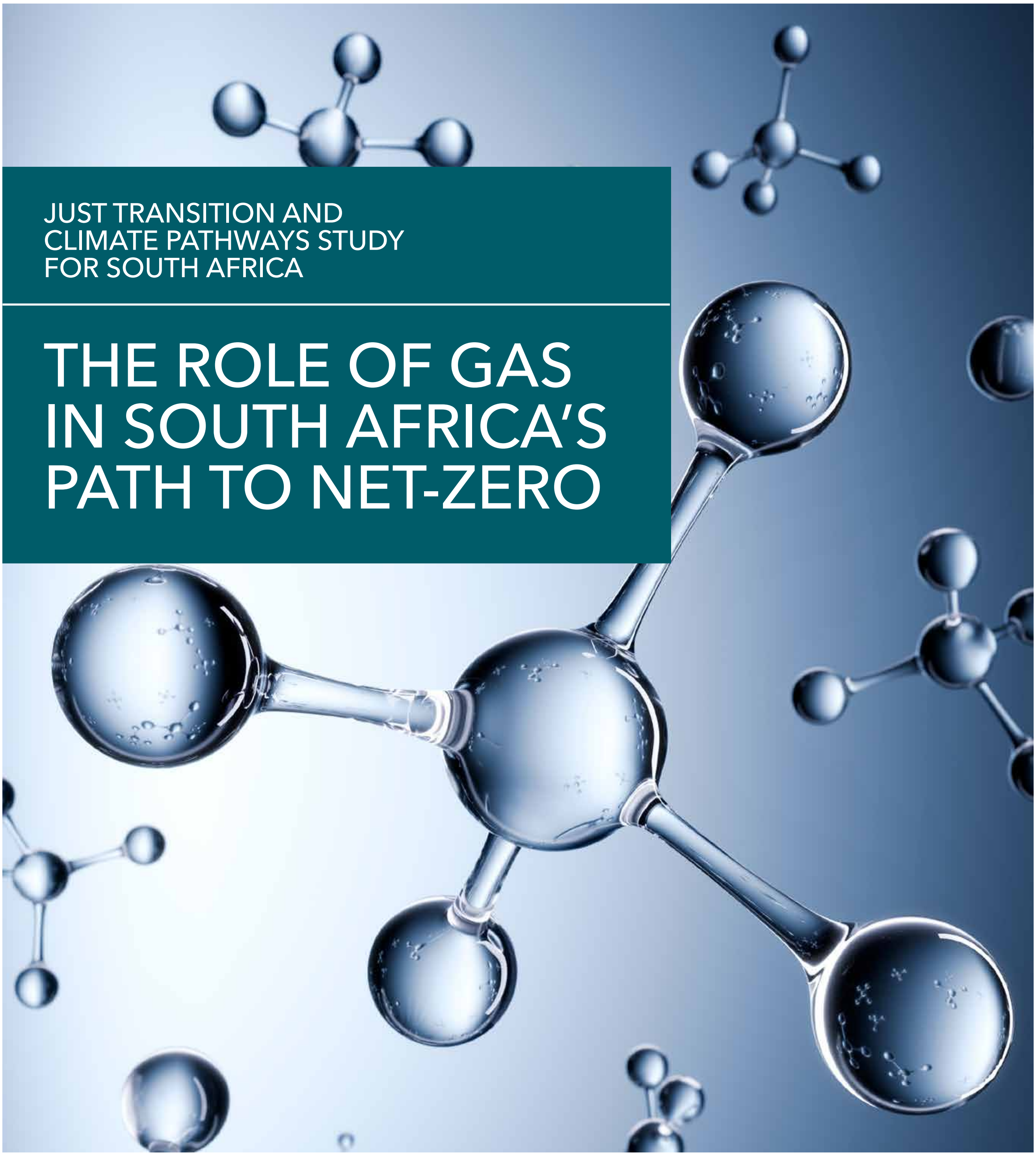
National Business Initiative



CHAPTER 03

JUST TRANSITION AND
CLIMATE PATHWAYS STUDY
FOR SOUTH AFRICA

THE ROLE OF GAS IN SOUTH AFRICA'S PATH TO NET-ZERO

IN PARTNERSHIP WITH

BUSA
BUSINESS UNITY SOUTH AFRICA

BCG
BOSTON
CONSULTING
GROUP

ACKNOWLEDGEMENTS

RESEARCH SUPPORTED BY

SOUTH AFRICA
UK PACT

UK PACT South Africa: UK PACT has partnered with South Africa to support action on Just Transition pathways and a low-carbon economic recovery. As the third largest economy in Africa, South Africa plays a critical role in economic and policy priority setting at a continental level and across the Southern Africa region. South Africa's long-standing participation in the United Nations Framework Convention on Climate Change (UNFCCC) processes creates a solid platform for an impactful and transformational UK PACT partnership. Moreover, UK PACT seeks to support climate action that will contribute to the realisation of other development imperatives in South Africa, such as job creation and poverty alleviation. Priority areas of focus for UK PACT in South Africa are aligned with key national priorities in the just energy transition, renewable energy, energy efficiency, sustainable transport, and sustainable finance. UK PACT projects can contribute to addressing industry-wide constraints, common metropolitan challenges, and bringing city, provincial and national level public and private partners together to address climate priorities.

WE MEAN
BUSINESS
COALITION

We Mean Business (WMB): This is a global coalition of non-profit organisations working with the world's most influential businesses to take action on climate change. The coalition brings together seven organisations: BSR, CDP, Ceres, The B Team, The Climate Group, The Prince of Wales's Corporate Leaders Group and the World Business Council for Sustainable Development. Together we catalyse business action to drive policy ambition and accelerate the transition to a zero-carbon economy. NBI has been a regional network partner to WMB since the beginning of 2015.

Supported by:

Federal Ministry
for the Environment, Nature Conservation
and Nuclear Safety

of the Federal Republic of Germany

Strategic Partnerships for the Implementation of the Paris Agreement (SPIPA): Climate change is a global threat that requires a decisive and confident response from all communities, particularly from major economies that represent roughly 80% of global greenhouse gas emissions. The 2015 Paris Agreement complemented by the 2018 Katowice climate package, provides the essential framework governing global action to deal with climate change and steering the worldwide transition towards climate-neutrality and climate-resilience. In this context, policy practitioners are keen to use various platforms to learn from one another and accelerate the dissemination of good practices.

To improve a geopolitical landscape that has become more turbulent, the EU set out in 2017 to redouble its climate diplomacy efforts and policy collaborations with major emitters outside Europe in order to promote the implementation of the Paris Agreement. This resulted in the establishment of the SPIPA programme in order to mobilise European know-how to support peer-to-peer learning. The programme builds upon and complements climate policy dialogues and cooperation with major EU economies.

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PARTNERS

National Business Initiative

At the National Business Initiative (NBI), we believe in collective action and collaboration to effect change; building a South African society and economy that is inclusive, resilient, sustainable and based on trust. We are an independent, business movement of around 80 of South Africa's largest companies and institutions committed to the vision of a thriving country and society. The NBI works with our members to enhance their capacity for change, leverage the power of our collective, build trust in the role of business in society, enable action by business to transform society and create investment opportunities.

Business Unity South Africa

BUSA, formed in October 2003, is the first representative and unified organisation for business in South Africa. Through its extensive membership base, BUSA represents the private sector, being the largest federation of business organisations in terms of GDP and employment contribution. BUSA's work is largely focused around influencing policy and legislative development for an enabling environment for inclusive growth and employment.

Boston Consulting Group

BCG partners with leaders in business and society to tackle their most important challenges and capture their greatest opportunities. BCG, the pioneer in business strategy when it was founded in 1963, today works closely with clients to embrace a transformational approach aimed at benefitting all stakeholders – empowering organisations to grow, build sustainable competitive advantage, and drive positive societal impact. Their diverse global teams are passionate about unlocking potential and making change happen, and delivering integrated solutions.

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TERMINOLOGIES

AFOLU	Agriculture, Forestry and Other Land Use
BEV	Battery Electric Vehicle
bbl	Barrel
bn	Billion
BUSA	Business Unity South Africa
c	Cents (in South African Rands)
CAPEX	Capital Expenditure
CCGT	Closed Cycle Gas Turbine: Gas turbines which are techno-economically competitive for mid-merit utilisation and above. South Africa currently does not have any CCGT capacity installed. Globally CCGTs run off gas, diesel or a combination of both. CCGTs require higher upfront CAPEX but have lower operational costs relative to Open Cycle Gas Turbines (OCGTs), which have lower upfront CAPEX costs but higher operational costs.
CCUS	Carbon Capture Utilisation and Storage: A suite of technologies that involve capturing CO_2 from large point sources (e.g., power generation, industry) or from the atmosphere. If the captured CO_2 is not used on-site, the CO_2 is compressed and transported to be used in a range of applications or permanently stored in geological formations (according to the International Energy Agency).
CNG	Compressed Natural Gas
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
COP26	26th UN Climate Change Conference of the Parties
CMH	Companhia Moçambicana de Hidrocarbonetos
CRD	Collaborative Regional Development
CSIR	Council for Scientific and Industrial Research
CTL	Coal-to-liquid
DACCS	Direct Air Carbon Capture and Storage: A suite of technologies which capture CO_2 directly from the atmosphere. These technologies compress the CO_2 either for the downstream use in products (e.g., cement) or for storage in geological formations.
DMRE	Department of Mineral Resources and Energy
e.g.	Exempli gratia
EC	Eastern Cape
EIA	United States Energy Information Administration
EJ	Exajoule
ENH	Empresa Nacional de Hidrocarbonetos
EU	European Union
EV	Electric Vehicle
FCEV	Fuel Cell Electric Vehicle
FID	Final Investment Decision
Flexibility	The extent to which a power system can respond (production- or consumption-side) to variability. Flexibility essentially refers to the ability of the system to restore stability. The system requires short- and longer-term flexible capacity – for short-term daily fluctuations and longer-term seasonal fluctuations.
FSRU	Floating Storage Regasification Unit: Ships which transport, store and regasify Liquified Natural Gas (LNG) on board. FSRUs typically require either an offshore terminal, with an undersea pipeline, to transport regasified LNG to shore, or an onshore receiving terminal.
GDP	Gross Domestic Product
GHGI	Greenhouse Gas National Inventory
GJ	Gigajoule
Green hydrogen	Hydrogen produced from renewable energy resources
Gt	Gigatonne (1 thousand million tonnes)
GTC	Gas-to-chemical
GTL	Gas-to-liquid
GTP	Gas-to-power
GW	Gigawatt
GWG	Gas Working Group
GWh	Gigawatt hours
H_2	Hydrogen
HDV	Heavy Duty Vehicle
ICE	Internal Combustion Engine
IEA	International Energy Agency
IPP	Independent Power Producer
IPCC	Intergovernmental Panel on Climate Change
IRP	Integrated Resource Plan
k	Thousand
kg	Kilogram
kWh	Kilowatt-hour
KZN	KwaZulu-Natal
LNG	Liquified Natural Gas

Load shedding	The interruption of electricity supply to reduce the load on a generating plant or the generation grid more broadly.
Minerals Council	Minerals Council South Africa
MCUS	Methane Capture, Utilisation and Storage
MMBTU	Metric Million British Thermal Unit
mn	Million
MRG	Methane Rich Gas
Mt	Megatonne (1 million tonnes)
Mtpa	Megatonne per annum
MW	Megawatt
n/a	Not Applicable
NDC	Nationally Determined Contribution: Commitments by countries to reduce national emissions and adapt to the impacts of climate change, under the Paris Agreement.
NERSA	National Energy Regulator of South Africa
NPC	National Planning Commission
NPV	Net Present Value
OCGT	Open Cycle Gas Turbines: Gas turbines which are techno-economically competitive for low levels of, mostly peaking, utilisation. South Africa currently has six OCGTs – Acacia, Ankerlig, Gourikwa, Port Rex, Dedisa, Avon – with a cumulative capacity of ~3.8 GW. All these OCGTs leverage diesel as a feedstock. OCGTs have lower upfront CAPEX costs, but higher operational costs, relative to CCGTs.
OPEX	Operational Expenditure
Peak load	Maximum of electrical power demand
PGMs	Platinum Group Metals
PJ	Petajoule
PJ/a	Petajoule per annum
PPA	Petroleum Production Agreement
PSA	Production Sharing Agreement
PV	Photovoltaic solar energy
Q4	Fourth Quarter
RCP	Representative Concentration Pathway
RE	Renewable Energy
REIPPPP	Renewable Energy Independent Power Producer Procurement Programme

RMIPPPP	Risk Mitigation Independent Power Producer Procurement Programme
ROMPCO	Republic of Mozambique Pipeline Company
SA	South Africa
Scope 1 emissions	All direct emissions from activities of an organisation under their control, including on-site fuel combustion for fleet vehicles, stationary machinery and heating processes, and fugitive emissions from drilling or spontaneous combustion of coal.
Scope 2 emissions	Indirect emissions from electricity purchased and used by the organisation. Emissions are created during the production of the electricity that is used by the organisation.
Scope 3 emissions	All indirect emissions (not included in Scope 2) that occur in the value chain of the respective organisation, including both upstream and downstream emissions (e.g., emissions linked to use of the organisation's products).
SMR	Small Modular Reactor
Synfuels	Synthetic fuels
SSA	Sub-Saharan Africa
TWh	Terawatt-hours
UNFCCC	United Nations Framework Convention on Climate Change
US	United States
US$	United States Dollar
Use case	Proven global commercial systems and processes across sectors where gas is used as a key input, either as a feedstock or fuel.
Variability	The extent to which the power supply fluctuates. Variability encompasses both predictable variability (e.g., day-night cycle) and unpredictable variability (e.g., weather forecasting) – also referred to as intermittency.
WACC	Weighted Average Cost of Capital
WC	Western Cape
ZAR	South African Rand
ZEV	Zero Emissions Vehicle

OVERVIEW OF CEO CHAMPIONS

Onboarding of additional CEOs ongoing


Joanne Yawitch
NBI CEO


Cas Coovadia
BUSA CEO


Mark Dytor
AECI CEO


Nolitha Fakude
Anglo American SA Chairperson


Taelo Mojapelo
BP Southern Africa CEO


Deidré Penfold
CAIA Exec Director


Theo Boschoff
AgBiz CEO


Yusa Hassan
Engen MD and CEO


André de Ruyter
Eskom CEO


Stuart Mckensie
Ethos CEO


Mxolisi Mgojo
Exxaro CEO


Alan Pullinger
First Rand CEO

Nyimpini Mabunda
GE SA CEO

Tshokolo TP Nchocho
IDC CEO

Mohammed Akoojee
CEO Imperial Logistics

Leila Fourie
JSE Group CEO

Vivien McMenamin
Mondi SA CEO

Marelise van der Westhuizen
Norton Rose Fulbright CEO

Roland van Wijnen
PPC Africa CEO

Njombo Lekula
PPC MD SA Cement and Materials

Ishmael Poolo
Central Energy Fund CEO

Alex Thiel
SAPPI CEO

Fleetwood Grobler
Sasol CEO

Hloniphizwe Mtolo
Shell SA CEO

Lungisa Fuzile
Standard Bank South Africa CEO

Gavin Hudson
Tongaat Hulett CEO

Paul Hanratty
Sanlam CEO

Portia Derby
Transnet CEO

1.
FOREWORD

JUST TRANSITION AND CLIMATE PATHWAYS STUDY FOR SOUTH AFRICA

South Africa is a signatory to the United Nations Framework Convention on Climate Change (UNFCCC) and to the Paris Agreement. As an energy and emissions intensive middle-income developing country, it recognises the need for it to contribute its fair share to the global effort to move towards net-zero carbon emissions by 2050, taking into account the principle of common but differentiated responsibilities and the need for recognition of its capabilities and national circumstances.

South Africa is highly vulnerable to the impacts of climate change and will need significant international support to transition its economy and to decarbonise. Furthermore, given the country's high rate of inequality, poverty and unemployment and the extent of dependence on a fossil fuel-based energy system and economy, this transition must take place in a way that is just, that leaves no-one behind and that sets the country onto a new, more equitable and sustainable development path; one which builds new local industries and value chains.

In response to the above imperatives, the National Business Initiative, together with Business Unity South Africa and the Boston Consulting Group has worked with corporate leaders to assess whether the pathways exist for the country's economic sectors to decarbonise by 2050, and whether this can be done in such a way as to build resilience to the impacts of climate change and to put the country onto a new, low emissions development path.

The work done by the business community has interrogated the energy, liquid fuels, mining, chemicals, AFOLU (Agriculture, Forestry and Other Land Use), transport and heavy industrial sectors. The results of the modelling and analytical work have been informed by numerous industry experts, academics and scientists. The results demonstrate that these pathways do exist and that even a country with an economy that is structurally embedded in an energy-intensive production system can shift.

The results of this work to date have shown that this can be done, and that to realise these pathways, efforts must begin now. Timing is of the essence and the business community is of the view that there is no time like the present to create the regulatory and policy environment that would support transitioning the economy. **Accordingly, business can commit unequivocally to supporting South Africa's commitment to find ways to transition to a net-zero emissions economy by 2050.**

Furthermore, on 27 September 2021, South Africa tabled its revised Nationally Determined Contribution (NDC) to the UNFCCC. Business recognises the need for greater ambition to position the country as an attractive investment destination and increase the chances of accessing green economic stimulus and funding packages. Specifically, business supported a level of ambition that saw the country committing to a

Upington, Northern Cape. Photo: scatec.com/locations/south-africa

range of 420–350 Mt CO_2e by 2030. This is significantly more ambitious than the NDC targets originally put out for public comment and requires greater levels of support with regard to means of implementation from the international community than is currently the case. It is consistent with international assessments of South Africa's fair share contribution to the global effort, and also ensures that the no-regret decisions, that would put South Africa onto a net-zero 2050 emissions trajectory, would be implemented sooner.

While South Africa has leveraged a degree of climate finance from the international community, the scale and depth of the transition envisaged will require substantial investments over an extended period of time. Critically, social costs and Just Transition costs must be factored in. Significant financial, technological, and capacity support will be required to support the decarbonisation of hard to abate sectors. Early interventions in these sectors will be critical.

Business sees the support of the international community as essential for the country to achieve its climate objectives. For this reason, business believes that a more ambitious NDC, and one that would place the country firmly on a net-zero emissions by 2050 trajectory, would have to be conditional on the provision of the requisite means of support by the international community. In this light the business community will play its part to develop a portfolio of fundable adaptation and mitigation projects that would build resilience and achieve deep decarbonisation.

Despite the depth of the challenge, South African business stands ready to play its part in this historical endeavour. Business is committed to work with government and other social partners, with our employees, our stakeholders, and the international community, to embark on a deep decarbonisation path towards net-zero and to build the resilience to the impacts of climate change that will ensure that our country contributes its fair share to the global climate effort.

2.
INTRODUCTION

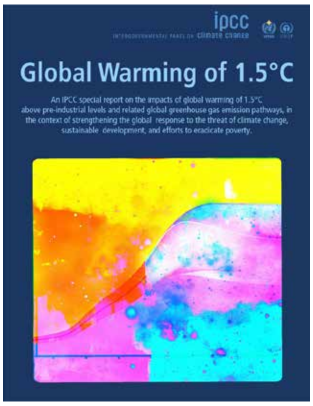
2.1 THE PURPOSE OF THIS REPORT

This report, focusing on the role of gas in South Africa's path to net-zero, is the third in a series being released to illustrate the findings of this project. These reports are intended to leverage further engagement with sector experts and key stakeholders, beyond the extensive stakeholder engagement that has been undertaken from August 2020 to December 2021 within the respective technical working groups of this project. We hope this will foster continued dialogue during the project as we work towards a final report that will collate the individual sector findings and provide collective insight.

2.2 THE CASE FOR CHANGE

2.2.1 CLIMATE CHANGE AND THE RACE TO GLOBAL NET-ZERO EMISSIONS BY 2050

Climate change is the defining challenge of our time. Anthropogenic climate change poses an existential threat to humanity. To avoid catastrophic climate change and irreversible 'tipping points', the Intergovernmental Panel on Climate Change (IPCC) stresses the need to stabilise global warming at 1.5 °C above pre-industrial levels. For a 66% chance of limiting warming by 2100 to 1.5 °C, this would require the world to stay within a total carbon budget estimated by the IPCC to be between 420 to 570 gigatonnes (Gt) of CO_2, to reduce net anthropogenic emission of CO_2 by ~45% of 2010 levels by 2030, and to then reach net-zero around 2050.[1]



ipcc
INTERGOVERNMENTAL PANEL ON climate change

Global Warming of 1.5°C

An IPCC special report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty.

Hence, mitigating the worst impacts of climate change requires all countries to decarbonise their economies. In the 2019 World Meteorological Organization report, 'Statement on the State of the Global Climate', the United Nations (UN) Secretary-General urged: "Time is fast running out for us to avert the worst impacts of climate disruption and protect our societies from the inevitable impacts to come."

South Africa, in order to contribute its fair share to the global decarbonisation drive, bearing in mind the principle of 'common but differentiated responsibilities and respective capabilities', should similarly set a target of reaching net-zero emissions by 2050, **and also keep it within a fair share of the global carbon budget allocated, estimated to be between 7 and 9 Gt CO_2e**.[2]

Even if global warming is limited to 1.5 °C, the world will face significantly increased risks to natural and human systems. For example, 2019 was already 1.1 °C warmer than pre-industrial temperatures, and with extreme weather events that have increased in frequency over the past decades, the consequences are already apparent.[3]

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[1] IPCC, 2018. *Special Report on Global Warming of 1.5°C*.

[2] Extrapolation of the medians of various methodologies described by Climate Action Tracker. The full range is 4–11 Gt CO_2e.

[3] World Meteorological Organization, 2019. 'Statement on the State of the Global Climate'.

> *"Time is fast running out for us to avert the worst impacts of climate disruption and protect our societies from the inevitable impacts to come."*
>
> **Mr António Guterres,**
> **United Nations Secretary-General**

Photo: UN Climate Action Summit

More severe and frequent floods, droughts and tropical storms, dangerous heatwaves, runaway fires, and rising sea levels are already threatening lives and livelihoods across the planet.

South Africa will be among the countries at greatest physical risk from climate change. South Africa is already a semi-arid country and a global average temperature increase of 1.5 °C above pre-industrial levels translates to an average 3 °C increase for Southern Africa, with the central interior and north-eastern periphery regions of South Africa likely to experience some of the highest increases.[4] Research shows that a regional average temperature increase of over 1.5 °C for South Africa translates to a greater variability in rainfall patterns. Models show the central and western interiors of the country trending towards warmer and dryer conditions, and the eastern coastal and escarpment regions of the country experiencing greater variability in rainfall, as well as an increased risk of extreme weather events.

Rising temperatures and increased aridity and rainfall variability may have severe consequences for South Africa's agricultural systems, particularly on the country's ability to irrigate, grow and ensure the quality of fruit and grain crops; and on the health of livestock, such as sheep and cattle, which will see decreased productivity and declining health at temperature thresholds. Parasites tend to flourish in warmer conditions, threatening people as well as livestock and crops. Increasing temperatures and rainfall variability threaten South Africa's status as a megabiodiverse country. Severe climate change and temperature increases could shift biome distribution, resulting in land degradation and erosion. The most notable risk is the impact on the grassland biome, essential for the health of South Africa's water catchments, combined with the risk of prolonged drought.

Finally, rising ambient temperatures due to climate change and the urban heat effect, threaten the health of people, particularly those living in cramped urban conditions and engaging in hard manual labour, as higher temperatures result in increased risk of heat stress and a reduction in

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[4] Department of Environmental Affairs, Republic of South Africa, 2018. *South Africa's Third National Communication Under the United Nations Framework Convention on Climate Change.*

productivity. Therefore, limiting global climate change and adapting to inevitable changes in the local climate will be critical to limit the direct, physical risks to South Africa. Like many developing countries, South Africa has the task of balancing the urgent need for a just economic transition and growth, while ensuring environmental resources are sustainably used and consumed, and responding to the local physical impacts of climate change.[5] While South Africa is highly vulnerable to the physical impacts of climate change, its economy is also vulnerable to a range of transition risks posed by the global economic trend toward a low-carbon future.

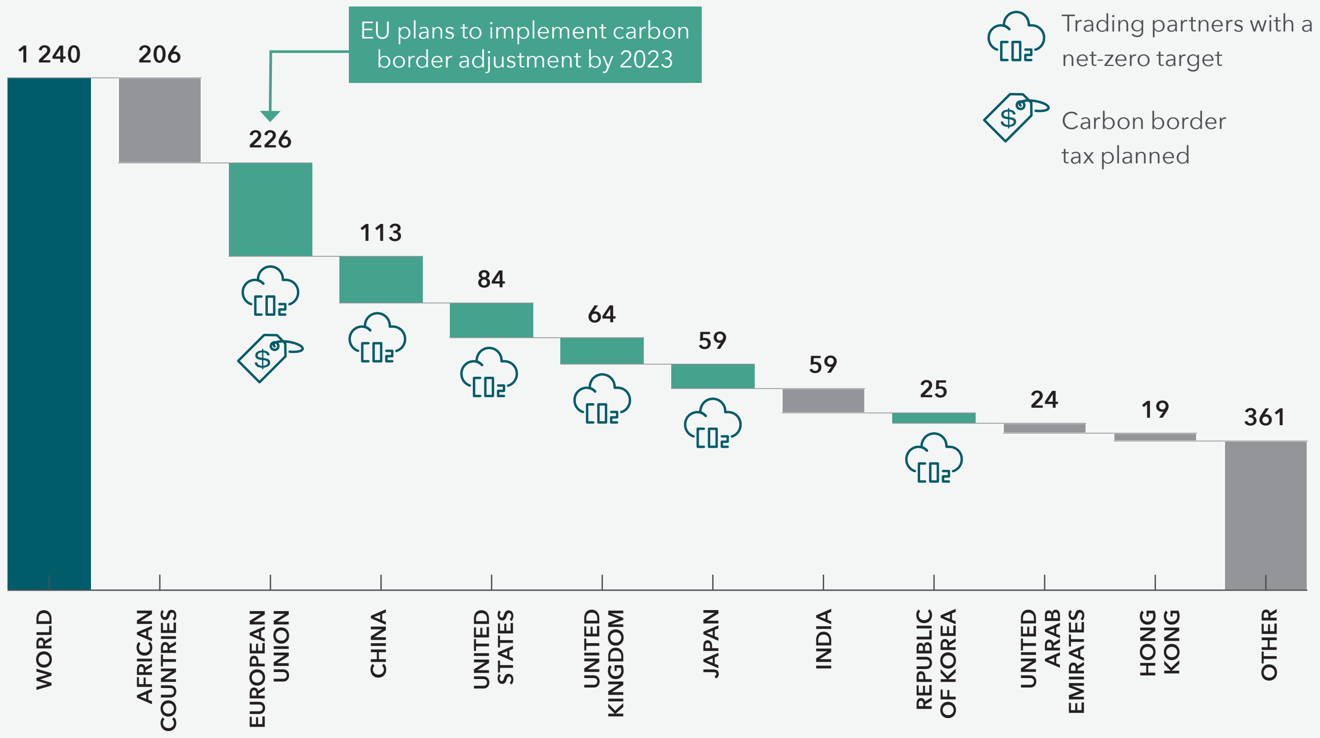
South Africa is also facing a significant trade risk. South Africa ranks in the top 20 most carbon-intensive global economies on an emissions per Gross Domestic Product (GDP) basis, and in the top five amongst countries with GDP in excess of US$100 billion (bn) per annum. The South African economy will face mounting trade pressure, as trade partners implement their low-carbon commitments. South Africa has predominantly coal-based power generation, the coal-to-liquid (CTL) process in the liquid fuels sector, and a coal-reliant industrial sector. In the mining sector, three of the four most significant minerals in South Africa's commodity footprint are at risk, given the global efforts to curb emissions: thermal coal, Platinum Group Metals (PGMs) with mainly palladium and iron ore. The fourth mineral is gold.

