers at EU airports will be required to gradually increase the share of sustainable fuels from 2% by 2025 to 63% by 2050. Ship vessels above 5000 gross tonnes calling at EU ports are required to reduce their greenhouse gas intensity of their energy use and from 2030 to connect to onshore power supply. The annual average carbon intensity reduction should increase gradually from 2% in 2025 to 75% by 2050 compared to the 2020 average.*

Table 4 summarises the above pathways, including a breakdown of the respective targets.

Table 4 Targets of REfuelEU aviation and FuelEU maritime (EC, 2023) (EC, 2015).

Year	Share of sustainable fuels - aviation		Annual average carbon intensity reduction by maritime vessels	
	overall SAF target	Synthetic sub-target (Mukhopadhaya, 2022)	overall target	emissions forecast (Gozillon, 2022)
2025	2%	-	2%	89.9 CO2e/MJ
2030	6%	0.7%	6%	86.2 gCO2e/MJ
2035	20%	5%	13%	79.8 gCO2e/MJ
2040	32%	8%	26%	67.9 gCO2e/MJ
2045	38%	11%	59%	37.6 gCO2e/MJ
2050	63%	28%	75%	22.9 gCO2e/MJ

Ship traffic to or from ports accounts for some 11% of all EU CO_2 emissions from transport and 3-4% of total EU CO_2 emissions. The aim is to reduce average carbon intensity (CO_2 per tonne-mile) by at least 40% by 2030 and by 70 % in 2050, as well as to cut total emissions by at least 50% by 2050, compared to 2008. Additional measures of the proposed FuelEU Maritime include stricter rules on the monitoring and reporting of methane emissions and limiting the release of methane, as well that vessels from 2025 and ships from 2030 will have to connect to onshore power supply at EU ports. In 2022 the European Parliament and European Council adopted a position to finalise the initiative with a starting date of 01 January 2025 (Bureau Veritas, 2023).

The EU Emissions Trading System (ETS) and the Energy Taxation Directive (ETD) will disincentivize the use of fossil fuels reducing greenhouse gas emissions, in order for the maritime transport sector to reach its targets and adopting new renewable energy share outlined in the Renewable Energy Directive (RED). **Based on the GHG intensity reduction target, as this is expressed in both the RED and the FuelEU Maritime Regulation, it seems that synthetic fuels would be the primary option for maritime fuels to meeting the needs of the EU regulations**. ("Green" fuels for shipping: synthetic fuels produced from non-fossil fuel substrates and using renewable electricity (e.g., e-H_2, e-NH_3, e-methane, e-methanol))

Sustainable aviation fuels (on the other hand) would require a significant amount of renewable electricity to be produced, in order to replace 70% of the aviation fuel consumed in Europe. There would be a need, therefore, to add at least 1.5 times more renewables in the EU just to produce jet fuels and to significantly reduce the number of flights in order to get to achievable amounts of e-fuels (Bellona, 2023).

However, the number of flights at EU27+EFTA airports increased by 15% between 2005 and 2019 to 9.3 million, while passenger kilometres almost doubled (+90%). The CO_2 emissions of all flights reached 147 million tonnes in 2019. Long-haul flights (above 4,000 km) represented only 6% of departures during 2019, but were responsible for half of all CO_2 emissions (EASA, 2022).

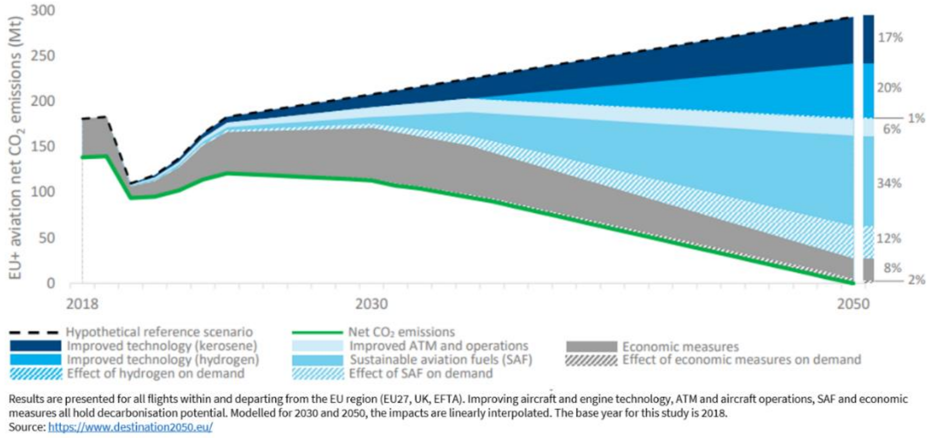
In 2021, five European associations representing airlines, manufacturers, airports, and air service navigation providers published the Destination 2050 report. It outlines a roadmap for the aviation sector to decarbonise by 2030 and reach net zero CO_2 emissions by 2050 (NRL SEO, 2021). Four key measures were identified to achieve the required CO_2 emission reductions. The improvements in aircraft and engine technologies (introduction of hydrogen-powered aircrafts) and the usage of sustainable aviation fuels would each reduce emissions by more than 30%. Economic measures and air traffic management and operations by another 8% and 6% respectively.

These measures would result in the following net CO_2 emissions reductions in the year 2050:

- 111 MtCO_2 through improvements in aircraft and engine technology;
- 60 MtCO_2 by hydrogen-powered aircraft on intra-European routes and
- 51 MtCO_2 by kerosene-powered or (hybrid-) electric aircraft;
- 18 MtCO_2 through improvements in air traffic management (ATM) and aircraft operations;
- 99 MtCO_2 through using drop-in sustainable aviation fuels (SAF);
- 22 MtCO_2 through economic measures (carbon removal projects only).

SAF, therefore, plays a major role in this pathway and its supply would need to increase from 3 Mt in 2030 to 32 Mt in 2050, equal to 83% of the total kerosene consumption. The pathway is illustrated in Figure 6.

Figure 6 European Aviation pathway to reduce Greenhouse gas emissions (NRL SEO, 2021).



REPowerEU plan: 2022

The Commission published the REPowerEU plan in May 2022 (EC, 2022) which sets out measures to rapidly reduce the dependence on Russian fossil fuels and to accelerating the clean energy transition. The Commission aimed to accelerate hydrogen technologies more quickly and to scale up demand and supply. The REPowerEU ambition is to produce 10 million tonnes of renewable hydrogen in the EU by 2030 – increased from the 5.6 million tonnes initially foreseen and to import 10 million tonnes of renewable hydrogen from third countries (EC, 2021).

The **REPowerEU plan builds on the full and fast implementation of the Fit-for-55 proposals** aiming to achieve at least -55% net GHG emissions by 2030 and climate neutrality by 2050. The plan also proposed to increase the target in the Renewable Energy Directive to 45% by 2030; this would bring the total renewable energy generation capacities to 1236 GW by 2030, in comparison to 1067 GW by 2030 envisaged under Fit-for-55 for 2030.

REPowerEU plan **puts** also **forward further actions based on saving energy, producing clean energy and diversifying the EU's energy supplies** and combining investments and reforms. The actions of the REPowerEU plan will structurally transform the European energy system in terms of quantities and directions of energy flows requiring effective regulatory and infrastructure measures.

The REPowerEU plan will support:

- innovative electrification and hydrogen applications in industry
- innovative clean tech manufacturing (such as electrolysers and fuel cells, innovative renewable equipment, energy storage or heat pumps for industrial uses) and
- mid-sized pilot projects for validating, testing and optimising highly innovative solutions

Renewable hydrogen will be key to replace the use of fossil fuels in hard-to-abate industries and the transport sector. REPowerEU sets a **target of 10 million tonnes of domestic renewable hydrogen production and 10 million tonnes of renewable hydrogen imports by 2030**. European industry is to accelerate the work on missing hydrogen standards, in particular for hydrogen production, infrastructure and end-use appliances and to deploy hydrogen infrastructure. This is, in particular, true for cross-border infrastructure requiring a total investment in the range of EUR 28 to 38 billion for EU internal pipelines and 6 to 11 billion for storage. The REPowerEU approach with respect to fuel diversification is summarised in Table 5.

Table 5 REPowerEU – Fuel Diversification (EC, 2022).

REPowerEU PLAN	Additional hydrogen	Joint EU and MS REPowerEU actions	Investment needs (EUR)
Fuel Diversification Renewable Hydrogen	+ 14 Mt of additional H2/ammonia of which 8 Mt replace natural gas equivalent to = 27 bcm 10 Mt is imported and about 4 Mt of additional domestic production	• RFNBO sub-targets in line with higher RED targets • Hydrogen Valleys • Regulatory framework: Delegated acts on definition and standards • Imports: Joint Gas and Hydrogen Purchasing Vehicle and International Hydrogen Partnerships • Industrial Capacity: Electrolyser Declaration • Innovation fund • RRF chapter	• 27 bn is direct investment in domestic electrolysers and distribution of hydrogen in the EU. • (excludes the investment of solar and wind electricity needed to produce renewable hydrogen, and it excludes the investments for the imported hydrogen)

Other targets set by the REPowerEU plan and Hydrogen Accelerator to fast-track the uptake of GH2 and synthetic fuels are:

- The request from industry to accelerate the work on missing hydrogen standards. The lack of standards increases uncertainties and transaction costs for industry. in March 2023 a Roadmap on Hydrogen Standardization (European Clean Hydrogen Alliance, 2023) was published. (Further details in section 0Standards and certification).
- Top up Horizon Europe investments on Hydrogen Joint Undertaking to EUR 1 billion (matched by industry) to double the number of Hydrogen Valleys in Europe from 23 to 46 by 2025 (EC, 2023). The objectives are to develop joint innovation projects to boost production, transport and use of GH2, support practice exchange and to transfer expertise and knowledge. The European Commission will present a Roadmap on Hydrogen Valleys later in 2023 (Clean Hydrogen Joint Undertaking, 2023). It is not clear whether EU funding is available for Hydrogen Valleys outside of Europe, however, the intention is the spread the concept across the globe and create networks and interconnections between Hydrogen Valleys. In the case of South Africa, the first pilot projects based on the Hydrogen Valley concept are indeed underway (Business Tech, 2023).
- Mobilization of EU funding under Connecting Europe Facility (CEF), the Recovery and Resilience Facility (RRF), the InvestEU Programme and Innovation Fund.
- Hydrogen imports will be facilitated by a dedicated work stream under the EU Energy Platform (EC, 2023). The set up of joint renewable hydrogen purchases will be open to Ukraine, Moldova, Georgia and the Western Balkans providing a significant leverage to imports from these countries. The platform will be pooling demand, coordinating infrastructure use, negotiating with international partners and preparing for joint gas and hydrogen purchases (EC, 2023), opening of demand aggregation and joint purchasing also with the Western Balkans and the three associated Eastern Partnership countries (Ukraine, Moldova and Georgia). The EU provides a legal framework for the EU Energy Platform to support EU countries in the preparation for the winter 2023/24. The regulations (EC, 2022) were adopted in December 2022, the platform was launched and the first call for companies to jointly buy gas was issued in April 2023.
- In April 2023, the European Parliament (EC, 2023) set new targets for CO2 emissions of new passenger cars and vans to help accelerate the transition to net zero emission. The new regulation is banning the sale of new petrol and diesel cars from 2035 and registration is only available for vehicles running on CO2 neutral fuels. This is to speed up the transition to electric

vehicles and to cut carbon emission in the transport sector. Currently, cars account for 15% of all CO2 emissions in the EU. Germany has reached an agreement with the European Commission over the continued sale of vehicles that run on CO2 neutral synthetic fuels. It is not certain if vehicles powered by e-fuels can compete against electric cars and whether synthetic fuels will play a role in the medium-term future of passenger cars; however, even the inclusion of the relevant recital in the said regulation provides the prospects for demand for synthetic fuels in the cars and vans sectors in Europe also after 2035 (Frost, 2023).

Renewable energy directive: 2009, revised 2018, amendment 2021, 2023

The renewable energy directive **(RED) is the legal framework for the development of renewable energy across all sectors of the EU economy**, originally introduced in 2009 (2009/28/EC) (EC, 2023).

In 2009 the goal was to achieve 20% usage of renewable energy by 2020, in particular in the transportation sector. RED was revised in 2018 and is legally binding since June 2021. In RED II (EC, 2018) the **target** for 2021 to 2030 for **renewable energy** was regulated and rose to **32%**. RED II has also included a **transport sub-target**, which requires fuel suppliers to supply a minimum of **14% of the energy consumed** in road and rail **transport** by 2030 as **renewable energy**.

The **Delegated Acts on Article 27 and 28 of the RED II** have drawn considerable attention as they determine key rules regarding electricity sourcing and greenhouse gas (GHG) emission accounting for **RFNBOs (Renewable Fuel of Non-Biological Origin)**,[i] including renewable hydrogen. The first Delegated Act defines under which conditions hydrogen, hydrogen-based fuels or other energy carriers can be considered renewable, across consumption sectors. The second Delegated Act provides a methodology for calculating life-cycle greenhouse gas emissions for RFNBOs. It provides a definition of the requirements to produce hydrogen and fuels based on hydrogen (ammonia, methanol, paraffin and other hydrogen-based e-fuels) so they can be considered a RFNBO. Article 27 (3) RED II applied the assumption for domestic and imported RFNBO that electrolysis will be the main technology used to produce hydrogen. The key principles of the Delegated Acts, with respect also to RFNBOs, are summarised in Table 6. **It should be relatively safe to assume that the RED II Delegated Acts on RFNBOs and GHG emissions reduction will largely determine the eligibility of imported RFNBOs to Europe, including those from South Africa.**

Table 6 Key aspects of the RED II Delegated Acts (Green Hydrogen Organisation, 2023).

Principle	Comment
Additionality	• Electricity powering electrolyser is taken from a RE asset via a direct line that has been built within 36 months before the electrolyser. Exemption from this requirement until 2028 for production from any RE assets that have received any form of subsidies up to 2038. OR A. Electricity is taken from the grid fulfilling one the following options: I. renewable PPA with contracted asset built within 36 months before electrolyser unit + no OPEX or CAPEX subsidy received. Exemption from this requirement until 2028 for production from any RE assets that have received any form of subsidies up to 2038 II. renewable share of bidding zone >90% III. emission intensity of electricity < 18 gCO2eq/MJ IV. consumption during RE curtailment periods • RFNBO producers must have a Power Purchase Agreement with RES-e plant operator, RES-e plants have to be new and to not have received operating or investment support.

Principle	Comment
Temporal correlation	Monthly until 2030 / hourly from 2030 RFNBOs will be produced at the same time period as renewable electricity is produced in the RES-e plant. The production of RFNBOs takes place during a one-hour period when the day-ahead price is below 20EUR/MWH or lower than 0.36 times the price of the EU ETS emission allowance.
Geographical correlation	Grid-connected electrolysers must prove that RE asset is located either: • in same bidding zone or • in interconnected bidding zone, including in another Member State, if day-ahead market price in this zone is equal or higher RFNBO plant and RES-e plants are located in the same bidding zone or interconnected bidding zones or an offshore interconnected bidding zone.
Imported hydrogen	The **hydrogen delegated acts apply to hydrogen consumed in the EU, regardless of whether the hydrogen is produced inside or outside the territory of the Union**. **The rules have to be met to count renewable hydrogen towards the targets set out in the RED. Complying with the rules is not a prerequisite for importing hydrogen or for placing hydrogen on the EU market, but may be a prerequisite for receiving public support**. **Hence, the DAs do not set out binding rules for hydrogen production in third countries *per se*** (EC, 2023)**.** In view of the above, a number of initiatives for importing H2 from SA are underway, including: in June 2023, Germany and South Africa agreed to cooperate on green hydrogen projects and Germany will assist in developing markets, facilitating imports and linking producers with technology partners. Alongside France, Britain, the United States and the European Union, $8.5 billion was committed towards the development of a green hydrogen economy in South Africa (EnergyCapital&Power, 2023). Also the Netherlands and Denmark launched a green hydrogen fund in South Africa (Mukherjee, 2023).
Carbon intensity	70% greenhouse gas emissions saving compared to fossil fuels comparator of 94 gCO2e/MJ. This equates to approximately 3.4 kgCO2e/kgH2 across the full lifecycle of the fuels, including upstream emissions, emissions associated with taking electricity from the grid, from processing, and those associated with transporting these fuels to the end-consumer.

The EU will put in place a database to enable the tracing of liquid and gaseous transport fuels and showing life-cycle greenhouse gas emissions. Article 28 (5) RED II defines calculation methods by the means of which compliance with the required 70 % GHG savings by RFNBO is to be determined. The relevant emissions are those during the entire life cycle of the fuels, including upstream emissions, emissions in connection with electricity supply, process emissions, and emissions from transport and combustion of the fuels.

Under the RED II EU framework, fuels that are used for transport should fulfil the sustainability criteria of RED II, as well as a specific threshold of emissions savings (see Article 29 of RED II). This threshold is calculated over the LCA of fuels and is expressed as grCO2-eq/MJ. Specific sub-targets or caps focusing on RFNBOs,[ii] or PtX fuels as referred to in RED terminology, will determine the demand which will in turn drive imports of PtX fuels. The greenhouse gas emission savings from the use of biofuels are shown in Table 7.

Table 7 Greenhouse gas emission savings in the transport sector (RED II Article 2).

Greenhouse gas emission savings at least % form the use of biofuels and biogas	Date
50%	on or before 05 October 2015
60%	from 06 October 2015 to 31 December 2020
65%	starting operation from 01 January 2021

Article 30 explains the verification of compliance with the sustainability and greenhouse gas emissions saving criteria. The following rules apply:

- when the processing of a consignment of raw material yields only one output that is intended for the production of biofuels, bioliquids or biomass fuels, renewable liquid and gaseous transport fuels of non-biological origin, or recycled carbon fuels, the size of the consignment and the related quantities of sustainability and greenhouse gas emissions saving characteristics shall be adjusted applying a conversion factor representing the ratio between the mass of the output that is intended for such production and the mass of the raw material entering the process;
- when the processing of a consignment of raw material yields more than one output that is intended for the production of biofuels, bioliquids or biomass fuels, renewable liquid and gaseous transport fuels of non-biological origin, or recycled carbon fuels, for each output a separate conversion factor shall be applied, and a separate mass balance shall be used.

Article 31 and Annex V provide a detailed calculation of the greenhouse gas impact of biofuels, bioliquids and biomass fuels.

On 30 March 2023 the EU Council and Parliament reached a provisional agreement on **RED III** to raise the share of renewable energy in the EU (EC, 2023) (expected to be adopted by member states by 2025) and set more ambitious targets for 2030. 42.5% of the EU energy consumption should be from renewable sources such as wind and solar, with binding targets for the respective sectors. In addition, a 2.5% top-up should be reached through voluntary contributions by member states or through European wide measures.

In RED III there are two general options for the transport sector:

1. The 2030 binding sub target increases to at least 29% of renewables with the final consumption of energy, or alternatively
2. A binding target of 14.5% reduction of the GHG intensity by using renewables is set

In addition to the above options, a minimum requirement of **1% of RFNBO in the share of renewable energy supplied and a minimum of 5.5% for the sum of biofuels and RFNBOs are expected. An official definition of RFNBO in RED III is not yet available,** however, it seems certain that the **confinement to the transport sector will be abolished since there is now also a RFNBO target for industry.**

RED III also introduced a **specific renewable energy target for the industry sector**. The indicative target for industry requires to **increase the use of renewable energy by 1.6% annually**. In addition, a binding target of **42% of hydrogen used in industry should come from RFNBO by 2030 and 60% by 2035.**

The clear distinction between green hydrogen and low carbon hydrogen remains. **Low carbon hydrogen is not included in the energy targets.**

Relevance of the delegated acts to CO2 for PtX

In addition to the applicability on activities inside the EU, these acts are likely to have an impact on global markets for PtX products, such as e-fuel from South Africa. It is also expected that the adoption of these Acts will prompt certification of hydrogen and RFNBO schemes to be recognised for the EU rules.

How the respective Delegated Acts might be modified in the RED III context is not yet clear, and it might well be that new DAs will form in the coming years, but for the time being the RED II DAs still apply. It is also noted that the EU Directives must be transposed into national legislation to become a legal framework.

What is of particular importance in the context of this study, and the RFNBO export potential for South Africa, **is that the EU does not forbid the use of CO2 from the power sector until 2036 (or 2041 for CO2 from outside the electricity generation industry) for RFNBO production**. **But in order to meet the 70% minimum GHG reduction threshold, using CO2 from 'avoided emissions' sources is critical**. Emissions that can be counted as 'avoided' and subtracted from the emissions of the RFNBO include (GIZ, 2023):

- CO2 from direct air capture.
- CO2 from biofuels/liquids/mass complying with the sustainability and GHG saving criteria of RED II.
- RFNBO or RCF according to RED II.
- Geological sources where CO2 was previously released naturally.

- CO_2 from activities subject to the EU Emission Trading Scheme. For outside EU this will likely be determined by the EU Carbon Boarder Adjustment Mechanism (CBAM).

Note that the following emissions are not considered ‘avoided’ and cannot be subtracted from the calculation of GHG emissions.

- Deliberately produced CO_2 from the combustion of fuels
- CO_2 that has received emissions credit under other provisions.

Finally, subtracting negative emissions is also possible via means of carbon capture and storage, provided the CO_2 is permanently captured (geologically) in accordance with the Directive 2009/31/EC.

Overview of relevant international policies

The relevant policy developments at an international level are presented herein, which alongside the above EU analysis should help form a well-rounded view with regard to RFNBOs opportunities and limitations for SA.

Maritime (IMO)

The International Maritime Organisation (IMO) is the body for regulating the vessels of the maritime sector internationally. (Note: the standardisation body of EU inland shipping is the European Committee for the Development of Standards in the Field of Inland Navigation (CESNI), established in 2015. (CESNI, 2023)). IMOs most recent study on GHG (IMO, 2020), which was prepared by an international consortium comprising ten consultancies, research institutes and universities from four continents, includes the following key findings:

- CO_2 emissions of total shipping (international, domestic and fishing) have increased from 962 million tonnes in 2012 to 1,056 million tonnes in 2018 (9.3% increase).
- The share of shipping emissions in global anthropogenic emissions has increased from 2.76% in 2012 to 2.89% in 2018.
- Voyage-based allocation of international shipping: CO_2 emissions have also increased over this same period from 701 million tonnes in 2012 to 740 million tonnes in 2018 (5.6% increase):
- Vessel-based emissions have increased over the period from 848 million tonnes in 2012 to 919 million tonnes in 2018 (8.4% increase).

The decarbonization of international shipping is a priority for IMO (IMO, 2023) and in July 2023, a revised and strengthened Strategy on Reduction of GHG Emissions from Ships was published (IMO, 2023). The 2023 IMO GHG Strategy envisages a reduction in the carbon intensity of international shipping by at least 40% by 2030. It also includes a new level of ambition relating to the uptake of zero or near-zero GHG emission technologies, fuels and/or energy sources which are to represent at least 5%, striving for 10%, of the energy used by international shipping by 2030. Currently, IMO is undertaking a project that aims to provide an assessment of the state of availability and readiness of low- and zero-carbon ship technology and marine fuels, in order to help inform IMO's Member States as they work towards the revision of the IMO GHG Strategy (IMO, 2023). The study should be completed by Ricardo- and DNV by June 2023.

IMO Initial GHG Strategy has set an objective of 40% reduction of CO_2 emissions per transport work compared to 2008[iii] by 2030, as an average across international shipping. The respective objectives for 2050 are a 50% reduction of the total annual GHG emissions and 70% reduction of CO_2 emissions per transport work compared to 2008, whilst pursuing efforts towards phasing them out. To meet the 2050 target, shipping has to undergo a global transition of energy sources that includes all alternative fuels.

Table 8 Total shipping and voyage-based and vessel-based international shipping CO2 emissions 2012 + 2018 (million tonnes) (IMO, 2020).

	2012	2018	Growth 2012 to 2018
Global anthropogenic CO2 emissions	34,793	36,573	5.1%
Total shipping CO2	962	1,056	9.3%
Total shipping as a percentage of global	2.76%	2.89%	
Voyage-based international shipping CO2	701	740	5.6%
Voyage-based international shipping a percentage of global	2.01%	2.02%	
Vessel-based international shipping CO2	848	919	8.4%
Vessel-based international shipping as a percentage of global	2.44%	2.51%	

Under a business-as-usual scenario (BAU), whereby the shipping sector has not adopted any new regulations that have an impact on energy efficiency or carbon intensity, the CO2 emissions of shipping are projected to increase from 1,000 Mt CO2 in 2018 to 1,500 Mt CO2 in 2050 (IMO, 2020). Emissions are projected to increase from about 90% of 2008 emissions in 2018 to 90-130% of 2008 emissions by 2050 for a range of plausible long-term economic and energy scenarios (IMO, 2020).

Aviation (CORSIA) (ICAO, 2023)

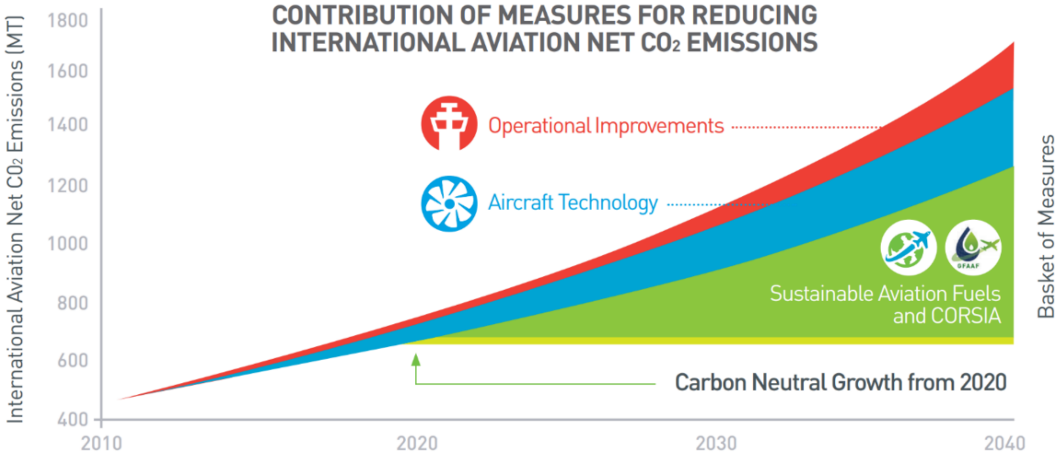
The Aviation Sector is also governed by ICAO CORSIA. The idea here is again to use fuels with lower carbon intensity, but the criteria are not as strict as in the EU directives. The Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA) is a UN deal designed to support the aviation industry to make all growth in international flights after 2020 carbon neutral. International aviation is responsible for 1.3% of global CO2 emissions (Timperley, 2019). The CORSIA is addressing CO2 emissions from international aviation and is the first global market-based measure that moves away from national or regional regulatory initiatives. Airlines purchase carbon credits to offset their emissions. The CORSIA aims to harmonize ways to reduce emissions from international aviation whilst minimizing market distortion. As of 1 January 2023, 115 countries had announced their intention to participate in CORSIA (ICAO, 2023).

