REGIONAL GAS MASTER PLAN

Phase 1

Prepared for: **SADC & DBSA**

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LIST OF ABBREVIATIONS

Abbreviation	Description
ANPG	Agência Nacional de Petróleo, Gás e Biocombustíveis
ARENE	Mozambique Energy Regulatory Agency
bbl	Barrel
bcf	Billion cubic feet
bcf/d	Billion cubic feet per day
bcm	Billion cubic metres
bcma	Billion cubic metres per annum
boe	Barrel of Oil Equivalent
BERA	Botswana Energy Regulatory Authority
BPC	Botswana Power Corporation
Btu	British thermal unit
CBM	Coal Bed Methane
CCGT	Combined Cycle Gas Turbine
CEB	Central Electricity Board
CNG	Compressed Natural Gas
COMESA	Common Market for Eastern and Southern Africa
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CTL	Coal to Liquids
DBSA	Development Bank of Southern Africa
DGEME	Director General of Energy, Mines and Water Resources of Comoros
Domgas	Domestic Gas
DMRE	Department of Mineral Resources and Energy
DRC	Democratic Republic of Congo
ECA	Economic Commission for Africa
ECCAS	Economic Community of Central African States
EDA	Electricité d'Anjouan
EDM	Electricidade De Moçambique
EEC	Eswatini Electricity Company
ENH	Empresa Nacional de Hidrocarbonetos
ENDE	Empresa Nacional de Distribuição de Electricidade
ÉNTSOG	European Network of Transmission System Operators for Gas
EPCC	Exploration and Production Concession Contract
ESERA	Eswatini Energy Regulatory Authority
ERB	Energy Regulation Board of Zambia
EU	European Union
EWURA	Energy and Water Utilities Regulatory Authority of Tanzania
FID	Final Investment Decision
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GJ	Gigajoules
GJ/a	Gigajoules per annum
GTL	Gas to Liquids

Abbreviation	Description
GTP	Gas to Power
GUMP	Gas Utilisation Master Plan
GW	Gigawatt
GWh	Gigawatt hours
Ha	Hectares
HDI	Human Development Index
H_2	Hydrogen
ICT	Information Communication Technology
IEA	International Energy Agency
IEP	Integrated Energy Plan
IOC	International Oil Companies
IPP	Independent Power Producer
IRP	Integrated Resource Plan
IRSEA	Instituto Regulador dos Serviços de Electricidade e de Água
ISO	Independent System Operators
km	Kilometre
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MARENA	Mauritius Renewable Energy Agency
MAMWE	Gestion de l'Eau et de l'Electricité aux Comores
MEEC	Seychelles Ministry of Environment, Energy, and Climate Change
MIREME	Ministry of Mineral Resources and Energy of Mozambique
MIREMPET	Ministry of Mineral and Petroleum Resources of Angola
MMBtu	Million British Thermal Units
MMscf	Million standard cubic foot
MPRDA	Mineral and Petroleum Resources Development Act of South Africa
MPSA	Model Production Sharing Agreement
MTPA	Million tons per annum
mtpd	Million tons per day
Moe	Millions of tonnes of oil equivalent
MW	Megawatt
MWh	Megawatt-hour
NAMCOR	National Petroleum Corporation of Namibia
NERSA	National Energy Regulator of South Africa
NG	Natural Gas
NGUMP	National Gas Utilisation Master Plan
NOC	National Oil Company
NWEC	North-Western Energy Corporation
O&M	Operations and Management
OCGT	Open Cycle Gas Turbine
OMC	Oil Marketing Companies
PASA	Petroleum Agency of South Africa
OPEC	Organisation of the Petroleum Exporting Countries
PAET	Pan African Energy Tanzania
PetroSA	Petroleum and Gas Operation of South Africa

Abbreviation	Description
PRODEL	Empresa Pública de Produção de Electricidade
PJ	Petajoule (Million GJ)
PJ/a	Petajoule per annum
PPP	Public Private Partnership
PSA	Production Sharing Agreement
PSC	Production Sharing Contract
PURA	Petroleum Upstream Regulatory Authority
RED	Regional Electricity Distributors
RGMP	Regional Gas Master Plan
RNT	National Electricity Transport Network of Angola
ROMPCO	Republic of Mozambique Pipeline Company
RSC	Risk Service Contract
SACU	Southern Africa Customs Union
SADC	Southern African Development Community
SAPP	Southern African Power Pool
SEC	Seychelles Energy Commission
SEYPEC	Seychelles Petroleum Company
SOE	State Owned Enterprise
SPV	Special Purpose Vehicle
SNEL	Société Nationale d'électricité
SSA	Sub-Saharan Africa
TANESCO	The Tanzania Electric Supply Company
tcf	Trillion cubic feet
TPDC	Tanzania Petroleum Development Corporation
URA	Utility Regulatory Authority of Mauritius
USA	United States of America
USAID	United States Agency for International Development
VAT	Value Added Tax
WAGP	West Africa Gas Pipeline
WAPP	West Africa Power Pool
WEF	World Economic Forum
ZDA	Zambia Development Agency
ZESA	Zimbabwe Electricity Supply Authority Holdings
ZESCO	Zambia Electricity Supply Corporation
$	United States dollar
̊C	Degrees Celsius

EXECUTIVE SUMMARY

1. INTRODUCTION

1.1 Context for Development of the Regional Gas Master Plan

The 37th SADC Summit of the Heads of State and Government held in Pretoria, South Africa in August 2017 directed the SADC Secretariat to coordinate and constitute an Inter-State (Regional) Gas Committee to promote the inclusion of gas in the regional energy mix and for industrial development. Furthermore, during the 38th SADC Summit of the Heads of State and Government held in Namibia in August 2018, the SADC Secretariat was directed to operationalise the Regional Gas Committee and to develop the Regional Gas Master Plan (RGMP).

The linkage between energy and economic development is a fundamental one. Energy is required for economic production, and therefore economic growth. SADC Member States require accessible energy that is secure, readily available, and affordable. This is required for investment in creating products of value to meet the needs of growing populations, while facilitating inclusive economic growth, and contributing to the reduction of poverty and income inequality. Yet we must be cognisant that the energy systems that are designed today must likewise cater to our needs of environmental sustainability and the global efforts to curb CO_2 emissions and mitigate the effects of climate change.

In this regard, globally, natural gas is the only fossil fuel that is expected to grow continuously, at least to 2035[1] – albeit curtailed by the current economic conditions caused by the Covid-19 global pandemic. As an important transitional fuel, building a gas economy through the various modes of utilisation can provide a viable path towards socio-economic development, job creation and poverty alleviation, while achieving the objectives of better regional (infrastructure and market) integration and cooperation in an environmentally sustainable manner. Due to the multitude of applications and uses; the proper harnessing of natural gas resources within the region could make a significant contribution towards the common goals of SADC Member States.

The role that natural gas can play extends beyond the energy sector for power generation and industrial heating, with effective utilisation of cost-competitive gas reserves possible as a chemical feedstock or transport fuel. As a chemical feedstock, natural gas can be used in the production of ammonia and urea, methanol, and diesel contributing towards sectors, including but not limited to, agriculture, mining, industrial development, consumer products and transportation.

To sustain economic growth, while reducing greenhouse emission levels, a large-scale energy transition is required, which is capital intensive and in which gas is recognised to play an important role. The importance and magnitude of the required transition highlights the need for investments to be scaled up across the region. Aggregating demand within the different gas-based value chains provides the opportunities to create the scale necessary for investment. At the same time, however, countries are trying to maintain and develop existing infrastructure and conventional energy resources to avoid stranded investments. The solution lies in the collaboration between member states, the private sector, and investors – enabling Governments' to facilitate the energy transition for their countries in a collaborative, prudent and sustainable manner, while leveraging the scale provided through regional integration.

[1] Global Gas and LNG Outlook to 2035, Energy Insights by McKinsey and Co.

Developing the natural gas market provides the opportunity to drive industrialisation and unlock regional development across sectors, industries, and countries; and realise the common objectives of SADC Member States.

1.2 Objectives and Methodology

A key element of the study was in determining the future supply and demand characteristics of the regional gas and gas product markets. Market development (and structures), infrastructure and investment are invariably linked; requiring an understanding of the mechanics of growth so that appropriate decisions on policy and optimal capital allocation can drive long-term economic development and value creation.

In understanding the supply and demand dynamics, the natural gas value chain, with demand drivers, supply options and routes to market must be defined.

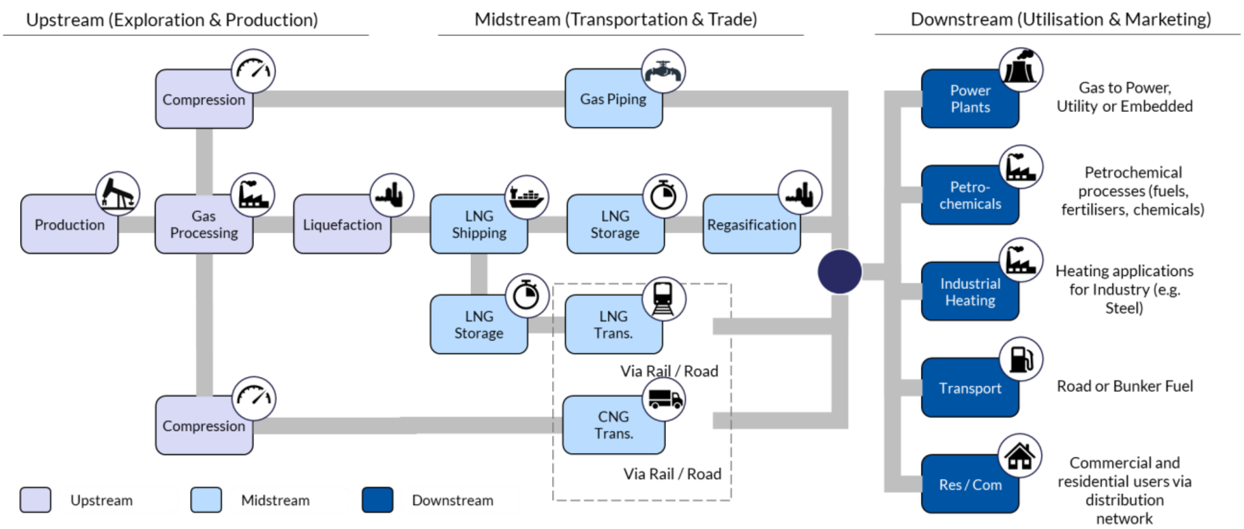


Figure 1-1: Natural Gas Value Chain

The natural gas industry consists of upstream, midstream, and downstream segments, as illustrated in Figure 2-1.

For gas to act as a catalyser for regional integration, cooperation and development, significant investment across the value chain is needed, together with the development of a regional gas market (or markets). As the regional market is largely at the nascent stage of development, a long-term scenario-based view is necessary, which for the purposes of this study is a 30-year horizon. The supply and demand landscapes are quantified across a national, regional, and international perspective, through a range of viable monetisation options and scenarios. In addition, analysis of the regional infrastructure, market and regulatory enablers are assessed to identify the requirements for standardisation and harmonisation to facilitate the development of a regional market. Due to the levels of uncertainty and the time horizon, a scenario-based approach was utilised and modelled across supply and demand towards achieving equilibrium.

The following was considered as part of the inputs for the modelling process.

- Macro-economic forecasts
- Stakeholder inputs
- Policy documents and stated policy intentions for different countries

The conceptual framework for development for Phase 1 of the RGMP is indicated in the figure below.

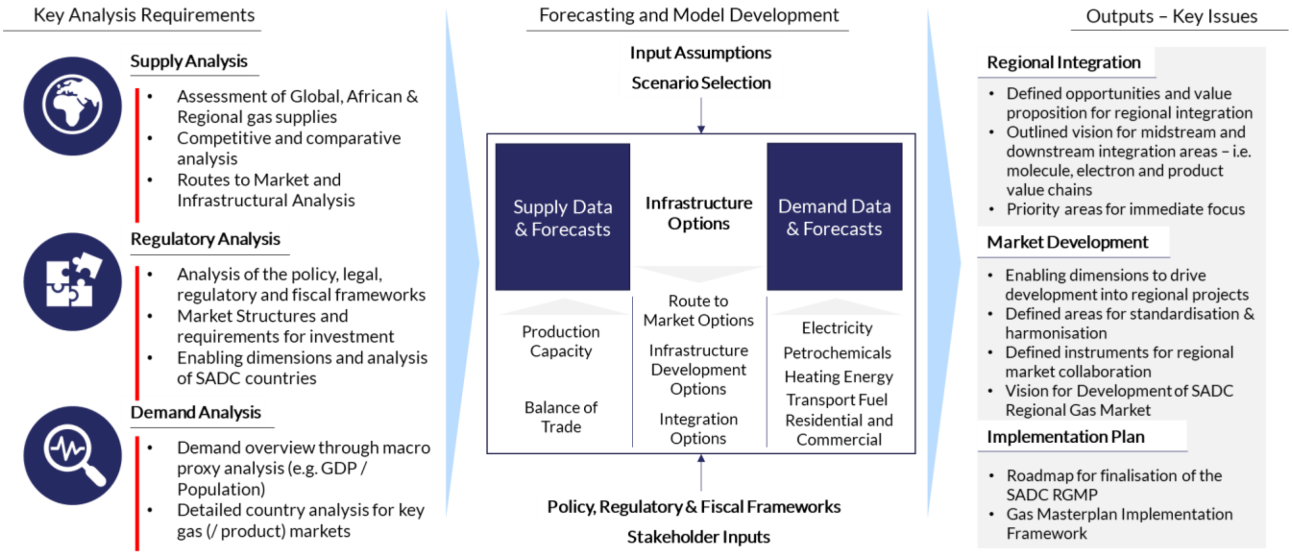


Figure 1-2: Conceptual Framework for RGMP Development.[2]

Delivering on this included a specific methodology, from a forecasting perspective, that sought to segment markets, assess trends, calculate outputs, and determine the impact of scenarios on the overall findings. This is highlighted in the figure below.

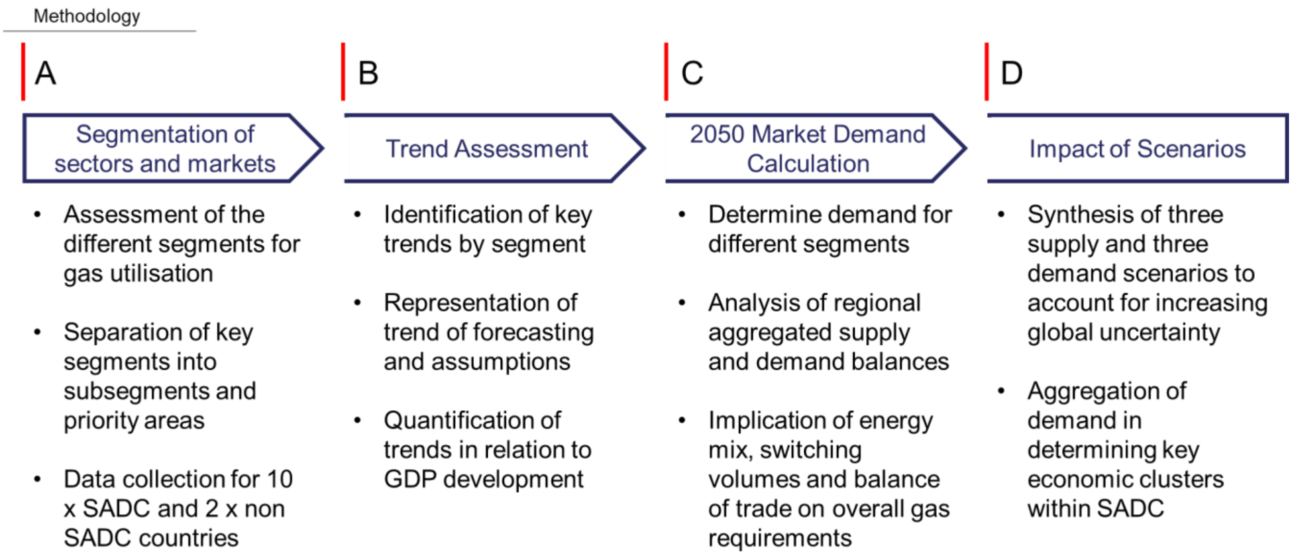


Figure 1-3: Forecasting methodology

The long-term forecasting approach considered key segments, base development per segment and impacts of industry-specific trends on demand. Gas supply requirements considered stated policy intentions (e.g. the country specific Integrated Resource Plans) and was escalated/deflated in line with demand growth projections and industry trends.

[2] Including elements of Phase 2 of the development of the RGMP.

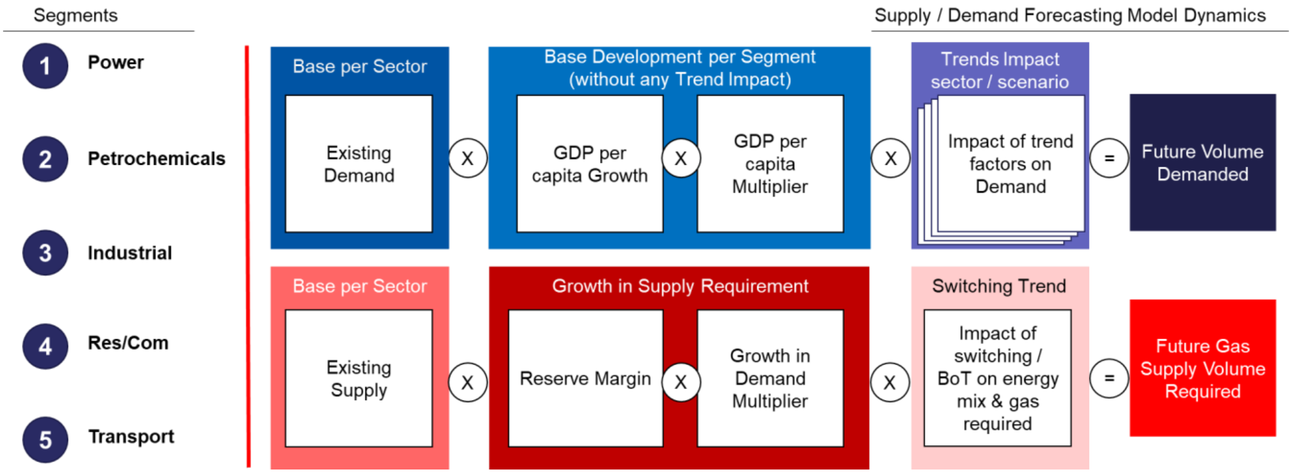


Figure 1-4: Supply Demand Forecasting Model Dynamics

The long-term demand forecasts provided the key focus areas for country integration, sector development and infrastructure development.

1.3 Dimensions for Enablement

Developing the regional market requires a concerted and coordinated approach by SADC Member States, with a focus on key dimensions for development. The key dimensions[3] were selected based on the centrality to the integration and development of a regional market and provided a consistent framework in analysing each member state and the requirements for standardisation and harmonisation. This considered:

- Market development, including:
  - Molecule Access (i.e. necessary volumes required for gas users)
  - Affordability (i.e. price of the molecule that is affordable for users and competitive against alternate energy sources)
- Infrastructural enablement, including:
  - Tariffs
  - 3rd Party access
  - Regional aggregation
- Security of supply, including:
  - Quality and security of supply
  - Multiple supply options, including LNG and domestic sources
  - Development of regional upstream sector

Enabling conditions are required to facilitate investment across the value chain. This includes investment in:

- Industrial demand applications, including power generation, petrochemicals, and heavy industry
- Infrastructure to connect supply and demand, including ports, LNG regasification and storage facilities, pipelines, rail, and road networks
- Supply options, including gas field exploration, development and production, and LNG liquefaction.

[3] Adapted from World Economic Forum, 2018, Fostering Effective Energy Transition.

Market development does not happen in isolation. Enabling factors must be present to attract investment and catalyse the required development. The enabling dimensions considered included:

- **Capital and Investment.** The availability of capital and the macro-economic and fiscal conditions for investment.
- **Policy, Legislative & Regulatory.** Policy direction, legislative and regulatory frameworks, with maturity, certainty, and consistency in application.
- **Institutions & Governance.** Roles and responsibilities of key governance entities within the regulatory, public, and private domains.
- **Infrastructure & Market Structure.** Quality of infrastructure, market size and 3rd party access.
- **People: Capacity & Participation.** The necessary skills, competencies, and talent in developing technical value chains and thereby providing the human capital.
- **Energy System Structure.** Maturity of the market and energy system structure, including energy mix (i.e. fossil fuels, renewable etc.)

1.4 Strategic and Policy Linkages

All SADC Member States have adopted 17 ambitious policy goals to end poverty, protect the planet, promote gender equality, and ensure prosperity, as part of the United Nations Sustainable Development Agenda, and are committed to achieving specific targets by 2030.

The SADC region has a specific set of key issues that requires focus and intervention which, in turn, means that different Sustainable Development Goals (SDGs) will be prioritised over others. Given the issues facing the sub-region, six priority themes have been identified by the African Union for sustainable development namely a) poverty eradication b) education and technical skills, c) gender equality and social inclusion, d) health and nutrition, e) environmental sustainability and, f) governance.

The SDG 7 seeks to ensure access to affordable, reliable, sustainable, and modern energy for all. It aims to increase, substantially, the share of renewable energy in the global energy mix, and to double the improvement of energy efficiency. Progress on this goal translates to progress on all the above listed priorities. The process of assessing SADC implementation of SDG7 will be in linking the various SADC strategies to these three targets. The RGMP thus considers the role gas will play in the achievement of the SDGs.

Finally, the focus that every country has placed on achieving the SDGs, and the nationally determined commitments to the Paris Agreements, has led to a concerted regional effort to bridge the energy gap in the SADC region over the last ten years. SADC Member States have strengthened energy policy and regulations, advanced infrastructure, expanded grid connections, increased knowledge of off-grid energy solutions, and more. This study sought to ensure that the relevant strategic and policy decisions taken on a regional and national level were considered and integrated, ensuring alignment and consistency in planning.

2. KEY FINDINGS

2.1 SADC Natural Gas Supply

The SADC region has several natural gas deposits in various countries. Mozambique is currently at the forefront, with an excess of 100 trillion cubic feet (tcf) of proven natural gas reserves. Countries such as Tanzania, Angola, Namibia, and South Africa have economic reserves that are currently, and can potentially be, monetised. Over and above the proven gas reserves, SADC Member States have sizable estimated / probable natural gas reserves. These estimates have been a result of ongoing exploration activities at various key areas. Most of the regional resources, nonetheless, are underdeveloped, raising concerns around their exploitation in the short term.

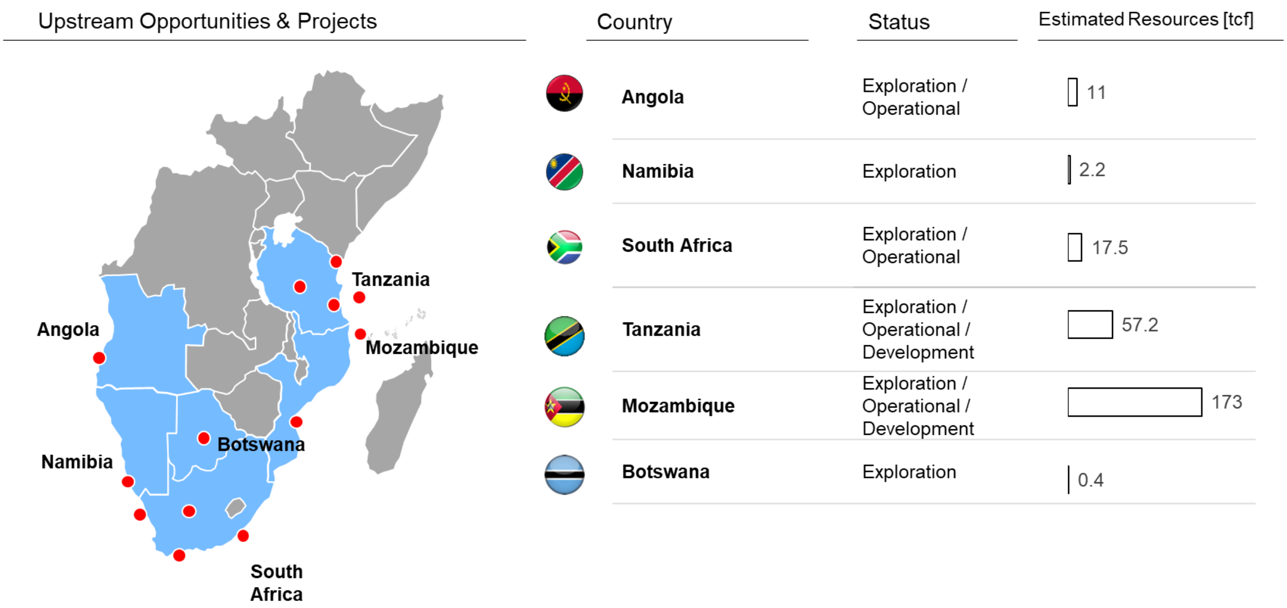


Figure 2-1: SADC Natural Gas Resources [4]

Current production of natural gas occurs within Mozambique, Angola, Tanzania, and South Africa, with combined current production levels of 9.6 billion cubic meters (bcm), which translates to approximately 360 PetaJoules per Annum (PJ/a)[5]. Natural gas production is forecast to grow rapidly and reach approximately 50 bcm (2035 PJ/a) by 2026 – driven largely by Liquefied Natural Gas (LNG) export projects - earmarked for export to global markets.

Currently, Angola is the only producer of LNG within SADC, with a capacity of 5.2 Million Tonnes per Annum (MTPA). The liquefaction capacity in the SADC region is likely to increase to 36.7 MTPA, with the installation of new liquefaction trains in Mozambique (Area 1 and Area 4), and potentially even higher with additional trains in Mozambique and possibly Tanzania. This liquefaction capacity is largely committed to international markets – however depending on the commercial and in-country arrangements, domestic gas allocations could possibly be utilised within the regional context through either trading of the molecule or trading of the downstream products, i.e. electrons, fertiliser etc.

When considering the supply and demand landscape, alternative supply options outside of SADC must be considered to meet demand needs – namely global LNG. LNG provides the opportunity to build a gas market characterised by multiple suppliers, integrating global and regional supply options while delivering gas to multiple regional off-takers.

[4] BMI Fitch Solutions Data, 2019
[5] IEA, 2017. Natural gas production.

2.2 Natural Gas Trade Dynamics

The monetisation of gas requires effective delivery mechanisms and routes to market. There are three specific ways in which gas can be delivered to the market; this includes:

- In-Situ transformation, i.e. power, ammonia, methanol, or diesel production where gas is produced and delivered via electrical transmission grids, road, rail, or ship
- Natural gas compression with conventional delivery via pipeline or small-scale CNG delivery through road, rail, or ship
- Liquefaction of natural gas with conventional delivery via large ships or small-scale delivery via road, rail, or smaller ships

Natural gas is still primarily utilised where produced, however, LNG has been increasingly facilitating global trade, which accounted for 10.7% of the total natural gas global supply in 2017.[6] Growth rates have been largest in the LNG market at 3.75% Compound Annual Growth Rate (CAGR), while overall, the gas market has seen consistent growth. Figure 5-9 illustrates the major global natural gas trade flows, and it indicates that there is limited intracontinental natural gas trade in the African continent.

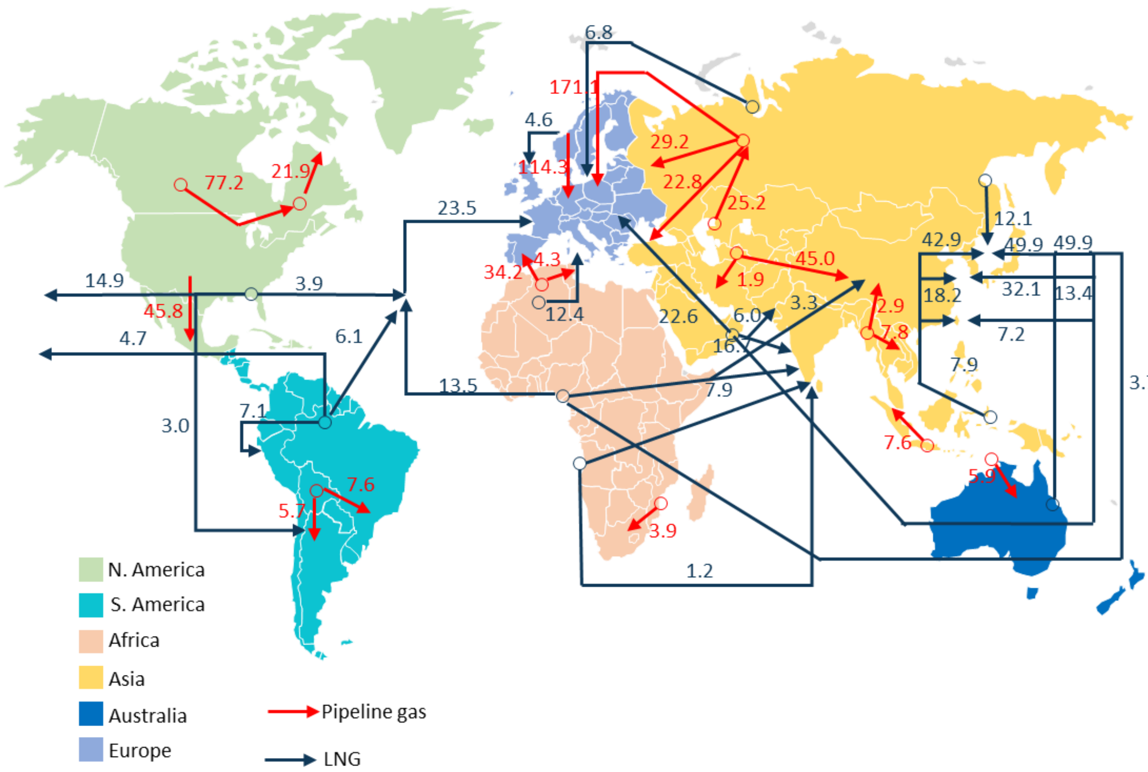


Figure 2-2: Major natural gas global trade flows by pipeline and LNG, 2018 [bcm].[7,8]

As an industry that is growing and still maturing, LNG has become a key delivery mechanism for natural gas where distance and terrain (i.e. deep water) prohibits pipeline delivery. As capital costs have historically been high due to the scale required for economic feasibility, the industry developed towards larger scale projects (both liquefaction and regasification) with long-term off-take contracts.

[6] International Gas Union. World LNG Report, 2019.
[7] BP, 2019. BP Statistical Review of World Energy 2019.
[8] International Gas Union, 2019. 2019 LNG World LNG Report.

Changes in the LNG industry have been driven both by the market as well as technological shifts. Greater global LNG supply has increased the commodification of the product that has impacted market liquidity and thus the trading mechanisms.

It is expected that the LNG market will remain a buyers' market for the next several years due to new supplies of LNG becoming available in the Middle East, Far East and Africa. Additionally, there is a divergence between pricing of crude and natural gas as more markets seek different commodities (e.g. coal) to index LNG pricing with. This would be an opportune time for regional suppliers and buyers to collectively develop a natural gas grid under the purview of an enabling policy and regulatory umbrella to create a competitive gas market in the SADC region.

Furthermore, technological shifts have featured small scale technologies as well as floating liquefaction and regasification facilities. These shifts have reduced overall infrastructural requirements, thereby decreasing capital expenditure, and improving overall economics. From a SADC perspective, integrated conventional LNG, small-scale LNG (ssLNG), and pipeline options should all be considered to ensure maximum demand aggregation while minimising unnecessary and unaffordable infrastructure and capital expenditure.

Local gas prices, particularly for imports, are influenced by global markets and impacted by regulatory and policy choices which in turn imposes costs through taxes and mandated technology choices. Taxes incentivise or disincentivise fuel choices, while grants, subsidies, and developing economies of scale as the adoption of new technology increases, can offset capital costs.

The development of reticulation infrastructure from sources of supply to markets within the SADC region will help develop the natural gas market. A regional public private partnership in which the suppliers & buyers are guaranteed off take at prices that are attractive will assist in the development of the regional gas market. Having a transnational natural gas grid, and where that is not possible, supply through a network of LNG terminals along the coastline with a virtual pipeline will help in disaggregating the natural gas market using the geographical advantages of these economies.

For the cost competitiveness of gas to be realised in the SADC context in the long term, the necessary incentives will be required, while the long term development of a physical market will assist in driving the decoupling of oil indexed gas pricing for the SADC context and move towards gas-on-gas, or alternative fuel indexing price formation mechanisms.

2.3 SADC Natural Gas Demand

Natural gas demand forecasts were conducted across ten (10) SADC Member States and two (02) non-SADC countries, namely: Angola, The Democratic Republic of Congo, Ethiopia, Kenya, Malawi, Mauritius, Mozambique, Namibia, South Africa, Tanzania, Zambia, and Zimbabwe. Although demand for natural gas varies across geographies and sectors, country-level volumes may be insufficient to drive the development of local gas markets and maximise the identified downstream potential in-country. However, through aggregation across certain geographic nodes, aggregated volumes are likely to provide the necessary scale for regional market development.

Current demand for natural gas is nascent within Southern Africa, as the countries who consume natural gas are those who produce gas, with limited intercountry trade. South Africa, as the largest consumer of natural gas in the Region, however, is the outlier that imports a significant amount of gas to fuel its domestic petrochemical industry through the ROMPCO pipeline from Mozambique.

Electrification rates vary across the region, yet current levels mostly hinder socio-economic development and the industrialisation of the respective economies. Additionally, the identified countries derive much of their power from either hydro sources or fossil fuels (i.e. coal and oil products). Generally, as energy mixes have shifted away from coal and incorporated a greater share of renewable (i.e. wind and solar), variability in power supply has been introduced into energy systems requiring storage or load-following generation capacity to balance supply and demand. Though hydro sources are important for the region, climate change is impacting rainfall patterns, thereby contributing towards uncertainty in this regard.

Natural gas demand in electricity generation will be driven by a combination of factors, including its favourability as a load-following source while being complementary to renewables at utility-scale, as well as its comparative resilience to the effects of climate change. This, while being at least 18%[9] cleaner than alternative fossil fuels in terms of greenhouse gas (GHG) emissions.

It was forecasted that approximately 400 PJ/a of existing and new gas to power potential could be realised by 2030, which represents approximately 50% of non-petrochemical gas demand within the region. Ultimately, this would form the basis for developing the market within the region by providing the anchor demand necessary. Assuming anchor demand is established, additional downstream offtake would increase total aggregated demand to approximately 1427 PJ/a by 2050, which would be driven largely by additional electricity demand, petrochemical demand, fertiliser demand and industrial demand.

General economic development shares a positive correlation with individual calorific uptake, thus increased volumes of fertiliser would be required to improve crop yields to supply food to growing populations with access to a higher standard of living. Additionally, as several of the identified countries develop from agrarian economies towards industrialised economies, industrial heating demand will grow across various sectors from Fast Moving Consumer Goods (FMCG) and agro-processing to metallurgical and construction materials production industries as urbanisation rates and industrialisation increase within the region.

The energy and chemical feedstock requirements were aggregated across countries and monetisation options and is presented below in the Base case scenario.

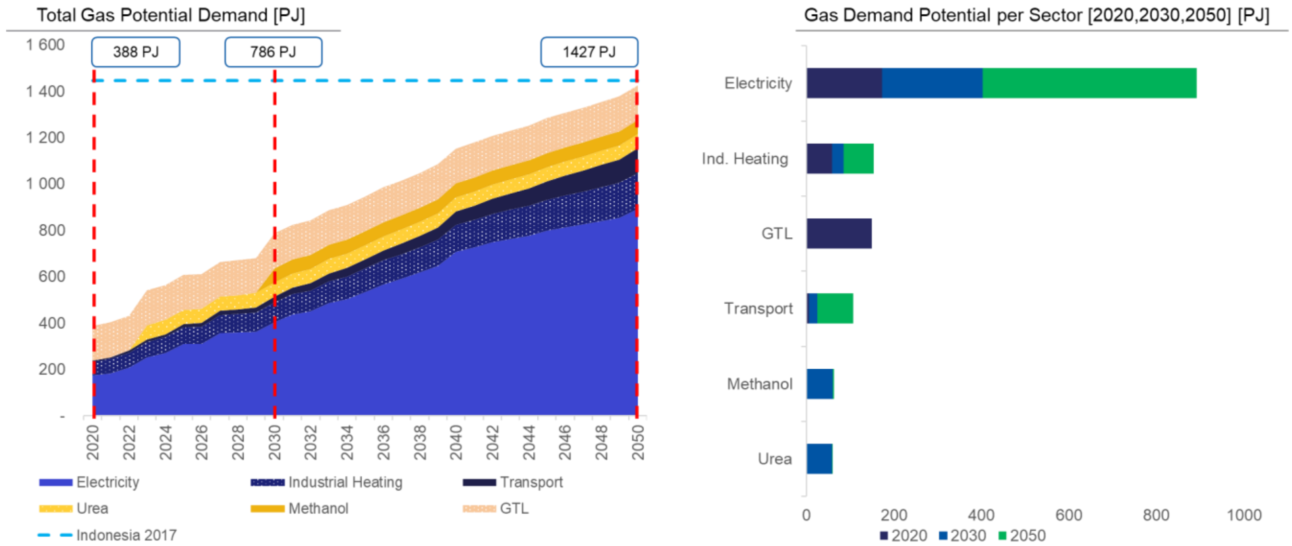


Figure 2-3: Total projected gas demand up to 2050 [Base case scenario]

Natural gas demand in the region over the next 30 years is closely tied to infrastructure capacity and supply. From a thermal heating perspective, which is dependent on individual country industrial

[9] IEA, CO_2 Emission Statistics

heating, electricity and transport demand, gas-to-power provides anchor demand and is encompassed in almost all the domestic energy projections. Petrochemical demand, which includes GTL demand in South Africa, ammonia / urea plants on the east and west coasts as well as a methanol plant in proximity to the Rovuma Basin. Tanzania and Mozambique are the two options for both the methanol facility as well as a fertiliser production plant on the east coast of the region.

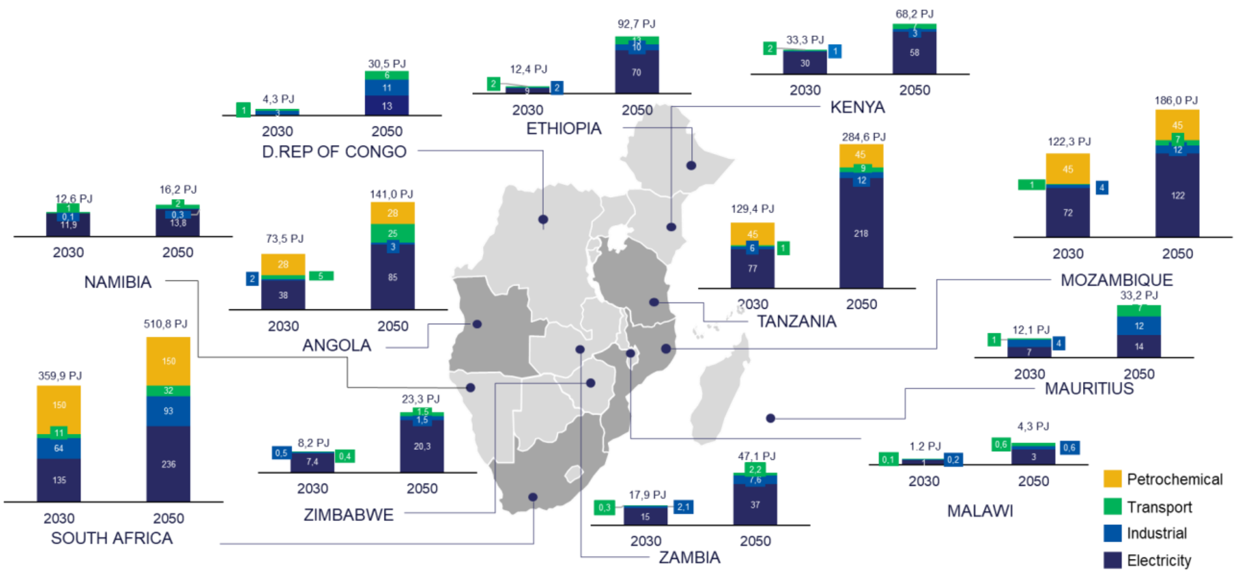


Figure 2-4: Aggregated Country Gas Demand '30/'50 [Base case scenario]

In the high case scenario (shown in the figure below) total aggregate demand is 41% above the base case by 2050. This is a result of a gradual increase in natural gas uptake by Sasol, as it transitions from using coal to produce liquid hydrocarbons. Additional growth is also attributed to GTP growth as the share of natural gas in the electricity supply mix grows with a greater shift towards renewables. In this scenario, the region has three urea producing plants to supply fertiliser to the region as well as exports into the rest of Africa. This scenario considers a future where natural gas is abundant and affordable within the region.

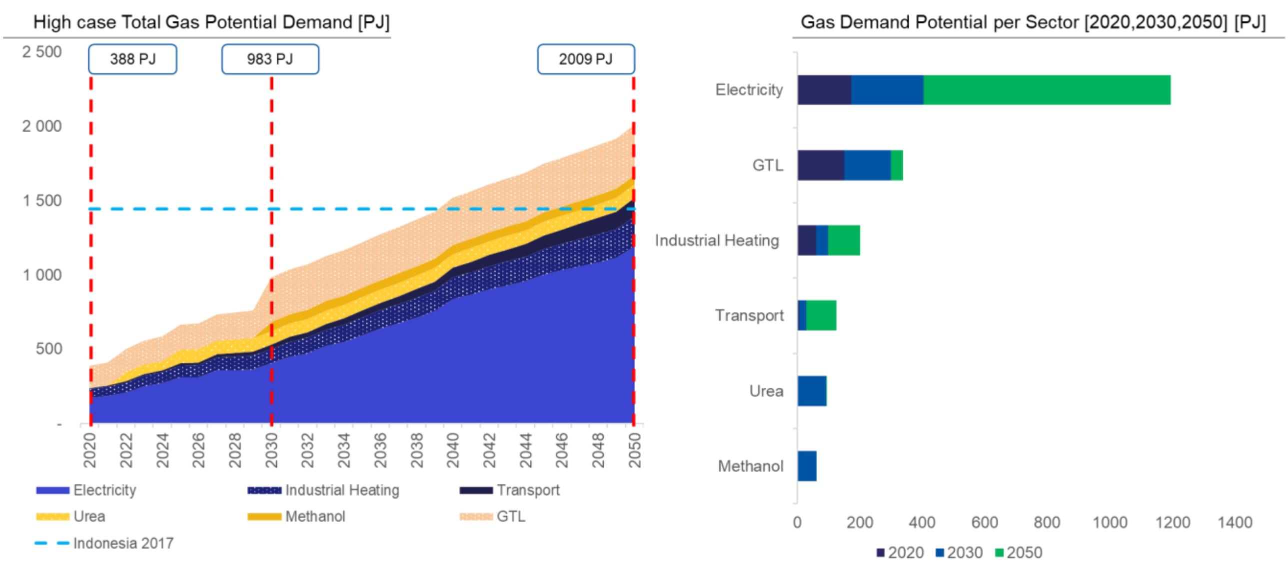


Figure 2-5: High case total aggregated projected gas demand up to 2050

In the low case scenario (show in the figure below), total aggregate demand reduces by approximately 30% from the base case by 2050. Key differences include the lack of a methanol facility within the region and only a single urea plant. GTP potential beyond 2030 is reduced as electricity planning adjusts to limited availability of cheap natural gas.