The bulk of South Africa's exports comprise carbon-intensive commodities from the mining, manufacturing, and agricultural sectors which will become less competitive in markets in a future decarbonised world. These sectors also provide the majority of employment of unskilled labour at a regional level.

The carbon-intensity of the South African economy, key sectors, and export commodities must be seen against the backdrop of the country's key trading partners committing to ambitious decarbonisation goals. By early 2021, countries representing more than 65% of global carbon dioxide emissions and more than 70% of the world's economy have made ambitious commitments to carbon-neutrality. Seven of South Africa's key export markets have all set net-zero targets, including the European Union (EU), China, the United States, the United Kingdom, Japan, and South Korea.[6]

At the UN Climate Change Conference of the Parties (COP26) in November 2021, all countries were expected to

Figure 1: Volumes of South Africa's exports to leading partners in 2018 (ZAR billion)



Source: World Integrated Trade Solution. 2018. 'Press research'.

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[5] Department of Environmental Affairs, Republic of South Africa, 2016. *South Africa's Second Annual Climate Change Report*.

[6] United Nations News, 2020. *The race to zero emissions, and why the world depends on it*.

Photo: Shutterstock.com

set out more ambitious goals, including setting concrete mid-term reduction targets. The COP26 Presidency's stated priorities included 'seizing the massive opportunities of cheaper renewables and storage', 'accelerating the move to zero-carbon road transport', and 'the need to unleash the finance which makes all of this possible and power the shift to a zero-carbon economy'.

Over and above this, select geographies like the EU are also considering carbon border taxes which could impact future trade. It is therefore essential to consider how South Africa's competitiveness in global markets, and therefore the viability of its industries, will be affected should key trading partners start taking steps to protect their net-zero commitments and enable their net-zero carbon growth trajectories. South Africa will need to address the risks and seize the opportunities presented by climate change.

South Africa will also have the chance to tap into new opportunities. Goldman Sachs estimate that around 35% of the decarbonisation of global anthropogenic greenhouse gas emissions is reliant on access to clean power generation, and that lower-carbon hydrogen and clean fuels will be required for hard-to-decarbonise sectors.[7] South Africa has key strategic advantages which can be leveraged to tap into such emerging opportunities. South Africa has a number of significant assets including plenty of sun and wind. Renewables-dominated energy systems and local manufacturing are key. South Africa's coal assets are aged, and decommissioning coal plants can be done within the carbon budget and with minimal stranded asset risk. South Africa's motor vehicle manufacturing expertise could be transitioned to electric vehicle production. The country's stable and well-regulated financial services sector, among the most competitive in the world, would make a strong base for green finance for the continent. The combination of wind and solar enables the right kind of conditions for green hydrogen, setting the stage for South Africa to be a net exporter. The role of PGMs in hydrogen and fuel cell technology and the increased demand for certain mined commodities, like copper for use in green technology, could bolster the minerals sector. South Africa's experience with the Fischer–Tropsch process positions it to be one of the world leaders in carbon-neutral fuels, and other innovations are thus waiting to be unlocked.

The imperative is clear: South Africa must decarbonise its economy in the next three decades and transform it into a low-carbon, climate-resilient, and innovative economy. This transition also needs to take place in a manner that is just and simultaneously addresses inequality, poverty and unemployment to ensure that no-one is left behind and that our future economy is also socially-resilient and inclusive.

2.2.2 THE NEED FOR A JUST TRANSITION

With a Gini coefficient of 0.63, South Africa is one of the most unequal societies in the world today.[8] A recent study shows that the top 10% of South Africa's population owns 86% of aggregate wealth and the top 0.1% close to one-

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[7] Goldman Sachs, 2020. *Carbonomics: Innovation, Deflation and Affordable De-carbonisation*.

[8] The World Bank, 2021. 'South Africa Overview'.

third. Since the onset of the COVID-19 pandemic, levels of poverty have further increased and have likely shifted beyond 55% of the population living in poverty. In July 2020, a record 30.8% of the population was unemployed.[9] Exacerbating this are levels of youth unemployment that are amongst the highest in the world.[10]

As South Africa grapples with the economic recession accompanying the pandemic, and copes with the need to rebuild the capacity of the State and its institutions following a decade of state capture, it must start rebuilding and transforming its economy to make it resilient and relevant in a decarbonised world. However, while a transition towards a net-zero economy will create new economic opportunities for South Africa, it is also a transition away from coal, which without careful planning and new investments, will put many jobs and value chains at risk in the short-term, and exacerbate current socio-economic challenges.

Today, the coal mining sector provides almost 0.4 million jobs in the broader economy, with ~80 k direct jobs and ~200 to 300 k indirect and induced jobs in the broader coal value chain and economy. The impact is even broader when it is taken into account that, on average, each mine worker supports 5–10 dependents. This implies a total of ~2 to 4 million livelihoods.[11] The low-carbon transition must do more than simply address what is directly at risk from decarbonisation. The transition must also address the broader economic concern of stalled GDP growth of ~1% for the last five years, rising unemployment with ~3% increase over the last five years,[12] deteriorating debt to GDP ratio, with growth of ~6% for the last 10 years, and the consistently negative balance of trade.[13]

These challenges are more severe given further deterioration during the COVID-19 pandemic. It is therefore critical that South Africa's transition is designed and pursued in a way that is just; meaning that it reduces inequality, maintains and strengthens social cohesion, eradicates poverty, ensures participation in a new economy for all, and creates a socio-economic and environmental context which builds resilience against the physical impacts of climate change.

This transition requires action, coordination, and collaboration at all levels. Within sectors, action will need to be taken on closures or the repurposing of single assets. Job losses must also be addressed with initiatives like early retirement and reskilling programmes, with the latter having the potential for integration with topics like skills inventories and shared infrastructure planning and development. A national, coordinated effort to enable the Just Transition will also be crucial to address the education system and conduct national workforce planning. In order to implement its Just Transition, South Africa will need to leverage global support in the form of preferential green funding, capacity-building, technology-sharing, skills development, and trade cooperation.

To move towards this net-zero vision for the economy by 2050, South Africa must mitigate rather than exacerbate existing socio-economic challenges and seize emerging economic opportunities to support its socio-economic development agenda. How to ensure a Just Transition towards net-zero and advancing South Africa's socio-economic context, is therefore the key guiding principle of this study.

2.3 OBJECTIVE AND APPROACH

Key objectives of this study. Achieving net-zero emissions in South Africa by 2050, whilst ensuring a Just Transition, is a complex and unique challenge. Extensive studies examining how a Just Transition towards a lower-carbon economy can be achieved in South Africa have already been conducted or are currently underway. There are many different views on what defines a Just Transition in South Africa, which decarbonisation ambitions South Africa is able to pursue and commit to, and how a transition towards a lower-carbon economy can be achieved.

This study is not advocating for a particular position. It is not setting ambitions around levels and timelines for South Africa's emission reduction. Nor is this study prescribing sector- or company-specific emission reduction targets.

The study does aim to develop the necessary technical and socio-economic pathways research and analysis to support decision-making and bolster a coordinated and coherent effort among national and international stakeholders.

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[9] StatsSA, 2017. *Poverty Trends in South Africa. An examination of absolute poverty between 2006 and 2015.*

[10] Chatterjee, A., et al, 2020. *Estimating the Distribution of Household Wealth in South Africa.*

[11] Minerals Council of South Africa, 2020. 'Facts and Figures'.

[12] Department of Statistics, Republic of South Africa, 2021.

[13] South African Reserve Bank, 2021.

This research is anchored around three key questions:

- What is the cost of inaction for South Africa should it fail to respond to critical global economic drivers stemming from global climate action?
- What would it take, from a technical perspective, to transition each of South Africa's economic sectors to net-zero emissions by 2050?
- What are the social and economic implications for South Africa in reaching net-zero emissions by 2050?

Approach of this study. To understand how a transition of the South African economy towards net-zero emissions can be achieved, this study assesses each sector and intersectoral interdependencies in detail (with this report detailing the analysis on the role of gas in South Africa's path to net-zero). Our analysis of the South African economy is structured along understanding what the decarbonisation pathways could be for key heavy emitting sectors, namely: electricity, petrochemicals and chemicals, mining, metals and minerals, manufacturing, transport and AFOLU (Agriculture, Forestry and Other Land Use) (Figure 2). Given this is a multi-year project, a preliminary report will be released as each sector is completed. Towards the end of the study, each sector analysis will be further refined on the basis of understanding interlinkages better. For example, insights gained from the transport sector analysis around the impact of electric vehicles on electricity demand will be leveraged for further refinement of the electricity sector analysis.

The first phase of the study focused on today's key drivers of South Africa's emissions: electricity and the petrochemicals and chemicals sectors which make up more than 60% of the country's total emissions. Given the socio-economic implications of decarbonising South Africa's energy landscape, particularly impacting coal mining regions and the mining workforce, the mining sector was assessed as part of the project's first phase. The second phase of the study focused on the transport and AFOLU sectors. Eventually, the study will provide a comprehensive view of the South African economy, its potential future net-zero economy and the pathways that can lead to this future economy as informed by various key stakeholders (see Figure 2).

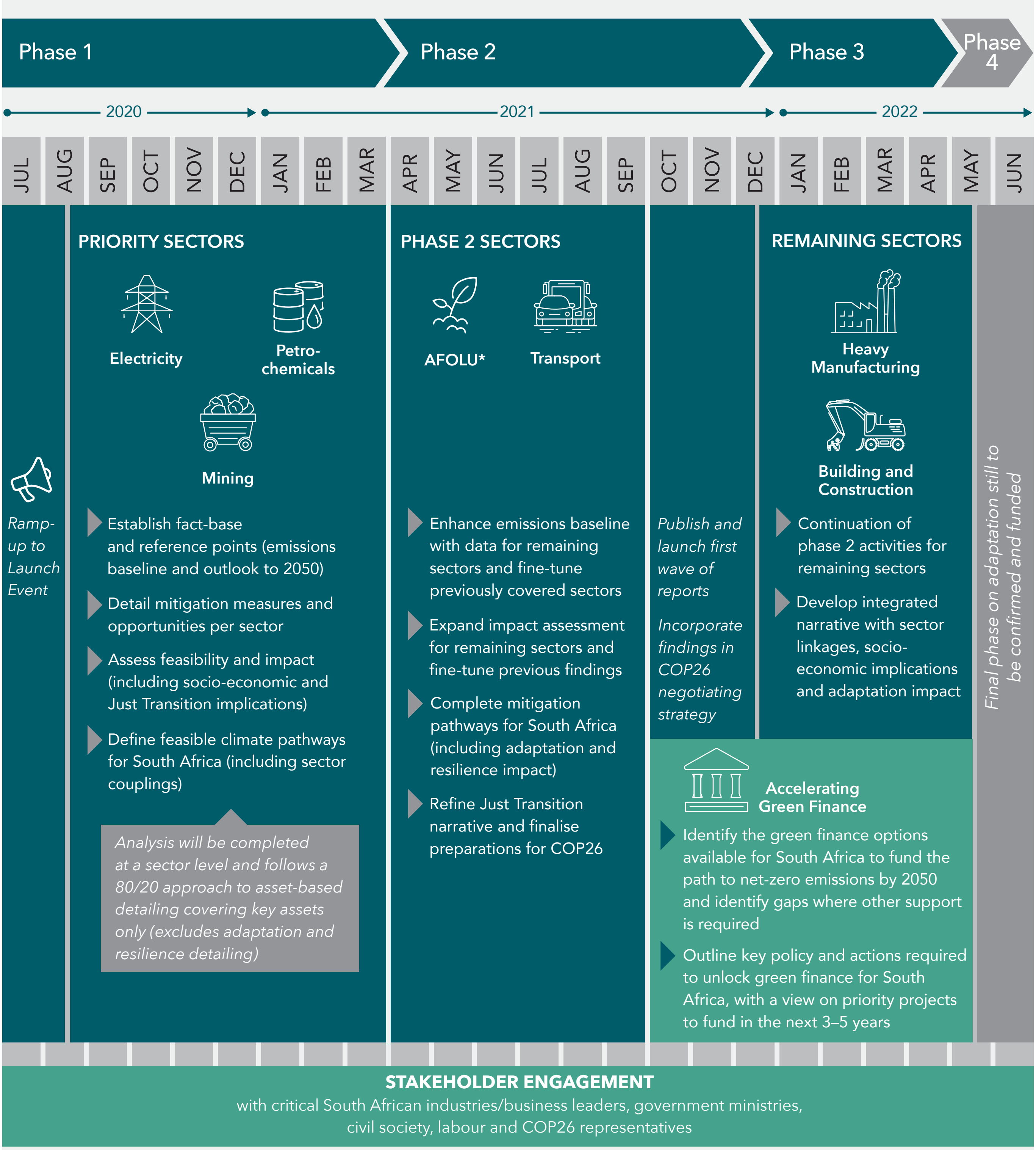
The study is a collaborative effort, aiming to create a 'unified voice of South African business' on the country's needs, opportunities, and challenges in achieving a net-zero economy, involving multiple stakeholders from all sectors. The governance arrangement that has overseen this work is key to enabling this collaborative, multi-stakeholder approach: across multiple levels, key stakeholders are involved in the content development.

The sector assessments are conducted within technical committees which include South African and international experts and stakeholders from private and public sectors, as well as civil society and academia. An advisory board consisting of high-profile representatives from various sectors including industry, government, labour, civil society, and academia; and a steering committee consisting of selected private and public sector representatives, provided continuous direction on content development. In addition, a group of 27 Chief Executive Officers (CEOs) from across the private sector endorsed and guided the study development (see Figure 3: Governance set-up of the study).

This report is the third in a series being released to illustrate the findings of this study. These reports are intended as consultation material to leverage further engagement with sector experts and key stakeholders, beyond the extensive stakeholder engagement that was already undertaken from August 2020 to December 2021 within the respective technical working groups of this project.

We hope this will foster continued dialogue during the project as we work towards a final report that will collate the individual sector findings and provide collective insight.

Figure 2: Approach of this study



Ramp-up to Launch Event

PRIORITY SECTORS

- Establish fact-base and reference points (emissions baseline and outlook to 2050)
- Detail mitigation measures and opportunities per sector
- Assess feasibility and impact (including socio-economic and Just Transition implications)
- Define feasible climate pathways for South Africa (including sector couplings)

Analysis will be completed at a sector level and follows a 80/20 approach to asset-based detailing covering key assets only (excludes adaptation and resilience detailing)

PHASE 2 SECTORS

- Enhance emissions baseline with data for remaining sectors and fine-tune previously covered sectors
- Expand impact assessment for remaining sectors and fine-tune previous findings
- Complete mitigation pathways for South Africa (including adaptation and resilience impact)
- Refine Just Transition narrative and finalise preparations for COP26

Publish and launch first wave of reports

Incorporate findings in COP26 negotiating strategy

REMAINING SECTORS

- Continuation of phase 2 activities for remaining sectors
- Develop integrated narrative with sector linkages, socio-economic implications and adaptation impact

Accelerating Green Finance

- Identify the green finance options available for South Africa to fund the path to net-zero emissions by 2050 and identify gaps where other support is required
- Outline key policy and actions required to unlock green finance for South Africa, with a view on priority projects to fund in the next 3–5 years

Final phase on adaptation still to be confirmed and funded

STAKEHOLDER ENGAGEMENT

with critical South African industries/business leaders, government ministries, civil society, labour and COP26 representatives

* AFOLU: Agriculture, Forestry and Other Land Use

Source: NBI-BCG project team.

Figure 3: Governance set-up of the study

To ensure representative, balanced and fact-based content, a comprehensive governance structure is in place.

CEO champions

CEOs

Advisory boards

Industry, government and civil society representatives

Steering committee

Company representatives

Core project team

NBI, BCG, IDDRI

Technical committees and expert meetings

- Energy sector
- Chemicals and petrochemicals sector
- Mining sector
- Transport sector
- AFOLU sector
- Other sectors

Socio-economic modelling for a Just Transition

Four key objectives of governance structure

- Enable multi-stakeholder inputs through an inclusive consultation process
- Create a platform for collaboration and alignment on key assumptions and methodology
- Ensure that the final output is fact-based and balanced in its recommendations
- Provide a fact-based business perspective into national consultations and planning processes hosted by government

3.

KEY FINDINGS OF THE ROLE OF GAS ANALYSIS

15 key findings on the role of gas analysis

1 *As South Africa decarbonises its economy, gas can, if affordably supplied, play a key role as a transition fuel to replace more emissions-intensive fossil fuels like coal and diesel, and provide flexible capacity to enable a rapid scale-up of renewables, until alternative energy storage solutions and greener fuels become affordable. New investments in gas infrastructure should consider the future repurposing of the assets for the usage of green gases (e.g., green hydrogen blends or green hydrogen). For South Africa to achieve a net-zero 2050 target, gas will need to be substituted with greener alternatives and phased out by 2050.*

2 *Today, South Africa consumes ~180 Petajoules per annum (PJ/a) of gas, predominantly in the synfuels sector (110 PJ/a) and the industrial sector (70 PJ/a), which supports up to 56 thousand (k) jobs across the value chain, generates up to ZAR215 billion (bn) in taxable revenue, and contributes ~1–2% of GDP.*

3 *All of today's gas demand is located in Gauteng (50 PJ), Mpumalanga (110 PJ) and KwaZulu-Natal (KZN) (20 PJ), supplied by gas from Pande-Temane in Mozambique (~160 PJ) via the ROMPCO pipeline and from Sasol operations – around 20 PJ of Methane Rich Gas – to KZN via the Lilly pipeline. Industrial consumers currently pay ~ZAR30–90/GJ for the gas from Pande-Temane.*

4 *The reserves of the Pande-Temane gas fields are declining, and supply is expected to be constrained from about 2025 onwards, presenting a supply risk if additional gas cannot be sourced at an affordable price. This poses a risk to the decarbonisation ambitions of key sectors in the South African economy, which will rely on gas as a transition fuel or low carbon feedstock. A future with no additional gas could lead to more cumulative emissions in the long-run across the synfuels, power and industrial sectors, due to the extended use of coal and diesel in the absence of greener alternatives.*

5 *South Africa's potential future gas demand will be driven by four key sectors with proven use cases for gas as a transition fuel or lower emission feedstock:*
*1) **Power**: Use gas in gas-to-power (GTP) plants to enable a high penetration of renewable energy in the power system by providing the flexible capacity to manage the long-duration intermittency, which battery storage cannot currently address.*
*2) **Synfuels**: Introduce additional gas to enable the phase-out of significantly more carbon-intense coal feedstock in the production of liquid fuels.*
*3) **Industry**: Phase out higher emitting coal, and to a lesser extent diesel, with additional gas as an energy source for industrial heat generation and other processes.*
*4) **Transport**: Use gas as an alternative to diesel, albeit at a small scale, for heavy-duty (predominantly >15 tonne) commercial road transport in the short- to mid-term while alternative greener technologies mature and become economically viable.*

6 *South Africa's actual future gas demand will be influenced by whether consumers can afford the delivered price of gas as an alternative energy source and feedstock. As an alternative to diesel, the power sector can afford gas, for predominantly peaking capacity, at delivered prices of up to ZAR300/GJ, whilst the transport sector's affordability threshold for gas is ZAR100–300/GJ. These affordability thresholds are the highest because of the high price of diesel. Synfuels has the lowest affordability threshold, and the industrial sector's affordability threshold is less than ~ZAR135/GJ, given the relatively cheap cost of the coal alternative.*

7 *Four scenarios are considered, structured on two key variables: whether additional gas supply is available; and the level of decarbonisation ambition. Cumulative emissions, across sectors, for scenarios with no additional gas are 400–600 Mt higher than scenarios with additional gas supply, due to the prolonged use of more carbon-intense fossil fuels like diesel and coal, before greener alternatives become economically viable. In scenarios that do allow for additional gas supply, 2030 demand ranges from ~230–550 PJ/a in a low vs. high gas demand scenario, with peaks of ~330 PJ/a and 800 PJ/a post-2030, respectively. In both scenarios, gas would either need to be phased out by 2050 via green alternatives like green* H_2*, or the residual emissions captured with Carbon Capture Utilisation and Storage (CCUS) or Direct Air Carbon Capture and Storage (DACCS). Across these scenarios, cumulative emissions from gas amount to 250–690 Mt, equivalent to 3–9% of an 8 Gt carbon budget for South Africa.*

8 *In both high and low gas demand scenarios, inland gas demand in Gauteng and Mpumalanga exceeds the capacity of South Africa's only major gas pipeline, ROMPCO, which has a capacity of ~210 PJ/a, and supplies the inland market. Inland gas demand reaches 280 PJ/a by 2030 in the high scenario, and 220 PJ/a by 2035 in the low scenario. Therefore, in both scenarios new midstream gas supply infrastructure may be required by 2030–2035. This decision on midstream infrastructure can be deferred at least until 2023.*

9 *The scale, pace of deployment, and location of GTP peaking plants in the power sector are critical swing factors to the quantum and location of demand. Given the high affordability threshold of GTP, it can serve as a demand anchor to enable the optimal supply option for South Africa. It is therefore critical that energy planning policy gives clarity to the deployment, operating regime, and location of GTP plants beyond 2030.*

10 *Potential supply options vary over the short- (2021–2024), mid- (2024–2030), and long-term (2030+). In the short- to mid-term, key options are extending piped gas supply from Pande-Temane via technical work on the reserves, and Liquified Natural Gas (LNG) via Floating Storage Regasification Units (FSRUs). The amount of additional gas available from Pande-Temane is not fixed, given contractual and technical uncertainties. However, this gas is the most cost-competitive of all options. In the long-term, potential supply options, in addition to LNG, are piped gas from Rovuma and potentially other Mozambique gas fields, and gas from exploration activities in South Africa's Brulpadda and Luiperd gas fields.*

11 *All supply and demand-side infrastructure needs to be assessed with a lens to minimise the risk of carbon lock-in and stranded assets. All investments considered should be financially resilient to future drops in demand and costs related to potential repurposing of gas infrastructure, for example, to enable a substitution of gas with green* H_2*, its derivatives or sustainable sources of carbon.*

12 Considering South Africa's supply options, five strategic gas infrastructure pathways exist: 1) No additional gas supply; 2) Piped gas and exploration – Rovuma and Brulpadda; 3) Piped gas only – Rovuma only; 4) Exploration only – Brulpadda only; and 5) LNG. The LNG pathway emerges as optimal for South Africa because of the socio-economic benefits it yields, and the inherent flexibility to ramp down supply post-2040 and minimise the risk of stranded assets and gas infrastructure lock-in.

- **Pathway 1**: A no additional gas supply pathway has the lowest infrastructure lock-in risk, but also the lowest socio-economic benefit, and leads to ~400–600 Mt higher cumulative emissions in the long-run. Given the higher carbon-intensity of alternatives, this pathway could yield higher carbon tax burdens for consumers.
- **Pathways 2–4**: These are only relevant in a high demand scenario and present a high risk of stranded assets and carbon lock-in, with large capital investments of ~ZAR70–200 bn required. Rovuma piped gas, in particular, is highly complex with significant political and security risks to be addressed. Extracting gas from Brulpadda and Luiperd may also be technically complex , which could further increase the cost of these pathways.
- **Pathway 5**: The LNG pathway is optimal for South Africa given the flexibility it provides, due to shorter lead times as demand ramps down post-2040 to achieve net-zero, and due to the positive socio-economic benefits it brings. The negative impact on the trade balance will need to be offset by new green export industries, such as a South African e-fuels industry.

13 Within the LNG pathway, a multi-hub approach with FSRUs in Matola, Richards Bay, Coega and Saldanha is assessed. In addition to Matola as a supply option, developing all three South African FSRUs in parallel emerges as the optimal supply scenario for South Africa, given the higher socio-economic impact and increased bargaining power for consumers, which will potentially yield a more competitive delivered LNG price. A scenario where Richards Bay is not developed restricts and locks the inland market into supply from Matola and should, therefore, be avoided.

14 Developing the three FSRU hubs in parallel will require limited CAPEX, focused on the FSRU and port modifications, with a maximum FSRU CAPEX of ZAR50 bn across scenarios. Critically, should an alternative greener technology for peaking support arise beyond 2035, the net present value of the investment at risk in a low demand power scenario is ~ZAR7 bn. This value at risk is relatively low, compared to the ZAR14–28 bn in OPEX saving arising predominantly from cheaper gas prices relative to diesel prices, and should not inhibit technology switching, particularly in the context of a higher carbon price.

15 South Africa must establish the enabling policy and commercial framework to: 1) Procure gas on an aggregated basis and achieve economies of scale; 2) Enable supply infrastructure within the time and to the scale of the gas demand required; and 3) Manage the risk of unconstrained demand and stranded supply infrastructure, for example, by putting in place phase-out targets. A detailed view on the gas supply-demand economics and affordability across all sectors should inform the Gas Master Plan which should in turn provide clarity on the long-term demand and preferred supply pathway for South Africa. Policy and specific stakeholder engagement platforms should also be leveraged to promote investment, drive public-private partnerships and bilateral relations with Mozambique, and to invest in research and development for solutions to address methane leakage and repurposing of gas infrastructure.

3.1 SCOPE AND APPROACH OF THE ANALYSIS ON THE ROLE OF GAS

> ***As South Africa decarbonises its economy, gas can, if affordably supplied, play a key role as a transition fuel to replace more emissions-intensive fossil fuels like coal and diesel, and provide flexible capacity to enable a rapid scale-up of renewables, until alternative energy storage solutions and greener fuels become affordable. New investments in gas infrastructure should consider the future repurposing of the assets for the usage of green gases (e.g., green hydrogen blends or green hydrogen). For South Africa to achieve a net-zero 2050 target, gas will need to be substituted with greener alternatives and phased out by 2050.***

To avoid catastrophic climate change, the world needs to rapidly decarbonise and limit global warming to 1.5 °C above pre-industrial levels.[14] Achieving this would require a reduction in global emissions of 45% relative to 2010 levels, by 2030, and to net-zero by 2050. A global transition to net-zero emissions requires a phase-out of fossil fuels. This also implies a long-term move away from natural gas. However, in the transition to net-zero, natural gas can play a key role in enabling the rapid phase-out of more carbon-intense fossil fuels, like coal, and oil products such as diesel. For example, natural gas can provide flexible power generation capacity to manage the variability in renewable energy (RE) dominant power systems. Gas can also play the role of a transition fuel to reduce emissions in heavy-emitting, energy-intensive sectors until greener alternatives become economically viable.

The International Energy Agency (IEA) finds in its *Net Zero by 2050* report, that the global share of fossil fuels in the energy mix will need to reduce from ~80% in 2020 (oil: 30%; coal: 26%; and natural gas: 23%) to ~20% in 2050 – with natural gas accounting for more than 50% of residual fossil fuels in 2050. Natural gas demand declines by 55% by 2050, with residual gas remaining for the following:

- More than 65% of the residual gas is paired with CCUS technology, predominantly for energy production,[15] like heat generation and liquid fuel production, and to a lesser extent in the power and industrial sectors.
- Approximately 15–20% of the residual gas is used for the production of non-energy products, for example, as a feedstock in the production of non-combustible chemicals.
- Approximately 15–20% of the remaining gas demand is linked to the unabated use of gas mainly in the industrial sector, but also in energy production, as well as in the power and building sectors.[16]

South Africa's economy is heavily reliant on coal as an energy source and industrial feedstock. This makes South Africa today one of the most carbon-intensive economies, with the 14th highest emissions intensity globally when indexed to GDP.[17] It will be critical for South Africa to decarbonise its economy to contribute to the global effort to mitigate the impact of climate change, to manage emerging trade risks and maintain competitiveness in the context of ambitious climate action across markets. This study finds that natural gas will play a critical role in enabling the phase-out of coal and diesel across South Africa's economy – particularly in the power and petrochemicals sectors – in line with the IEA *Net Zero by 2050* findings.