CORSIA is implemented in three phases: a pilot phase (2021-2023), a first phase (2024-2026), and a second phase (2027-2035). For the first two phases (2021-2026), participation is voluntary. From 2027 onwards, participation will be determined based on 2018 RTK data.

Note that under the ReFuelEU Aviation (and the EU ETS) framework, only half of the international (i.e. from non-EU to an EU country) flights should align with the EU GHG saving requirements; therefore, the other half, that falls under CORSIA, has to meet less stringent criteria and thus enhance the market.

Currently, the baseline is set to 85% of 2019 emissions from 2024 until the end of the scheme in 2035: This is a significantly more **ambitious target** than originally planned (IATA, 2023), and the respective **timeline is considered rather challenging**, as neither technology nor infrastructure is readily available (Timperley, 2019). Hence, **in-sector measures**, such as new aircraft technologies, operational improvements and deployment of sustainable aviation fuels, as well as out-of- sector measures, such as offsetting and carbon removals, are required to reach the CO2 emission reduction targets. This means also, that **SAF** (including synthetic kerosene) are **likely to be a significant part of the solution** to the sector's decarbonization efforts.

Figure 7 Carbon Offsetting and Reduction Scheme for International Aviation – Wikipedia based on (ICAO, 2023).



As analysed above, EU policy targets are also a major driver for SAF implementation (share of SAF from 2 % in 2025 up to 63 % in 2050, for all aircraft operators taking off from any airport within the European Economic Area with more than one million passengers or 100,000 tons of freight), including PtX sub-targets, which are strong signs of the critical importance of SAF in the future energy mix.

Data from IATA reinforce the importance of SAF, suggesting that from 8 billion liters of SAF in 2025, demand will grow to 23 in 2030, 229 in 2040, and eventually reaching 449 billion litres by 2050 in the frame of a Net Zero Approach for the aviation industry (IATA, 2023). Nevertheless, the targets set by EU and other bodies do **not include provisions aimed at bridging the cost differential between fossil fuels and SAF**, a major concern of airlines who fear that the cost differential will severely impact their competitiveness. The ambitious blending quota also poses technological challenges to the upscaling of SAF production – all aspects that need to be elaborated further in order for the respective ambitious targets to materialise.

Standards and certification

Establishing standards regarding RFNBOs is an important and essential step in their broader implementation, as standardisation will help address safety and quality issues, and ultimately reduce costs and promote a healthy market environment.

Certification schemes consist of two primary elements (GIZ, 2021):

1. The criteria outlining the specific certification requirements (the standard) and
2. The framework for carrying out the certification of conformity with the criteria; this includes the procedures to be followed for all necessary processes, the audit methodology applied by certification bodies to certify the given product or service, the governance of the system, etc.

In May 2022, the Green Hydrogen Standard (Green Hydrogen Organisation, 2023) was launched. It established a global definition of green hydrogen: "*Green hydrogen is hydrogen produced through the electrolysis of water with 100% or near 100% renewable energy with close to zero greenhouse gas emissions*". The global minimum standard will provide transparency and certainty that GH2 is made with renewable electricity (Green Hydrogen Organisation, 2022). The Green Hydrogen Standard is based on a project-level certification and accreditation. It applies the methodology for the electrolysis production pathway being developed by the International

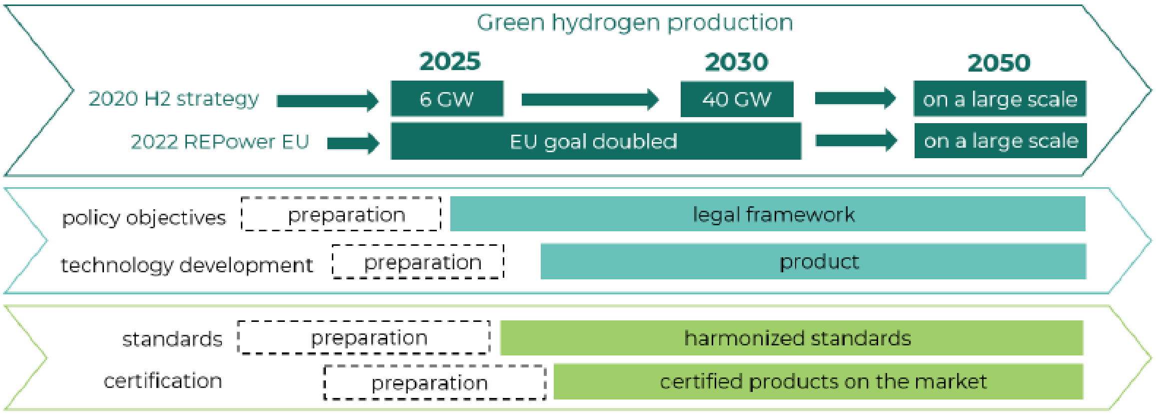
Partnership for Hydrogen and Fuel Cells in the Economy (IPHE). The requirements a project must satisfy are outlined in Figure 8.

Figure 8 Requirements of the Green Hydrogen Standard (Green Hydrogen Organisation, 2022).

In March 2023 the European Clean Hydrogen Alliance (ECH2A) published the Roadmap on hydrogen standardization (European Clean Hydrogen Alliance, 2023). The ECH2A is an alliance of industry, public authorities, civil society and others to support large-scale deployment of clean hydrogen technologies by 2030. The Roadmap reflects the identified priorities in the Standardization Annual Work Programme for 2023 and also follows the 2021 European Clean Hydrogen Alliance's Report, which identified the lack of hydrogen standards as an important barrier to the roll out of new hydrogen solutions. This roadmap covers standardisation needs for the entire hydrogen value chain, from production, distribution, transport and storage to end-use applications.

The standards are to align with the European legal and regulatory framework, outlined in Figure 9. The actual development of the standards will be performed by the European standardisation bodies CEN, CENELEC and their international counterparts ISO and IEC, which have the mandate to do so. The roadmap also highlights the need for an overall coordination of hydrogen standardisation activities focusing on the technical needs of industry and the alignment with and cooperation between other standardisation initiatives and bodies.

Figure 9 Policy framework in relation to development of hydrogen technologies (European Clean Hydrogen Alliance, 2023).



The wide breadth and complexity of the hydrogen value chain and rich diversity of hydrogen applications imply a multitude of diverse standardisation needs. In the roadmap, more than 400 topics are listed and are "clustered" along the segments of the hydrogen value-chain. The mobility sector in this roadmap includes the following modalities:

- road vehicles
- heavy-duty on and off-road vehicles
- railways
- maritime vessels
- aviation

The main topics to be considered in the standardisation process on mobility are summarized in (IATA, 2023).

Focusing on aviation (as a keep potential market for synthetic fuels), it is noted that the standardisation work is just starting. Hydrogen for aviation decarbonisation has recently been brought to the attention of International Civil Aviation Organisation (ICAO). One of the challenges identified is to develop dedicated standards regarding hydrogen for aviation and in particular issues related to the safety framework (leakage, firefighting, safe handling of cryogenic H2, etc). In the maritime sector, comprehensive standards for different propulsion systems in shipping are crucial to meet decarbonisation targets. Vessels with propulsion systems using LOHC as a H2 fuel carrier were to be rolled out for use in the second half of the 2020s, and as such the required standardised framework is a high priority.

The International Certification Framework (GIZ, 2021) identifies certification schemes applied in Europe for the production and import of green hydrogen and its derivatives (synfuels, methanol, ammonia, etc.) from green hydrogen exporting countries. However, dedicated hydrogen certification schemes so far only cover a very limited set of criteria, while other certification schemes cover wider sets of criteria, but may not be related to hydrogen. Hydrogen and derivates have been included in the EU regulation. The same criteria for RFNBO apply as outlined earlier and expressed in Table 6 .

Suppliers of transport fuels use **voluntary schemes** that cover the full chain of custody of transporting the renewable fuels from production to consumption, certifying compliance with the criteria defined in RED II. The **Commission has so far formally recognised 15 voluntary and national certification schemes** (EC, 2023). Nevertheless, these **mainly relate to biomass/biofuels and not RFNBO and H2**.

CertifHy and CMS70 are **two developing certification schemes in Europe for green hydrogen**, focusing on energy and climate-related sustainability criteria for the time being. These **schemes are not related to any**

legislation at present and their focus is on criteria associated to the electricity input to produce hydrogen and on the greenhouse gas balance.

- CertifHy (CertifHY, 2023) promotes the **sustainable production of hydrogen for all types of uses** including energy, transportation, chemical conversion, heating and power generation, hence providing environmental, social and economic benefits. It is a consortium led by HINICIO and composed of GREXEL, Ludwig-Bölkow-Systemtechnik (LBST), AIB (Association of Issuing Bodies), CEA (Commissariat à l'énergie atomique et aux énergies alternatives) and TÜV SÜD. The scheme recently **announced that Bureau Veritas is taking on the role of the certification body for CertifHy** (H2 View, 2023), reinforcing its **efforts to become an EU-approved Voluntary Scheme** for the certification of hydrogen as RFNBO, according to RED II.
- TÜV SÜD introduced the Green Hydrogen certification standard CMS70 (TÜV SÜD, 2021) in 2011. It is a quality feature of hydrogen products complying with the legal requirements of RED II. Through the certification green hydrogen is clearly identifiable and its sources are quantifiable.

Other certification schemes exist in California and China, while Australia and the United Kingdom are in the process of developing relevant schemes. A regional certification scheme is also in place for Latin America and the Caribbean.

What is of particular importance in the context of this study is that there **are no certification schemes that include any criteria related to CO2 sourcing**, as CO2 as a feedstock is not relevant in any established certification area. However, it will become more relevant for certain hydrogen derivatives, notably synfuels.

Table 9 provides an overview of the sustainability of various concentrated CO2 sources.

Table 9 Sustainability of various concentrated CO2 sources (GIZ, 2021).

CO_2 sources	Environmental sustainability	Alternative CO_2 uses	Towards carbon-neutrality; Risks
Extraction from air	Subject to electricity source		
Biogas upgrading	Subject to feedstock & process	Power-to-methane	Other biomass uses
Solid biomass fired heat (& power) plants	Subject to feedstock & process	Bio-CCS	Other biomass uses
Fermentation to alcohols	Subject to feedstock & process	Beverage industry	Other biomass uses
Geothermal sources	Subject to geo-phys. CO_2 cycle	CO_2 re-injection (closed loop)	Hot dry rock a potential no-go
Cement production	Short-term exemptions?	Power-to-chemicals	Shift to alternative materials, recycling; Technology lock-in
Steel production	Short-term exemptions?	Top-gas for heating & reduction	Shift to direct reduction with H_2
Fossil fuel firing	Short-term exemptions?	CCS	Phase-out; Technology lock-in

Concluding remarks

The EU's regulatory framework including the EU hydrogen strategy, Fit-for-55, the REPowerEU plan and the Renewable Energy Directives form a comprehensive platform to support the uptake of renewable and low-carbon hydrogen and fuels. The ambitious targets of the EU outlined in the hydrogen accelerator concept is to produce 10 million tonnes per year plus import 10 million tonnes per year of renewable hydrogen by 2030. However, the regulatory framework and hydrogen standards are not yet finalised creating uncertainty for industry and stakeholders in the transport, maritime and aviation sectors.

Often slow and complex permitting processes are seen as a key obstacle to develop renewable energy projects including hydrogen. To increase competitiveness in the renewable energy sector these processes have to be streamlined with an appropriate regulatory framework.

The EU's hydrogen targets in all industry sectors are ambitious. However, current available technologies, infrastructure and required volume of GH2 is lagging, creating uncertainty for consumers and industry.

The RED Delegated Acts state that the **rules** shall **apply to RFNBO consumed in the EU, regardless of whether the RFNBO is produced inside or outside the EU, if the RFNBO is to count against the EU's targets and be eligible for public support**. Hence, even though there are no binding rules for imported GH2/RFNBO to the EU *per se*, non-compliance with RED II, III is likely to make such imports rather hard to justify and pursue. The respective rules are mainly based on the European regulatory framework and are specific to the EU context. For countries outside the EU, compliance with these rules and regulations for RFNBO production might be challenging to demonstrate, not least because there is no EU-approved certification scheme for RFNBOs at present. In any case, **the closer an exporting country, such as SA, adheres to the EU framework regarding RFNBOs, the likelier it is to be able to export such products to the EU.**

3 SOUTH AFRICA'S CARBON (UTILISATION) DEMAND

This chapter focuses on estimating the potential domestic demand for carbon in South Africa, particularly in the context of utilising emitted CO2 for the production of synthetic fuels or other derivatives. The basic premise is to understand local demand and needs for CO2, projected in time, so as to be able to deduce informed assumptions about what the CO2 export potential might be.

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South Africa's carbon (utilisation) demand

GHG, CCUS and synfuels policy context in South Africa

Controlling emissions and capturing/utilising carbon may be subject to a number of drivers and forces. On one hand, there is a clear impetus for governments worldwide to reduce their GHG emissions. In the case of SA, according to its **NDC 2021** (Republic of South Africa, 2021), the country has set the following specific targets, as shown in Table 10.

Table 10 SA GHG emissions targets according to NDC 2021

Year	Target annual GHG emissions range	Corresponding period of implementation
2025	398-510 Mt CO2-eq	2021-2025
2030	350-420 Mt CO2-eq	2026-2030

Another relevant policy document is SA's Integrated Resource Plan (Republic of South Africa, Department of Mineral Resource and Energy, 2019), which analyses an electricity infrastructure development plan based on least-cost electricity supply and demand balance, taking into account security of supply and the environment (minimize negative emissions and water usage). The plan outlines the Eskom coal plants decommissioning schedule, in line with decarbonization and restructuring efforts towards HELE (high efficiency low emissions) technologies. But in terms of **exploiting the associated CO2 emissions it limits its scope** to the general statement: "*Given the **significant investments required for CCS and CCUS technology**, South Africa could benefit from **establishing strategic partnerships** with international organisations and countries that have made advancements in the development of CCS, CCUS and other HELE technologies*". It is a fact that CCS, let alone CCUS, is still an emerging and not mature enough approach for wider adoption[iv]. As of 2021, there were 27 CCS operational commercial facilities worldwide, of 37 Mtpa total capture capacity, with only three of them incorporating also carbon utilization processes (Global CCS Institute, 2021). Adding to the above that the **current (2022) effective CO2e tax rate in SA is less than USD 0.4/tCO2e** (official SA tax rate at USD 6.5) (International Monetary Fund. African Dept., 2023), which is **less than 1%** of the median **value** of USD 100/tCO2e estimated to be **required in order to reduce emissions in line with the temperature goals of the Paris Agreement** (World Bank, 2022), it is clear that **strong incentives for CCS and CCUS activities are currently lacking** (Republic of South Africa, Department of Trade, Industry and Competition, 2022).

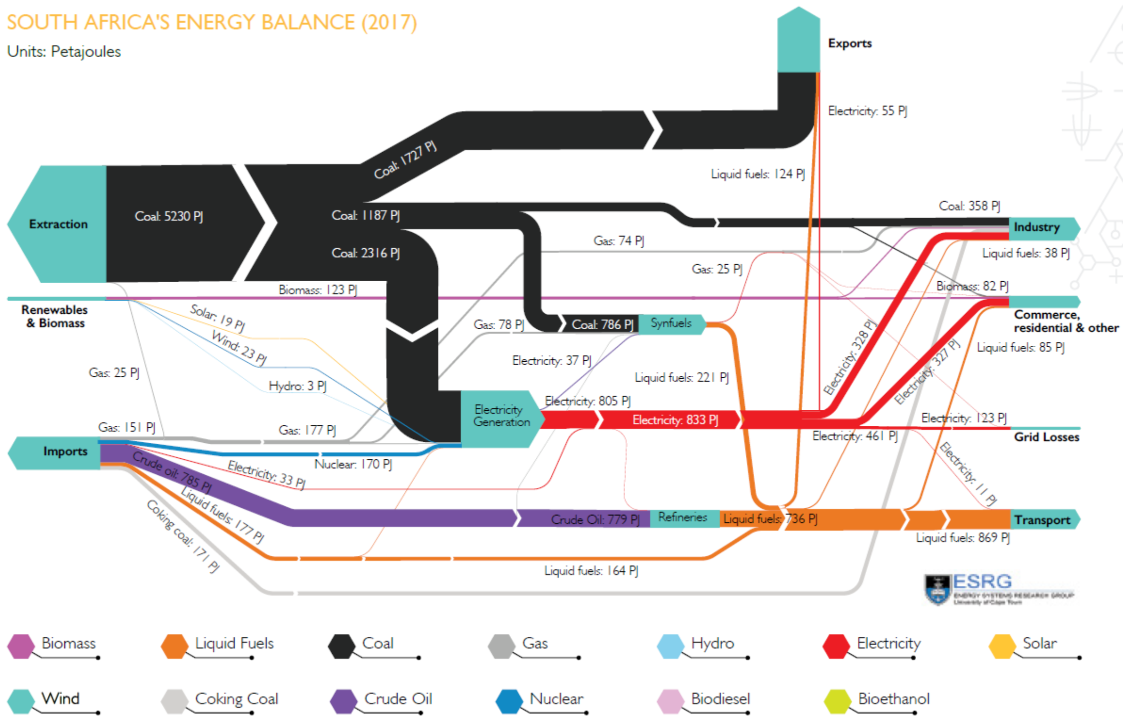
It becomes apparent by analysing SA's energy policy framework that **there are no concrete plans, nor specific targets, at present regarding the utilization of CO2** for synthetic fuel production (i.e. powerfuels). Even the recently published 'Hydrogen Society Roadmap for South Africa 2021' (Republic of South Africa Department of Science and Innovation, 2021), is limited to just giving an overview of the potential pathways to PtX, rather than providing specific targets, while the 'Green Hydrogen Commercialisation Strategy' (Republic of South Africa, Department of Trade, Industry and Competition, 2022) which was published in 2022, does not set specific targets, but it identifies however the need for setting a vision and specific targets for the penetration of hydrogen and for establishing a strategy for the development of alternative fuels.

In order, therefore, to appreciate the scale of the synthetic/liquid fuel market and the respective potential CO2 demand, an analysis of the current liquid fuels pathways in SA follows.

Synthetic/liquid fuels pathways in South Africa

SA's energy balance and respective conversion pathways (as of 2017) (Republic of South Africa Department of Science and Innovation, 2021) are illustrated in Figure 10. **South Africa is a pioneer of the Coal-to-Liquid (CTL) fuel process and a third of the country's liquid fuel demand is obtained from such CTL synthetic fuels** (8 bn litres pa.), requiring ca. 40 Mt coal pa.

Figure 10 SA's energy balance and conversion pathways (2017) (Republic of South Africa Department of Science and Innovation, 2021).



The **rest of the liquid fuel demand is met by both imported refined product and crude oil via domestic refineries**. Approximately **95% of liquid fuel demand** is consumed by the transport sector. Regional exports of petrol, diesel and jet fuel each amount to approximately 10% of the total product inventory, with **exports therefore not constituting a major driver** in the liquid fluid sector at present.

Looking into the respective petrochemicals industry, reveals a picture of a sector that is at a turning point. Stricter environmental regulations and ageing infrastructure, alongside the emerging hydrogen/PtX opportunities may have a significant impact on mid/long-term future operations.

There are **four conventional refineries**, processing imported crude oil, but **only two of them are currently operational**. **Synthetic fuels** are produced by **Sasol (Secunda, CTL FT process)** and Petro SA (GTL), but the latter is also not currently open, see Table 11 (NBI, 2021). If alternative, lower emissions operations and production are not realised (driven mainly by the restrictions of the 'Clean Fuels II Standard' (South Africa Petroleum Industry Association, 2023)), South Africa risks shut down of all local crude refineries by 2030.

Table 11 Overview of SA's refinery assets (NBI, 2021).

Facility	Capacity (Barrels/day)	Owner
Crude oil refined at the following refineries		
Astron§	100 000	Chevron South Africa
Enref§	120 000	Engen Petroleum
Natref	108 000*	Sasol (64%) Total South Africa (36%)
Sapref	180 000	Shell South Africa (50%) BP Southern Africa (50%)
Coal and gas processed and refined at		
Sasol Secunda	160 000*	Sasol
Gas processed and refined at		
Petro SA§	45 000*	PetroSA

**Crude equivalent average yield*
§Closed /currently not in operation
Source: South African Petroleum Industry Association.

This development could **pave the way for even more synthetic fuel to be produced** in order to cover local demand. **But the CTL FT process has a remarkable 26 times higher carbon-intensity** than conventional refined crude. In other words, even if all the local refineries – including the PetroSA GTL asset – were to shut down, almost 80% of South Africa's domestic refining capacity would have disappeared, but only ~6% of the sector's emissions – see data reported in (NBI, 2021). **Synthetic fuels production drives ~90% of the petrochemical sector's overall emissions baseline.**

It is evident therefore that the **current synthetic fuel pathway is not compliant with the commonly accepted sustainability standards**, given its high GHG emissions, but also increasing importance of synthetic fuels in the liquid fuel mix; the respective production would either **need to be transformed** and adopt 'greener' processes, **or be terminated/replaced altogether**, if a net-zero target were to be pursued e.g. by 2050.

What is attempted in the next section is to estimate, based on liquid fuel demand projections, what a transformation to e-synthetic fuel processes would require in terms of CO2 feedstock.

Scenarios for liquid fuels, and associated CO2, demand in South Africa

In the NBI's (National Business Institute) publication series 'Just Transition and Climate Pathways Study for South Africa – Chapter 2' (NBI, 2021) there are **three scenarios presented for SA's liquid fuel demand for transport applications up to 2050**.

The scenarios assume liquid fossil fuels will still play a major role in the mix, but the gradual penetration of H2, SAF and electricity (i.e. for EVs) is also foreseen.

Based on these NBI scenarios, **three own scenarios for the degree of CO2 exploitation** that could be aimed for have been interpolated, namely:

- **Max CO2 Exploitation**: all the projected liquid fossil fuel is substituted by green synthetic fuel. SAF production as per NBI scenario
- **Medium CO2 Exploitation**: half of projected liquid fossil fuel is substituted by green synthetic fuel. SAF production as per NBI scenario.
- **Min CO2 Exploitation**: no liquid fossil fuel is substituted. SAF production as per NBI scenario.

Table 12 shows the matrix of the various scenarios and the respective fuel demand values in PJ.

Table 12 Scenarios of green fuel exploitation (max-med-min) with respect to NBI's liquid fuel production projections.

Matrix of liquid fuel demand and green synthetic fuel exploitation scenarios				Max Exploitation All liquid fuel demand covered by green fuels		Medium Exploitation Half of liquid fuel demand covered by green fuels		Min Exploitation Only SAF projected demand is met	
	Year	Liquid fossil fuels (PJ)	SAF (PJ)	Green Synthetic fuel exc. SAF (PJ)	SAF (PJ)	Green Synthetic fuel exc. SAF (PJ)	SAF (PJ)	Green Synthetic fuel exc. SAF (PJ)	SAF (PJ)
Reference Technology Scenario	2030	791	1	791	1	396	1	-	1
	2040	668	30	668	30	334	30	-	30
	2050	500	80	500	80	250	80	-	80
Sustainable Development Scenario	2030	709	5	709	5	355	5	-	5
	2040	554	35	554	35	277	35	-	35
	2050	388	73	388	73	194	73	-	73
Global net-zero Scenario	2030	689	5	689	5	345	5	-	5
	2040	368	33	368	33	184	33	-	33
	2050	124	81	124	81	62	81	-	81

Note: *the CO2 exploitation scenarios are not limiting – using the staring NBI scenarios data and the corresponding conversion factors one can vary the level of exploitation as desirable and obtain results accordingly*.

The next step of the analysis is to attempt to **translate the energy demand for fossil fuels into CO2 demand for the production of PtX of equivalent energy**. To that end, we assumed that the fossil fuel in our scenarios is replaced by **e-diesel,**[v] **produced by the RWGS FT process**, and **SAF is produced by direct methanol synthesis, followed by e-methanol-to-kerosene conversion**[vi]. Table 13 shows the conversion factors used in the respective calculations and the respective estimations of CO2 demand.

Table 13 Conversion factors used in the calculations of CO2 demand.

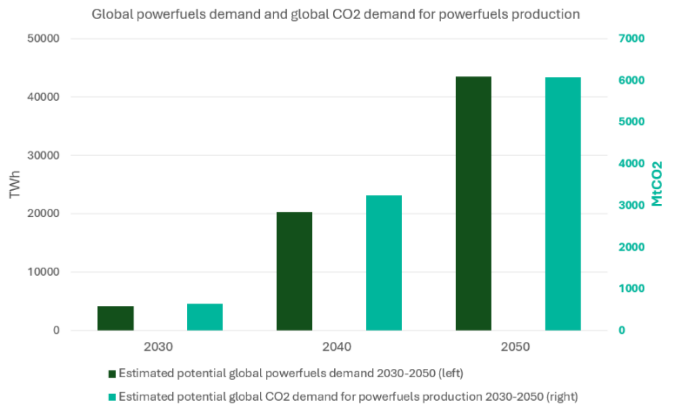
Process or conversion factor (Concawe, 2022)	**Units**
Fuel Processing	**CO2 in (kg/kg fuel)**
FT to e-diesel	3.715
e-methanol (two-step synthesis)	1.4
Fuel Processing	**e-methanol in (kg/kg fuel)**
e-methanol to e-kerosene	2.32
Conversion Factors (BP, 2022)	**tonnes to GJ (multiply by)**
diesel	43.38
kerosene	43.92

Table 14 CO2 demand estimations for the different scenarios considered.