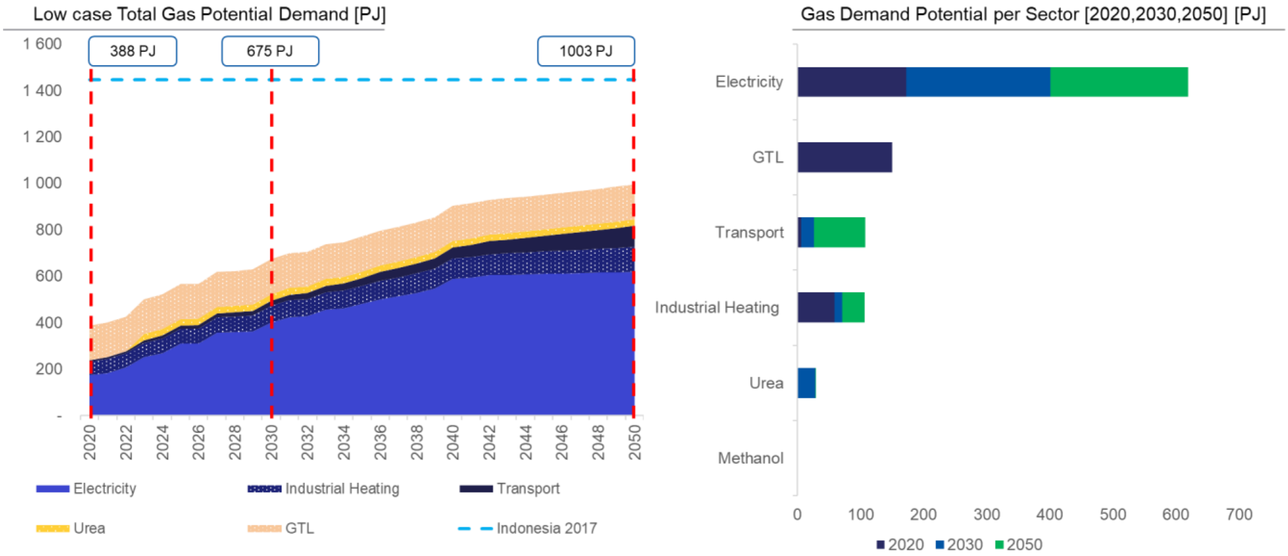


Figure 2-6: Low case total aggregated projected gas demand up to 2050

2.4 Gas and Related Market Infrastructure

From a strategic perspective, developing infrastructure can create market access and scale and is the area where regional cooperation will yield the most tangible results. Infrastructure is the vital link that connects the supply and demand nodes for natural gas, petrochemical products, industrial users, the transport sector, and power generation. Each of the categories of products highlighted has different infrastructural requirements for the security of access, and the optimised utilisation of the natural gas molecule.

Gas infrastructure in the SADC region is currently at its nascent stage due to limited existing demand Where it does exist, these markets and infrastructure can act as a broader enabler by improving resource utilisation through leveraging existing assets, thereby reducing capital allocation requirements and ultimately mitigating risks.

In the short-term, as highlighted, LNG will be a necessary stimulus for natural gas utilisation. Regionally, there will be a need to develop regasification and storage facilities, with planning for facilities currently at various stages within Mozambique (Maputo), South Africa (Coega, Richards Bay and Saldanha Bay), Namibia (Walvis Bay) and Mauritius. Regionally, the adoption of a 'hub and spoke' model should be considered, with conventional size LNG vessels delivering to a Floating Storage & Regasification Unit (FSRU). This FSRU would enable breaking bulk at central regasification facilities with small scale options then transferring gas to supply nodes, via small scale LNG (ssLNG) carriers, LNG road and rail options. Using ssLNG technologies, a virtual pipeline can be created, negating the need for large scale capital investment. Once the market has grown, the project economics for a conventional LNG terminal and natural gas reticulation infrastructure would follow.

The current Republic of Mozambique Pipeline Company (ROMPCO), and South African domestic pipelines (Sasol and Transnet Lilly) serve as the basis for integrating possible LNG facilities in Richards Bay and Maputo, and downstream markets across southern Mozambique and the economic and industrial heartlands of South Africa (i.e. Gauteng, Kwa-Zulu Natal, and Mpumalanga). Due to the various gas supply options and associated cost-profiles likely to be available in the short-medium term, i.e. Pande & Tamane, Mozambican domestic gas and imported LNG, a differential approach for gas pricing will be necessary.

Longer-term investment in pipeline infrastructure would be required to fully grow the industry, with opportunities to build around existing pipelines. On the east of SADC, the existing Mtwara to Dar es Salaam pipeline can be extended to serve several of the inland countries while long term consideration should be given to a northern extension to serve the Kenyan market. The proposed Mozambican North-South pipeline stretching from Rovuma in the north of Mozambique and connecting the existing ROMPCO pipeline will be an important development for securing long term integration within the region and providing a means of boosting the regional economies.

Though natural gas infrastructure is central in developing the midstream market, existing electricity structures and infrastructure is an important enabler for regional integration through downstream integration. Electricity grids, unlike natural gas reticulation systems, see line losses. The longer-term integration of transnational natural gas pipelines connecting the producing sites in Tanzania, Mozambique to the main markets in South Africa and to Botswana and Namibia and ultimately to Angola should be a longer-term objective.

In the shorter term, the SAPP network is necessary in ensuring electricity security for the region, with there being an additional need to integrate the three non-operating members: Angola, Malawi, and Tanzania to the existing network. Strengthening the transmission infrastructure with high-voltage lines in Mozambique through the development of the North-South transmission infrastructure will be necessary for evacuating power from northern Mozambique to demand centres in the south. This is highlighted in Figure 2-7 below.

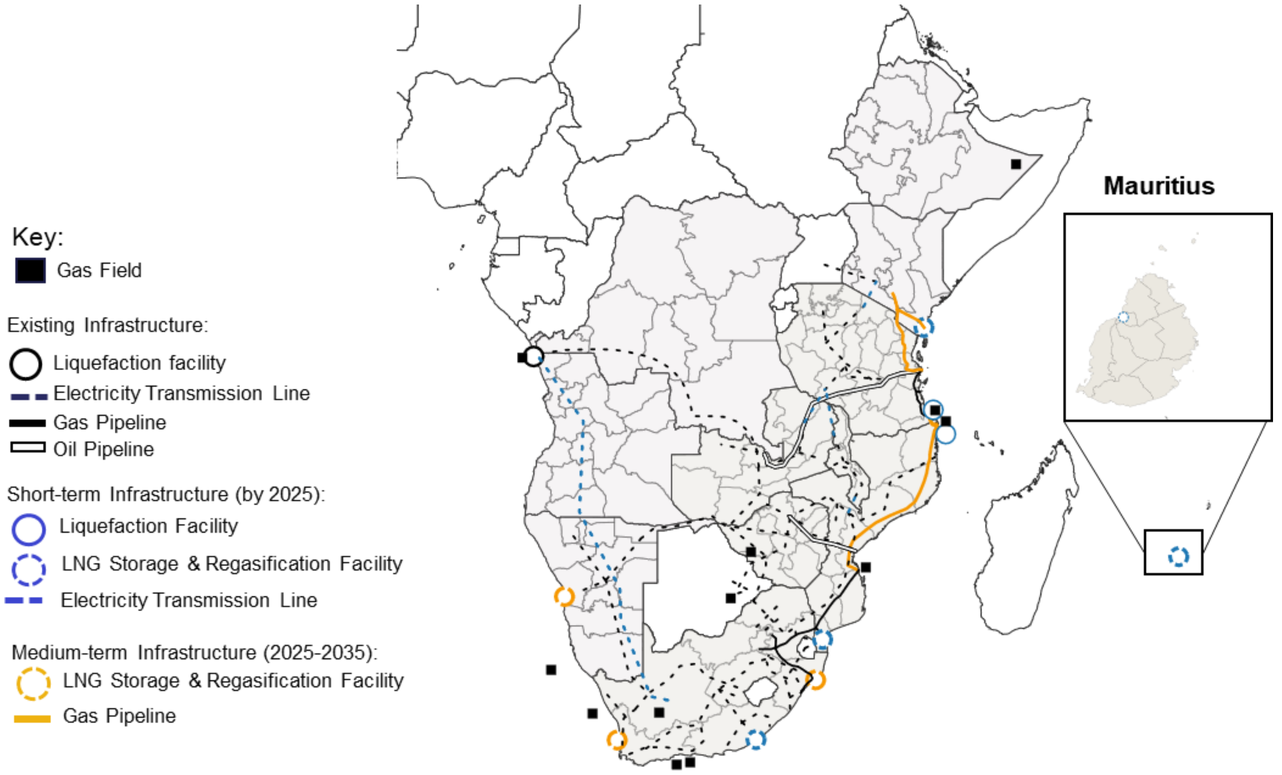


Figure 2-7: Infrastructure Requirements

The total planned installation of new Gas to Power (GTP) capacity in the region is ~8 800 MW, with which a significant component (i.e. Tanzania and Angola) will require interconnections to the SAPP network. Furthermore, in the region about ~14 000 MW of existing power stations can potentially be switched from fossil fuel sources to gas, which includes the switching of ~5 500 MW of coal-fired power stations planned for decommissioning in Mpumalanga, South Africa being a key component.

The repurposing of decommissioned coal-fired power plants in Mpumalanga can provide a fast track to justifying a conventional LNG train and upgrading of the ROMPCO pipeline to provide for the additional natural gas needs for such Combined Cycle Gas Turbine (CCGT) power plants at the Camden, Komati and Grootvlei sites, where power evacuation infrastructure is already in place, and local power demand is proven. The following presents various route to market options for infrastructure development to satisfy gas/gas product demand in the short, medium, and long term.

The development of infrastructure projects requires a roadmap that accounts for suitable funding mechanisms that enables the formation, development and capacitation of regional entities, where skills and dividends can be recycled back into the regional economy, to alleviate the debt burden required to develop such infrastructure. Furthermore, increasing collaboration on infrastructure projects through regional investment, specifically in helping develop downstream projects and assisting in establishing a natural gas supply base focused on local and regional development. Encouraging investment by member states and regional finance institutions is necessary to ensure development aligns to regional and local requirements and long-term benefit to local communities is prioritised, together with ensuring that these investments yield retention in value in the region.

Table 2-1: Member State Route to Market Options

Market	Route to Market Options
Angola	• Transportation of LNG from Soyo to in-country demand zones through existing road infrastructure. • Transportation of LNG through conventional, or small scale means to regional demand nodes.
Democratic Republic of Congo	• In the west of DRC, import LPG from Angola, and transferral of via existing road/rail network. In the short-term, this route can also serve the east of DRC.
Malawi	• Development of interconnectors with SAPP for electricity importation. • Import LNG / LPG or petrochemical products through existing railway
Mauritius	• Development of a regasification facility in Port Louis, as demand lies in proximity to this port, and mature road/rail infrastructure can transfer natural gas or its products to the rest of the country.
Mozambique	• Liquefaction of gas in the north of Mozambique, and then regasification in the South of Mozambique to serve gas demand in Maputo • Development of a 2600 km pipeline from the north of Mozambique, connecting to the existing ROMPCO pipeline in Temane.
Namibia	• Importation of LNG through planned regasification facility, with Angola as the closest supplier. • The development of new markets near to the Kudu gas field or regasification facilities so as to limit the length of the pipeline. • Exporting gas through the Trans-Kalahari corridor from Walvis Bay into the region
South Africa	• Increase capacity of ROMPCO pipeline through additions of loop lines, as support new natural gas demand in Mpumalanga from GTP.

	• Import LNG through planned regasification facilities (1 - Coega, then 2 - Richards Bay) as GTP potential lies along the coast. This can be complemented with pipeline development, and the leveraging of the existing pipeline such as the reversal of flow direction of the Lily Pipeline, which can serve the existing market in Mpumalanga.
Tanzania	• Connecting the existing gas pipeline to Mozambique Rovuma and potentially upward towards the EAC
Zambia	• Importation of LNG/LPG and petrochemical products from Tanzania/Mozambique via existing road.
Zimbabwe	• Importation of LNG/LPG and petrochemical products from Tanzania/Mozambique via existing road.

2.5 Summary of Findings

As gas supply sources within the Region will be unable to fully meet growth in demand, especially in the short to medium term, Liquefied Natural Gas (LNG) is a necessary option in catalysing development. Short term development becomes dependent upon importation of global LNG, requiring new port, storage, and regasification facilities in key locations. Strategic small-scale options are considered as part of 'the hub and spoke' model – whereby aggregating regional demand, and breaking bulk in strategic locations, may be implemented with small-scale LNG (ssLNG) delivery mechanisms within the region. This is specifically true around the SADC Oceanic Member States and SADC Mainland Member States through ship, road, and rail. This would provide the necessary aggregated volumes required for overall improvements in LNG importation economics.

This is at the centre of the regional impetus, and the drive for regional integration – through regional demand aggregation and leveraging off existing regional infrastructure and markets, suitable scale can be realised thereby improving gas price economics within the region. However, though aggregation is an important consideration, and certainly one that enhances the overall value proposition of a regional gas market, it is anchor demand that secures investment and development.

The existing infrastructure and markets, across the value chain, can serve as the backbone for developing and growing a regional gas market.

Where domestic gas sources are available and competitively priced, utilising gas as a chemical feedstock can create value through:

- developing the agricultural and mining sector(s) through the production of fertilisers and explosives,
- supplementing fuel refinery blend stock through Gas to Liquids (GTL) diesel or methanol, and
- catalysing downstream petrochemicals industries.

Through existing, strengthened, and new regional transport and economic corridors, gas-based products can contribute to economic and social development and aid in the creation of value for both the suppliers and consumers within the region. This will require strengthening of existing institutions and capabilities within the region, ensuring relevant technical skills are present to deliver on the promise of gas-based industrialisation.

In the medium to long-term, the market development must consider the creation of a gas hub, or gas trading market that allows for:

- *Market and infrastructure access to gas suppliers and off-takers*. That is, all gas related infrastructure such as natural gas pipelines, import and export terminals, regasification and storage infrastructure, and transmission networks, must allow for third party access.

- *Many market participants*. The policy structures must encourage competition at all levels except where there are natural monopolies, e.g. ports and pipelines where third party access must be made available utilising regulatory mechanisms that are fair and allow for transparency and competition.
- *Clear price formation mechanisms* providing confidence and transparency to both buyer and seller with price discovery that allows for effective trading and growth of the market.
- *Gas-to-gas / LNG competition and demand side responses* such as coal / oil switching capabilities with gas. This will allow for a fairer regional pricing mechanism, while consideration must be given to currency settlement structures relevant to the SADC context.

Finally, as part of the need to provide energy access for all within SADC, a balanced and integrated approach must be considered towards the role gas can play. Liquefied Petroleum Gas (LPG), ssLNG and conventional LNG all serve an important and collaborative role. LPG can facilitate improvement in cleaner energy access in the residential and commercial sectors, where its ease of transportation and handling can drive developments in less mature markets within SADC, while ssLNG can connect countries within SADC without the need for costly and inhibitive pipeline, or conventional LNG, infrastructure development.

3. RECOMMENDATIONS

3.1 Regional Integration

All countries in the region, separately and collectively through SADC membership, agree on the need for cooperating and collectively developing projects that are beneficial for the Region, in line with the SADC Protocol on Energy of 1996 (under review). In this regard, successful regional market development can be summarised across the factors below.

Table 3-1: Regional Integration Factors

Factor	Description
Regional Market Development	• Member States seek natural market integration, which most seamlessly occurs through the convergence of economic and social parameters. To enable this, countries must harmonise energy laws and policies across the region. • Efficient macroeconomic policy convergence underpins successful cross-border financial and monetary integration that stimulates trade among Member States.
Infrastructure	• Economic corridors on the East, West and Northern areas of the SADC region should be developed to facilitate the development of the regional gas market. Through creating a dynamic business environment along the corridors, Member States will harness sector linkages, enhance cross-border trade, and maximise economic growth. Political boundaries would cease to be economic boundaries while spatial-economic regional planning takes the lead. • The Southern African Power Pool (SAPP) is a necessary regional network and market to trade and transfer electrical power between utilities within SADC. In order to enhance the opportunity for gas generated power to be traded through the SAPP, the network must be developed and extended throughout the region, non-operating SAPP members must be connected, and transmission congestion must be relieved.
Aggregation	• Considering the concentration of supply and the potential distribution of demand (particularly if gas off-takers enter the market), aggregation will be required on a wholesale basis for distribution across downstream sectors. • The SAPP brokerage model, which has been successful in the region, is a key learning tool for the development of a regional gas aggregator which will consolidate the demand of national aggregators within the region against supply. This will facilitate cross-border, where transparency, fairness and competitive mechanisms are required to establish trust and cooperation between Member States and their entities. • The long-term opportunity for the SADC region is to develop a physical gas trading hub, leveraging off existing demand, infrastructure, and supply, thereby creating a mechanism for which price discovery can occur in a transparent, fair, and equitable manner allowing for trading of the commodity. • Any developments in this regard must comply with the individual Member State competition laws, or plans must be made to apply for exemptions or authorisations where required.

Factor	Description
Regulation	• 12 SADC Member States out of the 16 have existing electricity regulatory authorities. From these, ten currently hold membership with the Regional Electricity Regulation Association (RERA), namely: Angola, Eswatini, Lesotho, Malawi, Mozambique, Namibia, South Africa, Tanzania, Zambia, and Zimbabwe. • RERA should continue to be transformed into the SADC Regional Energy Regulatory Authority (SARERA) as per the adoption of the RIDMP in 2012 by Heads of Member States. • This will grant regulatory powers to SARERA over cross-border energy trade, facilitation of cross-border energy infrastructure investment, and energy regulatory capacity building.[10] Once this transition has taken place, it is expected that SARERA will be capacitated to provide a methodology for setting of cross-border electricity, natural gas, and natural gas petrochemical products transmission, and products tariffs.

Regional market development does not happen in isolation. Member States must facilitate the process by ensuring that their own domestic markets provide an enabling environment.

3.2 Regional Development

Regional organisations have a key role to play in the development of the regional gas market. Key initiatives are as follows:

Table 3-2: Regional Development Initiatives

Organisation	Recommendations
Southern African Development Community Secretariat (SADC)	• Introduce Model Energy Guidelines to encourage Member States to introduce integrated energy planning into their energy policies. • Involve teams overseeing the SADC Trade Protocol in the development of the African Continental Free Trade Area (AfCFTA) Implementation Strategy. • Introduce best practice policy instruments and guidelines to enable investment and skills development within Member States • Reinforce commitment and implementation of the Regional Infrastructure Development Master Plan for the Energy Sector
Southern African Power Pool (SAPP)	• Spearhead the development of a Regional Transmission Infrastructure Program to unlock regional transmission constraints

Southern African Development Community Regional Energy Regulatory Authority (SARERA)	• Develop and introduce key instruments to regulate the energy sector on a regional level as well as encouraging harmony in regulation on a national level. These include:
	  ○ Network Access protocols to enable cross-border trade
	  ○ Wheeling Charges for the setting of transmission charges
	  ○ Intervention protocols against anti-competitive behaviour

[10] SADC, 2019. Development of a framework and roadmap for the Establishment of a Regional Energy Regulatory Authority for SADC.

Organisation	Recommendations
	• Regional regulation of the gas market will follow similar mechanisms that speak to the bespoke infrastructure requirements to facilitate gas trade.
Southern African Gas Pool (SAGP)	• Using the lessons learnt from the creation of the SAPP, Member states within the SADC region must agree on the development of a regional institution that would aggregate demand to strengthen buying power when engaging with upstream and/or mid-stream gas sellers in the region. • The organisation will introduce the market codes and standards for national aggregators and private sector players to abide by to participate in the regional gas market. Additionally, its role as an aggregator would enable the organisation to investigate and potentially implant a local pricing index for natural gas trade that speaks to the unique dynamics of the SADC region.
Regional Petroleum and Gas Association (REPGA)	• The Regional Infrastructure Development Master Plan for the Energy Sector recommends the introduction of the Regional Petroleum and Gas Association (REPGA) to advise policy makers in harmonising gas policies and fostering trade between the SADC Member States. There may be a potential overlap between REPGA, RERA and the SAGP, and it would be advisable to develop mandates and function that are clearly segregated to avoid confusion.

3.3 National Development

Member states should adopt the Model Energy Guidelines (developed by the SADC Secretariat) to develop national energy policies, Integrated Energy Plans, as well as sector specific policies to encourage the increased uptake of natural gas within different parts of the energy sector, i.e. LPG, electricity, fertilisers and petrochemicals.

The ability to attract capital and investment into the region to drive the development of the regional gas market will depend on how SADC Member States play a balancing act in providing a degree of protection to investors while protecting state interests. Implementing best practice relating to foreign investment attraction and management, dispute resolution, institutional capacity development and establishing a non-discriminatory framework for energy imports and exports will be fundamental, inviting the required resource to invest in infrastructure and technology.[11]

Existing education institutions[12] have the potential to enhance their offerings in the natural gas space, obtain finance for the development and running of courses, and essentially be transformed into hubs of knowledge development (both technical and institutional). This will enable the development of a workforce with sufficient skill to sustain the various activities required across the natural gas value chain on the national and regional level.

3.4 Market Development

The SADC region is in the nascent phase of gas market development, with the majority of member states having limited- to-no gas infrastructure, policy, or regulatory structures in place. In order to achieve maturity in the gas market, national developments, as well as regional developments, are required in terms of regulation, aggregation, policy, and infrastructure congruency.

[11] As is provided for in the ECOWAS Treaty
[12] The Kafue George regional Training Centre, RERA, SADC, SACREEE, for example.

As a region, policy development should be prioritised and should take place at the beginning of the developmental process to ensure aggregation of demand can be facilitated to enable competitive pricing (i.e. affordability) and security of supply (i.e. availability). Clear mandates regarding natural gas and associated products must be assigned to relevant institutions who will regulate and oversee national and regional gas markets. This will create the required certainty to attract investment from current and potential market participants.

Developing the foundations to enable the scaling of infrastructure, regulatory and market requirements for both supply and demand is necessary, to ensure market growth can be catered for optimally. Identifying potential long-term demand hubs, will enable long-term planning to ensure market development is effective and efficient. Governments would need to create mechanisms to enable market offtake, and particularly provision for reduced prices in underprivileged communities in close proximity to demand centres, both for the commodity as a fuel source, as well as, secondary products.

The initial market demand is more affordable and suitable for industry; with gas to power and petrochemicals being the primary demand anchors. The continual expanding and interconnectivity of the global LNG market makes LNG the most suitable supply mechanism where demand does not yet warrant pipeline development. Strong anchor projects as well as the development of demand hubs enable widespread use of natural gas and the resulting maturity of the natural gas market.

From a supply perspective developing domestic supply mechanisms such as Liquification facilities and pipelines to major demand hubs is necessary and important. Developing and balancing both supply and demand capacity is essential to establishing a robust regional gas market. Adequate regional demand and sufficient liquidity in supply to enable a flexible approach to supply and pricing as well as developing the necessary infrastructure, would foster consumer reach and affordability; ultimately leading to deregulation and a sustainable and competitive regional gas market.

4. WAY FORWARD

Market development is dependent upon there being supply, demand, connecting infrastructure, and an enabling environment to facilitate. Downstream anchor demand projects with sound economics are important to finance the roll out of mid-stream infrastructure to transport gas from supply sources to markets. However, the availability of capital and willingness to invest, skills and capacity, policy and regulatory certainty, appropriate institutional support and suitable market structuring are all necessary enablers for development.

The implementation plan focuses on realising market development through:

- Creating regional policy alignment and the environment within which gas market investment and development can occur
- Finalising a gas and gas product infrastructure development blueprint, which would include pipeline, gas processing and liquefaction plants, LNG storage and regasification, road, rail, and port development
- Formalising regional clusters with cooperation modalities, through strengthened economic corridors and corridor management agencies, to facilitate trade in gas and gas products
- Securing anchor demand to enable investment in infrastructure development, where the immediate focus for anchor demand would be within the power sector
- Developing regional institutions for aggregation, securing regional supply and trading of the molecule, allowing for transparent access to infrastructure and providing clear price formation mechanisms necessary for market development
- Enhancement of regional energy regulator to include effective regulatory mechanisms for regional energy trade, including 3rd party access, tariffs and pricing of gas and related products
- Development of sector specific recommendations to standardise downstream products within the gas value chain (e.g. fertiliser standards)
- Development of skills across the gas and associated value chains thereby strengthening in-country capability around gas-based economies

At a programme level, strategic interventions have been recommended to enable the implementation of the Regional Gas Master Plan by the SADC Secretariat and Member States, underpinned by four strategic outcomes, namely:

1) Economic corridors that maximise regional integration and trade,
2) Effective trade of natural gas and its downstream products,
3) An enabling policy environment, and
4) A highly skilled and innovative workforce

This is highlighted in the table below.

Table 4-1: High Level Implementation Programme

Outcome	Strategic Interventions	Timeframe
Economic corridors that maximise regional integration and trade	*1. Formalise regional clusters and cooperation modalities 2. Strengthen existing interconnecting road, rail, port, and power transmission infrastructure which enables the movement natural gas and/or natural gas products 3. Establish a Corridor Management Group or Institutions to oversee existing and developing economic corridors 4. Strategic planning between all stakeholders*	*2021 - 2023*
Effective trade of natural gas and its downstream products	*1. Investigate key revisions to the SADC Trade Protocol which would foster trade of natural gas and derivative products 2. Facilitate the development of intergovernmental trade agreements that reduce the cost of trading natural gas and derivative products 3. Develop a natural gas aggregation framework which enables the establishment of demand aggregators across the clusters 4. Develop sector specific recommendations to standardise downstream products within the Gas Value chain 5. Analyse existing competition laws in Member States, engage with relevant competition commissions and pave the way forward for exemptions and authorisations.*	*2021 - 2025*
Enabling Policy Environment	*1. Develop Model Energy Policy Guidelines to capacitate member states in developing Integrated Energy and Integrated Resource Plans 2. Reinforce outcomes of the SADC Industrialisation Strategy 3. Analyse critical public sector performance gaps which would impact the development of a natural gas market*	*2021 - 2025*
A highly skilled and innovative workforce	*1. Assess key skills requirements within the natural gas value chain 2. Recommend skills development initiatives targeted at the natural gas value chain 3. Develop sector skills plans that close the skills gap*	*2021 - 2025*
Investment driven economic growth	*1. Ensure policy certainty to foster investment within the region 2. Analyse policy alignment measures to drive domestic investment and private-public partnership*	*2021 - 2030*

CONSOLIDATED REPORT

1. INTRODUCTION

1.1 The SADC Natural Gas Imperative

The 37th SADC Summit of the Heads of State and Government held in Pretoria, South Africa in August 2017 directed the SADC Secretariat to coordinate and constitute an Inter-State (Regional) Gas Committee to promote the inclusion of gas in the regional energy mix and for industrial development. Furthermore, during the 38th SADC Summit of the Heads of State and Government held in Namibia in August 2018, the SADC Secretariat was directed to operationalise the Regional Gas Committee and to develop the Regional Gas Master Plan (RGMP). Outlined herein is the overall project approach taken by the Project Team as part of the development towards a Regional Gas Master Plan.

The linkage between energy and economic development is a fundamental one. Energy is required for economic production, and therefore economic growth.[13] The market requires accessible energy that is secure (and readily available) and affordable in order to invest and thereby create products of value.

Since the industrial revolution, hydrocarbons have been at the centre of global energy systems due to its energy potential and the ability to transport it over large distances. It has, undeniably, been a key driver of growth and human progress globally. However, continuous burning of fossil fuels to meet our energy needs has had the effect of increasing atmospheric CO_2, thereby causing a greenhouse effect. This effect has created temperature anomalies that have begun to disrupt global ecosystems. Governments globally have committed to decarbonising in order to stabilise and decrease atmospheric CO_2 levels.[14]

The need for energy, however, is as relevant today as it was 100 years ago. Growing populations, the need for inclusive economic growth, and the reduction of poverty and income inequality all require intervention in creating a better life for all, meaning the evolving energy systems that have emerged in a decarbonising world must cater to various needs and interests. This includes critically – the need for sustainable, equitable, and inclusive growth.

Within the Southern African Development Community (SADC) context, the need to increase energy access, security and affordability is one that affects every Member State. Yet our countries are facing challenges in infrastructure development and public service delivery, with Governments making limited progress in addressing the infrastructure gap required to facilitate the energy needs due to low implementation rates of capital projects, low economic growth rates and cash flow challenges.

To sustain economic growth while reducing greenhouse emission levels, a large-scale energy transition is required, which is capital intensive.[15] The importance and magnitude of the required transition highlights the need for investments to be scaled up across the continent. At the same time, however, countries are trying to maintain and develop the existing infrastructure and conventional energy resources to avoid stranded investments. The solution lies in the collaboration between Governments, businesses, and investors – Public Private Partnerships (PPP) - enabling Governments to facilitate the energy transition in their countries in a manner that is prudent and sustainable.

[13] David I Stern, 2010. The Role of Energy in Economic Growth.
[14] United Nations Framework Convention on Climate Change, 2015. Adoption of the Paris Agreement, 21st COP.
[15] Almari, Blackwell, 2014. Improving risk sharing and investment appraisal for PPP procurement success in large green projects.

The role that natural gas can play extends beyond the energy sector (power and heating), with effective utilisation of cost-competitive gas reserves in the regional context possible as a chemical feedstock or transport fuel. As a chemical feedstock, natural gas can be used in the production of ammonia and urea, methanol, and liquid fuels (e.g. diesel) contributing towards sectors, including but not limited to, agriculture, mining, industrial development, consumer products and transportation.

Developing the natural gas market provides the opportunity to drive industrialisation and unlock regional development across sectors, industries, and countries.

1.2 The Objectives and Methodology

Globally, gas is the only fossil fuel that is expected to grow continuously, at least to 2035.[16] Building a gas economy through the various modes of utilisation; including gas-based electricity generation, chemicals and fuel production, industrial heating, embedded generation, reticulation and transport applications can provide a viable path towards socio-economic development, job creation and poverty alleviation, while achieving the objectives of better regional (infrastructure and market) integration and co-operation. Due to the multitude of applications and uses; the proper harnessing of natural gas resources within the region could make a significant contribution towards the common goals of SADC Member States.

For gas to act as a catalyser for regional integration, co-operation and development, significant investment across the value chain is needed, together with the development of a regional gas market (or markets). Since gas is a low energy density molecule whose route to market infrastructure development requires scale for economic viability – regional integration that leverages existing infrastructure and allows for market aggregation becomes the driver for development. This requires a clear, coherent, and consistent legislative, regulatory and policy framework (at a national and regional level) that is necessary for investment and thus development.

As the regional market is largely at the nascent stage of development, a long-term scenario-based view is necessary, which for the purposes of this study is a 30-year horizon. The supply and demand landscapes are quantified across a national, regional, and international perspective, through a range of viable monetisation options and scenarios. In addition, analysis of the regional infrastructure, market and regulatory enablers are assessed to identify the requirements for standardisation and harmonisation to facilitate the development of a regional market.

This report is part of the first phase of developing the Regional Gas Master Plan for SADC.

1.2.1 Regional Gas Master Plan Modelling

To achieve the outcomes of creating a viable blueprint for regional integration and development over a 30-year horizon – several key analyses across the supply, demand and regulatory environments were conducted as inputs towards developing a long-term outlook. Due to the levels of uncertainty and the time horizon, a scenario-based approach was utilised and modelled across supply and demand towards achieving equilibrium.

The following was considered as part of the inputs for the modelling process.

- Macro-economic forecasts
- Stakeholder inputs
- Policy documents and stated policy intentions for different countries

The conceptual framework for development for Phase 1 of the RGMP is indicated in the figure below.

[16] Global Gas and LNG Outlook to 2035, Energy Insights by McKinsey and Co.

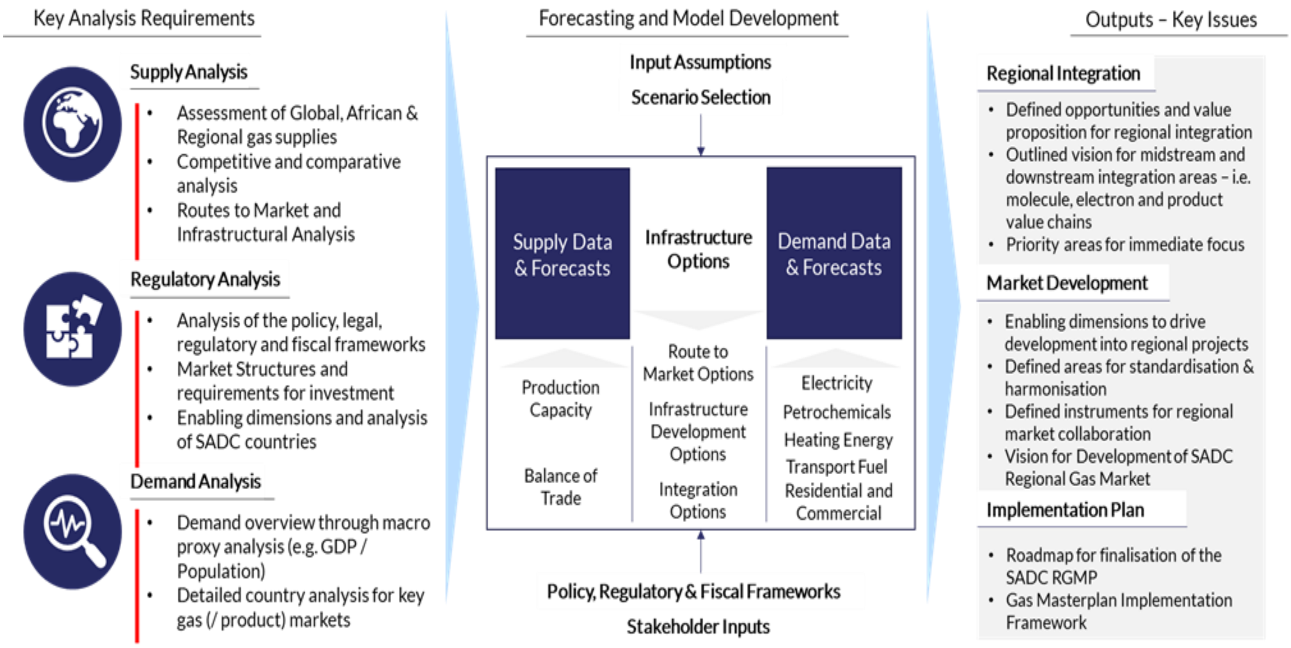


Figure 1-1: Conceptual Framework for RGMP Development.[17]

Delivering on this included a specific methodology, from a forecasting perspective, that sought to segment markets, assess trends, calculate outputs, and determine the impact of scenarios on the overall findings. This is highlighted in the figure below.

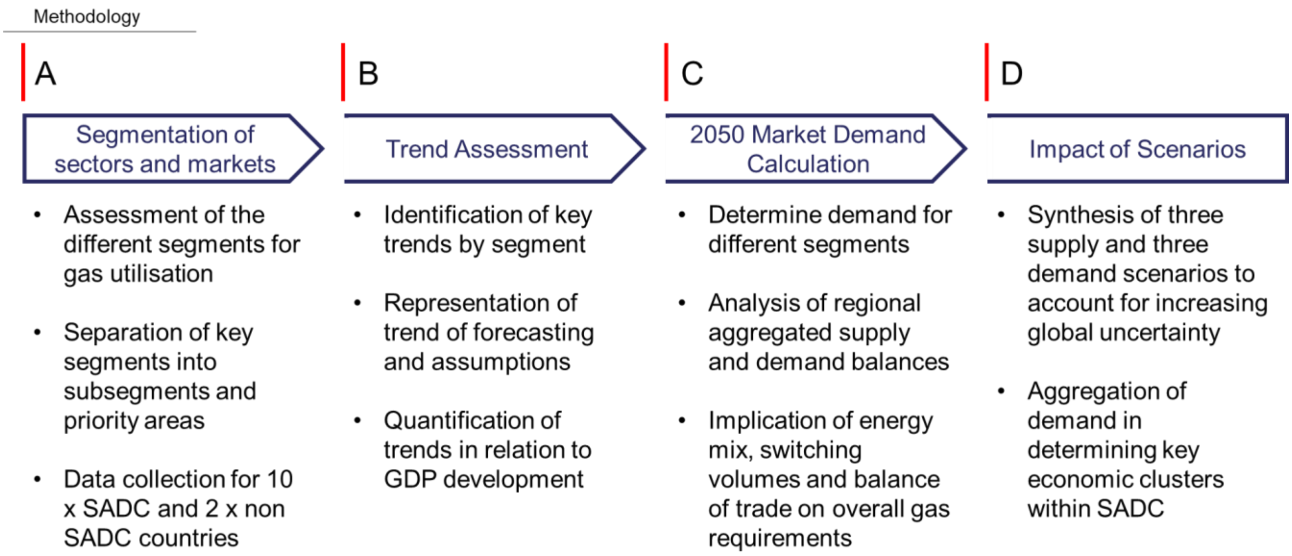


Figure 1-2: Forecasting methodology

The long-term forecasting approach is demand focused, considering key segments, base development per segment and impacts of industry-specific trends on demand. Gas supply requirements considered stated policy intentions (e.g. the country specific Integrated Resource Plans) and was escalated/deflated in line with demand growth projections and industry trend. This then formed the basis for which the model was developed.

[17] Including elements of Phase 2 of the development of the RGMP.

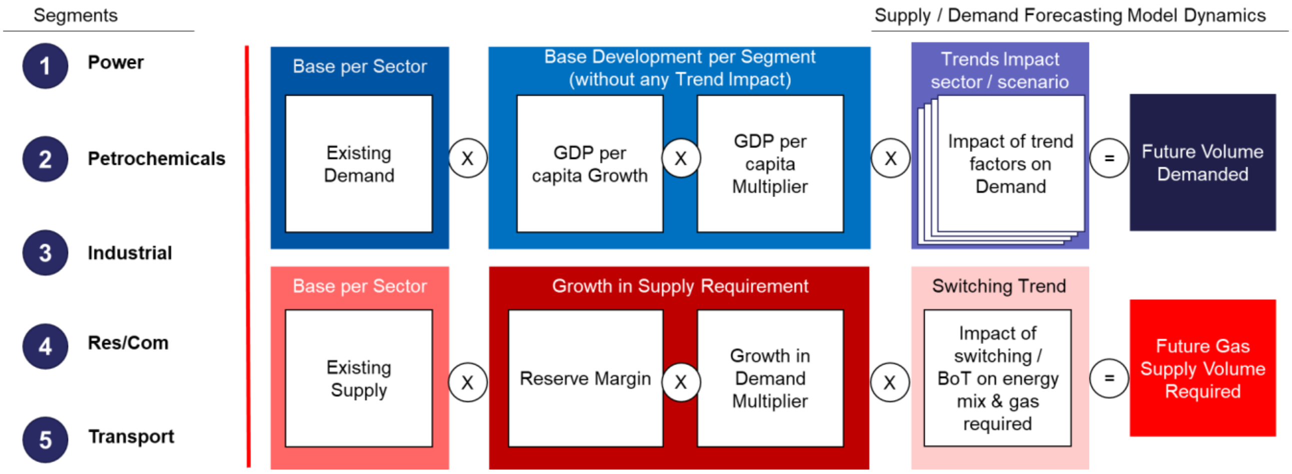


Figure 1-3: Supply Demand Forecasting Model Dynamics

The long-term demand forecasts provided the key focus areas for country integration, sector development and infrastructure development.

1.2.2 Dimensions for Enablement

Developing the regional market requires a concerted and coordinated approach by Member States, with a focus on key dimensions for development. The key dimensions[18] were selected based on the centrality to the integration and development of a regional market and provided a consistent framework in analysing each SADC Member State and the requirements for standardisation and harmonisation. This considered:

- Market development, including:
  - Molecule Access (i.e. necessary volumes required for gas users)
  - Affordability (i.e. price of the molecule that is affordable for users and competitive against alternate energy sources)
- Infrastructural enablement, including:
  - Tariffs
  - 3rd Party access
  - Regional aggregation
- Security of supply, including:
  - Quality and security of supply
  - Multiple supply options, including LNG and domestic sources
  - Development of regional upstream sector

Enabling conditions are required to facilitate investment across the value chain. This includes investment in:

- Industrial demand applications, including power generation, petrochemicals, and heavy industry
- Infrastructure to connect supply and demand, including ports, LNG regasification and storage facilities, pipelines, rail, and road networks
- Supply options, including gas field exploration, development and production, and LNG liquefaction.

[18] Adapted from World Economic Forum, 2018, Fostering Effective Energy Transition.

Market development does not happen in isolation. Enabling factors must be present in order to attract investment and catalyse the required development. The enabling dimensions considered included:

- **Capital and Investment.** The availability of capital and the macro-economic and fiscal conditions for investment.
- **Policy, Legislative & Regulatory.** Policy direction, legislative and regulatory frameworks, with maturity, certainty, and consistency in application.
- **Institutions & Governance.** Roles and responsibilities of key governance entities within the regulatory, public, and private domains.
- **Infrastructure & Market Structure.** Quality of infrastructure, market size and 3rd party access.
- **People: Capacity & Participation.** The necessary skills, competencies, and talent in developing technical value chains and thereby providing the human capital.
- **Energy System Structure.** Maturity of the market and energy system structure, including energy mix (i.e. fossil fuels, renewable etc.)

This is highlighted in the figure below.

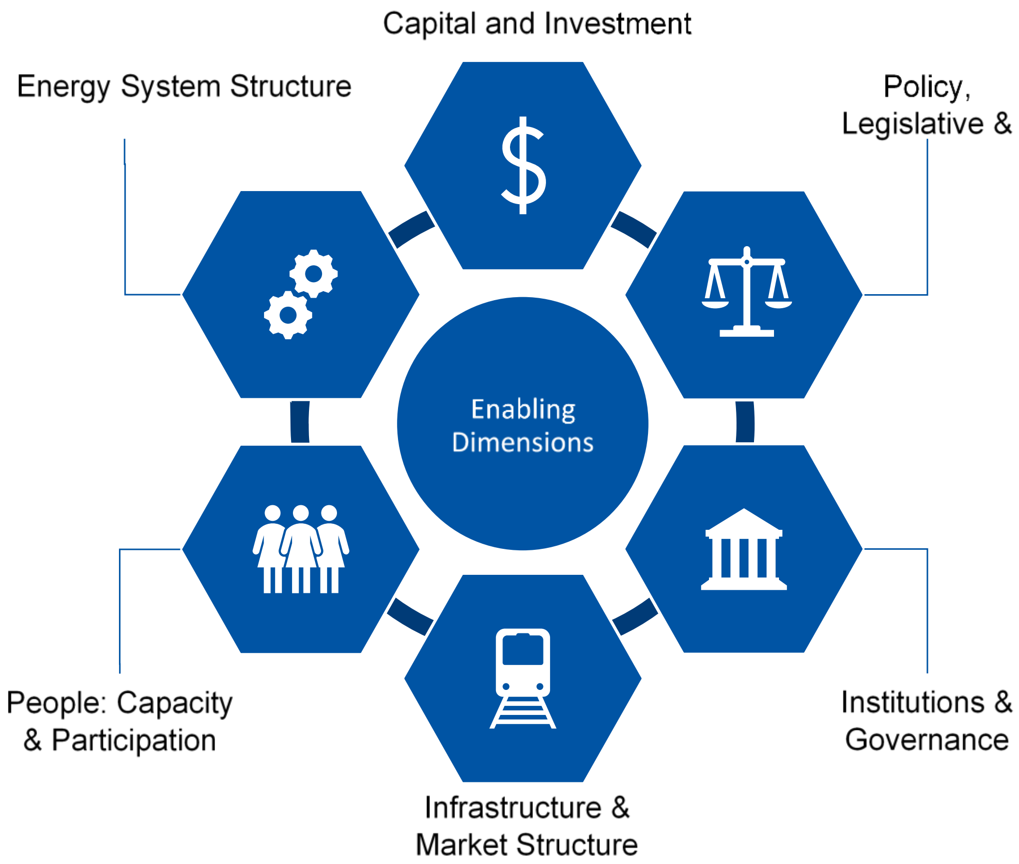


Figure 1-4: Enabling Dimensions for Regional Market Development and Integration.[19]

[19] World Economic Forum, 2018. Fostering Effective Energy Transition.

1.3 Strategic and Policy Linkages

1.3.1 Sustainable Development Goals (SDGs)

All SADC Member States have adopted 17 ambitious policy goals to end poverty, protect the planet, promote gender equality, or ensure prosperity, as part of the United Nations Sustainable Development Agenda, and committed to achieving specific targets by 2030.

The SADC region has a specific set of key issues that require focus and intervention which, in turn, means that different SDGs will be prioritised over others. Given the issues facing the subregion, six priority themes have been identified by the African Union for sustainable development namely a) poverty eradication b) education and technical skills, c) gender equality and social inclusion, d) health and nutrition, e) environmental sustainability and, f) governance.