Gas can enable the integration of renewable energy at scale in the power sector, the phase-out of coal as a feedstock in the production of synthetic fuels (synfuels), the phase-out of coal and diesel as energy sources in broader industry, and the transition away from diesel in heavy transport. South Africa's gas consumption will need to ramp down over time to ensure the country can achieve net-zero emissions by 2050. A ramp-down and eventual phase-out of gas in South Africa is of particular importance in a national context where CCUS, which is the pre-requisite for prolonged use of gas in a net-zero scenario, is potentially unfeasible, given the current lack of proven suitable storage sites.[18] South Africa also has a unique socio-economic context with high levels of inequality, poverty, unemployment and sovereign debt. Therefore, the role of gas for South Africa is two-fold. Firstly, gas can set the country on a net-zero trajectory by serving as an interim, lower-carbon energy source and industrial feedstock. Secondly, gas can enable a Just Transition by addressing some of the existing socio-economic and energy security challenges in South Africa.

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[14] IEA, 2018. *Special Report on Global Warming of 1.5 °C.*

[15] Gas is used with CCUS predominantly to generate heat and produce liquid fuels, with ~33 Exajoules (EJ) of natural gas converted to hydrogen with CCUS in 2050.

[16] IEA, 2021. *Net Zero by 2050 – A Roadmap for the Global Energy Sector.*

[17] World Bank, 2018.

[18] NBI-BUSA-BCG, 2021. 'Decarbonising South Africa's petrochemicals and chemicals sector', pp. 40–43.

Deep dive: The natural gas value chain

The largest component of natural gas is methane. It can also to a lesser extent contain natural gas liquids and non-hydrocarbon gases, like carbon dioxide and water vapour. Natural gas is formed beneath the Earth's surface, with deposits found in oceans and other bodies of water, and on land below sand, silt and other rock formations. Along the gas value chain, upstream activities include the onshore and offshore exploration and production of reserves. Midstream activities involve the transportation, processing and storage of natural gas. Downstream activities refer to end-use applications, such as in the power, synfuels, industrial and transport sectors.[19]

Gas is commonly transported as Compressed Natural Gas (CNG). For CNG, the gas goes through a multi-stage process to compress it to only 1% of its volume. CNG can be transported via pipelines, with the main downstream use case in CNG trucks in the transport sector, where emissions are at least 10% lower than diesel.[20]

Alternatively, natural gas is converted to LNG – wherein the gas is converted to liquid form via liquefaction, reducing the volume of the gas 600 times, requiring less storage space than CNG. LNG can be transported via barrels or converted to CNG and transported via pipelines. The creation of LNG can be more costly but is the most viable option for long-distance gas transportation. There are a range of downstream uses for LNG, from power to synfuels, to heavy-duty trucks, with LNG emitting up to 40% less than the alternative of coal for downstream power generation.[21]

LNG can either be purchased on the spot market, commonly for smaller volumes of gas, or it can be purchased at negotiated contract prices for specific, typically larger, gas volumes. Gas spot prices ranged from **~ZAR70/GJ** in January 2020 (Japan Korea Marker ~ZAR70/GJ; Dutch TTF ~ZAR60/GJ; and US Henry Hub ~ZAR35/GJ), up to **more than ~ZAR470/GJ** in January 2021 (Japan Korea Marker ~ZAR450/GJ; Dutch TTF almost ZAR150/GJ; and US Henry Hub ~ZAR40/GJ).[22] LNG is also priced on Brent Crude prices – ranging from 9–15% of Brent prices. LNG spot prices can be volatile, variable, and therefore, unpredictable over geography and time – although there are contracts and agreements to mitigate this volatility. Contracted LNG prices are fixed for the duration of the contract.

There are varying views on the role of gas as a transition fuel, with much dispute on whether it plays a role in the path to net-zero. As such, this report holistically assesses the role of gas in South Africa's decarbonisation by answering seven key questions:

1. What are the gas supply-demand dynamics in South Africa today?
2. What are the key drivers of future gas demand and what volumes of gas demand could these drivers yield for South Africa over time?
3. What local, regional and global supply options are available to bridge diminishing supply?
4. What long-term strategic gas infrastructure pathways are available to maximise value for South Africa and to set the country on a net-zero trajectory?
5. How can South Africa mitigate and manage the risk of stranded assets and a carbon lock-in?
6. What are the key signposts on gas to monitor in the next 10–15 years?
7. What are the urgent no-regret actions required to unlock gas as a transition fuel for South Africa?

Gas scenarios referenced in this report

This report references a range of gas scenarios and options across both the supply and demand side of the gas value chain. These include:

Gas demand scenarios: Projections of South Africa's potential demand for gas in key sub-sectors from 2020–2050 based on the economy's level of decarbonisation ambition, end user affordability and the availability of additional gas supply.

Gas supply options: Upstream local, regional and global LNG supply options available to meet future gas demand.

Strategic gas infrastructure pathways: Upstream and midstream long-term (post-2030) supply infrastructure pathways to enable supply options.

LNG scenarios: Combinations of LNG infrastructure options to enable LNG supply to South African end users.

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[19] US Energy Information Administration, 2020. 'Natural Gas Explained'.

[20] UK Government, 2021. *GHG Conversion Factors for Company Reporting.*

[21] Coal is also approximately 1.5–2.5 times more emissions-intensive along the value chain than gas for power generation. See 'Appendix 2.5 Comparison of the value chain emissions of gas vs coal' on "Appendix 2.5 Comparison of the value chain emissions of gas vs coal" on page 67.

[22] Shell, 2021. *LNG Outlook 2021.*

Photo: Shutterstock.com

A semi-submersible drilling rig moored in Cape Town harbour for maintenance

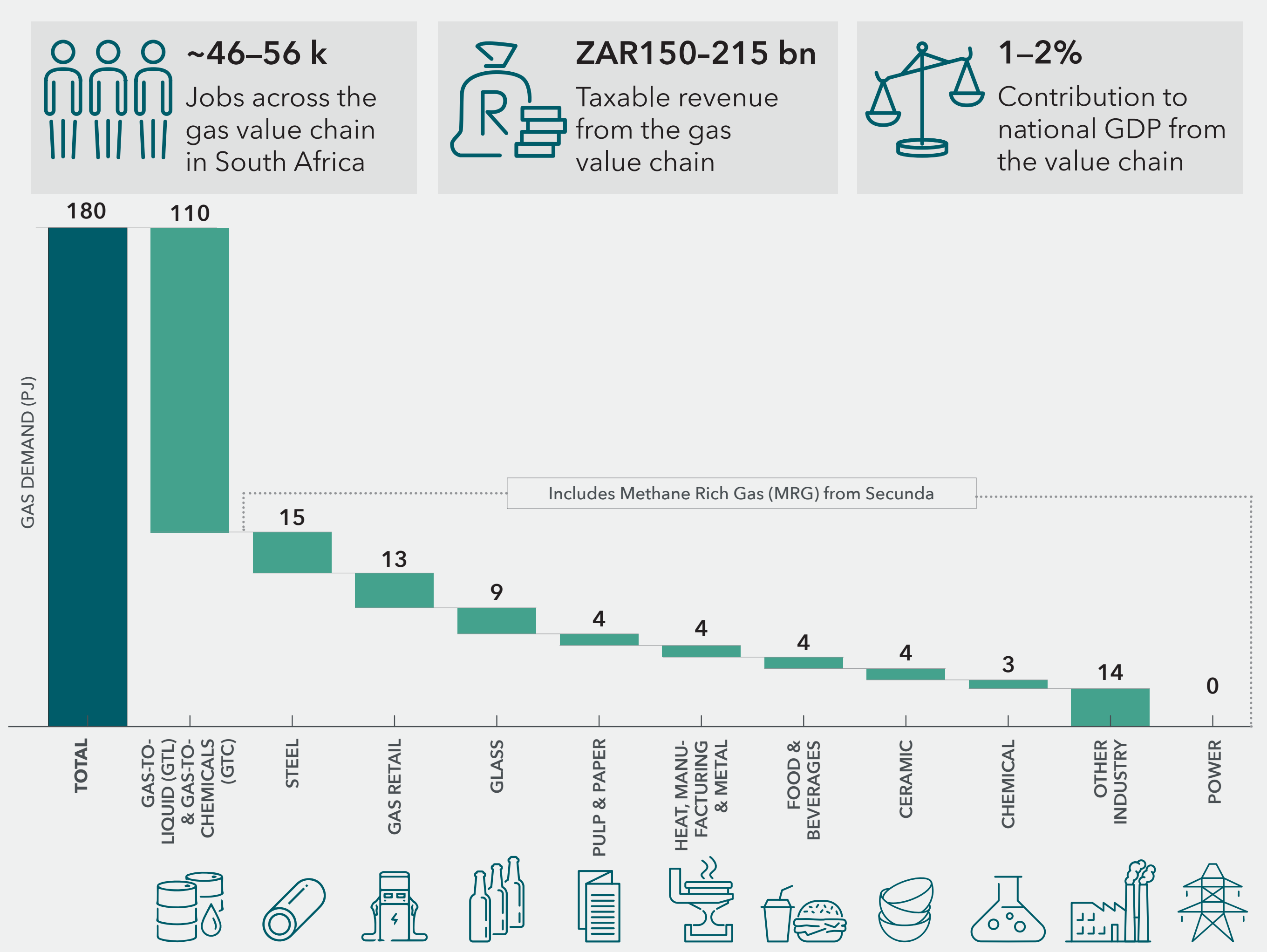
3.2 THE ROLE OF GAS IN SOUTH AFRICA'S PATH TO NET-ZERO

3.2.1 WHAT ARE THE GAS SUPPLY-DEMAND DYNAMICS IN SOUTH AFRICA TODAY?

> *Today, South Africa consumes ~180 Petajoules per annum (PJ/a) of gas, predominantly in the synfuels sector (110 PJ/a) and the industrial sector (70 PJ/a), which supports up to 56 thousand (k) jobs across the value chain, generates up to ZAR215 billion (bn) in taxable revenue, and contributes ~1-2% of GDP.*

South Africa currently consumes ~180 PJ of gas per annum – driven by the petrochemicals and chemicals sector, which uses gas as a feedstock for gas-to-liquid (GTL) and gas-to-chemicals (GTC) processes, and to a lesser extent, by the industrial sector, which uses gas primarily for industrial heating. The petrochemicals and chemicals sector consumes ~110 PJ/a, with industrial sectors like steel, gas retail, glass, pulp and paper, consuming ~70 PJ/a. Household consumption of gas today is negligible at ~1 PJ/a, and as such is excluded from the baseline (Figure 4).[23] Despite its relatively low share in South Africa's total energy mix, the gas value chain has a significant socio-economic impact. Between 46–56 k jobs are created along the gas value chain, contributing to ZAR150–210 bn in taxable revenue,[24] and resulting in an overall GDP contribution of 1–2%.[25]

Figure 4: Overview of the gas value chain in South Africa today (2020)



Note: Gas demand excludes any latent unmet demand and historic PetroSA demand.

Source: Quantec baseline SAM; Capital IQ; Sappi Annual Integrated Report 2019; ArcelorMittal audited financial statements 2019; AECI 2019 Annual Integrated Report; Omnia Integrated Annual Report 2019, StatsSA; NBI-BCG project team.

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[23] IGUA, 2021. *Annual Report of The Industrial Gas Users Association – Southern Africa 2019;* Egoli gas, 2021.

[24] Taxable revenues refer to the total revenue which is taxed by the government.

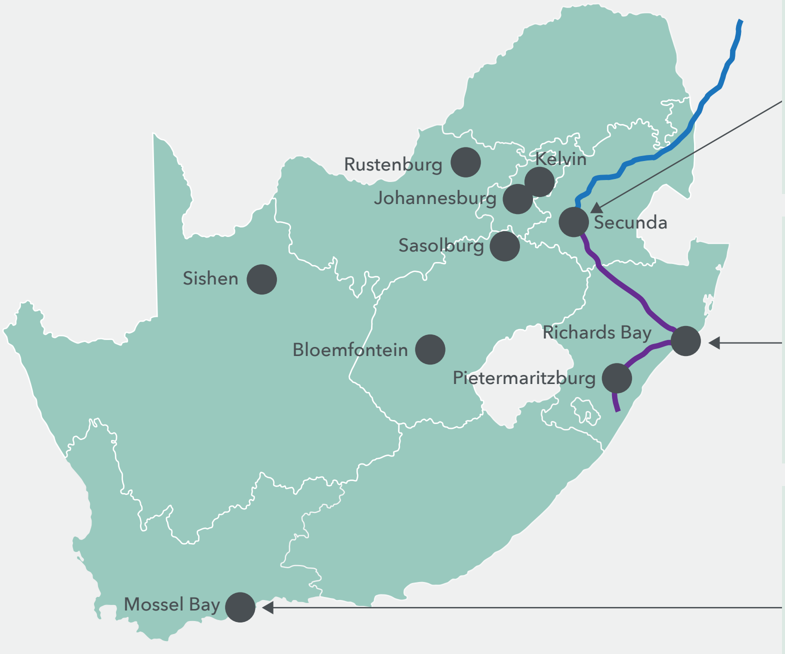
[25] Quantec Baseline Social Accounting Matrix for South Africa (2020).

> ***All of today's gas demand is located in Gauteng (50 PJ), Mpumalanga (110 PJ) and KwaZulu-Natal (KZN) (20 PJ), supplied by gas from Pande-Temane in Mozambique (~160 PJ) via the ROMPCO pipeline and from Sasol operations – around 20 PJ of Methane Rich Gas – to KZN via the Lilly pipeline. Industrial consumers currently pay ~ZAR30–90/GJ for the gas from Pande-Temane.***

Regionally, South Africa's gas demand is clustered in Gauteng, Mpumalanga and KZN. Most of South Africa's gas demand, 110 PJ/a, is centred around the Secunda-Sasolburg complex in Gauteng and Mpumalanga. Other industrial users in Gauteng and Mpumalanga account for an additional ~50 PJ/a in this region, with the remaining ~20 PJ/a accounted for by industrial users in KZN. These demand hubs are primarily supplied with gas from the Pande-Temane gas fields in Mozambique via the ROMPCO pipeline. From the ROMPCO pipeline, which terminates in Secunda, a series of transmission pipelines and distribution networks transport gas to the various end markets. Natural gas from Mozambique supplied via ROMPCO accounts for ~160 PJ/a of total supply, whilst an additional ~20 PJ of Methane Rich Gas (MRG) is supplied from Sasol's Secunda operation to meet the country's gas demand.[26] The MRG is dedicated to supply industrial users in KZN via the Lilly pipeline, which is owned by Transnet (Figure 5).[27]

Until 2020 South Africa's gas demand was up to 70 PJ higher per annum, due to the operations of PetroSA's GTL refinery in Mossel Bay in the Western Cape, according to the IGUA estimates.[28] Block 9 supplied this refinery with gas while it was still operational. However, the Block 9 reserves are assumed to be exhausted as of the end of 2020, and given the halting of production of PetroSA's refinery this consumption is excluded in the 2020 demand baseline.[29]

Figure 5: Regional based view of gas demand in South Africa (2020)



Gauteng and Mpumalanga: ~160 PJ/a

- Synfuels demand for gas ~110 PJ/a supplied via ROMPCO and a transition pipeline.
- Sasol supplies ~50 PJ/a of gas to inland facilities, like Egoli Gas and other steel industry players, that neighbour Secunda.

Kwa-Zulu-Natal: ~20 PJ/a

- Supported by Lilly pipeline, connected from the end terminal of ROMPCO pipeline in Secunda to Richards Bay.
- The Lilly pipeline supplies MRG to industrial clients within Richards Bay industrial zone mostly focused on refinery operations.

Western Cape: 72 PJ/a

- Supply from Block 9 supplied PetroSA's gas-to-liquid refinery in Mossel Bay, though this is assumed to be exhausted as of the end of 2020.

● Demand nodes
— ROMPCO pipeline
— Lilly pipeline

⚠ Pande-Temane is South Africa's only major gas supply today via the ROMPCO pipeline. This supply is at risk with reserves declining from ~2025, but can be supplemented with capital investments on existing assets and LNG.

Note: ROMPCO = Republic of Mozambique Pipeline Company; MRG = Methane rich gas; GTL = Gas-to-liquid; LNG = Liquified Natural Gas.

IGUA 2020 Annual Report; Sasol Production Reports; Sasol Form 20F 30 June 2021; Expert interviews; NBI-BCG Project Team.

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[26] MRG is a by-product of Secunda's production process.

[27] IGUA, 2021.

[28] There is uncertainty about the annual gas consumed by PetroSA, but the 70 PJ/a baseline is aligned the estimates of IGUA.

[29] IGUA, 2021.

The South African gas industry is regulated by the *Gas Act 48 of 2001* (Gas Act). The Gas Act serves to regulate natural gas prices and pipeline tariffs and falls under the auspices of the National Energy Regulator of South Africa (NERSA), which reports to the Department of Mineral Resources and Energy (DMRE).[30] While LNG is currently not consumed in South Africa, the Gas Act also makes provisions for regasification licences and regulated LNG prices to bring in new LNG.

From a commercial perspective, South Africa's gas supply from Pande-Temane is managed under the Petroleum Production Agreement (PPA), which was signed in 2000 by Sasol, Empresa Nacional de Hidrocarbonetos (ENH), Companhia Moçambicana de Hidrocarbonetos (CMH) and the Government of Mozambique. The agreement covers the development and production of the gas resources from the Pande-Temane reserves.[31]

> ***The reserves of the Pande-Temane gas fields are declining, and supply is expected to be constrained from about 2025 onwards, presenting a supply risk if additional gas cannot be sourced at an affordable price. This poses a risk to the decarbonisation ambitions of key sectors in the South African economy, which will rely on gas as a transition fuel or low carbon feedstock. A future with no additional gas could lead to more cumulative emissions in the long-run across the synfuels, power and industrial sectors, due to the extended use of coal and diesel in the absence of greener alternatives.***

The supply of gas from Pande-Temane is structurally cost-advantaged, with downstream industrial users of this gas paying in the range of ~ZAR30–90/GJ today.[32] This is almost half of what LNG could cost on a long-term contract basis and less than 5–10 times the average spot market prices in October 2021.[33] However, the reserves of gas at Pande-Temane are declining and supply is anticipated to be constrained from around 2025 onwards. This presents a security of supply issue and poses a risk to the decarbonisation ambitions of key sectors in the South African economy, which could rely on gas as a transition fuel.[34]

If new gas can be affordably supplied, addressing the Pande-Temane supply risk, gas could play a transitionary role in the decarbonisation of South Africa's economy as a substitute for diesel and coal until alternative green technologies become economically viable.

However, if South Africa is unable to access a new, affordable gas supply, a future with no gas could result in higher cumulative carbon emissions, due to a delayed phase-out of coal and diesel across sectors. This could in turn put the emission reduction targets underpinning South Africa's latest NDC at risk. In the power sector in particular, where gas could be a less carbon-intense alternative to diesel as a fuel for the provision of predominantly peaking capacity, being unable to access affordable gas could result in a prolonged use of diesel peaking capacity. This prolonged use of diesel could lead to higher operational expenditure due to the higher cost of diesel compared to gas (see 'Deep dive: The trade-offs of switching to gas from diesel in the power sector pre-2035', on page 53).

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[30] South African Government. *Gas Act 48 of 2001.*

[31] Instituto Nacional De Petroleo, 2014. *Pande & Temane PPA Area.*

[32] IGUA, 2021.

[33] EIA, 2022. *Natural Gas Weekly Update – October 2021 natural gas spot price.*

[34] Sasol, 2021. Form 20F.

3.2.2 WHAT ARE THE KEY DRIVERS OF FUTURE GAS DEMAND AND WHAT VOLUMES OF GAS DEMAND COULD THESE DRIVERS YIELD FOR SOUTH AFRICA OVER TIME?

> *South Africa's potential future gas demand will be driven by four key sectors with proven use cases for gas as a transition fuel or lower emission feedstock:*
> *1) **Power**: Use gas in gas-to-power (GTP) plants to enable a high penetration of renewable energy in the power system by providing the flexible capacity to manage the long-duration intermittency, which battery storage cannot currently address.*
> *2) **Synfuels**: Introduce additional gas to enable the phase-out of significantly more carbon-intense coal feedstock in the production of liquid fuels.*
> *3) **Industry**: Phase out higher emitting coal, and to a lesser extent diesel, with additional gas as an energy source for industrial heat generation and other processes.*
> *4) **Transport**: Use gas as an alternative to diesel, albeit at a small scale, for heavy-duty (predominantly >15 tonne) commercial road transport in the short- to mid-term while alternative greener technologies mature and become economically viable.*

Future demand for gas in South Africa will be driven primarily by four key sectors, where gas has proven use cases globally as a transition fuel or lower emission feedstock, namely: 1) electricity; 2) synfuels; 3) transport; and 4) broader industry, which includes for example, manufacturing and construction, and minerals and metals production.

South Africa's future household gas demand is assumed to be negligible. Current household gas demand is ~1 PJ/a, with limited need for additional gas for household heating, given South Africa's warm climate. In addition, significant investment would be required for a more extensive gas distribution network, which could result in stranded assets.

1) Electricity

The electricity sector is the highest emitting sector in South Africa today, accounting for almost 45% of national gross emissions, with 216 Mt CO_2e in 2017.[35] The power sector's emissions footprint is largely due to the sector's heavy reliance on coal-fired generation, with ~40 Gigawatt (GW) installed capacity producing more than ~90% of the total power generation.[36] South Africa is not just challenged by the power sector's high carbon-intensity, but also by the significant power supply security risk. The degradation of the existing coal fleet, coupled with the delayed commissioning and underperformance of Medupi and Kusile, has been a significant contributor to load shedding in recent years.[37] Energy shed has increased from ~190 Gigawatt-hours (GWh) in 2018 to ~1 350 GWh in 2019 and ~1 800 GWh in 2020 (approximately 10% of annual hours).[38]

According to the findings of the 'Decarbonising South Africa's power system' report the combination of renewable energy (130–160 GW), short-term battery storage (15–40 GW), and gas-powered turbines (30–40 GW) is the cheapest option to decarbonise the power system while ensuring energy security.[39]

As the share of renewable energy in the system increases, being able to match supply with demand becomes more challenging given the variable nature of renewable energy technologies like wind and solar plants.[40] Solutions to address this variability are critical for a stable power supply. Battery storage can help address this variability, however there is a technical limit on the extent to which batteries can solve this. Batteries, like Lithium-ion batteries for example, can store and discharge energy over short periods of time, typically 2–6 hours, beyond which the batteries start to lose charge.[41] Additional Lithium-ion batteries can be installed to increase the duration to a maximum of ~10 hours, beyond which the batteries are no longer economically viable and pose other technical risks, like overheating. The main issue with these short discharge periods, is that the stability of the system requires longer durations of variability to be addressed.[42] In an atypical week where wind and solar generation are structurally lower due to unseasonal weather conditions, some form of dispatchable capacity is needed to make up the supply deficit caused by lower than predicted solar

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[35] Department of Forestry, Fisheries, and the Environment (DFFE), 2021. *National GHG Inventory Report – 2017.*

[36] 'Integrated Resource Plan (IRP) 2019', p. 42.

[37] Load shedding refers to the interruption of electricity supply to reduce the load on a generating plant or the generation grid more broadly.

[38] Wright, JG. & Calitz, JR, 2020. 'Systems analysis to support increasingly ambitious CO_2 emissions scenarios in the South African electricity system'. CSIR.

[39] NBI-BUSA-BCG, 2021. 'Decarbonising South Africa's power system', Capacity required by 2050 as outlined on pages 25–29 in the report.

[40] Variable renewable energy sources produce energy intermittently, rather than on-demand because the energy produced is dependent on the weather in terms of the Sun's radiation and the wind's speed.

[41] Lithium-ion batteries, based on current technology, deplete in ~4 hours of full discharge. Increasing this duration is technically viable, but comes at a significant cost.

[42] The system is stable when there is sufficient supply to meet demand.

Photo: Shutterstock.com

and wind capacity factors.[43] Battery storage cannot play this dispatchable role over such a long period of time, with current technology. These atypical weeks are uncommon and may only occur, for example, once a year, but the power system stability needs to be maintained and the system must be designed for the lowest availability of variable generation sources.

Pumped-storage hydroelectricity has a similar duration, typically less than one day, and cost to battery storage, and could, therefore, complement batteries for shorter-term variability management. Platinum mines are a promising potential location for pumped storage in South Africa, but there is a limit on the potential pumped storage capacity available, given geological constraints and the ecological footprint of virgin, undeveloped sites. According to the 'Global Resource Summary' (2021), the potential pumped storage capacity in South Africa is ~25 GW, which is insufficient to meet the system needs of ~60 GW. As such, pumped storage is unlikely to displace battery storage entirely.

New, long-duration, battery storage technology is in the process of being developed, however, none of these technologies are commercially viable at grid-scale yet. It will take time for long-duration battery storage to reach cost parity with gas, even with high carbon tax regimes applied, given the nascency of the technology. Based on the current technological maturity of battery storage, batteries are only affordable for a maximum discharge of ~10 hours, which is insufficient to address all system variability requirements.

Small modular nuclear reactors (SMRs) are also in the process of being developed and piloted, however given the nascency of this technology and the lack of examples of utility scale installations, SMRs remain a key signpost to monitor, but are not currently considered to be a viable alternative.

Better demand-side management could also help manage system variability, however there is a technical and economic limit to how much demand can be sufficiently ramped up or down. For purposes of the power system modelling conducted as part of this study, demand management was limited to ~2.5 GW.

Two supply-side solutions are viable today to address system variability, as outlined above, and to serve as dispatchable capacity – diesel or gas peaking plants. This study concludes that gas is the most techno-economically competitive solution given the high price and significantly higher emissions factor of diesel (see 'Deep dive: The trade-offs of switching to gas from diesel in the power sector pre-2035' on page 53). The consumption of diesel in the power sector, in place of gas, has the potential to increase the system's real relative costs by up to 30c/kWh – compared to the real cost for the system of ~120–160c/kWh.

This study does not see the need for baseload gas, with utilisation >50% in the South African power system, as it is neither the least-cost approach nor a technical requirement for system stability.

In the modelling conducted for the power sector report, gas turbines are limited to primarily peaking generation sources only, with low utilisation of less than 10%. For a limited number of years, where large coal-fired plants are decommissioned, the gas turbines are used for mid-merit purposes with slightly higher utilisation of 10–

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[43] Dispatchable capacity can be deployed on-demand to ensure supply sufficiently meets demand.

30%, however they are later relegated to peaking capacity in the system merit order.

When a greener alternative becomes economically viable, these gas turbines could be converted to run off green H_2 as a feedstock or repurposed to become synchronous condensers for system inertia management in a renewable energy dominant power system, thereby minimising the risk of these assets becoming stranded.

These findings on the role of gas in South Africa's power sector are similar to the findings of the Federation of German Industries (BDI) *Climate Paths 2.0* report for Germany, authored by BCG. This report finds that by 2030 an additional 43 GW of gas capacity will be required, on top of the 31 GW currently installed, to enable the doubling of wind and solar capacity to phase out coal and to ensure the security of the energy supply. To reach the net-zero by 2045 target, these gas turbines will be exclusively run off green gases by 2045.[44] The German Government has also publicly announced that gas will be required as a transition fuel to reach net-zero by 2045.