Matrix of liquid fuel demand and green synthetic fuel exploitation scenarios, including respective CO2 demand				Max Exploitation All liquid fuel demand covered by green fuels		Medium Exploitation Half of liquid fuel demand covered by green fuels		Min Exploitation Only SAF projected demand is met	
	Year	Liquid fossil fuels (PJ)	SAF (PJ)	CO2 (Mt) for e-diesel	CO2 (Mt) for SAF	CO2 (Mt) for e-diesel	CO2 (Mt) for SAF	CO2 (Mt) for e-diesel	CO2 (Mt) for SAF
Reference Technology Scenario	2030	791	1	67.7	0.1	33.9	0.1	-	0.1
	2040	668	30	57.2	2.2	28.6	2.2	-	2.2
	2050	500	80	42.8	5.9	21.4	5.9	-	5.9
Sustainable Development Scenario	2030	709	5	60.7	0.4	30.4	0.4	-	0.4
	2040	554	35	47.4	2.6	23.7	2.6	-	2.6
	2050	388	73	33.2	5.4	16.6	5.4	-	5.4
Global net-zero Scenario	2030	689	5	59.0	0.4	29.5	0.4	-	0.4
	2040	368	33	31.5	2.4	15.8	2.4	-	2.4
	2050	124	81	10.6	6.0	5.3	6.0	-	6.0

CO2 demand for SAF production is in the range of 0.1-6.0 Mt pa. across scenarios, and it could be considered as the **baseline of CO2 demand overall**. This is probably still at the higher end of the spectrum, since Sasol's published targets (SASOL, 2021) indicate only 5-10% sustainable carbon use before 2040, and 100% carbon from DAC after that. The **fossil fuel substitution is much more arbitrary**, and in effect yields a somewhat counterintuitive trend, in that CO2 demand for PtX appears to drop in future years. That is because liquid fuels will be competing also with other energy sources, such as pure H2, as well as direct electrification of vehicles, and the share of liquid fuels is likely to be much smaller than nowadays.

Figure 11 Projections of global PtX (powerfuels), and corresponding CO2, demand. Estimates based on the assumption of a fully renewable global energy system by 2050 (Global Alliance Powerfuels, 2020).



From a **global perspective**, the German Energy Agency DENA, has estimated the demand for CO2 (for PtX production) as illustrated in Figure 11 (Global Alliance Powerfuels, 2020). Compared to the **SA scenarios**, the highest **estimate in 2030 (ca. 60 Mt CO2) corresponds to roughly 10% of the global CO2 demand**, which is fair to assume it is **probably not a very realistic** prospect, given also the short timeframe to 2030. To assume, however, **0.1 Mt CO2 demand for SAF production by 2030** in SA is **more plausible**, both regionally, as well as within the global perspective discussed.

On the other hand, if one looks at the **2040 and 2050 projections**, the respective SA scenarios might depict a **more likely picture**. Even the top end prediction, **of ca. 50 Mt CO2 demand in SA**, would correspond to **ca. 1% of the global CO2 demand**, which **aligns well with the current energy consumption share of SA in the World**, which also sits at ca. 1% (worldometer, 2023).

In any case, the analysis above helps give some **ballpark figures** and a general feel about what the **CO2 utilisation demand might be in SA in the coming years**. In the next Chapter 5, a detailed analysis of current, and projected, CO2 emissions per point source in SA is presented, in an effort to better understand the overall CO2 balance and what the potential might be for CO2 utilisation across borders.

4 SOUTH AFRICA'S CARBON SUPPLY POTENTIAL

In this chapter, the potential carbon supply of South Africa will be assessed based on the anticipated evolution of the country's CO2 emission profile. In the context of the present work, carbon supply potential is estimated by considering the total CO2 emissions from the country's identified point sources (industrial and energy sectors), which can theoretically be captured and, therefore, utilized for the production of synfuels.

GREEN HYDROGEN SOUTH AFRICA

International PtX Hub

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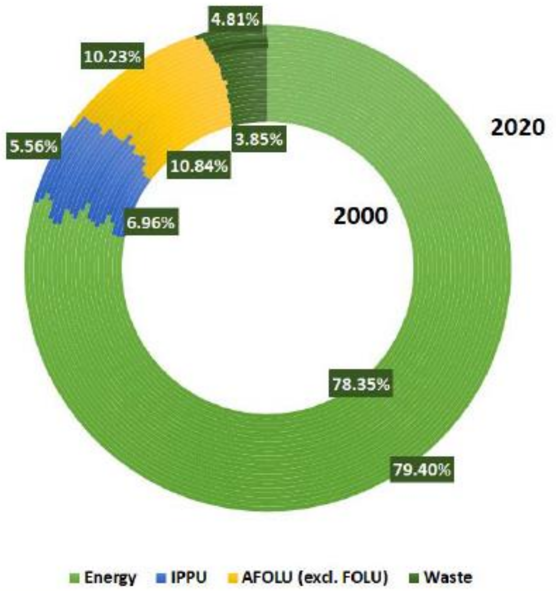
South Africa’s carbon supply potential

Overall emission profile

South Africa is one of the largest greenhouse gas (GHG) emitters on the African continent and is responsible for 1.2% of global GHG emissions (World Bank, 2022). The country's power and industrial sectors are the primary sources of its GHG emissions, with coal-fired power plants and heavy industries, such as iron & steel and petrochemicals, being the major emitters. According to data from the South African Department of Environment, Forestry and Fisheries (Republic of South Africa Department of Forestry, Fisheries and the Environment, 2022), in 2020, the energy sector accounted for 79.4% of South Africa's GHG emissions, as expressed in terms of CO2 equivalent (excluding Forestry and other land use - FOLU), while the industrial processes and product use (IPPU) sector accounted for 5.6%, see Figure 12. As per the National GHG Inventory Report, the Energy sector includes fuel combustion activities among energy industries, manufacturing/construction, transport and other sectors, as well as fugitive emissions from fuels. With respect to the above, South Africa’s power sector is responsible for around 40% of the country’s GHG emissions (NBI, 2021).

Figure 12 Sector contribution to total CO2eq emissions (excluding FOLU) in SA between 2000 and 2020 (Republic of South Africa Department of Forestry, Fisheries and the Environment, 2022).



As a result of the country’s abundant coal reserves and consistent domestic coal production, the power sector in South Africa is largely dependent on coal-fired power plants, which emit high levels of carbon dioxide (CO2) and other pollutants. In 2021, South Africa had a total installed capacity of 53.7 GW, of which 39.3 GW (73%) corresponded to coal-fired power plants (CSIR, 2022). Despite South Africa’s abundant and complementary wind and solar energy resources, less than 6% of electricity is generated via renewables today. According to a report by the South African Department of Mineral Resources and Energy (DMRE) (Republic of South Africa, Department of Mineral Resource and Energy, 2019), **the power sector's GHG emissions are expected to continue to peak between 2020 and 2025**, with coal remaining the primary source of power generation. However, the government has set a target of reducing the share of coal in the energy mix from almost 90% in 2019 to around 60% by 2030 while the share of RES is planned to increase to 42% by 2030. In any case, considering the anticipated evolution of the country's energy mix, as planned up to 2030 according to the IRP 2019 and extended to 2050 by the Council for Scientific and Industrial Research (CSIR) (CSIR, 2020), **coal is expected to retain its dominant role in the electricity mix (approx. 40% in 2050) and thus can still be considered as a main CO2 point source for synfuels up to 2050**.

The industrial sector is also a significant contributor to South Africa's GHG emissions, particularly in heavy industries such as iron and steel production, cement production, and mining. The industrial sector's GHG emissions are expected to continue to rise in the coming years, driven by the expected increasing demand for products such as steel and cement as the country develops[vii]. The South African government has set a **target of reducing industrial emissions by 30% below business-as-usual levels by 2030**, but achieving this target will require significant investment in clean technologies and energy efficiency measures.

Power sector

Current status of power sector

The South African power system currently relies on a few primary energy sources, which are presented in the following Table 15 (CSIR, 2022):

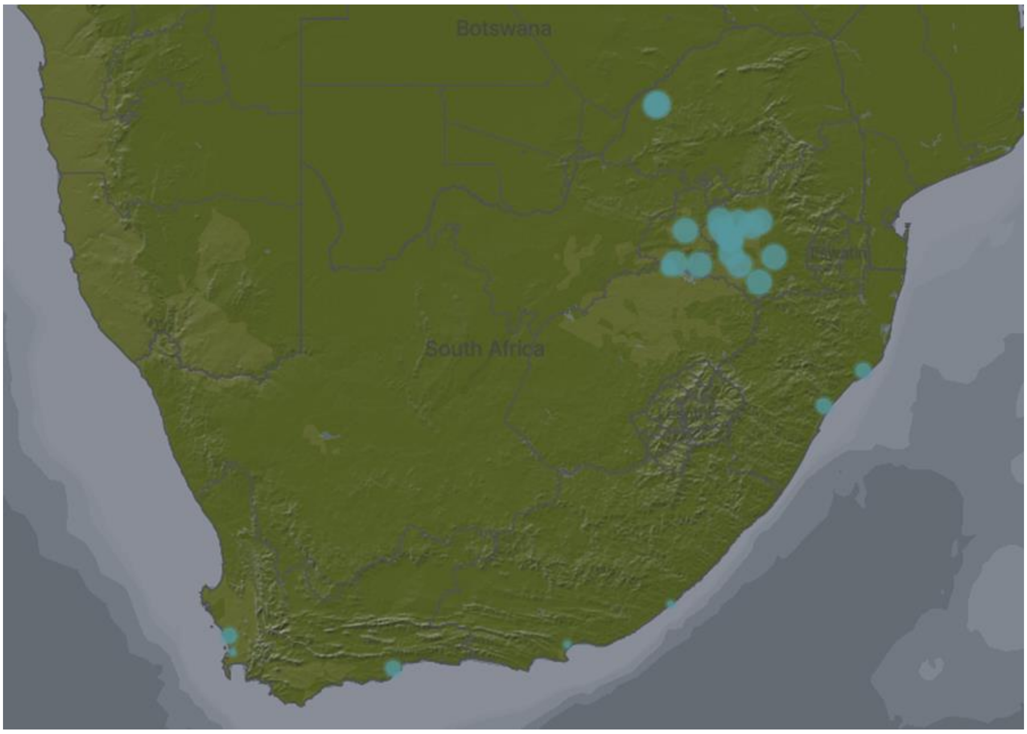
Table 15 Installed capacity by power plant type in the SA power sector

Energy source	Installed capacity (GW) in 2021
Coal	39.3
Nuclear	1.9
Pumped storage	2.7
Hydro	0.6
Diesel	3.4
RES	5.2

Electricity generation, transmission and distribution in the country is managed by Eskom (total nominal capacity as of March 2019 amounted to 44 GW), which also purchases electricity from Independent Power Producers (IPPs) as well as from electricity generating facilities beyond the country's borders. Eskom owns and operates a number of coal-fired plants, including, for instance, Medupi, Kusile, Kendal, and Kriel, as well as gas-fired, hydro and pumped storage power stations and one nuclear power station. Most power stations are located in Mpumalanga, except for Lethabo and Matimba which are located in the Free State and Limpopo provinces respectively. Figure 13 provides a map with South Africa's coal-fired power plants.

Coal-fired power plants are responsible for the majority of South Africa's greenhouse gas emissions, with an estimated 226 million tonnes of carbon dioxide equivalent (CO2eq) emitted in 2019, according to the International Energy Agency. Even though the South African government is making efforts to reduce the country's dependence on coal-fired power and to diversify its energy mix, coal is expected to play a significant role in for South Africa's electricity generation in the foreseeable future, as it is expected to continue constituting the largest share of installed capacity and making up for the largest amount of generated power.

Figure 13 South Africa's coal-fired power plants – own elaboration based on Carbon Brief, 2018.

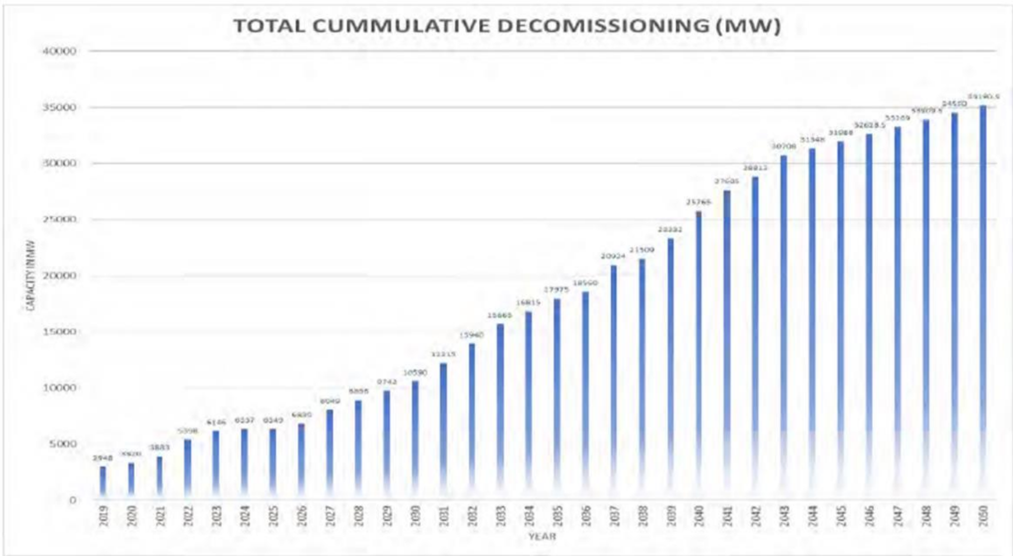


Already in 2012, the average age of the South African coal-powered plants was 30 years, with some of them having already exceeded their design life (ESKOM, 2012). Several coal-fired power plants in South Africa have already been decommissioned, with more set to be decommissioned in the coming years. For example, the 1,200 MW Kriel power station was decommissioned in 2021, while the 1,500 MW Hendrina power station is set to be decommissioned by 2026. In addition, there are plans to decommission several older coal-fired power plants and replace them with renewable energy sources.

The construction of new coal-fired power plants in South Africa has also been a topic of debate in recent years. In 2021, the DMRE granted environmental authorisation for the construction of the 1,500 MW Thabametsi coal-fired power plant, despite objections from environmental groups. However, there are also plans to construct new renewable energy projects, such as wind and solar farms, to help meet the country's growing energy demand.

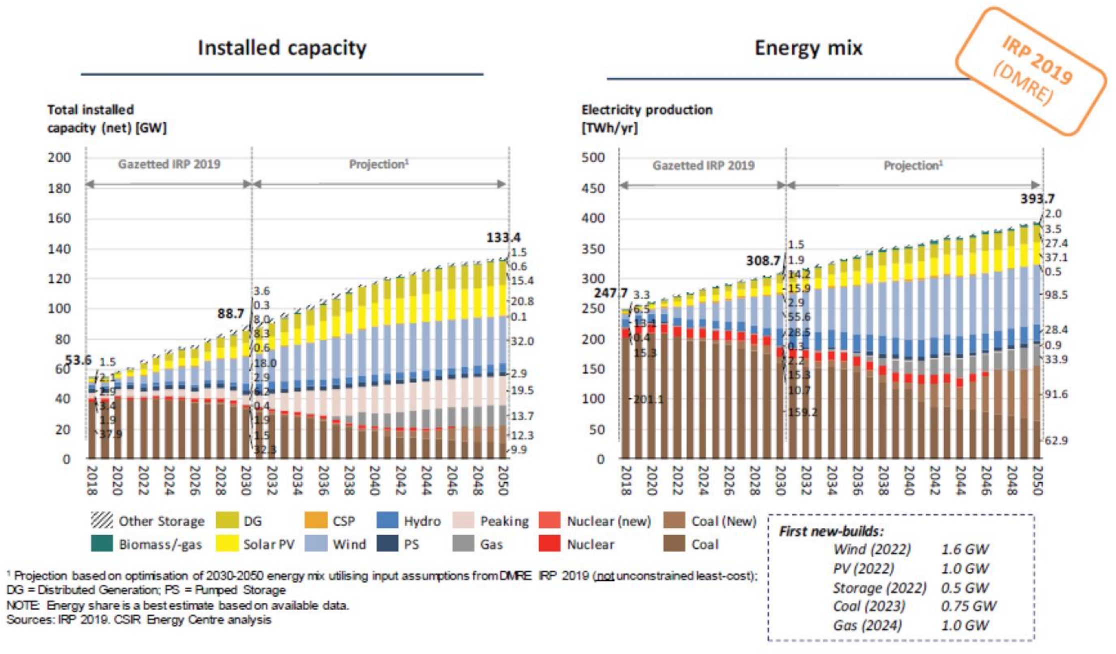
In the IRP 2019, which presents South Africa's current energy policy position, the evolution of the electricity supply sector is projected based on the country's long-term electricity demand projection. According to the published decommissioning schedule, about 10,599 MW of Eskom's coal generation capacity will be decommissioned by 2030, while the figure increases to 35,000 MW for 2050[viii], see Figure 14. It must also be noted that a drop is foreseen for coal fired electricity generation around 2040, with no straightforward interpretation provided in the original publication.

Figure 14 Cumulative Eskom Coal Generation Plants Decommissioning (Republic of South Africa, Department of Mineral Resource and Energy, 2019).



The evolution of the country's energy mix, as planned up to 2030 according to the IRP 2019 and extended to 2050 by the CSIR, is presented in the following Figure 15.

Figure 15 Evolution of the country's energy mix (Republic of South Africa, Department of Mineral Resource and Energy, 2019).



Installed capacity and energy mix for IRP 2019 (extended to 2050 by CSIR) revealing intentions for an increasingly diversified energy mix

Projection of CO_2 emissions from power sector

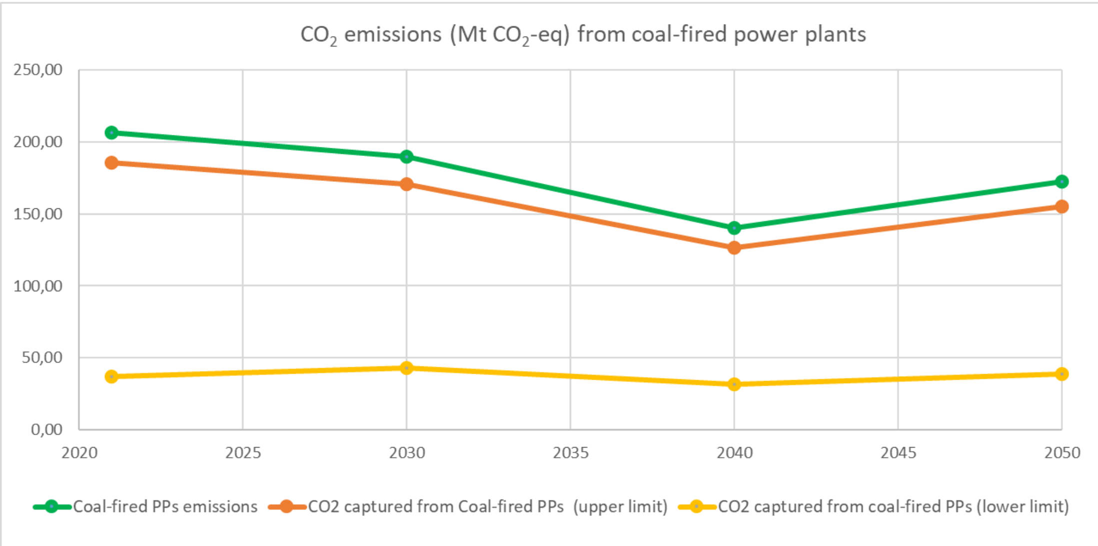
The evolution of South Africa's power sector emissions can be estimated through a combination of factors such as current emission levels, future energy demand projections, and policy and regulatory frameworks. The government's Integrated Resource Plan (IRP of 2019), which outlines the country's energy mix and electricity generation capacity, provides a basis for estimating future emissions from the power sector. In addition, the government's nationally determined contribution (NDC) under the Paris Agreement also sets a target for reducing emissions across all sectors, including power and industry.

In order to estimate the evolution of South Africa's power sector emissions, this study utilises data published by Eskom. In 2021, the Eskom's CO2 emissions from power generation accounted for 206.4 MtCO2. This figure includes coal-fired and gas turbine power stations, as well as oil consumed during power station start-ups. However, since coal is the main fuel for Eskom's power plants, we can assume that these emissions correspond entirely to coal-fired power plants. Furthermore, according to CSIR power statistics publication of 2022, 184.7 TWh were generated in 2021 from coal-fired power plants, which implies that **the average emission factor (EF) of the country's coal-fired power plants is equal to 1.12 tCO2/MWh**[ix].

By applying this EF to the country's coal-fired power generation as is planned up to 2030 according to the IRP 2019 and extended to 2050 by the CSIR, the CO2 emissions from coal-fired power plants are estimated, as presented in Figure 16[x]. The second line in the graph corresponds to the CO2 quantities which could potentially be captured by coal-fired power generation, assuming that a CC technology with a carbon capture rate of 90% is applied to such power plants, which is a realistic figure according to available technology reviews, e.g. (IRENA, 2021) (P. Bains et al., 2017)

It should be noted that that the above represents the theoretical upper limit of captured carbon – practical and market considerations in operating plants can reduce the expected captured carbon to as low as 20-30% of the theoretical values.

Figure 16 Estimation of emitted and captured CO2 from coal-fired power plants in SA.



Industrial sector

Current status of industrial sector

According to the classification of South Africa's 2022 National GHG Inventory Report, the Industrial sector includes manufacturing, mining and oil and gas and the main emission result from direct and indirect releases from the chemical or physical transformation of raw materials, as well as emissions used in products such as refrigerators, foams and aerosol cans.

South Africa's industrial sector is diverse and plays a significant role in the country's economy. It encompasses various sectors, including mining, manufacturing, construction, and chemical production, among others. The industrial sector in South Africa is responsible for a significant portion of the country's greenhouse gas (GHG) emissions. **In 2018 the industrial sector produced 164 Mt CO2e, which is around 40% of South Africa's total GHG emissions**. The largest source category is the petrochemical industry category (petroleum refining + coal to liquid), which contributes 68% to the total industrial sector's emissions. The metal and the mineral industry subsectors contribute 15% and 10%, respectively, to the industrial sector's emissions (McKinsey, 2021).

The following industrial processes are included in South Africa's industrial sector:

- Production of cement
- Production of lime
- Glass production
- Other Process Uses of Carbonates
- Production of ammonia
- Nitric acid production
- Carbide production
- Production of titanium dioxide
- Soda Ash Production
- Petrochemical and carbon black production
- Hydrogen Production
- Production of steel from iron and scrap steel
- Ferroalloys production
- Aluminium production
- Production of lead
- Production of zinc
- Lubricant use
- Paraffin wax use

Iron and steel production, cement production (including lime) and the petrochemical industry (including coal-to-liquid operations and conventional crude refineries) constitute the most significant sectors in terms of GHG emissions. These industries involve energy-intensive processes that emit CO2, as well as other greenhouse gases such as methane and nitrous oxide. The industrial sector's emissions are mainly associated with energy use, combustion of fossil fuels, and chemical reactions/processes. According to data from "Africa's Green Manufacturing Crossroads" (McKinsey, 2021), the GHG emissions of each sector are presented in the following table:

Table 16 Estimated GHG emissions of industrial sector in 2018 for South Africa

Industrial sector	MtCO2eq
Aluminium	0.4
Ammonia	1.5
Mineral (Cement / Lime)	9.1
Coal to liquid / petroleum refining	63.5
Iron and Steel	13.7

Geographical distribution of key industrial installations

The geographical distribution of industrial emissions in South Africa is concentrated in specific regions, such as Mpumalanga, Gauteng, and KwaZulu-Natal. These areas host a significant number of mining operations and industrial facilities. The proximity to coal reserves and transportation infrastructure contributes to the concentration of emissions in these regions.

It's important to note that the specific GHG emissions figures and geographical distribution can vary over time and are subject to ongoing changes and regulatory efforts to mitigate emissions. The South African government, along with various stakeholders, is actively working to reduce emissions in the industrial sector through policy interventions, energy efficiency measures, and the promotion of cleaner technologies.

In terms of key industrial plants for each of the aforementioned sectors, some notable facilities in South Africa include:

Metal industry

South Africa possesses huge reserves of chromium, iron, uranium, platinum, vanadium, titanium, lead, zinc, manganese and many other metals required by other countries for the production of goods. South Africa is one of the major producers of steel on the African continent, producing 5.7 Mt of crude steel in 2019 according to the World Steel Association, while it is the 21st largest crude steel producer in the world. At the same time, it is the largest producer of chromium, vanadium, iron and manganese ores (Republic of South Africa, 2014) (Republic of South Africa, 2015). South Africa's steel is used in the automotive, mining, construction and agriculture industries, while the sector contributes to about 1.5% of the country's GDP. The main plants with their corresponding locations and emissions are presented below in Figure 17 and Table 17 respectively.

Direct reduction of Iron (DRI) with the use of H2 seems like a realistic development for the steel industry, which would have a direct impact on the sector's future emissions. However, the extent to which such solutions might be developed in the short term is not clear. Therefore, carbon capture is in principle an emissions abatement technology that could be a transition solution for the countries metal industry.

Figure 17 Location of the main metal industry installations in SA (Climate Trace, 2023).

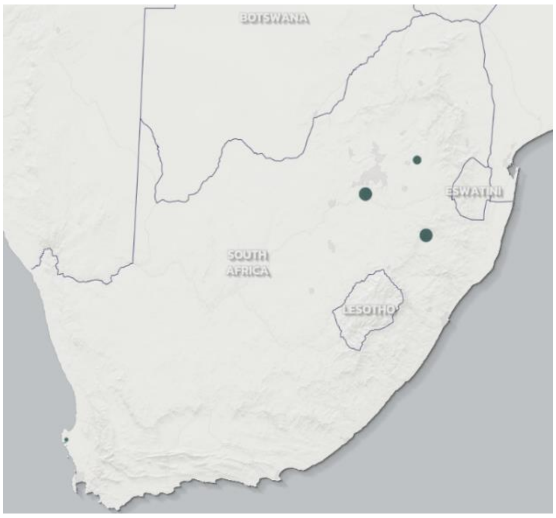


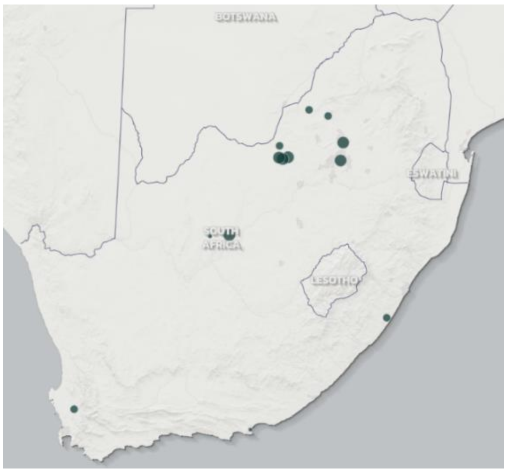
Table 17 CO2 emissions of the main metal industry installations in SA[xi]

#	Company	Plant	2021 CO2 emissions (MT CO2)
1	ArcelorMittal	Vanderbijlpark	2.9
2	ArcelorMittal	Saldanha	Mothballed
3	ArcelorMittal	Newcastle	1.17
4	Acerinox	Columbus	0.2
5	Hillside Aluminium	Richards Bay	1.63

Mineral industry

South Africa is considered among the most important producers of cement in the African continent, producing Portland cement and blended cement products, such as CEM I (Portland cement, which has a clinker content of >95%,), and, more recently, CEM II (clinker content between 65-94%) and CEM III (clinker content between 20-64%). Cement produced in South Africa is sold locally and to other countries in the Southern Africa region, such as Namibia, Botswana, Lesotho and Swaziland. Cement plants in South Africa vary widely in age, from 5 up to 70 years (Ige OE, 2023). Cement production in the country has been in decline the recent years, producing 10.8 Mt in 2020 with respect to 13.8 Mt produced in 2018 (Onestone Consulting Ltd., 2021). The main plants with their corresponding locations and emissions are presented in Figure 31 and Table 23 respectively.