The SDG 7 seeks to ensure access to affordable, reliable, sustainable, and modern energy for all. It aims to increase, substantially, the share of renewable energy in the global energy mix, and to double the improvement of energy efficiency. Progress on this goal translates to progress on all the above listed priorities.

The 2019 Tracking SDG7: The Energy Progress Report is a joint initiative of the International Energy Agency, International Renewable Energy Agency, United Nations Statistics Division, World Bank Group, and the World Health Organisation, which tracks the progress of the achievement of SDG7. The group measured progress based on three targets:

- Target 7.1 is to ensure universal access to affordable, reliable, and modern energy services, which is broken into two measurements, a) the proportion of the population with access to electricity and b) the proportion relying primarily on clean fuels and technologies for cooking);
- Target 7.2 is to increase, substantially, the share of renewable energy in the global energy mix; and
- Target 7.3 is to double the global rate of improvement in energy efficiency.

The process of assessing SADC implementation of SDG7 will be in linking the various SADC strategies to these three targets. The RGMP thus considers the role gas will play in the achievement of the SDGs.

1.3.2 Key SADC Strategic Documents

The focus that every country has placed on achieving the SDGs, and their Nationally determined commitments to the Paris Agreements has led to a concerted regional effort to bridge the energy gap in the SADC region over the last ten years. SADC Members States have strengthened energy policy and regulations, advanced infrastructure, expanded grid connections, increased knowledge of off-grid energy solutions, and more.

SADC, as a coordinating force in this regard, has introduced a variety of energy related or energy specific strategy documents over the years, their purpose and linkages are illustrated in the table below:

Table 1-1: Linkage between Existing SADC Strategies and RGMP

Document	Strategic Aim	Linkages to the RGMP
SADC Treaty	To achieve development and economic growth, alleviate poverty, enhance the standard and quality of life of the peoples of Southern Africa and support the	The RGMP is an implementation mechanism for the Treaty under which it exists, in enabling regional integration through the creation of a regional market.

Document	Strategic Aim	Linkages to the RGMP
	socially disadvantaged through regional integration.	
SADC Protocol on Energy 1996, under review	To encourage Member States to cooperate on energy development, harmonise policies, strategies, and procedures throughout the region. It also advises that these policies ensure the security, reliability, and sustainability of the energy supply, with Member States cooperating on research and development of low-cost energy sources applicable to Southern Africa.	The Energy Protocol informs all strategy/policy documents that relate to energy security, reliability, and sustainability. The completed RGMP, therefore, needs to refer to the Energy Protocol as a reference point for achievement of goals.
Regional Energy Access Strategy and Action Plan 2010, awaiting approval	Increase access to sustainable energy sources and clean cooking systems until there is universal access for all. The objective is to half the proportion of people without access to adequate, reliable, least-cost, environmentally sustainable energy services within 10 years, and thereafter halving it again in successive 5-year periods.	Gas (both natural gas and LPG) has a role to play in providing sustainable and accessible energy for all. A residential focus has been considered as part of the RGMP.
Regional Infrastructure Development Master Plan Energy Sector Plan, 2012-2027 Assessment Report 2019	Aim is to define regional infrastructure requirements and conditions to facilitate the realisation of key infrastructure in the energy sector. A key objective is the harnessing of renewable energy potential and energy efficiency opportunities in the region and diversifying the energy mix.	The plan relates to electricity generation plants, transmission lines, petroleum, and gas refineries, pipelines, storage reserves, and port facilities, among others. These are all infrastructure developments that would facilitate the route of electrons/molecules derived from natural gas reserves to the market.
Regional Indicative Strategic Development Plan (RISDP 2015-2020, RISDP 2020-2030 under development)	The Revised RISDP's focus is on industrialisation to facilitate the deepening and acceleration of market integration, with equitable distribution of regional integration opportunities. The RISDP is the blueprint for SADC's regional integration agenda – the process whereby MS agree to integrate their markets, co-operate, and work closely together to achieve peace, stability, and wealth.	One RISDP objective is to achieve energy security access for rural needs and development. Similarly, an RGMP objective is to do the same, through the provision of natural gas. Creating a regional gas market that facilitates the local production of gas products is directly linked to the RISDP's aim for MS to be dynamic and competitive, producing high quality products, for national, regional, continental and world markets, with a positive spill-over effect in the region.

Document	Strategic Aim	Linkages to the RGMP
		The RGMP works into each of the four priorities (A-D), facilitating industrial development and market integration, infrastructure development in energy and transport, encouraging peace and security cooperation (through MoUs) and ensuring human development.
SADC Industrialisation Strategy and Road Map, 2015	The technological and economic transformation of the SADC region through industrialisation, modernisation, skills development, science and technology, financial strengthening, and deeper regional integration.	The RGMP is an implementation mechanism of the Industrialisation Strategy, enabling regional integration in the energy sector.
Industrialisation Strategy and Road Map: Action Plan, 2017	The Action Plan considers the mineral sector in SADC for potential value chains, including the energy mineral and the fertiliser mineral value chains. Opportunities for enhancing/developing value chains are considered.	The RGMP is an implementation mechanism of the Industrialisation Strategy, enabling regional integration in the energy sector.
Renewable Energy and Energy Efficiency: Strategy and Action Plan, 2016 and Renewable Energy and Energy Efficiency Status Report, 2018	To contribute to increased regional energy access and energy security by promoting market-based adoption of renewable energy and energy efficiency.	The RGMP promotes the use of natural gas within the electricity sector to meet efficiency and sustainability goals.
Energy Monitor 2018	To ensure that progress made towards the implementation of the SADC energy commitments in line with the SADC Protocol on Energy and other regional strategies and policies are documented and distributed.	The RGMP would, too, become a regional policy monitored for progress in subsequent editions of the Energy Monitor, in so far as it related to the achievement of goals under the SADC Protocol on Energy.
Regional Framework for Harmonisation of Low Sulphur Fuels and Vehicle Emission Standards	To reduce sulphur levels in fuels to 50 ppm or less by end 2022 for importing countries and 2025 for refining countries and to 10 ppm from 2025 to 2030 for all countries.	The framework calls for the development of a refinery investment plan by the end of 2020 for refining countries as well as harmonisation of fuel standards and practices by 2022. This will improve the enabling environment for cross-border trade of gas products, thus enabling the regional gas market.
SAPP Plan, 2017	To identify a core set of generation and transmission	The Plan sets out generation and transmission development goals, which directly link with the

Document	Strategic Aim	Linkages to the RGMP
	investments of regional significance that can provide adequate electricity supply to the region under different scenarios, in an efficient and economically, environmentally, and socially sustainable manner and support enhanced integration and power trade in the SAPP region.	requirements needed to enable the movement of the Gas-to-Power (GTP) electron across borders.

The two most recent SADC documents have been considered in detail: The 2019 Assessment Report of the Regional Infrastructure Development Master Plan (RIDMP) - Energy Sector Plan, and the 2019 Review of the Regional Energy Access Strategy and Action Plan.

1.4 Drivers for a Regional Gas Market

1.4.1 Sustainability & Climate Change

Global temperature anomalies[20] have been steadily increasing, correlating to an increase in CO_2 emissions. Public perception has thus shifted, with policy direction and buying patterns changing as a result of the effects of environmental degradation – with both consumers and producers opting for more sustainable practices.

The effect of CO_2 emissions and temperature anomalies, a key contributor in this regard, are indicated in the figures below.

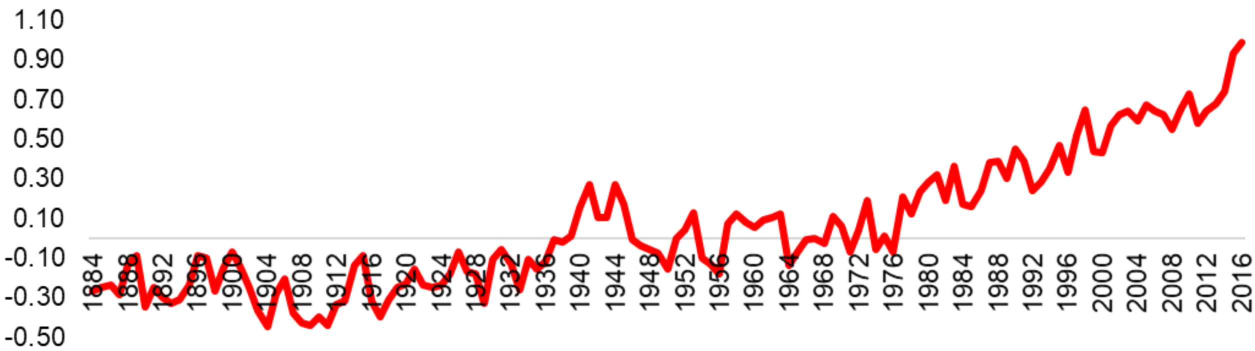


Figure 1-5: Global Temperature Anomalies [º C].[21]

This trend has been experienced in the SADC region. Instrumental observations from several SADC Member States show an increase in temperatures, especially the minimum temperatures. Between 1950 and 2000, Namibia experienced warming at a rate of 0.023 degrees Celsius per year[22] and Botswana received warming at a rate of 0.017 degrees Celsius per year.[23] The increase in temperatures is expected to continue (even if global CO_2 levels plateaued today) and the temperatures in the region are expected to warm by between 1.0 and 3.0 degrees Celsius by 2080.[24]

In addition to the warmer temperatures that SADC is expected to experience as a result of climate change, there are expected changes in rainfall characteristics (changes in intensity, extreme rainfall

[20] A temperature anomaly is the measurement of the departure from a long-term average.
[21] Global Change Data Lab (Our World in Data). CO_2 and Greenhouse Gas Emissions, 2019.
[22] Government of Namibia, 2002.
[23] SADC Policy Paper on Climate Change.
[24] *Ibid*

events and changes in the season). The impacts that these changes could have are wide ranging and include an increase in pests, more diseases and malaria spreading to new areas, increased heat stress to natural ecosystems and agricultural crops, likely to negatively impact on the productivity of both the rangeland, grazing and food production.

In the energy sector, specifically, the climate variability described above poses a serious threat to energy security. Several SADC Member States rely primarily on hydropower and are thus especially vulnerable to changes in rainfall. River-flow rates and water availability are inevitably affected by variations in rainfall, resulting in unreliable electricity supply. A decrease in rainfall as expected under climate change will further accelerate deforestation, compounding associated problems. An increase in irrigation will place further pressure on river-flow rates and volumes. During times of low rainfall, reduced river flows reduce the hydropower output, leaving these countries with no alternative but to import a significant proportion to meet their energy needs.

As the most common form of fuel for rural communities across the SADC region is biomass –securing of wood for energy purposes contributes to deforestation, causing severe land degradation and soil erosion, which, in turn, causes river siltation, affecting hydroelectric power generation. The net effect is that SADC Member States must consider the impact of climate change and will be forced to make proactive and reactive changes as a result of this – thereby contributing to the burden on the economies of the region.

The responses of governments have been in adopting climate friendly policies that seek to decarbonise and create a more sustainable energy mix, with increased renewables and thus variability - the result of which has been a marked shift in the structure of energy systems.

The policy shifts have extended beyond the power sector. SADC has, in its regional policy documents, placed emphasis on the transport sector and its contribution to air pollution and CO_2 emissions. It highlights that the sector remains the main source of urban air pollution in many developing and transitional countries, contributing to as much as 50% of urban air pollution in some cities. The key pollutant, for which transport is a major source, is small particulate matter (PM) that is estimated to cause approximately 4.2 million premature deaths annually. The smaller part of PM, black carbon, is an important climate pollutant (short-lived climate pollutant). Diesel engines account for 99% of black carbon from road transport.

To reduce PM emissions from vehicles, SADC has introduced the Regional Framework for Harmonisation of Low Sulphur Fuels and Vehicle Emission Standards. This Framework aims to encourage the adoption of low sulphur fuels, i.e. 50 parts per million (ppm) fuels and below, ideally 10-15 ppm. The adoption of low-sulphur fuels will enable the introduction of cleaner vehicles in the region and combined; these two changes will have a substantial reduction impact on black carbon emissions from the transport sector.

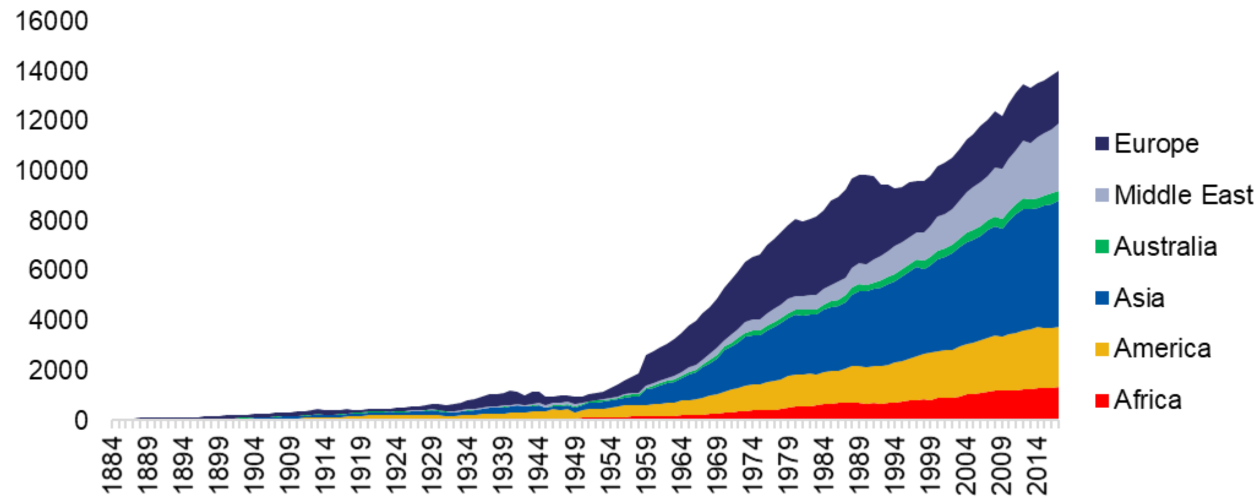


Figure 1-6 CO_2 Emissions [Tons].[25]

Gas responds to this in two ways. As a direct fuel source, either as CNG or LNG, natural gas provides a cleaner burning fuel for use in transportation. In addition, through the GTL process, gas is used to produce ultra-low sulphur diesel which can then be used as a blend in refinery feedstocks.

1.4.2 Security of Supply and Improved Energy Access

Sub-Saharan Africa (SSA) has the lowest energy access rates in the world. Only half of its population has access to electricity, and one-third has access to clean cooking fuels.[26] According to the SADC Renewable Energy and Energy Efficiency Status Report 2018,[27] 48% of the region's residents have access to electricity which is comparable with Sub Saharan Africa estimates.[28] Further electrification is required to enable economic growth and sustainable development.[29]

There is a need for SADC Member States to seek growth, in an inclusive and sustainable manner to improve the lives of all its citizens through the adoption of policies and the development of sectors that can facilitate broad socio-economic growth.

[25] Global Change Data Lab (Our World in Data). CO_2 and Greenhouse Gas Emissions, 2019.
[26] International Energy Association, 2018. World Energy Outlook 2018.
[27] SADC Renewable Energy and Energy Efficiency Status Report 2018.
[28] SSA electricity access estimated to be 45% by IEA and 48% by the World Bank respectively for the same period.
[29] International Monetary Fund, 2018. Data Mapper, World Economic Outlook.

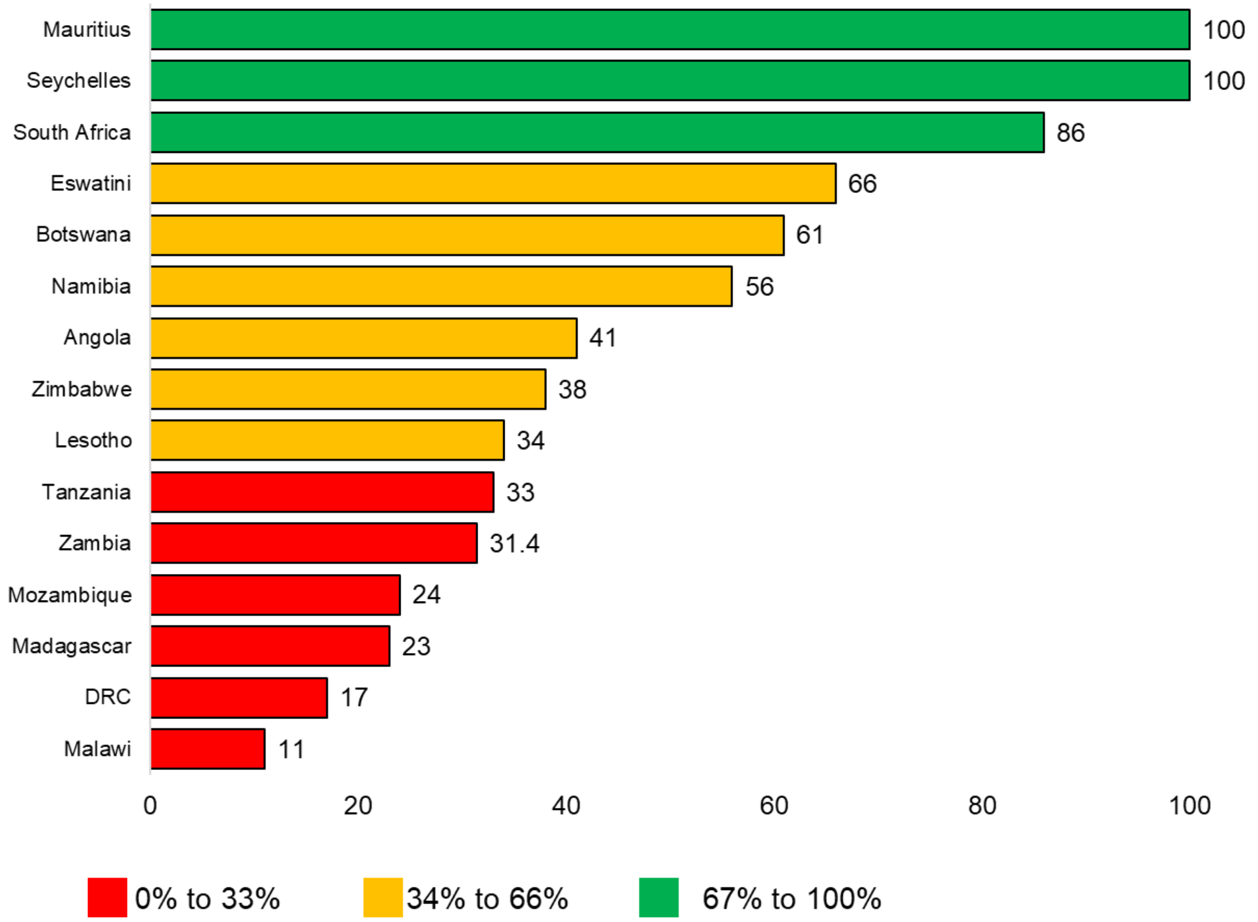


Figure 1-7: Electricity Access (% of Population) for SADC Member States[30]

The Energy Monitor of 2018 highlighted that, according to the African Development Bank, the overall hydropower capacity and natural gas potential in Southern Africa is largely underutilised, with only a fraction of able resources and reserved being harnessed. This calls for improved cooperation between and among SADC Member States to ensure that access and availability to energy is prioritised to allow the region to realise its vision of a united, prosperous, and integrated community.[31]

The SADC Energy Access Strategy and Action Plan of 2010 is in the process of revision.

[30] World Bank Data, 2017
[31] Energy Monitor 2018

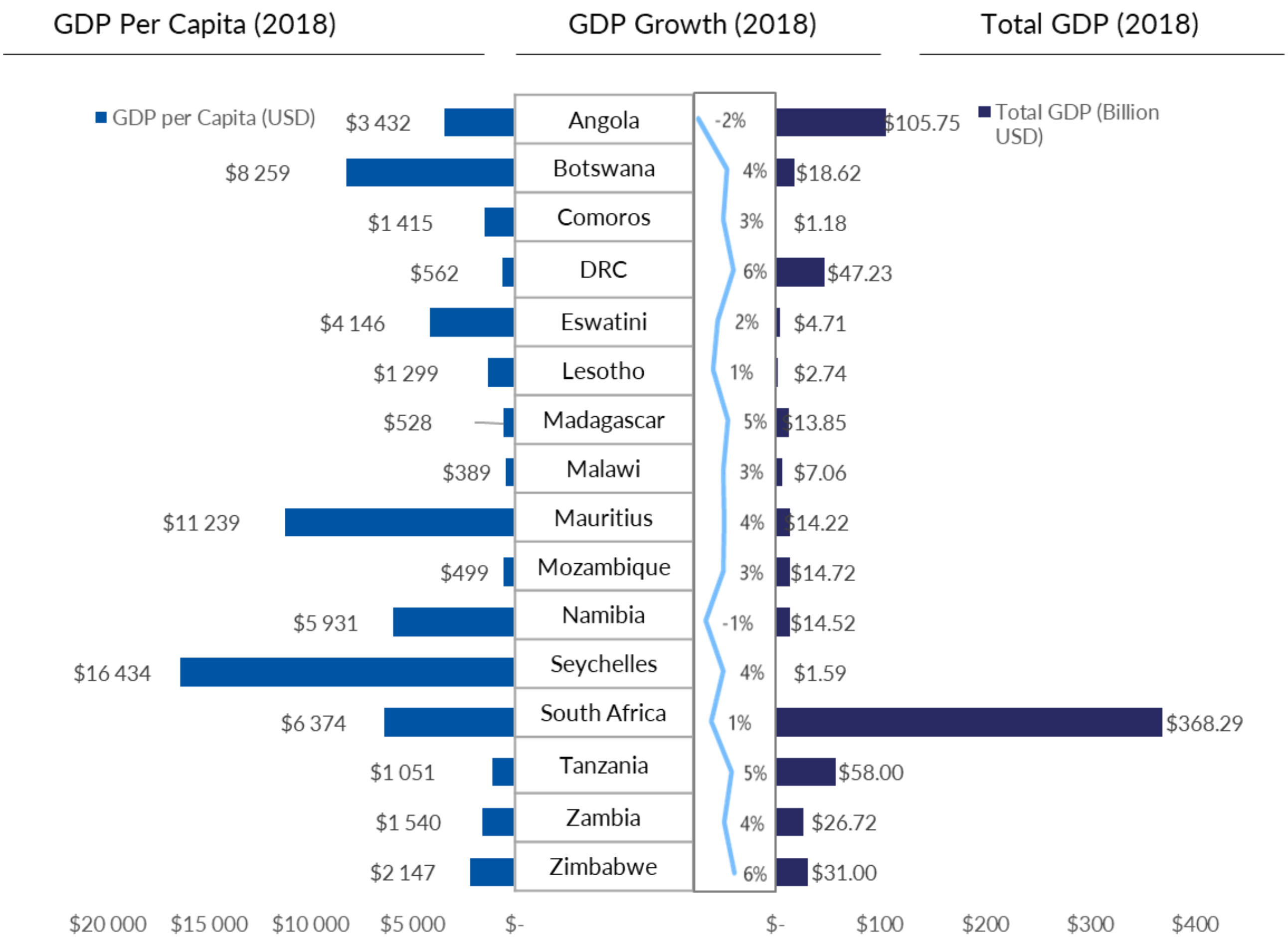


Figure 1-8: GDP/Capita, GDP Growth Rates and GDP[32]

As highlighted, the linkage between economic output and energy is a fundamental one. It can be seen from the figure above that countries with a high GDP / Capita similarly have greater electricity access for citizens. Economic growth is fulfilled by the availability of resources – energy being foundational.

Having responsive energy systems, inclusive of a mix of sources such as Electricity, LPG, and natural gas, will be necessary to address these twin challenges.

1.4.3 Evolving Energy System Structures

Globally, energy systems are experiencing significant and fast change, driven by forces such as technological innovation, changes in consumption patterns, supply dynamics and policy shifts. The structural changes that are occurring within energy systems call for greater integration between energy sources, through the processes of energy planning and implementation of delivery systems that are responsive and relevant to the specific context that we are in.

These forces offer opportunities to resolve the challenges that the global energy system faces today, namely: providing energy access to the more than one billion people who lack it, and meeting the demand for an additional two billion people by 2050 while also delivering that energy at an affordable cost and with a declining carbon and emissions footprint.

[32] World Bank Data, 2019

Factors that must be considered when designing, developing, and implementing these structures, include the following:

Technology: The effect of technology will be profound and impact all aspects of the value chain. These considerations include:

- **Energy Efficiency:** Across all scenarios, improvements in energy efficiency will be a major driver in dampening future demand
- **Grid Evolution:** Including the benefits accrued from smart grids and associated technologies
- **Off-grid and Embedded options:** For security of supply (opportunity cost of producers), as well as rural communities – embedded and off-grid options will become part of the mix.
- **Battery Storage and Hydrogen Fuel Cells:** The experience curve effect will drive down the costs of battery storage and hydrogen fuel cells, making it viable mixtures within the energy system
- **Delivery Mechanisms:** Small scale LNG options have become more affordable and has therefore made LNG opportunity applicable to markets otherwise inaccessible

Energy Sources and Energy Mix: The integrative approach and complementary features of different energy sources must be considered in totality when designing the energy system structure and would include:

The objective is to create a relevant energy system structure that responds to the needs of the market in providing energy access, security and affordability to participants while contributing to environmental sustainability in a manner that provides for sustainable and equitable development and growth. The key features discussed as part of this Energy System is highlighted below.

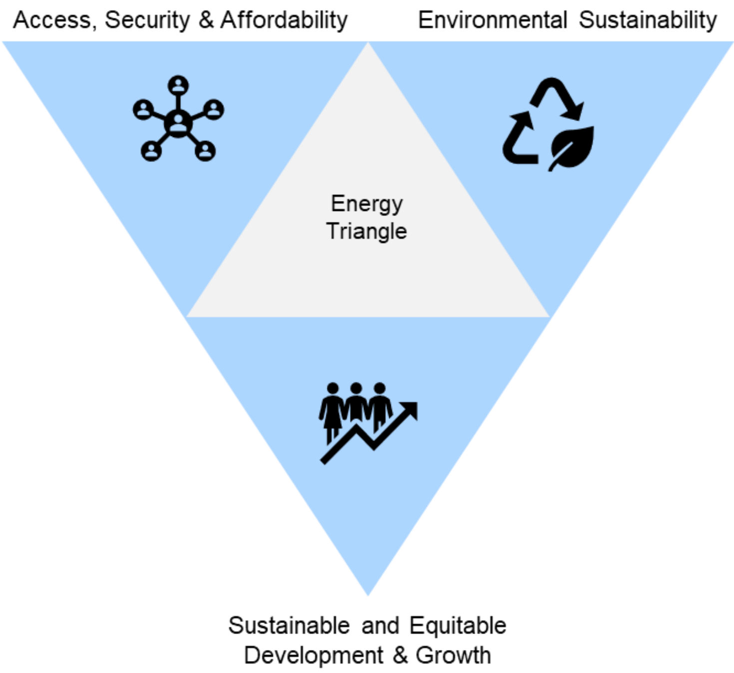


Figure 1-9 Key Features of an Energy System.[33]

[33] Ibid

1.4.4 Cost Competitiveness and Economics of Gas

Natural gas is a structurally cheaper energy source than alternative hydrocarbon sources (excluding Coal). However, alternative hydrocarbons due to their characteristics (i.e. gaseous at ambient temperatures versus liquid alternatives) require significantly less logistics and transport infrastructure. Natural Gas, as highlighted, requires scale to justify building delivery infrastructure for the economic benefits of this energy source to be realised.

Even before the market collapse in 2020 caused due to a glut in supply and dramatic decline in demand due to the global Covid-19 pandemic – natural gas, and LNG, on a landed barrel of oil (boe) equivalent basis was structurally cheaper than crude products.

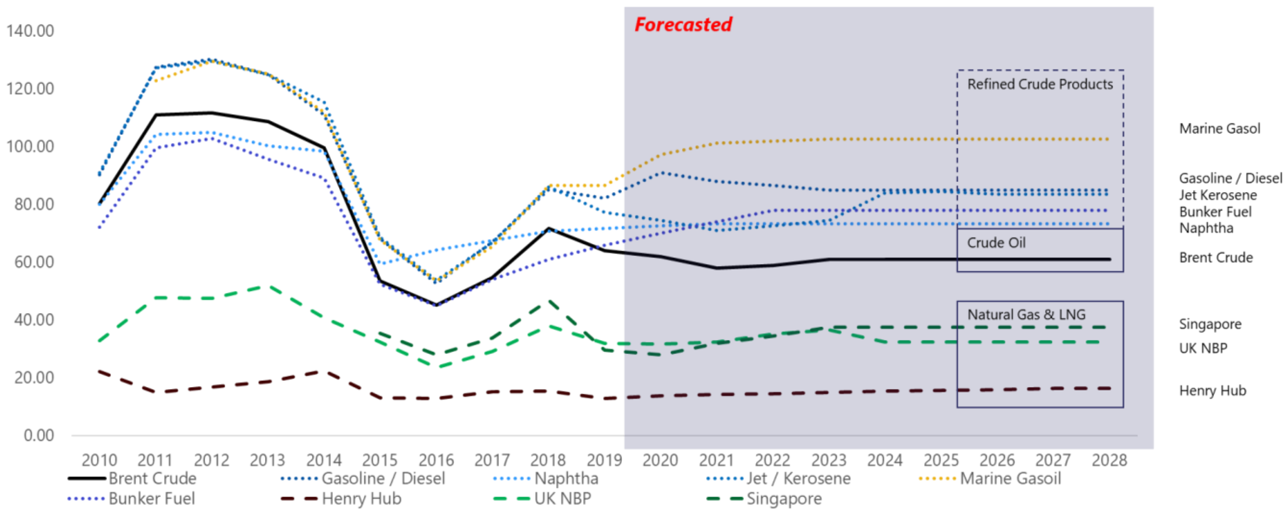


Figure 1-10: Global Energy Pricing ($/bbl) (landed boe for Gas).[34]

Perhaps the biggest current challenge to switching to natural gas fuels has been the recent collapse in crude oil prices and the attendant decline in refined product prices (e.g. of distillates and heavy fuel). Power Utilities, Shipping Lines, Industry & the Transport sector need to be convinced that the benefits of switching to natural gas outweigh both the next best alternative and the risks of change. First and foremost, industry must be convinced that natural gas will be economically available at their chosen fuelling location, with the readiness of fuel supply infrastructure, both in equipment and suppliers, and must be provided with the comfort of long-term reliability.

Local gas prices, particularly for imports, are influenced by global markets and impacted by regulatory and policy choices which in turn imposes costs through taxes and mandated technology choices. Taxes incentivise or disincentivise fuel choices, while grants, subsidies, and developing economies of scale as the adoption of new technology increases, can offset capital costs.

The development of reticulation infrastructure from sources of supply to markets within the SADC region will help develop the natural gas market. A regional public private partnership in which the suppliers & buyers are guaranteed off take at prices that are attractive will greatly assist in the development of the regional gas market. Having a transnational natural gas grid, and where not

[34] Fitch Solutions. BMI Research (with Fitch Forecasted information),2019/2020.

possible, supply through a network of LNG terminals along the coastline with a virtual pipeline will help in disaggregating the natural gas market using the geographical advantages of these economies.

For the cost competitiveness of gas to be realised in the SADC context in the long term, the necessary incentives will be required, while the long term development of a physical market will assist in driving the decoupling of oil indexed gas pricing for the SADC context and move towards gas on gas, or alternative fuel indexing price formation mechanisms.

It is expected that natural gas market will remain a buyers' market for the next several years due to new supplies of LNG becoming available in the Middle East, Far East and Africa. Additionally, there is a divergence between pricing of crude and natural gas as more markets seek different commodities (e.g. coal) to index LNG pricing with. This would be the most opportune time for regional suppliers and buyers to collectively develop a natural gas grid under the purview of an enabling policy and regulatory umbrella to create a competitive gas market in the SADC. This will assist in the:

- development of a regional natural gas logistics system,
- provision to industry of a cleaner source of fuel,
- creation of greater energy security and diversity,
- creation of a regional gas economy,
- provision of a location market to suppliers, which will provide security of offtake,
- security for buyers in not having to rely on the supply of LNG over long distances from remote sources,
- industrialisation in the region through natural gas,
- creation of greater interdependencies in the regional markets,
- the creation of a regional gas market pricing mechanism providing greater stability and predictability for both suppliers and buyers,
- liquidity in the marketplace resulting in greater pricing transparency for both suppliers and buyers, and
- investment in storage and logistics infrastructure and the resultant reliability for off takers and suppliers.

1.4.5 The Resource Curse

Finally, as has been seen too often in Africa, many countries with new natural resource finds remain underdeveloped and poor. The resource curse describes the paradox of high government revenues generated from the exports of natural resources and the economic stagnation, prevalent poverty, high levels of corruption and political instability evident in these countries.

The figure below shows oil export revenues in USD against the Human Development Index (HDI - a measure of the quality of life) and Gross Domestic Product (GDP) per capita for 2018 for major oil economies. This illustrates the Resource Curse situation for many African countries.

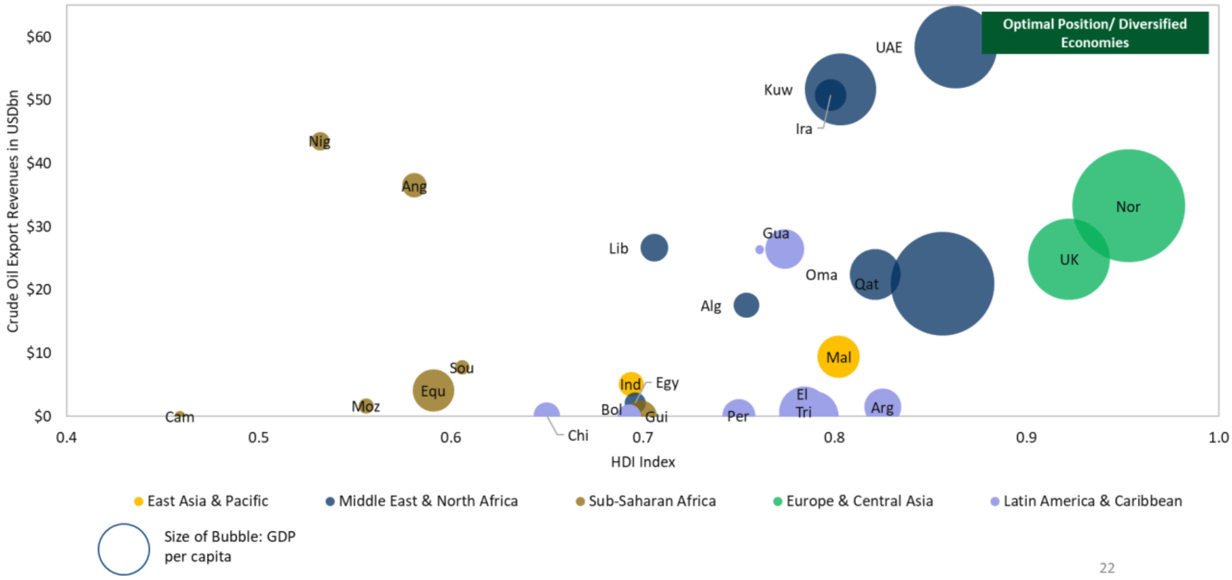


Figure 1-11 Crude Oil Export Revenues vs HDI Index for Major Oil Economies

The better-known cause of this phenomenon is the ‘Dutch Disease’, which describes a situation where attention and resources are often diverted away from other key sectors of the economy once another more attractive resource such as oil is discovered. A good example of the Dutch Disease is in Nigeria, where agriculture used to be a major contributor to the economy before the discovery of oil.

This is another driver of the regional gas market and motivation for the enhanced trade natural gas and gas products amongst SADC countries. Development of natural gas must be holistic, spurring off other revenue-generating, development inducing local sectors. The goal is to diversify the local economy and avoid over-reliance on gas exports. If the development of local and regional gas markets can be achieved transparently, leveraging off local, regional and international expertise (as in the case of the Chad-Cameroon Petroleum Development), it will enable the region to derive maximum value from this resource holistically, sustainably and in a coordinated fashion – thereby avoiding the Dutch Disease and the Resource Cure phenomenon.

2. THE NATURAL GAS VALUE CHAIN

Every industry has activities that transform raw materials, knowledge, labour, and capital into products that are purchased by customers. Natural gas is no different, with end-use that includes electricity generation, transportation, and heating applications, as well as the production of petrochemicals. Natural gas, therefore, lends itself to various downstream applications, some of which are interlinked – creating a need for an integrated energy outlook.

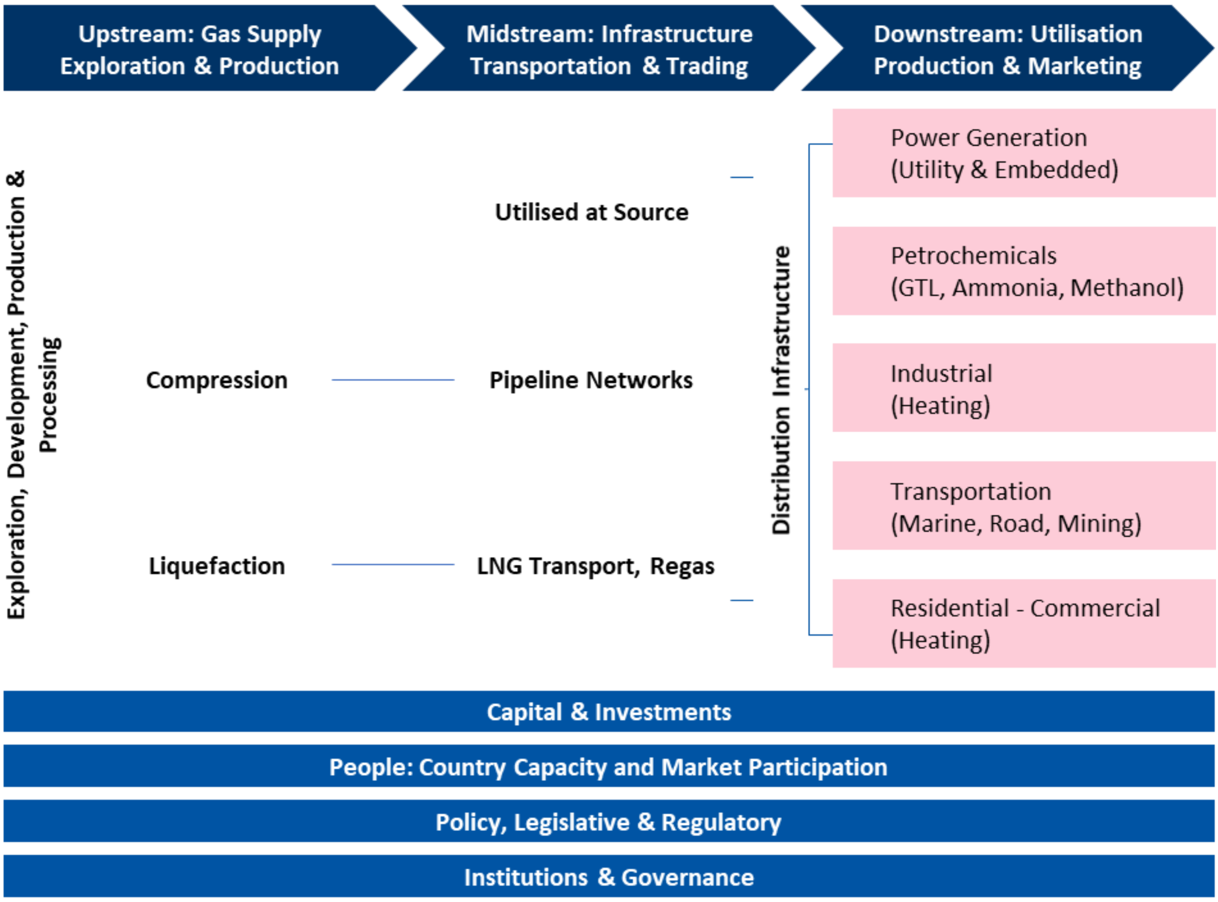


Figure 2-1: Natural Gas Value Chain.

Starting with Exploration & Development, upstream players depend on stable and clear fiscal regimes in order to invest resources (capital and human) in exploring for gas that could be viably (technically and economically) developed to generate value through the production, processing and sale of the molecule, thereby generating a return on investment.

Once produced, severable viable paths to downstream gas monetisation exist; however, an understanding of the nature of molecule is important in its monetisation paths. Natural gas, in its ambient state, as a single chain hydrocarbon is a low energy density molecule. Compression or liquefaction is therefore required to increase energy density, thereby allowing for the transportation of the molecule across large distances. The dynamics of which are further discussed in Section 4.2 of the document.

Midstream developments, i.e. the routes to market, have been evolving in large part due to the advances in Liquefied Natural Gas (LNG) technologies. This has mitigated the limitations of pipeline infrastructure – thereby increasing the commodification of the molecule.

End-use, i.e. Downstream application finds power generation and heating options are important due to the flexibility gas adds to an energy system, as well as the energy transition role gas can play (and which is viable through pipeline or LNG options). However, domestic gas sources (or in situ sources) can additionally be monetised via the petrochemicals route, including diesel, methanol, and ammonia production.

To develop the gas market; including upstream, infrastructure and downstream users; several key enablers must be present. The scale at which development is required to occur, in an environment (SADC), with limited existing infrastructure, requires broad co-operation and co-ordination between stakeholders across the Private and Public sectors. Without a viable value chain, including economical supply options and defined off-takers within the downstream – capital investment will be unlikely; thereby inhibiting development.

2.1 Characteristics of Natural Gas

Typically, reserves consist mostly of methane (CH_4). However, depending on the nature of the gas field, other hydrocarbons could exist along with methane. Gas from fields with predominantly methane – ± 95% methane, ±2.5% ethane (C_2H_6), ±1% propane (C_3H_8) – and smaller percentages of the higher hydrocarbons) are considered dry gas, whereas those with higher proportions of other hydrocarbons (ethane, propane, butane (C_4H_{10}) and higher chained hydrocarbons) is wet gas.[35] These additional hydrocarbons are called condensates or Natural Gas Liquids (NGLs).

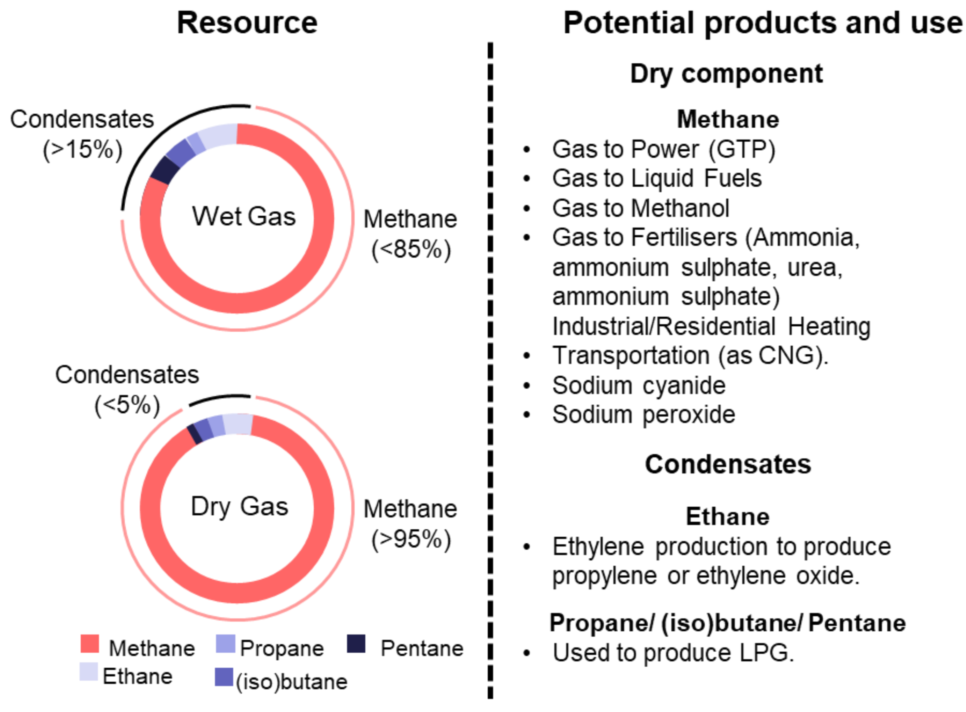


Figure 2-2: Components in dry and wet gas, and their potential applications.