2) Petrochemicals and chemicals

The petrochemicals and chemicals sector is the second largest emitter in South Africa, with 63 Mt CO_2e (equivalent to more than 10% of gross national emissions) in 2017. More than 90% of the sector's emissions are produced in the heavy-emitting CTL processes, with the emissions intensity of South Africa's CTL refineries ~26 times higher than other local refineries.[45] Decarbonising synfuels operations requires the phase-out of coal as a feedstock, with gas as a potential alternative if affordably sourced and if no greener alternatives mature in the short- to mid-term. Sasol recently announced a 30% emission reduction target by 2030 and a commitment to net-zero by 2050. As part of this announcement, gas plays a key transition role in phasing out coal in the short- to mid-term with 40–60 PJ/a increase in gas consumption by 2030 to enable the aforementioned 30% emissions reduction.[46]

3) Transport

The transport sector is the third largest emitter in South Africa, with 55 Mt CO_2e, driven by predominantly road transport (~50 Mt CO_2e), and to a lesser extent by domestic aviation and rail transport (~4 Mt and 1 Mt CO_2e, respectively)[47]. Gas is not anticipated to play a major role in the decarbonisation of the transport sector, with Battery Electric Vehicles (BEVs) expected to account for most of the decarbonisation of the road transport sector. BEVs are projected to reach cost parity with Internal Combustion Engine (ICE) vehicles used in passenger and light to medium commercial road transport pre-2030, with gas potentially playing an interim role for heavier freight trucks, weighing >15 tonnes, until greener alternatives like Fuel Cell Electric Vehicles (FCEVs) mature.[48]

4) Broader industry

Broader industry, which includes mineral and metal production, manufacturing and construction, emits ~53 Mt CO_2e, of which mineral and metal production emits ~31 Mt CO_2e, and manufacturing and construction ~22 Mt CO_2e.[49] Industry's emissions are driven predominantly by the combustion of coal and diesel for the generation of power and heat. In 2016, 40% of the energy demand in South Africa's broader industry was met by coal and diesel via direct combustion, 10% from gas, 25% from carbon-intensive electricity, and 25% from renewables.[50] The industrial sector could leverage gas to phase out heavy-emitting fossil fuels in the energy mix, until greener alternatives become economically viable. According to industry, up to ~70 PJ/a of latent industrial gas demand exists, predominantly to phase out coal, and to a lesser extent diesel, from the energy mix with a potential emissions reduction of at least 2 Mt per annum.[51]

> ***South Africa's actual future gas demand will be influenced by whether consumers can afford the delivered price of gas as an alternative energy source and feedstock. As an alternative to diesel, the power sector can afford gas, for predominantly peaking capacity, at delivered prices of up to ZAR300/GJ, whilst the transport sector's affordability threshold for gas is ZAR100–300/GJ. These affordability thresholds are the highest because of the high price of diesel. Synfuels has the lowest affordability threshold, and the industrial sector's affordability threshold is less than ~ZAR135/GJ, given the relatively cheap cost of the coal alternative.***

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[44] BCG-BDI, 2021. 'Climate Paths 2.0 – A Program for Climate and Germany's Future Development'.

[45] Sasol Climate Change reports and Annual Reports.

[46] Sasol, 2021. Capital Markets Day presentation.

[47] South Africa's transport sector emissions baseline only includes domestic transport. In the absence of domestic shipping, shipping is not represented in the baseline.

[48] Cost parity in terms of the Total Cost of Ownership (TCO). TCO = Purchase costs + Energy costs + Maintenance costs + Insurance costs - Terminal value after 5 years.

[49] Department of Forestry, Fisheries, and the Environment (DFFE), 2021. National GHG Inventory Report – 2017.

[50] Department of Energy, 2019. *The South African Energy Sector Report 2019.*

[51] BUSA Gas Working Group, 2021. 'Outlook: National gas demand & supply position'.

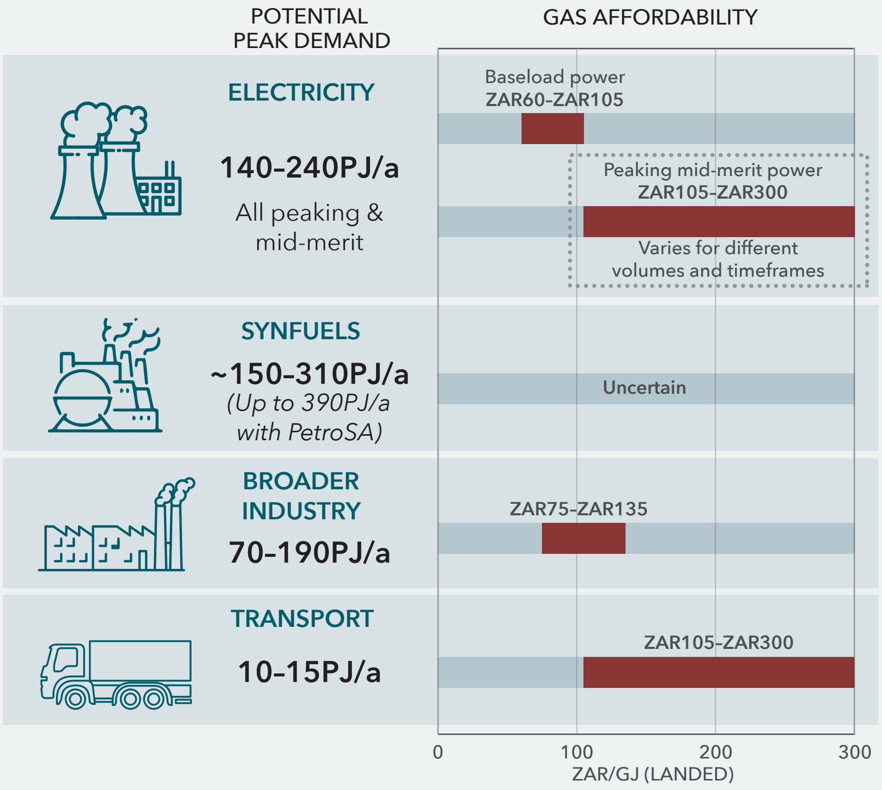
South Africa's actual future gas demand will be influenced by the availability of supply and whether consumers can afford the delivered price of gas into the country. Multiple supply options exist for gas and are covered later in this report. Each end user's affordability threshold is based on how competitive gas is as an alternative energy source or feedstock. The power sector's affordability for gas as a peaking or mid-merit generation source, not baseload, is up to ~ZAR300/GJ,[52] and the transport sector's affordability is around ZAR100–300/GJ (see Figure 6).[53] The power and transport sectors' affordability thresholds are the highest, given the high cost of the diesel alternative. The gas demand in the power sector will largely be influenced by the cost and maturity of greener alternatives, like green H_2, SMR and demand management solutions.

In the transport sector, the uptake of gas in heavy commercial road transport will partly be determined by whether policy choices incentivise FCEVs, which could support the local Platinum Group Metals (PGM) mining industry over CNG trucks for heavy freight transport. The demand for gas for Heavy Duty Vehicles (HDVs) will also be influenced by the cost and technology evolution of BEVs, with potentially lower gas and green H_2 demand if BEVs overcome technological constraints for range and charging time, for example.

In contrast to the power and transport sectors, the synfuels and industrial sectors have much lower affordability thresholds given the relatively low cost of coal, the predominant energy source and feedstock used today.[54] For example, a large portion of South Africa's broader industrial sector can only afford gas prices of less than ~ZAR135/GJ. If gas is not economically viable, the industrial sector will likely extend the use of coal and diesel, until alternative greener technologies like green H_2 and biomass become commercially viable. Alternatively, some businesses risk shutting down operations as they lose competitiveness due to higher energy and/or feedstock costs.

Figure 6: Affordability of gas across sectors

Ensuring the right supply infrastructure pathway is critical to unlocking demand and meeting affordability thresholds



Source: IGUA Annual Report 2020, NBI-BCG project team.

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[52] The power sector's affordability is assessed by comparing the fuel price for gas vs diesel for the turbines in the power sector, given the technology costs are assumed to be similar. The upper bound of the affordability threshold is aligned to the upper bound diesel price of ZAR300/GJ for the OCGTs.

[53] The lower bound of the transport affordability is based off a US benchmark. The upper bound affordability for gas is assessed by estimating the breakeven fuel cost for CNG trucks to reach cost parity with ICE trucks in the NBI-BCG transport TCO model, given the differences in technology costs.

[54] The industrial affordability threshold is developed with the upper limit of current customer affordability range of ZAR45–75/GJ (delivered) and BUSA GWG assumption of ZAR105–140/GJ for latent industrial demand.

> ***Four scenarios are considered, structured on two key variables: whether additional gas supply is available; and the level of decarbonisation ambition. Cumulative emissions, across sectors, for scenarios with no additional gas are 400–600 Mt higher than scenarios with additional gas supply, due to the prolonged use of more carbon-intense fossil fuels like diesel and coal, before greener alternatives become economically viable. In scenarios that do allow for additional gas supply, 2030 demand ranges from ~230–550 PJ/a in a low vs. high gas demand scenario, with peaks of ~330 PJ/a and 800 PJ/a post-2030, respectively. In both scenarios, gas would either need to be phased out by 2050 via green alternatives like green H_2, or the residual emissions captured with Carbon Capture Utilisation and Storage (CCUS) or Direct Air Carbon Capture and Storage (DACCS). Across these scenarios, cumulative emissions from gas amount to 250–690 Mt, equivalent to 3–9% of an 8 Gt carbon budget for South Africa.***

Reflecting these demand and affordability dynamics, four gas demand scenarios are considered (Table 1). The first two scenarios assume a moderate decarbonisation ambition for South Africa, mostly in line with current policy in key sectors, like the Integrated Resource Plan (IRP) in the power sector:

1. **No additional gas supply, high demand scenario** assumes that stated power sector policies are implemented, with additional gas turbines installed but run off diesel instead, in the absence of additional gas supply to South Africa. This scenario assumes that the residual emissions from diesel in the power sector are captured with DACCS in the longer-term to reach net-zero emissions. For the synfuels, transport and industrial sectors, there is no additional gas demand and the use of coal and diesel is extended because both gas and green alternatives are assumed to not be economically viable, even in the long-term.

2. **Additional gas supply, high demand scenario** assumes gas demand significantly increases across all sectors, especially from 2030–2040, given the availability of affordable gas. In the power sector, the IRP and Risk Mitigation Independent Power Producer Procurement Programme (RMIPPPP) are implemented with an increase in private power generation capacity and an increase in additional, non-policy related, peaking gas capacity to address the power supply insecurity and the peaking needs of the system.[55] In the absence of other economically viable green alternatives, the residual emissions from gas are offset with DACCS technology leading up to 2050 to reach net-zero emissions. This scenario also assumes that additional gas is consumed in the synfuels sector and broader industry, in line with the upper bound of Sasol's commitments and industry's estimates.

The second two scenarios assume a higher level of decarbonisation for South Africa – leveraging more disruptive green technology and phasing out coal earlier:

3. **No additional gas supply, low demand scenario** assumes that greener alternatives become commercially viable in the longer-term. For the power sector, this scenario assumes an accelerated ramp-up of renewable energy and an early decommissioning of the coal-fired power capacity, with all coal power capacity being decommissioned by 2042. The long duration flexibility needs of the power system are met predominantly with diesel peaking capacity. As in the no additional gas supply, high demand scenario, the use of coal and diesel are extended in the synfuels and industrial sectors in the short- to mid-term (pre-2040), with no additional gas consumption beyond the current consumption of 180 PJ/a. Across sectors, residual coal, gas, and diesel consumption is phased out in the mid-to long-term as greener alternatives become economically viable.

4. **Additional gas supply, low demand scenario** assumes that gas is affordable in the short- to mid-term. In the power sector, gas is consumed in GTP plants to address the peaking needs of the system, but the policy commitments of the IRP and RMIPPPP are not implemented. The synfuels sector also consumes additional gas, beyond current consumption, while the transport sector and broader industry's gas consumption remains mostly in line with current levels. Across sectors, gas is phased out over time as green alternatives become economically viable in the mid- to long-term in line with the no additional gas supply, low demand scenario.

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[55] Additional GTP capacity required for the reliability of the power system, as outlined in the NBI-BCG net-zero power sector report (see Table 1).

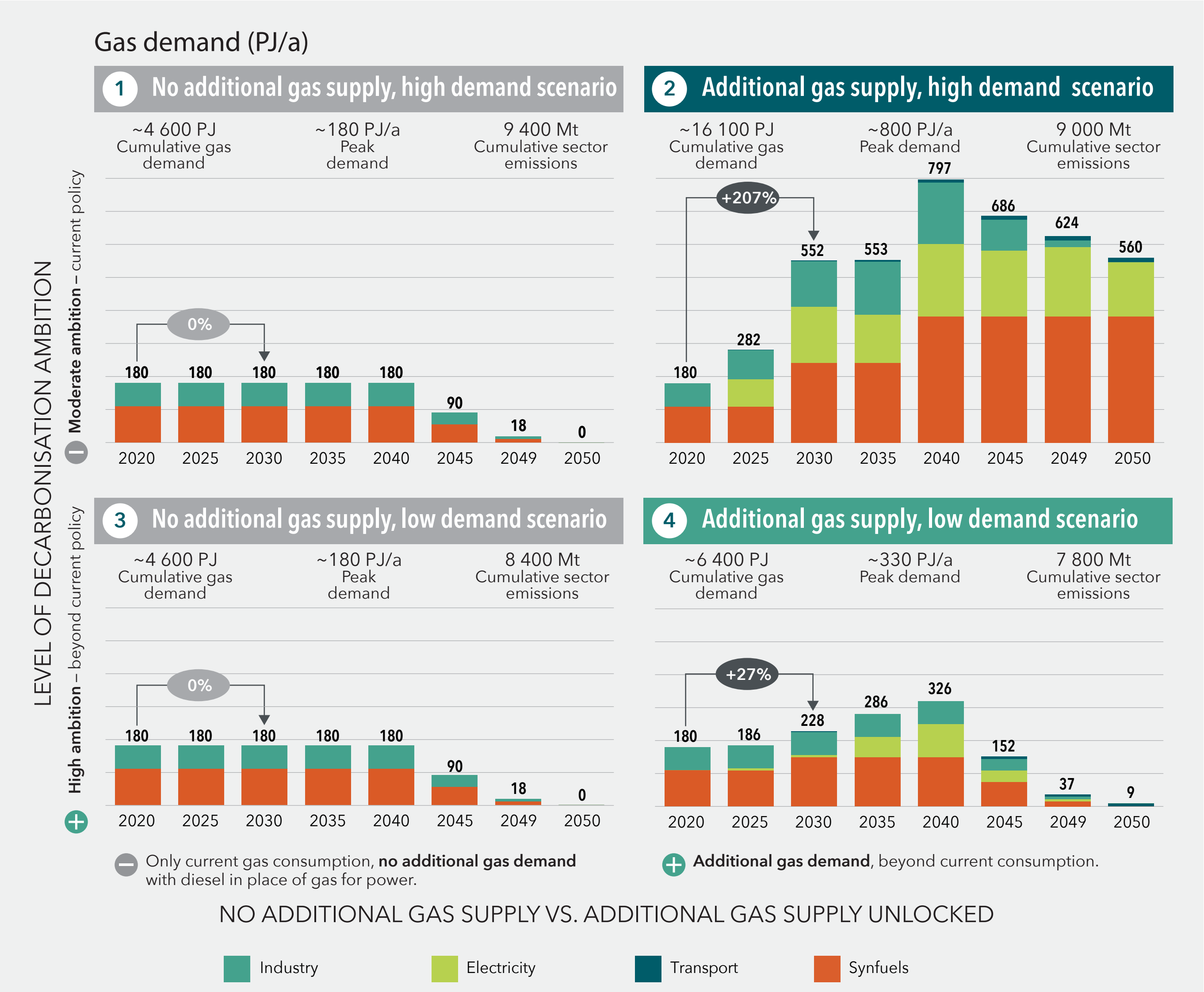
Table 1: Four gas demand scenarios

		NO ADDITIONAL GAS SUPPLY VS. ADDITIONAL GAS SUPPLY UNLOCKED	
		⊖ No additional gas, only current gas consumption	Additional gas, beyond current gas consumption ⊕
LEVEL OF DECARBONISATION AMBITION	⊖ Moderate ambition – current policy	**1. No additional gas supply, high demand scenario**	**2. Additional gas supply, high demand scenario**
		a) **Electricity**: Mid-merit and peaking needs of system met with diesel, complemented with DACCS post-2040 (Power sector pathway: IRP gas and DACCS path with diesel in place of gas).	a) **Electricity**: Gas demand ramps up with current policy pre-2030, additional Open Cycle Gas Turbines (OCGT) and Closed Cycle Gas Turbines (CCGT) capacity post-2030 and DACCS post-2040 (Power sector pathway: IRP gas and DACCS path).*
		b) **Synfuels**: Gas demand remains flat at current levels (~110 PJ/a) to 2040, linearly ramping down to 0 PJ/a 2040–2050.	b) **Synfuels**: Gas ramps up to ~20% of Secunda feedstock by 2030 (+60 PJ/a) and ~40% by 2040 (+ ~140 PJ/a); PetroSA revived with demand of ~70 PJ/a by 2030.
		c) **Industry**: Gas demand remains flat at current levels (70 PJ/a) to 2040, linearly ramping down to 0 PJ/a 2040–2050.	c) **Industry**: Gas economically viable, unlocking 72 PJ/a latent demand pre-2030 to phase out coal, growing by 3% post-2030 in line with GDP and ramping down to 0 PJ by 2050.
		d) **Transport**: Gas demand remains flat at current levels of 0 PJ/a.	d) **Transport**: Gas demand increases to 2 PJ/a by 2030 (15 PJ/a by 2050), in line with the IEA Reference Technology scenario.
	⊕ High ambition – beyond current policy	**3. No additional gas supply, low demand scenario**	**4. Additional gas supply, low demand scenario**
		a) **Electricity**: Mid-merit and peaking needs of system met with diesel, until green H_2 available from ~2040 (Power sector pathway: low emissions green H_2 path with diesel in place of gas).	a) **Electricity**: Gas demand peaks in ~2035 in line with coal decommissioning and is substituted with green H_2 from ~2040 (Power sector pathway: low emissions green H_2 path with diesel in place of gas).
		b) **Synfuels**: Aligned to the no additional gas supply scenario – current consumption to 2040.	b) **Synfuels**: Gas demand increases by 40 PJ/a by 2030, in line with ~20% gas feedstock for Secunda, ramping down to 0 PJ/a post-2040; PetroSA not revived.
		c) **Industry**: Aligned to the no additional gas supply scenario – current consumption to 2040.	c) **Industry**: Aligned to the no additional gas supply scenario.
		d) **Transport**: Aligned to the no additional gas supply scenario – no gas consumption.	d) **Transport**: Gas demand increases to 2 PJ/a by 2030 (10 PJ/a by 2050) in line with the IEA Sustainable Development scenario.

Note: * Pre-2030 gas capacity as per current policy: IRP (3 GW), RMIPPPP (1 GW), conversion of existing OCGTS (3.8 GW) and latent private power demand (1.4 GW) with additional CCGT and OCGT capacity post-2030, as per Plexos pathways with some residual gas capacity in 2050.

Source: NBI-BCG analysis.

Figure 7: Cumulative gas demand, peak gas demand and net cumulative emissions across demand scenarios



Note: Cumulative emissions are net of any negative emissions technology (e.g., DACCS).

Source: NBI-BCG analysis.

These assumptions yield gas demand ranges as shown in Figure 7 above.

Across scenarios, there is at least 180 PJ/a of gas demand up until 2040, assuming current consumption persists and there is no closure of any major synfuels or industrial assets. Cumulative demand varies greatly though depending on the scenario, and ranges from 4 600 PJ–16 100 PJ over the next 30 years.

Scenarios with no additional gas being supplied beyond current supply levels today (scenarios 1 and 3) result in more cumulative, economy-wide emissions than scenarios that do allow for additional gas supply (scenarios 2 and 4). For example, in the high demand scenarios 1 and 2, if no additional gas is supplied, cumulative emissions are ~400 Mt higher over a 30-year period than if additional gas was available to meet demand. This is due to gas displacing higher emitting alternatives in the economy, like diesel and coal, in the absence of greener alternatives being available (see Appendix 2.2 for an overview of the cumulative emissions calculation).

Across all scenarios, the emissions from gas are relatively low, only 250–690 Mt in the low and high additional gas supply scenarios (scenario 2 and 4), and only 150 Mt of emissions in the no additional gas scenarios (scenarios 1 and 3). These emissions translate into a 3–9%[56] direct contribution to cumulative emissions and a net negative impact on cumulative emissions, given the higher emitting fossil fuels that gas displaces. Although some re-optimisation may be required to comply with an 8 Gt carbon budget, the role for gas in further emissions reductions may be limited.

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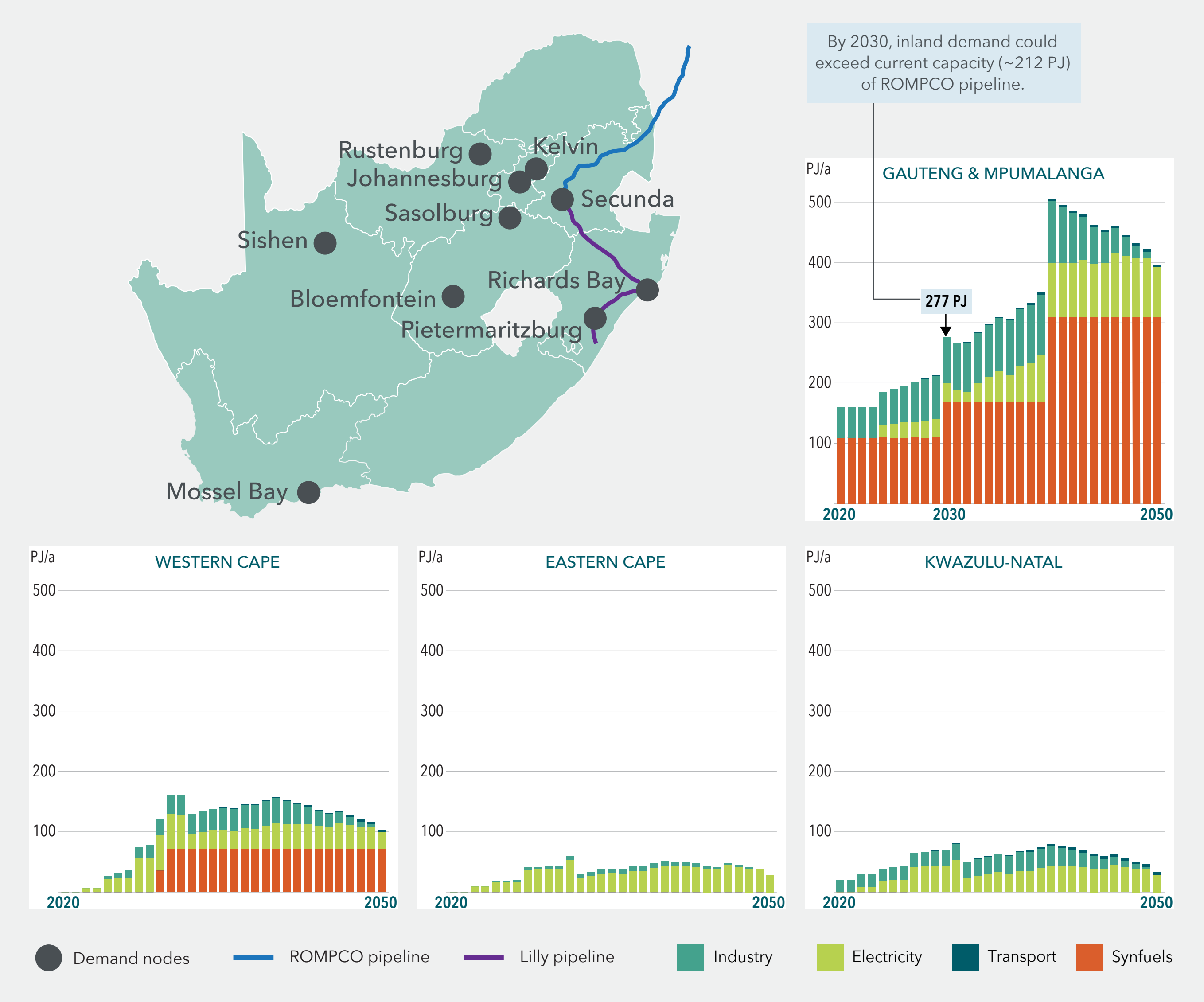
[56] Assuming an 8 Gt carbon budget for South Africa through to 2050.

> *In both high and low gas demand scenarios, inland gas demand in Gauteng and Mpumalanga exceeds the capacity of South Africa's only major gas pipeline, ROMPCO, which has a capacity of ~210 PJ/a, and supplies the inland market. Inland gas demand reaches 280 PJ/a by 2030 in the high scenario, and 220 PJ/a by 2035 in the low scenario. Therefore, in both scenarios new midstream gas supply infrastructure may be required by 2030–2035. This decision on midstream infrastructure can be deferred at least until 2023.*

In both no additional gas supply scenarios, no additional supply infrastructure would be required. However, in scenarios 2 and 4, that allow for additional supply of gas, inland gas demand exceeds the current capacity of the ROMPCO pipeline, which has a capacity of ~210 PJ/a. The ROMPCO pipeline is the only major gas supply pipeline into South Africa today. The pipeline supplies gas from the Pande-Temane gas fields Central Processing Facility in Mozambique to South Africa. Subsequently, the inland market (Gauteng, Mpumalanga and the Free State) is wholly reliant on the supply of gas through this pipeline.

Figure 8: Additional gas supply, high demand scenario – node-based view of gas demand

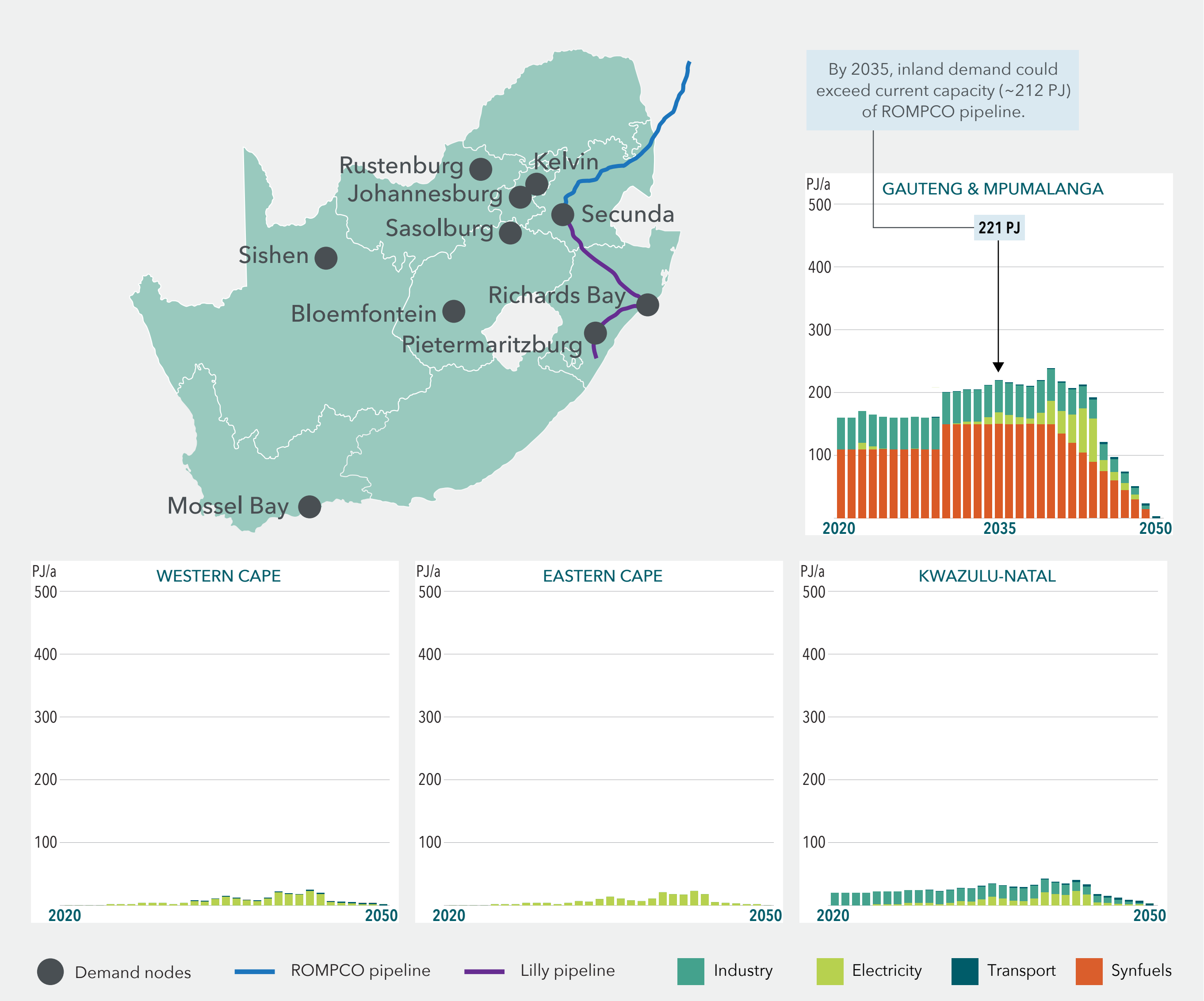


Source: NBI-BCG analysis.