Figure 18 Location of the main cement plants in SA (Climate Trace, 2023).



It is noted that the moment cement industries in South Africa consider the use of waste or alternative fuels and resources (AFRs) such as scrap tyres to be used as a substitute for traditional fuel (coal) and CCUS does not appear to be considered for the 2050 horizon[xii]. However, in case of realization of strong international developments, adoption of CCUS options also in the country could not be excluded.

Table 18 CO2 emissions from the main cement plants in SA[xiii]

#	Company	Plant	2021 CO2 emissions (MT CO2)
1.	Sephaku Cement Ltd	Aganang	0.72
2.	Natal Portland Cement Ltd	Simuma	0.48
3.	Mamba Cement Company	Limpopo	0.3
4.	Cemza Ltd	Coega slag mill	0 (0.137 kT of CO2)[xiv]
5.	PPC Ltd	De Hoek	0.11
6.	PPC Ltd	Dwaalboom	0.57
7.	PPC Ltd	Hercules	0.76
8.	PPC Ltd	Jupiter	0.72
9.	PPC Ltd	Riebeeck	0.62
10.	PPC Ltd	Saldanha	
11.	PPC Ltd	Slurry	0.6
12.	AfriSam Ltd	Dudfield	0.71
13.	AfriSam Ltd	Roodepoort	
14.	AfriSam Ltd	Ulco	0.71
15.	AfriSam Ltd	Vanderbijlpark	
16.	Lafarge Ltd / Holcim Ltd	Lichtenburg	1.56
17.	Lafarge Ltd / Holcim Ltd	Randfontein	

Refineries – petrochemical sector

The upstream petrochemicals sector can be divided into the conventional local crude refineries and South Africa's synfuels assets. The sector not only produces conventional liquid fuels, but also critical feedstock for the downstream chemicals value chain. Located in Secunda and Sasolburg, Sasol operates large-scale coal-to-liquids (CTL) and gas-to-liquids (GTL) plants. These facilities produce synthetic fuels, chemicals, and other petroleum-based products. Together with PetroSA's gas-to-liquid (GTL) operations (currently not in operation), these assets constitute South Africa's upstream petrochemicals value chain. The downstream petrochemicals value chain consists of various players, producing a range of products, including basic chemicals, rubber products, plastic products etc. It is noted that more than 90% of the sector's direct emissions are driven by the country's synfuel production, while it contributes to about 6.2% of the country's GDP.

The refineries with their corresponding emissions are presented in Table 19.

Sasol is arguably the larger player in this sector and based on its 2023 Climate Change report (SASOL, 2023) it has set a net zero target by 2050. Sasol is actively investigating CCUS technology and considers this technology as an option to achieve its 2050 net zero ambition.

Table 19 CO2 emissions from refineries in SAxv

#	Company	Plant	2021 CO2 emissions (MT CO2)
1.	Sasol (64%), Total SA (36%)	Natref	0.68
2.	Shell SA (50%), BP SA (50%)	Sapref	1.13
3.	Sasol	Sasol Secunda	58.7
4.	Engen	Durban	0.78

Projection of CO2 emissions from industrial sector

In view of a lack of an integrated forward-looking study on the future emissions of the industrial sector to the 2050 horizon, the evolution of emissions from South Africa's industrial sector will be determined within the frame of this study through a combined consideration of factors such as current emission levels, policy and regulatory frameworks, etc. It should be noted that the National Climate Change Response Policy (Republic of South Africa, 2011), which however dates back to 2011, provides a framework for reducing emissions from the industrial sector, without the consideration of a quantitative sectoral baseline emissions trajectory.

Apart from the figures presented above regarding the emissions of South Africa's industrial emissions per sector, it was not possible to identify projections for the evolution of the country's industrial sector in the available reports and studies. For projecting the emissions of each of the above sectors up to 2050, projections referring to the emissions of the entire African continent were used instead (McKinsey, 2021), scaled down with the share of the current production level in South Africa as compared to the continent's overall levels. By comparing South Africa's current CO2 emissions to Africa's current GHG emissions, a coefficient is deduced allowing for scaling down the evolution of Africa's GHG emissions up to 2050, as per each scenario originally considered within the pan-African context, to the CO2 emissions of South Africa.

Figure 32 reports Africa's manufacturing emissions for 2018, as presented in the aforementioned McKinsey study, and used in the present work as a starting point for the projection of SA's industrial emissions following the approach explained above[xvi].

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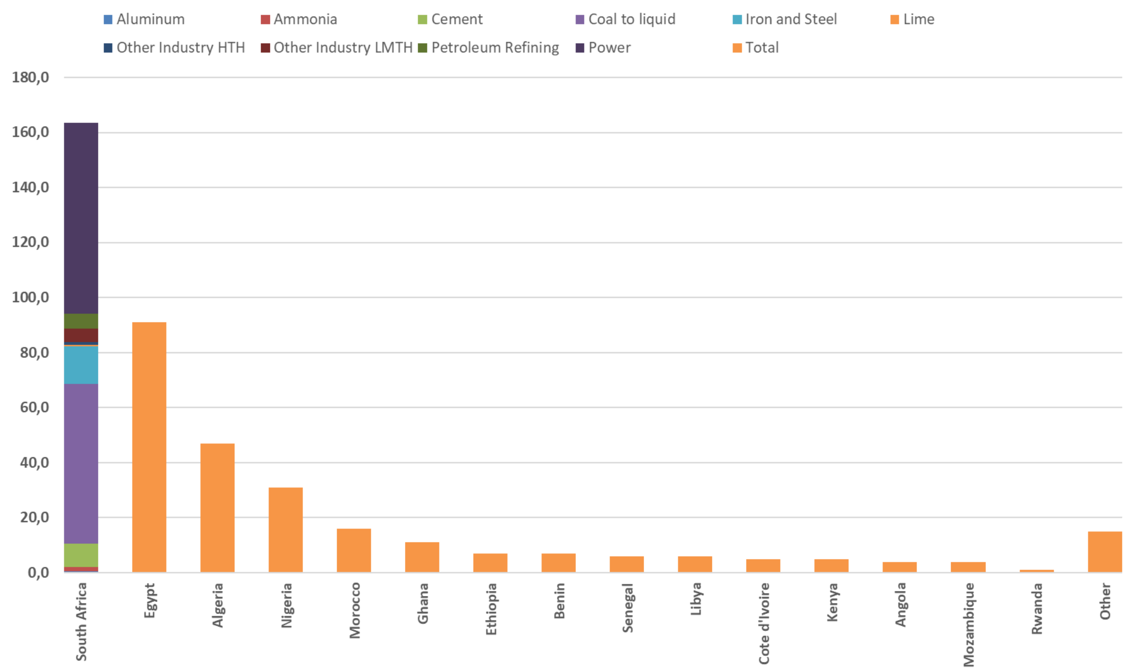
Figure 19 Africa's manufacturing emissions in 2018 as reported in (McKinsey, 2021).[xvii]



The projections of Africa's manufacturing GHG emissions in the McKinsey report, are based on the IEA's decarbonization scenarios framework, namely:

- A base case, where African countries comply with their current NDC commitments and Industry does not make any specific decarbonization efforts beyond the set NDC requirements;
- A global NDC-guided case, that aligns Africa's NDC with the global average and the Industry undertakes mainly relatively inexpensive brownfield improvements (e.g., use of biofuels);
- A net-zero case, that aspires to the ultimate goal of keeping temperature increases to 1.5 °C, where Industry is assumed to engage to brownfield (e.g., CCS) and greenfield (e.g., DRI H2 EAF, electrification) investments.

The projected GHG emissions of the entire African continent, as reported for the base case and for the global NDC-guided cases, suggest the following:

- **Base case:** an overall increase of 71% is observed from 2020 to 2050 in the total emissions (Scope 1 and 2) of Africa's manufacturing sector, reaching ca. 754 Mt CO2 eq (including power, which accounts for 121 Mt CO2e). In this scenario, the main driver for the increase in the emissions is the growth of the cement industry, estimated to contribute up to ca. 45% to the total figure of 2050.
- **Global NDC-guided case**: total emissions (Scope 1 and 2) of Africa's manufacturing sector are reduced by 25% from 2020 to 2050, going down to ca. 340 Mt CO2 (including power, which accounts for ca. 73 Mt CO2e). In this case, with the exception of cement (still cement dominates up to ca. 40% the total emissions in 2050), all industrial sectors contribute to overall reduction, with the coal-to-liquid sector exhibiting the most significant reduction of ca. 84%.

The net-zero scenario has not been considered as, following the assumptions in the original study, a range of measures have been considered to achieve Net Zero, some of which result in structural changes of the industry, and therefore, further insights would be needed to render the high-level approach of this work relevant.

Depending on the carbon capture process that will be applied to each industrial source, the respective CO2 capture rate will be determined, allowing for an estimation of the amount of CO_2 that can be captured per source. **In the following analysis, it is assumed that carbon capture is applied to the process emissions, which are unavoidable**, as energy related emissions can be reduced by switching to cleaner fuels. It must be noted however, that the definition of process emissions is crucial, as in some cases heat generation and combustion processes can also be considered to contribute to process emissions, raising their share significantly.

For the ***cement industry***, process emissions associated with the calcination of limestone account for almost 65% of total emissions (IEA, 2019), while the remaining emissions are energy related. According to available relevant technological assessments, **chemical absorption[xviii] and calcium looping are the most mature technologies that can be applied to the cement industry**, both having a carbon capture rate higher than 90% (JRC, 2022) (IRENA, 2021) (P. Bains et al., 2017).

For the ***iron and steel industry***, process emissions account for around 12% of total sectoral emissions (IEA, 2020). Chemical absorption is the most mature carbon capture technology with a TRL between 6-8. The carbon capture rate of this technology is greater than 90%.

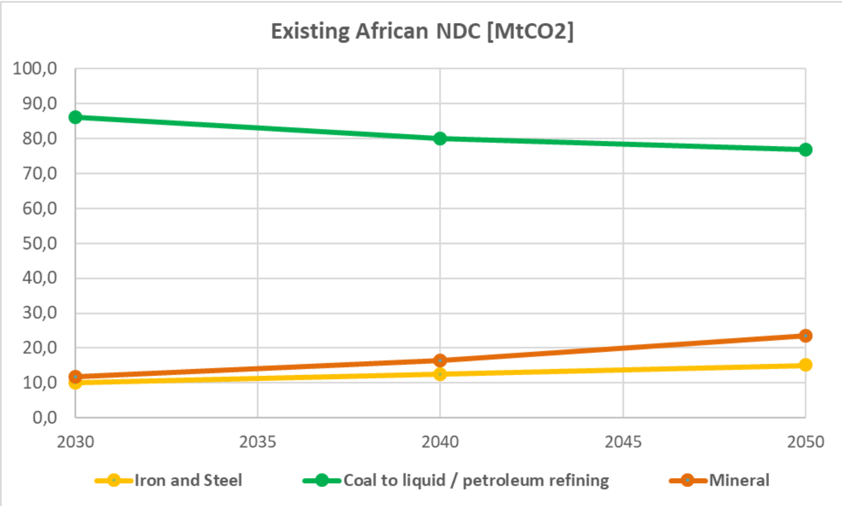
The ***petrochemical*** sector, including coal-to-liquid operations and conventional crude refineries, is currently the largest GHG emitter in South Africa (63.5 $MtCO_2e$ in 2018). The production of synfuels accounts for almost 90% of the sector's emissions, while around 50% of the sector's emissions are non-energy related (NBI, 2021). CO_2 is produced in petrochemical process streams mostly by reactions with oxygenates. However, most of the CO_2 in the petrochemical industry is emitted in the flue gas as a result of burning fuel oil and fuel gas. For capturing CO_2 from flue gases of petrochemical plants, adsorption and absorption appear to be the optimal choice, at least in short- and medium-term perspective, with carbon capture rates greater than 90%.

Base case scenario

The base case scenario expects emissions from African manufacturing to grow by about 70% by 2050. In this scenario, it is assumed that demand is in line with predictions for growth and that no additional abatement efforts are made, other than those that have already been committed to through the Paris Agreement NDCs. More than half of the continent's absolute abatement efforts in terms of $MtCO_2e$ are likely to come from South Africa because the country is starting at a higher baseline of emissions.

Scaling the emission projections of the base case scenario (Figure 20) to the current emission levels of the industrial sectors considered in South Africa, the following figures for the **total** CO_2 emissions of each sector can be estimated.

Figure 20 Estimated industrial CO2 emissions in SA according to Base Case Scenario.



Taking into consideration the percentage of each sector's emissions that correspond to the unavoidable process emissions, as well as the capture rate of each carbon capture technology that is applied per sector, the quantities of captured CO2 are estimated in Table 20.

Table 20 Quantities of captured CO2 according to base case scenario

Industrial sector	carbon capture technology / CO2 capture rate	process emissions (%) (IEA, 2019)	2030 MtCO2e	2040 MtCO2e	2050 MtCO2e
Iron and Steel	Chemical absorption / 90%	12%	1,1	1,4	1,6
Coal to liquid / petroleum refining	Adsorption-absorption / 90%	50%	38,7	36,0	34,6
Mineral	Chemical absorption / 90%	65%	6,9	9,6	13,7

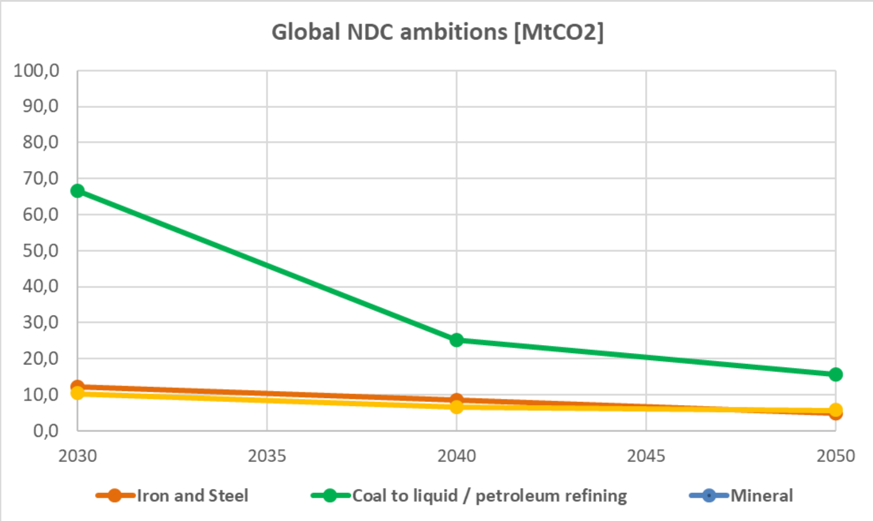
Global NDC-guided scenario

The global NDC-guided scenario assumes that Africa's NDC commitments are aligned with more ambitious global commitments until 2030. This pathway could see pan-African emissions peak around 2025 and drop back (due to the application of decarbonization and emission abatement measures) to 2018 levels in 2030. By 2050, overall emissions would be expected to fall by about 25 percent relative to 2018 levels, totalling to 330 MTCO2e. This is equivalent to a 56 percent reduction compared to the base case scenario estimates of 755 MtCO2e.

A continued reduction of scope 1 manufacturing emissions would be driven by rapid technology adoption, including a switch to biomass and the use of green hydrogen[xix].

Following the scaling approach on the total emissions on the basis of the share of South Africa's emissions, the evolution of industrial emissions is obtained as presented in Figure 21. It is noted that based on the McKinsey work, in this scenario, CCS is applied in South Africa's Coal-to-Liquids and therefore the shown emissions in Figure 21 for this industrial sector do not essentially constitute a potential for carbon capture.

Figure 21 Estimated industrial CO2 emissions in SA according Global NDC-guided Scenario.



Taking into consideration the percentage of each sector's emissions that correspond to process emissions, as well as the capture rate of each carbon capture technology that is applied per sector, the estimated available quantities of captured CO2 are presented in Table 21.

Table 21 Quantities of captured CO2 according to global NDC-guided scenario

Industrial sector	carbon capture technology / CO2 capture rate	process emissions (%)	2030 MtCO2e	2040 MtCO2e	2050 MtCO2e
Iron and Steel	Chemical absorption / 90%	12%	1,3	0,9	0,5
Coal to liquid / petroleum refining[xx]	adsorption-absorption / 90%	50%	29,9	11,4	7,1
Mineral	Chemical absorption / 90%	65%	6,0	3,8	3,3

It should be noted that the rate of deployment of Carbon Capture technologies might not be sufficient to capture the amount of CO2 that has been calculated for each scenario in the previous tables. The development of a few pilot projects could act as catalyst for the fast adoption of CC solutions in industrial plants. It should also be noted that a few industrial stakeholders are already assessing the deployment of CC solutions.

Biomass

Alongside Carbon Capture from the sectors that were covered in the previous sections, biomass could also be considered as a sustainable source of carbon, when used for the production of low- and zero-carbon fuels (such as SAF) and chemicals. Based on its production method and specific feedstock used, biomass is classified into three categories:

- **First generation** biomass, consisting of agricultural crops grown on arable land (e.g. corn, soybeans, sugar cane), has previously played a large role in the production of lower-carbon fuels but is no longer seen as the main source of biomass, as it poses a risk to food security and food prices due to its direct competition with food crops. According to EU's Renewable Energy Directive II, the use of biomass should maintain food security, thus excluding a large scope of first-generation biomass.

- **Second generation** biomass consists of sustainable biomass sources that do not result in land use change or compete with food crops, such as non-edible agricultural waste (e.g. maize, sugar cane), invasive alien plants (e.g. prickly pear, eucalyptus), organic waste (e.g. sewerage, wastewater, solid waste) and forestry waste (e.g. sawmill, plantation, pulp and paper waste). This generation is currently considered as the most promising and relevant source of biomass.
- **Third generation** biomass, consisting of algae engineered to harvest oil in ponds, tanks or the sea, is still techno-economically unfeasible and questionable with regards to its sustainability.

According to the NBI, Decarbonization of the petrochemical sector report, the existing second generation biomass in South Africa amounts to approximately 77 Mtpa, consisting of agricultural residues (47 Mtpa), invasive plants (11 Mtpa), forestry residues (10 Mtpa) and organic waste (9 Mtpa). From this amount, **4 Mtpa are allocated to applications such as energy and composting, while around 24-36 Mtpa are considered readily available for other applications, such as SAF, decarbonization of synfuel plants etc.** As it is noted by the NBI, that there is some uncertainty with respect to these figures, due to the lack of data and analysis around the availability of second generation biomass in South Africa.

Further, the same NBI report on the decarbonization of South Africa's Petrochemicals and Chemicals Sector (NBI, 2021), reports the geographical allocation for the production of the various types of biomass to be found in South Africa. Agricultural residue, only 15% of which is estimated to be available for collection, is predominantly maize residue around the region of eastern Highveld. Invasive species are primarily located in the areas of KwaZulu-Natal, the Eastern Cape and Mpumalanga. Organic waste is mostly produced in urban regions, such as Johannesburg, Pretoria, Durban and Cape Town. Forestry residue is mainly concentrated in KwaZulu-Natal and eastern Mpumalanga. It is noted that the geographical distribution of the various types of biomass is important for the potential utilization of that biomass, since transporting biomass has been traditionally proven as not a cost optimal solution.

Further, and as noted in the NBI report, any prior to any more detailed assessment of how South Africa's available biomass could be exploited for the decarbonization of certain applications, the following considerations must be taken into account:

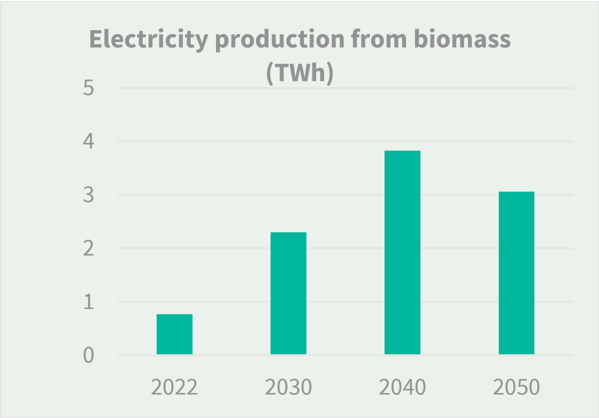
- it is not possible to accurately estimate how much biomass can be exploited without causing soil degradation or reducing the soils capacity to capture carbon, due to the lack of data and analysis around the availability and accessibility of second generation biomass in South Africa.
- the carbon footprint of the infrastructure and services that need to be established for the collection, processing and transportation of biomass to the respective end users must be assessed, which is expected to be a challenging factor given the multiple dispersed locations of biomass sources and that it is not in a form that can be directly fed to the respective industrial processes.

A final consideration with respect to the analysis of biomass as carbon source in South Africa, relates to the competition for biomass to other uses, and in particular for SAF. Based on the work of WWF (WWF, 2022) and RSB (RSB, 2021), it is noted that there is a palette of innovative feedstock, such as crops can be grown on degraded land or where alien invasive plants are used, which can be used for SAF production (see also section 0.).

Exploitation of biomass in the power sector

According to the foreseen evolution of the country's energy mix (see also Section 5.1.1.), a small fraction of South Africa's electricity production is expected to come from biomass / biogas. This is also in line with the respective NBI report on the decarbonization of South Africa's petrochemical sector, according to which 4 Mtpa of biomass are allocated for applications such as energy generation. According to the projections of the IRP 2019, as extended to 2050 by the CSIR, the contribution of biomass to the country's electricity production is presented in the following Figure 35..

Figure 22 Contribution of biomass to electricity production, according to the IRP2019, as extended to 2050 by the CSIR (own elaboration of data).



The amount of CO_2 emitted per kilowatt-hour (kWh) of electricity produced from biomass can vary depending on several factors, including the type of biomass feedstock, the conversion technology used, and the efficiency of the system. The actual CO_2 emissions per kWh from biomass will depend on the specific circumstances and the carbon content of the biomass feedstock.

As an approximate value, biomass power generation typically emits around 230 grams of CO_2 per kilowatt-hour of electricity produced (World Nuclear Association, 2022). This average value takes into account different biomass sources, conversion technologies, and efficiencies. It's worth mentioning that these values are estimates and can vary based on specific conditions and the particular biomass-to-energy conversion process employed.

It is important to consider that sustainable biomass practices, such as using agricultural residues, dedicated energy crops, or sustainably managed forest biomass, can further reduce the carbon emissions associated with biomass power generation. Additionally, coupling biomass power generation with carbon capture and storage (CCS) technologies can enable the capture and storage of CO_2 emissions, further reducing the net carbon emissions from biomass-based electricity production.

From electricity production alone, the amount of CO_2 emitted from bioenergy is projected in the following Table 22. Estimations are based on the reported contribution of biomass in the power sector by the IRP of 2019. Then, again considering information in available review studies (IRENA, 2021) (P. Bains et al., 2017), the theoretical maximum amount of CO_2 that can potentially be captured would equal to the 90% of the emitted quantities.

However, due to the fact that there is not a centralized biomass-fired power plant in South Africa, it is quite probable that the application of CCS at such a small scale is not feasible, rendering thus this path as an almost irrelevant (from the practical point of view) source of sustainable carbon for synthetic fuels and other P-to-X products.

Table 22 Estimated CO_2 emitted by electricity produced from bioenergy and amounts of CO_2 captured

Year	CO_2 ($MtCO_2$) emission	CO_2 ($MtCO_2$) captured
2022	0.18	0.16
2030	0.53	0.48
2040	0.88	0.79
2050	0.70	0.63

Exploitation of biomass in other industrial sectors

According to various studies, **biomass has a promising potential for the decarbonization of South Africa's petrochemical sector**. According to the NBI report on the decarbonization of SA's petrochemicals sector, between 15 and 20 Mtpa of the biomass that is readily available in the country would be needed to decarbonize the existing CTL synfuels plant, provided CCU and green H2 are introduced at scale. Hence, the currently available biomass, ranging between 24 – 36 Mtpa will be sufficient to serve this demand. Furthermore, according to a WWF report (WWF, 2022), it is estimated that South Africa has the potential to produce up to 4,5 billion litres of sustainable aviation fuels (SAF) per year, while taking into account sustainability principles that restrict the production of purposely produced feedstocks to a level that would not affect food security or environmental integrity. This estimate is based on feedstock availability from different sources, which assume a much higher estimate of invasive alien plants (215 million tonnes of IAPs, Stafford et al. 2021) than what is assumed by the NBI report (11 Mtpa according to NBI, 215 Mtpa according to WWF)[xxi,xxii].

It is also worth mentioning that SASOL is investigating the potential of agricultural biomass utilised for rehabilitation of previously mined areas for the production of biofuels.

Classification of carbon sources

In the previous sections, the point sources, namely emissions from the power and key industry sectors, that can potentially supply CO2 for the production process of synthetic fuel are assessed. Based on the current emissions of each sector/industry, their expected evolution up to 2050 according to three different scenarios and the maturity of the potentially applicable carbon capture technologies, the amount of CO2 that can technically be captured for each point source was estimated. For each point source, this amount of CO2 can be considered as indicative and rather considered as an upper limit, as economical parameters and sustainability criteria will further determine the actual quantities that the market could realistically expect.

Since both economic (primarily) and sustainability (to an extent) parameters are much depended on the specifics of a particular application, further detailed analysis at the local/site level would be needed to essentially determine the real carbon capture potential. This section discusses the above issues at a high level, as a first attempt to approach such issues in South Africa.