NGLs from wet gas can be separated from methane by chilling and fractionation and then used in a wide range of processes. One of the most important uses is as cracker feedstock to produce ethylene, propylene, and their derivatives (i.e. polyethylene, olefins, polypropylene, etc.). Alternatively, they can be fractionated and then used as Liquefied Petroleum Gas (LPG). Wet gas is usually more attractive to producers because the additional higher hydrocarbons are more marketable and follow oil prices.

[35] Associated gas found in oil deposits and can be wet or dry gas based on its composition.

Angola's associated gas produced during the production of crude oil is wet and therefore has additional economic value, while the Mozambican and Tanzanian gas is mostly dry gas. This gas form contrasts with the unconventional gases (i.e. shale gas) found in the United States of America (USA) which is typically wet gas. The fewer percentages of condensates found in dry gas mean that there are fewer options for its monetisation and therefore requires greater scale for economic viability.

2.2 Uses and Applications

Natural gas is used is a variety of industries and sectors, and similarly contributes directly and indirectly to many others. The overall elements are highlighted in the image below:

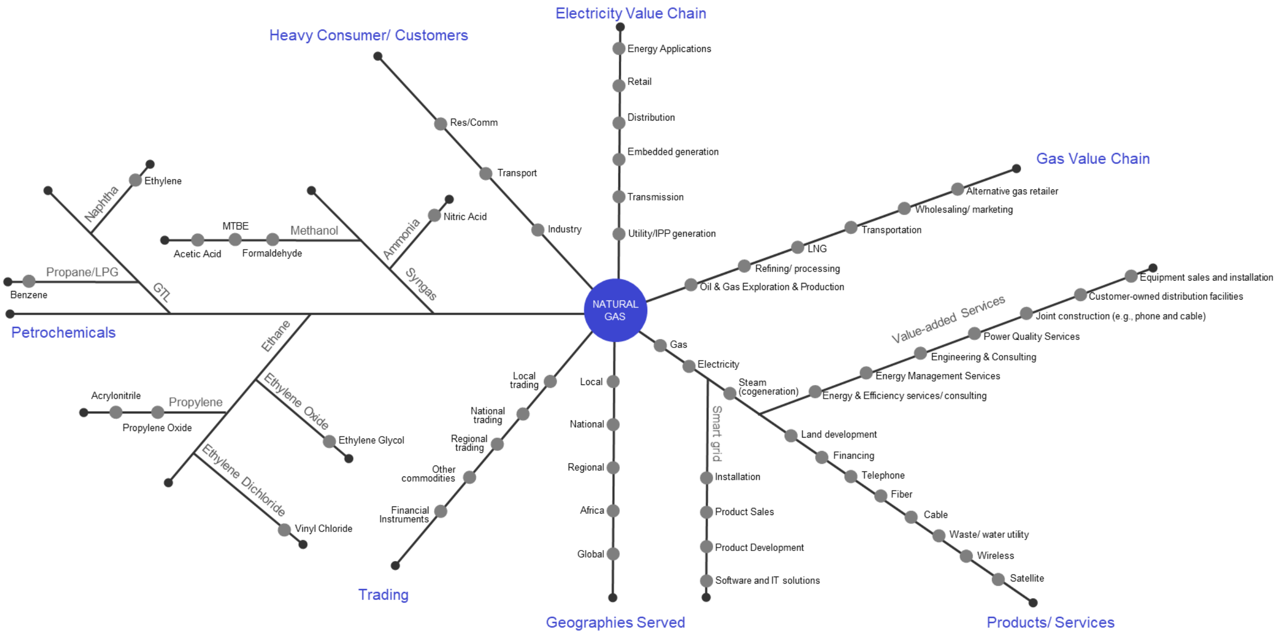


Figure 2-3: Direct and Indirect Contributions

Fundamentally there are two key uses for natural gas, i.e. (1) ***in the generation of thermal energy*** that is used for power generation, transportation and industrial heating applications, and (2) ***as a chemical feedstock*** in chemical transformation processes used in the manufacture of ammonia/urea, methanol and diesel, amongst a wide slate of other downstream petrochemical products. The trends in these industries are further expanded in the sections below.

3. END-MARKET INDUSTRY TRENDS

The end market was broken into 4 segments and 11 sub-segments. The segmentation was clustered according to areas which would be considered anchor demand, i.e. sufficient individual demand to anchor infrastructure projects. The second cluster includes aggregated demand, which would develop around the anchor projects and would be aggregated through a distribution network.

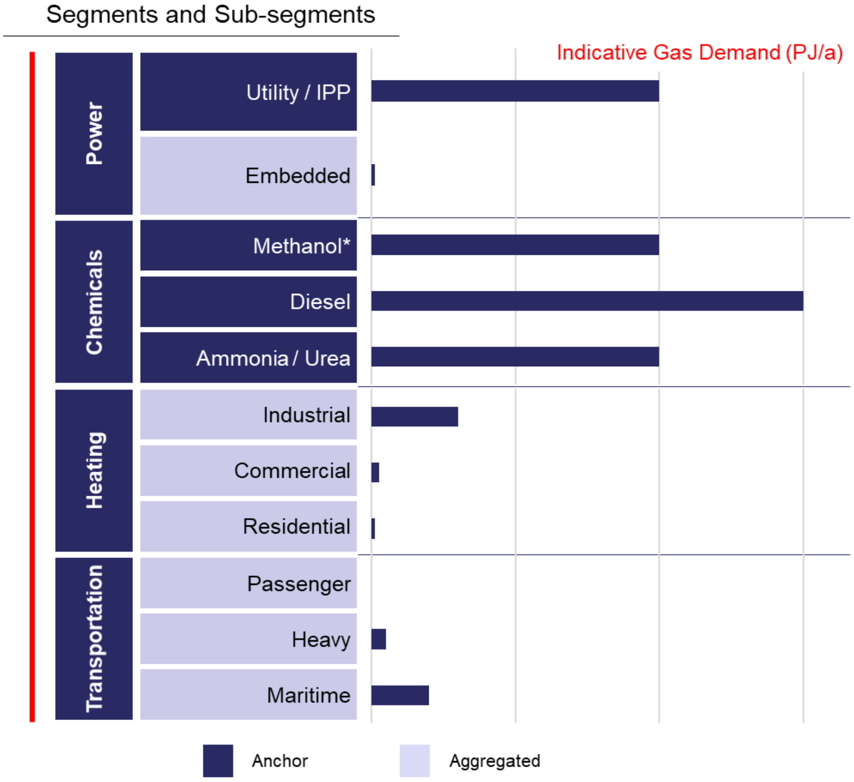


Figure 3-1: Segments and Sub-segments

In addition, trends, and the impact of trends were analysed across all segments / sub-segments.

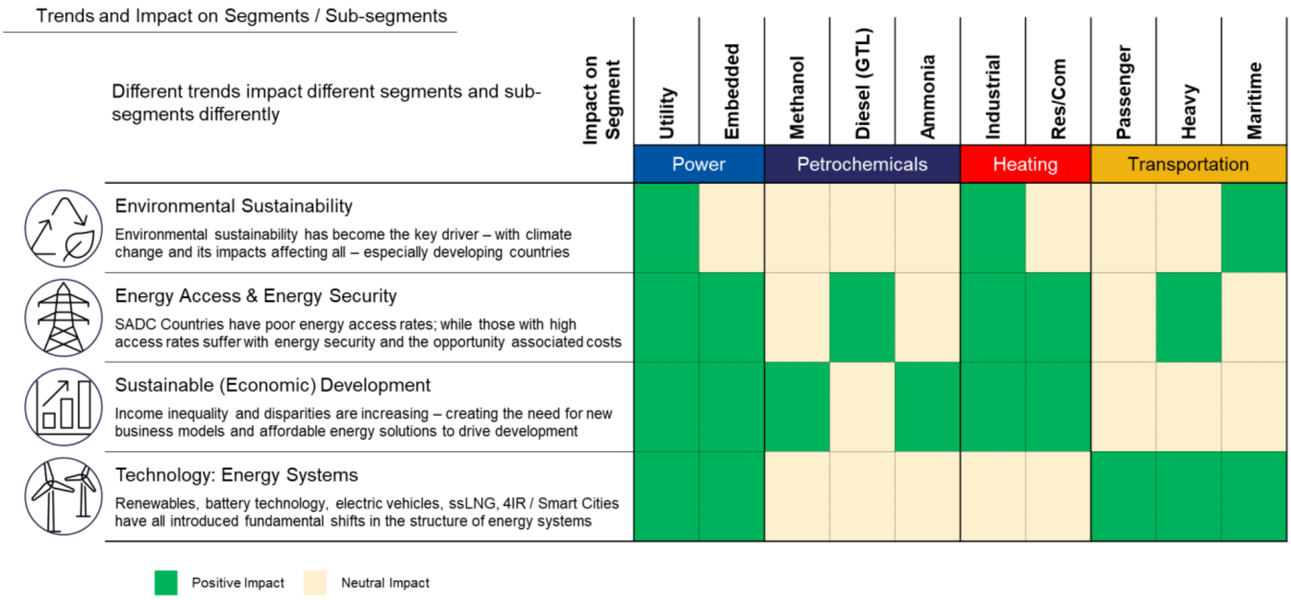


Figure 3-2: Trends and Impact of Trend on Segment

3.1 Power Sector: Energy System Transition

3.1.1 Energy Demand

Within the overall power sector, two key trends will drive demand into the future, this includes (1) improvements in overall energy efficiency across sectors and (2) a change in the profile of the electricity mix, favouring renewables, and gas within the global context. This is indicated in the overall global energy mix, as highlighted in Figure 3-3.

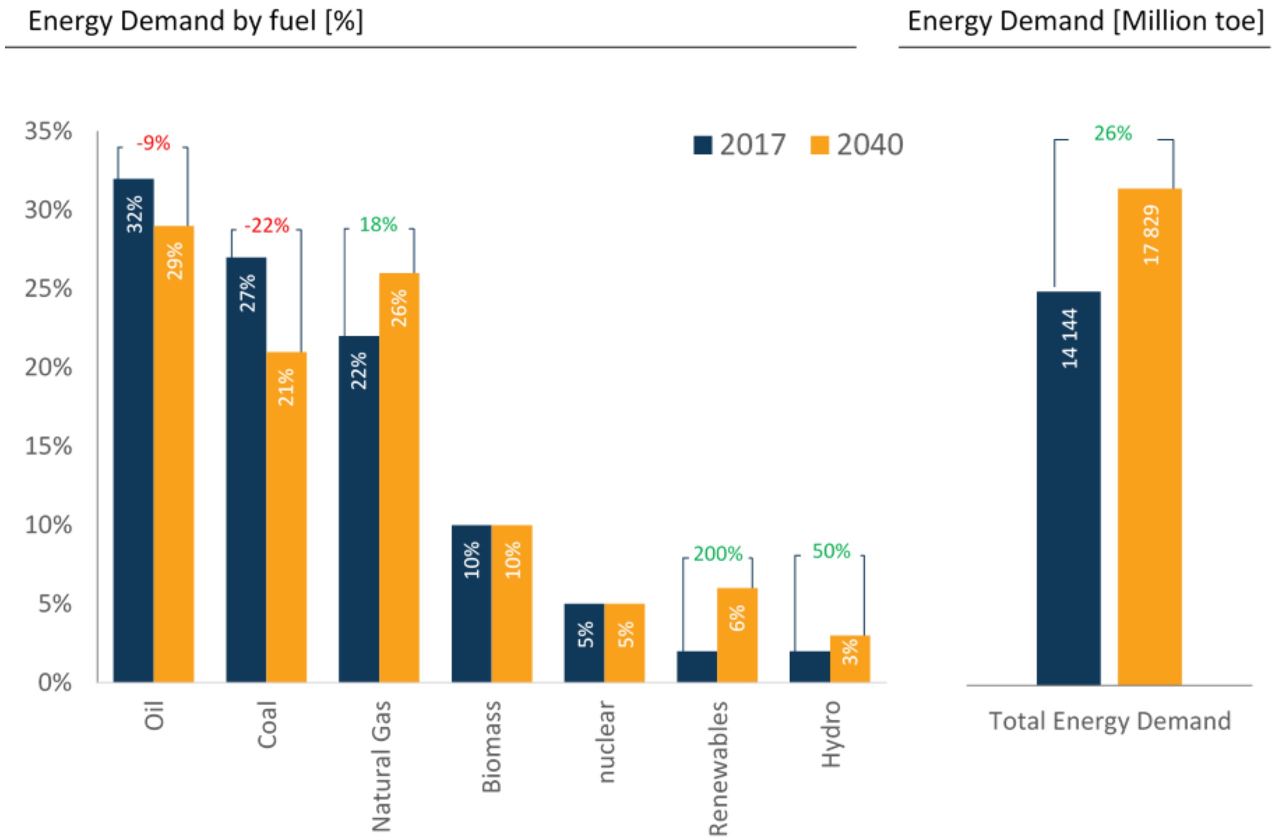


Figure 3-3 Energy Demand by Fuel Type [%] and Total Energy Demand [Mtoe].[36]

Globally, natural gas is the only fossil fuel forecasted to grow, while renewables show the largest global increase.

Within the Power Sector specifically, various drivers are set to impact overall electricity demand outlook, and thus the volumes of sources utilised in electricity generation. In the global north, the energy intensity, defined as the amount of energy required to produce one unit of GDP, has been decreasing. This can be attributed to a shift from an industrialisation economy to a more service based one which has a lower energy requirement, and an increase in the efficiencies of power generation technologies. Other technological shifts include the introduction of electric vehicles which will shift direct demand away from fossil fuels to electricity.

[36] Gas Exporting Countries Forum. Global Gas Outlook, 2018

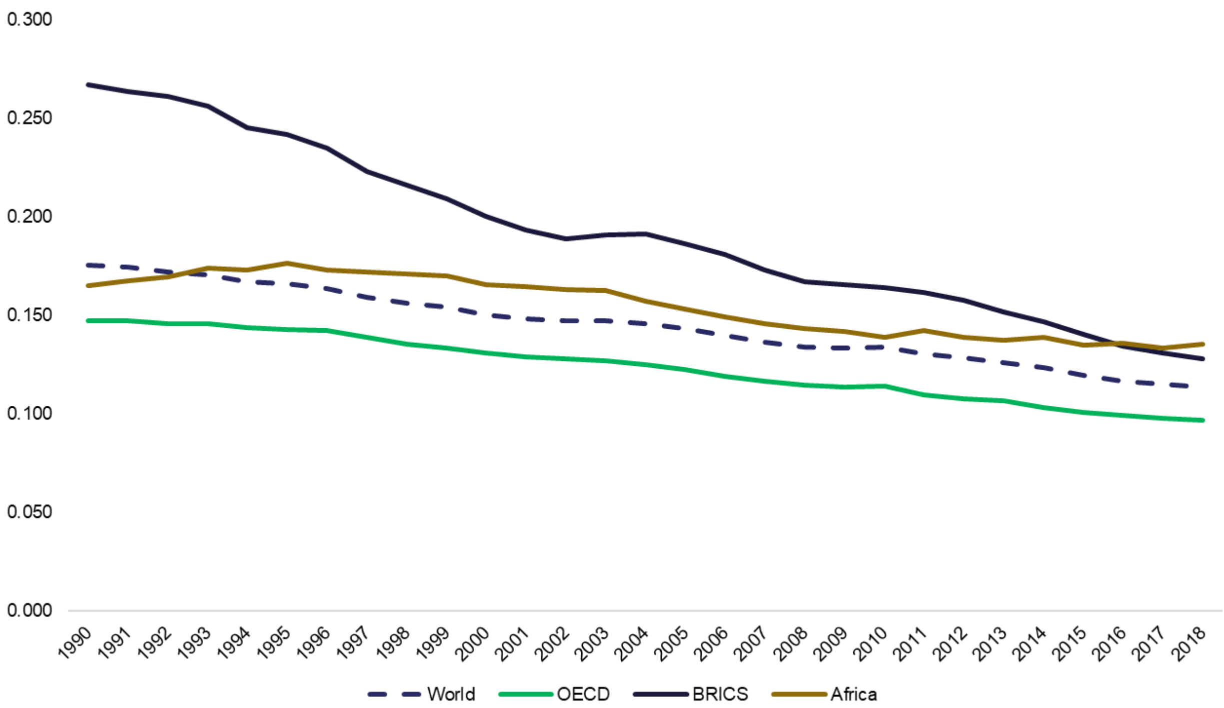


Figure 3-4: Energy Intensity of GDP at constant purchasing power parities (ktoe/$2015p)

3.1.2 Utility

Driven in large part by environmental technological and digital shifts, energy systems have been undergoing profound changes. Global policy shifts towards decarbonised economies have resulted in increased investment into renewable technologies which has thus benefited from the experience curve effect. This has driven (and continues to drive) the cost curve downwards, thereby increasing the favourability of renewables within the energy mix. The characteristics of renewables, however, is that of variable supply, requiring energy storage (or swing) capacity in order to facilitate ready availability for the market. In this regard, natural gas has a role to play in complementing renewables, providing swing electricity generating capacity, while being a transitionary fuel towards a decarbonised future. Natural gas, along with renewables and hydro, is thus the energy source expected to grow over the next 20 years.[37]

On the transmission and distribution side of the value chain, embedded options and advances in digital technologies and Information Communication Technology (ICT) infrastructure has created smart cities (and smart grids) with improved responsiveness and efficiency of delivery systems.

This has created the opportunity and need to develop new energy systems that are more responsive to the energy mix that is being developed while addressing the demand needs of consumers. In this regard, the World Economic Forum (WEF) has proposed an Energy Triangle[38] as a feature of an energy system which speaks to the key dimensions of (1) Access, Security (and Affordability); (2) Environmental Sustainability and (3) Sustainable Development and Growth. According to the WEF:

> *"the diverse challenges facing the energy system today cannot be addressed by a single government, industry, company or other institution alone. A broader variety of expertise, convictions and resources are required for effective action. Moreover, relevant actors and initiatives must be organised to understand and prepare to successfully leverage the*

[37] GECF, 2018. Global Gas Outlook.
[38] World Economic Forum, 2018. Fostering Effective Energy Transition.

underlying transformational forces and direction of energy transition. To progress in energy transition, the world requires a collaborative platform that fosters a systemic approach to solving problems and capturing opportunities."

The characteristics of this are highlighted below:

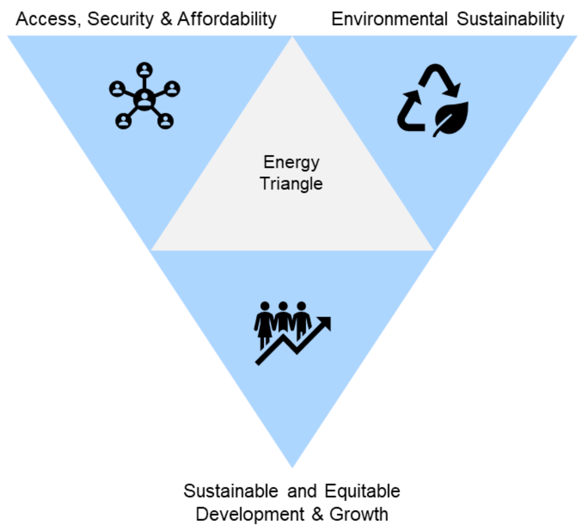


Figure 3-5 Key Features of an Energy System.[39]

Market fundamentals require energy access, energy security and affordability (i.e. price and volume) that must be secure, predictable, transparent, accessible, and affordable – relative to the needs of the market. Renewables have introduced variability and unpredictability into the supply mix; requiring systems that meet the market demands through enhanced responsiveness. Energy storage through batteries, for example, is thus important in facilitating this transition; however, storage technology pricing is still prohibitive on a utility scale; thus, requiring alternative load-balancing and load following technologies which favour gas.

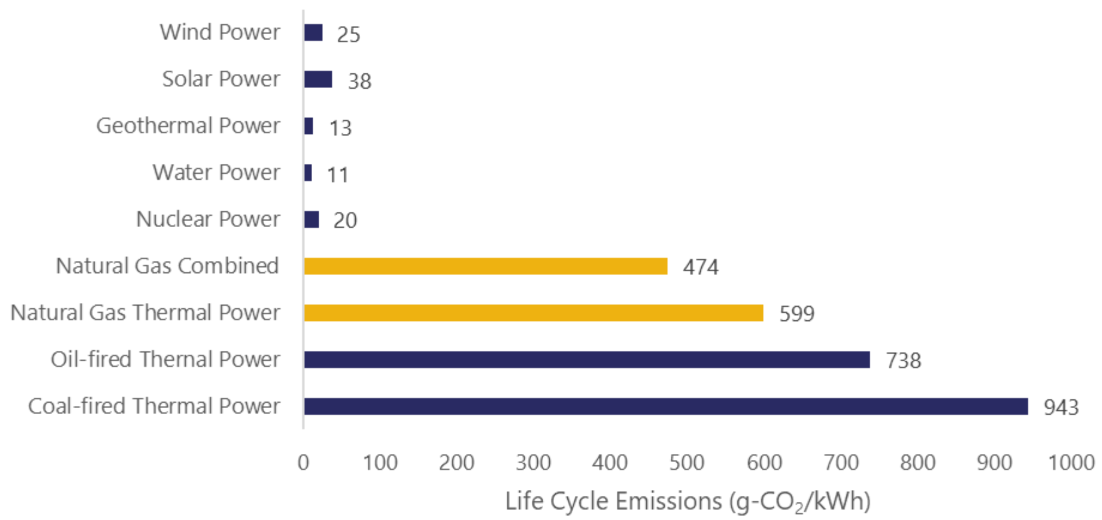


Figure 3-6: Life-Cycle Emissions (g-CO_2/kWh) CO2 Emissions compared across Power Sources

[39] Ibid

Finally, as indicated, natural gas provides lower CO_2 emissions when compared to alternative fossil fuel sources.

3.1.3 Embedded Generation and Electricity Access

Over the years, the differing needs of various electricity consumers have been highlighted, indicating the limits that the conventional national grid has in meeting the requirements of some consumer segments. Mines and commercial buildings such as hospitals, airports, and data centres rely on an uninterrupted supply of electricity which would ensure that critical processes can be performed, whilst homesteads can reduce their utility bills. These shifts have led to the adoption of embedded generation, which is the generation of electricity closer to the demand node and primarily for internal utilisation, however, the option for exporting to other users may be exercised.

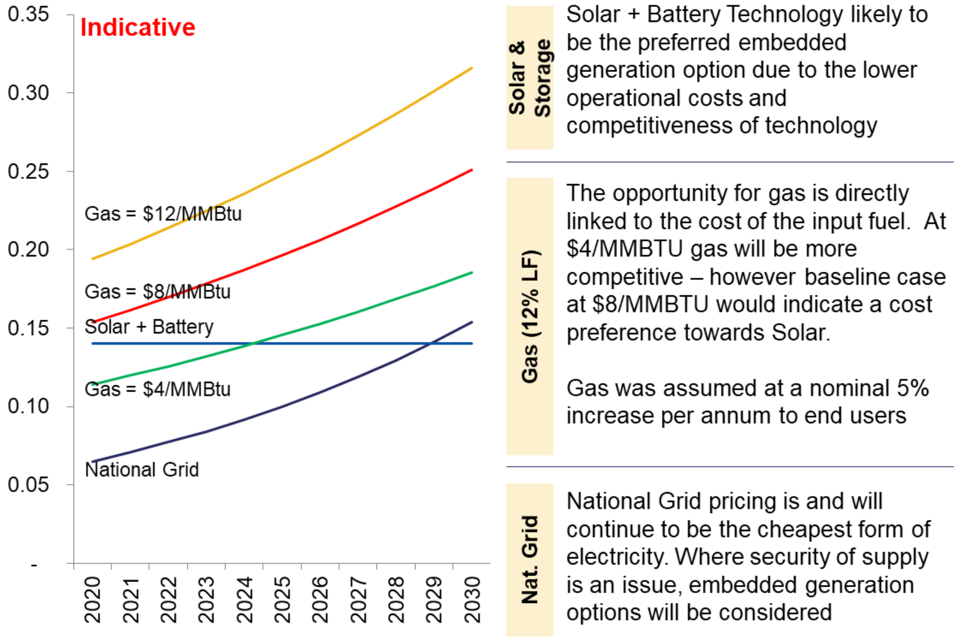


Figure 3-7: The levelised cost of electricity (LCoE) (US$/kWh) generation range for various technologies.[40] [41]

The increase in the adoption of embedded generation has largely been driven by falling costs of renewable electricity generation, as indicated in the figure above. The intermittent nature of solar, and limited battery storage capacity give way to viable competing of natural gas electricity in serving the mining sector, with the additional possibility of switching fossil fuel-based generation to natural gas. In addition, rural electrification can be realised through off-grid electricity generation. It is expected that because of space availability and limits in greenhouse gas emissions, solar PV +battery will be favoured for generation in commercial buildings and homesteads.

Figure 3-8 indicates the electricity potential in rural communities within the regional communities. In ensuring the security of supply for both these segments, implementation of ssLNG, CNG or LPG would be critical, as these can be delivered via rail or road infrastructure.

[40] IRENA, 2019. Utility Scale Batteries: Innovation Landscape Brief
[41] NREL Transforming Energy: Levelised Cost of Energy Calculator

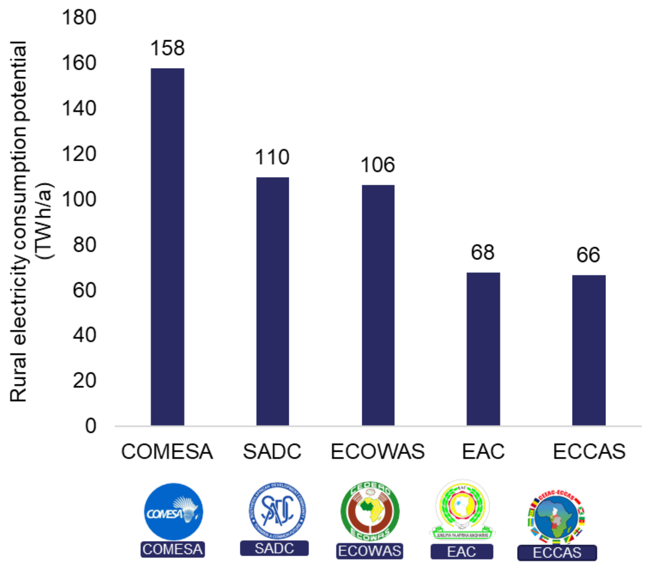


Figure 3-8: Rural electricity consumption potential within various regional communities as of 2017[42]

3.2 Petrochemicals: Moving towards Sustainability

3.2.1 Chemicals Value Chains

Natural gas, as a petrochemicals feedstock, can produce a slate of chemicals depending on the technology path chosen – inclusive of liquid fuels (methanol, diesel), olefins (i.e. plastics) and ammonia/urea (i.e. fertiliser and explosives).

The chemicals use, technologies and applications are highlighted in the figure below.

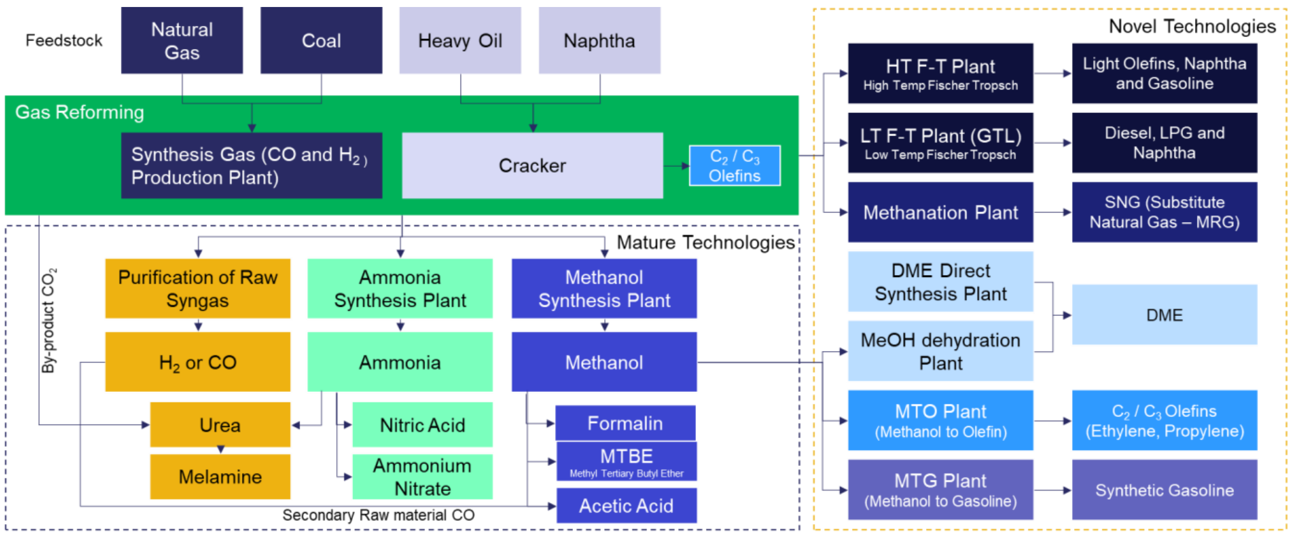


Figure 3-9: High Level Petrochemicals Value Chains

3.2.2 Diesel

GTL presents a monetisation option for countries with large NG reserves and helps reduce the domestic economy's dependence on imported refined products and increases revenue generation

[42] World Bank, 2017. World Bank Open Data. Based on annual electricity consumption of 700 kWh per capita of rural population.

through exports. These opportunities are, however, dependent on the country's local refinery capacity and ability to export NG/ LNG/ gas products. In 2016, fuels and oils accounted for about 12% of imports within Africa.[43] All the countries in the SADC region are net importers of refined fuel; therefore, there are opportunities for the region's fuel demand to be fulfilled with the development of liquid fuel plants which would consume NG.

GTL technology is the primary method for liquid fuel production from gas molecules. In the low temperature GTL process, syngas is converted to syncrude via the Fischer-Tropsch reaction and then hydrocracked to produce diesel, naphtha, and LPG. High temperature Fischer-Tropsch produces an additional suite of products which include detergent alcohols and olefins, and products that can be used in the plastic-making process. Most of the commercial plants operating around the world use technology from two companies – Sasol and Shell. This technology relies on the difference between the oil and NG prices, making them challenging to justify in a low oil price environment, as illustrated in Figure 3-10.

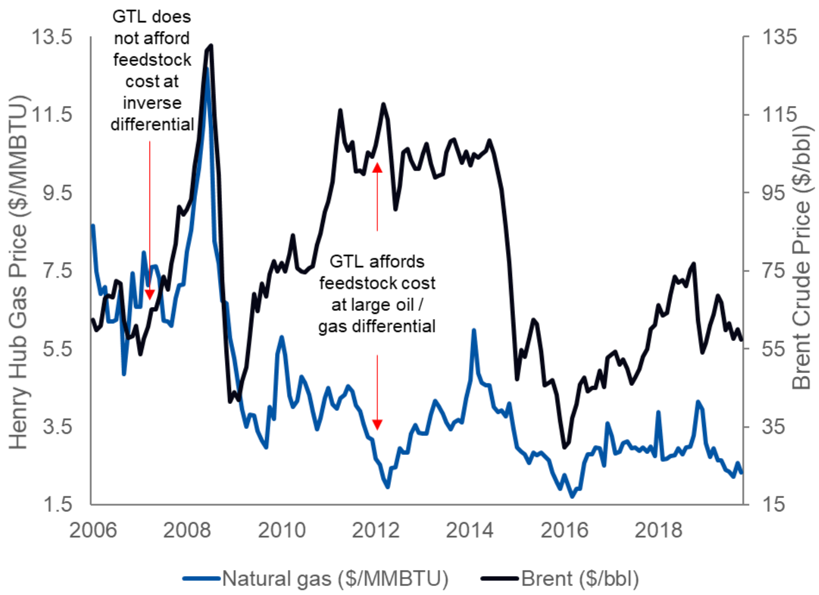


Figure 3-10: Historical USA Oil and Gas Prices and its impact on GTL affordability.[44]

GTL Diesel is a comparative clean fuel, virtually free of sulphur and aromatics leading to a large reduction in exhaust emissions, while GTL Naphtha is also a premium product which is almost exclusively paraffinic and has virtually no aromatics, sulphur, or metallic contaminants.

The SADC region is an exporter of crude oil and to redress the region's dependence on imported refined products; it could alternatively build oil refineries to process the crude which is currently exported. Angola is the major exporter of crude in the SADC region, and it plans a new Lobito (Benguela) refinery with a capacity of 200,000 bbl/d and a refinery in Cabinda with a capacity of 60,000 bbl/d. In addition, the rehabilitation, expansion, and modernisation of the former 65,000 bbl/d Luanda Refinery is underway.

[43] African Union, 2017. Africa Trade Statistics Yearbook.
[44] EIA Statistics and St. Louis Fed Statistics. Accessed November 2019

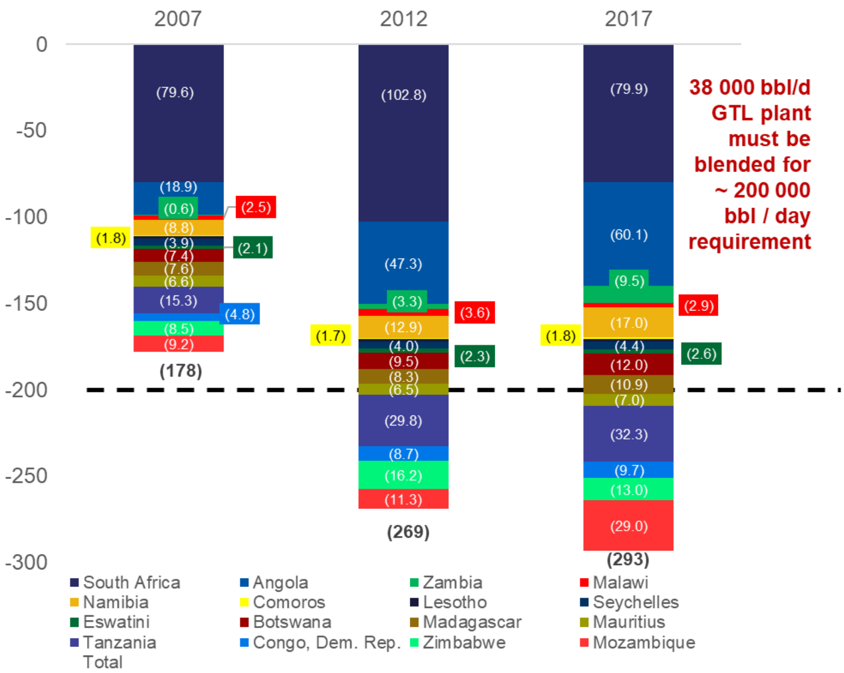


Figure 3-11: Regional Diesel Deficits ['000 bbl/day]

3.2.3 Fertilisers: Ammonia / Urea

The growing world population has necessitated the need for increased food production. It is expected that by 2030, an additional 600 million tonnes/annum of grain will be required[45] (above 2010 levels) to cater for the increasing world population. Available agricultural land is in short supply globally, with the largest non-cultivated arable land located in SSA, Latin America and the Caribbean regions.

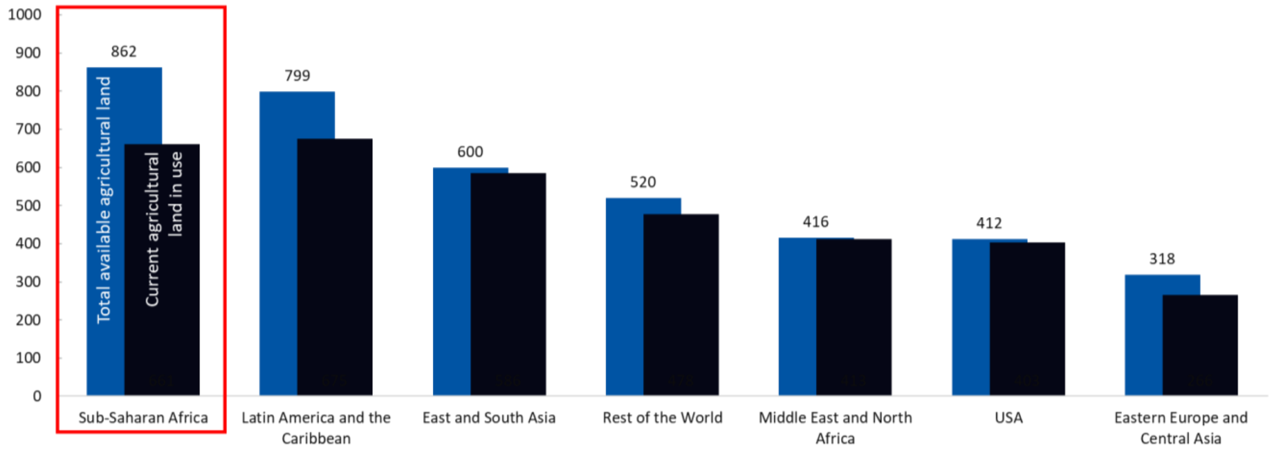


Figure 3-12: Current land in use versus total available agricultural land across regions (million ha)[46]

If the available agricultural land in SSA is to be sustainably and effectively cultivated, significant improvements must be made to improve crop yields and farming technology. Crop yields in SSA are currently the lowest in the world (Figure 3-13). A contributing factor to this is low fertiliser utilisation in SSA (Figure 3-14).

[45] Food and Agriculture Organisation of the United Nations, 2012. World Agriculture towards 2030/2050: The 2012 Revision.
[46] The World Bank, 2011. Rising Global Interest in Farmland. FAOSTAT, United Nations.

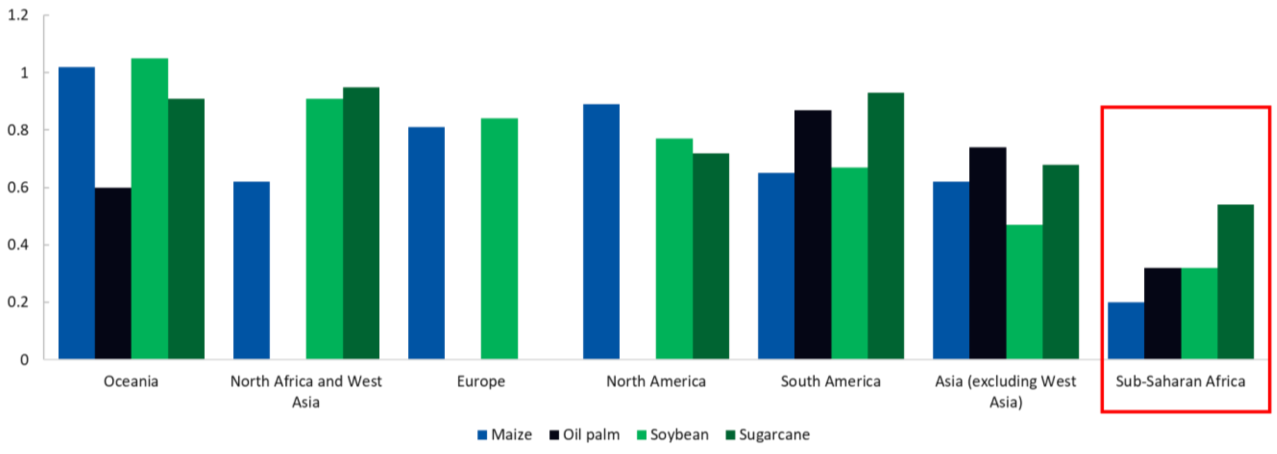


Figure 3-13: Current yield relative to estimated potential yield.[47]

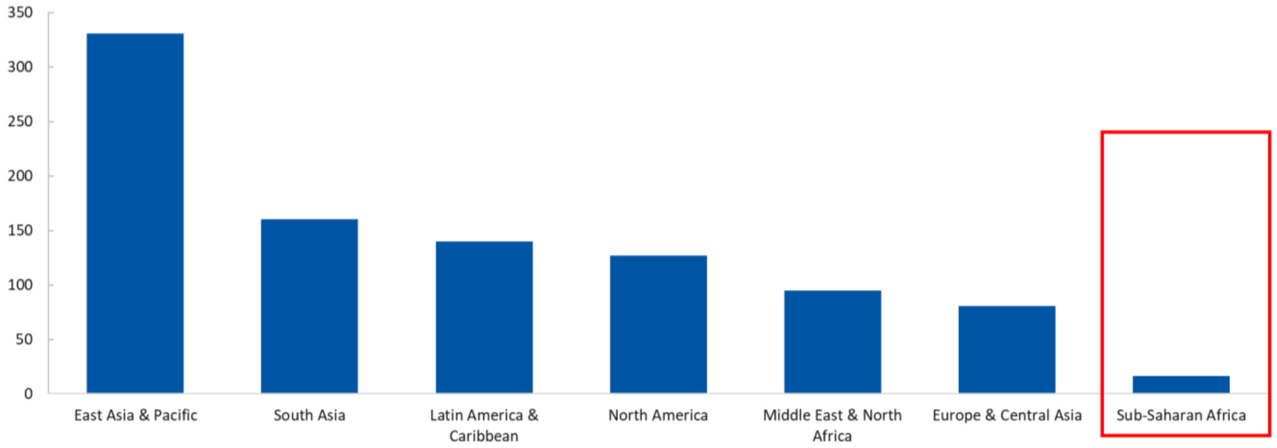


Figure 3-14: Fertiliser consumption in kilograms per hectare of arable land.[48]

Cultivating a significant portion of SADC arable land could contribute to meeting the global demand for food, but realising this potential is only possible if paired with improved farming methods. Achieving this would create a significant demand for fertilisers in SADC -which provides an opportunity for ammonia/urea production.

3.2.3.1 Ammonia / Urea

The syngas is converted to H_2 via the water-gas-shift reaction, which is then reacted with nitrogen (N_2) to produce ammonia via the Haber-Bosch process. Ammonia production technology is a mature technology and is offered off-the-shelf by many technology licensors. Ammonia can be converted to a range of downstream derivatives but is used predominantly in the fertiliser industry. About 85% of all ammonia produced is used in the fertiliser industry in the form of Urea, Ammonium Nitrate, Ammonium Phosphate and Ammonium Sulphate.

Ammonia is also used in the explosives industry (as Ammonium Nitrate) and to produce acrylonitrile, fibres, resins, refrigeration, and alkaline cleaners. Urea and ammonium nitrate are the main fertilisers used in Southern Africa. A typical single-train ammonia plant is about 2,000mtpd and would require approximately 60 to 80MMscf/d of gas feedstock. Capital and operating costs are location-dependent,

[47] The World Bank, 2011. Rising Global Interest in Farmland. FAOSTAT, United Nations.
[48] World Bank, Sustainable Energy for All, 2019. Databank.

and it should be noted that a significant capital cost component is required for such a facility. As the primary operating cost would be the gas feedstock, low gas prices influence overall project economics.

3.2.4 Methanol

The Methanol value chain is an important consumer of natural gas. Natural gas is reformed to syngas – carbon monoxide (CO), hydrogen (H_2) and small amounts of carbon dioxide (CO_2). The CO and CO_2 are reacted with H_2 in the catalytic methanol synthesis process to produce methanol and water. Gas-based methanol technology is mature and is offered by several licensors.

Methanol is used in a large variety of applications:

- Chemical feedstock (traditional demand): The main overall use for methanol is to produce formaldehyde which is used in the production of industrial resins for use in the construction and automotive industries. Another product, Acetic Acid is used primarily in the production of vinyl acetate monomer, an intermediate product in the production of adhesives, paints, coats, and other similar products
- Energy: Methanol can be used as a gasoline substitute for fuel blending, as a diesel additive in DME, in biodiesel production or as MTBE (an oxygenate fuel additive). It is also finding increasing application as a marine fuel.
- Methanol to Olefins (MTO) process: MTO is a technology which has emerged commercially in the past few years, particularly in China, whereby methanol is converted to ethylene and propylene. This is the fastest growing demand for methanol.