Note: For ease of reference, from this point forward in the report, scenario 2 is also referred to as the high demand scenario and scenario 4 the low demand scenario.

In the high demand scenario, inland demand reaches ~280 PJ/a by 2030 (Figure 8). In the low demand scenario, this tipping point is reached later, with demand volumes reaching ~220 PJ/a by 2035 (Figure 9). As such, new gas infrastructure may be required across the two scenarios – albeit within marginally different time horizons, and therefore, requiring decisions within different timeframes.

Figure 9: Additional gas supply, low demand scenario – node-based view of demand



By 2035, inland demand could exceed current capacity (~212 PJ) of ROMPCO pipeline.

Source: NBI-BCG analysis.

Deep dive: The node-based geographic view of the low and high gas demand scenarios

Across both the high and low gas demand scenarios 2 and 4, the node-based view makes assumptions on the geographic allocation of gas pre-2030.

Gas demand scenario 2: High demand scenario

Key assumptions on the demand split pre-2030

- **Power sector**: RMIPPPP capacity is allocated with 450 MW in KZN, 320 MW in Western Cape, and 450 MW in Eastern Cape; the coastal OCGTs are converted to gas; Kelvin and an additional 0.8 GW of inland coal capacity are converted to gas. The remaining IRP and private GTP capacity is equally distributed at the three coastal nodes.
- **Synfuels sector**: All gas demand is inland (Secunda, Sasolburg) until ~2029. From 2029 gas demand ramps up in the Western Cape due to the revival of PetroSA.
- **Broader industry**: Latent demand is unlocked and split per BUSA Gas Working Group (GWG), with 38% in Gauteng and Mpumalanga, 9% in Eastern Cape, 46% in Western Cape, and 7% in KZN.
- **Transport sector**: Gas is split as per BUSA GWG transport demand, split with ~37% in Gauteng and Mpumalanga, 4% in the Eastern Cape, 22% in Western Cape, and 37% in KZN.

Key assumptions on the demand split post-2030

- **Power sector**: 50% of all new capacity is allocated inland with coal conversions, and residual capacity is split equally among the remaining three coastal nodes.
- **Synfuels sector**: Inland gas demand is for Secunda/Sasolburg, and coastal (Western Cape) gas demand is for PetroSA.
- **Broader industry**: Gas demand at each node grows in line with GDP, and then linearly ramps down to 0 PJ/a from 2040–2050.
- **Transport sector**: Allocation as per pre-2030 split.

Gas demand scenario 4: Low demand scenario

Key assumptions on the demand split pre-2030

- **Power sector**: Only 0.3 GW inland coal capacity is converted to gas, with all residual new capacity split evenly at the three coastal nodes.
- **Synfuels sector**: All gas demand is inland (Secunda, Sasolburg). PetroSA gas demand is not revived at the coast.
- **Broader industry**: No latent industrial demand is unlocked, with 50 PJ/a in Gauteng and Mpumalanga, and 20 PJ/a in KZN in line with current demand.
- **Transport sector**: Allocation as per the high demand scenario.

Key assumptions on the demand split post-2030

- **Power sector**: 50% of all new capacity is allocated inland with coal conversions, and residual capacity is split equally among the remaining three coastal nodes.
- **Synfuels sector**: All gas demand is inland (Secunda, Sasolburg), with no revival of PetroSA; inland synfuels gas demand ramps down to 0 PJ/a post-2040.
- **Broader industry and transport sector**: Allocation as per pre-2030 split.

A decision on the midstream infrastructure to serve these nodes does not need to be made now and can be deferred to ~2023–2025 pending greater certainty on the volume and location of future gas demand.

Source: BUSA Gas Working Group; NBI-BCG pathways project.

Photo: Shutterstock.com

> ***The scale, pace of deployment, and location of GTP peaking plants in the power sector are critical swing factors to the quantum and location of demand. Given the high affordability threshold of GTP, it can serve as a demand anchor to enable the optimal supply option for South Africa. It is therefore critical that energy planning policy gives clarity to the deployment, operating regime, and location of GTP plants beyond 2030.***

The location, scale and operating regime of GTP plants combined with relatively high affordability thresholds could create clarity on the quantum, timing, and certainty of demand. Energy planning policy has a critical role to play in providing this clarity to de-risk supply infrastructure investments and to enable the optimal gas supply option for South Africa. Ideally, energy planning policy must clarify the future of GTP with granularity on the location and quantum of demand from GTP for a time horizon beyond 2030, given that supply infrastructure investments are made on a time scale beyond 10 years.

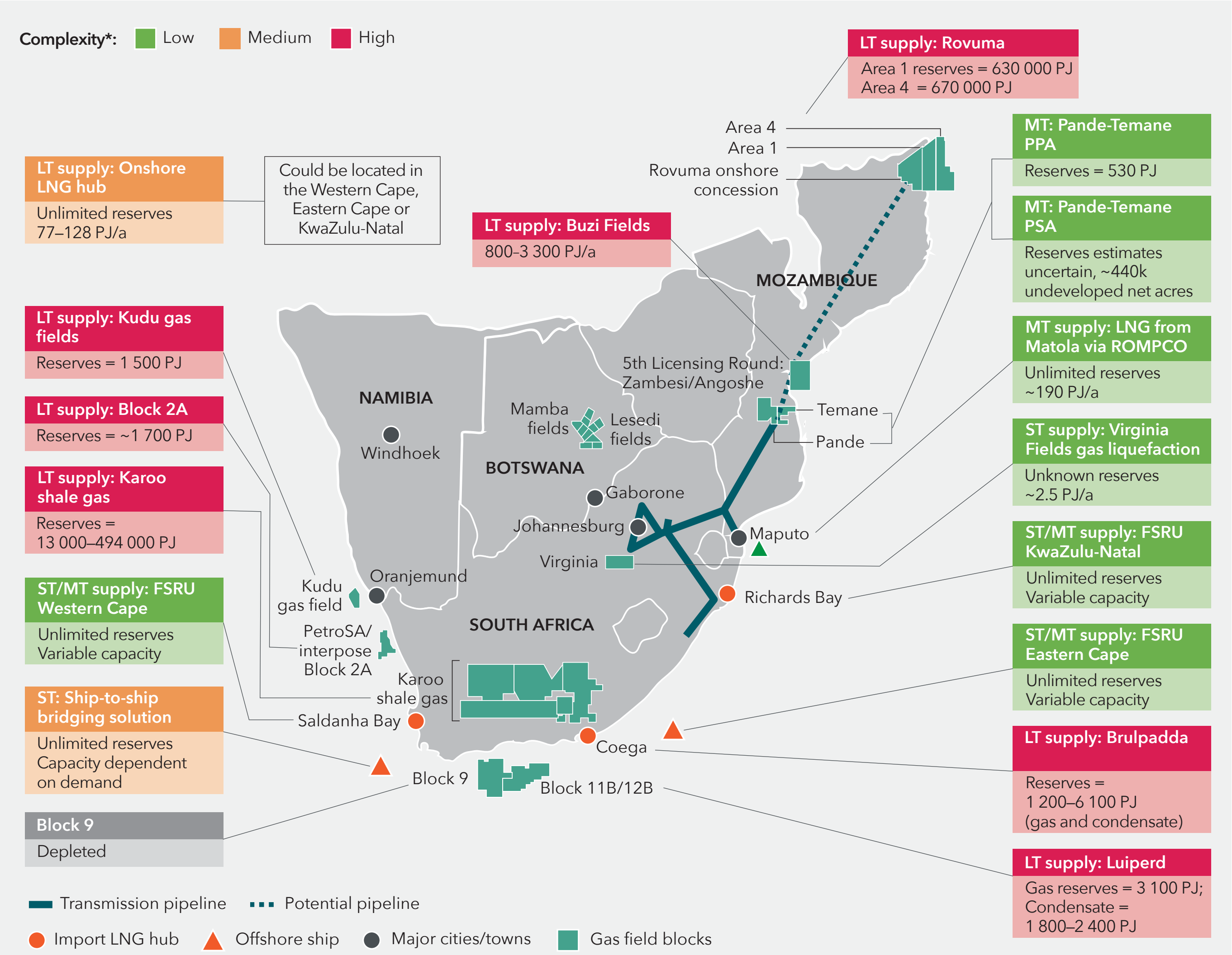
For example, the decision on whether GTP plants are located inland or at the coast, will need to balance technical and socio-economic trade-offs like grid infrastructure availability and job creation in areas affected by the decommissioning of coal-fired power stations. Inland GTP plants could support the repurposing of existing inland coal-fired power stations to minimise adverse socio-economic implications of the coal decommissioning and utilise existing grid infrastructure to distribute power. These GTP plants will need to be CCGTs or gas engines to account for the efficiency reduction at altitude. Conversely, coastal GTP plants can offer higher efficiency, however they may require new grid infrastructure to be developed.

3.2.3 WHAT LOCAL, REGIONAL AND GLOBAL SUPPLY OPTIONS ARE AVAILABLE TO BRIDGE DIMINISHING SUPPLY?

> ***Potential supply options vary over the short- (2021–2024), mid- (2024–2030), and long-term (2030+). In the short- to mid-term, key options are extending piped gas supply from Pande-Temane via technical work on the reserves, and Liquified Natural Gas (LNG) via FSRUs. The amount of additional gas available from Pande-Temane is not fixed, given contractual and technical uncertainties. However, this gas is the most cost-competitive of all options. In the long-term, potential supply options, in addition to LNG, are piped gas from Rovuma and potentially other Mozambique gas fields, and gas from exploration activities in South Africa's Brulpadda and Luiperd gas fields.***

As previously stated, the reserves of South Africa's only major gas supply source today, Pande-Temane are declining and supply is anticipated to be constrained from around 2025 onwards. It is therefore critical to identify alternative future gas supply options to meet the demand outlined in this study. There are a range of potential local, regional and global gas supply options to be considered to meet demand across the short- to long-term (Figure 10). This study uses the different reserve sizes and varying degrees of complexity across the supply sources as a proxy to determine how much effort and risk is associated with each option, in terms of landing gas molecules from the source to demand centres within South Africa.

Figure 10: Map of local, regional and international supply options



Complexity*: 🟩 Low 🟧 Medium 🟥 High

LT supply: Onshore LNG hub
Unlimited reserves
77–128 PJ/a

Could be located in the Western Cape, Eastern Cape or KwaZulu-Natal

LT supply: Kudu gas fields
Reserves = 1 500 PJ

LT supply: Block 2A
Reserves = ~1 700 PJ

LT supply: Karoo shale gas
Reserves =
13 000–494 000 PJ

ST/MT supply: FSRU Western Cape
Unlimited reserves
Variable capacity

ST: Ship-to-ship bridging solution
Unlimited reserves
Capacity dependent on demand

Block 9
Depleted

LT supply: Buzi Fields
800–3 300 PJ/a

LT supply: Rovuma
Area 1 reserves = 630 000 PJ
Area 4 = 670 000 PJ

MT: Pande-Temane PPA
Reserves = 530 PJ

MT: Pande-Temane PSA
Reserves estimates uncertain, ~440k undeveloped net acres

MT supply: LNG from Matola via ROMPCO
Unlimited reserves
~190 PJ/a

ST supply: Virginia Fields gas liquefaction
Unknown reserves
~2.5 PJ/a

ST/MT supply: FSRU KwaZulu-Natal
Unlimited reserves
Variable capacity

ST/MT supply: FSRU Eastern Cape
Unlimited reserves
Variable capacity

LT supply: Brulpadda
Reserves =
1 200–6 100 PJ
(gas and condensate)

LT supply: Luiperd
Gas reserves = 3 100 PJ;
Condensate =
1 800–2 400 PJ

▬ Transmission pipeline ▪▪▪ Potential pipeline

● Import LNG hub ▲ Offshore ship ● Major cities/towns 🟩 Gas field blocks

Notes: * Complexity refers to all dimensions: infrastructure overlay, technical and commercial.
Options which are greyed out are excluded from scope of view due to small scale and complexity.

Source: Local stakeholder interviews; IGUA-SA Annual Report 2020; NBI-BCG analysis.

Of the potential supply options presented on page 41, this analysis focuses on those with sufficient scale and commercial traction to potentially supply the demand centres in South Africa (Figure 11):

Note: The Kudu gas fields and Block 2A are excluded from further consideration due to their limited reserves relative to other options, distance from centres of demand and lack of commercial traction. The Karoo shale gas field is also excluded from further consideration due to the high degree of uncertainty in terms of reserve size and significant environmental risk associated with this supply option.

- **Short-term supply options** (2021–2024): LNG can play a critical role in bridging the supply decline from Pande-Temane with four potential supply options possible at various locations in Southern Africa:
  1) LNG from an FSRU stationed at the Matola port terminal in Mozambique, supplied to South Africa via the ROMPCO pipeline and a connecting pipeline from the Matola port to ROMPCO
  2) – 4) LNG from FSRUs stationed at either Richards Bay, Coega or Saldanha.

  The East Coast of South Africa, including the inland market, can be supplied in the short-term by FSRUs at Matola and Richards Bay. The Final Investment Decision (FID) on Matola, could be finalised in 2022/23, with commercial discussions to secure anchor demand currently ongoing. The West Coast of South Africa can also be supplied with LNG in the short-term via an FSRU at any of its major ports – Coega and Saldanha. The earliest FID dates for FSRUs in Richards Bay, Coega or Saldanha will be ~2023/2024. Any further delays in decision-making regarding these FSRU's will result in them becoming a mid-term supply option rather than a short-term one.

- **Mid-term supply options** (2024–2030): In the mid-term, supply could be extended from Pande-Temane via technical work on the reserves. This could yield the most competitively priced gas for South Africa, however the amount of additional gas available is not fixed, given contractual and technical uncertainties. The reserves at Pande-Temane are also limited and cannot meet the full scale of demand outlined in the various scenarios. Reserves of gas at Pande-Temane are governed under two commercial agreements: the Petroleum Production Agreement (PPA) and the Production Sharing Agreement (PSA). The PPA is linked to reserves of ~530 PJ, of which ~420 PJ are proved developed reserves, and ~110 PJ are proved undeveloped reserves. The PSA, which reached FID in the first quarter of 2021, could also further extend reserves with another ~440 k undeveloped net acres.[57] The volumes of gas supply available to South Africa under the PSA and the PPA are highly uncertain – both technically and contractually.

- **Long-term supply options** (2030 and beyond): Three local long-term supply options and one regional option are possible for South Africa in the long-term. The local offshore Brulpadda and Luiperd reserves range from 1 200–6 100 PJ and 3 100 PJ, respectively, but both require technical challenges to be addressed, linked to extraction, such as deep water and rough seas. If Brulpadda and Luiperd are not developed in the long-term, onshore LNG hubs at Richards Bay, Coega and Saldanha are possible. However, this will depend on demand, and given the long-term demand outlook noted in this analysis, FSRUs are likely to remain in place rather than more capital-intensive and large-scale onshore hub facilities. The regional supply options, Rovuma and the other Mozambique gas fields like the Buzi fields and Zambezi basin, are also possible supply sources in the long-term. Rovuma is one of the largest global gas discoveries in recent times, with 63 000 PJ in Area 1 and 67 000 PJ in Area 4, but building a pipeline to South Africa from these reserves will be highly complex and costly. The pipeline will require high utilisation and a long-term payback period. Given the risk of stranded assets and the complex political landscape, this option poses significant commercial and security of supply risks.

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[57] Sasol, 2021. Form 20F.

Figure 11: Potential upstream supply options for the short- to long-term

		TOTAL RESERVES	ANNUAL CAPACITY	COMMERCIAL OPERATION DATE	MUST-BELIEVES TO SUPPLY SOUTH AFRICA
Short-term (2021–2024)	**FSRU KZN**	Unlimited	Variable*	▨	■ Demand in KZN large enough to justify investment.
	FSRU EC	Unlimited	Variable*	▨	■ Political support is maintained and Coega industrial development proceeds.
	FSRU WC	Unlimited	Variable*	▨	■ Demand in Western Cape large enough to justify investment.
Mid-term (2024–2030)	**LNG-MATOLA**	Unlimited (global LNG market)	~190 PJ/a (South Africa only)	*FiD initially planned for Q4 2021 (at the earliest) – likely delayed given uncertainty on minimum demand*	■ Gauteng and Mpumalanga markets can absorb higher costs of delivered gas relative to today. ■ Sufficient inland GTP demand.
	PSA GAS	~440k undeveloped net acres	▨	FiD already taken on PSA – *pending outcome of further upstream exploration activities*	■ Mozambican demand is insufficient; buy-in from Mozambican Government obtained and negotiations successful.
	PPA GAS	~530 PJ**	▨	▨	■ The lifetime of the reserves can be extended. ■ Mutually beneficial inter-governmental cooperation between South Africa and Mozambique established.
Long-term (2030 and beyond)	**BRULPADDA**	1 200–6 100 PJ***	▨	▨	■ Gas can be extracted and piped to shore at low cost.
	LUIPERD	Gas: 3 100 PJ C: 1 800–2 400 PJ	▨	▨	■ Gas can be extracted and piped to shore at low cost.
	ONSHORE HUBS	Unlimited	77–128 PJ/a	▨	■ Brulpadda/Luiperd piped gas option not developed.
	ROVUMA AND OTHER MOZAMBICAN FIELDS	Area 1: 63 000 PJ Area 4: 67 000 PJ	▨	▨	■ Sufficient demand at the right affordability level to trigger investment.

Notes: FID = Financial Investment Decision; FSRU = Floating Storage Regasification Unit; PSA = Production Sharing Agreement; PPA = Petroleum Production Agreement.
* Dependent on demand.
** As per Sasol Form 20F – ~420 PJ proved developed reserves + ~110 PJ proved undeveloped reserves.
*** Includes gas and condensate.
▨ Grey cells indicate where no publicly available information is available.

Source: Local stakeholder interviews; Sasol Form 20F; NBI-BCG project team.

3.3 STRATEGIC INFRASTRUCTURE GAS PATHWAYS FOR SOUTH AFRICA AND HOW TO AVOID THE RISK OF A CARBON LOCK-IN

3.3.1 WHAT LONG-TERM STRATEGIC GAS INFRASTRUCTURE PATHWAYS ARE AVAILABLE TO MAXIMISE VALUE FOR SOUTH AFRICA AND TO SET THE COUNTRY ON A NET-ZERO TRAJECTORY?

> *All supply and demand-side infrastructure needs to be assessed with a lens to minimise the risk of carbon lock-in and stranded assets. All investments considered should be financially resilient to future drops in demand and costs related to potential repurposing of gas infrastructure, for example, to enable a substitution of gas with green H_2, its derivatives or sustainable sources of carbon.*

Given the evolution of the upstream supply options and the fragmentation of demand over geography and time, it is critical to assess what the optimal long-term strategic gas infrastructure pathways for South Africa are. To enable the decarbonisation of South Africa's economy while maximising economic value, the country's strategic pathway should adhere to a set of guiding principles:

1. **Optimise the socio-economic impact** in terms of job creation, managing the trade impact and the impact on adjacent sectors in the value chain.

   Note: The logic behind this consideration is primarily based on timing. Given the current role gas has in South Africa and the impending supply constraint from Pande-Temane, pathways that enable supply, affordably and before the onset of the aforementioned decline are considered to have a better socio-economic impact.

2. **Ensure cost-optimal delivered gas prices** factoring in the upstream molecule cost, midstream costs, complexity and impact on South Africa's bargaining power.
3. **Minimise climate and environmental impact**, considering both the emissions impact and the broader environmental impact of supply options comprising the pathway.
4. **Avoid the risk of stranded assets and carbon lock-in**, ensuring all supply investments are resilient to demand uncertainty, and allow for optionality for alternatives to gas pre-2050.

> *Considering South Africa's supply options, five strategic gas infrastructure pathways exist: 1) No additional gas supply; 2) Piped gas and exploration – Rovuma and Brulpadda; 3) Piped gas only – Rovuma only; 4) Exploration only – Brulpadda only; and 5) LNG. The LNG pathway emerges as optimal for South Africa because of the socio-economic benefits it yields, and the inherent flexibility to ramp down supply post-2040 and minimise the risk of stranded assets and gas infrastructure lock-in.*
>
> - ***Pathway 1:** A no additional gas supply pathway has the lowest infrastructure lock-in risk, but also the lowest socio-economic benefit, and leads to ~400–600 Mt higher cumulative emissions in the long-run. Given the higher carbon-intensity of alternatives, this pathway could yield higher carbon tax burdens for consumers.*
> - ***Pathways 2–4:** These are only relevant in a high demand scenario and present a high risk of stranded assets and carbon lock-in, with large capital investments of ~ZAR70–200 bn required. Rovuma piped gas, in particular, is highly complex with significant political and security risks to be addressed. Extracting gas from Brulpadda and Luiperd may also be technically complex , which could further increase the cost of these pathways.*
> - ***Pathway 5:** The LNG pathway is optimal for South Africa given the flexibility it provides, due to shorter lead times as demand ramps down post-2040 to achieve net-zero, and due to the positive socio-economic benefits it brings. The negative impact on the trade balance will need to be offset by new green export industries, such as a South African e-fuels industry.*

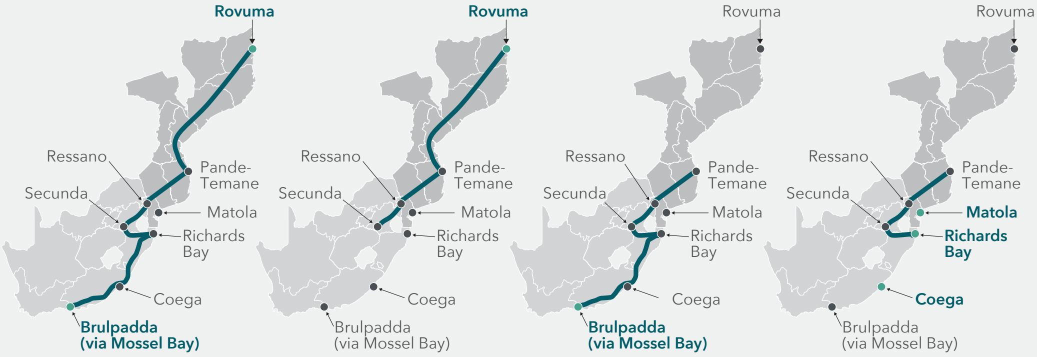
Given the potential supply options laid out in Figures 10 and 11, five long-term strategic infrastructure pathways exist for South Africa (Figure 12):

1) **No additional gas:** Supply remains at current levels before ramping down to 0 PJ/a from 2040–2050. The limited gas demand in this scenario is predominantly inland in Gauteng and Mpumalanga. On the demand side, this scenario assumes no additional gas demand as per gas demand scenarios 1 and 3.

2) **Piped gas and exploration** (Rovuma and Brulpadda and Luiperd): For the Rovuma piped gas, gas is supplied from coastal FSRUs and potentially LNG from Matola in the short- to mid-term pre-2030. In the longer-

Figure 12: Five long-term strategic gas pathways for South Africa

LONG-TERM SUPPLY LANDSCAPE (POST-2030)



	1 No additional gas pathway	2 Rovuma + Brulpadda pathway (Piped gas and exploration play)	3 Rovuma pathway (Piped gas play)	4 Brulpadda pathway (Exploration play)	5 LNG pathway *Highly contingent on timing of LNG options* (Coega, Richards Bay, Brulpadda and Matola)
SUPPLY	Current gas supply to 2040.	■ Maximise supply from PPA and/or PSA in Pande-Temane. ■ FSRU in KwaZulu-Natal and/or LNG from Matola. ■ FSRU in Western Cape and/or Eastern Cape.			
	No long-term gas supply for South Africa beyond 2040.	■ Rovuma pipeline for Gauteng and Mpumalanga, Brulpadda to supply Western Cape and connect Western Cape and Eastern Cape demand.	■ Rovuma pipeline for Gauteng and Mpumalanga.	■ Brulpadda to supply Western Cape and connect Western Cape and Eastern Cape demand.	■ Pipeline to connect FSRU in KwaZulu-Natal to Gauteng and Mpumalanga.
DEMAND	■ **Inland**: Inland synfuels and industry demand ramp-down to 0 PJ/a 2040–2050.	■ Enables gas pathway for synfuels post-2030, enables conversion of Eskom CFPS post-2030.	■ Enables gas pathway for synfuels post 2030, enables conversion of Eskom CFPS post-2030.	■ Gas pathway for synfuels challenged, limited potential to convert Eskom CFPS post-2030.	■ Potential to enable gas pathway for synfuels and conversion of Eskom CFPS post-2030.
	■ **Coastal**: KwaZulu-Natal industry demand ramps-down to 0 PJ/a 2040–2050.	■ Pre-2030 GTP demand is coastal (shift to inland post-2030), enables unlocking of latent industry demand, potential to revive PetroSA.*	■ PetroSA is not revived.	■ Potential to revive PetroSA*; all GTP demand coastal.	■ PetroSA not revived, potential to unlock latent industry demand.

Short- to mid-term (pre-2030)

Long-term (post-2030)

Note: CFPS = Coal Fired Power Stations.

* Revival of PetroSA via Brulpadda gas highly dependent on final cost of gas from Brulpadda.

Source: NBI-BCG analysis.

term, post-2030, the gas supply is complemented by Rovuma piped gas with a new pipeline connecting to the existing ROMPCO pipeline. In the Brulpadda and Luiperd exploration pathway, the long-term supply by Brulpadda and Luiperd unlocks unmet industrial demand and connects the demand in the Western and Eastern Cape. This pathway assumes a range of gas demand as per the low and high gas demand scenarios 2 and 4.

3) Piped gas only (Rovuma only): Rovuma piped gas, as outlined above in strategic infrastructure pathway 2, with Brulpadda and Luiperd fields not being developed.

4) Exploration only (Brulpadda only): Gas exploration at Brulpadda, as in strategic infrastructure pathway 2 above with pipeline from Rovuma not being developed.

5) LNG: Coastal FSRUs are maintained beyond the short- to mid-term, with the inland supply in the longer-term met via a pipeline from the Richards Bay FSRU or from Matola via the ROMPCO pipeline. Like the exploration and piped gas pathway, this also assumes the gas demand range across the low and high gas demand scenarios.