Economic parameters

Several economic parameters, such as the cost of captured CO2 (USD/tCO2), as well as environmental, such as the carbon source's emission intensity, and technological, e.g. the technical feasibility and the efficiency of the capturing process, should be considered in detail to determine the selection of the point sources from which CO2 will be captured.

The cost of carbon capture is a significant factor in determining the classification of point sources. It refers to the expenses associated with capturing, transporting, and storing or utilizing carbon emissions. If the cost of carbon capture is prohibitively high compared to the value or benefits derived from captured carbon, which are also much depended on the prevailing (or expected/assumed) market conditions (e.g. electricity prices, presumed carbon value, etc.), it may not be economically feasible to implement carbon capture technologies.

Sustainability criteria

Carbon capture from fossil sources and processes can have both positive and negative impacts on the environment and climate change. The use of carbon capture technologies can help reduce carbon emissions by capturing and reusing carbon, which would otherwise be released into the atmosphere. Furthermore, synthetic fuels produced from captured CO2, have the potential to serve as low-carbon alternatives to traditional fossil fuels for the decarbonization of sectors that are difficult to electrify, such as aviation, long-haul shipping and heavy-duty transportation. However, the use of captured CO2 from fossil sources and processes can also have negative effects, such as locking in the continued use of fossil fuels and limiting the development of renewable energy. This occurs when the continued use of fossil fuels is justified or even encouraged by the existence of CCUS technologies, which can result in a delay in the realization of the energy transition and the uptake of climate protection actions.

When it comes to avoidable versus unavoidable sources, CCU can be used to capture carbon emissions from both types of sources. Avoidable sources include coal-fired power plants and other industrial facilities that can reduce their emissions through energy efficiency measures or by transitioning to renewable energy sources (including fuel switch). Unavoidable sources, such as certain chemical processes of cement production, have emissions that are more difficult to reduce and may require the use of CCU technologies to capture carbon emissions.

However, **it is important to note that the use of CCU technologies from avoidable sources should not be seen as a long-term solution**. It is still necessary to transition away from fossil fuels and reduce greenhouse gas emissions to limit the impacts of climate change. While CCU technologies from avoidable sources could be seen as a necessary step in the transition towards a more sustainable future, it is important to consider the potential negative impacts and carefully evaluate the long-term viability of these technologies. **The use of CCU should be viewed as a complementary technology to be used in**

conjunction with other mitigation measures, rather than a substitute for more fundamental changes in the energy and industrial sectors.

Estimated overall carbon supply potential

The share of process emissions (i.e. unavoidable CO2 emissions) with respect to the total emissions of each sector that has been covered in the previous sections, together with the captured process emissions for 2030, 2040 and 2050, are presented in the following table, considering all three scenarios for the evolutions of the industrial sector's emissions, together with the respective capture rates (theoretical values, e.g. (IRENA, 2021) (P. Bains et al., 2017).

Table 23 provides an overview of the estimated potential for captured CO2 from the analysed sectors in South Africa, considering applicable technologies and assuming that carbon capture is applied to unavoidable industrial emissions.

In terms of sustainability criteria, sectors with highest share of unavoidable emissions should be prioritized for carbon capture. Starting from the cement sector which has the highest share of unavoidable emissions (most sustainable) and moving up to the power sector which has the lowest share (least sustainable), the estimated amount of captured CO2 per point source is presented in the following graphs for the years 2030, 2040 and 2050.

The two following figures (Figure 23 and Figure 24) present the lowest and highest amounts of captured CO2 respectively, as derived from the Base Case and Global NDC-guided scenarios, as were presented before.

Table 23 Overview of captured CO2 from each sector, considering applicable technologies and assuming that CC is applied to unavoidable emissions

Sector	Process emissions share (unavoidable emissions)	2030 MtCO2	2040 MtCO2	2050 MtCO2
Mineral (cement / lime)	65%	6,0-6,9	3,8-9,6	3,3-13,7
Petrochemical (CTL/petr. refining)	50%	29,9-38,7	11,4-36,0	7,1-34,6
Iron and steel	12%	1,1-1,3	0,9-1,4	0,5-1,6
Power	0%	170,9	126,2	155,4

Figure 23 Potential for captured CO2 ordered according to sustainability criteria – Global NDC ambitions scenario.

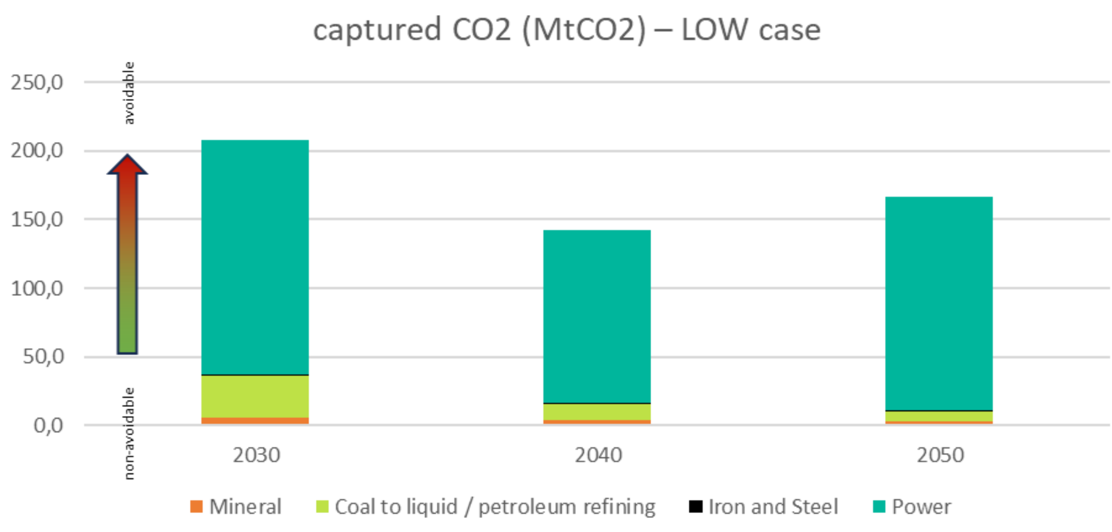
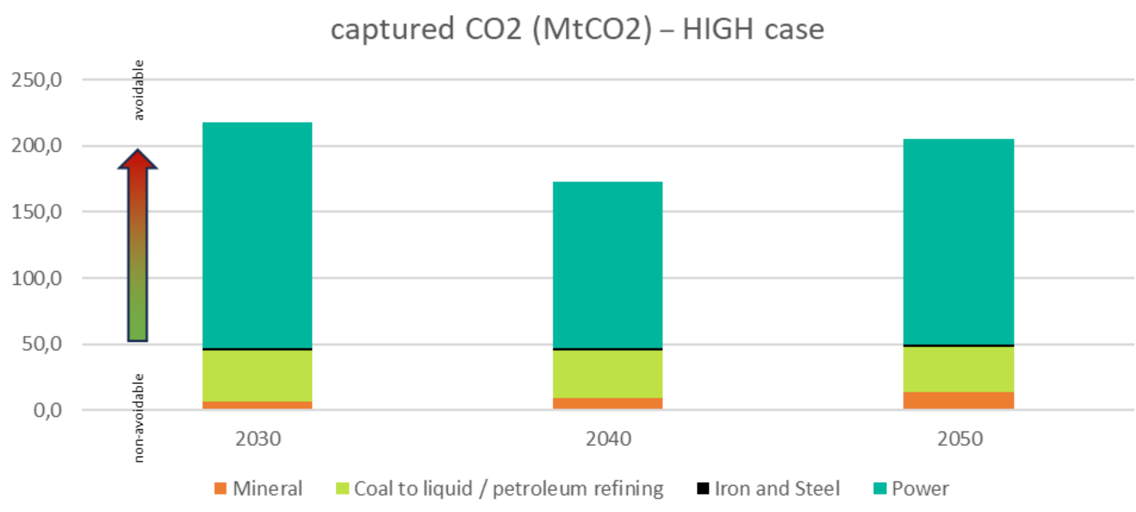


Figure 24 Potential for captured CO2 ordered according to sustainability criteria – Existing African NDC scenario



Estimated carbon exports potential

By comparing these values to the domestic carbon demand, as estimated in Chapter 3, it is evident that **there is a considerable export potential for PtX commodities or CO2 in pure form, for 2030, 2040 and 2050, for all supply scenarios that have been considered**, and for most domestic demand scenarios as well.

Table 24 provides an overview of:

- The estimated captured CO2 from the point sources examined in the present work (i.e. power sector, iron and steel, cement and petrochemical industries), following the two scenarios considered (base case and global-guided NDC case), as discussed in Chapter 4;
- Results are presented considering the quantities coming from the power sector, as well as considering only CO2 from process emissions (i.e. only the unavoidable emissions)
- The estimated quantities of CO2 needed for the production of synthetic fuels to cover domestic needs in South Africa, as per scenarios analysed in Chapter 3;
- The estimated exports potential, determined by subtracting the domestic CO2 demand from the overall produced CO2.
- Results are presented considering the quantities coming from the power sector, as well as considering only CO2 from process emissions (i.e. only the unavoidable emissions).

Table 24 Overview of estimated captured CO2 from point sources, estimated CO2 quantities of CO2 to cover domestic needs, and estimated available CO2 for exports

CO2 quantities (MtCO2)	2030	2040	2050
Captured CO2 – incl. power sector[xxiii]	207.9 – 217.8	142.3 – 173.1	166.3 – 205.3
Captured CO2 – without power sector	37.0 – 46.9	16.1 – 46.9	10.9 – 49.9
Domestic CO2 demand	29.9 – 67.8	18.2 – 59.4	11.3 – 48.7
CO2 available for export – incl. power sector	**137.5 – 187.9**	**79.4 – 155**	**107.8 – 194**
CO2 available for export – without power sector	0 – 17.0	0 – 28.7	0 – 38.6

Based on the results, it can be concluded that if South Africa were to substitute all projected fossil fuel consumption with locally produced synthetic fuel, there would be potentially enough captured CO2 from its point sources to meet that ‘domestic’ demand. Further, there is also significant CO2 surplus that could be utilised for exports. However, sustainability considerations would limit the available quantities that can in principle be eligible for exports to international markets, since unavoidable emissions are a relatively small portion of the total emissions, which are dominated by coal power production. In the case CO2 from the power sector is not considered, the estimated export potential for CO2 is drastically reduced, and depending on the scenarios for the domestic demand and degree of achievement of the global climate ambition, captured CO2 from industrial processes would not even been sufficient to cover the expected domestic demand[xxiv].

Figure 25 CO2 available for exports, including CO2 captured from the power sector (MtCO2)[xxv]

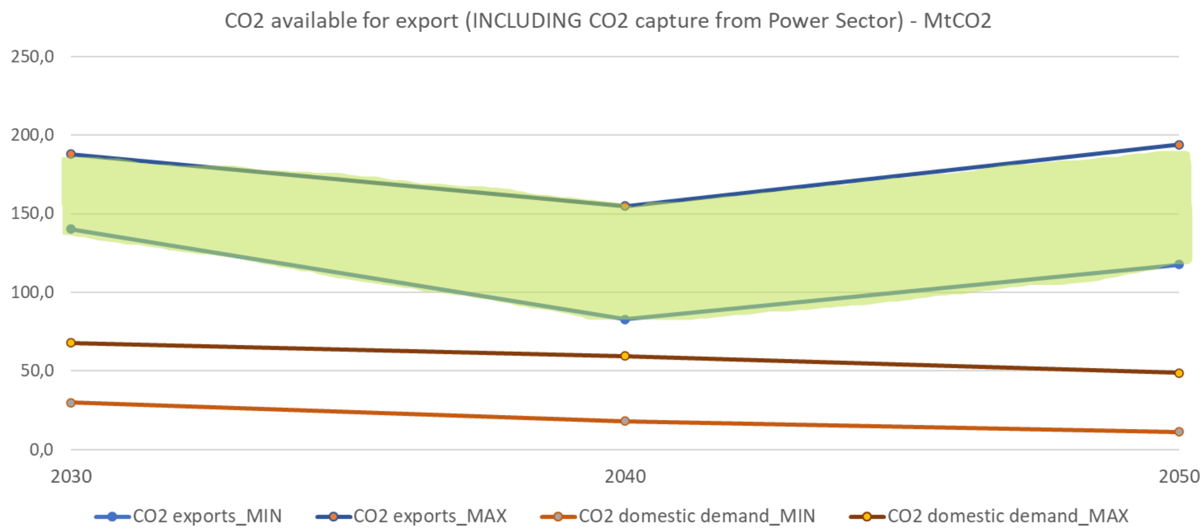
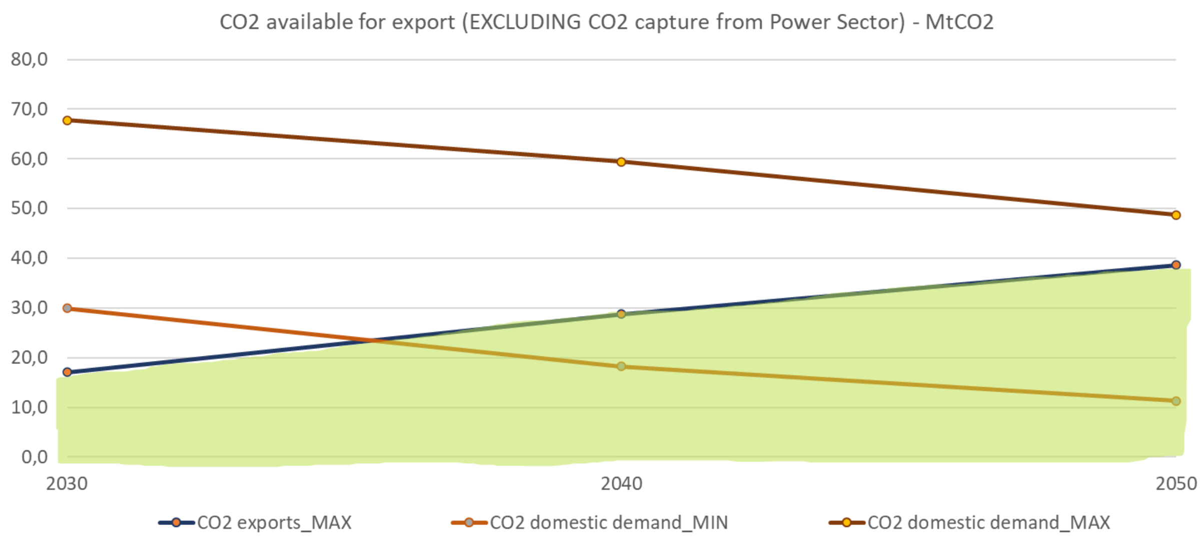


Figure 26 CO2 available for exports, excluding CO2 captured from the power sector (MtCO2)



5 SCENARIOS OF CARBON (CO2) SUPPLY FOR THE PRODUCTION OF SYNTHETIC FUELS IN SOUTH AFRICA

This chapter provides a first assessment of the various supply scenarios of CO2 that could be developed for the production of synfuels in South Africa. Parameters, such as the location of ports for potential exports of synfuels, areas with high RES potential that could facilitate production of green H2, existing infrastructure, including industrial installations and potential actors of the synfuels value chain, as well as CO2 transport costs are considered in the analysis of each scenario.

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Scenarios of carbon (CO2) supply for the production of synthetic fuels in South Africa

CO2 transport/logistics background info

CO_2 transport applies to both the CO_2 captured from fossil fuel-based processes as well as to CO_2 from Carbon Dioxide Removal (CDR) measures, i.e. biomass with carbon capture and direct air capture. Captured CO_2 requires compression, liquefaction, solidification or hydration before being transported to a storage or a utilisation site. The choice is linked to the transport mode and depends on several factors (IRENA, 2021):

- the quantity of CO_2 transported;
- the distance to the storage or utilisation site;
- technology maturity and associated costs;
- social acceptance of the particular transport mode in the area.

As transportation serves as a bridge between CO_2 capture and storage sites, it's crucial for all three phases (capture, transportation, and storage) to align harmoniously. This alignment entails considering design, material choices, and operational strategies to minimize unnecessary excess and expenses, all the while factoring in the establishment of hubs, clusters, and networks to prevent both shortages and redundancies. Moreover, it's imperative to uphold safety standards throughout this integrated process.

Compression and **liquefaction** are well established technologies with accumulated knowledge and experience borrowed from the oil and gas industries. There are more than ten compression technologies, which vary in terms of their energy savings and associated costs. Compression technology may require 80–120 kWhe/tCO_2 (Jackson S, 2019). **Solidification** is also a commercially viable option, but it is more energy- and cost-intensive than the other options (i.e. compression and liquefaction). Researchers are exploring activities that are both more cost- and energy-efficient and scalable, including converting the gaseous CO_2 into a solid carbon by using liquid metals as a catalyst at room temperature. **Hydration** is the least developed technology. Current research and development activities focus on natural gas hydration to replace LNG and its use for CO_2 may be considered in the future.

Transport modes

Numerous potential modes of transportation exist, including offshore and onshore **pipelines**, **shipping**, and **landways** (railways and trucks). The suitability of these modes hinges on factors like costs, influenced by flow rates and distances, and extends to social and environmental factors. Achieving optimal cost-effectiveness could require a combination of pipelines and maritime vessels, alongside the development of clusters, networks, and hubs to leverage economies of scale.

Pipeline transport

Both onshore and offshore pipelines are constructed using a similar approach to that of hydrocarbon pipelines, although their inspection and venting procedures can exhibit notable differences. Globally, long-distance CO_2 pipelines extend over 6,500 km, with the majority associated to Enhanced Oil Recovery (EOR) activities. Predominantly concentrated in the United States, these pipelines have facilitated the transportation of around 0.05 Gtpa of CO_2 since 1980. The rest of the world has very limited experience with CO_2 pipelines. The European Union's strategy revolves around repurposing existing gas and petroleum pipelines that are no longer in use for CO_2 transport, an approach that could significantly cut down on capital expenditures and accelerate the implementation of Carbon Capture and Storage (CCS) projects. **For CO_2 transport through pipelines, the CO_2 is maintained in a supercritical state**, with pressure greater than 74 bars and temperature greater than 31°C. Depending on the transportation distance, intermittent recompression might be necessary. Research is also underway regarding the viability of conveying CO2 in liquid form at 10 bars and -40°C, although this approach requires additional pipe insulation.

The costs of construction of pipeline infrastructure to transport CO2 over long distances are high (circa 90% of overall costs) and proportional to the distance. This can be mitigated by building shared infrastructure to benefit from economies of scale.

Ships

Ships present an alternative choice suitable for **longer distances (exceeding 1,000 km),** offshore storage, and small distributed sources. The transportation of CO2 by sea has primarily been propelled by the food and beverage industry over the last three decades, although the quantities involved are significantly less than what is required for substantial Carbon Capture and Storage (CCS) projects. These vessels typically possess a transport capability of 1,000 m^3 and engage in trade flows of approximately 3 Mtpa. However, to accommodate larger quantities, the availability of ships is limited. For instance, Larvik Shipping operates four liquid tankers, each with a capacity of 1,200 to 1,800 tCO2, whereas IM Skaugen maintains six carriers capable of transporting between 10,000 and 40,000 m^3 of captured CO2. The CO2 is transported by ships in a liquid state at approximately 7–9 bara and -50°C to -55°C.

Ships entail lower initial investment compared to pipelines due to their reduced reliance on transport distance and scale. **However, a significant portion of their overall costs is attributed to operational expenses** (such as fuels, temporary storage, liquefaction, and loading/unloading). Addressing these expenses, as well as optimizing the injection system's design and operations, presents notable technical complexities. Standards for safety are covered by the international gas code of the International Maritime Organisation.

In addition to technical and cost challenges, potential **legal obstacles concerning the utilization of ships for CO2 transportation might exist[xxvi].**

Trucks and railway

Trucks and railway can be employed for **small quantities** of transported CO2. At present, trucks are utilized on project premises to transfer CO2 from the capture site to adjacent temporary storage facilities.

Costs

While the expenses associated with capture typically constitute the majority of total CCS project costs, **CO2 transport costs can also be significant**. These costs are frequently depicted as fixed amounts that overlook factors such as flow rate, proximity to storage and utilization destinations, the method of storage, and the mode of transportation. Often, these estimates are formulated based on large-scale plants with substantial CO2 volumes, overlooking smaller installations that may require a combination of transportation modes to benefit from economies of scale through clusters, hubs and transport networks.

Only a limited number of studies have undertaken cost calculations that consider capacity and distance as factors for determining the most appropriate transport modes or their combinations. For pipelines, CAPEX emerges as a major component, accounting for as much as 90% of overall transport expenses. For ships, OPEX is a major component for tasks such as liquefaction, fuels, loading/unloading, and interim storage. The cost profiles vary based on the specific type of transportation, the distance covered, and the volume of CO2 being transported, as illustrated in the following Table 25. It is noted that a detailed assessment of transport costs for the case of South Africa would require a detailed analysis considering details of specific projects.

Table 25 Costs of CO2 transport per medium and distance used (Zero emissions platform, 2011) (IRENA, 2021).

Distance	up to 200 km	200-750 km	750-1500 km
Capacity	15-20 Mtpa CO2	2.5-20 Mtpa CO2	2.5-20 Mtpa CO2
Onshore Pipeline		USD 1.7–6.1/tCO2	
Offshore Pipeline		USD 3.8–32.4/tCO2	Up to USD 58.4/tCO2
Shipping			USD 12.5–22.4/tCO2
Trucks	USD 14.7/tCO2		
Rail		USD 8.2/tCO2	

Transport of CO_2 scenarios for South Africa

Rationale

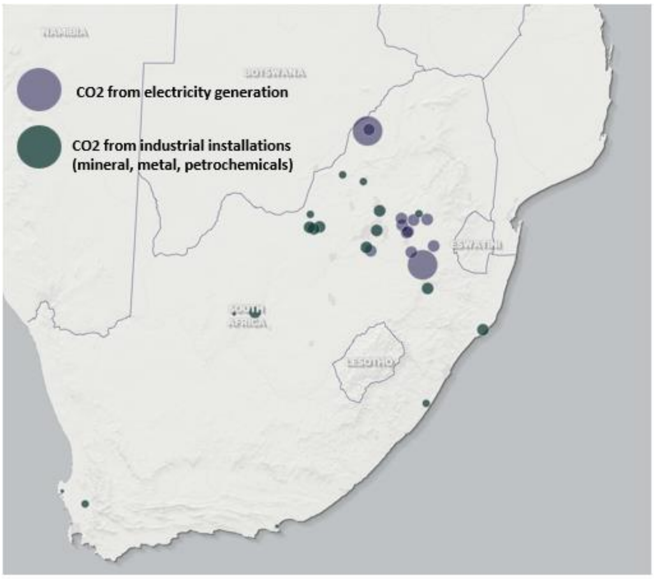
The following section will attempt to investigate the different CO_2 transport scenarios for synfuels and related feedstock, such as H_2 and CO_2, in order for the final product to reach one of the country's major ports for export and/or industrial end-users. CO_2 capture at point sources, green H_2 production and synthesis of synfuels do not necessarily take place in the same location, so transportation costs of feedstocks and products to various locations by different means of transport need to be assessed.

A high-level analysis is performed herein, in order to investigate whether there is a scenario that clearly prevails over the others, and to identify areas in which better insight can provide directly comparable results.

Underlying assumptions

The geographical distribution of CO_2 point sources in South Africa is mainly concentrated around the region of Mpumalanga. Specifically for the power sector, the majority coal-fired power plants are located in Mpumalanga, except for two power stations which are located in the Free State and Limpopo provinces respectively. Cement plants are mainly located North of Mpumalanga, with a few minor exceptions located at the centre and the coastline of the country. The metal industry's main activity is also located around Mpumalanga, while the petrochemical sector is the one with the greatest geographical dispersion, with some facilities located above Mpumalanga and with others located on the country's coast. It is noted however that Sasol's CTL and GLT plants are located in Secunda, right next to Mpumalanga (Figure 27).

Figure 27 Map of CO_2 point sources in SA – elaboration based on (Climate Trace, 2023).



To simplify the calculations regarding distances for CO_2 transport, it has been assumed that CO_2 point sources are located in Mpumalanga. The main transport modes considered in the analysis that follows, are pipelines, trucks and railway.

Pipeline transport

Transnet Pipelines, a subsidiary of Transnet, is the principal operator of South Africa's fuel pipeline system. It is responsible for over 3,000 kilometres (1,900 miles) of pipelines. It is also responsible for petroleum storage and pipeline maintenance. Transnet Pipelines transport petrol, diesel fuel, jet fuel, crude oil and natural gas (methane rich gas). Total throughput is over 16 billion litres per year. The liquid fuels network traverses the provinces of KwaZulu-Natal, Free State, Gauteng, North West and Mpumalanga. The intake stations are the two Durban refineries – the crude refinery at Coalbrook (Natref) and the Sasol 2 and Sasol 3 synfuel plants in Secunda. The network includes a tank farm, at Tarlton, with a capacity of 30 million litres which is used mainly for storage and the distribution of liquid fuels into Botswana. The gas pipeline, a converted line previously used for liquids, runs from

Secunda to Durban via Empangeni. It has take-off points at Newcastle and Richards Bay as well as along the route between Empangeni and Durban – see the detailed map in (Transnet, 2019)

Rail transport

Rail transport in South Africa is an important element of the country's transport infrastructure. All major cities are connected by rail, and South Africa's railway system is the most highly developed in Africa. Shosholoza Meyl used to operate long-distance routes covering the major metros in the country: Johannesburg, Cape Town, Durban, Port Elizabeth and East London (Figure 28)

Figure 28 Map of SA railway network (Wikipedia, 2023)

According to a national whitepaper on rail, which was adopted by South Africa's Department of Transport, a major issue that hinders the possibility of CO2 transport through railway is that cape gauge is currently used in South Africa's railways, instead of standard gauge. Since cape gauge is narrower than standard gauge, it is not possible to achieve double stacking of containers or to achieve competitive speeds. However, according to the whitepaper, there is a commitment towards the adoption of standard gauge, which would render the transportation of goods through railway more competitive in the future.

Once CO2/synfuels are transported from their capture/production location to the country's ports, further transport to destination countries is assumed to take place via ships[xxvii]. For the purposes of the present analysis, the PtX Business Opportunity Analyser tool that has been developed by Agora Energiewende (Agora, 2023) has been used for calculating the delivered cost of PtX molecules from an export country to an import country.

CO2 quantities

In order to estimate the potential CO2 quantities that may need to be transported/exported, the analysis performed in Chapters 4 and 5 has been used. By taking into account the total potential CO2 emissions (Chapter 5) including the power sector and considering the domestic carbon utilization scenarios (Chapter 4) an estimate of the CO2 quantities available for export has been deduced as shown in Table 26. It is noted that only the max and medium CO2 exploitation scenarios have been considered, as described in Chapter 4.