Methanol is a pure commodity and market demand (particularly for MTO), coupled with economies of scale, have driven the trend towards much larger sized methanol plants of around 5,000mtpd. These methanol facilities require gas feedstocks of approximately 160 to 200 MMscf/d.

Methanol can be used as an important building block for the development of downstream chemical industry, particularly in regions where there are limited sources of other petrochemical feedstocks such as crude derived naphtha. This is particularly true if it is coupled with the production of ammonia and urea. The methanol can be used to produce formaldehyde and the urea to produce melamine. These products can be coupled to produce the liquid resin urea formaldehyde. These products are used in a variety of construction applications such as laminates, plywood as well as the automotive industry – all growing markets in the SADC region. The downstream production of DME could also be considered for use in the diesel market and, in the long term, MTO production could be considered - although this would require the development of a much larger regional ethylene and propylene market. The development of the Trinidad and Tobago gas based chemical industry is a good example of how the initial development of ammonia and urea production facilities for use in the fertiliser industry, followed later by methanol production and later melamine, was used to develop a downstream gas based chemical industry[49]. The value of downstream chemical industries can be realised through job creation, development of technical skills and less reliance on importation of value-added goods but will require regional market integration to ensure large enough demand.

The dilemma is that the capital cost of methanol plants is substantial and requires that world scale facilities be established to make them economical. These quantities are too large to be absorbed into regional SADC markets (either for formaldehyde production or for energy applications) in the short to medium term. So, a large portion of the product must be exported (predominantly for use in MTO facilities) as the domestic and regional downstream market is developed. As the primary operating

[49] Ministry of Energy and Energy Industries - Trinidad and Tobago, “Gas-based Industries in Trinidad and Tobago”,

cost is also gas feedstock, low gas costs are necessary for overall project economic viability and therefore leads to competition with other gas-rich regions.

3.3 Heating: Security of Supply and Cost Advantage

3.3.1 Industrial Heating Demand

The industrial sector consumes 46% of all heat generated globally, followed by the residential sector (38%) and the commercial sector (13%). Industrial heat consumption is closely tied to overall economic activity as it can be observed in the figure below that industrial consumption dipped following the 2008 global recession and increased with the global economic recovery afterwards. Residential heat energy consumption is largely driven by households within northern climates which ramp up consumption during colder winter seasons. Heat consumption in the residential sector is on a downwards trend due to rising average global temperatures which impact seasonal weather patterns and overall decreases in energy intensity.

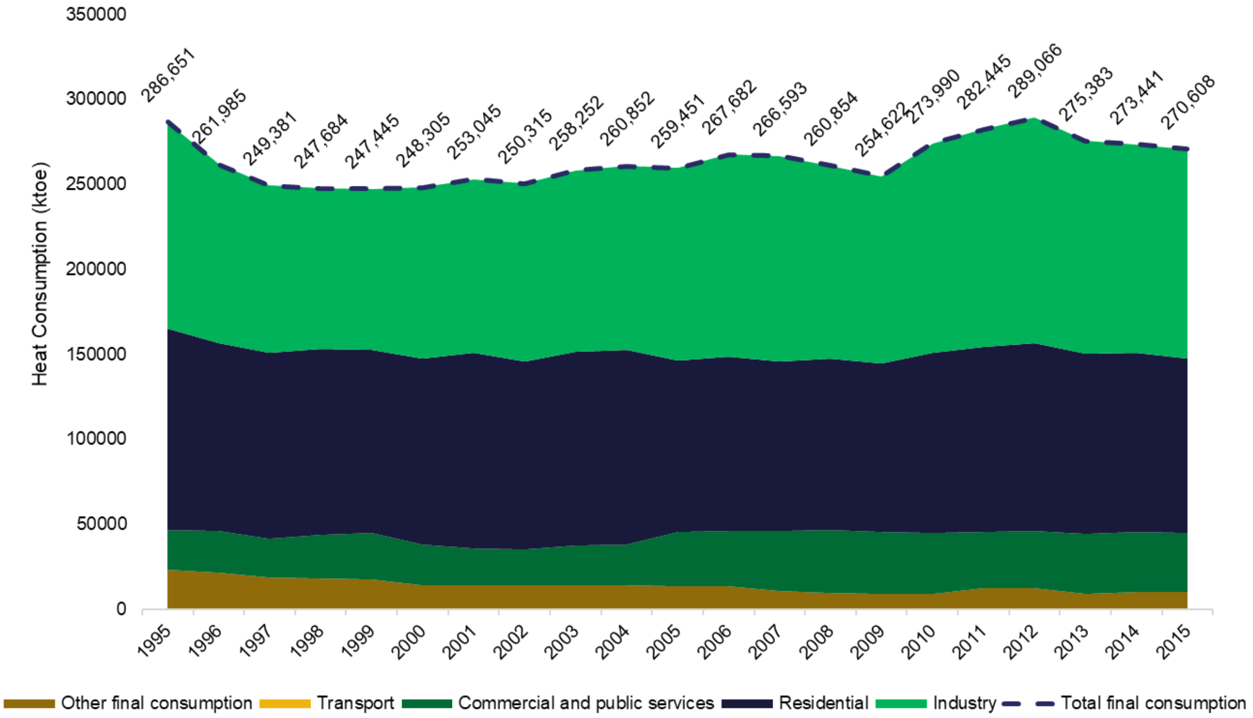


Figure 3-15: Profiles of heat consumption by sector (2018, ktoe).[50]

Industrial energy is forecast to be generated primarily through liquid fuels (i.e. oil and derivative products), natural gas and coal, as shown in the figure below. The share supplied by natural gas will grow by 1.7% per annum from 23% in 2020 to 26% by 2040 driven by growth in non-energy intensive manufacturing sectors (i.e. chemical production industries as well machine and component manufacturing industries). This trend will be supported by the global response to greenhouse gas emissions (which drive climate change) and an increase in the share of renewables in electricity generation.

[50] IEA Headline Energy Data 2018

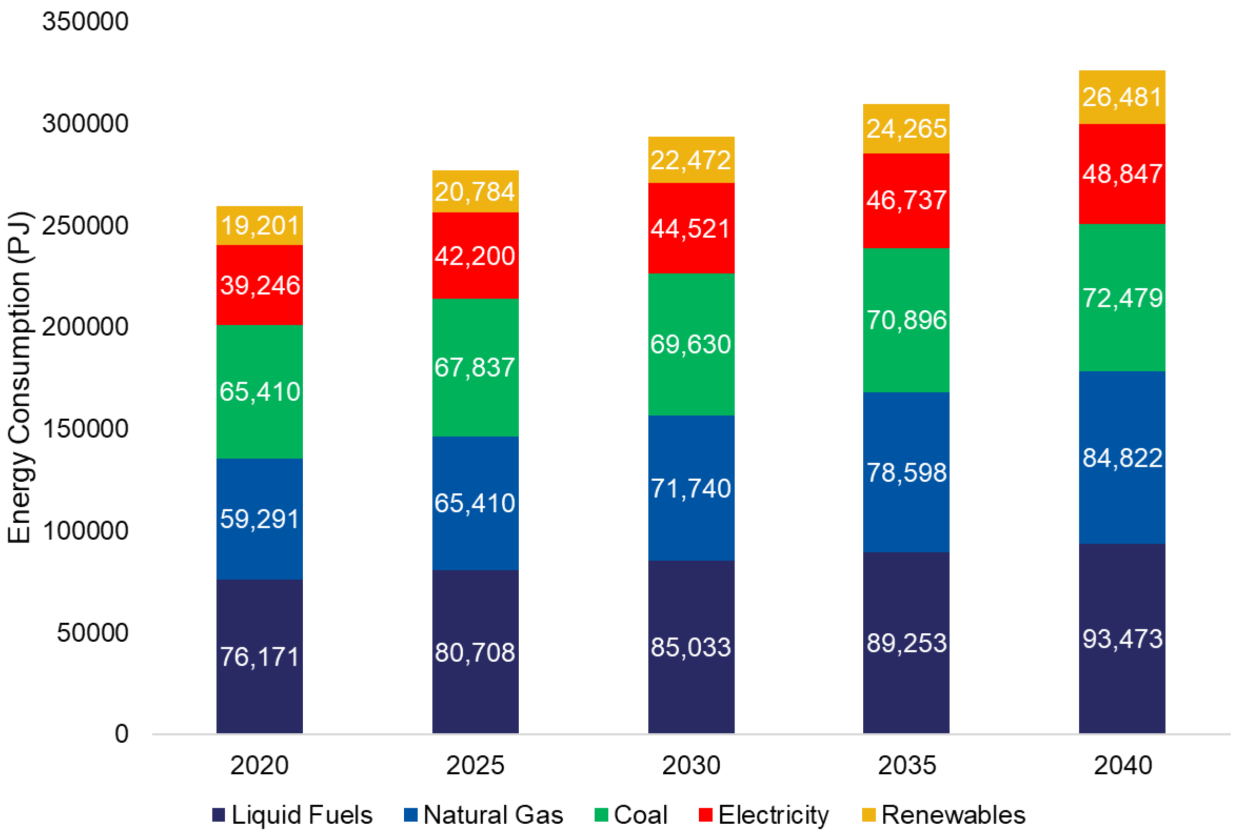


Figure 3-16: Global industrial energy consumption by source (2020-2040, PJ).[51]

3.3.2 Residential & Commercial Demand

Globally, residential, and commercial buildings energy accounts for about 20%[52] of total energy, amounting to about 2 108 284 ktoe in 2018[53], used for space heating and cooling, appliances, cooking, lighting, and water heating. About 90%[54] of the energy consumed in residential households and commercial buildings is used for heating. The EIA has projected that global energy consumption in buildings will grow by an average of 1.3% per year between 2018 and 2050, primarily driven by household expenditure and each country's energy intensity.

On a global scale, energy consumption in buildings has increasingly been driven more by electricity, especially in high GDP countries. Electricity appears to be a more convenient source in countries with adequate supply. In Africa, due to its low electrification rate, consumption appears to be driven more by renewables and biomass as a primary energy source for residential and commercial heating, as shown in Figure 3-17.

[51] EIA, International Energy Outlook, 2016
[52] EIA, International Energy Outlook, 2019
[53] IEA, Headline Energy Data, 2019
[54] Energypedia, Facts on Cooking Energy, 2020

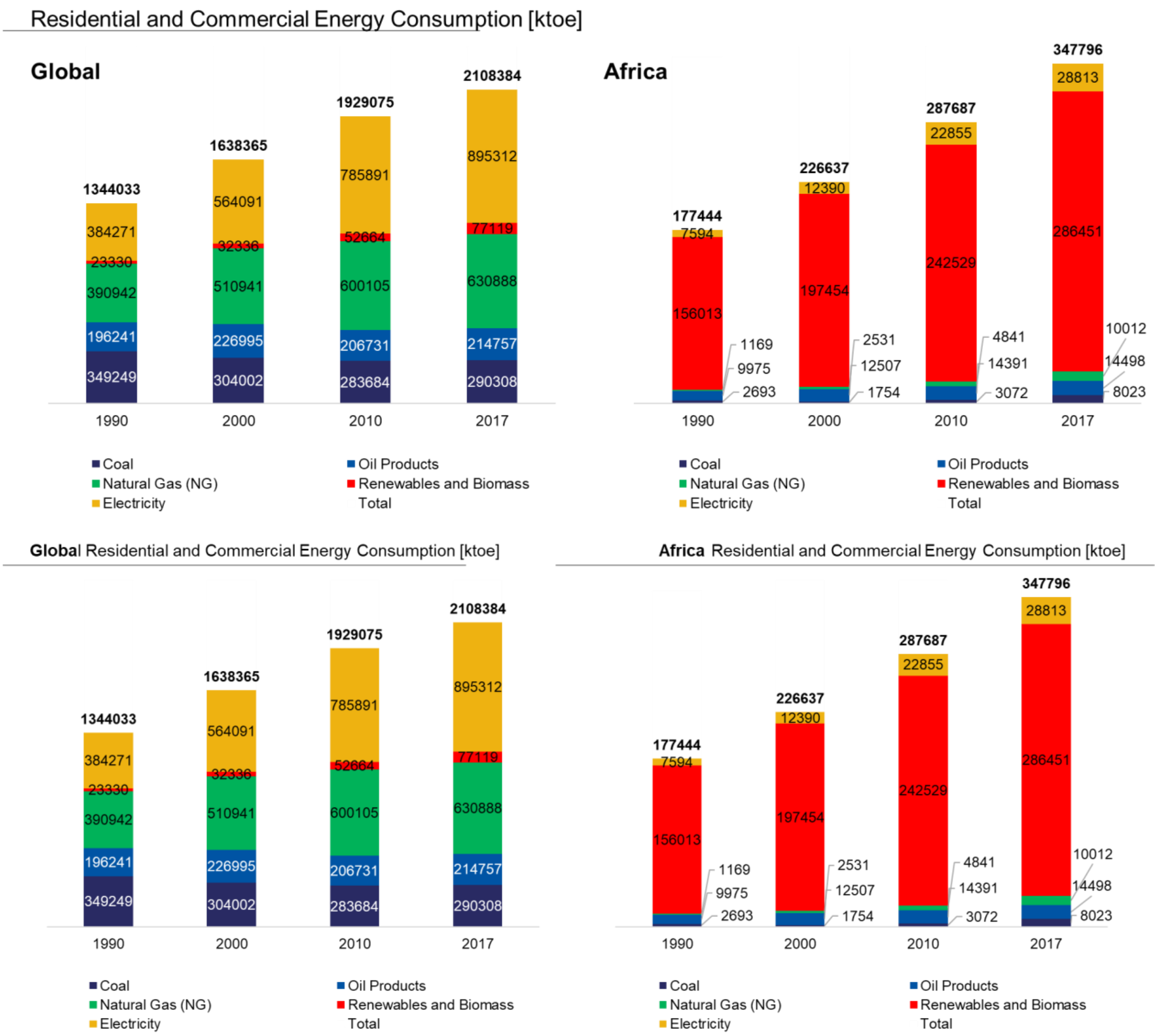


Figure 3-17: Residential and Commercial Energy Consumption [ktoe][55]

The large reliance on biomass in Africa is due to its low electricity access, which was 48% in 2016 for Sub-Saharan Africa against a global 88%[56]. Biomass is the primary source of energy in rural residential areas which are prevalent in the subcontinent as a result of the level of industrialisation. Industrialisation drives urban population growth which reduces the demand for biofuels as urban areas generally afford higher value forms of energy supply. Most urban areas currently make use of LPG for their residential and commercially heating needs. The availability of natural gas in certain segments of the continent may incline policies towards the uptake of natural for local utilisation, with the residential sector being one of the key local markets. A potential switch from LPG or other fossil fuels is further motivated by its low carbon emissions, hence viewed as a cleaner source of energy.

[55] SADC Renewable Energy and Energy Efficiency Status Report 2018.
[56] World Bank Data, Electricity Access (%of Population), 2020.

3.4 Transportation: Ecomobility

3.4.1 Road

The international gas market for transport is developing quickly in other parts of the world, with light vehicle consumption of CNG, while long haul vehicles trucks and locomotives are adopting LNG, to reduce carbon emissions as well as smog and acid rain resulting from NOx and Sox.

The Southern African region has lagged in terms of adoption of natural gas to power transportation vehicles due to having a strong oil-based transportation fuel sector, a limited gas supply as well as the infrastructure requirements to shift from oil-based fuels to gas. However, South Africa, Tanzania and Mozambique have recently introduced gas powered vehicles into governmental fleets and have also promoted its usage in public transportation initiatives.

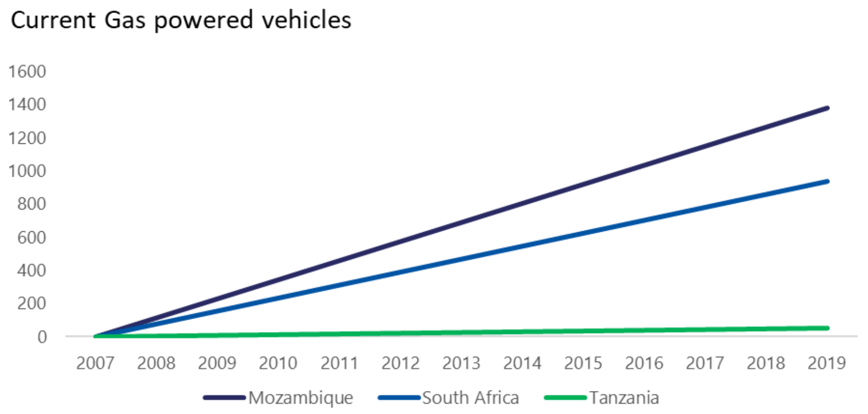


Figure 3-18: Current natural gas-powered vehicles in the region

Tanzania has plans to convert 8000 vehicles including state and private vehicles onto Natural Gas Vehicle (NGV) technology and are developing three CNG refuelling stations, while retrofit centres that convert gasoline cars with electronic fuel injection systems to NGVs in accordance to international standards have been established in Dar es Salaam. [57] The Mozambique government also recognises the importance of switching to natural gas for all segments and are planning on replacing diesel buses to CNG and are planning on importing 1000 gas powered buses from China over the next 5 years.[58] South Africa is a major exporter of bakkies to Europe and would need to acclimatise to European regulations for exports to continue, and a shift towards may be a possibility. The South African government is promoting CNG initiatives by drafting regulations that will require 10% of municipal fleets to be converted to CNG annually. They also provide funding options for minibus taxi conversions and retrofit filling stations as well as planning to convert public and quasi-public transport to dual-fuel vehicles within 10 years.[59]

The implementation of gas-powered vehicles would require a city-by-city approach and would require a phased approach due to infrastructure challenges as well as penetrating a strong oil-based industry. The projected personal vehicle growth in Africa provides optimism and would allow for NGVs to obtain market share through new vehicle purchases. The lower resale value in comparison to diesel vehicles provides a challenge for the NGV industry in developing countries; however, the lower running costs, as well as a supportive local policy, may mitigate some of these issues.

[57] Natural gas for vehicles, IGU & UN ECE joint report
[58] Green Building Africa, 2019. Mozambique to import gas powered buses from China
[59] Green Transport Strategy 2018

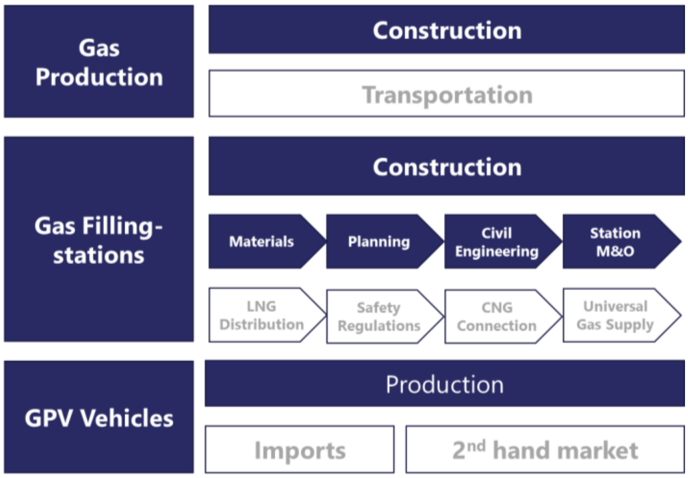


Figure 3-19: Gas powered vehicle value chain

3.4.2 Maritime (Bunkering)

The bunkering sector in Southern Africa forms an integral part of the shipping industry as the provision of fuel enables transport by sea. Cargo vessels have developed over the years to cater for international trade, with technology advancements rapidly enabling the use of LNG as a more viable and efficient option to diesel. These advancements mean higher productivity for shipping lines at a reduced fuel cost. This, coupled with LNG emerging as a new source of bunkering fuel supply given the IMO 2020 sulphur regulations,[60][61] is expected to create sufficient demand for LNG in the region.

A feasibility study was done by the U.S. Trade and Development Agency for the Western Cape Integrated Liquefied Natural Gas Importation, and Gas-to-Power Project considered the potential demand for LNG in the marine transport sector. It noted that the marine portion of the transportation sector represents a potentially large, single-point demand source via a single buyer and distributor.

Bunkering sales in South Africa have declined significantly over the past several years due to high port calling costs, problems with supply, and a limited range of fuel types on offer in Cape Town and Durban.[62] The forecasted LNG bunkering demand used in the study was based upon the number of expected vessel calls to the Port of Cape Town over the forecast period, the percentage of those vessels requiring LNG bunkering fuel, and the average amount of LNG loaded on to each refuelled ship. Under the study's base case assumptions, marine LNG bunkering demand will rise to 10 million GJ by 2050.[63] The assumptions used were more conservative than those used by the World Maritime University – which would have resulted in much higher demand forecasts.

The SADC oil consumption is the highest in Africa and assuming the international projected maritime industry switch from HFO to gas, which is expected to be 7.5%, is adopted in the region, the projected gas consumption is expected to be around 450000 ktoe per annum.[64] The gas switch, however, is a short-to-medium term solution, with long term solutions expected to be through the development of renewables to meet the maritime demand.

[60] International Maritime Organisation, 2016. IMO sets 2020 date for ships to comply with low sulphur fuel oil requirement.
[61] Regulations will cut the use of fuels emitting high levels of sulphur oxide, including many high-sulphur bunkering fuels derived as residuals from crude oil distillation.
[62] Cape Business News,2016. IBIA in Africa Forum explores bunkering trends and potential.
[63] U.S. Trade and Development Agency, 2019. Feasibility Study for the Western Cape Integrated Liquefied Natural Gas Importation and Gas-to-Power Project
[64] McKinsey Global Energy Outlook to 2035, McKinsey Energy Insights – Global Energy Perspective 2019 Reference Case Summary|

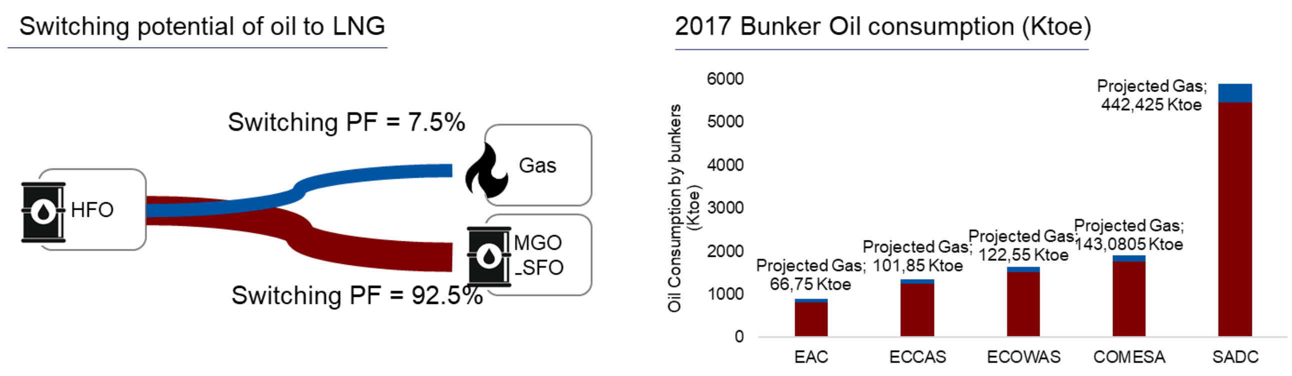


Figure 3-20: Maritime oil to LNG switching potential

3.4.3 Transportation Demand

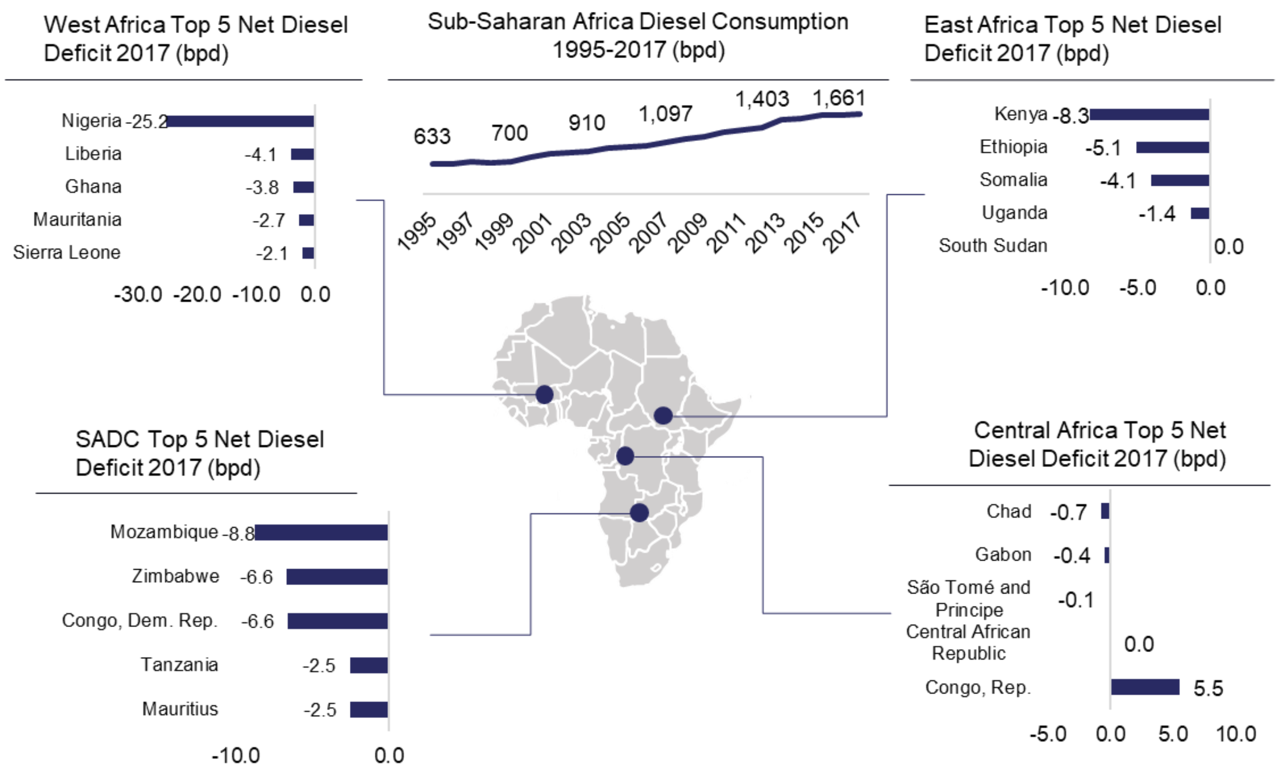


Figure 3-21: African continent trend in diesel consumption, with an indication of the countries with diesel deficits around the continent

The trend of negative net diesel deficit in the region, together with climate considerations and more stringent regulations creates a gap in the market for which gas or gas derived products such as GTL provides a suitable alternative to fill, provided a consistent supply of gas is available to meet the demand.

4. GAS SUPPLY & PRODUCTION

4.1 Upstream Overview

4.1.1 Gas Field Development Cycle

Hydrocarbon basins typically follow a lifecycle of licensing-exploration-development-decline-abandonment. The maturity of a basin is important for a variety of reasons, including:[65]

- Tax and incentives that the host nation needs to put in place to attract investments
- State revenues and national budget planning
- Type of company most interested in investing, i.e. IOCs, independents, or mature field specialists

Legal frameworks (see Appendix B) are necessary before any exploration work begins – to provide certainty for the investment required. SADC Member States such as Angola, South Africa, Namibia, Mozambique, and Tanzania are all governments that have auctioned leases for exploration acreage at regular intervals. Lease durations vary and are usually awarded under one of two fiscal regimes, i.e. Production Sharing Contracts (PSCs) or Tax & Royalty Concession (see Appendix B).

Regionally, certain countries such as Angola, South Africa and Mozambique have experienced the full lifecycle – and are in certain instances entering periods of decline (e.g. the F-A Field and South Coast Complex fields in the Bredasdorp Basin) and thus eventual abandonment.

4.1.2 Conventional and Unconventional Gas

The evolution of conventional and unconventional gas, and the extraction thereof, has seen profound changes in the global gas industry. The US Shale revolution, as an example, involving the extraction of natural gas from shale deposits (as opposed to conventional sandstone deposits) – shifted the US from being an LNG importer to becoming a key force in the global LNG export market. This impacted LNG export projects (e.g. the Angola LNG project) – while contributing to the shift in the global LNG market that is discussed in Section 5.4

It must be noted that “unconventional” gas is the same commodity as “conventional” gas. It is the form of the commodity in its natural state – and the extraction technology used that delineates the difference.

SADC Member States have a blend of conventional (Angola, Mozambique, Tanzania) and unconventional resources (Coal Bed Methane in Botswana and Zimbabwe, Shale in the Karoo, South Africa) that can be extracted for use in the region.

4.1.2.1 Shale Gas

From an upstream perspective, shale gas developments have been amongst the most profound changes the industry has undergone in recent times. Interest in developing tight and shale gas reserves, particularly in the US has been significant as improvements in technology have improved productivity and reduced costs.

As US Shale contains ‘wet gas’, the economic viability (coupled with the drive to reduce dependence on volatile oil producing regions and increase consumption of more environmentally friendly sources of energy) has driven gas prices in the US to historic lows.

[65] Deutsche Bank, Oil & Gas for Beginners, 2014

In this regard, **tight gas** is gas that is trapped in reservoirs (often sandstone) that have low porosity and permeability (typically less than 0.1millidarcy). It is known as a non-conventional resource since simply drilling a conventional well through the middle of such reservoirs will not result in enough gas production to make the well economic.[66]

Shale gas is similar to tight gas, the key difference being that the rock is shale. Shale is the earth's most common sedimentary rock, rich in organic carbon but characterised by ultra-low permeability. In many fields, shale forms the seal that retains the hydrocarbons within producing reservoirs, but in a handful of basins, shale forms both the source and reservoir for natural gas.[67]

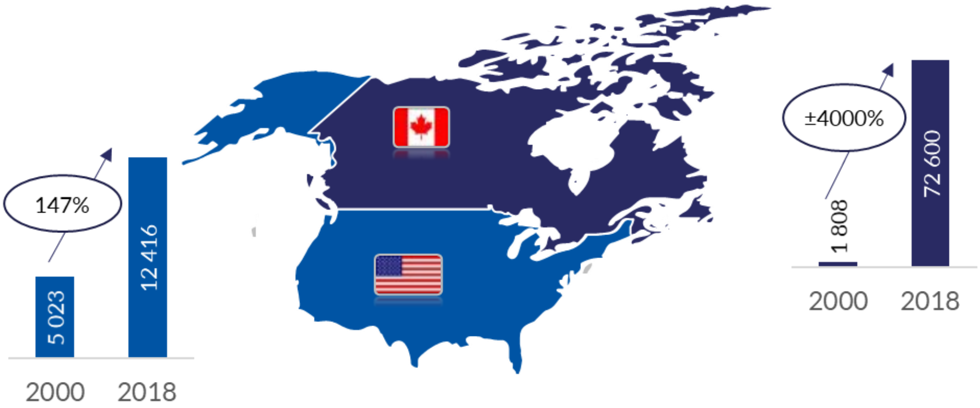


Figure 4-1: North American Proven Reserves (bcm).[68]

The Shale boom has had a pronounced effect on natural gas pricing in the US, with gas now at the US$ 2 / MMBtu price range.

From a SADC perspective, this change has several key implications:

1. Historic LNG export projects (e.g. Angola LNG in Soyo), initially developed for the US market, must now find alternative markets, providing an opportunity for supply into the SADC regional market
2. Cheap US gas, and US LNG export facilities, make LNG importation into SADC Member States more economically viable
3. Unconventional gas plays provide options for domestic development, e.g. Karoo Shale in South Africa and CBM in Botswana.

4.1.2.2 Coal Bed Methane

While natural gas is commonly associated with oil, it also occurs with coal. Coal Bed Methane (CBM), or coal seam gas is methane that is found in coal seams. It is generated either from:

- biological processes as a result of microbial action, or
- thermal processes as a result of increasing heat with the depth of the coal.

Whereas in a natural gas reservoir the gas is held in the void spaces within the rock, methane in coal is retained on the surface of the coal within the micropore structure.[69] Often a coal seam is saturated with water, with methane held in the coal by water pressure. Releasing this pressure allows methane to dissociate and so escape from the coal.

[66] Deutsche Bank, 2014. Oil and Gas for Beginners.
[67] *Ibid.*
[68] IHS Cera. Fuelling the Future with Natural Gas, 2015.
[69] Deutsche Bank, Oil and Gas for Beginners, 2014

Botswana has sizable CBM resources and there are indications of CBM resources in Zimbabwe. These can be exploited for domestic purposes, including electricity generation, which can then be regionally traded.

4.1.3 Condensates and LPG

Condensate is a low-density mixture of hydrocarbon liquids that are present in raw natural gas. The make-up of these hydrocarbon liquids differs based on the gas source, in terms of gas type and composition. When the temperature of the gas is reduced below the hydrocarbon dew point, the condensate condenses out of the raw natural gas.[70]

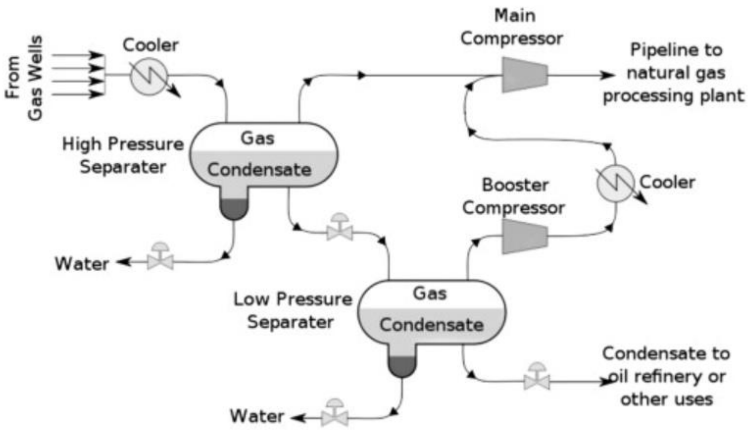


Figure 4-2: Condensates from Natural Gas separation[71]

Gas condensate is predominately pentane (C_5H_{12}) with varying amounts of higher-boiling hydrocarbon derivatives (up to C_8H_{18}), but relatively little methane or ethane. Propane (C_3H_8) and butane (C_4H_{10}) may be present in condensate by dissolution in the liquids. Depending upon the source of the condensate, benzene (C_6H_6), toluene ($C_6H_5CH_3$), xylene isomers ($CH_3C_6H_4CH_3$), and ethyl benzene ($C_6H_5C_2H_5$) may also be present.[72]

Pentane (C_5H_{12}) can be used in the petrochemical industry for polystyrene foam, and other plastic foam production; hexane (C_6H_{14}) is used in gasoline blending, solvents, and other chemical applications; Heptane (C_7H_{16}) is commonly used in solvents; Octane (C_8H_{18}) is used in gasoline (petrol), as it has anti-knock properties.[56]

Liquified Petroleum Gas (LPG) is a colourless, odourless and non-toxic gas made up of propane, butane or a mixture of the two, and can be converted into a liquid under relatively low pressures at ambient temperatures and stored in pressure vessels.[73] LPG is used as a fuel in residential, commercial and agricultural heat applications. It is also used as a vehicle fuel, petrochemical feedstock, propellant, and refrigerant.[74]

4.2 Overview of SADC Upstream Gas Activity

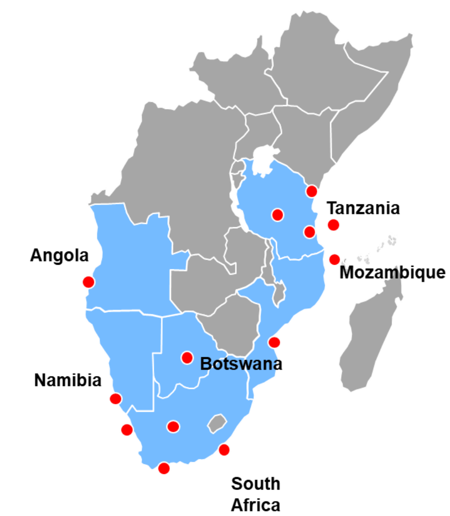
The SADC region has several natural gas deposits split between various countries. Mozambique is currently at the forefront of proven natural gas reserves, in excess of 100tcf. Other countries like Tanzania, Angola, Namibia, and South Africa have economic reserves that are, and can, be monetised. Over and above the proven gas reserves, SADC Member States have sizable estimated

[70] Handbook of Industrial Hydrocarbon Processes, 2011
[71] Handbook of Industrial Hydrocarbon Processes, 2011
[72] Natural Gas (Second Edition), 2019
[73] TOTAL: LPG PROPERTIES
[74] ELGAS: Natural Gas Liquids - NGL

natural gas reserves. These estimates have been a result of ongoing exploration activities at various key areas. Most of the regional reserves, nonetheless, consist of proved underdeveloped resources, raising concerns around their exploitation in the short term.

The region currently faces various challenges in monetising its gas resources (e.g. suitable downstream markets, access to capital and skills, policy, and regulatory enablers). The active presence of IOCs provides a clear indication of the possibility of this occurring, requiring, however, clear national direction and support. Chevron and others are currently active in Angola. Total is active in the Brulpadda blocks, where it is set to drill up to three exploitation wells in 2020,[75] in partnership with Africa Energy. The upstream consortiums in Mozambique's Area 1 and Area 4 blocks within the Rovuma basin are working with ENH towards the monetisation of the Rovuma gas through LNG exportation. The various gas blocks in Tanzania are currently explored by various IOCs like Shell and Equinor.[76]

Upstream Opportunities & Projects



Country	Status	Estimated Resources [tcf]
Angola	Exploration / Operational	11
Namibia	Exploration	2.2
South Africa	Exploration / Operational	17.5
Tanzania	Exploration / Operational / Development	57.2
Mozambique	Exploration / Operational / Development	173
Botswana	Exploration	0.4

Figure 4-3: SADC Natural gas upstream activities.[77]

4.3 Domestic Gas Reserves and Resources

The African continent is endowed with several natural resources, which include natural gas. Natural gas reserves have been discovered at various locations within the continent under different regions. The ECOWAS region carries about 180tcf of proven natural gas reserves, with COMESA and SADC following closely. Overall, the continent has total gas reserves in excess of 450 tcf out of a global proven reserves volume of 7 124tcf.[78] The African continent thus carries about 6% of the world's proven gas reserves. The ECCAS region, having the least number of member countries, also has the least total proven gas reserves.

[75] Offshore Energy Today, Total to drill up to three exploration wells near Brulpadda in 2020, 2020.
[76] Lexology, Oil & Gas in Tanzania, 2020.
[77] BMI Flitch Solutions Data, 2019
[78] EIA, 2018

Figure 4-4: African proven natural gas reserves per region [tcf].[79]

With its proven gas reserves, the continent has several major players in the gas sector, with Egypt and Nigeria being at the forefront. Figure 4-5 gives an indication of some of the major players in the gas sector based on gas production, imports, exports, and consumption. The amount of gas production is currently low compared to the number of proven gas reserves, indicating the potential and need for further development of the gas sector within the continent.

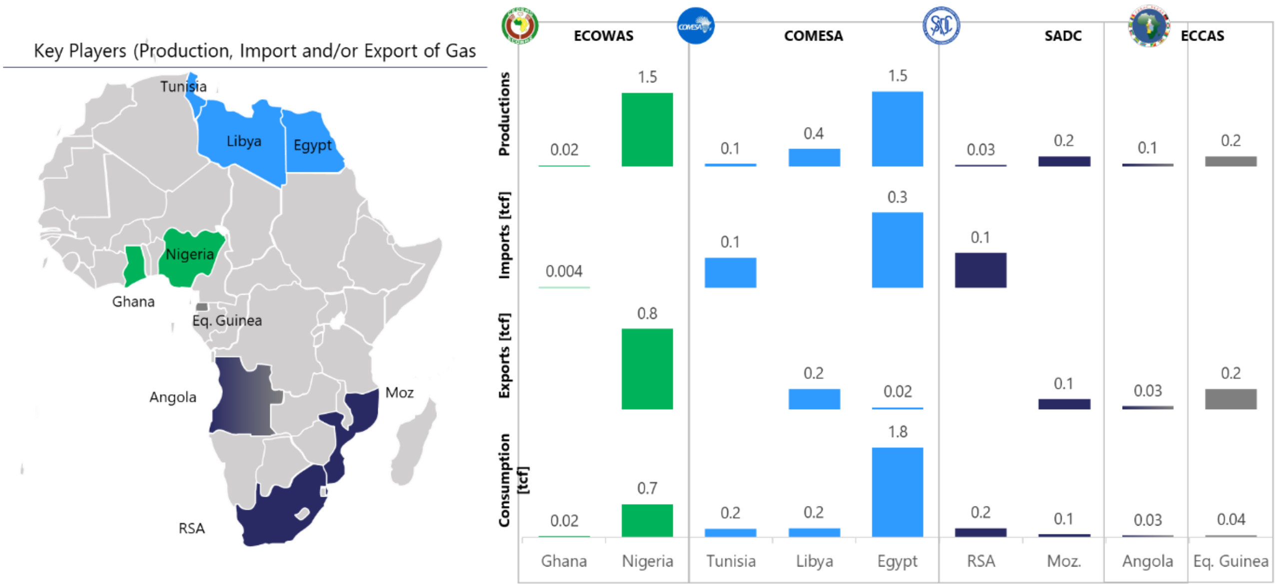


Figure 4-5: Key gas sector players in different regions.[80]

The SADC Member States have gas reserves at various stages of exploration and development. The following sub-sections looks at the different opportunities within each Member State.

4.3.1 Angola

The country's proven reserves are estimated at ±11tcf and are predominantly found as associated gas. Most major oil companies in Angola have put their focus on oil, with gas historically seen as a valueless by-product which was either re-injected, flared or vented. This has begun changing due to

[79] EIA, Natural Gas Production, 2016
[80] IEA, 2016.

the political will to monetise the gas as evidenced by the lowering of taxation for gas projects in 2018 and the Angolan Government's target for natural gas to supply 21% of its energy needs by 2025. With its current production, Angola is the only exporter of LNG within the region.

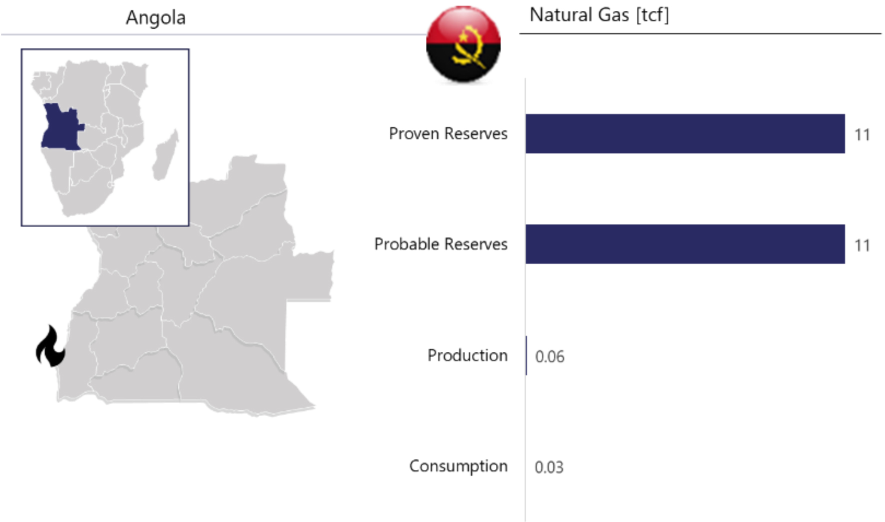


Figure 4-6: Angola natural gas.[81]

4.3.2 Botswana

The Botswana gas resources were discovered in 2014, with drilling starting in late 2018. The 2P and 3P gas reserves are currently 0.04tcf and 0.4tcf[82] respectively. The contingent gas resources are 3.0tcf. The development is in its early stages, and additional drilling is being done with a view to increase the bookable reserves. The development has political support as it will assist Botswana in self-sufficiency for electricity and in its industrial development.

Given the limited size of the gas reserves and the deficit of electricity in the region, the plan is to focus only on electricity generation located close to the reserves. A 10MW plant is initially planned, but this may be scaled up depending on the quantities of additional gas.