Across all the infrastructure pathways, excluding the no additional gas pathway, leveraging gas from Pande-Temane, LNG from Matola and from FSRUs in South Africa in the short- to mid-term, if affordable, is a no-regret action. LNG can be supplied to South Africa via any combination of these sources pre-2030 with no new permanent midstream infrastructure required. In the longer-term, post-2030, additional infrastructure may be required, pending greater clarity on the scale and location of GTP plants, but decisions on this should be deferred to at least 2023–2025.

Each of these long-term strategic infrastructure pathways are assessed against the guiding principles. Two key dimensions are quantified in this analysis:

1. **Trade impact**: Assesses the impact on trade through the import of gas across the strategic infrastructure pathways. The cost of importing gas is quantified by multiplying the delivered price of gas by the gas demand ranges for the corresponding demand scenarios, as articulated previously. The delivered price of gas into South Africa is:
   - **For piped gas**: gas molecule cost at well-point + CAPEX for any new pipeline infrastructure required.
   - **For LNG (to the FSRU in South Africa):** Gas molecule cost + liquefaction costs + shipping costs + CAPEX for any new pipeline infrastructure required (i.e., excluding any regasification charges).

2. **Midstream CAPEX required**: Quantifies the total CAPEX for any midstream infrastructure, including pipelines, FSRUs, and distribution pipelines.

Of the strategic pathways assessed, the LNG pathway emerges as the optimal pathway for South Africa (Figure 13). Despite the trade impact, with ZAR470–1 700 bn increase in imports, which will need to be offset with, for example, new exports of green fuels, the LNG pathway has the lowest capital expenditure requirements of ZAR20–50 bn for the FSRU, and ZAR25–50 bn for the inland pipeline, and the lowest complexity. Green exports may take time to materialise, hence there could be a role for bridging finance to mitigate and manage the trade risks in the shorter-term.[58] The LNG pathway also provides the flexibility to ramp down supply if demand ramps down beyond 2040, due to alternative green technologies coming online at scale, thereby reducing the risk of stranded assets and carbon lock-in. By diversifying South Africa's supply, this pathway also has the potential to improve the country's bargaining power – assuming the gas demand can be aggregated.

The no additional gas pathway is not optimal for South Africa given the climate impact of 8 400–9 400 Mt cumulative emissions, due to the extended use of coal and diesel across sectors; the impact on the competitiveness of sectors, like the synfuels sector; and the carbon tax liability associated with the higher carbon-intensity of the economy.

The piped and exploration gas pathways are also not optimal for South Africa, with high CAPEX requirements of ZAR70–120 bn for Rovuma and ZAR90–100 bn for Brulpadda and Luiperd, and the high levels of complexity.[59] In line with the high CAPEX requirements, as well as the long asset lifetimes and long investment lead times. The piped gas pathways pose a high risk of stranded assets and carbon lock-in.

Given the assessment against guiding principles described earlier (Figure 13) – the analysis concludes that the LNG pathway is the optimal pathway to meet South Africa's gas supply needs.

Photo: Shutterstock.com

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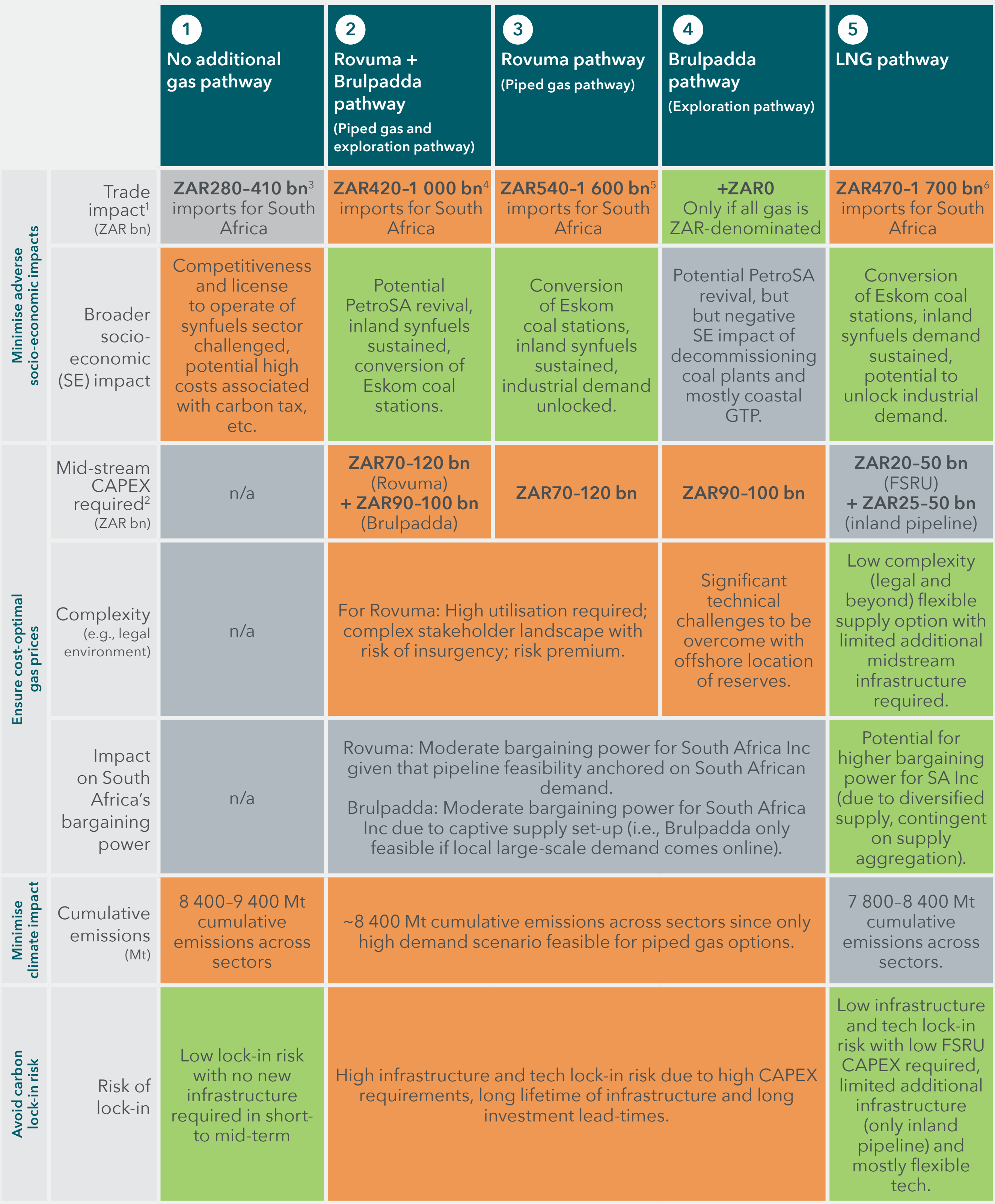
[58] Bridging finance is an interim financing option that can be used in the shorter-term, until longer-term financing options become available or can be secured, typically in the form of a loan or equity investment.

[59] Brulpadda is a wet gas resource. As such, this piped gas pathway would require additional infrastructure to separate the condensate and process the gas. These additional infrastructure costs are not quantified.

Figure 13: Assessment of long-term strategic gas infrastructure pathways



		① No additional gas pathway	② Rovuma + Brulpadda pathway (Piped gas and exploration pathway)	③ Rovuma pathway (Piped gas pathway)	④ Brulpadda pathway (Exploration pathway)	⑤ LNG pathway
Minimise adverse socio-economic impacts	Trade impact[1] (ZAR bn)	**ZAR280–410 bn**[3] imports for South Africa	**ZAR420–1 000 bn**[4] imports for South Africa	**ZAR540–1 600 bn**[5] imports for South Africa	**+ZAR0** Only if all gas is ZAR-denominated	**ZAR470–1 700 bn**[6] imports for South Africa
	Broader socio-economic (SE) impact	Competitiveness and license to operate of synfuels sector challenged, potential high costs associated with carbon tax, etc.	Potential PetroSA revival, inland synfuels sustained, conversion of Eskom coal stations.	Conversion of Eskom coal stations, inland synfuels sustained, industrial demand unlocked.	Potential PetroSA revival, but but negative SE impact of decommissioning coal plants and mostly coastal GTP.	Conversion of Eskom coal stations, inland synfuels demand sustained, potential to unlock industrial demand.
Ensure cost-optimal gas prices	Mid-stream CAPEX required[2] (ZAR bn)	n/a	**ZAR70–120 bn** (Rovuma) **+ ZAR90–100 bn** (Brulpadda)	**ZAR70–120 bn**	**ZAR90–100 bn**	**ZAR20–50 bn** (FSRU) **+ ZAR25–50 bn** (inland pipeline)
	Complexity (e.g., legal environment)	n/a	For Rovuma: High utilisation required; complex stakeholder landscape with risk of insurgency; risk premium.		Significant technical challenges to be overcome with offshore location of reserves.	Low complexity (legal and beyond) flexible supply option with limited additional midstream infrastructure required.
	Impact on South Africa's bargaining power	n/a	Rovuma: Moderate bargaining power for South Africa Inc given that pipeline feasibility anchored on South African demand. Brulpadda: Moderate bargaining power for South Africa Inc due to captive supply set-up (i.e., Brulpadda only feasible if local large-scale demand comes online).			Potential for higher bargaining power for SA Inc (due to diversified supply, contingent on supply aggregation).
Minimise climate impact	Cumulative emissions (Mt)	8 400–9 400 Mt cumulative emissions across sectors	~8 400 Mt cumulative emissions across sectors since only high demand scenario feasible for piped gas options.			7 800–8 400 Mt cumulative emissions across sectors.
Avoid carbon lock-in risk	Risk of lock-in	Low lock-in risk with no new infrastructure required in short- to mid-term	High infrastructure and tech lock-in risk due to high CAPEX requirements, long lifetime of infrastructure and long investment lead-times.			Low infrastructure and tech lock-in risk with low FSRU CAPEX required, limited additional infrastructure (only inland pipeline) and mostly flexible tech.

🟩 Relative Pro 🟧 Relative Con ⬜ Neutral

Notes:Assuming exchange rate of ZAR15/$.

1. Reflects range of delivered cost of gas to SA across all pathways, and range in gas demand in piped gas & LNG pathways.
2. Range reflects high and low gas demand scenarios with ~700 PJ/a and ~200 PJ/a respectively – with the high case requiring expansion of existing ROMPCO infrastructure.
3. Low case: all Gauteng, Mpumalanga and KwaZulu-Natal gas supplied by Matola; High case: all gas supplied by Coega.
4. Assuming Rovuma supplies all inland demand and Brulpadda all coastal demand.
5. Assuming Rovuma supplies all inland and coastal demand.
6. Western Cape and Eastern Cape supplied by Coega and in low case: Richards Bay supplies KwaZulu-Natal, Gauteng and Mpumalanga (and by Coega in high case).

Source: NBI-BCG analysis.

Deep dive: Midstream supply routes to connect upstream supply with inland demand

Natural gas needs to be transported from upstream reserves to downstream consumers. In the case of LNG, natural gas is liquified through the liquefaction process, transported via a ship, whereafter it is compressed for storage and regasified for consumption. Alternatively, natural gas can be compressed for transportation via a pipeline. To connect supply and demand, the least-cost midstream infrastructure with the lowest environmental impact for the coastal nodes are FSRUs, which can transport, store and regasify the LNG onboard. FSRUs have a capital cost of US$200 million/Megatonne per annum (mn/mtpa).[60] The gas molecule can be from any cost-competitive supply source.

FSRUs are the optimal flexible supply options for coastal gas demand in the Western Cape, Eastern Cape, and KZN with limited onshore infrastructure required. Given its distance from the ports, there are a range of midstream supply options to be considered to meet the inland nodes in Gauteng and Mpumalanga depending on the upstream source (Figure 14):

- **LNG from Matola**: Transport of this upstream source inland would require a pipeline connecting to the current ROMPCO pipeline from Ressano, a new parallel ROMPCO pipeline from Ressano into South Africa (**only if the gas demand exceeds current capacity of 212 PJ/a**), and a last mile distribution pipeline to end consumers (predominantly power stations).[61] The **maximum** CAPEX investment required in a high gas demand scenario is:
  - Matola connecting pipeline: ~ZAR5.1 bn
  - New parallel ROMPCO pipeline: ~ZAR18.3 bn
  - Last-mile distribution pipeline could require a maximum of ~ZAR6.6 bn.

- **LNG from Richards Bay (or Coega)**: On top of the FSRU, this would require an inland pipeline from the Richards Bay (or Coega) port, and a similar last-mile distribution pipeline to the Matola option. Transporting LNG from Richards Bay to the inland nodes can leverage the Lilly pipeline servitude, if not the infrastructure. Transporting LNG from Coega instead, to the inland market requires a much longer pipeline (1 000 km compared to 600 km from Richards Bay) and cannot leverage any existing infrastructure or servitudes.

The **maximum** CAPEX investment required in a high gas demand scenario is:

  - Richards Bay pipeline: ~ZAR30.8 bn, OR
  - Coega pipeline: ~ZAR50.3 bn
  - Last-mile distribution pipeline could require a maximum of ~ZAR6.6 bn.

- **Rovuma piped gas**: Transport of Rovuma gas (including gas from other smaller Mozambique gas fields) would require a new North-South Rovuma pipeline connecting into the existing ROMPCO pipeline, with a parallel ROMPCO pipeline (both Pande-Temane to Ressano and Ressano to South Africa), if gas demand exceeds 212 PJ/a and the last-mile transmission pipeline mentioned above. The **maximum** CAPEX investment required in a high gas demand scenario is:
  - New Rovuma pipeline: ~ZAR72.7 bn
  - New parallel ROMPCO pipeline: ~ZAR44.3 bn (with ZAR26 bn required for the Mozambique section and ZAR18.3 bn for the South Africa section of the pipeline)
  - Last-mile distribution pipeline could require a maximum of ~ZAR6.6 bn.

- **Brulpadda piped gas:** Brulpadda gas is the only upstream option that cannot leverage existing infrastructure and would require entirely new development of an inland pipeline from the port in Mossel Bay (and the last-mile transmission pipeline). The **maximum** CAPEX investment required in a high gas demand scenario is:
  - New Brulpadda pipeline: ~ZAR93.4 bn
  - Last-mile distribution pipeline could require a maximum of ~ZAR6.6 bn.

Any new pipeline being built must be able to accept green H_2 or its derivatives when they become economically viable. Fibre reinforced polymer pipeline is one example of a potential technology that could be employed. The real, relative breakeven tariff is used to compare the midstream options – factoring in gas molecule costs; upstream production costs; liquefaction, shipping and regasification costs; and last-mile distribution pipeline costs. These costs reflect neither the impact of inflation nor the impact of the National Energy Regulator of South Africa (NERSA) policy determination on the actual tariff.

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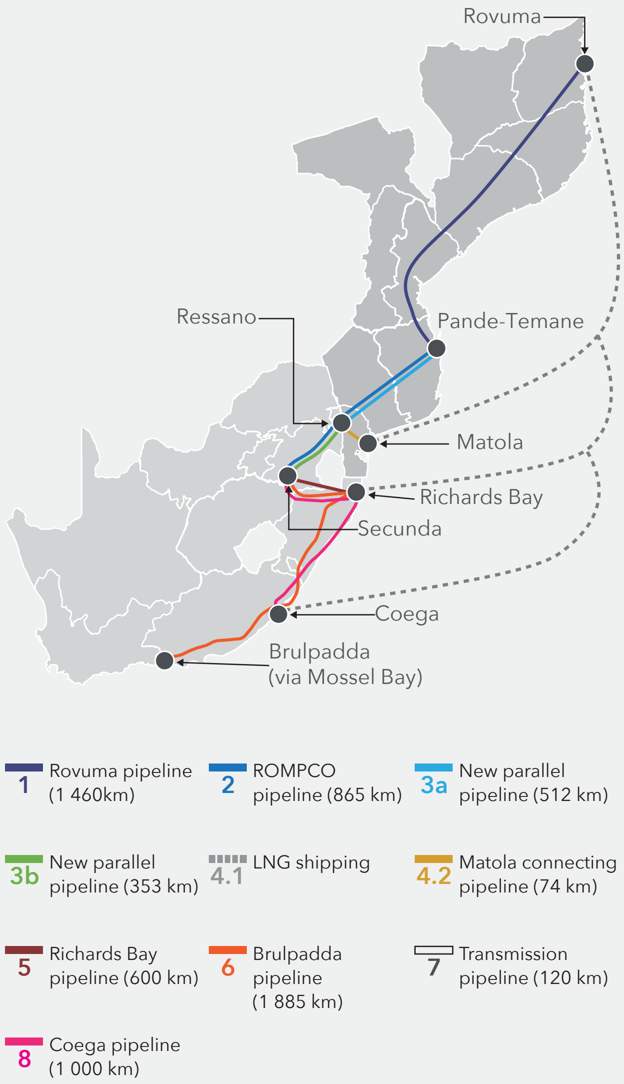
[60] BCG Centre for Energy, 'Impact Analysis, 2020'.

[61] In the absence of a last mile distribution pipeline, there could be a role last mile delivery trucks but the emissions impact and broader impact on road congestion, for example, of these trucks would need to be addressed.

Figure 14: Midstream supply routes to inland demand nodes



A **Rovuma piped gas**	1 + Rovuma North-South Pipeline 2 + ROMPCO current pipeline (used up to 212 PJ/a capacity) 3a + New parallel PT-Ressano pipeline (Mozambique) (used for additional volume >212 PJ/a) 3b + New parallel Ressano-Secunda pipeline (South Africa) (used for additional volume >212 PJ/a) 7 New transmission pipelines to deliver gas to power stations
B **LNG via Matola**	4.1 + LNG transportation (including liquefaction, shipping and regas) 4.2 + Matola connecting pipeline 2 + ROMPCO current pipeline from Ressano (used up to 212 PJ/a capacity) 3b + New parallel Ressano-Secunda pipeline (South Africa) (used for additional volume >212 PJ/a) 7 New transmission pipelines to deliver gas to power stations
C **LNG via Richards Bay**	4.1 + LNG transportation (including liquefaction, shipping and regas) 5 + New direct line from Richards Bay to the inland nodes 7 New transmission pipelines to deliver 160–200 PJ/a of gas to power stations
D **LNG via Coega**	4.1 + LNG transportation (including liquefaction, shipping and regas) 8 + New direct line from Coega to the inland nodes 7 New transmission pipelines to deliver gas to power stations
E **Brulpadda piped gas**	6 + New direct line from Mossel Bay port to inland nodes via Richards Bay 7 New transmission pipelines to deliver gas to power stations

Note: For volumes above 212 PJ/a, a new pipeline parallel to ROMPCO will be built to Secunda to accommodate higher demand levels; the throughput is assumed to equal the 'target demand' minus 212 PJ.

Source: Global Data pipeline capex and capacity repository; BCG Centre for Energy Impact Analysis on Shipping, Liquefaction and Regassification trend; NBI-BCG project team.

For **piped gas**, the breakeven tariff includes:

Molecule cost at the well-point + Transport cost from CAPEX for any new pipeline infrastructure (on /GJ basis) = **Breakeven tariff (ZAR/GJ)**

For **LNG**, the breakeven tariff includes:

Molecule cost at the well-point + Liquefaction cost (on /GJ basis) + Shipping cost (on /GJ basis) + Regas cost (on /GJ basis) + Transport cost from CAPEX for any new pipeline infrastructure (on /GJ basis) = **Breakeven tariff (ZAR/GJ)**

Of the options considered, Rovuma and LNG from Matola or Richards Bay have the potential to yield the lowest breakeven gas costs – 10–30% lower than the breakeven costs for Coega LNG and Brulpadda piped gas. Starting with the upstream costs, Richards Bay and Coega have the potential to yield the lowest molecule costs at the well-point – 20–25% lower than Rovuma and Matola, 50–60% lower than Brulpadda. However, Rovuma and Matola have the lowest midstream costs (most of which are beyond South Africa's borders). Rovuma and Matola's midstream costs are 10–30% lower than the other options.

LNG via Richards Bay or Coega have higher midstream transportation costs associated with liquefaction, shipping and regasification. As such, Rovuma and Matola, with higher molecule costs at the well-point but lower midstream costs, and Richards Bay LNG, with lower molecule costs and marginally higher midstream costs, yield the lowest overall breakeven tariff for South Africa.

For the Rovuma option, however, the midstream pipeline is highly complex due to several factors:

- **High utilisation required**: Gas demand needs to ramp up significantly from where it is today and remain at sufficient levels to achieve payback in ~20 years.
- **Complex stakeholder landscape**: This will require well-orchestrated bilateral stakeholder discussions between the South African Government and the Mozambique Government at the presidential level.
- **Risk of insurgency**: The risk of insurgency in the north of Mozambique needs to be managed.
- **Risk premium**: This will require investors with risk appetite and funds to finance the pipeline.

> ***Within the LNG pathway, a multi-hub approach with FSRUs in Matola, Richards Bay, Coega and Saldanha is assessed. In addition to Matola as a supply option, developing all three South African FSRUs in parallel emerges as the optimal supply scenario for South Africa, given the higher socio-economic impact and increased bargaining power for consumers, which will potentially yield a more competitive delivered LNG price. A scenario where Richards Bay is not developed restricts and locks the inland market into supply from Matola and should, therefore, be avoided.***

Within the LNG strategic infrastructure pathway, three potential scenarios are considered:

1. **All three South African FSRUs in Richards Bay, Saldanha and Coega are developed in parallel**: The FSRU in Richards Bay comes online in the short- to mid-term for eastern demand (i.e., inland and KZN demand), with FSRUs developed in parallel in Coega and Saldanha, as required. The FSRU in Coega serves predominantly the Eastern Cape industrial consumers, the Saldanha FSRU supplies mainly the Western Cape industrial and synfuels (PetroSA) consumers, and the Richards Bay FSRU supplies the KZN industrial and potential GTP consumers.[62] This multi-hub option with Saldanha, Richards Bay and Coega in parallel, connects to inland demand, with a pipeline from the FSRU in Richards Bay to the inland nodes, if there is sufficient inland GTP demand.
2. **Matola and Coega are developed ahead of Richards Bay and Saldanha**: Only Matola LNG and the FSRU in Coega come online in the short- to mid-term, with a delay most notably in the FSRU in Richards Bay. In this scenario, the FSRU in Richards Bay and Saldanha as required, are developed post-2030.
3. **Richards Bay is not developed, but Coega, Saldanha and Matola are developed**: The FSRU in Richards Bay is not developed and both Coega and Matola are developed in the short- to mid-term. As such, Matola supplies predominantly the inland market via the existing ROMPCO pipeline and a new Matola-connecting pipeline (Figure 15).

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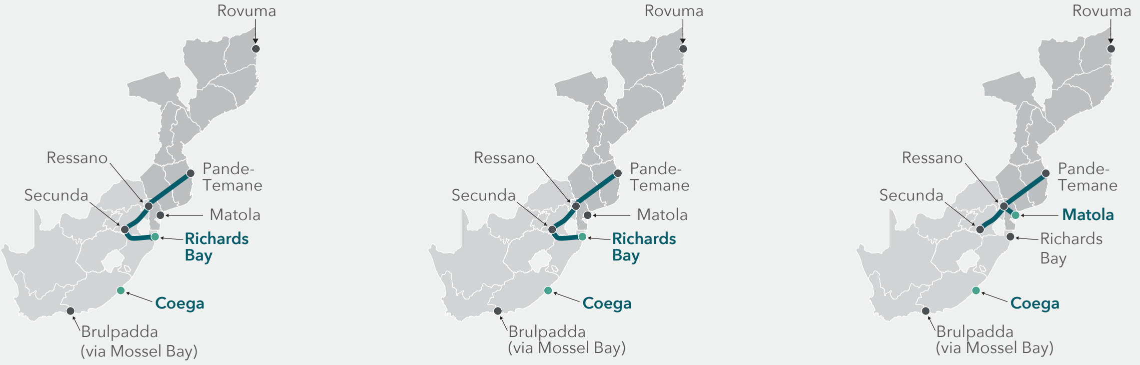
[62] As previously mentioned, the Richards Bay FSRU could in the long-term also supply inland demand markets via a new pipeline – however the decision on pipeline infrastructure can be deferred to at least 2023–2025.

Figure 15: Three potential scenarios within the LNG pathway

		Richards Bay, Coega and Saldanha (in parallel)	**Coega, then Richards Bay and Saldanha**	**Coega and Matola**
		*Assuming FSRU in Richards Bay online in short- to mid-term for KwaZulu-Natal and inland demand; FSRU in Coega and Saldanha as required.	*Assuming only FSRU in Coega in short- to mid-term delaying the FSRU in Richards Bay; with Richards Bay (and Saldanha as required) in the longer-term.	*Assuming only FSRU in Coega in short- to mid-term delaying Richards Bay and with only Matola coming online in longer-term for coastal and KwaZulu-Natal demand.

LONG-TERM SUPPLY LANDSCAPE (POST-2030)



SUPPLY	Short- to mid-term (pre-2030)	■ FSRU in KwaZulu-Natal, PPA and/or PSA, LNG from Matola. ■ FSRU Western Cape and Eastern Cape.	■ PPA and/or PSA in Pande-Temane ■ FSRU in Eastern Cape ■ LNG from Matola.	
	Long-term (post-2030)	■ Pipeline to connect FSRU KwaZulu-Natal to Gauteng/ Mpumalanga, leveraging existing pipeline servitude (Lilly pipeline).	■ FSRU KwaZulu-Natal (and Western Cape) and pipeline to connect FSRU KwaZulu-Natal to Gauteng/Mpumalanga. ■ FSRU in Western Cape.	■ FSRU in Eastern Cape. ■ FSRU in Western Cape.
DEMAND		■ **Inland**: Enables gas pathway for synfuels post-2030, enables conversion of Eskom CFPs post-2030.	■ Gas pathway for synfuels challenged; enables conversion of Eskom CFPs post-2030.	■ Gas pathway for synfuels not feasible; limited potential to convert Eskom CFPs post-2030.
		■ **Coastal**: Pre-2030 GTP demand is coastal (shift to inland post-2030), enables unlocking of latent industrial demand, PetroSA not revived.	■ All pre-2030 GTP demand is coastal (shift to inland post-2030), challenge unlocking latent industrial demand, PetroSA not revived.	■ All GTP demand is coastal, challenge unlocking latent industrial demand, PetroSA not revived.

◔ Short- to mid-term (pre-2030)
◕ Long-term (post-2030)

Source: NBI-BCG analysis.