Table 26 Estimates of SA max CO2 quantities available for export based on the present analysis, including CO2 captured from the power sector

	2030	2040	2050
Produced CO2 (MtCO2)	207.9 - 217.8	142.3 - 173.1	166.3 - 205.3
Domestic CO2 demand (MtCO2)	29.9 - 67.8	18.2 - 59.4	11.3 - 48.7
CO2 available for export (MtCO2)	140.1 - 187.9	82.9 - 154.9	117.6 - 194

Scenario 1: Transport of CO2 directly to ports for export

The coasts of South Africa lie on the Southern end of the continent's landmass. The country touches the Indian Ocean on its east and the South Atlantic on its West coast. This allows cargo and cruise vessels of all sizes to have 3-way access to the South African coasts. The major ports in South Africa line up along the 1,739 miles long coastline. As of 2019, the country has over 8,856 port calls that include ships of all sizes. The major ports contribute 92% of its 30,400 million dollar shipping trade. These ports export mainly to China, Germany, and the USA (Sinha, 2021).

Figure 29 Map of SA's major ports (own elaboration based on google maps)

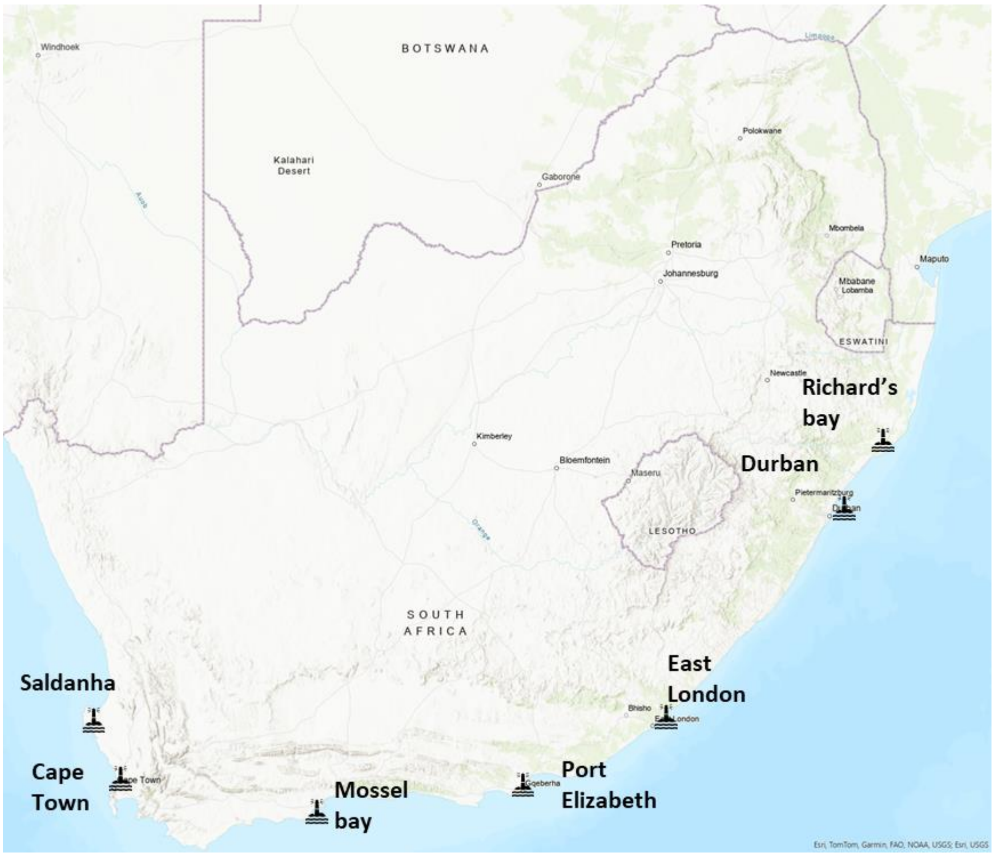


Figure 29 present the SA map indicating the main ports. The Port of Cape Town, located in the Western Cape Province, is the oldest port in the country, handling diverse cargo such as containers, bulk commodities, and automotive exports. The bustling Port of Durban, situated in KwaZulu-Natal, is the busiest port in South Africa and serves as a key link for regional and international trade. The Port of East London, in the Eastern Cape Province, specializes in bulk cargo, including minerals and automotive components. Mossel Bay, another notable port, focuses on petroleum and gas-related cargo, while Port Elizabeth (Ngqura) serves as an essential hub for various goods, including containers and automotive components. The Port of Richards Bay is a major coal export port, while the Port of Saldanha Bay specializes in iron ore exports. These ports collectively facilitate trade, handle different types of cargo, and contribute to South Africa's maritime industry and economic growth.

According to the aforementioned assumptions, **the entire CO2 capture process is expected to take place in Mpumalanga**. As Durban is the largest harbour facility in South Africa, and due to its proximity to Mpumalanga, it can be assumed that **CO2 is transported to Durban for shipping to other (importing) countries**. Pipelines for refined products (liquid fuels) already exist between Mpumalanga and the port of Durban, which is the largest and busiest shipping terminal in sub-Saharan Africa. Furthermore, railway infrastructure is already in place connecting the two areas. Since such infrastructure is already in place, transport of CO2 to the port of Durban through pipelines seems like the most cost-efficient solution, even assuming that some modifications or retrofitting are required. Alternatively, due to the existence of this pipeline (Secunda–Durban Lilly Gas Pipeline), the construction of a new CO2 dedicated pipeline could be facilitated by following the route of the existing pipeline[xxviii]. In any case, further studies must be conducted regarding the retrofitting of the pipeline, so that the feasibility and cost can be assessed. Transport costs to the port of Durban have been estimated, according to the transport costs that have been presented in Table 25.

Figure 30 Transport of CO2 from Mpumalanga to Port of Durban (own elaboration based on google maps)

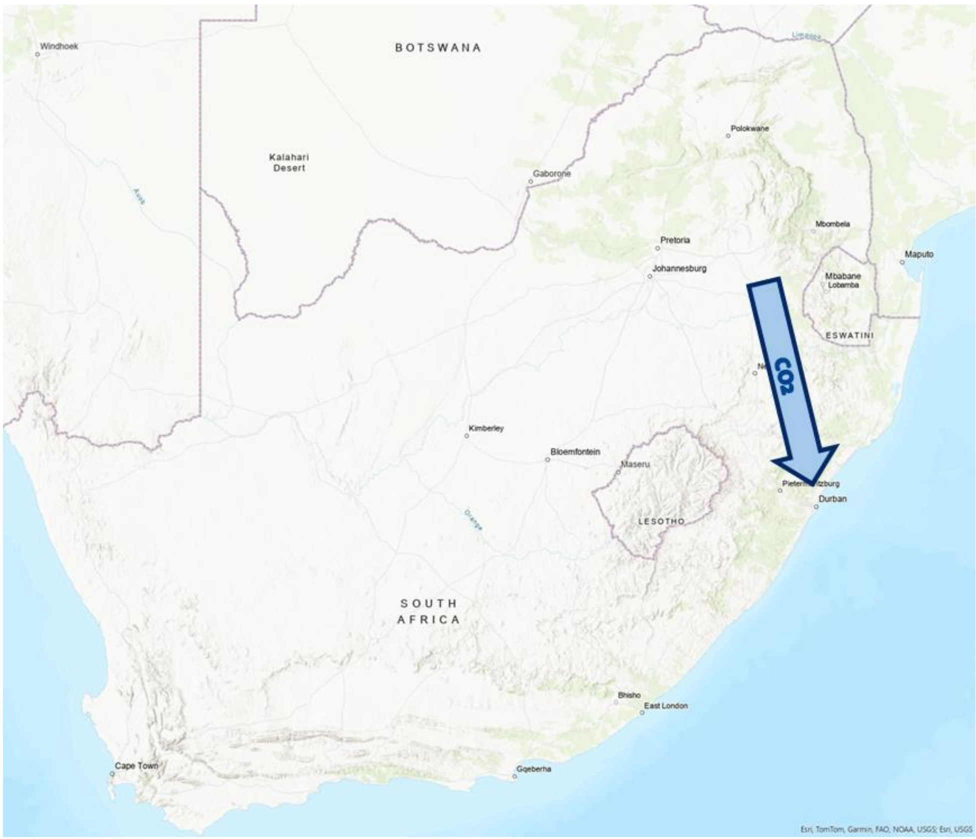


Table 27 CO2 transport costs from Mpumalanga to Port of Durban[xxix]

	Distance (km)	Pipeline	Rail	Truck
Mpumalanga-Durban	~ 600 (Global Energy Monitor Wiki, 2023)	1.7-6.1 (USD/tCO2)	8.2 (USD/tCO2)	14.7 (USD/tCO2)
		190 – 1,090 (mil. USD)	930 – 1,470 (mil. USD)	1,670 – 2,630 (mil. USD)

Scenario 2: production of synfuels at Sasol's facilities

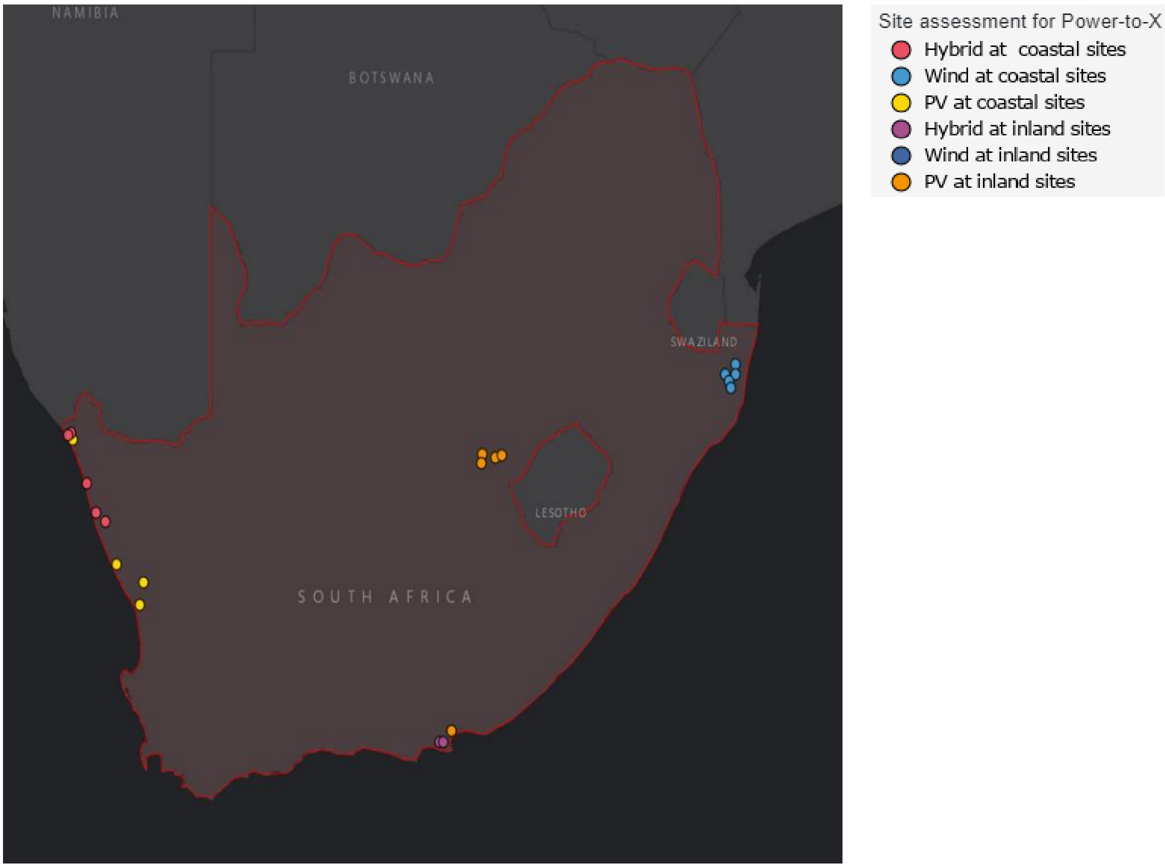
In this scenario, the case whereby synfuels are produced in South Africa, before being exported to other countries by tanker ship is considered. **CO2 and H2 which are required for the production of synthetic fuels, are assumed to be**

transported to Sasol's synfuel facility in Secunda. It is noted that the installation of Sasol in Secunda has a capacity of Coal and gas processed and refined at 160,000 barrels/day.

Transport of CO2 and H2 at Sasol's facilities

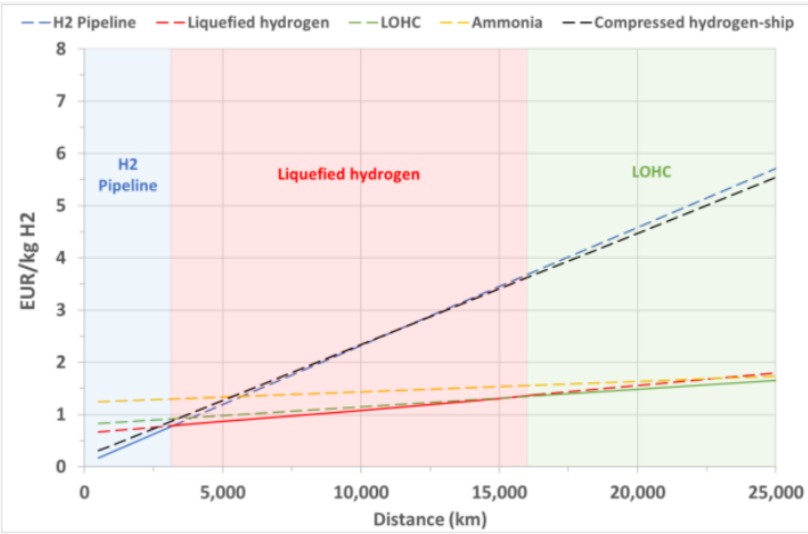
As it has been assumed that the entire CO2 capture process is taking place in Mpumalanga, the cost of CO2 transport to Sasol is neglected at a first high level approach, since the facility is also located in the region. Significant emitters, such as Arcelor Mittal, are already assessing the possibility of capturing and transporting CO2 to Sasol[xxx]. However, H2 must be transported from the location of production (RES plants in the case of green H2) to Secunda. The map in Figure 31, which has been developed by Fraunhofer, presents the preferred locations for the deployment of RES especially for the production of PtX products. Fraunhofer modelling has taken high-resolution spatial data, long-term weather data and socio-economic data into consideration.

Figure 31 Preferred locations for the deployment of RES aimed at the production of PtX products (Fraunhofer, 2023)



Assuming that renewable H2 will be produced via electrolysis at the points that are indicated in the map presented in Figure 31, the calculation of H2 transport to Secunda is performed considering the information of Figure 32[xxxi]. Furthermore, it is assumed that the H2 produced is sufficient for the production of synfuels, as competition in green H2 supply is expected for the production of other green products as well (e.g. green steel)

Figure 32 Estimates of transport cost for H2 as a function of distance and transport mode (JRC, 2021)



The distance between Secunda and the H2 production sites ranges between 300 and 1,400 km, indicating that transport through pipelines appears to be the most suitable, in terms of cost, solution[xxxii]. For these distances, the transport cost ranges from 0.15 to 0.35 €/kg (1.6-3.8 $/tH2) and is mostly related to infrastructure, suggesting that repurposing existing natural gas pipelines for H2 transport would significantly decrease the associated transport cost (if applicable[xxxiii]). It is estimated that such cost savings could be more than 50% compared to a newly built pipeline (European Hydrogen Backbone, 2020), however, the existing pipeline network does not extend to the country's South or West. To assess whether transporting H2 from its production sites to Secunda, for the production of synfuels, makes economic sense, requires a more detailed analysis of the respective volumes of H2 involved, which is not within the scope of this study.

According to this scenario, after synfuels production takes place in Secunda, the produced synfuels are transported to the port of Durban for export. In this scenario, since transport concerns synfuels instead of CO2 (cf. Scenario 1), the existing pipeline for refined products between Mpumalanga and the port of Durban may be used, without further modifications. Any benefits, in particular transportation cost savings, stemming from the use of the existing pipeline, however, will need to be balanced against the needs (volume- and distance-wise) for H2 transport from the respective RES plants to Secunda.

Figure 33 Green hydrogen is transported from RES installations to Sasol's facilities, where synfuels are produced and transported to the Port of Durban (own elaboration based on google maps)

Mossel Bay could also be considered as a viable option for the shipment of synthetic fuels, since Petro SA facility is located there, with a capacity of 45 000 barrels/day. This is an existing brownfield Fischer-Tropsch facility for which only the CO2 transport aspect should be resolved. When considering the production of synthetic methanol, specific site restrictions are alleviated, allowing to move away from Fischer-Tropsch facilities. Since the **port of Durban** is an urban port, it is no longer suitable, as the development of RES around it would be problematic. **Saldanha bay** could be considered more suitable, when considering shipping as the main market off-taker. Furthermore, **Richards Bay,** which has also been identified as one of the three proposed hydrogen valleys of South Africa (Republic of South Africa, 2021), could also be considered as a special case, even though there are no RES installations in place. However, the development of off-shore wind generation is possible and should be further examined. In addition, a significant Just Transition element exists for the port of Richards Bay, as most of today's activity concerns handling of coal.

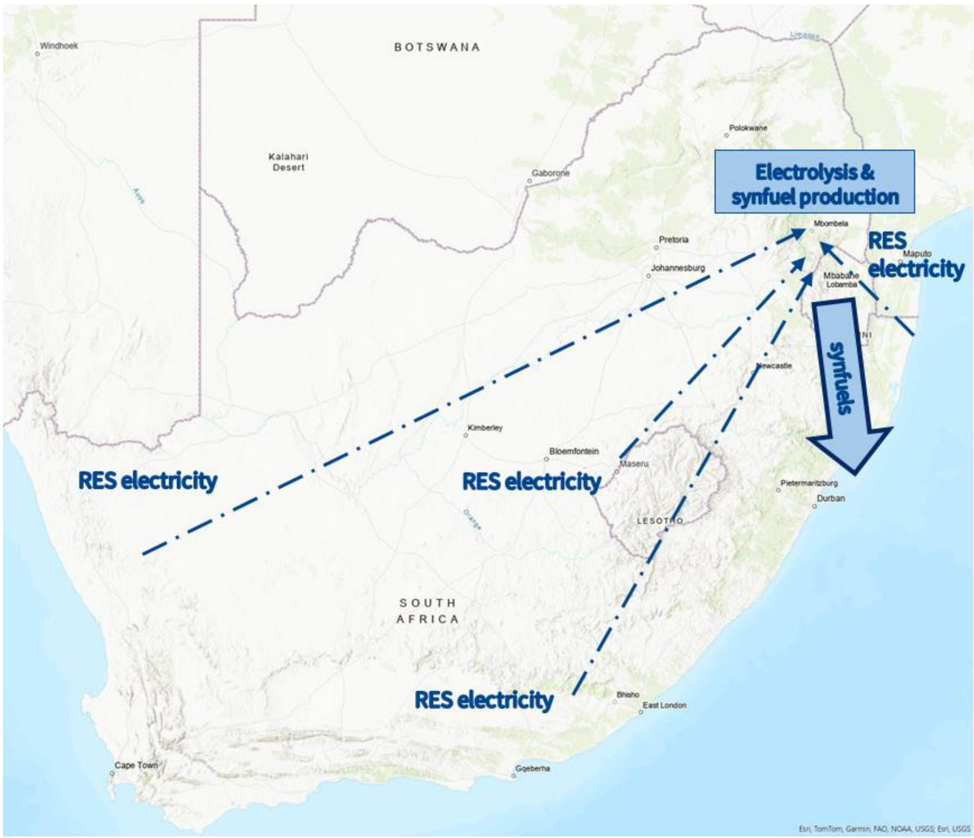
Another parameter that should be considered with respect to the scenario in question, is the possibility of **developing an H2 pipeline from Namibia (Luderitz) to Saldanha Bay**, with a T-junction all the way to Secunda where Sasol's petrochemical hub is located. The objective of such infrastructure would serve both Namibia's need to export H2 through South Africa, as this is not technically possible through its national ports, as well as Sasol's decarbonization goals. The construction of this pipeline is estimated to be a €20 billion project (The Brief, 2022) and its realization will largely depend on whether Namibia will partially undertake the construction cost.

Electrolysis at Sasol facilities

Another scenario that could be considered for the production of synfuels at Sasol's Secunda facility, is that of electrolysis for the production of H2 taking place on site at Secunda. Many mines located in the area, filled with water and close to the end of their life, could be considered for covering the water needs of H2 production. Furthermore, water could also be diverted from coal operations as they are shut down over time, while coal operations also have reverse osmosis facilities which can be used for H2. Even if the local resources for producing H2 locally are not sufficient, partially meeting H2 demand from local production should be considered to reduce H2 transport cost, while more analysis would be required on the feasibility and the quantities of water that are available. Such a set up however would require (a) an appropriate mechanism in place (PPA, GoOs, additionality criteria etc.) so that the grid electricity provided for electrolysis to be considered 'green' and sustainability criteria for RFNBOs are met[xxxiv] while overcoming the limitations of SA's heavily saturated grid, and (b) a reliable and stable electricity grid and interrupted power supply to the electrolysis facility.

In this case, the cost for the installation of RES to the selected RES-favourable locations, the cost of electrolysers at Sasol facilities (see Figure 31), as well as any costs to ensure grid infrastructure amelioration and strengthening, have to be considered for the assessment of the total cost. The produced synfuels will be transported to the port of Durban through the existing pipeline for refined products. Exports through the Richards Bay port could be considered provided the required infrastructure is built.

Figure 34 Renewable electricity is transported to Sasol's facilities through transmission grid, where synfuels are produced and transported to the Port of Durban (own elaboration based on google maps)



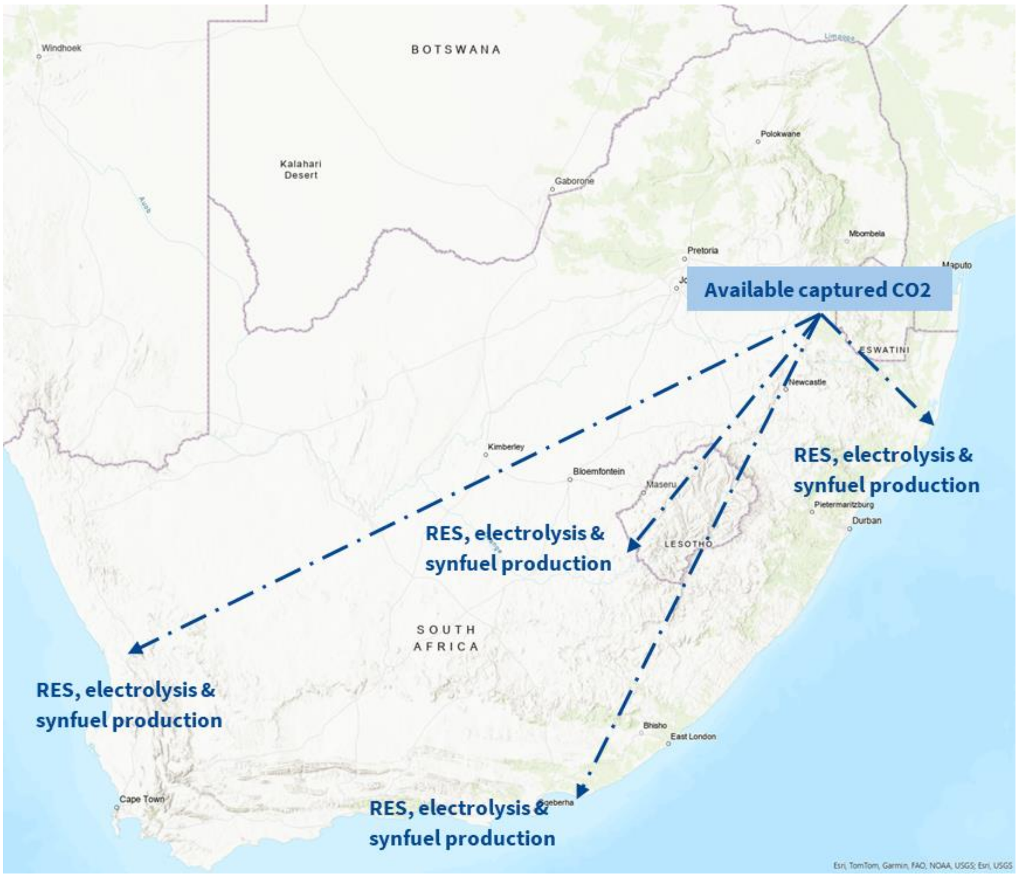
It should be noted that RES generation can also be developed in the area of Mpumalanga, which although is not South Africa's best, features high solar energy capacity factors compared to international standards. The benefit would be that RES generation would take place in an area with a good grid that is not saturated, and which is currently home of many coal-fired power plants that are facing retirement. Furthermore, Mpumalanga is an area that will require the creation of green jobs as an integral part of the just energy transition.

Scenario 3: transport of CO2 at RES facilities

The last scenario that is examined in this assessment, is the one according to which CO2 is transported from Mpumalanga to the RES sites of Figure 31, where electrolysis and synfuel production is taking place. This scenario assumes that RES facilities, electrolysers and synfuel production facilities are developed in the regions that have been identified as most suitable for RES production. **All of these locations but one[xxxv], are on coastal areas close to major ports, such as the port of Saldanha, port Elizabeth and port of Richards Bay**. As with the assessment of the previous section, the distances between the RES sites identified in Figure 31 and Mpumalanga range between 300 and 1,400 km. It is noted that there is no pipeline network connecting Mpumalanga to the RES production sites that are located to the country's South or West exist, however, railways that could be of use are in place. The development of a pipeline for CO2 transport would lead to a transport cost of 1.7-6.1 $/tCO2, while transport through rail would lead to a transport cost of 8.2 $/tCO2. Transport cost of synfuels to the nearby major ports can be considered negligible, as most RES sites are in close proximity to such ports. However, the development of RES facilities, electrolysers and synfuel production facilities must be taken into account in order to assess the total cost.