[81] Export.gov. Angola - Oil and Gas, 2019.
[82] Tlou Energy. Lesedi CBM Project, 2018.

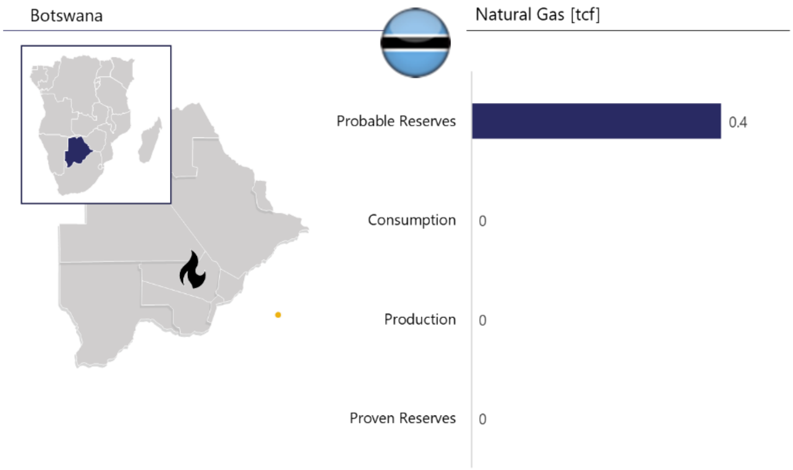


Figure 4-7: Botswana natural gas.[83]

4.3.3 Mozambique

Mozambique has various gas deposits along the coast of the country, with key reserves located in Rovuma in the Afungi Peninsula. Area 1 has gas-in-place estimates of 92 tcf[84], with Area 4 having estimates of 78 tcf[85]. Gas-in-place in the PSA is estimated at 2.5 to 3 tcf[86]. These resources have been explored extensively by major IOCs and are thus in advanced development stages. Concession holders are obligated to provide 25% of all-natural gas produced to the domestic market (domgas),[87] which is coordinated by ENH. The Area 1 LNG project led by Total has reached the Final Investment Decision (FID) while FID in Area 4 between ExxonMobil, ENI and others is expected in 2020. These projects seek to fulfil global demand; however, domgas allocations are available for use in Mozambique - the key hurdle being in securing suitable projects and infrastructure development to monetise locally.

[83] Tlou Energy. Lesedi CBM Project, 2018.
[84] INP Website, Exploration and Production, Rovuma Offshore Area 1
[85] INP Website, Exploration and Production, Rovuma Offshore Area 4
[86] INP Website, Exploration and Production, Pande&Temane PSA Area
87 Mozambique Petroleum Law, 2014.

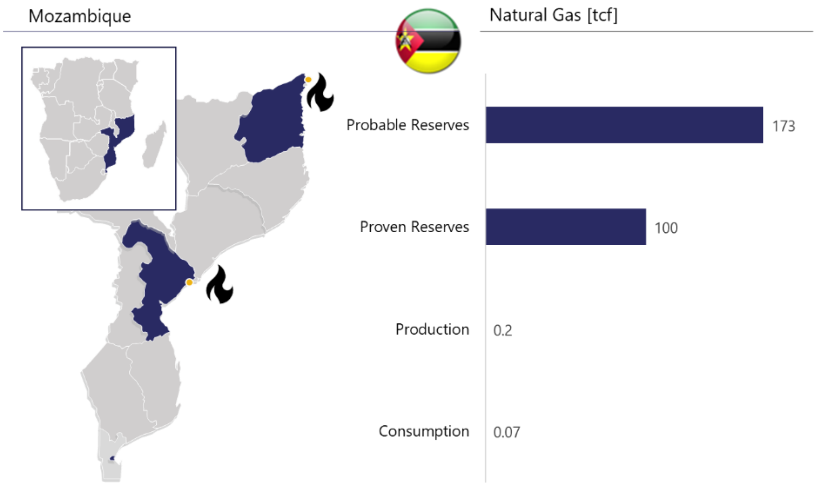


Figure 4-8: Mozambique natural gas.[88]

4.3.4 Namibia

Discovered in 1974 and at depths greater than 4000m, Kudu gas fields are located 170 km off the coast of Namibia. Several gas companies, including Shell, Chevron, and Tullow Oil, have shown interests in the field. In 2007 however, Tullow Oil announced that it would not be doing further drilling at Kudu, and it is unlikely that Kudu will be developed in the short/medium term.

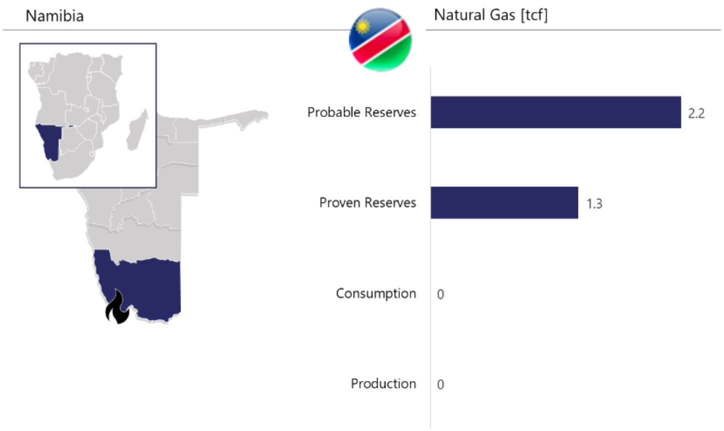


Figure 4-9: Namibia natural gas.[89]

4.3.5 South Africa

South Africa has natural gas reserves located at various points around the country. The Karoo shale deposits, discovered in 2011, is the largest. Resource estimates at ±13tcf[90] would be the 34th largest shale-gas resource in the world. The gas resource figures were revised downward from initial estimates of 485tcf. Serious infrastructure and water challenges exist in the region, questioning the viability of monetisation within the medium term. Bredasdorp also has approximately 1.9tcf[91] of natural gas reserves. PetroSA has exploited these fields to feed gas to their GTL plant since 1992. The gas

[88] BMI Fitch Solutions Data, 2019.
[89] Deloitte, 2016. Oil and gas taxation in Namibia.
[90] Econometrix. Karoo Shale Gas Report, 2012.
[91] Petroleum Agency SA. Petroleum Exploration in South Africa: Information and Opportunities, 2017.

production from these fields has tapered off to the extent that the PetroSA GTL plant is not running at full capacity. These reserves are almost depleted.

The Ibhubesi gas fields, estimated at 0.5tcf,[92] were discovered in 1981. The Ibhubesi Gas Project is a mature natural gas field development with eleven wells drilled thus far consisting of seven gas discoveries. The location of the reserve is 105km off the Northern Cape coast where there is limited industrial development and demand for gas.

The Brulpadda gas fields were discovered in 2019, with resource estimates of about 1.9tcf[93] of 'wet' natural gas. The presence of liquids will make its development more likely (economically more viable). It is still in the early stages of development, and only one hole has been drilled to date. Total is considering whether it should drill 4 more wells, and Brulpadda is currently only a prospect. Its proximity to potential anchor clients (PetroSA and the 740MW Gourikwa OCGT plant) would reduce the quantum of infrastructure required and help enable its development. There is the political will for gas to be available in the region given that PetroSA is short of gas and the Gourikwa OCGT currently uses more expensive diesel fuel. Both these plants are state owned. Unlike the eastern part of South Africa, this region currently does not have gas.

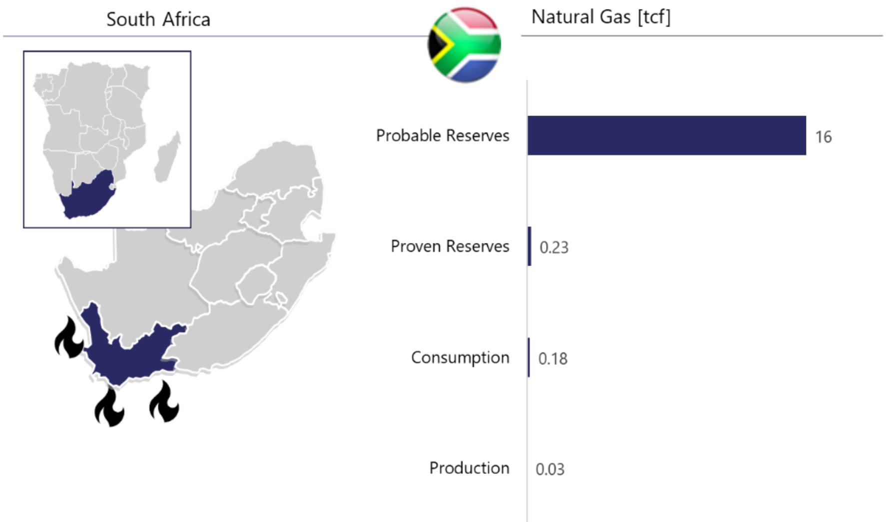


Figure 4-10: South Africa natural gas.[94]

4.3.6 Tanzania

The Tanzania natural gas reserves are estimated at 56tcf.[95] Natural gas demand is rapidly growing due to the Government's desire to have industrial economies, and thus, require gas for electrical and energy-efficient industries. Two gas fields are currently in production, Mnanzi Bay, and Songo. Currently, the natural gas extracted is for domestic use rather than export. Depending on the state of investment and implementation of relevant policies and regulations, the natural gas sector could bring great benefits to Tanzania.

[92] *Ibid.*
[93] Engineering News. Brulpadda field unlikely to support a globally competitive chemicals industry, more exploration needed – experts, 2019.
[94] Petroleum Agency SA. Petroleum Exploration in South Africa: Information and Opportunities, 2017.
[95] The Stanford Natural Gas Initiative. Natural Gas in East Africa: Domestic and Regional Use, 2017.

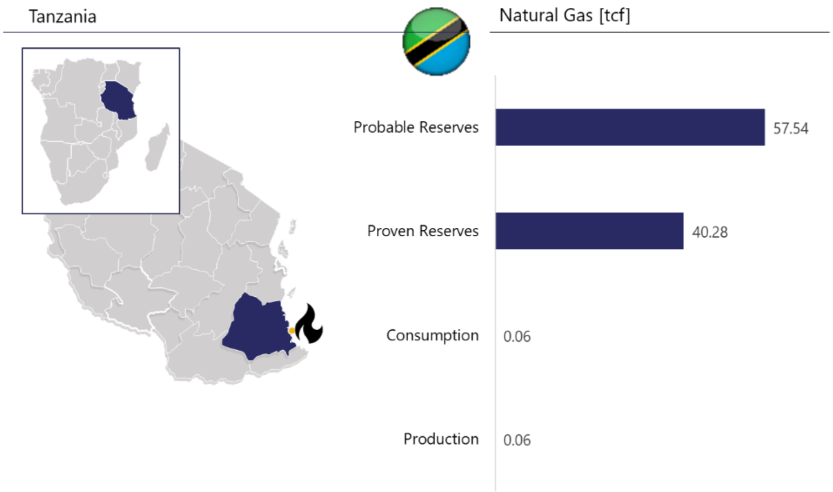


Figure 4-11: Tanzania natural gas.[96]

4.4 Domestic Production Outlook

Natural gas production within the SADC region has been ongoing for several years. Even though the production rates are not reflective of the region's proven gas reserves, the focus is on maturing the gas sector and increasing production in the short-to-medium term. Angola currently leads production in the region, with well-established LNG facilities in place. Mozambique is a close current competitor, and the LNG developments are foreseen (EIA, 2019) to grow its production volumes in the short-to-medium term, becoming the main player in the region, as seen in Figure 4-12.

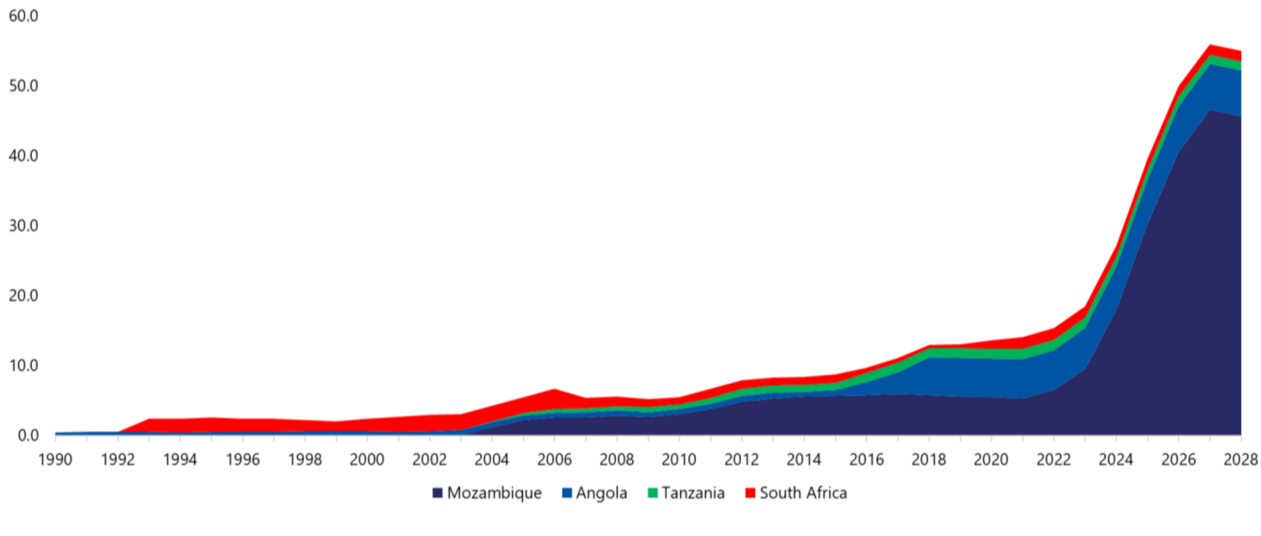


Figure 4-12: SADC Natural gas production outlook [bcm].[97]

Within the SADC region, Mozambique, Angola, Tanzania, and South Africa are the main producers and as such consumers of gas, with the Pande and Temane production facilitating regional gas trade between South Africa and Mozambique. Pande and Temane, however, will be entering a period of decline from approximately 2024 onwards and will require alternate sources of gas to fulfil the South African demand.

[96] Ministry of Energy and Minerals, 2016. Natural Gas Master Plan 2016-2045.
[97] EIA, Gas Production: dry natural gas production, 2019.

4.5 Alternative (non-Natural Gas) Feedstock and Competitive Landscape

4.5.1 ECOWAS

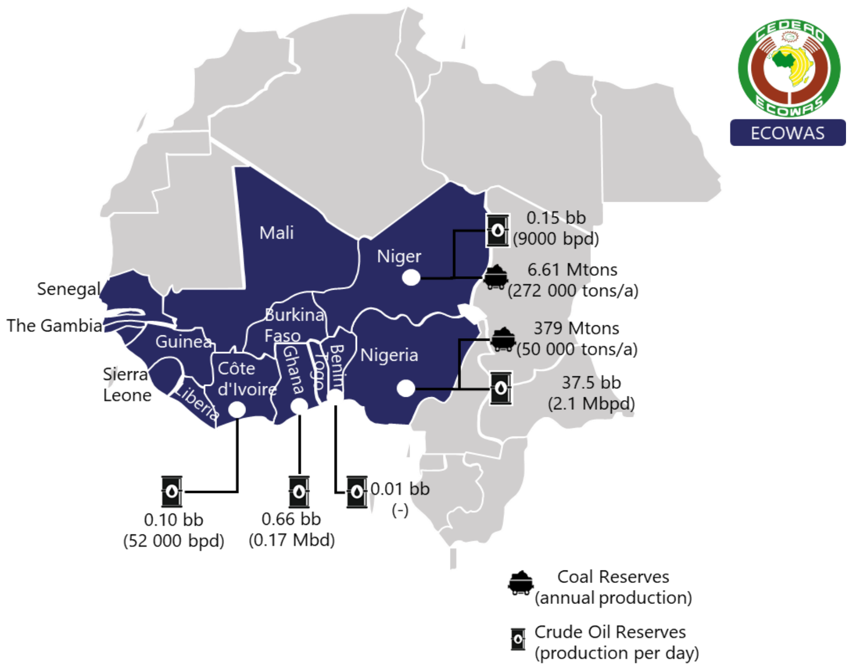


Figure 4-13: Production and proven coal and crude oil reserves in the ECOWAS region.[98]

In the ECOWAS region, Niger and Nigeria are the only members with proven coal reserves totaling 387 Mtons, and production sits at 0.32 Mtons/a, which is below 1% of total reserves. Relative to SADC, this coal production rate is low since a huge focus has been on the development of oil fields. Produced coal in Niger is utilised domestically for the generation of electricity, whilst in Nigeria, coal is used for industrial heating.

Proven crude oil reserves in the ECOWAS region sit at 38.2 billion barrels, with Nigeria accounting for 98% of this. Current crude oil production in the ECOWAS region sits at 2.33 million barrels per day. However, limited refinery capacity in the ECOWAS region culminates into approximately 94% of crude oil being exported to international markets. The ECOWAS region is, therefore, a net importer of refined petroleum products.

[98] BP, 2019. Statistical Review of World Energy.

4.5.2 EECAS

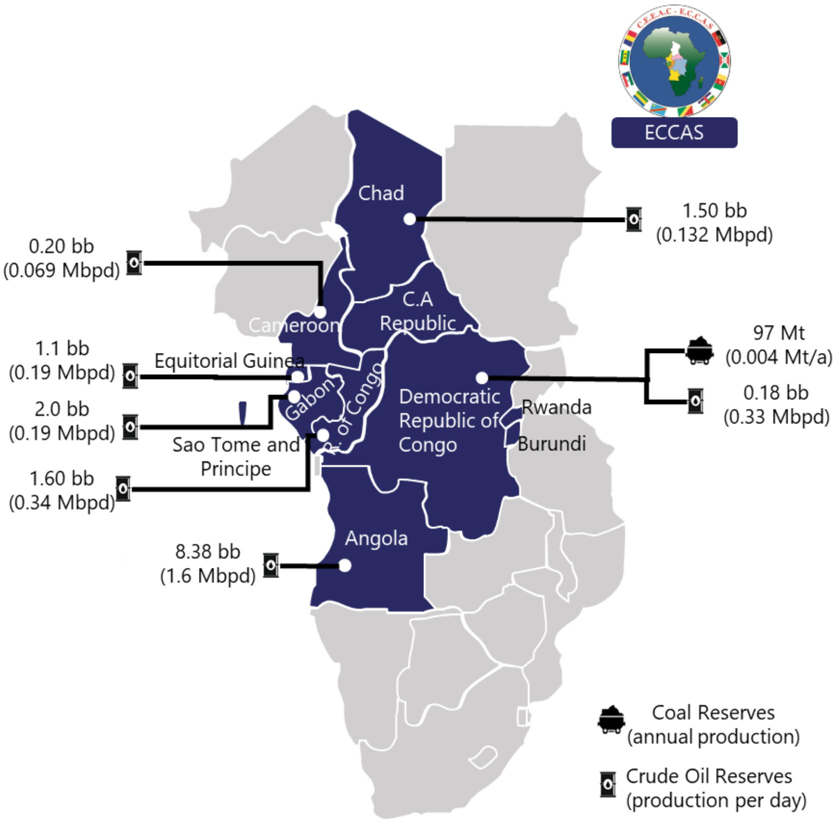


Figure 4-14: Production and proven coal and crude oil reserves in the ECCAS region.[99]

The DRC is the only member of ECCAS with proven coal reserves at 97 Mt, and 4000 tons. Relative to the SADC region, this is low. Coal production in the DRC only serves the domestic market, with the other ECCAS Member States importing negligible amounts of coal.

Proven crude oil reserves in the ECCAS region sits at 15.0 billion barrels, with Angola accounting for more than half of this (56%). Currently, 3.2 million barrels of crude oil are produced per day. At the current rate of production, it is estimated that crude oil reserves in the region will deplete in 13 years. Crude oil refining capacity in the ECCAS region is limited. The ECCAS region is, therefore, a net importer of refined petroleum products.

[99] BP, 2019. Statistical Review of World Energy.

4.5.3 COMESA

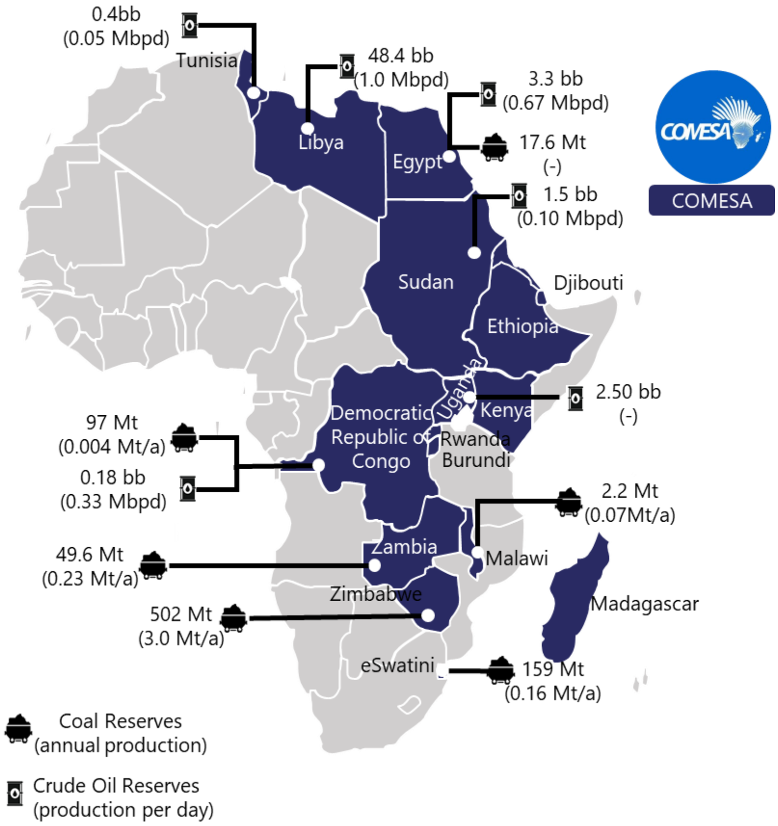


Figure 4-15: Production and proven coal and crude oil reserves in the COMESA region.[100]

Total proven coal reserves in the COMESA region is 809.8 Mt, with current production at 3.4 Mt/a. Proven coal reserves in the COMESA region lie in Southern Africa, with Zimbabwe holding 62% of the region's total reserves.

Proven crude oil reserves in the COMESA region sits at 56.3 billion barrels, with 86% of these reserves lying in Libya. Currently, 2.2 million barrels of crude oil are produced per day in the region. Crude oil refining capacity in the COMESA region is limited. The COMESA region is, therefore, a net importer of refined petroleum products.

[100] BP, 2019. Statistical Review of World Energy.

4.5.4 SADC

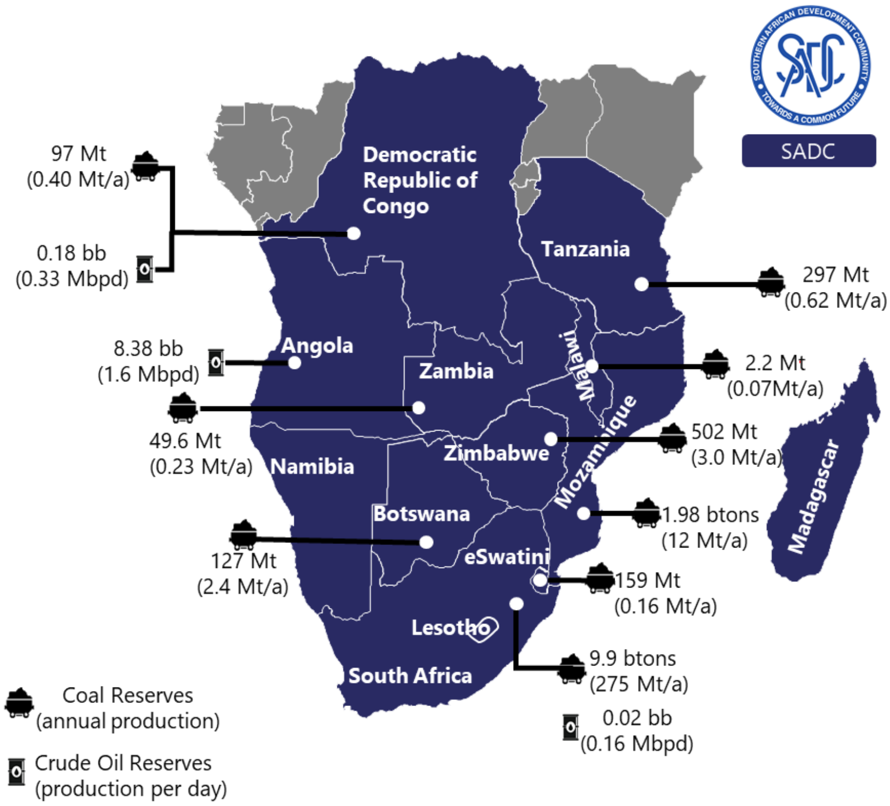


Figure 4-16: Production and proven coal and crude oil reserves in the SADC region.[101]

Total proven coal reserves in the SADC region are at 13.1 billion tons, with total production at 294 Mt/a. South Africa is endowed with the largest coal reserves, followed by Zimbabwe. South Africa's reserves account for 76% of SADC proven reserves. At the current rate of production, proven coal resources would deplete in 45 years. Produced coal is used in the generation of electricity. The South African Integrated Resource Plan (IRP), specifies that 24 100 MW of coal-fired plants shall be decommissioned between the years 2030 and 2050.

Proven crude oil reserves in the SADC region are 8.58 billion barrels, with Angola accounting for 98% of this. Crude oil refining capacity is limited in the SADC region, with operating refineries in Angola, Zambia, and South Africa. SADC is thus a net importer of petroleum products.

[101] BP, 2019. Statistical Review of World Energy.

5. THE NATURAL GAS MARKET (TRADING)

The monetisation of gas requires effective delivery mechanisms and routes to market. There are three specific ways in which gas can be delivered to the market; this includes:

- In-Situ transformation, i.e. power, ammonia, methanol, or diesel production where gas is produced and delivery via electrical transmission grids, road, rail, or ship
- Natural gas compression with conventional delivery via pipeline or small-scale CNG delivery through road, rail, or ship
- Liquefaction of natural gas with conventional delivery via large ships or small-scale delivery via road, rail, or smaller ships

The monetisation route is dependent upon the market needs and the distance to market as indicated in image Figure 5-1 below.

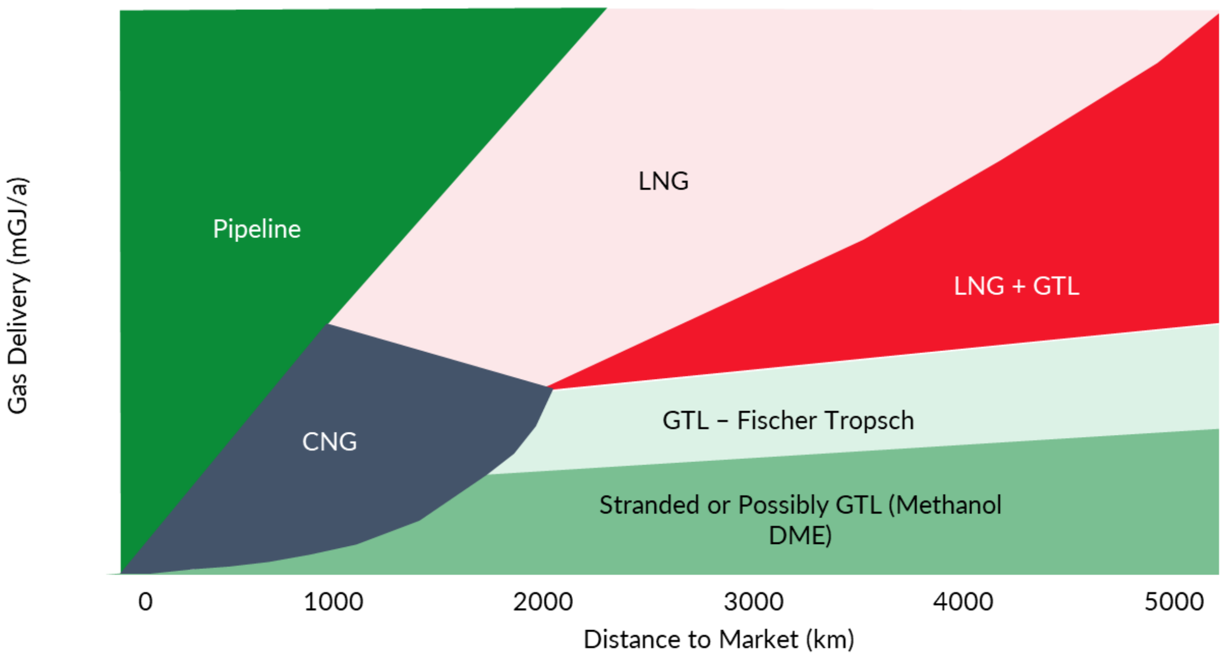


Figure 5-1: Gas Delivery Systems[102]

As methanol, ammonia and diesel production are sensitive to input gas prices, monetisation for these routes are generally preferred close to large gas resources, thereby limiting the additional expense of infrastructure and transportation cost of the gas molecules.

5.1 Compressed Gas

Natural gas can be transferred from producing nodes to demand nodes via pipeline. This route can be classified into three distinct stages: natural gas gathering, transmission, and finally, distribution to end users. Natural gas gathering combines natural gas from different sources, or gas field concession holders. This step requires a processing plant that will remove natural gas condensates and impurities. Gathering facilities allow for the economic transfer of natural gas through one transmission line. To transfer natural gas over a distance away from the processing plant, it is then compressed. Compression allows for the smooth flow of gas through the pipeline, whilst reducing its volume such that more molecules can be transferred over a smaller diameter pipeline. As the gas flows through the pipeline, it will lose pressure due to distance and friction; hence a natural gas pipeline has several

[102] Shell, Gas Monetisation Options

compression stations along it, which are usually at 60 to 160 km intervals. The distance between compressors requires optimisation, as compressors form a significant fraction of the total capital costs of any pipeline project.

Transmission pipelines account for most of pipeline infrastructure capital costs, as they carry high pressure natural gas between 4 to 80 bar, hence requiring steel construction, and they have a typical diameter between 6 to 48 inches. In contrast, since distribution pipelines require gas at low pressure (below 4 bar), these are typically constructed with polyethylene, with diameters between 6 to 16 inches.

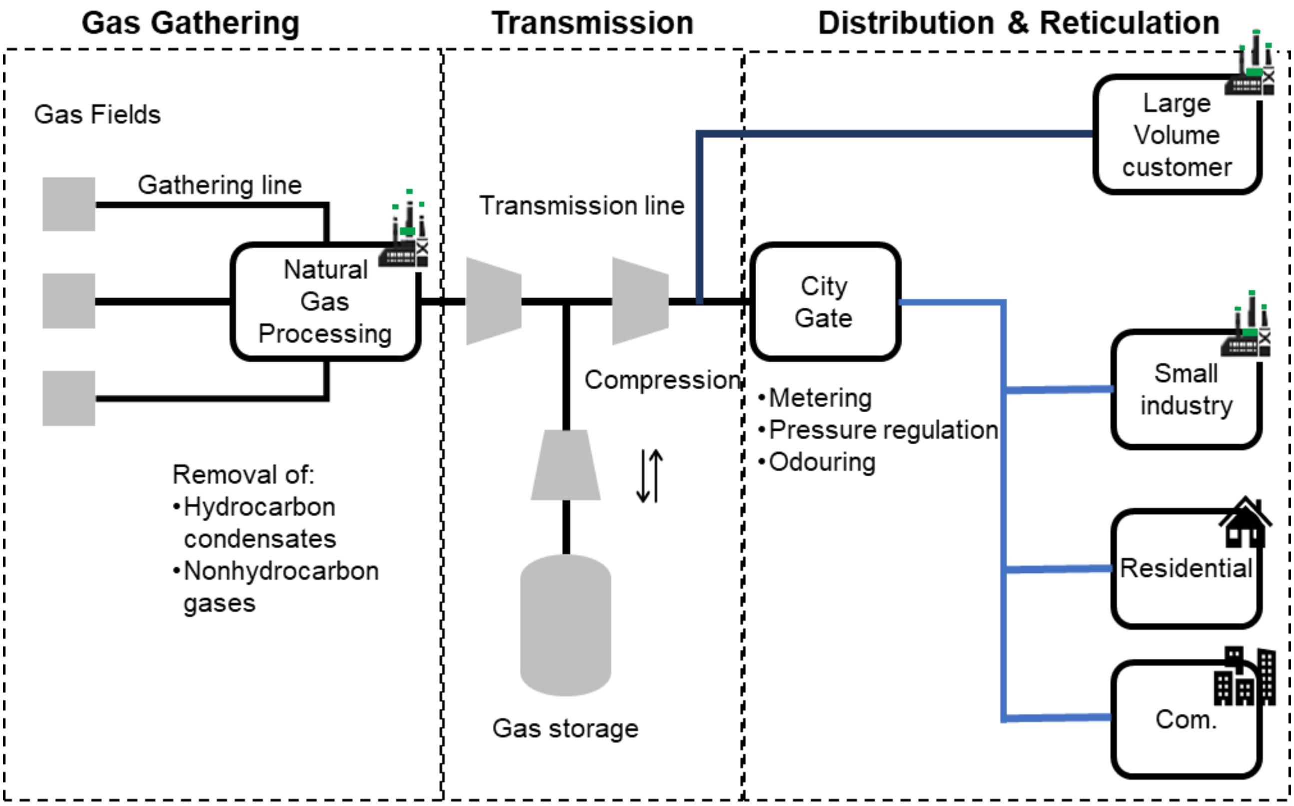


Figure 5-2: Overview of infrastructure required in developing the natural gas gathering, transmission, distribution & reticulation system

The maximum amount of gas a pipeline can transfer is constrained by its diameter. The implications, therefore, highlight the need for initial pipeline design to account for existing and future gas demand, whilst making considerations for capital costs which increase with pipe diameter. In the case of unexpected growth opportunities, a pipeline's capacity can be increased through the introduction of looplines. These are pipelines that run parallel to the main pipeline, which offers the benefits of increasing the flow as demand increases.

Developers of gas pipelines assume a high risk due to high capital cost requirements, and technical, economic, and political uncertainties may pose a threat to their operations. Therefore, the development of a pipeline requires an initial large anchor demand which would allow developers of pipeline infrastructure to recover capital costs, and a reward commensurate to the assumed risk. The development of a pipeline can drive the development of various industries that can tap natural gas along the pipeline.

5.2 Liquefied Natural Gas

Liquefied natural gas (LNG) is produced when natural gas (predominantly methane) is cooled to a temperature of -162°C at atmospheric pressure and condenses to a liquid occupying about a 600th of the volume of natural gas.

As an industry that is growing and still maturing, LNG has become a key delivery mechanism for natural gas where distance and terrain (i.e. deep water) prohibits pipeline delivery. As capital costs have historically been high due to the scale required for economic feasibility, the industry developed towards larger scale projects (both liquefaction and regasification) with long-term off-take contracts.

Changes in the LNG industry have been driven both by the market as well as technological shifts. Greater global LNG supply has increased the commodification of the product that has impacted market liquidity and thus the trading mechanisms – further discussed in Section 5.4 of the document.

Furthermore, technological shifts have featured small scale technologies as well as floating liquefaction and regasification facilities. These shifts have reduced overall infrastructural requirements, thereby decreasing capital expenditure, and improving overall economics.

From a SADC perspective, integrated conventional LNG, ssLNG, and pipeline options should all be considered to ensure maximum demand aggregation while minimising unnecessary and unaffordable infrastructure and capital expenditure. This is demonstrated in the configuration below.

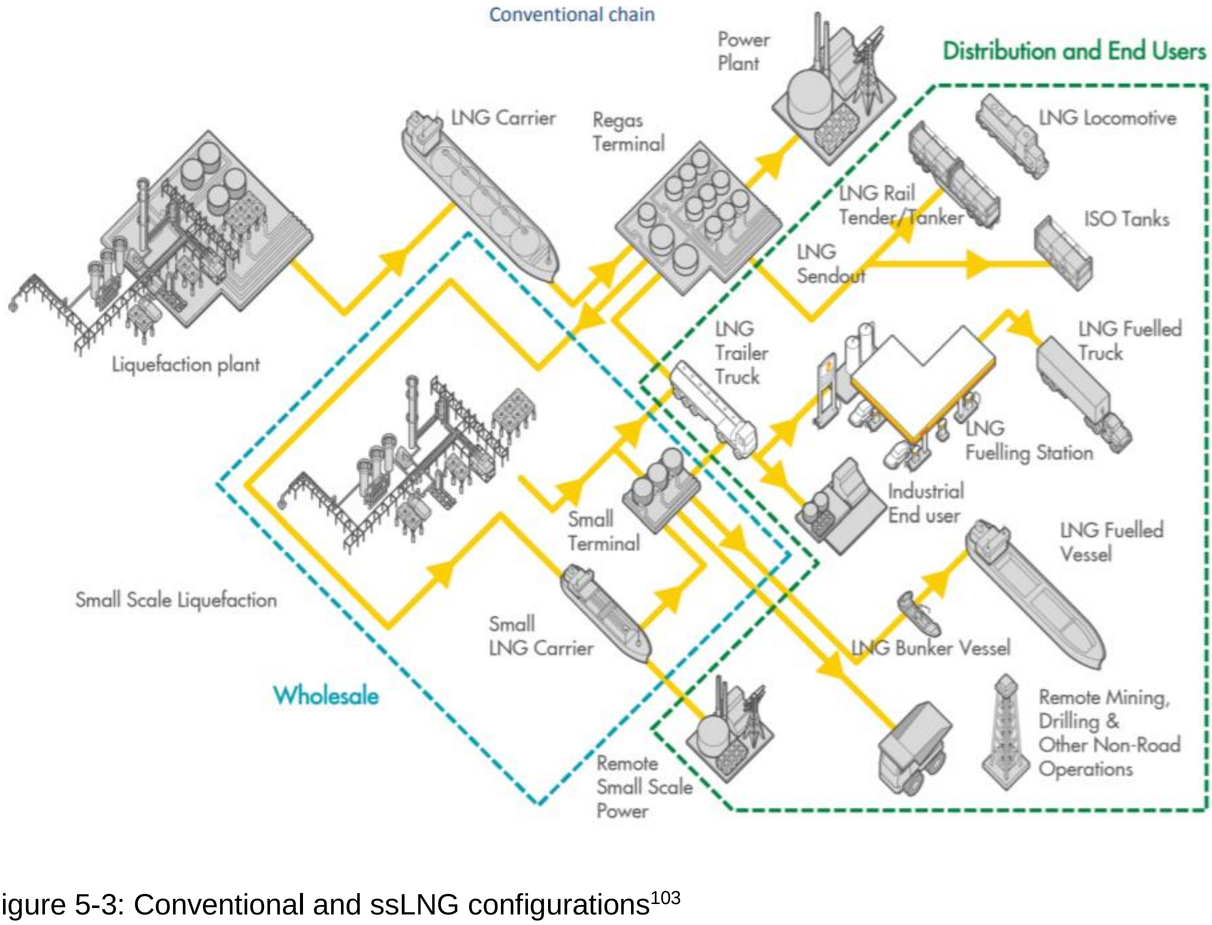


Figure 5-3: Conventional and ssLNG configurations[103]

[103] International Gas Union (IGU), 2017, Small Scale LNG Triennium Working Report

LNG and ssLNG are considered as key delivery mechanisms - from both supply and demand perspective:

- Supply: Limited local/regional gas production to meet the aggregated demand needs of SADC Member States
- Demand: SADC Member States have smaller relative demand needs when compared to global LNG

The conclusion, therefore, is that: due to limited indigenous regional supply, LNG will be required as a gas source to develop the gas market. Furthermore, ssLNG options can facilitate aggregation of smaller markets through the utilisation of 'hub and spoke' model thereby increasing and improving the overall, integrated economics. **Regional aggregation, therefore, becomes a key mechanism and driver for regional integration.[104]**

5.2.1 LNG Infrastructure

LNG infrastructure facilitates the transfer of large quantities of natural gas from gas fields to demand nodes, through its liquefaction. The LNG value chain is composed of three distinct phases: gas production and liquefaction, transportation of LNG, and storage and regasification of LNG.

Upon processing of the natural gas to remove nonhydrocarbon components and condensates, it is liquefied to -162°C at atmospheric pressure and stored. LNG is can then be transferred to the demand market, via LNG carriers, or specialised LNG trucks, with the latter being used to supply low demand regions. Currently, LNG tankers are designed to hold capacity between 76 500 to 81 000 tonnes.[105]

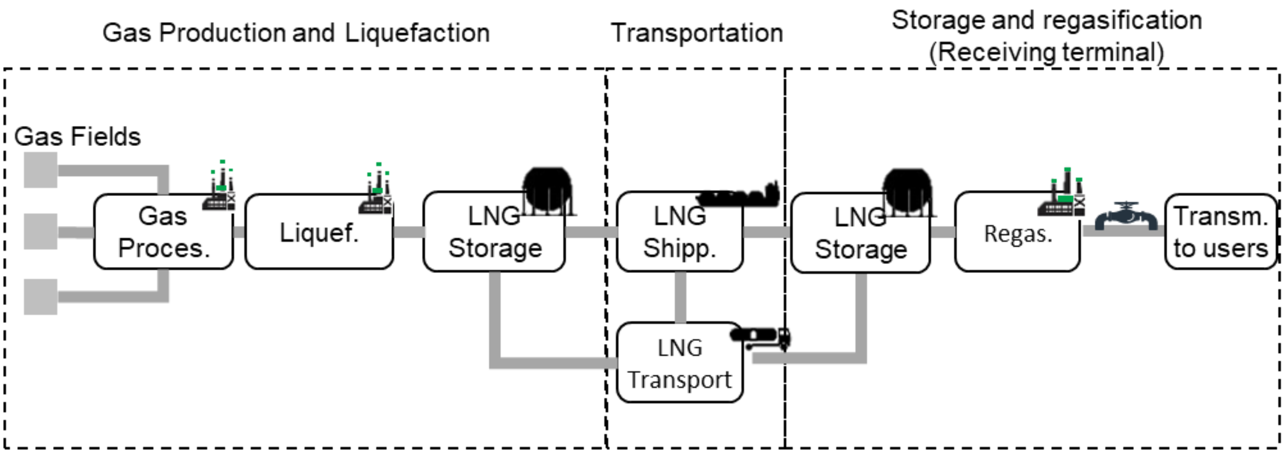


Figure 5-4: The LNG value chain.[106]

LNG regasification terminals receive, store, and convert liquefied natural gas back to its gaseous phase prior to being transferred to end users. Transmission and distribution to end users through pipelines would then follow the same value chain as discussed in Section 5.1. Regasification terminals have three major infrastructure requirements: marine berths for mooring of LNG tankers, LNG storage, and then finally regasification plants. Over the years, regasification facilities have experienced technological shifts which have mitigated high capital costs risks, allowing countries to import LNG at a smaller scale.

[104] Please see further elaboration in Section 10 and 11.
[105] International Gas Union, 2018. World LNG Trade 2018.
[106] Ibid

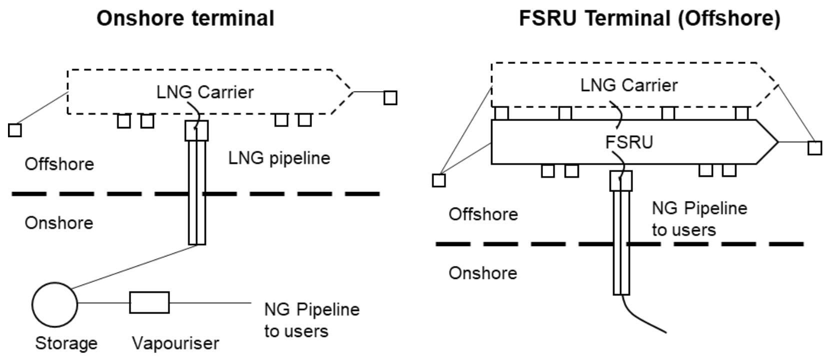


Figure 5-5: Various regasification facility configurations.[107, 108]

There are currently three configurations for regasification facilities, which are illustrated in Figure 5-5, these are the conventional onshore terminal, Floating Storage and Regasification Unit (FSRU), and Floating Storage Unit (FSU) with an offshore berth regasification unit. The configuration of the conventional regasification terminal is such that both its storage and vaporiser lie onshore, whilst the FSRU has both of these on the ship's platform, with the FSU configuration having LNG storage on ship and vaporiser offshore. The advantages of the FSRU and FSU units are that they have lower capital costs relative to the onshore configuration[109], and the flexibility of their configurations allows for them to be deployed in secondary locations. However, it should be considered that onshore terminals can cater to a diverse mode of supply with the ability to receive and store LNG from trucks, as well as for bunkering purposes.