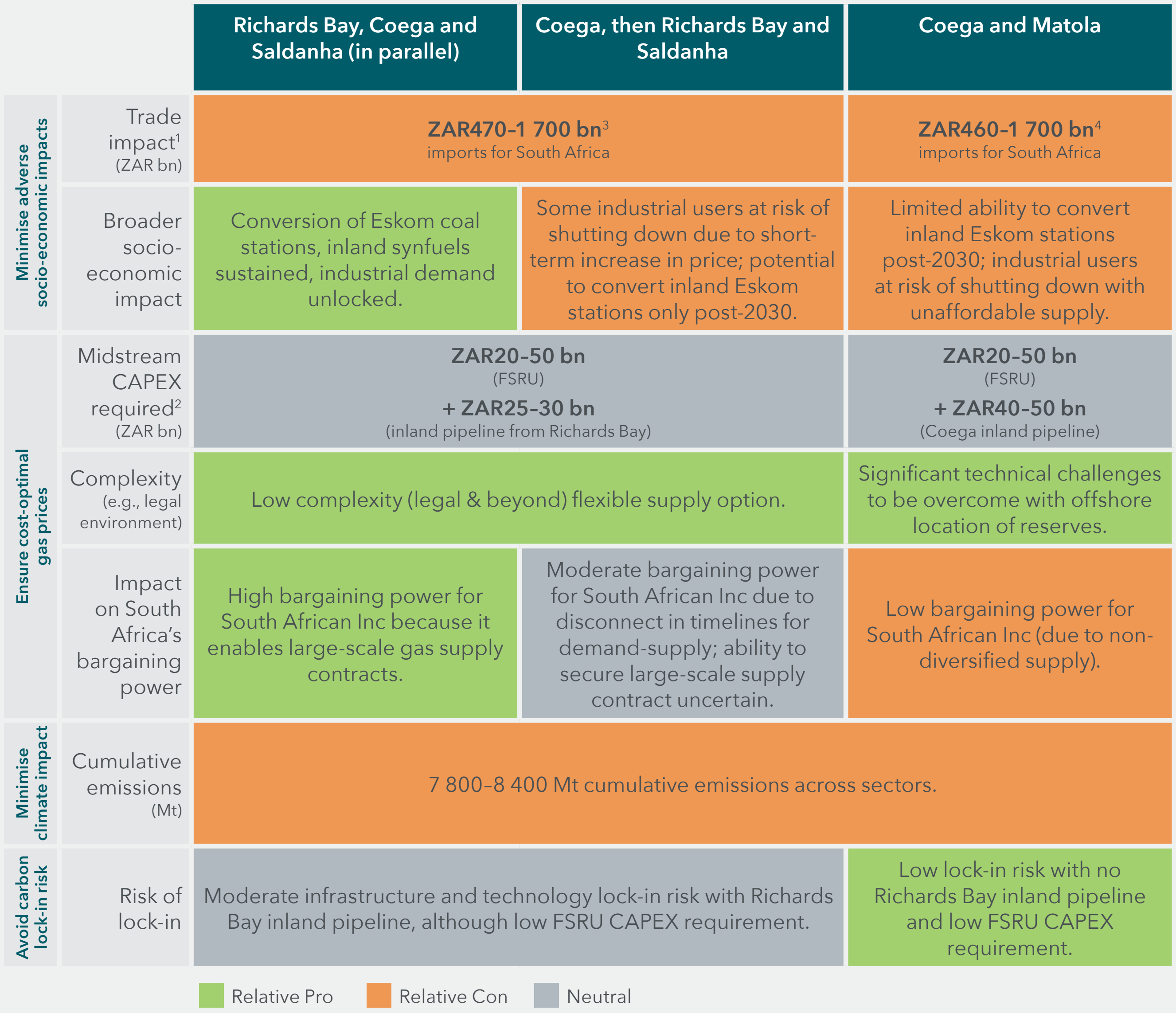
Of the LNG scenarios considered, the multi-hub scenario with Saldanha, Coega and Richards Bay being developed in parallel, drives the most positive socio-economic impact. At the same time, it ensures more competitive gas prices for South Africa by increasing the optionality of supply for gas consumers and enables larger-scale off-take contracts, as represented in Figure 16.

Leveraging the Richards Bay FSRU in the short- to mid-term enables the conversion and repurposing of Eskom coal-fired plants with CCGTs or gas engines. This option addresses some of the socio-economic challenges of coal decommissioning and has the potential to sustain the inland synfuels sector.

The second LNG scenario, which delays the development of the FSRU in Richards Bay, has the negative socio-economic impact of putting industrial users at risk of shutting down in the short-term. This is due to delayed availability of gas and potentially less competitively priced gas, due to reduced optionality of supply and, in turn, reduced bargaining power for South Africa, because these customers will only have one supply option – Matola.

The Coega and Matola LNG option also has negative socio-economic impacts by limiting the ability to convert inland coal-fired plants and sufficiently meet inland demand due to the limited capacity of the ROMPCO pipeline. Industrial users are also at risk due to potentially unaffordable gas supply. The Coega and Matola scenario results in the lowest bargaining power for South Africa, which due to non-diversified supply, could yield higher gas prices. This scenario, where Richards Bay is not developed, and inland supply is limited to Matola, should be avoided.

Figure 16: Assessment of the scenarios in the LNG pathway



		Richards Bay, Coega and Saldanha (in parallel)	Coega, then Richards Bay and Saldanha	Coega and Matola
Minimise adverse socio-economic impacts	Trade impact[1] (ZAR bn)	🟧 **ZAR470–1 700 bn**[3] imports for South Africa		🟧 **ZAR460–1 700 bn**[4] imports for South Africa
	Broader socio-economic impact	🟩 Conversion of Eskom coal stations, inland synfuels sustained, industrial demand unlocked.	🟧 Some industrial users at risk of shutting down due to short-term increase in price; potential to convert inland Eskom stations only post-2030.	🟧 Limited ability to convert inland Eskom stations post-2030; industrial users at risk of shutting down with unaffordable supply.
Ensure cost-optimal gas prices	Midstream CAPEX required[2] (ZAR bn)	⬜ **ZAR20–50 bn** (FSRU) **+ ZAR25–30 bn** (inland pipeline from Richards Bay)		⬜ **ZAR20–50 bn** (FSRU) **+ ZAR40–50 bn** (Coega inland pipeline)
	Complexity (e.g., legal environment)	🟩 Low complexity (legal & beyond) flexible supply option.		🟩 Significant technical challenges to be overcome with offshore location of reserves.
	Impact on South Africa's bargaining power	🟩 High bargaining power for South African Inc because it enables large-scale gas supply contracts.	⬜ Moderate bargaining power for South African Inc due to disconnect in timelines for demand-supply; ability to secure large-scale supply contract uncertain.	🟧 Low bargaining power for South African Inc (due to non-diversified supply).
Minimise climate impact	Cumulative emissions (Mt)	🟧 7 800–8 400 Mt cumulative emissions across sectors.		
Avoid carbon lock-in risk	Risk of lock-in	⬜ Moderate infrastructure and technology lock-in risk with Richards Bay inland pipeline, although low FSRU CAPEX requirement.		🟩 Low lock-in risk with no Richards Bay inland pipeline and low FSRU CAPEX requirement.

🟩 Relative Pro 🟧 Relative Con ⬜ Neutral

Notes: Assuming exchange rate of ZAR15/$.

1. Reflects range of delivered cost of gas to South Africa across all plays, and range in gas demand in LNG plays.
2. Range reflects high and low gas demand scenarios with ~700 PJ/a and ~200 PJ/a respectively – with the high case requiring expansion of existing ROMPCO infrastructure.
3. Assuming Richards Bay supplies inland and Coega supplies coastal demand.
4. Assuming Coega supplies Eastern Cape and Western Cape and Matola all inland and KwaZulu-Natal demand.

Source: NBI-BCG analysis.

> ***Developing the three FSRU hubs in parallel will require limited CAPEX, focused on the FSRU and port modifications, with a maximum FSRU CAPEX of ZAR50 bn across scenarios. Critically, should an alternative greener technology for peaking support arise beyond 2035, the net present value of the investment at risk in a low demand power scenario is ~ZAR7 bn. This value at risk is relatively low, compared to the ZAR14–28 bn in OPEX saving arising predominantly from cheaper gas prices relative to diesel prices, and should not inhibit technology switching, particularly in the context of a higher carbon price.***

Deep dive: The trade-offs of switching to gas from diesel in the power sector pre-2035

This analysis aims to answer four key questions to unpack the trade-offs of switching from diesel to gas in the power sector pre-2035 for energy security and variability management:

1. What is the operational cost saving of switching to gas pre-2035?
2. What volume of CO_2 emissions are avoided pre-2035?
3. What is the cost of converting existing diesel OCGTs to gas?
4. What is the cost of the stranded assets (post-2035) for the additional midstream infrastructure required for gas?

This analysis indicates that the switch to gas saves costs and reduces cumulative emissions, with the following key findings:

1. Switching to gas from diesel in the power sector, in the low gas demand scenario, saves **ZAR14–28 bn in operational expenditure** (including fuel costs) pre-2035.
2. Switching to gas also saves up to **10 Mt in cumulative CO_2 emissions** due to the lower carbon-intensity of gas.
3. The conversion of the existing diesel OCGTs, with a combined capacity of 3.8 GW to gas could cost up to **ZAR3 bn**, ZAR1.8 bn of which may already have been spent on the conversion of Gourikwa (0.8 GW) and Ankerlig (1.5 GW) to dual-fuel OCGTs, which commenced in ~2016.
4. Of the ~ZAR13 bn FSRU investment required for the low demand GTP scenario, **ZAR7 bn residual CAPEX** remains by 2035, assuming other midstream infrastructure is not required pre-2035 in the low demand scenario, and the decision on this can be made after 2030, pending clarity on the locations of GTP plants.

Key assumptions:

- **Gas demand scenario**: Power sector low emissions green H_2 path, which corresponds to the power sector in the additional gas supply, low demand scenario.
- **Costs to convert existing diesel OCGTs to dual fuel (i.e., gas and diesel)**: ZAR 0.8 bn/GW of OCGT
- **Diesel prices**: ZAR200–300/GJ
- **Gas prices**: ZAR140/GJ
- **Emission factors**: Diesel = 0.27 t CO_2/MWh; Gas = 0.20 t CO_2/MWh

Note: See Appendix 2.3 for the overview of the calculations used in this analysis.

3.3.2 HOW CAN SOUTH AFRICA MITIGATE, WHERE POSSIBLE, AND MANAGE THE RISK OF STRANDED ASSETS AND A CARBON LOCK-IN?

South Africa must establish the enabling policy and commercial framework to: 1) Procure gas on an aggregated basis and achieve economies of scale; 2) Enable supply infrastructure within the time and to the scale of the gas demand required; and 3) Manage the risk of unconstrained demand and stranded supply infrastructure, for example, by putting in place phase-out targets. A detailed view on the gas supply-demand economics and affordability across all sectors should inform the Gas Master Plan, which should in turn provide clarity on the long-term demand and preferred supply pathway for South Africa. Policy and specific stakeholder engagement platforms should also be leveraged to promote investment, drive public-private partnerships and bilateral relations with Mozambique, and to invest in research and development for solutions to address methane leakage and repurposing of gas infrastructure.

Given the potential uncertainty in location and timing of both gas demand and supply options, a market aggregation mechanism is key to unlocking the lowest cost of gas for South Africa. This mechanism is required to aggregate demand and link it to larger-scale gas contracts, with lower prices closer to the marginal cost of production, than the higher priced and more volatile spot market in which smaller-scale, fragmented, volumes would be purchased.

This aggregation mechanism, along with South Africa's broader gas strategy, needs to be actively managed and orchestrated at a national level in order for this to be realised. Optimising bilateral relations with Mozambique is another reason why a national-level approach is critical. Successfully extending supply from Pande-Temane is dependent on both countries cooperating to maximise the potential of these cost-advantaged reserves.

It is also critical that policies be put in place to mitigate the risk of unconstrained demand and carbon lock-in, which would derail South Africa's path towards net-zero.

Deep dive: Overview of a carbon lock-in

A carbon lock-in refers to the tendency for carbon-intensive technological systems to persist over time, including the related physical infrastructure. Two main types of carbon lock-in occur:

- The infrastructure and technological lock-in typically results from physical infrastructure with long asset lifetimes or short-term investments that require long lead times and delay payoffs resulting in sunk costs. Avoiding this type of lock-in requires infrastructure which is flexible and can be repurposed – this includes, for example, gas turbines in the power sector that are financially resilient to long-term drops in demand and which can be built to accept an increasing blend of green H_2.
- An institutional lock-in refers to policy, regulatory frameworks, contracts and economic rules that lock in carbon-intense technological systems. Institutional lock-ins can be mitigated with appropriate contract terms, phase-out targets, limits, and incentives.

For example, it is recommended that energy planning policy limit the role of GTP to peaking purposes only, with very limited, short-duration contracts awarded for mid-merit plants in those exceptional years where higher utilisation may be required.

In addition, policy should prescribe that all GTP assets installed have green H_2 phase-in targets, dependent on the price of green H_2 achieved over time, and be procured with the technical condition of being able to handle green H_2 blends. New pipeline infrastructure should also be prescribed to be resilient to the cost of repurposing or be constructed at the outset with alternative materials that are resilient to the effects of increased green H_2 blends like hydrogen embrittlement on weld connections, for example. Lastly, energy planning policy should set phase-out targets for gas by, for example, 2050 to ensure a net-zero future is possible. This is of course dependent on the trajectory of alternative green technology cost curves.

3.4 HOW TO ENABLE GAS AS A TRANSITION FUEL FOR SOUTH AFRICA'S JUST TRANSITION

3.4.1 WHAT ARE THE KEY SIGNPOSTS ON GAS TO MONITOR IN THE NEXT 10–15 YEARS?

The multi-hub LNG pathway maximises value for South Africa, but there is still uncertainty on the evolution of the supply-demand dynamics over time. Given this uncertainty, South Africa's approach to gas needs to be flexible and responsive to key outcomes and decisions, as shown in Table 2 on the next page.[63]

Prior to 2030, gas demand ranges from 180 PJ/a to ~550 PJ/a. The supply options for this short- to mid-term horizon include the two Pande-Temane extension options, Matola LNG and FSRUs in Coega, Saldanha and Richards Bay – which could come online around 2025 (Figure 17). To aggregate demand as these supply options evolve over time, and to maximise value for South Africa in line with its decarbonisation objectives, the following key signposts should be monitored.

- By **2021/2022**, key signposts to monitor include:
  - FID on the Matola terminal, pending certainty on the minimum demand
  - The outcome of further upstream exploration on the PSA
  - The outcome of the Eskom feasibility study on the conversion of existing power plants
  - Decisions on the FSRUs in each port
  - The outcome of the remaining Renewable Energy Independent Power Producer Procurement Programme (REIPPPP) rounds
  - The final decision and outcome of the RMIPPPP process
  - The publication of the Gas Master Plan
- By **2024/2025,** decisions will need to be made on whether the ROMPCO pipeline needs to be expanded, and if, and when, the inland pipeline from Richards Bay should be developed. These decisions will be critical to ensure affordable inland supply for industrial, power and synfuels consumers.

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[63] The outcomes presented in Table 2 are linked to the high and low gas demand scenarios. The outcomes of the no gas demand scenarios are not included as these are assessed to be sub-optimal from the perspective of cumulative emissions and cost (especially in the power sector).

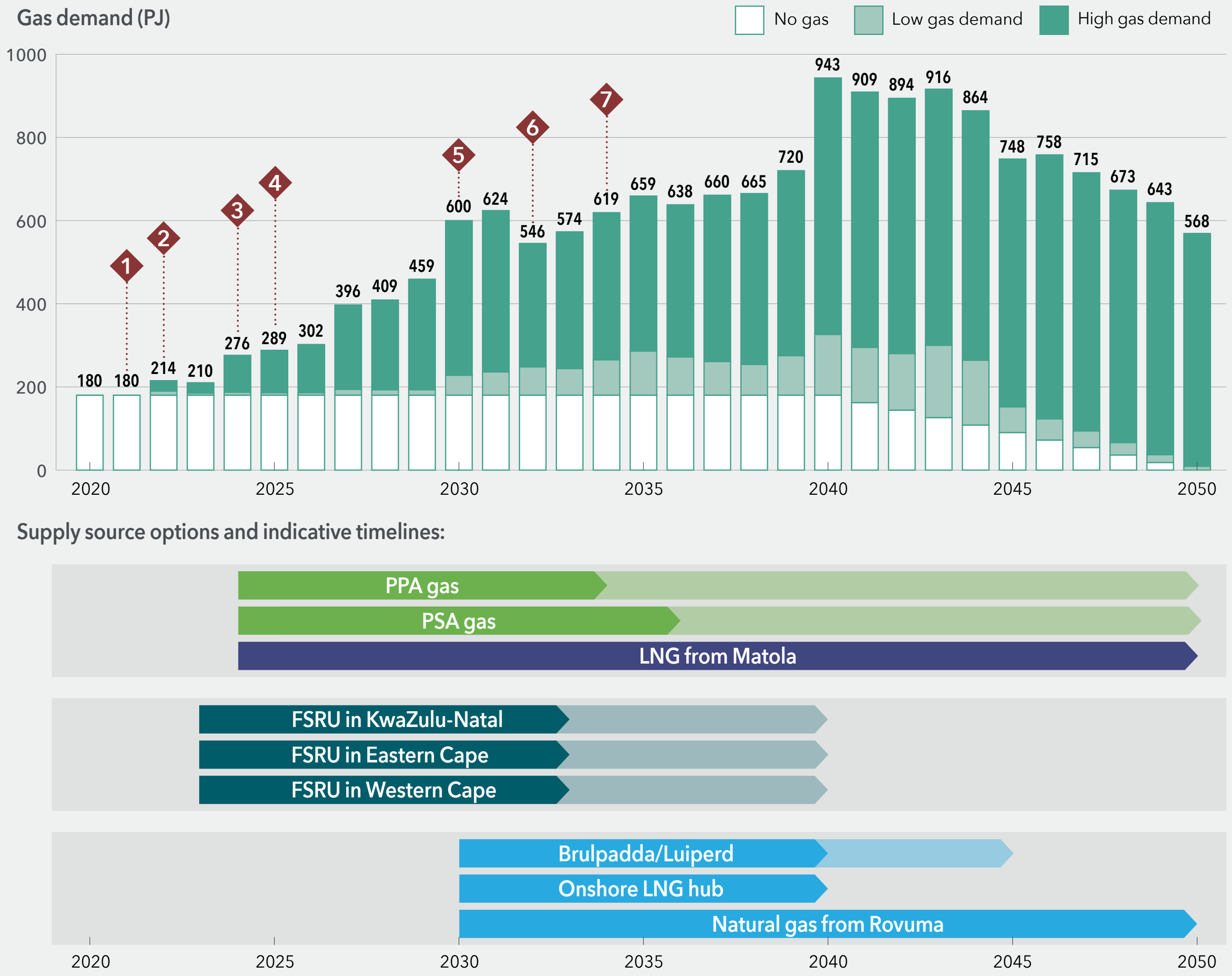
Table 2: Potential outcomes for the role of gas in South Africa's path to net-zero

	2021-2030	2031-2040	2041-2050
Electricity	10–170 PJ/a required for GTP to ensure security of supply.	100–220 PJ/a required for GTP (predominantly peaking and for a limited number of years, mid-merit) to manage variability.	
Synfuels	40–60 PJ/a additional synfuels gas consumption by 2030 (on top of 110 PJ/a current consumption) to substitute coal as a feedstock. Up to ~70 PJ/a additional gas by 2030, if PetroSA is revived (highly dependent on affordability).	~150–380 PJ/a consumed in the synfuels sector (+140 PJ/a in a high demand scenario by 2040 to substitute coal as a feedstock).	~0–380 PJ/a of gas left in 2050, with gas either substituted with green alternatives or complemented with emissions-capturing solutions, like DACCS in the last 5–10 years.
Industry	~0–70 PJ/a additional industrial gas consumption (on top of current consumption of 70 PJ/a) to phase out coal and diesel in the energy mix (highly dependent on affordability).	~0–50 PJ/a additional gas consumption predominantly to phase out fossil fuels in the energy mix, if gas is affordably supplied.	0 PJ/a of gas consumption left in 2050 with gas phased out of broader industry from 2040–2050.
Transport	Max of 15 PJ/a for HDVs as a transition away from diesel, with BEVs the least-cost option for passenger and light commercial transport (even in the short-term) and FCEVs in heavy commercial (from the mid-term).		
Supply	Ship-to-ship solutions until ~2023. LNG via FSRU in Richards Bay and/or Matola; FSRU in Coega and Saldanha, as needed.	FSRUs at Richards Bay, Coega and Saldanha as required for South Africa's coastal gas demand in the long-term, with inland gas demand met via a pipeline from Richards Bay, if required.	
Just Transition	Local content should be prioritised in all upstream and midstream supply infrastructure developments.		

Source: NBI-BCG analysis.

As in the short-term, key longer-term decisions should also be reflected in South Africa's gas strategy. The decision on the conversion of Sasol's Secunda complex should also be made to ensure the availability of affordable feedstock. By the mid-2030s, a decision should be made on the viability of green H_2 for industrial and power uses so that green H_2 applications can be ramped-up beyond initial pilots, if viable.

Figure 17: Key decisions and outcomes to monitor in the next 15 years



Key decisions/outcomes to monitor in the next 15 years:

1
- Outcome of further upstream exploration activities for PSA
- Outcome of feasibility study: Kelvin power station conversion

2
- FID on Matola Terminal pending certainty on minimum demand
- Outcome of Eskom feasibility study for conversion of existing power plants
- Publication of Gas Master Plan
- Decision on FSRU in Eastern Cape
- Decision on FSRU in KwaZulu-Natal
- Decision on FSRU in Western Cape
- The outcome of remaining REIPPPP rounds
- The final decision and outcome of the RMIPPPP process

3
- Decision on ROMPCO expansion and Richards Bay pipeline
- FID Rovuma pipeline

4
- Decision on viability and scale of supply from Luiperd/Brulpadda
- Decision on shift to onshore hub (Richards Bay, Coega, Western Cape)

5
- Sasol's Secunda complex conversion

6
- Rovuma potentially coming online

7
- Viability of green H_2 for industrial and power use

Notes: Beyond 2022, timelines of key decisions are indicative and could vary.
PSA = Production Sharing Agreement; FID = Financial Investment Decision; FSRU = Floating Storage Regasification Unit.

Source: NBI-BCG analysis.

3.4.2 WHAT ARE THE URGENT NO-REGRET ACTIONS REQUIRED TO UNLOCK GAS AS A TRANSITION FUEL FOR SOUTH AFRICA?

Urgent action, on both the demand and supply side, is required to actively manage South Africa's gas strategy and to put the country on a just net-zero trajectory, avoiding the risk of unconstrained gas demand and stranded assets. Given the constraints on South Africa's fiscus, which are even more severe in the wake of the COVID-19 pandemic, public-private partnerships will be critical to unlocking gas as a transition fuel.

On the demand side, action will be required across downstream sectors, but most notably in the power and synfuels sectors. Within the next 3–5 years, it will be critical for the power sector to do the following:

- Reduce the 20-year term of the PPAs being considered for powerships as part of RMIPPPP to avoid higher costs, from the pass-through of sub-optimal LNG prices to consumers, and unnecessarily high load factors (>50%) for an extended period of time.
- Decide on which power stations will be repowered and how (split of gas vs. RE vs. decommissioned vs. other).
- Assess the feasibility of converting the remaining diesel OCGTs to run on gas and verify the average utilisation factor of ~10%.
- Provide regulatory visibility on post-2030 gas demand.
- Limit GTP usage to predominantly peaking capacity, and mid-merit capacity for a limited number of years when large coal-fired plants are decommissioned.
- Extend the power sector plan beyond 2030 as part of a broader national integrated energy planning exercise to provide regulatory and policy clarity.

Within the next 3–5 years, the supply side of the gas value chain will need to do the following:

- Maximise supply from remaining reserves at Pande-Temane under PPA and PSA. To do this, it is critical that regional cooperation between South Africa and Mozambique is optimised so that both countries are operating from a 'win-win' negotiation position.
- Enable and fast-track the parallel development of FSRUs in Richards Bay, Coega and Saldanha.
- Conduct a detailed gas market study with a view on the gas supply-demand economics and affordability.
- Finalise the Gas Master Plan informed by the market study for South Africa, ensuring alignment and clear division of responsibilities and mandate with the *Gas Act 48 of 2001* and the *National Ports Act of 2005*.
- Establish a new fit-for-purpose tariff mechanism to enable gas as a transition fuel for South Africa.
- Decide on an official entity to serve as the market aggregator to take the balance sheet risk, consolidate off-take agreements, and secure long-term, competitively priced LNG supply contracts. The market aggregator will have a key commercial role in the gas value chain connecting supply and demand over time to enable South Africa's decarbonisation and to maximise value for South Africa. This role will be required to aggregate fragmented demand over geography and time, take the balance sheet risk, and secure larger-scale gas contracts. These larger-scale contracts are typically priced closer to marginal production costs, and as such are more value accretive than smaller demand volumes that could be purchased on the spot market.
- Investigate potential to repurpose gas infrastructure for green H_2 and green synfuels.
- Establish intergovernmental collaboration between South Africa and Mozambique, focusing on south Mozambique gas extension.
- Develop a clear roadmap on how to fund gas as a transitionary fuel and low-carbon feedstock, leveraging climate finance.
- Finalise local content requirements for upstream participation as part of the Upstream Petroleum Resources Development Bill to promote a national Just Transition.

In conclusion, gas can, if affordably sourced, play a critical role as a transition energy source in South Africa's net-zero journey. Gas can minimise cumulative emissions in the economy to 2050 and yield socio-economic benefits like maintaining jobs and economic activity in key sectors, such as the petrochemicals sector for example, in South Africa. This will, however, not be possible without a nationally orchestrated and optimised approach that coordinates key supply and demand decisions. It is critical that all spheres of society work together in ensuring that this nationally coordinated approach is realised for the benefit of South Africa.

4.

OUTLOOK

As was stated in the foreword of this report, South African business commits unequivocally to supporting South Africa's commitment to find ways to transition to a net-zero emission economy by 2050. Furthermore, business supports an enhanced level of ambition in the NDC that sees the country committing to a range of 420–350 Mt CO_2e by 2030. However, this enhanced ambition is conditional on the provision of the requisite means of support by the international community. In this light, the business community will play its part to work with international and local partners to develop a portfolio of fundable adaptation and mitigation projects that would build resilience and achieve deep decarbonisation.

A managed Just Transition is important, and such a transition is impossible without a broad multi-stakeholder effort. National Government, through the Presidential Climate Commission and the National Planning Commission and supported by key government ministries, are leading this effort.

In support of this national programme, the NBI membership together with BCG and BUSA are running a multi-year project to understand net-zero decarbonisation pathways, sector by sector. This will provide a solid input into national and local dialogues, as well as identify critical investment areas. Furthermore, this level of detail enables policy frameworks and engagement with providers of international support to maximise the potential to leverage concessional finance and trade support to attract local public and private finance.

This work is ongoing and is intended as a basis for further consultation and a foundation for future work. The work on each sector will be released in stages as it is completed and will form a basis on which others can build. Ultimately a final body of work of the combined sector content will be made up of reports, including:

- An introduction to the project and to a managed Just Transition, including analysis from our economic modelling
- Electricity
- Petrochemicals and chemicals
- The role of gas
- The role of green H_2
- Mining
- Transport
- Agriculture, Forestry and Other Land Use
- Construction
- Heavy industry
- A concluding chapter highlighting key investment opportunities and no-regret decisions.

Each of these reports will be published via our Just Transitions Web Hub (http://jthub.nbi.org.za). Please monitor this website for the latest report versions, supporting data and presentation material, as well as news of other Just Transition initiatives and a wide range of current opinion and podcasts on a Just Transition for South Africa.