The concept of Scenario 3 is aligned with the prospects of developing Hydrogen Valley & Hydrogen Hubs in Southa Africa. A Hydrogen Valley feasibility study (Republic of South Africa, 2021) has identified three hubs – **Johannesburg hub**, extending to Rustenburg and Pretoria; **Durban hub**, encompassing the city itself and Richards Bay; and **Limpopo province hub**, centred around Mogalakwena PGM mine. According to the said study, these hubs can have a fundamental role to play in integrating hydrogen, and thus potentially synfuels, into the country's economy, and in establishing South Africa and its abundant renewable energy resources as a strategically important centre for green hydrogen, and also RFNBOs, production.

Figure 35 CO2 is transported from Mpumalanga to RES sites, where electrolysis and synfuel production will take place (own elaboration based on google maps)



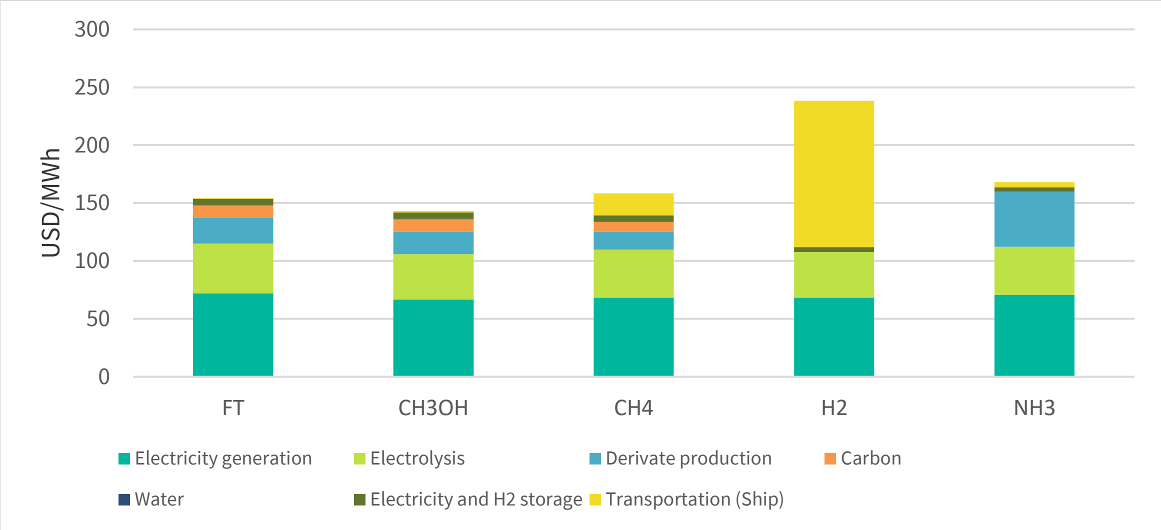
Following the Northern Cape Green Hydrogen Strategy (Republic of South Africa, 2023), which was launched in COP26 in 2021, the potential development of the Boegoebaai Port and a Green Hydrogen Cluster in the area, is fully in line with this scenario of carbon utilization (Global Africa Network, 2023).

Transport of Synfuels to other countries

Determining the transport costs of synfuels from South Africa to abroad, is another cost component that needs to be determined to map the synfuels import costs. For this purpose, Agora Energiewende has developed the PtX Business Opportunity Analyser tool, which allows calculating the delivered cost of PtX molecules from an export country to an import country.

Assuming Germany, which can act as the geographical representative of the EU, as the country of import for synfuels fuels from South Africa, the total synfuels costs for 2040, as estimated by Agora's PtX Business Opportunity Analyser (Agora, 2023), are presented in the following Figure 36[xxxvi].

Figure 36 Estimated total costs of PtX products delivered from South Africa to Germany in 2040 - elaborated based on (Agora, 2023)



Overview of scenarios assessed and directions for further study

Table 28 provides a summary of the Scenarios of CO2 transport and utilization for the production of synfuels considered in the present analysis.

While conducting the assessment of the previous sections, it became evident that information that was required for performing direct quantified comparison between scenarios was not available. For this reason, the assessment focused more on presenting different scenarios around the utilization of the captured CO2 for synfuel production in South Africa, by providing the underlying assumptions and required infrastructure, without prioritizing among the considered scenario.

In order to be in the position to perform direct comparisons between the different scenarios, the total cost of the logistics for synfuel production must be estimated, which will require that the total amount of synfuel production must be determined. This information would determine the most appropriate mode of transport for CO2 and H2, as well as to perform the dimensioning of the RES, electrolysis and synfuel installations, which will also contribute to the total cost of each scenario. In addition, better insight on the total amount of synfuels to be produced will also serve as useful input for the assessment of CO2/H2 storage, which was not considered in any scenario so far. Finally, the existence of clear strategies for the development of major infrastructure projects and policies, which are currently not in place or sufficiently developed, would serve as a useful ground for prioritizing transport scenarios and developing them in further detail.

Table 28 Summary of the Scenarios of CO2 transport and utilization for the production of synfuels considered in the present analysis

Scenario	Description	Transport	Infrastructure required	Infrastructure in place	Comments
CO2 transport directly to ports – exports of CO2 as synfuel feedstock	CO2 captured from the point sources (power and industry) in Mpumalanga area	CO2 from Mpumalanga to port of Durban	Modification/retrofitting of existing pipeline for refined products, or construction of a new pipeline to transport CO2 from Mpumalanga to the port of Durban	• Pipeline for refined products between Mpumalanga and Durban • Railway infrastructure between Mpumalanga and Durban	• Cost for modification/retrofitting of existing pipeline must be considered • CO2 off-takers are needed
Synfuel production at Sasol (Secunda) by transporting H2 to Sasol	• CO2 captured from the point sources (power and industry) in Mpumalanga area • H2 is produced at the RES production sites (Fraunhofer, 2023) where electrolysis will take place • Synfuels are produced at Sasol facilities	• CO2 transport costs to Sasol facilities are neglected (due to proximity) • H2 produced via electrolysis at the RES sites is transported to Sasol facilities (Secunda) • Synfuels from Sasol (Secunda) to the port of Durban – exports of synfuels	• RES/electrolyser facilities • Pipeline for transport of H2 from RES sites to Secunda	• Pipeline for refined products between Mpumalanga and Durban • Railway infrastructure between Mpumalanga and Durban	• Cost for development of RES plants and electrolysers must be considered • Amount of H2 that will be required must be defined to determine the optimal pipeline connection of Secunda to RES plants • Synfuels off-takers are needed
Electrolysis and synfuel production at Sasol (Secunda)	• CO2 captured from the point sources (power and industry) in Mpumalanga area	• Renewable electricity from RES sites to Sasol (Secunda) through	• RES capacity for the production of green hydrogen	• Electricity grid strengthening • Pipeline for refined products	• Cost for development of RES plants and electrolysers must be considered

Scenario	Description	Transport	Infrastructure required	Infrastructure in place	Comments
	• H2 is produced at the RES production sites (Fraunhofer, 2023) where electrolysis will take place • Synfuels are produced at Sasol facilities	existing electricity grid • Synfuels from Sasol (Secunda) to the port of Durban	• Electrolyser capacity at Secunda • Access to water supply for electrolysis at Secunda • Stable and non-saturated electrical grid	between Mpumalanga and Durban • Railway infrastructure between Mpumalanga and Durban	• Synfuels off-takers are needed
Transport of CO2 at RES facilities	• CO2 captured from the point sources (power and industry) in Mpumalanga area • H2 is produced at the RES production sites (Fraunhofer, 2023) where electrolysis will take place • Synfuels are produced at the RES production locations, assuming that electrolysers are installed near RES plants	• CO2 captured in Mpumalanga to RES facilities (mostly coastal areas) • Transport cost of synfuels to the nearby major ports is neglected	• Pipeline for CO2 transport • RES/electrolyser facilities • Synfuel production facilities at RES sites (mostly coastal areas)	Railway for transporting CO2 from Mpumalanga to RES facilities	• When assessing cost of transport, it must be noted that the cost of transport through rail is significantly reduced due to the fact that rail infrastructure is already in place • Synfuels off-takers are needed

6

CASE STUDY: SYNTHETIC METHANOL FROM COAL FIRED POWER PLANTS

This chapter aims to set the framework for the Carbon Capture Utilization (CCU) analysis exercise for a coal-fired power plant in South Africa. Carbon Capture Utilization (CCU) technologies include the CO2 capture unit in large industrial and energy plants, and then the utilization of CO2 as part of a conversion process, for the synthesis of new products.

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Case study: synthetic methanol from coal fired power plants

Introduction

As it has discussed in previous chapters, by 2021, South Africa had 53.7 GW of wholesale/public nominal capacity with coal-fired installed capacity comprising 39.3 GW. The electricity mix is naturally dominated by coal-fired power generation, which contributed over 80% to system demand in 2021 (81.4% or 184.7 TWh) (CSIR, 2022). Recently, the country has undertaken efforts to accelerate the decarbonisation of its economy, such as the new **Just Energy Transition Investment Plan (JET IP)** for South Africa announced during COP27, with a focus on the electricity system. Despite the expected increase of RES penetration into the power system, coal appears to retain a significant part in the electricity fuel mix until 2050 (Republic of South Africa, Department of Mineral Resource and Energy, 2019). Therefore, the applicability of CCU (and CCS if carbon storage is considered for the captured CO2) technologies into coal-fired power plants can potentially support the decarbonization efforts, while allowing exploitation of a significant natural resource and without jeopardizing the viability of key energy infrastructure assets.

In this respect, **CCU constitute an essential pillar for the supply of carbon to a synthetic fuel formulation process**. The utilization of renewable energy and hydrogen is imperative for synthetic e-fuel production. **Power-to-Fuel technology** addresses electricity markets at local and national levels, acting as an energy storage solution. Simultaneously, it caters to the thermal power and industrial sectors by applying the CO2 capture concept. Additionally, it targets the chemical market and global transportation sector, serving as a measure for CO2 emissions reduction.

The capacity and flexibility challenge or the surplus electricity utilization can be solved by the direct conversion of electricity to fuels and other chemicals. Power-to-Fuel refers to Power-to-gas, either hydrogen or SNG or in the production of liquid fuels (to Power-to-Liquid) such as methanol, dimethyl-ether (DME), oxy-methylene ethers (OMEs), other chemicals and derivatives. As a means of energy storage, electrolyser technology simultaneously converts water to hydrogen via the use of electricity while also providing grid balancing services. CCU combined with the Power-to-Fuel concept addresses the need of CO_2 reduction in Power, Steel and Process Industries by exploiting both, the surplus electricity available due to increased content of RES via water electrolysis, as well as the advantageous use of coal and biomass resources for fuel production. Hydrogen can be produced via water electrolysis or recovered from hydrogen rich gases and then used to commute the captured CO_2 to SNG, methanol and to second generation chemicals and fuels. The technologies involved have already reached commercial scale, while Power-to-Fuel can find application to all industrial generating or being close to CO_2 sources and have a basic industrial infrastructure in terms of water, steam/heat, cooling water and electricity provision, see (Koytsoumpa et al., 2016) (Koytsoumpa et al., 2018).

Below, the main parameters considered for analysing the potential application of carbon capture in coal-fired power plants in South Africa are presented and analysed[xxxvii].

Analysis of CCU in coal-fired power plants in South Africa

Framework of the analysis

In the present work, **chemical absorption with amine solvents** will be considered as it is the most common technology to have already reached commercialization and a TRL 9, constituting thus a readily implantable solution that could also be compatible with the overall operation of the plant.

CCU integrated in thermal power plants interacts in three main factors: a) Flue gases that are the main source of CO_2, b) the heat integration aspects for covering the heat demands of the amine based absorption process and c) power consumption for the compression of CO2 and power demand of the capture unit.

As a key activity of this exercise, the analysis of coal-fired power plants is based on the impacts of implementing carbon capture technology on the technical and also economic performance of the plants.

This exercise only provides a theoretical analysis of CCU application to a new coal power plant, such as Kusile. Kusile Power Station consists of 6 x 800 megawatt (MW) coal-fired power plants with a total generating capacity of 4,800 MW and it is the first in ESKOM's fleet with flue gas desulphurization technology (ESKOM, 2023). It is noted that the analysis is based on assumptions drawn from the international experience, and not Kusile's technical data.

Captured CO2 is assumed to be used for methanol synthesis. Synthetic methanol is considered as an alternative fuel to fossil fuels and is particularly attractive as a maritime fuel since it is liquid at room temperature, it is less costly to store and transport than other suitable for ships gaseous fuels, and has an attractively low carbon footprint in terms of grCO2/MJ as compared to other fuel options. Synthetic methanol is being discussed as a potential candidate to decarbonise deep-sea shipping[xxxviii]. Methanol can also be used in principle in both internal combustion engines, as well as to power fuel cells, providing flexibility depending on individual needs and the needs of the particular application.

At the same time, the Maritime Transport Sector in South Africa has the potential to become a high-impact sector and one which could offer a substantial contribution to addressing developmental challenges in South Africa and fulfilling the goals of the National Development Plan (NDP) (Ncwadi, 2022). Within the framework of the Power-to-X analysis for South Africa, methanol fits in particular well considering the emerging opportunities for the country in this area (Global Maritime Forum, 2022).

At the **technical side of synthetic methanol production**, it is noted that the world's largest carbon capture plant, with a CO2 capture capacity of 4700 t/day has been built by Mitsubishi Heavy Industries in Houston, US Texas (Petra Nova) and has been commissioned in 2016 (U.S. Department of Energy, 2020) (Modern Power Systems, 2020). CO2 is captured from a subbituminous coal power plant, is over 99% pure, and is further compressed, transported and injected into the oil wells of Texas, towards Enhanced Oil recovery. The plant has been taken out of operation in 2020 for commercial reasons, due to low oil prices caused by the COVID-19 pandemic. The plant went back in operation in September 2023. The above example, also confirms the technical feasibility of the investigated case study.

Assumptions for the coal fired power plant and the integrated capture unit

For the present analysis of CCU in a coal-fired power plant, the basic steam reheat cycle configuration of a coal power plant has been considered as it is shown in

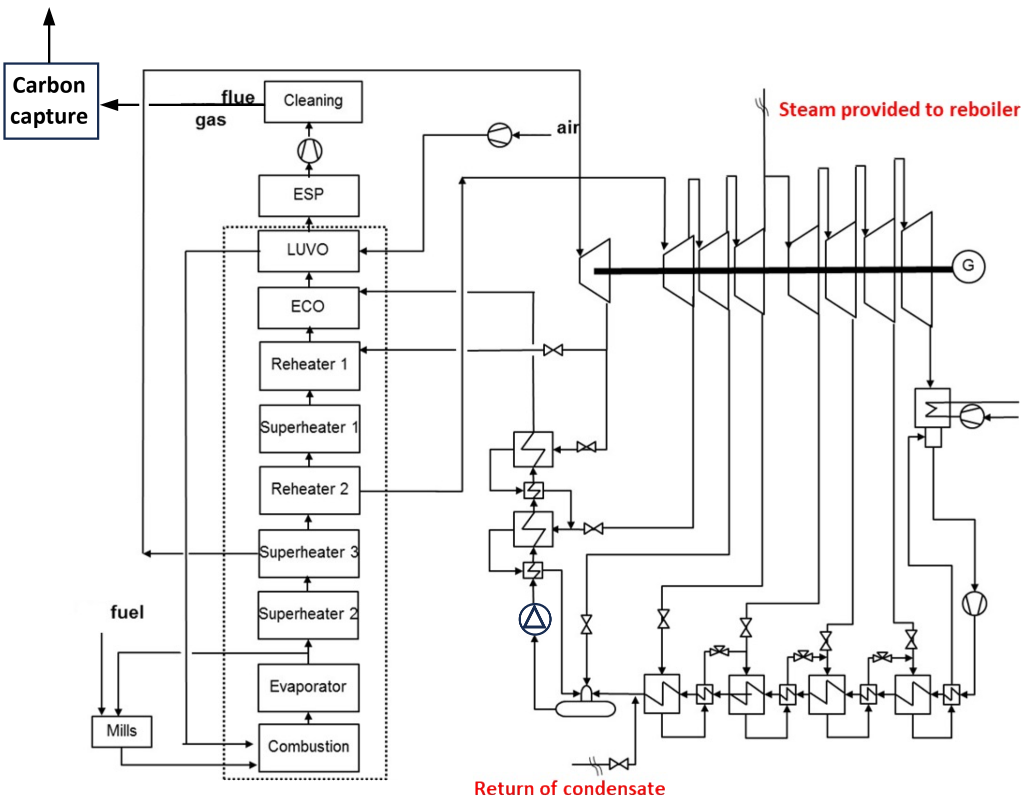
Figure 37. The cycle configuration includes a multi-stage turbine with intermediate steam extraction for feedwater preheating and deaeration. The flue gas produced during the combustion flows through the evaporator, superheaters 2 and 3, reheater 2, superheater 1, reheater 1 and finally the economizer (ECO) and air preheater (LUVO) before being supplied to the electrostatic precipitators (ESP) and flue gas cleaning section (deNOx and the deSOx) of the power plant. After leaving the flue gas cleaning section, it is supplied to the Carbon Capture (CC) unit for CO_2 sequestration.

The Carbon Capture (CC) unit requires a significant amount of heat for the reboiler in the stripper unit. This heat demand will be covered by steam extraction from the steam cycle of the turbine. The heat demand of the carbon capture unit is covered by steam that would be otherwise (i.e. in the absence of the CC unit) directed to the middle or low pressure (MP or LP) turbines for power generation. The power loss or "**energy penalty**" from this heat extraction will have an impact on emission limits for hard coal power plants and on their economics as well. As there is no information (i.e. real data for an actual operating coal-fired power plant) on the pressure, temperature and mass flows of basic streams such as HP inlet, Hot reheat, MP and LP turbines and intermediate steam bleeds, the energy penalty for the power plant is estimated based on the international experience from similar cases having studied by the study team. The steam bleed is considered to be extracted from the medium pressure turbine and the condensate to return after the low pressure, low temperature preheaters. The amount of steam to be extracted is estimated at 1.0 - 1.2 t steam per t of captured CO, according to public information on the current state-of-the-art (U.S. Department of Energy, 2020) (Takashi Kamijo, 2013).

However, it should be commented that 1.0 t of steam / t CO2 is a rather optimistic value for Carbon Capture project in coal power plants.

Considering the current state-of-the-art (Petra Nova project in Texas, US), 2.3 GJ/t_{CO2} are needed which correspond to approximately 1.2 tonnes of 5 bara steam per tonne of CO_2 based on a proprietary solvent. Other solvents like MEA, MDEA will have a 20-30% higher specific steam consumption (Modern Power Systems, 2020).

Figure 37 Power plant configuration with estimated connection points of the carbon capture unit.



In the present analysis, **post combustion capture is assessed using MDEA (methyldiethanolamine) as solvent**. Because of its low vapor pressure, MDEA can be used in concentrations up to 50 wt% in aqueous solutions without significant evaporation losses.

Furthermore, MDEA is highly resistant to thermal and chemical degradation, is essentially non-corrosive, has low specific heat and heat of reaction being more stable with no spurious shutdowns over longer periods. However, it has a slower reaction rate but possible activators such as Piperazine could be used to provide high reaction rate. In addition, MDEA, when used in pressurised operation, pressure throttling can be used to partially regenerated the solvent before fed to desorber.

The following reactions are accounted for the capture unit with MDEA:

$CO2+2H2O \leftrightarrow HCO_3^- + H3O^+$ (Reaction 1)

$HCO_3^- + H_2O \leftrightarrow CO_3^{2-} + H3O^+$ (Reaction 2)

$MDEA + H3O^+ \leftrightarrow MDEAH^+ + H_2O$ (Reaction 3)

$2\ H_2O \leftrightarrow OH^- + H3O^+$ (Reaction 4)

A typical configuration of the post combustion capture is can be found in (Zhiwu (Henry) Liang, 2015). The flue gas enters the absorber column from the bottom after being slightly compressed to overcome pressure losses where it interacts with the lean amine solvent that enters from the top of the column. The CO2 is entrained in the solvent, called “rich solvent stream” and it is sent to the stripper column via liquid pumps. The poor CO2 flue gas stream exits the absorber column and is sent to the chimney of the power plant. The rich solvent after being pre heated in the cross-flow heat exchanger, it is regenerated in the stripper column. The required heat is provided in the reboiler located at the bottom of the stripper column. The pure CO2 exits at the top of the stripper column and is sent to the compression unit.

The coal that has been used is a typical south African coal from the Highveld mines. According to the literature, several samples of this coal has been analysed with the proximate and ultimate analysis (low moisture high ash content) as shown in Table 29 (Matjie, 2016).

Table 29 Proximate and ultimate analysis data of South Africa coal (Republic of South Africa, Department of Energy, 2017)

Proximate analysis (air dried basis) of Coal						
Sample number	1	2	3	4	5	6
moisture	3%	3%	3%	3%	3%	4%
Ash	25%	29%	30%	27%	27%	22%
Volatile matter	22%	23%	21%	22%	22%	23%
fixed xarbon	51%	45%	46%	48%	48%	51%
Total sulphur	1%	1%	1%	1%	1%	1%
Volatile matter (daf basis, %)	30%	34%	32%	31%	32%	31%

Ultimate analysis data for the coals tested (dry, ash-free basis)						
Sample number	1	2	3	4	5	6
Carbon	80%	79%	77%	78%	79%	78%
Hydrogen	4%	5%	4%	4%	5%	4%
Nitrogen	2%	2%	2%	2%	2%	2%
Total sulphur	2%	1%	1%	2%	2%	1%
Oxygen (% by difference)	12%	14%	16%	15%	13%	15%

An average composition of the above samples has been used in the analysis, whereas the heating value of the coal is according to real data from the department of energy in the range of 21-23MJ/kg (Republic of South Africa, 2016).

The composition of flue gas, after the gas treatment and for an assumed air ratio λ=1.24, is 20.8%vol CO2, 4% H2O and 4% O2 with the rest to be mainly nitrogen. The amount of steam varies according to case scenarios of 100% flue gas feed to the Post combustion Carbon Capture (CC) unit or Partial flue gas feed. **From the total feed to the Post Combustion Carbon Capture unit, a 90% capture ratio is considered**. The basis for emission calculations is changing as for the same amount of coal input, the same absolute emissions occur but the power output is reduced. However, the impact is hereby not quantified as the original values for the emissions have not been determined.

Assumptions for CCUS power train integrated in the coal fired power plant for the production of methanol

In the present work, the assumed Power-to-Fuel concept to be combined with the coal-fired plant CCU, is focusing on the production of (synthetic) methanol and includes the following over an integrated consideration:

- the technology of water electrolysis;
- the post combustion carbon capture technology;
- the CO2 derived methanol synthesis and distillation technology.

(Koytsoumpa et al., 2018) presents the basic technology blocks and key elements of the energy balance for a 100 kt methanol production plant. Methanol is a chemical substance with the chemical formula CH_3OH or CH_4O (one atom of carbon, one atom of oxygen and four atoms of hydrogen). Methanol is the simplest alcohol, highly volatile, colourless and it behaves as polar liquid at room temperature (also used as a solvent due to this characteristic). Methanol can be used in a broaden field of applications for the production of petrochemical components and fuels and for the production of electrical, thermal and mechanical energy. In chemical industry, methanol is used basically for the production of formaldehyde, acetic acid, methyl tert-butyl ether (MTBE), dimethyl ether (DME) and other chemicals. Today, the industrial production of methanol is mainly carried out through a catalytic process from synthetic gas composed mainly of carbon monoxide and hydrogen (syngas) with more than 70% of the production to be natural gas derived methanol.

The synthesis is described by the following main reaction scheme:

$CO+2H_2 \rightarrow CH_3OH$ (Reaction 5)

$CO_2+3H_2 \rightarrow CH_3OH + H_2O$ (Reaction 6)

$CO_2 + H_2 \rightarrow CO + H_2O$ (Reaction 7)[xxxix]

For methanol production using CO_2 as a feed stream, it is required to have at least 1 mol of CO_2 and 3 moles of hydrogen. For the production of hydrogen, only water electrolysis is considered when the approach is to integrate CCUS in thermal power generation.

Results and discussion of CCUS and methanol production in a coal-fired power plant

The baseline scenario of the coal-fired power plant does not include any carbon capture unit as shown in Table 30 and thus no flue gas is fed to the CC unit. The **nominal efficiency of the power plant is assumed at 46%** based on nominal coal input of 1,739.13 MW_{th}, that results in 800 MWe power generation for 1 unit.

The integration of CC in the power plant for treatment of the full flue gas flow is named as the “100% CCU” scenario, or CCU100, meaning that the 100% of the quantity of flue gases is directed to the CC unit. In the CC unit 90% capture of CO2 is achieved. The uncaptured CO2 (remaining 10% in the CCU100 scenario) escapes as “CO2 poor flue gas stream” at the top of the desorber column and is sent to the chimney of the power plant. **The integration of carbon capture at the power plant results to an energy penalty of approximately 100 MWe or 5.70% loss in efficiency points**. The captured CO2 is equal to around 543 t/h.

Besides the energy penalty to be paid for the extraction of steam needed to be supplied in the methanol synthesis process, power is also needed for the electrolysis unit to supply the required hydrogen as well. From the sustainability of the final synthetic fuel point of view, renewable power must be used. As it cannot be always practically possible to co-locate the coal-fired power plant with the CC unit and the RES-driven electrolysis installation, or the required RES-based electricity cannot be provided by the electricity grid, an integrated complex (i.e. power plant + CC unit + electrolyser) is considered. In such cases, it is noted that the quantity of flue gases that is directed to the CC unit, is limited to the percentage that it makes sense from an overall energetic and economical perspective for the operation of the complex[xl].

Based on the above, the integration of CC in the power plant for treatment of the partial flue gas flow is depicted as scenario "20% CCU", or CCU20. In this scenario, only 20% of the flue gas and thus produced CO2 is fed to the CC unit, where again 90% capture is achieved. The uncaptured CO2 (remaining 10%) escapes as "CO2 poor flue gas stream" at the top of the desorber column and it is mixed with the remaining 80% of flue gas before sent to the chimney of the power plant. **In this case, the integration of carbon capture at the power plant results in an energy penalty of approximately 14 MWe or 0.74% loss in efficiency points**. The captured CO2 is equal to around 109 t/h. If all of this CO2 quantity was used for methanol production and assuming an availability of 97% per year for the methanol plant, the yearly production could reach around 673 kt methanol.

Results of the two examined scenarios for a hypothetical unit of 800 MWel output, are summarized in Table 30.