5.2.2 Small-scale LNG (ssLNG)

Given the dynamics in the global natural gas markets – lower commodity prices, oversupply, and industry focus on cost reduction – small scale options have received increased interest in recent years with key factors favouring development – specifically in more dispersed markets. Generally, ssLNG initiatives, allows "plug and play" service with lower investment requirements and accelerated commissioning schedules, minimising risk within higher risk environments. Furthermore, ssLNG is scalable, where capacity can be added to serve increased demand while gaining supply chain synergies. This flexibility allows for ssLNG to stimulate demand in areas of the market that are considered unsuited to conventional LNG as pipeline gas, such as off-grid power generation (e.g. the islands) and in remote areas.[110] It's a bespoke solution, utilised and developed on a case by case basis where large facilities may not be feasible.

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[107] Wartsila,2018. Developers Guide to Small Scale LNG.
[108] Offshore, 2017. Review of LNG terminal options show advantages of FSU Facilities.
[109] ERIA, 2018. Investment in LNG Supply Chain Infrastructure Estimation.
[110] Strategy& - PWC, 2017, Small going big – Why small-scale LNG may be the next big wave

Some of the opportunities for ssLNG include:

Transport: Maritime	Transport: Road (Heavy Fleets)	Embedded / Off-grid
Environmental: International Maritime (Marpol) Regulations and movement away from high sulphur HFO Economic: Affordability and Competitiveness of Natural Gas (TCO)	Economic: Affordability and Competitiveness of Natural Gas (TCO) Access & Security: LNG more complex handling and value chain than liquid fuels – theft prevention mechanism	Economic: Affordability and Competitiveness of Natural Gas (TCO) Access and Security: Opportunity cost of loss of production due to, e.g. no Electricity

Development of a gas market through ssLNG in Norway

In 2018, Norway exported 4.6 MTPA of LNG.[111] *Though natural gas production is high, Norway is a country with high mountains, and a wide geographical population distribution, hence natural gas transmission through pipeline to demand nodes is not cost-effective. The Norwegian domestic gas market has thus developed through small scale LNG. Norway has multiple small scale LNG liquefaction and import facilities scattered throughout the country, as shown in* Figure 5-6*. The LNG liquefaction facilities have a production capacity in the range 0.01 to 0.3 MTPA, while the two LNG import terminals have a storage capacity of 5,900 m^3 and 6,500 m^3.*[112]

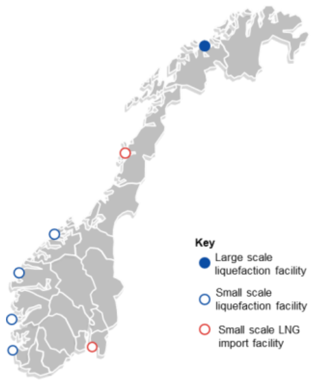

Figure 5-6: Norway LNG facilities

The LNG from small scale terminals is transferred to demand nodes by road tankers, and small LNG shipping carriers (with a capacity of 10 000 m^3 and 12 000 m^3). Shipping carriers transfer LNG to various satellite sites in Norway, where LNG is vapourised and gas is supplied via pipeline to various industrial customers.

The 0.3 MTPA Stavenger LNG plant in the south of Norway plays a critical role in satisfying demand domestically and in neighbouring Sweden. The LNG facility was designed to have the following areas: natural gas treatment and liquefaction, LNG storage, one LNG ship loading area, and a truck filling station, which was constructed over a 68m by 47m area. Due to its proximity to Sweden, this facility ships LNG to a small-scale regasification facility in Nynashamn, Sweden. This facility, which has a total LNG storage capacity 20 000 m^3 LNG, supplies the Swedish domestic market via road tankers.

[111] International Gas Union, 2019. World LNG Report.
[112] Gas Infrastructure Europe, 2019. LNG Map Database.

5.2.3 The Hub and Spoke Model

Aggregation is one of the key mechanisms to improve overall economics in natural gas (both LNG and pipeline) projects. Utilising large local LNG import hubs (e.g. Coega, Richards Bay, Maputo) to break bulk and from which LNG is then is distributed via smaller carriers to decentralised locations ("Hub and spoke") is an important consideration from a SADC perspective. This allows gas distribution to smaller gas consuming countries while improving the overall economics through larger aggregated volumes.

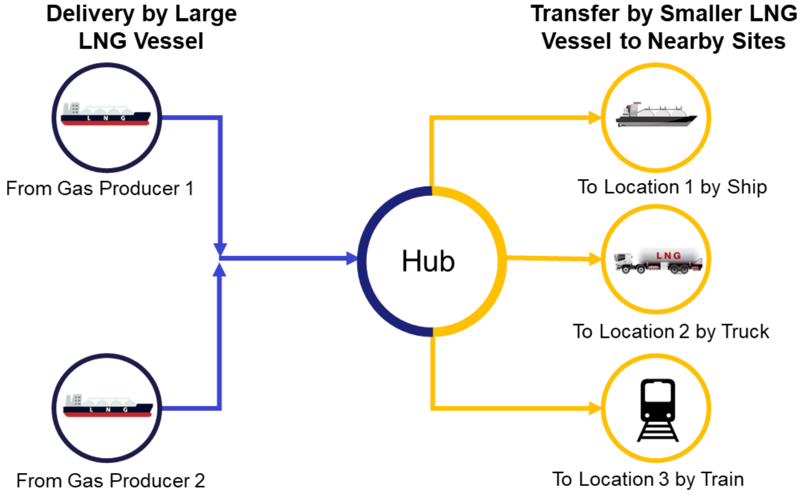

Figure 5-7: The Hub and Spoke Model.

5.3 At Source (In-Situ) Monetisation

The location of monetisation projects for natural gas is largely driven by the project economics and is dependent upon (1) the cost of the gas and (2) infrastructure requirements – including transmission, pipeline, road, rail, and port infrastructure.

For example, the chemical transformation of natural gas into petrochemical products such as methanol, ammonia, and diesel require competitively priced gas, favouring development at locations with readily accessible gas. Transport costs of natural gas can thus be prohibitive to the overall economics of petrochemical projects, thereby favouring in-situ monetisation.

5.4 Global Gas Trade

Gas is still primarily utilised where produced, however, LNG has been increasingly facilitating global trade, which accounted for 10.7% of the total natural gas global supply in 2017.[113] Growth rates have been largest in the LNG market at 3.75% CAGR, while overall, the gas market has seen consistent growth as illustrated in Figure 5-8.

[113] International Gas Union. World LNG Report, 2019.

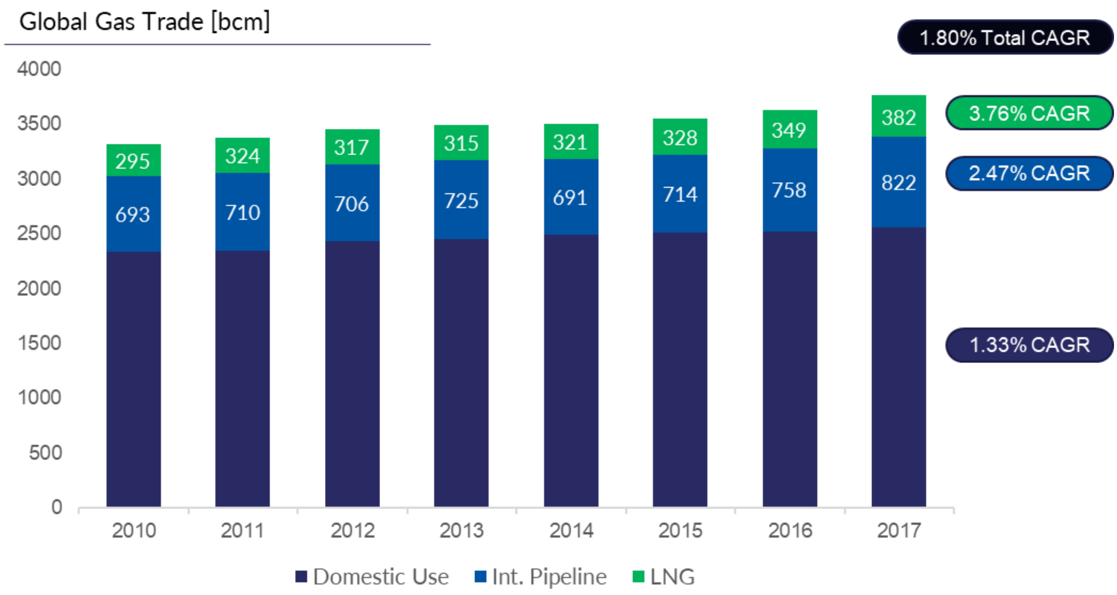

Figure 5-8: Global Gas Trade [bcm][114]

5.4.1 LNG Supply Volumes

Figure 5-9 illustrates the major global natural gas trade flows, and it indicates that there is limited intracontinental natural gas trade in the African continent.

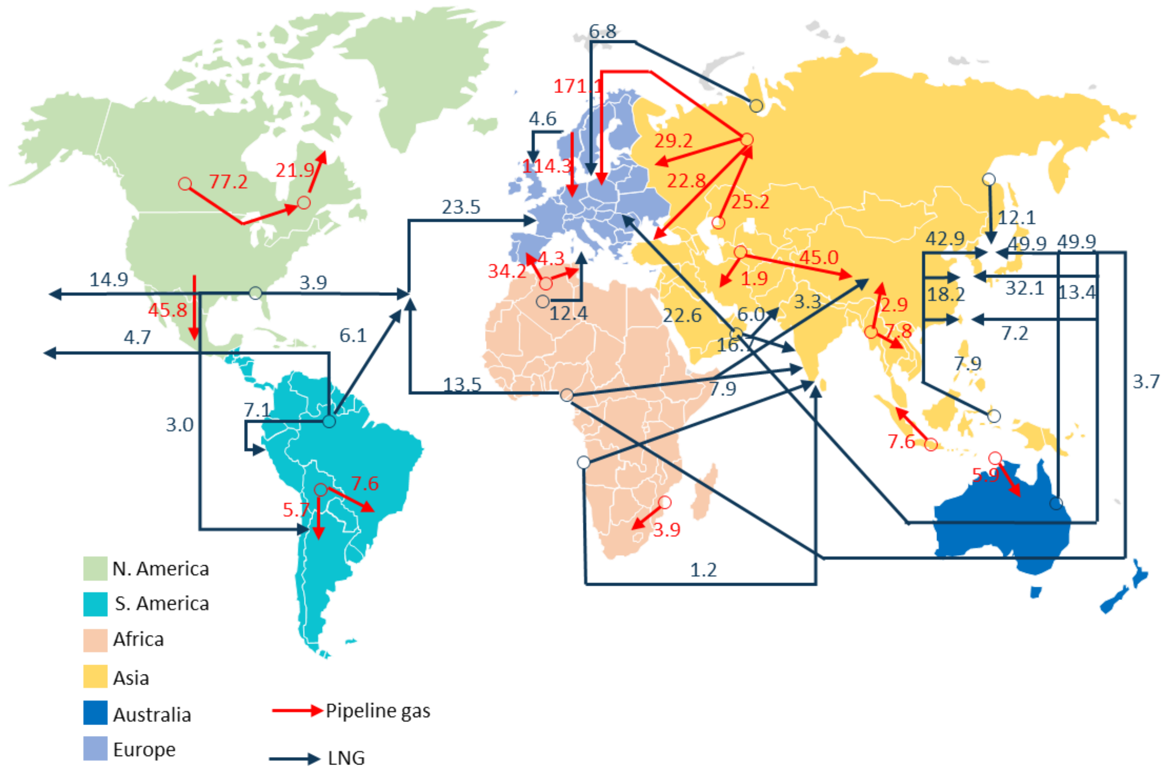

Figure 5-9: Major natural gas global trade flows by pipeline and LNG, 2018 [bcm].[115,116]

[114] Enerdata, 2019, International Gas Union. World LNG Report, 2019.
[115] BP, 2019. BP Statistical Review of World Energy 2019.
[116] International Gas Union, 2019. 2019 LNG World LNG Report.

The only existing major intercountry natural gas trade in Africa is between Algeria and Tunisia, and Mozambique and South Africa, which are both delivered via pipeline. South Africa is currently the only importer of natural gas in the SADC region, through the ROMPCO pipeline from Mozambique. Nigeria is a major player in the African continent, serving the European and Asian markets.

In 2018, total gas importation stood at 319.5 MT (~16 617 PJ), with the biggest importing regions being Asia and Europe, each holding a global importing share of 65.4%, and 22.8%, respectively. Demand in the Asian market is led by Japan and China. In Japan, natural gas is consumed largely by the power sector, with some natural gas being utilised for residential heating, and in the industrial sector,[117] indicating that demand will continue in the long term, especially in servicing the power sector. In Europe, Spain is the largest LNG importer, with no domestic natural gas production. Imported LNG in Spain is utilised largely for residential heating and in the industrial sector.[118]

Global liquefaction capacity has been increasing and will continue to increase into the future, driven in large part by the continued increase in demand - as well as the need to monetise local gas resources.

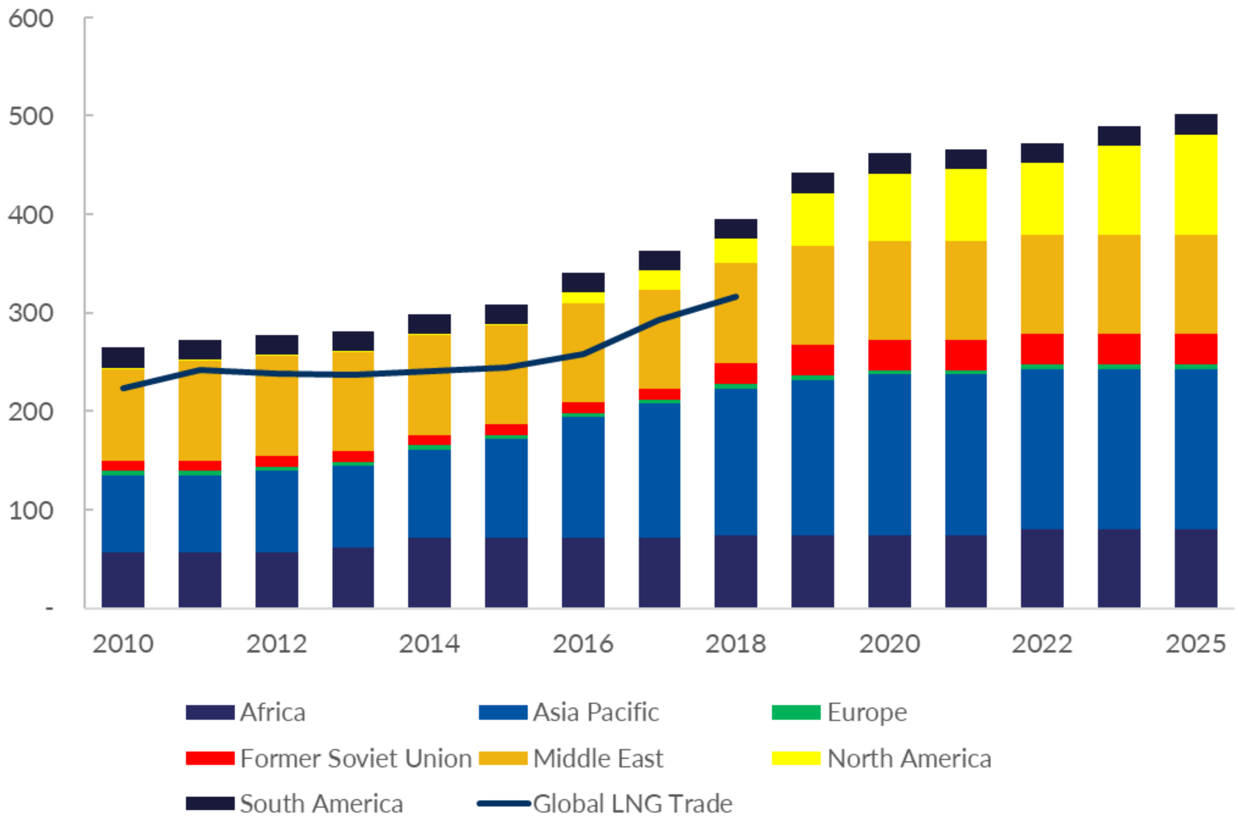

Figure 5-10: Global Liquefaction Capacity [MTPA].[119][120]

[117] International Energy Agency, 2017. Japan Energy Balance.
[118] International Energy Agency, 2017. Spain Energy Balance.
[119] International Gas Union. World LNG Report, 2019. Future values include Liquefaction plants sanctioned or under construction.
[120] World Bank. Executive Summary Report - Phase 2: Liquefied Natural Gas (LNG) demand projection, procurement strategy and risk management, 2019

5.4.2 LNG Market Structure and Pricing

The global LNG market has, however, been undergoing structural reformation. Historically the industry, which makes up ~10% of global gas trade and is still maturing as a technology, was priced on long term contracts (15 – 20 years) between buyers and sellers. As large volumes of older contracts are now up for renegotiation in the next 2 – 5 years. (±6% of global LNG contracts will expire in 2020, and ±20% will expire by 2025), both buyers and sellers will be able to renegotiate terms. This trend, together with increased LNG liquefaction capacity, has increased the spot and short-term market to approximately 30 - 35 % [121] of LNG trade. This trend is expected to continue with smaller contracting volumes now possible.

In addition to this, and with the effect of gas-on-gas pricing of the US market - there is likely to be a longer term convergence of global LNG pricing, while a structural shift to a lower oil-indexation slope is expected in the medium term; due to increased supply of US Shale into the LNG market.

The implication is that US Shale pricing, which is driven by supply/demand fundamentals, will facilitate the movement away from Oil price indexing.

Historically, the Global LNG market was characterised by the following:

- In most markets, LNG prices have been indexed against a certain benchmark, like Brent crude oil, as the price of LNG needs to reflect the energy market into which it is sold
- Gas contracts in established markets like the US use gas hub-based or oil-linked pricing, and often both
- In Asia and many emerging markets without established markets and liquid gas trading markets, the price of LNG is in the most part set via oil-linkages, supplemented by a smaller share of spot prices
- Current LNG contracts are long-term contracts between buyers and sellers with fixed delivery points and volumes

Where the movement is now towards the following:

- In more developed gas markets, like Europe, the gas market has developed to the extent that LNG must compete directly with pipeline gas. As a result, oil-linked pricing contracts are being replaced by pricing formulae that are set by reference to competing gas prices. With the increasing uptake of LNG, this trend is expected to spread.
- While historical LNG deliveries were under long term contracts, there has been a growing portion of LNG being sold under short term contracts, or on the spot market.
- This offers flexibility in the volumes delivered and the destinations for deliveries.
- Since 2016, the volume of LNG delivered on short term contracts has grown by 19% year-on-year in 2017 and 18% in 2018.

Specific global markets facilitating LNG trade include:

Europe (~20% of global demand)

- National Balance Point (NBP) - UK
- Title Transfer Facility (TTF) - Netherland - Spot Market Driven

Asia (~50% of global demand)

- Japan/ Korea Marker (JKM - Platts) - Spot Market Driven

[121] Platts, LNG sector transformation. Long-term-contracts.

- Singapore LNG Index Group (SLING) Singapore Exchange - Stopped October 2019 – due to lack of liquidity
- China Pricing Hub (potentially post 2025) - Inter Fuel Pricing posing a threat to Japanese crude cocktail pricing benchmark

USA (~ 20% of global demand)

- Henry Hub - Predominantly Natural Gas trade
- US - Gulf Coast FOB Hub (Platts)

Rest of the World (~ 10 % of global demand)

- India
- Pakistan
- Bangladesh
- Kuwait

5.4.3 Price Formation Mechanisms

Price formation mechanisms are necessary in developing and evolving a gas market. The following are the general mechanisms utilised.

Table 5-1: Price Formulation Mechanisms.[122]

OIL PRICE ESCALATION (OPE)	The price is linked, usually through a base price and an escalation clause, to competing fuels, typically crude oil, gas oil and/or fuel oil. In some cases, coal prices can be used as well as electricity prices.
GAS-ON-GAS COMPETITION (GOG)	The price is determined by the interplay of supply and demand – gas-on-gas competition – and is traded over a variety of different periods (daily, monthly, annually, or other periods). Trading takes place at physical hubs (e.g. Henry Hub) or notional hubs (e.g. NBP in the UK). There are likely to be developed in futures markets (NYMEX or ICE). Not all gas is bought and sold on a short-term fixed price basis, and there will be longer term contracts, but these will use gas price indices to determine the monthly price, for example, rather than competing fuel indices. Also included in this category are any spot LNG cargoes, any pricing which is linked to hub or spot prices and bilateral agreements in markets where there are multiple buyers and sellers.
BILATERAL MONOPOLY (BIM)	The price is determined by bilateral discussions and agreements between a large seller and a large buyer, with the price being fixed for a period of time – typically this would be one year. There may be a written contract in place, but often the arrangement is at the Government or state-owned company level. Usually, there would be a single dominant buyer or seller on at least one side of the transaction, to distinguish this category from GOG, where there would be multiple buyers and sellers.
NETBACK FROM FINAL PRODUCT (NET)	The price received by the gas supplier is a function of the price received by the buyer for the final product the buyer produces. This may occur where the gas is used as a feedstock in chemical plants, such as ammonia or methanol, and is the major variable cost in

[122] International Gas Union. Wholesale Gas Price Survey, 2019.

	producing the product.
REGULATION: COST OF SERVICE (RCS)	The price is determined, or approved, by a regulatory authority, or possibly a Ministry, but the level is set to cover the “cost of service”, including the recovery of investment and a reasonable rate of return.
REGULATION: SOCIAL AND POLITICAL (RSP)	The price is set, on an irregular basis, probably by a Ministry, on a political/social basis, in response to the need to cover increasing costs, or possibly as a revenue raising exercise – a hybrid between RCS and RBC.
REGULATION: BELOW COST (RBC)	The price is knowingly set below the average cost of producing and transporting the gas often as a form of state subsidy to the population.

Regulators within the SADC context must ensure that the mechanisms adopted allow for the benefits of gas use to be passed on to industries and the consumers – and this must consider issues of supply and demand, the cost of gas as well as energy alternatives.

5.4.4 Pricing & Forecasts

Globally, LNG is currently in excess supply, indicating the opportunity for buyers to sign LNG contracts. In comparison to other fuel sources (non-electricity and coal), globally, natural gas is structurally cheaper than its alternatives on a barrel of oil equivalent (boe) basis. Forecasts show that this will remain as such in the next ten years, as shown in the figure below.

Currently, various markets for Natural gas exist, with LNG markets typically oil linked, while Henry Hub and the US market has worked on supply/demand fundamentals.

LNG Price per Market ($/MMBTU), Index 2010 = 100

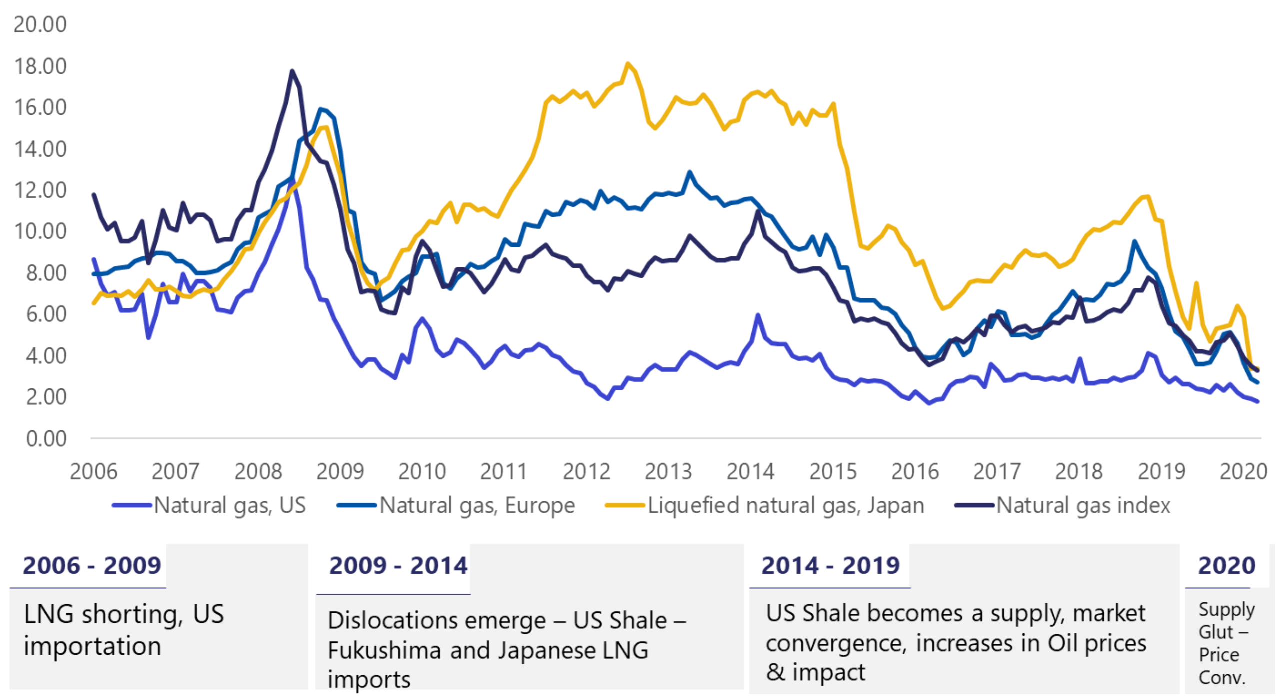

Figure 5-11: LNG Price per Market ($/MMBtu),[123] Index 2010 = 100

The Japanese spot market has been oil indexed and has typically tracked Brent at a 14% price slope with a 5-month lag. At $20 / bbl oil, the global natural gas market would have converged at ~$3/MMBtu price range – however, due to the COVID-19 crisis, great uncertainty is present within the market.

Due to the switching potential between natural gas and oil derivatives (and possibly coal), natural gas and oil will have a market linkage into the future. Oil price forecasts will determine the price range of LNG importation and exportation assumptions into the medium term.

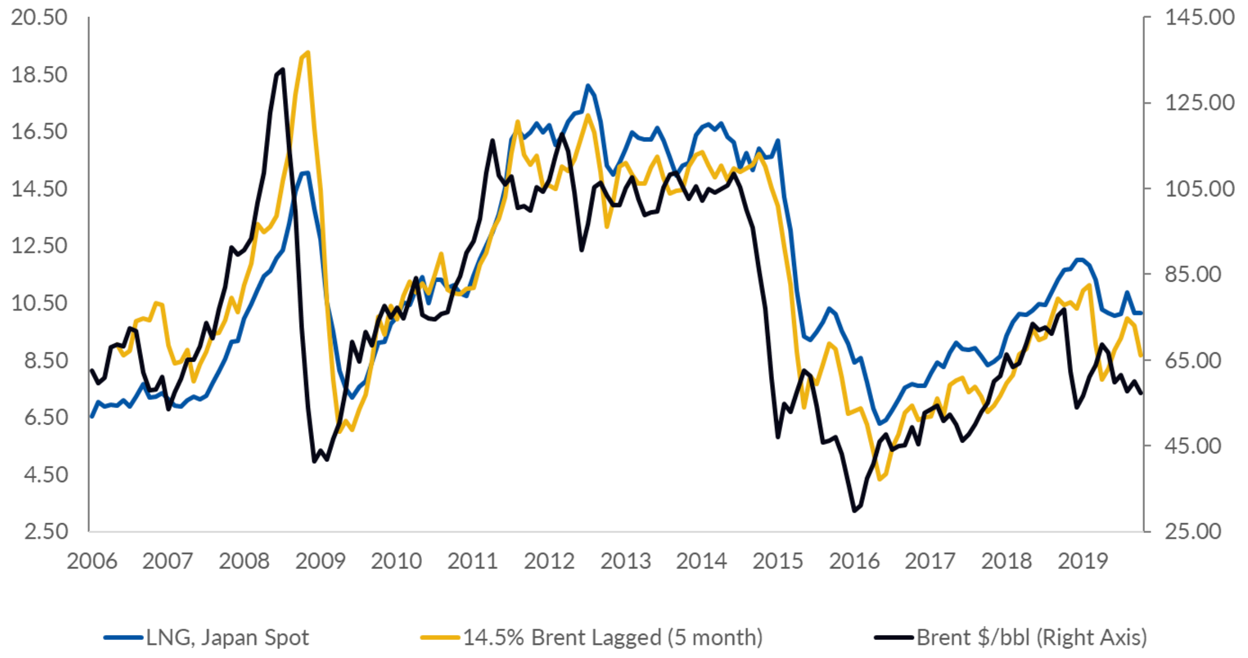

Figure 5-12: LNG Spot Price ($/MMBtu) tracked against Brent ($/bbl) - 5 month lag,14.5% slope[124]

[123] BMI Fitch Data
[124] World Bank Commodity Information, 2019. AIA Analysis.

6. GAS AND RELATED MARKET INFRASTRUCTURE

6.1 Existing Infrastructure: LNG and Pipeline

The SADC regional gas market is still at its nascent stages, with limited gas traded between countries. South Africa currently imports 3.9 billion m^3 of natural gas per annum from Mozambique,[125] which is mainly used for Sasol's activities and supplied to other downstream users within the country. This has been achieved through the development of the ROMPCO pipeline which transports gas from the Pande and Temane gas fields to the Maputo and South African markets. However, gas supply from these gas fields is uncertain from 2024[126] onwards; therefore, existing markets would thus require additional supply alternatives.

The proposed North-South gas pipeline (from the gas fields to the South of Mozambique) would ensure the security of gas supply in existing and new markets in Mozambique, South Africa, and surrounding countries. The pipeline is proposed to leverage on existing pipeline infrastructure, by transferring gas from Palma (in the North of Mozambique), and connect it to the ROMPCO pipeline, as illustrated in Figure 6-1. From a Mozambican perspective, this would drive growth in petrochemical industries and gas utilisation, as natural gas could be tapped along the pipeline. Additionally, this development would also provide a natural gas trading option to Zambia, Malawi, and Zimbabwe.

In Tanzania, the existing gas pipeline runs from Mtwara and Lindi to Dar es Salaam, where along its route, it supplies gas to existing GTP plants, and gas utilising industries. To increase in-country gas utilisation, the Tanzania Gas Utilisation Masterplan[127] proposes the development of an additional gas pipeline network in five-year phases, which would supply various in-country industries. This is illustrated in Figure 6-1. The development of this pipeline network would be a gateway to surrounding markets in Zambia, Malawi, Kenya, Uganda, and the DRC. Additionally, there are further considerations to connect the existing pipeline with the proposed Renaissance gas pipeline.

LNG also provides an alternative for natural gas supply within the prioritised countries. Within SADC, Angola is currently the only exporter of LNG, exporting gas mainly to India and Kuwait.[128] Mozambique and Tanzania, on the other hand, each have planned liquefaction facilities located close to the Rovuma basin. Upon commissioning of these liquefaction facilities, this would bring the total liquefaction capacity in SADC to 36.7 MTPA. The development of these liquefaction facilities is complemented by planned regasification facilities in Namibia and South Africa. The South African, LNG to Power IPP programme has identified three sites as potential regasification facilities, Richards Bay, Coega, and Saldanha Bay, all with a preliminary combined capacity of 5 MTPA. Namibia plans to develop an FSRU regasification facility in Walvis Bay. The development of LNG infrastructure allows states to participate in regional trade, whilst also granting access to the global market, thus increasing the security of supply and demand options.

[125] BP, 2019. BP Statistical Review of World Energy 2019.
[126] Industrial Gas User Association – Southern Africa, Interim Report, 2019
[127] Tanzania Ministry of Energy and Minerals. Tanzania Natural Gas Utilisation Masterplan, 2016.
[128] International Gas Union, 2019. 2019 LNG World LNG Report.

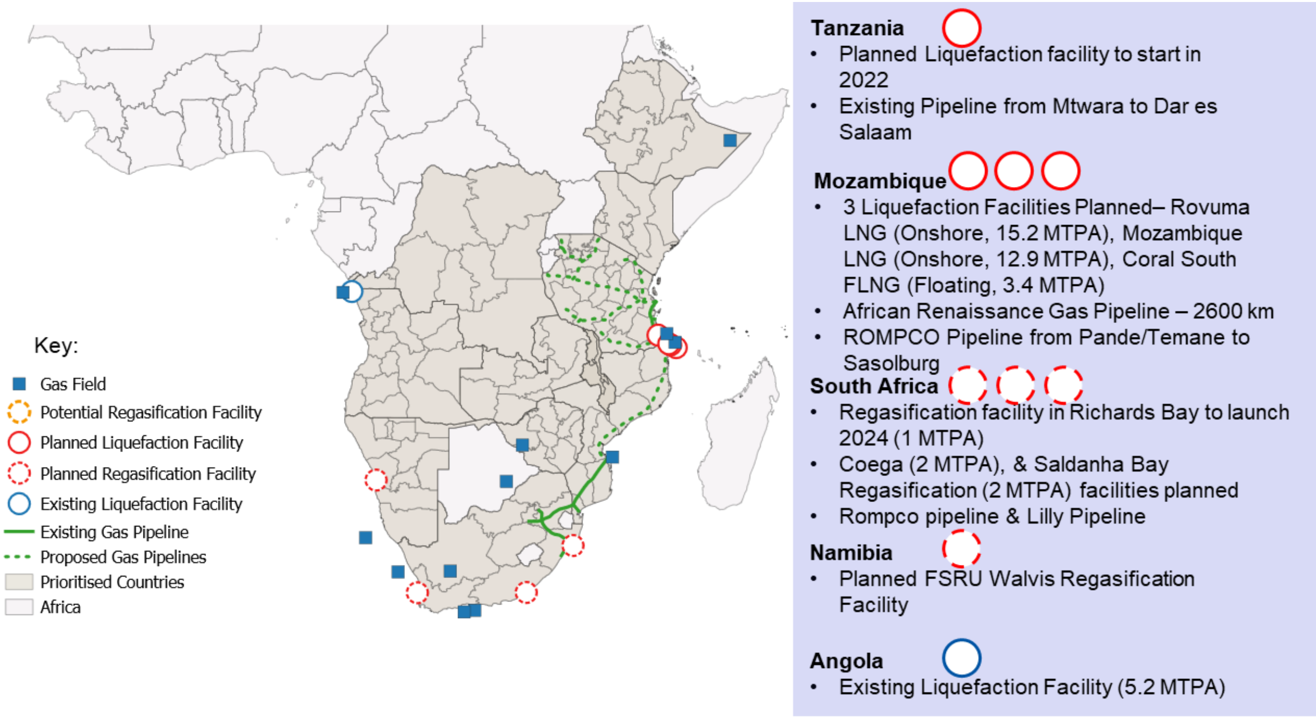

Figure 6-1: Prioritised Countries Existing and Planned Gas Transport Facilities.[129,130, 131]

6.2 Regional Power Sector Infrastructure Development

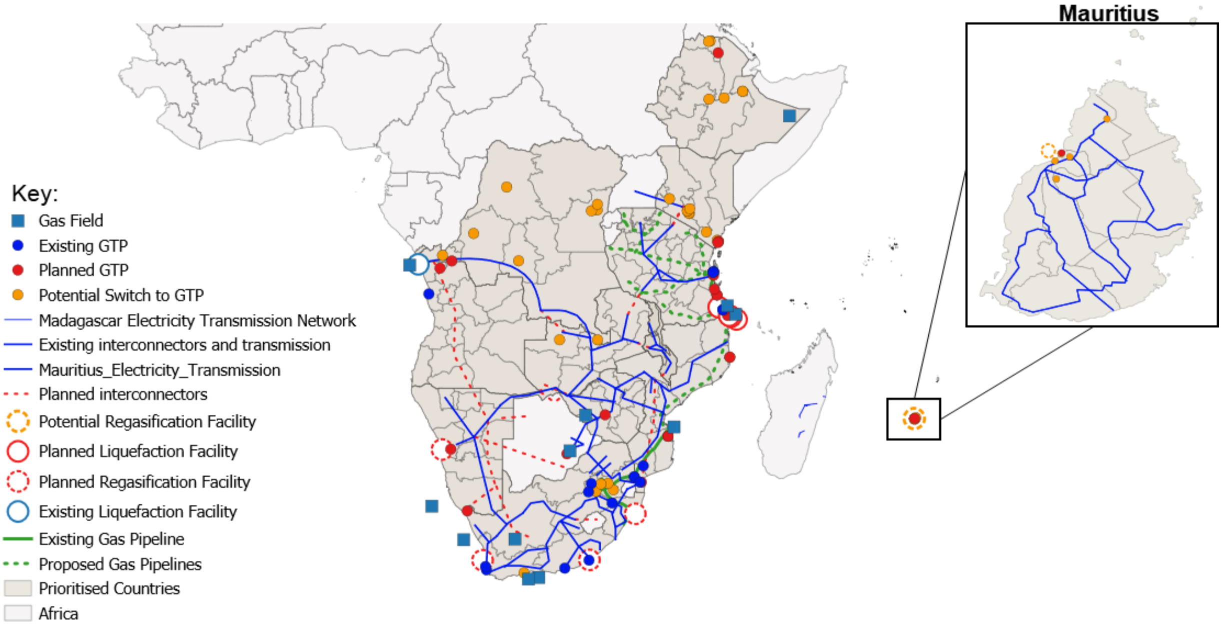

Figure 6-2: Prioritised countries existing and planned power infrastructure.[132,133]

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[129] Tanzania Ministry of Energy and Minerals. Tanzania Natural Gas Utilisation Masterplan, 2016
[130] Rompco, 2020.
131 Exxon Mobil, 2019. World LNG Interactive Map.
[132] BMI Fitch Solutions, 2020.
[133] SAPP, 2017

Within the SADC region, there are several gas fuelled power stations in operation, of which the largest of this capacity is located in Tanzania, with a 2020 capacity of 892,7 MW. The existing gas power plants in Tanzania are provided with gas through the existing pipeline from Mtwara to Dar es Salaam, while in Mozambique and South Africa gas provision is facilitated by the ROMPCO pipeline.

GTP is seen as a transitionary fuel towards a renewable future in the SADC region, this is largely due to availability of supply, mature technology as well as security of supply. The cost of GTP will be considerably more expensive than coal produced electricity, however the lower carbon emissions as well as the load following capacity to supplement renewable energy, propels natural gas as a latent electricity demand fuel source in the short to medium term. Mechanisms to make GTP feasible in a region where electricity is not universally available due to unaffordability, is necessary. Natural gas can be expected to play a load-following role in the sector, complementing hydro and renewable sources of supply during peak demand periods.

Electricity generation from gas is set to increase following planned installation capacity in the SADC region totalling 8826 MW, 1200 MW in Kenya, and 500 MW in Ethiopia. As illustrated in Figure 6-2, a majority of generation capacity will occur in proximity to the Rovuma basin. In the SADC region, Tanzania, and Mozambique will account for 45%, and 32% of new gas generation capacity, respectively, while Angola, Botswana, Zimbabwe, Namibia, and Mauritius will account for the rest of the new capacity.

In addition, within the prioritised countries, there is a great potential to switch existing fossil fuelled power stations to gas. An installed capacity of 13 921 MW can potentially be switched to gas, with 87% of this potential lying in South Africa. This switch largely depends on the retrofitting Camden, Grootlvlei, Hendrina, and Komati coal-fired power stations in Mpumalanga, South Africa to GTP plants. These coal-fired power stations with a total installed capacity of 5469 MW are planned for decommissioning by 2024.[134]

The SAPP network has been vital for Member States as it has been a mechanism for evacuating excess power, ensuring the security of power supply in times of power shortages such as droughts, and for provision of energy from lowest cost generation capacity.[135] Currently, the SAPP membership has 12 Member States, with three non-operating members: Tanzania, Angola, and Malawi[136]. However, there are plans to integrate these entities to the existing network, which would enhance electricity trading from new and existing gas to power stations.

In Angola, there are plans to develop a transmission line from Soyo where two new GTP projects are planned, to the west coast of South Africa and Namibia, as well as Botswana. To integrate Malawi to the SAPP network, interconnector projects are planned between its all its neighbouring Member States, which will enhance electricity importation. The development of these interconnector projects would culminate in the integration of the east and west of southern Africa.

[134] South Africa Department of Energy. Integrated Resource Plan, 2019.
[135] SAPP. SAPP Pool Plan 2017, 2017.
[136] J.Wright & J.Coller. System Adequacy in the Southern African Power Pool: A Case for Capacity Mechanisms.

6.3 Transportation Corridors

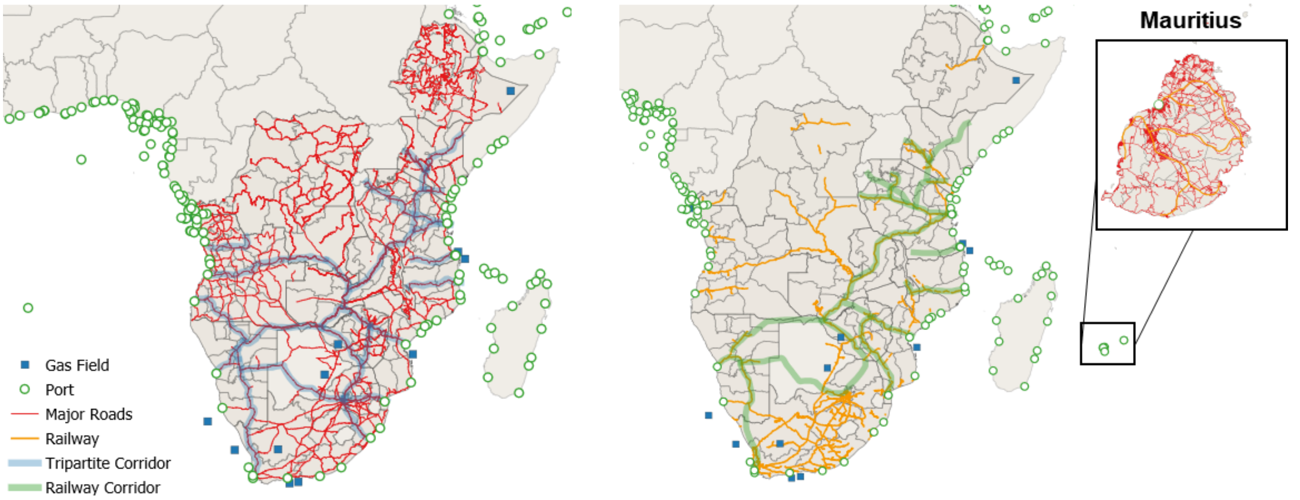


Figure 6-3: Prioritised countries existing transport infrastructure.[137,138]

To reduce pipeline development requirement, natural gas petrochemical plants should be developed close to the gas fields. Therefore, port, road, and rail infrastructure will form the linkage between petrochemical supply and demand zones. As a majority of the Southern African proven gas fields lie along the coast, port infrastructure will be crucial in trading. As illustrated in Figure 6-3, the prioritised coastal countries have mature port infrastructure, with various entry options. Port infrastructure is complemented by access to major road or rail which has reach to the whole country. Figure 6-3 also highlights that though road infrastructure has developed to facilitate ease of trade between countries over the tripartite corridors, rail infrastructure between countries over the railway corridor remains limited. The SADC Regional Infrastructure Masterplan attributes this to limited anchor volumes and the competitive pricing that road transportation has offered, thus limiting the justification for railway development.[139] Port and road infrastructure is, therefore, the most mature for intraregional petrochemical transportation.

6.4 Route to Market Outlook

Infrastructure forms the backbone that connects supply and demand. Each of the prioritised countries is at a unique trajectory where they can leverage existing infrastructure to develop their local gas market in the short-term. However, in realising a mature regional gas market, cross-border infrastructure investment is required in the long term. The following presents various route to market options for infrastructure development to satisfy gas/gas products demand in the short and long term.