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APPENDIX: ASSUMPTIONS AND KEY CALCULATIONS

This appendix provides transparency on the key input assumptions and calculations used across this report. The appendix is structured as follows:

1. **Input assumptions**
    1.1 Midstream: pipeline and FSRU investments
    1.2 Downstream: power sector
    1.3 Value chain emissions
    1.4 Other
2. **Overview of calculations**
    2.1 Emissions per sector
    2.2 Breakeven tariffs
    2.3 Trade impact
    2.4 Gas vs diesel trade-offs for the power sector
    2.5 Comparison of the value chain emissions of gas vs coal

1. INPUT ASSUMPTIONS

APPENDIX 1.1 MIDSTREAM: PIPELINE AND FSRU INVESTMENTS

- Investment cycle for pipelines = 6 years
- Investment cycle for LNG terminals = 3 years
- CAPEX for FSRU = US$200 mn/Mt per annum

APPENDIX 1.2 DOWNSTREAM: POWER SECTOR

Table 1.1: New build CAPEX (ZAR/kW)

ZAR/kW	2020	2030	2040	2050
Diesel - CCGT	11 800	11 200	10 700	10 700
Diesel - OCGT	9 300	8 800	8 400	8 400
Gas - CCGT	11 800	11 200	10 700	10 700
Gas - OCGT	9 300	8 800	8 400	8 400

Table 1.2: Fixed OPEX (ZAR/kW)

ZAR/kW	2020	2030	2040	2050
Diesel - CCGT	240	220	210	210
Diesel - OCGT	190	180	170	170
Gas - CCGT	240	220	210	210
Gas - OCGT	190	180	170	170

Table 1.3: Variable OPEX (ZAR/MWh)

ZAR/MWh	2020	2030	2040	2050
Diesel - CCGT	80	80	80	80
Diesel - OCGT	80	80	80	80
Gas - CCGT	40	40	40	40
Gas - OCGT	46	46	46	46

Table 1.4: Fuel cost (ZAR/GJ)

ZAR/GJ	2020	2030	2040	2050
Diesel	200–300	200–300	200–300	200–300
Gas	140	140	140	140

Table 1.5: Heat rate (GJ/MWh) and efficiency (%)

GJ/MWh (%)	2020	2030	2040	2050
Diesel - CCGT	7.4 (49%)	7.4 (49%)	7.4 (49%)	7.4 (49%)
Diesel - OCGT	11.5 (31%)	11.5 (31%)	11.5 (31%)	11.5 (31%)
Gas - CCGT	5.6 (64%)	5.6 (64%)	5.6 (64%)	5.6 (64%)
Gas - OCGT	9.1 (40%)	9.1 (40%)	9.1 (40%)	9.1 (40%)

Table 1.6: Emission factor (t CO_2/MWh)

t CO_2/MWh	2020	2030	2040	2050
Diesel	0.27	0.27	0.27	0.27
Gas	0.20	0.20	0.20	0.20

APPENDIX 1.3 VALUE CHAIN EMISSION

- **Energy input**
    - 1 barrel (bbl) of liquid fuel = 6 GJ of energy
    - 1 MWh of electricity = 3.6 GJ of energy

- **Emission factor**
    - Coal = 95 kg CO_2e/GJ
    - Natural gas (LNG or piped gas) = 56 kg CO_2e/GJ

- **Efficiency loss – liquid fuel production**
  - Coal = 64% combined
    - Mining and transportation = 2%
    - Liquid fuel production = 57%

  - LNG = 51% combined
    - Gas extraction = 0.6%
    - Liquefaction = 9%
    - Shipping = 7%
    - Regasification = 2%
    - Liquid fuel production = 40%

  - Piped gas = 41% combined
    - Gas extraction = 0.6%
    - Pipeline transportation = 1.5%
    - Liquid fuel production = 40%

- **Efficiency loss – power generation**
  - Coal = 64% combined
    - Mining and transportation = 2%
    - Power generation = 63%

  - LNG = 47–67% combined
    - Gas extraction = 0.6%
    - Liquefaction = 9%
    - Shipping = 7%
    - Regasification = 2%
    - Power generation = 36-60%

  - Piped gas = 38-62% combined
    - Gas extraction = 0.6%
    - Pipeline transportation = 1.5%
    - Power generation = 36–60%

APPENDIX 1.4 OTHER

- Weighted average cost of capital = 7.75%
- Exchange rate = ZAR15/US$

2. OVERVIEW OF CALCULATIONS

APPENDIX 2.1 EMISSIONS PER SECTOR

*Assuming constant emission factors over time

1. Power sector

$$\sum\left(\text{Emission factor per generation tech (t }CO_2\text{ /MWh)} \times \text{Generation per tech per annum (MWh)}\right) = \text{Total emissions per annum (t }CO_2\text{)}$$

2. Synfuels sector

$$\underset{\underset{\text{Sum of emissions per technology}}{\uparrow}}{\sum}\left(\overbrace{\left(\underset{\underset{\text{All other emissions assumed fixed}}{\uparrow}}{\text{Baseline emissions, disaggregated by feedstock (t }CO_2\text{)}} \div \text{Baseline feedstock consumed (PJ)}\right)}^{\text{Proxy emission factor per tech (t }CO_2\text{/PJ)}} \times \text{Feedstock consumed per annum (PJ)}\right) = \text{Total emissions per annum (t }CO_2\text{)}$$

3. Industrial sector

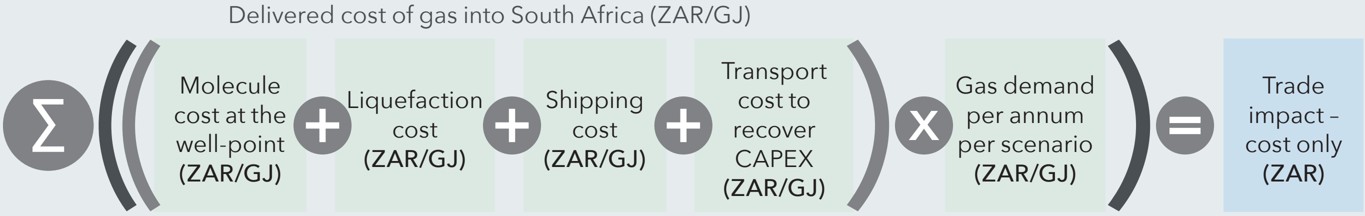
$$\sum\left(\overbrace{\left(\text{Baseline emissions per energy source (t }CO_2\text{)} \div \text{Baseline energy consumed (PJ)}\right)}^{\text{Proxy emission factor per tech (t }CO_2\text{/PJ)}} \times \text{Energy consumed per annum (PJ)}\right) = \text{Total emissions per annum (t }CO_2\text{)}$$

4. Transport sector

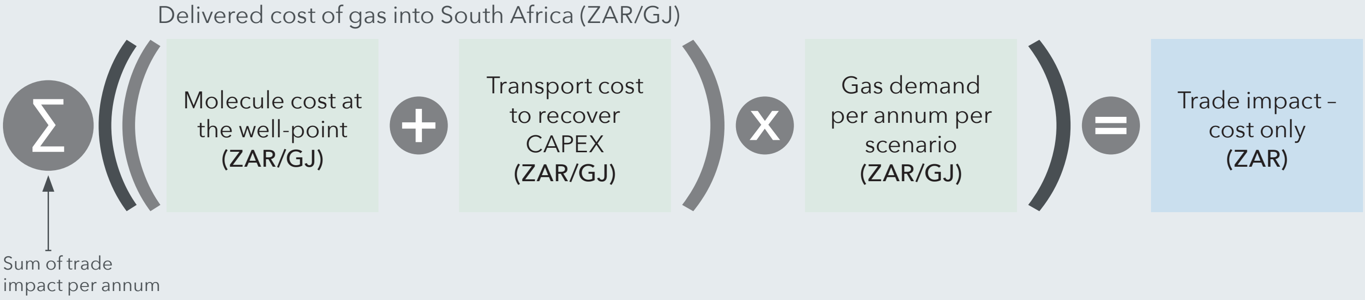
$$\underset{\underset{\text{Sum of emissions per technology}}{\uparrow}}{\sum}\left(\text{Emission factor per generation tech (t }CO_2\text{ /km)} \times \text{Km per mode of transport per annum (km)}\right) = \text{Total emissions per annum (t }CO_2\text{)}$$

APPENDIX 2.2 TRADE IMPACT

Trade impact for LNG via FSRU



Trade impact for piped gas



APPENDIX 2.3 GAS VS DIESEL TRADE-OFFS FOR THE POWER SECTOR

1. Difference in operational costs

(Fuel cost for gas and diesel (ZAR/GJ, assumed constant over time) × Gas demand and diesel demand for power (GJ per annum)) + (Variable OPEX for gas and diesel (ZAR/MWh) × Gas generation and diesel generation (MWh per annum)) = Total operational cost (ZAR)

Total operational cost for **low emissions no gas** power demand scenario – total operational cost for **low emissions low gas** power demand scenario

2. Difference in emissions (power sector only)

∑ (Emission factor for diesel and gas in power generation (t CO_2 /MWh) × Generation per tech (MWh)) = Total emissions (t CO_2)

Total emissions for **low emissions no gas** power demand scenario – total emissions for **low emissions low gas** power demand scenario

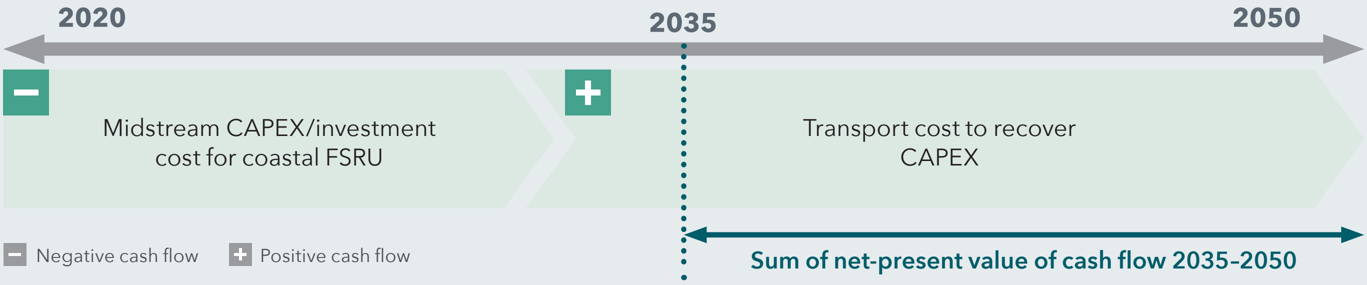
3. OCGT conversion cost (power sector only)

(Cost of converting Ankerlig and Gourikwa to dual-fuel* (ZAR) ÷ Capacity of Ankerlig and Gourikwa (GW)) × Total OCGT capacity in South Africa (GW) = Max conversion cost, assuming cost for Gourikwa and Ankerlig not yet paid off (ZAR)

Based on publicly available data

Cost only assumed in the **low emissions low gas** scenario. All other additional capacity (gas/diesel) and therefore CAPEX would be incurred in both scenarios – **low emissions no gas** and **low emissions low gas** (same new capacity and new-build CAPEX ZAR/kW)

4. Residual FSRU CAPEX post-2035

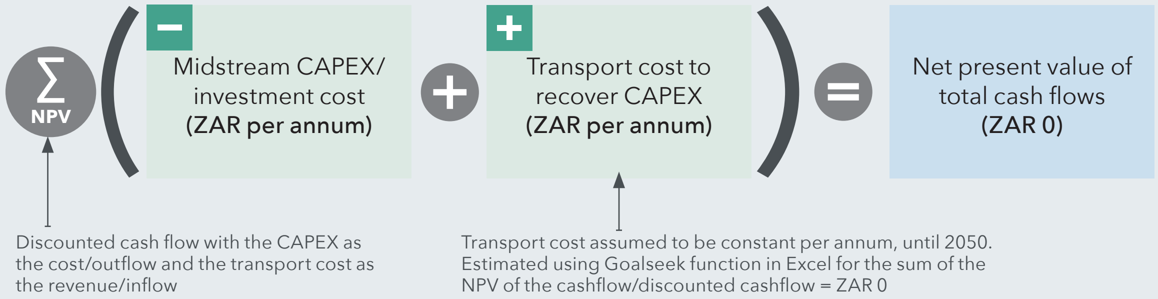


APPENDIX 2.4 BREAKEVEN TARIFF

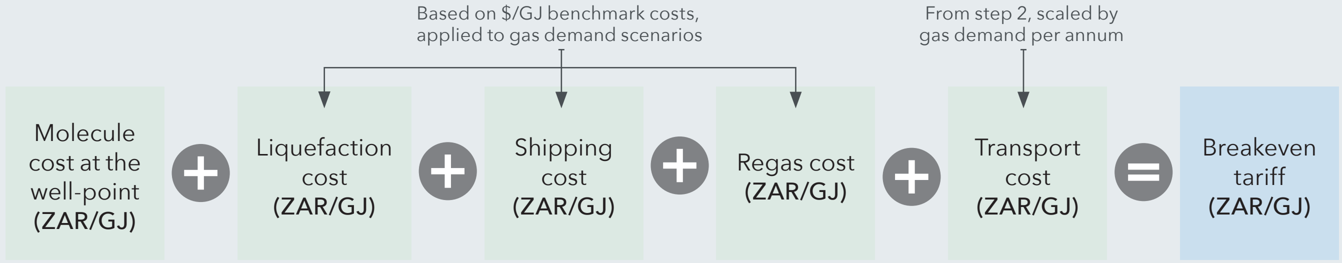
Step 1: Investment cost/midstream CAPEX (FSRU)

Step 1: Investment cost/midstream CAPEX (pipeline)

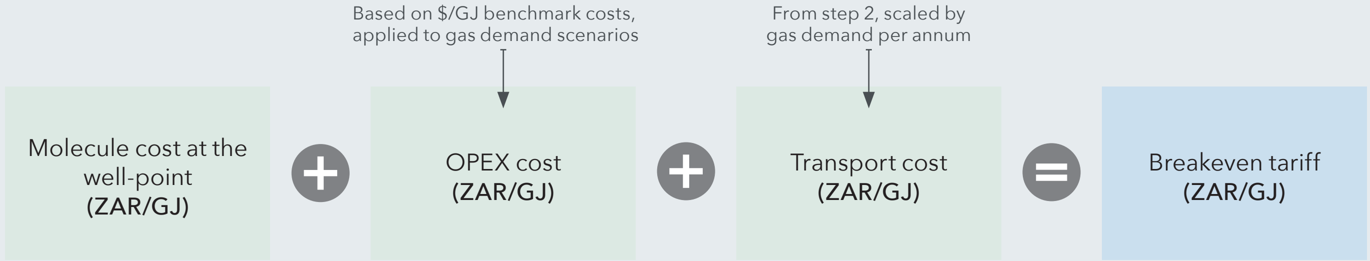
Step 2: Transport cost to recover midstream CAPEX (FSRU or pipeline)



Step 3: Breakeven tariff (FSRU)



Step 3: Breakeven tariff (pipeline)



APPENDIX 2.5 COMPARISON OF THE VALUE CHAIN EMISSIONS OF GAS VS COAL

Approach

This analysis estimates the total value chain emissions of coal, LNG, and piped natural gas to produce 1 MWh of electricity or 1 barrel (bbl) of liquid fuel, reflecting the efficiency losses at each step of the value chain – including the upstream mining or extraction, the midstream transport and storage, and finally the downstream end-use. Leveraging the energy input at each step of the value chain and the efficiency losses, the analysis quantifies the emissions at each step from the combustion of fuel and from leakages.

The analysis consists of two major steps:

Step 1: Estimate the energy input at each step of the value chain.

- Illustrative example for power generation with piped natural gas: 5.6–9 GJ of gas is required as an input to the gas turbines to produce 1 MWh, equivalent to 3.6 GJ, of electricity given efficiency losses of 36–60% (i.e., 3.6/(1–0.36) = 5.6 GJ). Similarly, 5.7–9.1 GJ of gas need to be transported in the gas pipelines given efficiency losses of ~1.5%. Finally, 5.8–9.2 GJ of gas need to be extracted given upstream efficiency losses of ~0.6%.

Step 2: Estimate the total CO_2e emissions and disaggregate per step of the value chain.

- Estimate the total cumulative value chain emissions, measured as the total energy extracted or mined, scaled by the emission factor for the given energy source. Using the example above:
  5.8 GJ *56 kg CO_2e/GJ = 313 kg CO_2e
- Disaggregate the emissions at each step of the value chain. Each step in the value chain's contribution to emissions is equivalent to the energy losses at each step scaled by the emission factor for the respective energy source.

Findings

Figures 18 and 19 (on the next page) provide an overview of the range of total value chain emissions, measured in kg CO_2e, for each energy source or feedstock to produce 1 MWh of power and 1 bbl of liquid fuel, respectively.

The following conclusions can be drawn:

1. For liquid fuels production, total coal value chain emissions (CO_2e) are 2.3 times higher than LNG and piped natural gas, despite taking an optimistic view of coal extraction and transportation losses. Producing 1 barrel of liquid fuels from coal emits more than 1 500 kg of CO_2e, relative to ~670 kg and ~570 kg from LNG and piped natural gas, respectively.
2. For power generation, the total LNG value chain emits 1.6–2.5 times less than coal, and piped gas emits 1.8–3 times less than coal. Producing 1 MWh of electricity from coal emits ~940 kg of CO_2e, relative to ~380–610 kg and ~320–510 kg from LNG and piped natural gas, respectively.

In the long-term, it will be critical not only to improve the efficiency of gas technology, but also reduce the emissions of the gas (i.e., produce 'cleaner' gas). This will require a combination of capturing technologies and solutions to mitigate leakages along the value chain.

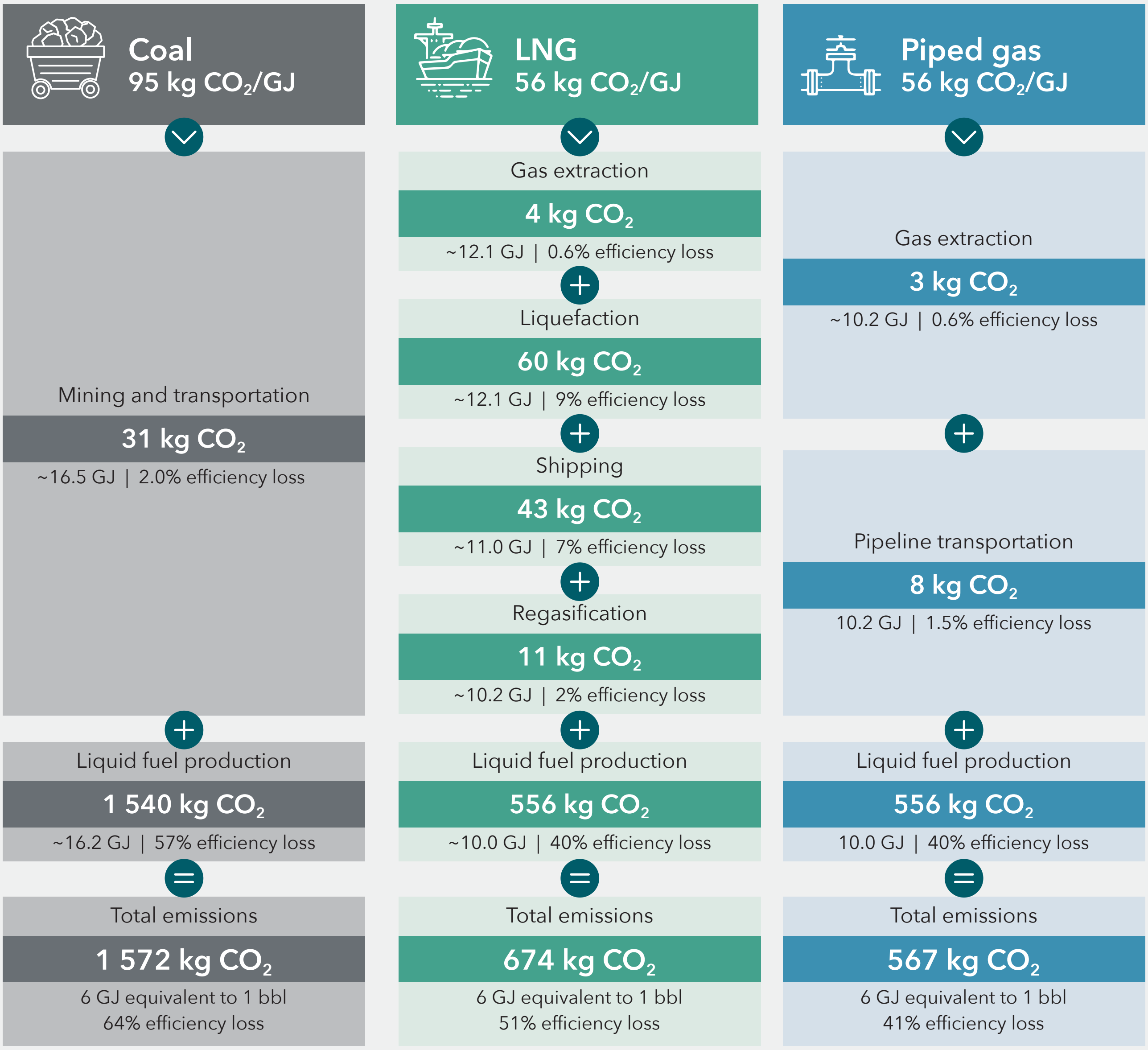


Figure 18: GHG emissions for liquid fuels production

Coal
95 kg CO_2/GJ

Mining and transportation
31 kg CO_2
~16.5 GJ | 2.0% efficiency loss

+

Liquid fuel production
1 540 kg CO_2
~16.2 GJ | 57% efficiency loss

=

Total emissions
1 572 kg CO_2
6 GJ equivalent to 1 bbl
64% efficiency loss

LNG
56 kg CO_2/GJ

Gas extraction
4 kg CO_2
~12.1 GJ | 0.6% efficiency loss

+

Liquefaction
60 kg CO_2
~12.1 GJ | 9% efficiency loss

+

Shipping
43 kg CO_2
~11.0 GJ | 7% efficiency loss

+

Regasification
11 kg CO_2
~10.2 GJ | 2% efficiency loss

+

Liquid fuel production
556 kg CO_2
~10.0 GJ | 40% efficiency loss

=

Total emissions
674 kg CO_2
6 GJ equivalent to 1 bbl
51% efficiency loss

Piped gas
56 kg CO_2/GJ

Gas extraction
3 kg CO_2
~10.2 GJ | 0.6% efficiency loss

+

Pipeline transportation
8 kg CO_2
10.2 GJ | 1.5% efficiency loss

+

Liquid fuel production
556 kg CO_2
10.0 GJ | 40% efficiency loss

=

Total emissions
567 kg CO_2
6 GJ equivalent to 1 bbl
41% efficiency loss

Notes: bbl = barrels.

Source: NBI-BCG project team; 3rd IPCC assessment report; IEA; Report: *Life cycle greenhouse gas perspective on exporting liquefied natural gas from the United States*, 2019.

Figure 19: GHG emissions for power generation

Coal
95 kg CO_2/GJ

Mining and transportation
19 kg CO_2
~9.9 GJ | 2.0% efficiency loss

+

Power generation
924 kg CO_2
~9.7 GJ | 63% efficiency loss

=

Total emissions
943 kg CO_2
3.6 GJ equivalent to 1 MWh
64% efficiency loss

LNG
56 kg CO_2/GJ

Gas extraction
2-4 kg CO_2
~6.8–10.9 GJ | 0.6% efficiency loss

+

Liquefaction
34-54 kg CO_2
~6.8–10.9 GJ | 9% efficiency loss

+

Shipping
24-38 kg CO_2
~6.2–9.9 GJ | 7% efficiency loss

+

Regasification
6-10 kg CO_2
~5.7–9.2 GJ | 2% efficiency loss

+

Power generation
313-500 kg CO_2
~5.6–9.0 GJ | 30-60% efficiency loss

=

Total emissions
379-607 kg CO_2
3.6 GJ equivalent to 1 MWh
46–67% efficiency loss

Piped gas
56 kg CO_2/GJ

Gas extraction
2-3 kg CO_2
~5.8–9.2 GJ | 0.6% efficiency loss

+

Pipeline transportation
5-8 kg CO_2
~5.7–9.1 GJ | 1.5% efficiency loss

+

Power generation
313-500 kg CO_2
~5.6–9.0 GJ | 36–60% efficiency loss

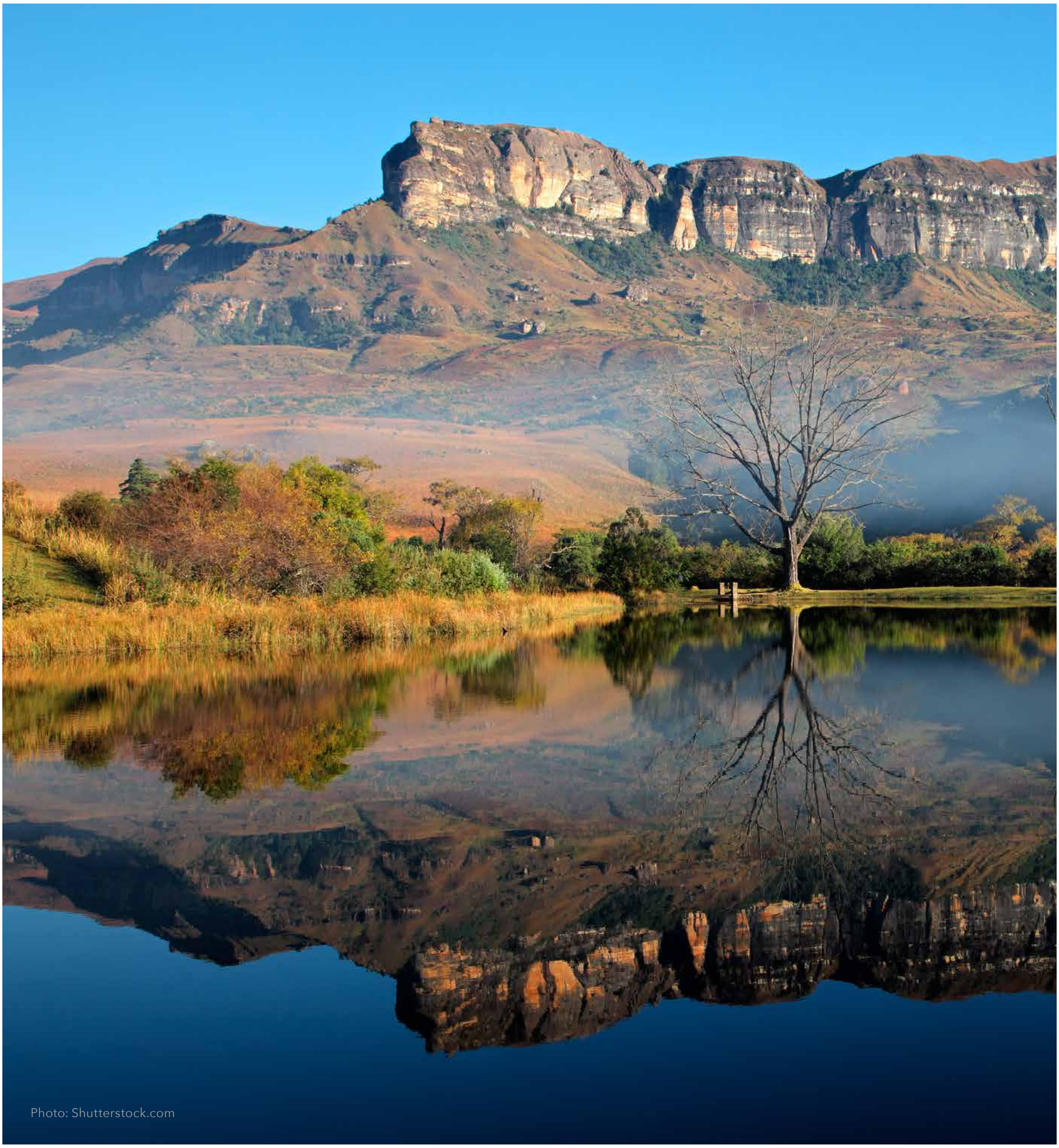
=

Total emissions
319-511 kg CO_2
3.6 GJ equivalent to 1 MWh
38–62% efficiency loss

Notes: Chinese and Russian benchmarks used as upper bounds for LNG and piped gas, respectively.
IEA pipeline emissions estimation method used.

Source: NBI-BCG project team; 3rd IPCC assessment report; IEA; Report: *Life cycle greenhouse gas perspective on exporting liquefied natural gas from the United States*, 2019.

National Business Initiative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