Table 30 Main results of the two scenarios studied for carbon capture integrated in coal fired power plants

SCENARIO		BASELINE	CCU100	CCU20
Coal Input	MW_{th}	1739.13	1739.13	1739.13
Power Output	MW_e	800	700	787.2
Efficiency of power plant	%	46%	40.25%	45.26%
Efficiency loss	%	-	5.75%	0.74%
Flue gas treated in CC	%	-	100%	20%
Flue gas treated in CC	t/h	-	2050.3	410.1
CO_2 captured	%	-	90%	90%
CO_2 feed in CC	t/h	-	603.7	120.7
CO_2 captured in CC	t/h	-	543.3	108.7

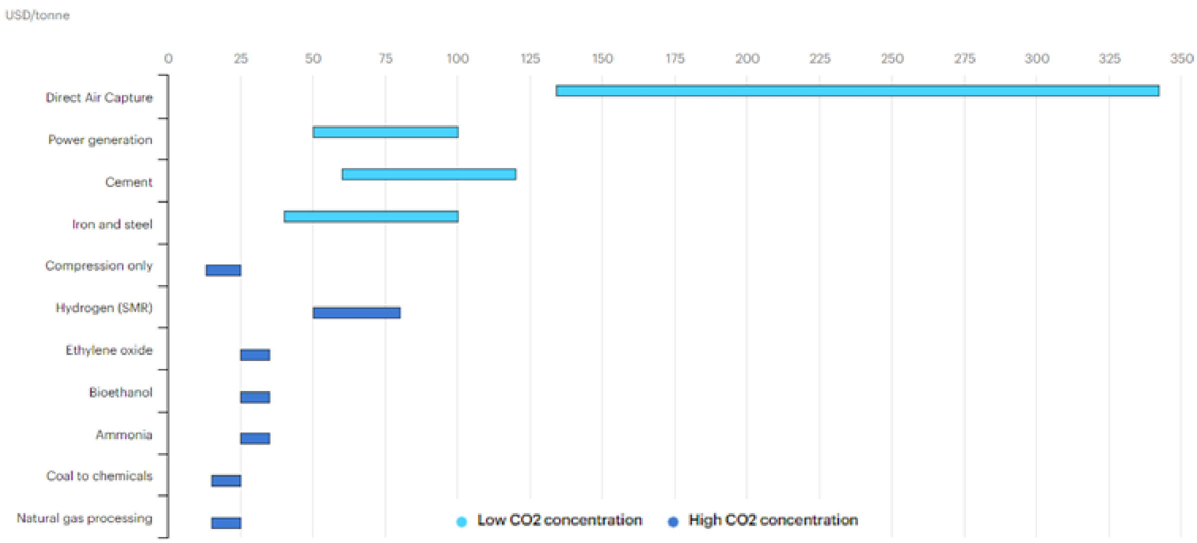
If all of the CO2 quantity of the CCU100 scenario was used for methanol production, a considerable energy penalty of approximately 100 MWe or 5.70% loss in efficiency points would have been paid in that case. As far as methanol is concerned, and assuming an availability of 97% per year for the methanol synthesis plant, the yearly production could reach 3,363 kt methanol. To put these numbers into perspective, the world's largest methanol production plant has a capacity 1,851 kt (TOPSOE, 2020).

Carbon capture energy penalties as well as costs may differentiate according to the technology used. IEA presents an analysis on the ranges carbon capture cost per application, where also the concentrations of CO2 differ as shown in Figure 38 where an IEA analysis of the levelized cost of CO2 capture by sector and initial CO2 concentration is shown. **For power generation, these costs range from 50 to 100 USD per ton of CO2**.

For CCUS applications, the transport of CO2 plays also a significant role. For Enhanced Oil Recovery applications, which is the most common CCUS application currently, the CO2 transport cost would increase due to the typically longer distances (as it is noted that there are limited sites around the world where CO2 can be stored). Liquefaction of CO2 would decrease the transport costs for longer distances, as discussed in the previous Chapter 6, but increase the energy penalty at the capture site. Overall, considering the example of EOR installation, a typical cost for a short onshore pipeline (180 km) and a small volume of

CO_2 (2.5 Mtpa) are estimated to be of the order of €5/tonne of CO_2[xli].

Figure 38 Levelised cost of CO2 capture by sector and initial CO2 concentration (IEA, 2021)



In terms of **total costs that are impacting the operation of the power generation plants as a whole**, the Zero Emissions Platform has parametrically studied the impact in terms of levelized cost of electricity, and results suggest that with current (2023) EU ETS prices higher than 80 EUR/tCO_2, carbon capture can potentially already constitute a business case in Europe.

The main aspects when it comes to CCU, where the CO_2 is not long transported overseas or stored, lie on (a) who benefits from the environmental impact of carbon reduction and (b) who pays the costs. **For the case of power to methanol plants, the costs of CO_2 capture and hydrogen need to be covered by the sales of CO_2-derived methanol**. In terms of hydrogen production with water electrolysers, costs are highly dependent on electricity prices.

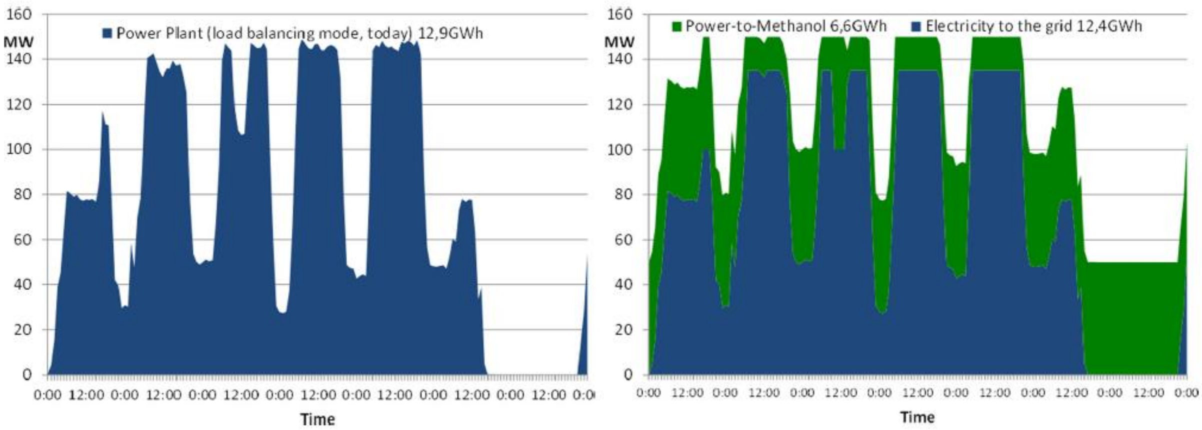
Europe intends to produce green hydrogen with prices lower than 3 EUR/kg H_2 and even lower than 1.8 EUR/kg H_2 after 2030 (EC, 2021). There are several Gigawatt hours of RES electricity that are currently being lost due to curtailment, which results in high financial losses as FIT payments continuously run even if green energy is curtailed. EU legislation provides a price premium and high incentives for green hydrogen and transport fuel investments. With the large deployment and commercialisation of the technologies involved, different labels, colours and carbon footprint of fuels could be traded.

Alkaline electrolysis (AEL) is currently the most mature technology having reached commercial sized and it can be optimally integrated with power generation plants. AEL can have power consumption per system in the range of 4.3–6 kWh/Nm^3 H_2. The subsequent use of hydrogen in the catalytic reactor of methanol synthesis does not necessitate a high purity of 99.99% as in other applications. The integrated electrolyser can be connected to the electric grid at the power plant. In a coal-fired power plant, flue gas produced during coal combustion can be led, after the desulphurization unit, to the CO_2 capture unit, where CO_2 is separated, and compressed. It can be mixed with the H_2 from the electrolyser unit before being fed to the reactor. The methanol reactor unit for the conversion of CO2 to methanol is designed for low heat loss and high conversion of H2 to methanol high catalytic selectivity at above 99% at low pressure and temperature, which is the state-of-the art process after 1960. Purification of crude methanol to IMPCA or AA grade methanol[xlii] by distillation is necessary and also energy intensive due to the reboiler needs for the separation of methanol from water. The resulting thermal efficiency of power-to-methanol operation is in the range of 50% for green field application to 61% for large-scale applications with heat integration (based on electric energy to Lower Heating Value (LHV) of methanol).

The size of the power to methanol operation can be tailored to the capacity management requirements for the applicable coal power plant. The size of the electrolyser is determined by the necessary load for the power plant to be efficient during periods where high feed-in of renewable electricity takes precedence. Nominally, the hydrogen generation capacity is targeted to be in the range of 20% of the capacity of a coal power plant. The arbitrage is producing methanol during low electrical load and high feed-in renewable energy and generating electricity during high electrical load and low feed-in renewable energy as shown in

Figure 39. The load of the power plant would increase as instead of only one offtaker, the electricity grid, the power to methanol plant is also consuming power and is using the emitted CO_2.

Figure 39 Synergies between coal fired plant and power to methanol plant: Example of flexible operation of integration of 50 MWe power to Methanol plant with 150 MWe coal fired plant in Germany (EC, 2021)



7 RECOMMENDATIONS AND FUTURE WORK

In this chapter, key recommendations for unlocking South Africa's PtX potential are provided, considering the particular characteristics of South Africa's energy system, as well as its key geopolitical position.

GREEN HYDROGEN SOUTH AFRICA
International PtX Hub
Supported by:
Federal Ministry for Economic Affairs and Climate Action
on the basis of a decision by the German Bundestag
IKI INTERNATIONAL CLIMATE INITIATIVE
Implemented by
giz Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) GmbH
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Recommendations and future work

Recommendations

Power-to-X (PtX) fuels (and products) can provide a crucial solution that can replace fossil fuel consumption in the hard to abate sectors, mainly in industry and transport (including heavy-duty vehicles, shipping and aviation). Both hydrogen and carbon are needed for the synthesis process of a PtX product, and the way these two elements can be secured largely determine the technical, economic and sustainability potential for the finally produced synthetic fuel. The particular characteristics of South Africa's energy system, as well as its key geopolitical position in the southern part of Africa, well located for the global trade routes and with significant trade national history, have an important influence on the development of the PtX value chain. Key recommendations to unlock the PtX products potential of South Africa are provided below.

Recognise synthetic and PtX fuels as a key component of the energy mix for 2030 and 2050

Decarbonization efforts worldwide and the related studies supporting energy policy and planning, suggest that synthetic fuels will have a key role to play in the decarbonized era. Key prerequisite, for synthetic fuels establishing themselves as an obvious replacement of fossil fuels, constitutes their sustainable production. This largely comes with the requirement of utilization of green hydrogen and sustainably sourced carbon.

Recommended actions:

- Substantial participation in consultations with relevant stakeholders abroad, including neighbouring African countries, key trade counterparties, countries and/or regions abroad that are in principle interested to import PtX products.
- Engagement with current trade partners – gradually replace fossil-based fuels with PtX fuels.
- Identify new markets. Low hanging fruit will be markets that currently trade with partners that do not have the resources required for PtX fuels, or where the exporter has a high risk of transforming to green fuels (could be political or social).
- Identify new markets that will benefit from having lower cost PtX fuels supplied than current opportunities.
- Identifying markets that strive to diversify to eliminate supply risk – can accept small % of supply at a higher cost.
- Informing and engaging with domestic stakeholders, along the entire value chain, about upcoming developments regarding PtX fuels penetration.

Create a long-term national energy strategy taking PtX fuels into account

There is a need for South Africa to proceed with the development of an up-to-date long-term national energy strategy that will identify specific targets for the introduction of PtX fuels in the energy mix, on the basis of a least cost approach within a frame of decarbonization of the national economy and ensuring security of energy supply. The targets for the introduction of PtX fuels in the energy sector should take into account the individual targets for the utilization of domestic resources, both fossil and renewables, as it is important to be able to identify any energy surplus (i.e. beyond the quantities required to meet domestic energy needs) for each of the aforementioned energy carriers. A special reference should be made to biomass, the potential of which in South Africa needs to be studied in detail because (a) biomass is very much related to the energy-water-food nexus, (b) biomass offers biogenic source of carbon for sustainable PtX products.

It is important to mention that the long-term national energy strategy should take into account the relevant future energy mix in final consumption sectors, such as transport and industry, where PtX fuels participate as crucial energy carriers under a decarbonization (or net zero) trajectory.

Recommended actions:

- Validation of the available high level strategic documents to consider the introduction of PtX fuels
- Discuss an updated energy national strategy with the stakeholders and the wider energy community of South Africa of the estimated necessary quantities of PtX fuels to cover the domestic demand until 2030 and 2050.
- Assessment and/or review of existing strategies to establish the feasibility, requirements, resources, timelines, funding, and international support needed to update critical infrastructure (electricity, pipelines, rail, ports, users, etc.) essential to support a PtX fuels market, domestic and export.

Create a framework to allow participants to formulate a PtX market

Active participation of relevant parties and stakeholders constitutes a prerequisite for the successful and smooth operation of the PtX vlaue chain and the respective market. The creation of a framework that will allow the above, should take place in parallel with the integration of PtX fuels into the national energy strategy.

Key axes of the respective framework:

- Presentation of the benefits (environmental, economic, energy security, technological, social) deriving from the creation of the PtX value chain both as a whole and at each individual stage.
- Ensure that both supply and demand actors understand the potential of PtX fuels within the frame of a decarbonized national economy and possess the know-how to exploit such types of fuels for their businesses. It is important that the different participants along the value chain are aware of the development possibilities that will be supported by systems and frameworks suitable for each energy carrier and related technologies.

Recommended actions:

- Creation of a dedicated specialized national Institution/Agency/Forum with representative participation from stakeholders along the value chain and with the support of relevant state organizations.
- Such institution should coordinate with, directly or at higher level, the already announced hydrogen (and associated PtX) hubs, identify new hubs, and engage with stakeholders. Creating and managing hubs are key to prevent duplication of resources and provides access to, and pools resources for upstream and downstream stakeholders.

Align the national regulatory frame with the relevant international best practices

Key regulatory interventions are needed to allow the valorisation of the CCUS potential for PtX products development, including, among others, (a) infrastructure development, (b) access to the CO2 or H2 or PtX fuels network (pipelines or trucks), (c) safety standards and regulations, (d) support for project financing, etc.

Alongside the specific regulatory framework for PtX, any possible need to amend the regulatory framework in other energy sectors, notably electricity and renewables, should be considered. The aim is to establish a framework for regulation, design, and support that enables the coordination of different segments of the energy market to enable the development and use of the necessary PtX infrastructure.

Recommended actions:

- Recognition of gaps in primary legislation in relation to the relevant international acquis for the integration of PtX products into the energy system and corresponding legislation by Law. Adoption of all necessary Regulations (secondary legislation) for the implementation of the related Laws.
- Amendment of the existing regulations of the electricity, natural gas, liquid fuels markets to facilitate the penetration and use of PtX products.

Promote technologies and demonstrate feasibility

The technological maturity of CCUS crucial elements, directly influences their deployment phase. A faster implementation of CCUS technology in many branches of industry at the commercial level will be of fundamental importance in the effort to valorise PtX pathways. For South Africa, although coal-power generation is the highest emitting industry, focusing on hard-to-abate industry sectors, such as Iron & Steel, Cement and Petrochemicals, may make more sense in sustainability terms, and potentially reduces the risk of carbon lock-in effects in the power generation. CCUS technology readiness and costs may vary depending on process targeted, and capture methods are expected to become more competitive and cost-effective in the next 5-7 years[xliii].

Recommended actions:

- Perform indicative feasibility studies on identified CCU cases to allow for an accurate determination of the realistic potential in the key industrial sectors. Look at the environmental issues and the public acceptance of such projects.
- Conduct studies on development of required infrastructure for the potential transport of the captured tonnes of CO2 across South Africa, considering the need for reliable, non-discriminatory, open-access national transport network[xliv.]

Future work

The present study examined the potential of South Africa to produce PtX products exploiting its potential of carbon coming from mainly industrial sources, namely, from the power sector and key sectors of main industrial activity (cement, petrochemicals, steel). The work considered the potential domestic demand for synthetic fuels in the transport sector, as one pathway to channel the produced PtX products. This quantification allowed for a high level estimation of the potential for exports.

The analysis considered that the EU transport fuels, the international maritime and the international aviation fuel markets, are three key markets that South Africa can target. However, each of these markets has its own sustainability and emissions saving criteria. This is of particular importance when a PtX product utilizes carbon from South Africa's Industry, as the latter is heavily relying on coal.

Within the above framework, key next steps towards the determination of the 'marketable' exports potential of PtX products produced in South Africa would include the following:

- **Consideration of biogenic carbon sources and quantification of their potential as carbon feed in the PtX process**. Biogenic carbon would largely improve the overall sustainability of the PtX value chain and would unlock the more stringent PtX fuels market (e.g. the EU market, operating under the RED sustainability criteria). However, the determination of the appropriate biomass potential that would be mobilized within an economically feasible frame, is an elaborate work on its own[xlv].
- **Consideration of PtX products other than fuels, such as chemicals to be used as feedstock in the relevant industry**. When domestic demand is considered, this would result in higher domestic demand for CO2, leaving therefore less room for exports. On the contrary, when international demand is considered, an additional exports stream is generated. However, such analysis should be considered along with the analysis of the relevant regulatory frame (including also the provisions relevant to recycling) in South Africa and the key international markets.
- **Determination of the real potential for implementation of carbon capture in the industrial point sources in South Africa**. Such an exercise, would require a detailed bottom-up analytical approach for typical installations considering also the expected evolution of the relevant markets (such as electricity prices, materials prices, etc.). Within this framework, analytical work to evaluate the actual percentage of the unavoidable emissions of the key industrial processes is needed as well, taking into account at the same time the expected fuel mix evolution (which is still largely envisaged to be coal).

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[i] RFNBO is a subpart of Power-to-X products that are produced with electricity from renewable energy and meet certain GHG emissions reduction thresholds.

[ii] RFNBOs are renewable liquid or gaseous transport fuels for which none of the energy content of the fuel comes from biological sources. RFNBOs are fuels made from renewable sources.

[iii] 2008 baseline based on the Third IMO Greenhouse Gas Study.

[iv] See also DNV Energy Transition Outlook 2023, Chapter 7.2, pg. 126 “"For all the existing and announced policies on CCS, its uptake will be very limited in the near- to medium-term, and effectively too late and too little in the longer term."

[v] The assumption of meeting all liquid fuel demand with e-diesel is made for simplifying the respective calculations and in the absence of detailed data about the liquid fuel mix consumed. In any case, the assumption is deemed appropriate for depicting the broader picture about the CO2 required for producing synthetic fuels.

[vi] This route for SAF production is not exhaustive, and has been chosen due to the readily available data, but it is also a methodology Topsoe has expertise in (see here), a company that Sasol recently partnered with in order to explore SAF production opportunities (Sasol’s news).

[vii] For instance, it is noted that the National Development Plan: Vision 2030 foresees economy to be growing at a rate of 5.4 percent.

[viii] Based on information from Eskom, the Department of Mineral Resources and Energy (DMRE) reports that by 2030, 9.6 GW of existing capacity will be decommissioned, with less than 10 GW of existing capacity still in operation by 2050 (source: Republic of South Africa, Department of Science and Innovation (2021) South African Hydrogen Society Roadmap)

[ix] It is also noted that Eskom’s generation and emission figures of 2021 were compared to relevant data from previous years prior to 2020 (so as to exclude the effects of the COVID pandemic), and it was confirmed that 2021 can be considered as a base year for the estimation of the emission factor.

[x] Emission factor has been considered constant for the entire study period. Improvements in the operating efficiency of the coal-fired power plant fleet could lead to a reduction on the emission factor, and therefore a reduction to the theoretically total CO2 available for capture. Particularly for the case of South Africa, efficiency gains could be expected due to additional optimization on the dispatch schedule and reduced maintenance. **Based on previous studies, a reduction of up to 10% could be expected considering the above**. Further reductions could be expected in the case of supercritical and ultra-supercritical power plants, or combustion with high quality coal (accompanied by any required equipment upgrade in the plant); however, none of these options are considered for the case of South Africa. Therefore, **for the purpose of the present study, the Emission Factor has been considered constant for the entire study period**.

[xi] It is noted that the available information at plant level as presented in the identified reports, is reported always in a consistent manner. Figures presented in this table are provided by climatetrace.org, after crosschecking with the annual reports of each company

[xii] For instance, see PPC and Sephaku.

[xiii] Information at plant level is not presented in a consistent manner among identified reports. Figures presented are provided by climatetrace.org, after crosschecking with the annual reports of each company.

[xiv] This plant produces limestone

[xv] Information at plant level is not presented in a consistent manner among identified reports. Figures presented are provided by climatetrace.org, after crosschecking with the annual reports of each company. In particular for Sasol, information has been taken from the most recent publicly available Climate Change Report.

[xvi] The emissions presented in the McKinsey study, and which will be used as South Africa's current emissions, correspond to 2018. In the following years, Sapref was closed (since 2018), while Chevron, which was also closed down, went (and currently is) back in operation. Although the capacity of the plants that seized and resumed operation is comparable, the projected emissions from the petrochemical sector can thus be subject to some uncertainty, as the reference year emissions might be slightly changed.

[xvii]The McKinsey study is based on 2018 data. However, due to the COVID 2019 implication, a drop was observed in the industrial activity for the years 2020-2021, while current, 2022 data, converge back to 2018 values. Therefore, the choice of the reported data as a basis for the calculations can be considered as adequate for the context of the present work.

[xviii] Amine scrubbing using MEA

[xix] For reasons of completeness, it is noted that Scope 2 emissions would be kept in check by a higher share of renewable energy sources—reaching 75 percent by 2050— even though power demand grows faster in this scenario than in the base case owing to increased electrification.

[xx] The CO2 emission figures corresponding to CTL are roughly estimated in this scenario, as 100% CCS application has been assumed for SA during the projection of the entire continent's emissions by IEA, without providing further details for scaling the emissions down to South Africa's level.

[xxi] The difference is so big that the suggestion is questionable. Cleared IAP is the most significant feedstock by far according to WWF table, and their amount is completely out of range according to NBI information.

[xxii] IAPs and garden waste are potentially the largest available lignocellulosic feedstocks in the country. They could be converted to 1,8–3 billion litres of SAF annually using Fischer- Tropsch synthesis. This is also the most economic pathway to produce SAF from IAPs and garden waste.

[xxiii] Reported values represents the theoretical upper limit of captured carbon – practical and market considerations in operating plants can reduce the expected captured carbon to as low as 20-60% of the theoretical values (see also discussion in Chapter 5).

[xxiv] It is noted that in this theoretical analysis, the min scenario of the captured CO2 from industrial sources, can be combined with the max scenario for domestic demand, since in principle the drivers under each scenario consideration are different and their evolution is independent to each other's. The uncertainty in the quantities of produced and captured CO2, and the domestic CO2 to cover the domestic fuels market, possesses significant challenges for an accurate determination of the available CO2 quantities for exports.

[xxv] According to IRP 2019, a drop is foreseen for coal fired electricity generation around 2040, with no straightforward interpretation provided.

[xxvi] A recent analysis is provided in: Tsimplis and Noussia, The use of ships within a CCUS system: Regulation and liability, Resources, Conservation & Recycling 181 (2022) 106218 (Elsevier): "*For CO2 carriers the regulatory legal framework is contained in the IGC Code. The implementation through the SOLAS convention means that this regulatory framework is inapplicable to CCS and CCUS-EOR systems trading within one jurisdiction. In turn, this means that, provided that the administration of the relevant state can be persuaded for the safety of a novel design, there is no constrain in the type of vessel or the type of containment used to store the CO2. Such a ship will have to be dedicated to the specified jurisdiction, and will not be able to negotiate its participation to CCS/CCUS-EOR systems in other parts of the world without modification*."

[xxvii] Exporting of CO2 and/or synfuels may require the amendment of the relevant regulatory frame in the country and/or relevant developments in the counter-trade countries.

[xxviii] The issue of permitting of CO2 pipelines in South Africa is not covered within the scope of the present report.

[xxix] In the second row of the table, the foreseen transportation cost has been calculated, considering the transport cost per medium and distance from Table 25, and the amount of CO2 that is available for export in 2030, 2040 and

2050 according to Table 26, where the minimum and maximum values have been averaged across the different years.

[xxx] Sasol is conducting a pre-feasibility study, regarding the transport of CO2 from the Vanderbijlpark park plant to Sasolburg by pipe, where a Fischer Tropsch facility is in place.

[xxxi] For the development of the graph, the following assumptions have been considered in the original publication: transport of 1 MtH2/year, a production site electricity cost of 10 €/MWh and a consumption site electricity cost of 50 €/MWh (JRC (2021) Assessment of Hydrogen Delivery Options)

[xxxii] A detailed feasibility analysis for the determination of the optimal means of hydrogen transport in South Africa is needed.

[xxxiii] It is noted however that South Africa has limited infrastructure of natural gas pipeline and repurposing does not appear to be a viable option. Due to its limited domestic production in off-shore fields opposite of the Mossel Bay, South Africa imports the majority of its natural gas from Mozambique via a 865 km transmission pipeline (from the Temane and Pande gas fields to Secunda in Sasol) (Republic of South Africa, Department of Energy (2019) The South African Energy Sector Report. 2019).

[xxxiv] Currently Eskom is developing a Virtual Wheeling Platform, that will connect power consumers, with multiple off-take sites, to generators via the Eskom grid.

[xxxv] It should be noted that the inland site does not have apparent access to any significant source of water.

[xxxvi] It is noted that similar costs are also obtained from the Fraunhofer Global PtX Atlas Application.

[xxxvii] It is noted that the analysis draws from the international experience and published studies, as it was not possible to acquire real data for ESKOM's power plants.

[xxxviii] For a an analysis of the advantages and limitations of methanol as a marine fuel, see for example: oeko institute, 2023

[xxxix] Reverse Water Gas Shift (RWGS) reaction

[xl] It is noted that due to the current RES penetration to the overall power fuel mix in South Africa, the state/quality of grid, and the prevailing issues of load shading, the development of a dedicated RES-unit to supplement the coal-fired plant, would constitute a realistic alternative.

[xli] The example is in principle aligned with the findings of the "Atlas on the geological storage of carbon dioxide in South Africa" and the therein identified off-shore potential storage sites (Council for Geoscience 2010, ISBN: 978-1-920226-24-4)

[xlii] Grade AA purity is 99.85% methanol by weight. Grade "AA" methanol contains trace amounts of ethanol as well. Methanol for chemical use normally corresponds to Grade AA.

[xliii] A recent review can be found in Dziejarski et al., Current status of carbon capture, utilization, and storage technologies in the global economy: A survey of technical assessment, Fuel 342 (2023) 127776

[xliv] A dedicated regulatory frame is also needed for this.

[xlv] A recent example is the PtX international study: A sustainable carbon carrier for PtX use: from Namibia to a global market (2023)