Market	Route to Market Options
Angola	• Transportation of LNG from Soyo to in-country demand zones through existing road infrastructure.
Democratic Republic of Congo	• In the west of DRC, import LPG from Angola, and transferral of via existing road/rail network. In the short-term, this route can also serve the east of DRC.
Ethiopia	• Importation of petrochemical products via the port in Djibouti, or through road infrastructure.

137 SADC, 2012. Regional Infrastructure Development Masterplan.
138 World Bank. World Bank Data Catalog.
139 SADC, 2012. Regional Infrastructure Development Masterplan.

Market	Route to Market Options
Kenya	• Development of a regasification plant close to Mombasa with importation of SADC LNG, complemented by pipeline development to the rest of the country. • Possible long-term development of gas pipeline from Tanzania to meet domestic demand.
Malawi	• Development of interconnectors with SAPP for electricity importation. • Import LNG / LPG or petrochemical products through existing railway
Mauritius	• Development of a regasification facility in Port Louis, as demand lies in proximity to this port, and mature road/rail infrastructure can transfer natural gas or its products to the rest of the country.
Mozambique	• Liquefaction of gas in the north of Mozambique, and then regasification in the South of Mozambique to serve gas demand in Maputo • Development of a 2600 km pipeline from the north of Mozambique, connecting to the existing ROMPCO pipeline in Temane.
Namibia	• Importation of LNG through planned regasification facility, with Angola as the closest supplier. • The development of new markets near to the Kudu gas field or regasification facilities so as to limit the length of the pipeline. • Exporting gas through the Trans-Kalahari corridor from Walvis Bay into the region
South Africa	• Increase capacity of ROMPCO pipeline through additions of loop lines, as support new natural gas demand in Mpumalanga from GTP. • Import LNG through planned regasification facilities (1 - Coega, then 2 - Richards Bay) as GTP potential lies along the coast. This can be complemented with pipeline development, and the leveraging of the existing pipeline such as the reversal of flow direction of the Lily Pipeline, which can serve the existing market in Mpumalanga.
Tanzania	• Connecting the existing gas pipeline to Mozambique Rovuma and potentially upward towards Kenya • Liquefaction of gas in the south of Tanzania to supply gas domestically, and the rest of SADC region through ship, road/rail.
Zambia	• Importation of LNG/LPG and petrochemical products from Tanzania/Mozambique via existing road.
Zimbabwe	• Importation of LNG/LPG and petrochemical products from Tanzania/Mozambique via existing road.

7. COUNTRY ASSESSMENT

7.1 SADC Energy Balances and Pricing

Natural gas exists within an energy mix which contains alternative fuels and energy sources, which all compete for utilisation within overlapping industries. This energy mix affects the supply and price of natural gas for SADC Member States.

The following table provides an overview of the average fuel pricing and some of the critical considerations of the competitive supply for various demand nodes.

Table 7-1: Average Fuel Prices (2019).[140,141,142]

Country	Average Fuel Prices ($/GJ) (2019)				
	Coal	LPG	Fuel Oil	Diesel	Gasoline
South Africa	1	12.27	18.49	29.67	30.24
Tanzania	3.39	32.42		24.64	27.16
Mozambique	2.63	19.27	17.41	23.68	27.17
Zambia	-	24.07	-	28.16	33.73
Mauritius	5.08	12.44	10.38	24.44	37.8
Angola	-	9.91	2.69	8.09	10.16
Zimbabwe	7.77	36.73	-	29.9	31.75
Namibia	6.65	-	-	25.17	25.53
Botswana	2.39	35.56	-	24.16	25.71
DRC	-	-	-	35.04	37.3
Comoros	-	-	-	38.35	34.38
Eswatini	1.96	33.01	-	23.15	24.44
Lesotho	-	12.28	-	24.77	24.34
Malawi	4.65	48.29	-	33.65	35.89
Seychelles	-	22.44	33.57	34.32	39.11
Madagascar	-	34.57	-	25.18	32.18

SA Max Natural Gas Price – $9.55/GJ
Tanzania Natural Gas Price (Pooled Wellhead Price) – $3.396/GJ[143]

Key:
High
Low

South Africa

South Africa has a high reliance on coal, which is also the cheapest alternative fuel. South Africa also consumes oil in industries such as power generation, industrial use, transport and residential/commercial.

[140] International Energy Agency, 2017.
[141] United Nations Economic Commission for Africa, 2018.
[142] United Nations Library, 2016.
[143] Data provided by the Tanzania representatives on the Interstate Gas Committee.

Tanzania

Tanzania utilises a high amount of biomass for residential/commercial. There is a high probability of switching to natural gas where existing infrastructure and competitive pricing exist.

Mozambique

Mozambique's current fuel sources include coal and biomass for exports and residential/commercial uses. The recent find of the gas reserves will boost domestic supply for applications in power generation and industrial use and increase exports.

Zambia

Zambia primarily utilises biomass and oil in various industries, and also has the lowest electricity cost; however, price increases are expected.

Mauritius

For gas to be a strong competitor in Mauritius, it has to be better priced than LPG, coal, and fuel oil, as these three fuel prices are competitive in this region compared to other countries. Additionally, their use in power generation, transport and residential/commercial sectors is high due to the demand of the growing tourism sector.

Angola

Angola is the best ranked in price compared to all other countries per fuel category. Their oil exports are the largest, with good supply in domestic markets as well.

Zimbabwe

Coal is the cheapest fuel in Zimbabwe and has the highest demand. It is mainly utilised for electricity. Biomass is also primarily used in residential/commercial sectors. There is a large potential for natural gas as an alternative fuel for this industry.

Namibia

Similar to Zimbabwe, coal is the primary fuel source for electricity generation and has a high price in comparison to the other countries in the region. The opportunity for natural gas remains as an alternative to coal. Furthermore, the lower population means infrastructure requirements are not required at the scale of higher populous countries.

Botswana

Botswana utilises coal for power generation. However, it is competitively priced, making it difficult for natural gas to compete. However, natural gas can compete with LPG as it is highly priced and is utilised in industries such as industrial use, transport and residential/commercial. Due to Botswana's low population, infrastructure requirements will not be as high as compared to more populous countries.

DRC

DRC heavily depends on biomass for industrial use and residential/commercial. The capability to switch to gas highly probable for this country. Prices of other fuels are high for this country, presenting an opportunity for natural gas to plat a competitive role within this market

Comoros

Oil is the largest in demand, being utilised for power generation and transport; however, there is an opportunity for gas to play a pivotal role as a supply for power generation given the high volatility in oil prices.

Eswatini

Eswatini is also a large user of oil; however, its close proximity to South Africa and Mozambique provides it with a substantial opportunity to switch to natural gas as an alternative fuel for most of its industries. This can be done by taking advantage of the infrastructure between South Africa and Mozambique.

Lesotho

Oil is a significant fuel source for various industries in Lesotho. The geographical advantage of being close to South Africa and Mozambique present opportunities for natural gas; however, infrastructure can prove to be an issue due to the difficult terrain involved in the country.

Malawi

Malawi has the most expensive fuel prices in the whole of the SADC region. Biomass is the most utilised fuel, especially for residential/commercial, presenting an opportunity for natural gas to take over as there is a high switching capability.

Seychelles

Seychelles solely utilises oil for its industries. However, compared to other countries in the SADC region, its oil prices are relatively high. This presents an opportunity for natural gas. Due to its location, infrastructure may prove to be a problem for accessibility and utilisation of natural gas.

Madagascar

Here, oil is a prime fuel source, and prices often fluctuate based on national oil pricing. The oil is utilised in various industries, with principal distributions targeted at power generation.

7.2 Country Prioritisation

Twelve countries were selected for the demand assessment, ten SADC Member States and two non-SADC countries, as indicated in the figure below.

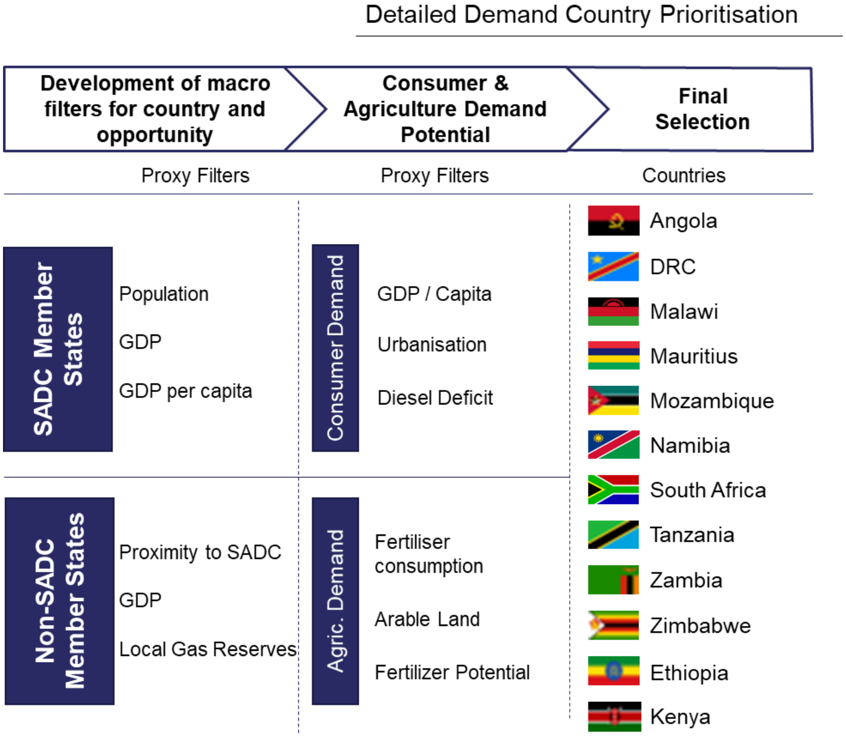


Figure 7-1: Prioritised Countries for Demand Assessment

The SADC Member States were selected across several variables. Economic size and growth (measured in terms of GDP) were essential to ensure that reasonably sized markets were under consideration, which also had a long-term history of consistent growth. Non-SADC countries were selected primarily on their proximity to SADC, economic size, and the scale of the proven gas reserves. Demand drivers such as economic prosperity (i.e. GDP per capita), urbanisation and diesel trade deficits would be considered to establish downstream demand potential. Fertiliser demand presents significant gas to chemical potential in the African context; thus, agricultural indicators such as fertiliser consumption and arable land were considered.

7.3 Prioritised Country Analysis

This section of the study summarises key institutions within each of the prioritised countries that would have a role in the development of the regional gas market as well as a breakdown of energy supply and consumption.

7.3.1 Angola

The Ministry of Mineral and Petroleum Resources is the responsible authority related to the geological and mineral activities of petroleum, gas, and biofuel. All mineral rights are vested in the national regulator of hydrocarbons, ANPG, otherwise known as the National Oil, Gas and Biofuel Agency. There are three public entities operating under the Ministry of Energy and Water regarding the electricity sector, i.e. PRODEL for generation, RNT for transmission and ENDE for distribution along with the participation of the private sector. Regarding natural gas, Sonangol (the old NOC) functions are limited to carrying out prospection, research, production, and related petrochemical activities. The figure below indicates the key market and regulatory players across the Natural Gas Value Chain.

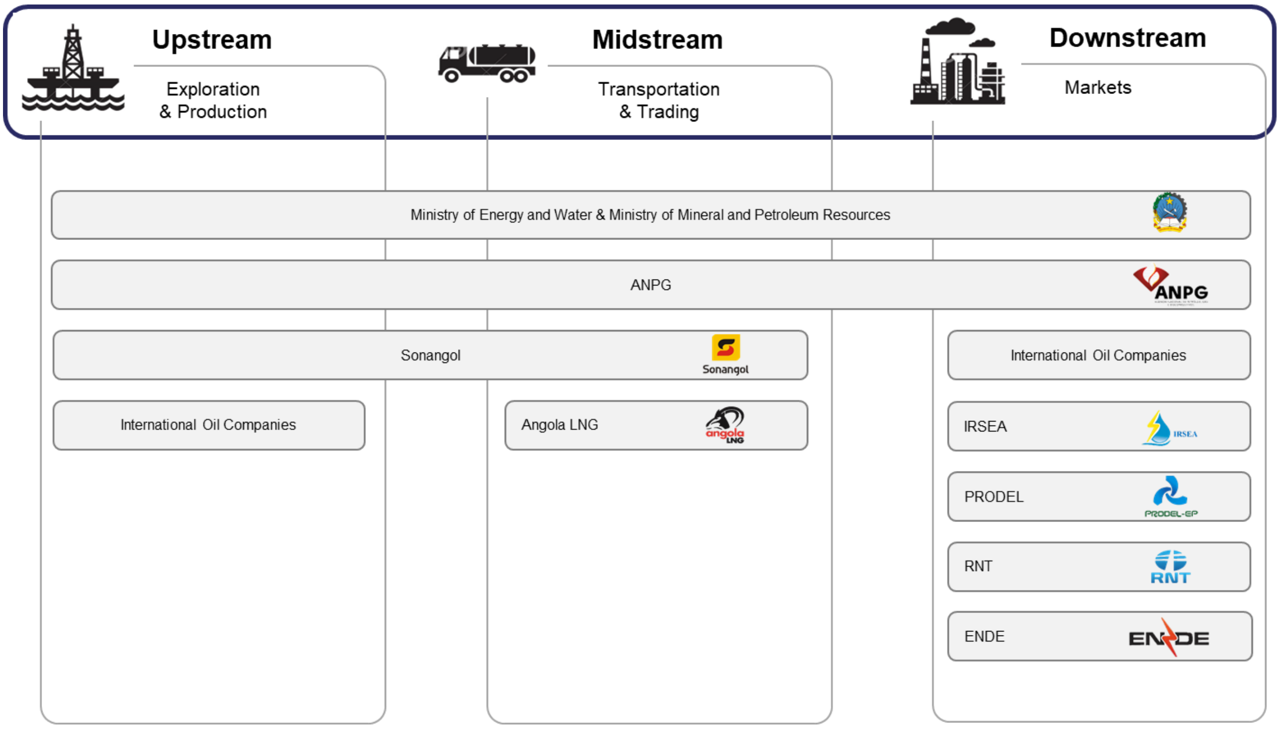


Figure 7-2: Angola Energy Market and Governance Structure

The residential sector accounts for 59% of national energy consumption, as indicated in the figure below, which is largely supplied in the form of biomass for cooking and heating needs. Domestic energy consumption accounts for 10% of total energy productions as oil and oil products exports account for a significant proportion of total Angolan exports.

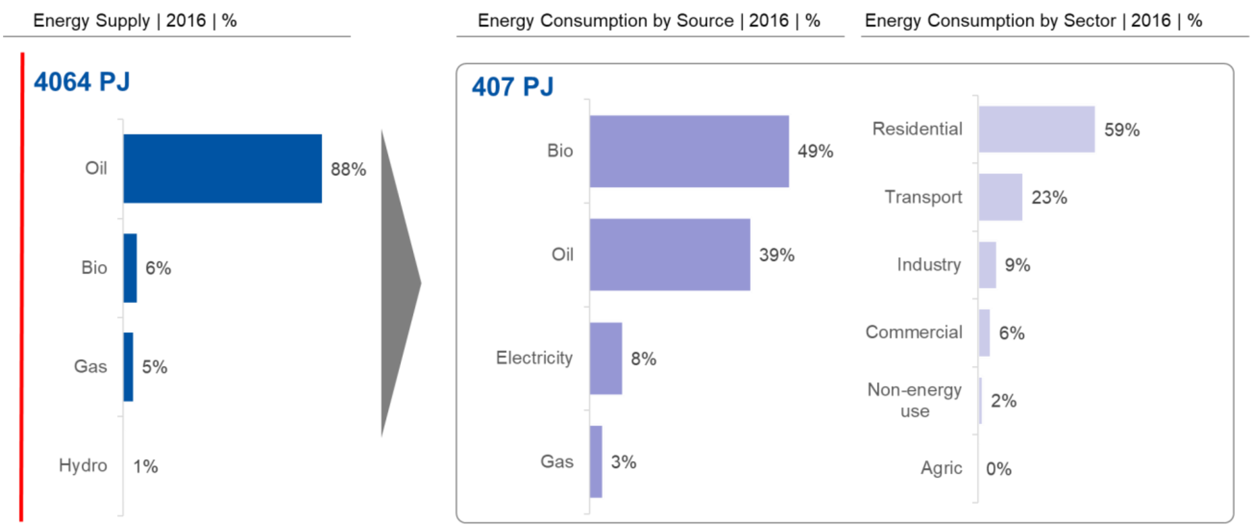


Figure 7-3: Angola Energy Profile

The existing Angolan natural gas market is anchored through gas exports which could be transformed into power generation, chemical production, and industrial heating applications. The existing 3175 MW of power generation potential is derived from three plants, namely: Luaca, Cambambe (both being hydropower plants) and Luanda, which is an open cycle gas turbine plant. Additional capacity Gas to Power generation capacity will add 19.1 PJ of demand by 2030, as indicated in the figure below. Additionally, identified industrial application of natural gas in the cement and fertiliser industries has the potential to add approximately 3.6 PJ of natural gas demand by 2030.

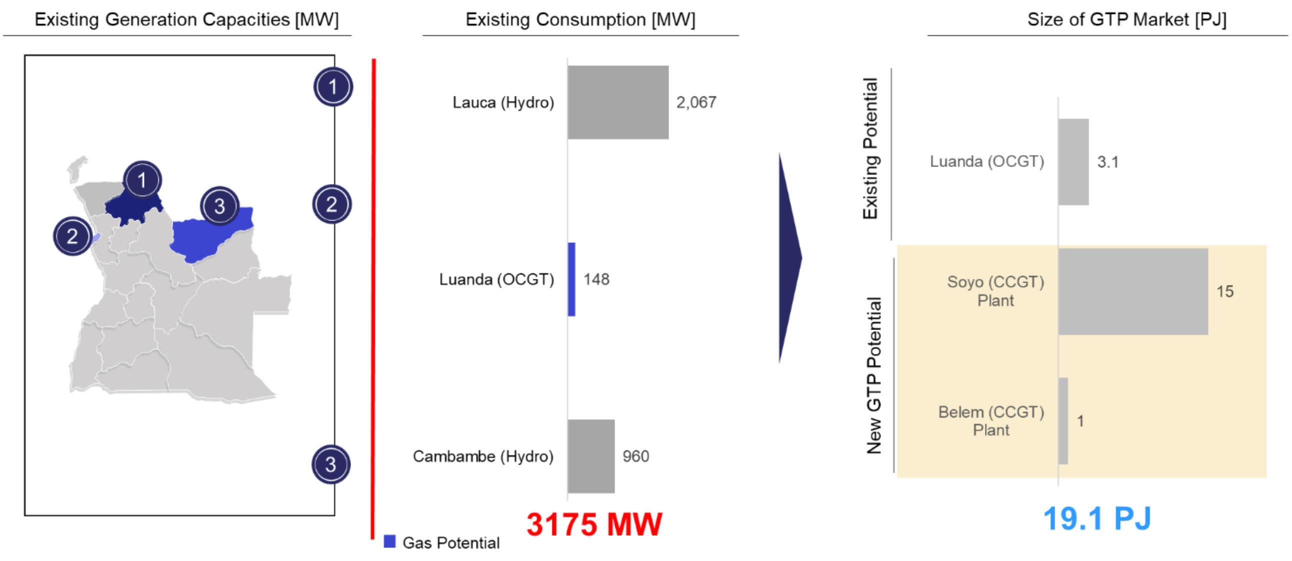


Figure 7-4: Angolan Electricity Capacity

7.3.2 Democratic Republic of Congo

The Ministry of Hydrocarbons is responsible for the exploration, production, refining, distribution, marketing, import, export, and conservation of petroleum, natural gas, petroleum products, as well as LNG. The electricity sector is dominated by the vertically integrated national utility, Société Nationale d'électricité (SNEL), which controls generation, transmission, distribution, importation, and exportation of electricity. A few IPPs also sell produced electricity in the national grid. Société Nationale des Petroles du Congo (SNPC) is the NOC which manages government-owned shares of production from oil fields in the country and owns the refinery company named Congolaise de Raffinage. The figure below indicates the key market and regulatory players across the Natural Gas Value Chain.

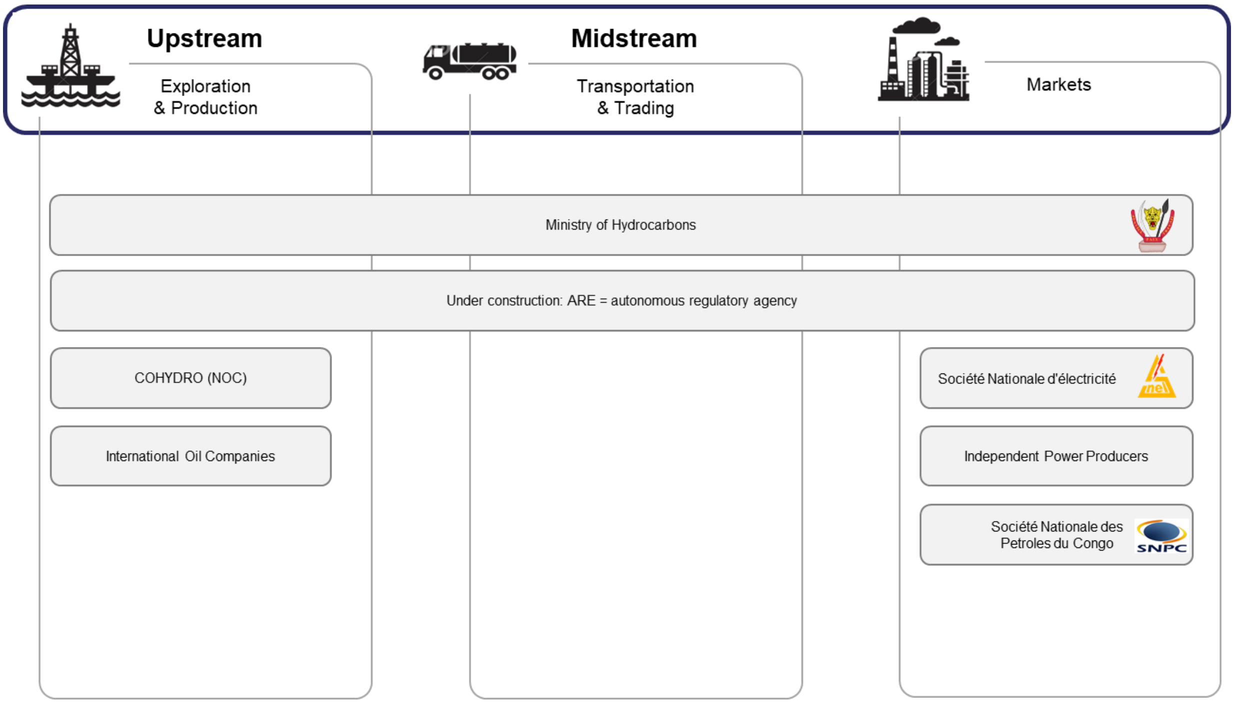


Figure 7-5: DRC Energy Market and Governance Structure

The residential sector accounts for 80% of national energy consumption, as indicated in the figure below, which is largely supplied in the form of biomass for cooking and heating needs. Total domestic energy consumption is mostly consistent with energy production, with 91% of energy production being in the form of bioenergy.

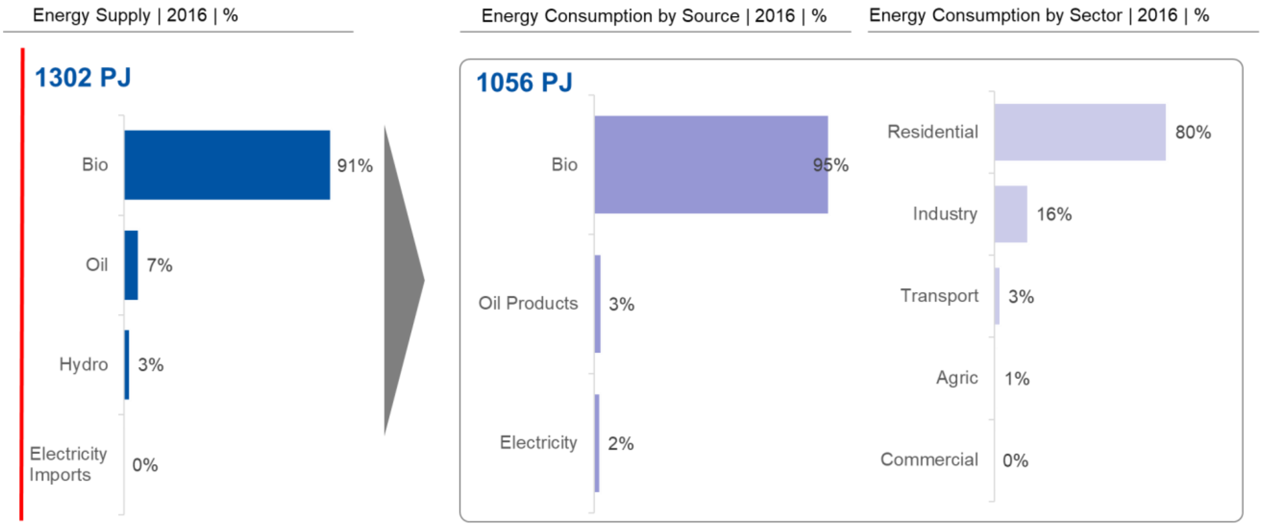


Figure 7-6: DRC Energy Profile

The DRC currently consumes negligible quantities of natural gas which presents an opportunity for industrial switching within cement industries of 0.3 PJ alongside 0.9 PJ of gas to power potential that has been identified for development by 2030 as indicated in the figure below. Existing electricity generation capacity amounts to 2582 MW, with the majority provided through hydropower, which has significant upside potential trough the Grand Inga project. Although two units are currently online, the project could deliver 40 GW upon completion of all eight units.

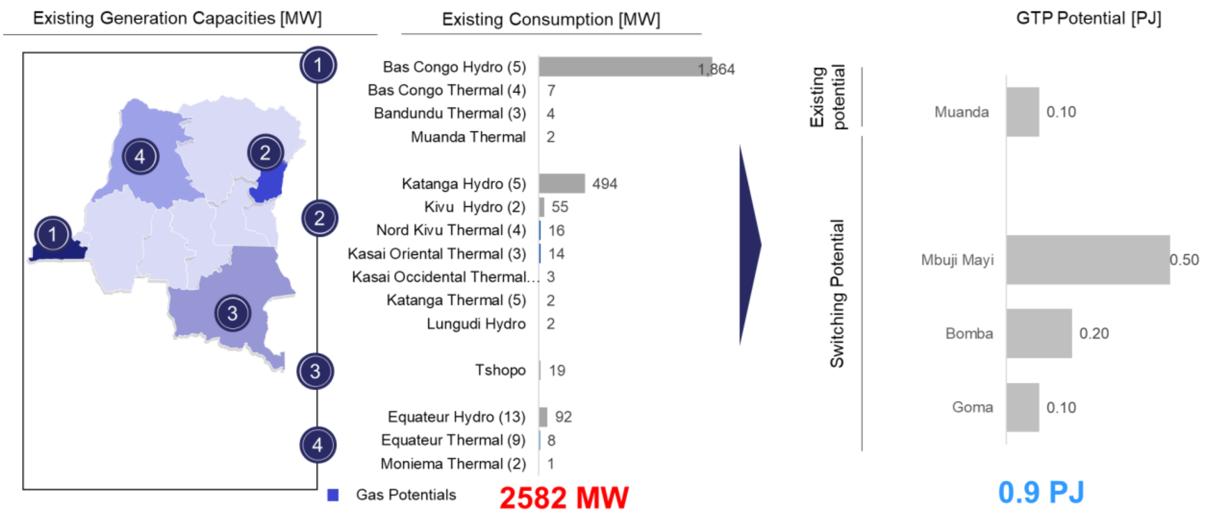


Figure 7-7: DRC Electricity Capacity

7.3.3 Malawi

The Ministry of Natural Resources, Energy and Environment oversees Malawi's energy sector, and the energy regulator is the Malawi Energy Regulatory Authority (MERA). ESCOM governs transmission and distribution of electricity, whilst the Electricity Generation Company (EGENCO) deals with electricity generation. Other players in the electricity sector are independent power producers who sell electricity to ESCOM. The Ministry of Agriculture and Food Security regulates fertiliser production and usage within Malawi. The Malawi Fertiliser Trade Association (which consists of 15 suppliers, manufacturers, and importers in the industry) and the Malawi Fertiliser Regulatory Services are all active within this space. The figure below indicates the key market and regulatory players across the Natural Gas Value Chain.

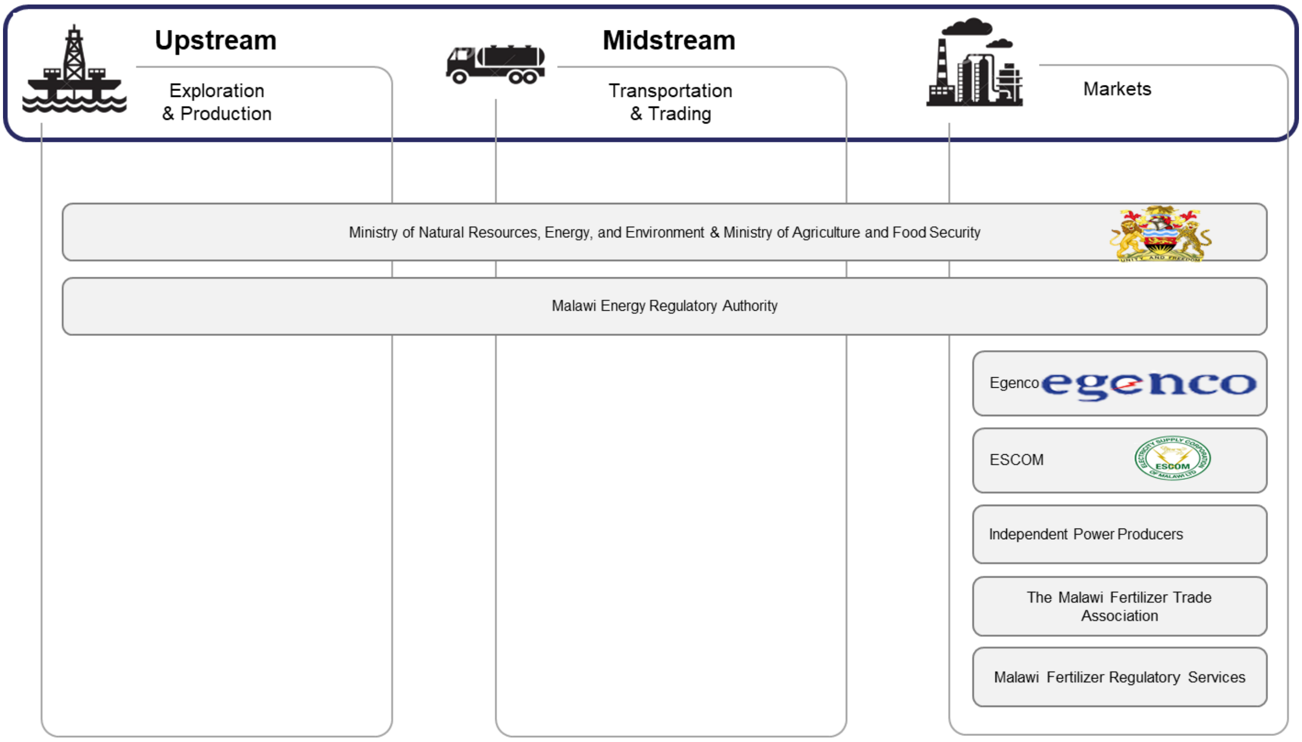


Figure 7-8: Malawi Energy Market and Governance Structure

Malawian energy production is primarily consumed domestically. Charcoal accounts for 26% of energy consumption, which feeds into the residential and industrial sectors alongside the LPG component of the oil stream, as shown below. The country has relatively low energy consumption relative to other SADC Member States, although it is steadily increasing.

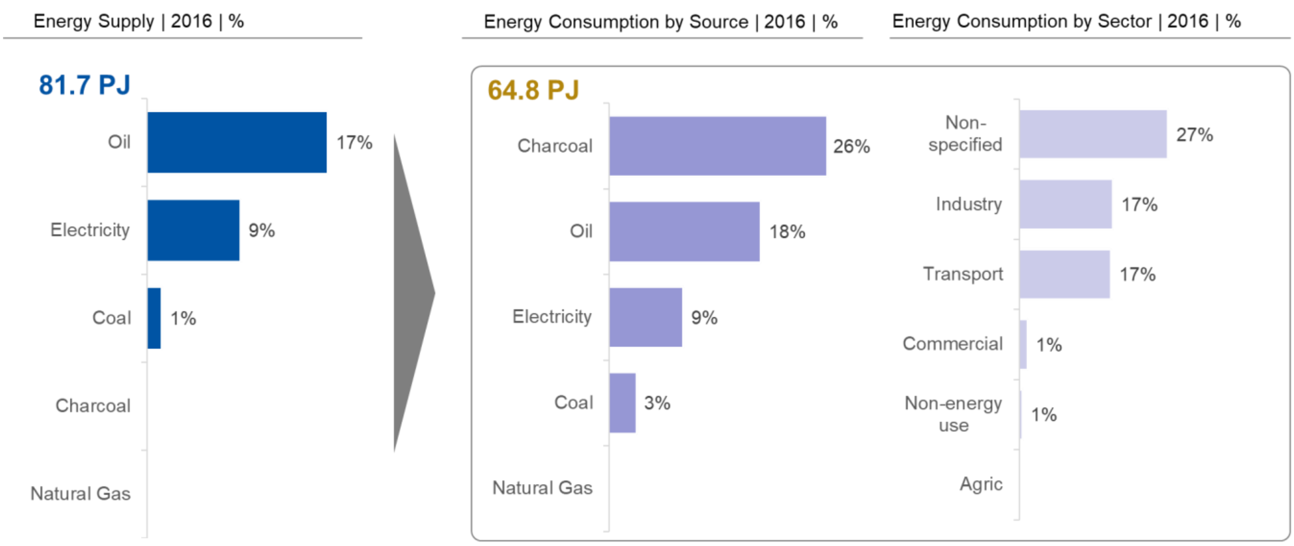


Figure 7-9: Malawi Energy Profile

Malawi's gas potential by 2030 is primarily driven by industrial development, as indicated in the figure below. 75% of the 13.4 PJ potential is driven by developments in the mining sector, graphite production and cement production.

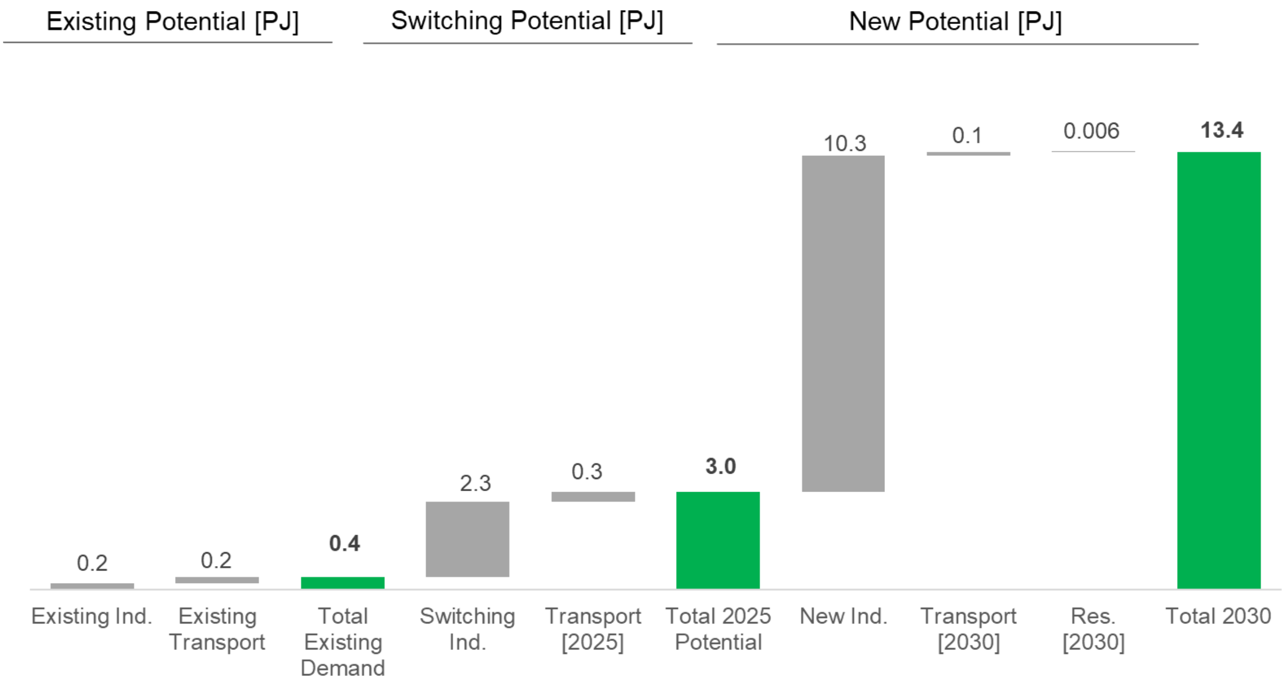


Figure 7-10: Malawi Natural Gas Potential 2020 – 2030

7.3.4 Mauritius

The Ministry of Energy and Public Utilities is the Government authority tasked with energy policies and overall regulation in the energy space while the Utility Regulatory Authority (URA) oversees the electricity market and industry in line with the policies of the Ministry. The Central Electricity Board (CEB) is the Mauritian vertically integrated electricity utility while the Mauritius Renewable Energy Agency (MARENA) promotes development in the renewable energy sector. The State Trading Corporation is the trading arm of Government responsible for the importation of strategic commodities such as petroleum products, including LPG. The Mauritius Chemical and Fertiliser Industry Ltd is a manufacturing company which blends fertilisers for utilisation in domestic crop production. The figure below indicates the key market and regulatory players across the Natural Gas Value Chain.

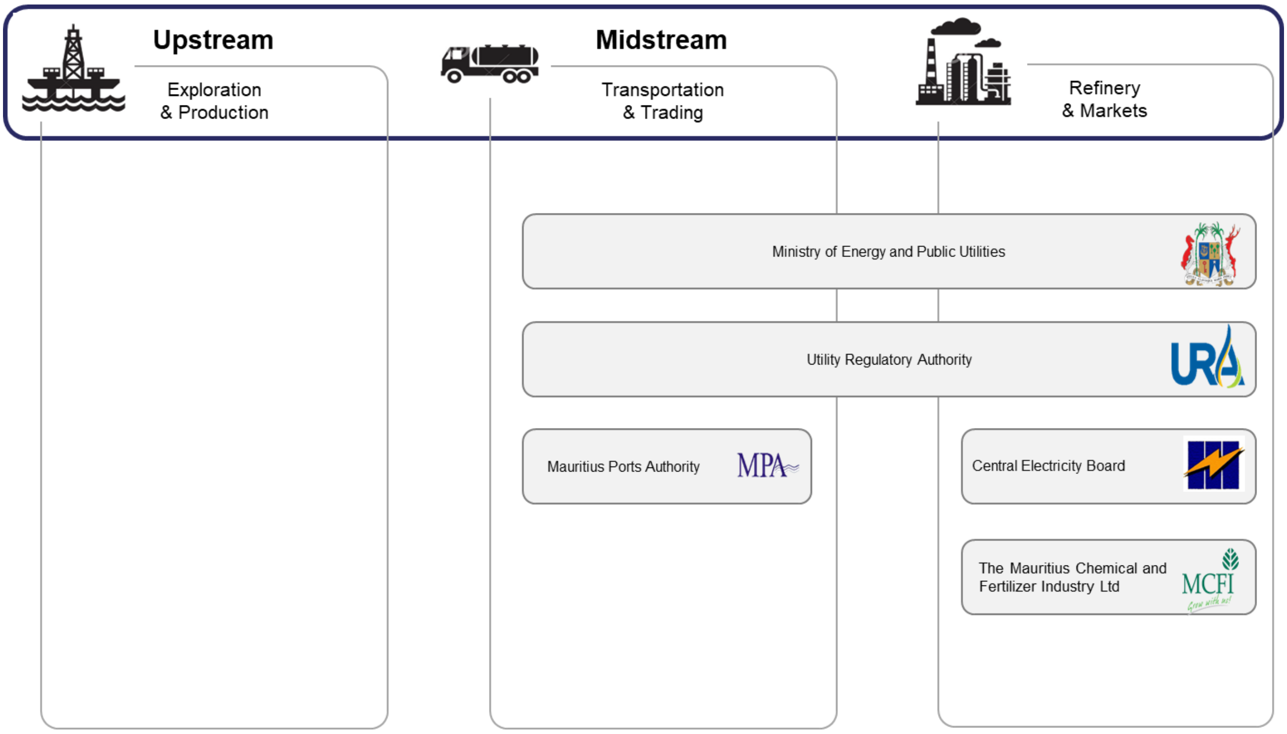


Figure 7-11: Mauritius Energy Market and Governance Structure

As a net energy importer, supplied energy is largely consumed domestically with little exports leaving the nation. Imported oil products account for 71% of the total energy supply and largely fuel the maritime and road transport sectors. 96 % of the coal supplied is utilised to generate electricity with the remainder being supplied to industrial processes.

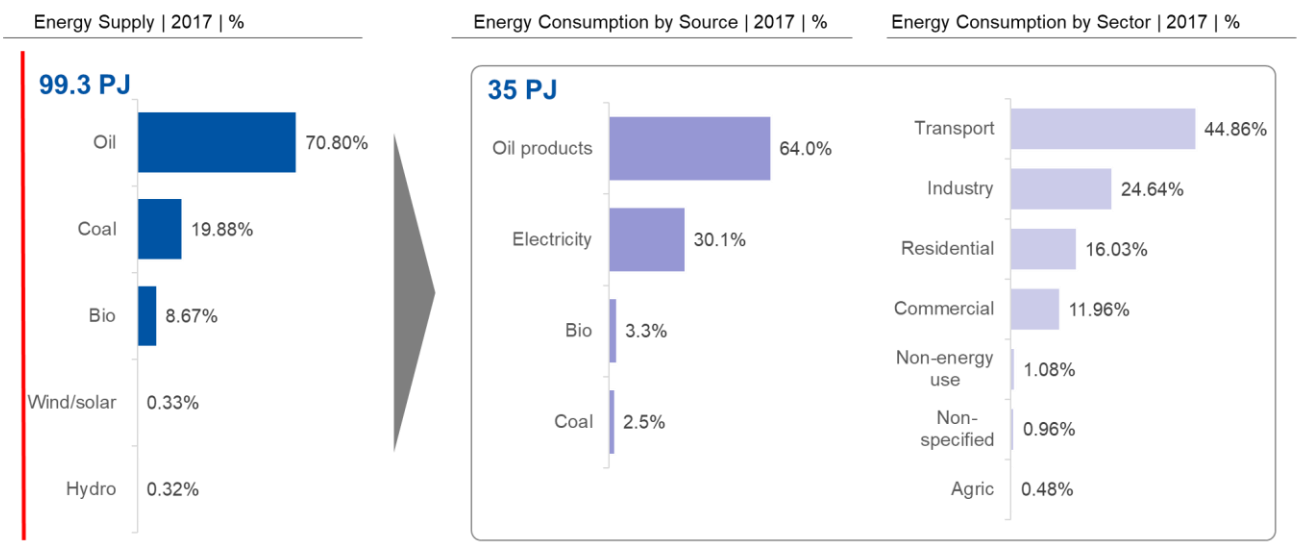


Figure 7-12: Mauritius Energy Transformation

Existing electricity generation capacity stands at 814.16 MW[144] and is fuelled by coal (35.85%), oil products (44.91%), bioenergy (11 %), Hydro (3.36%), PV (3.77%), Wind (0.44%) and Landfill Gas (0.68%).

[144] 2019 Data, provided by Interstate Gas Committee Representatives from Mauritius.

Natural gas demand potential of 5-10 PJ, by 2030, is driven by the switching of HFO, Kerosene and Coal fuelled power plants to natural gas.

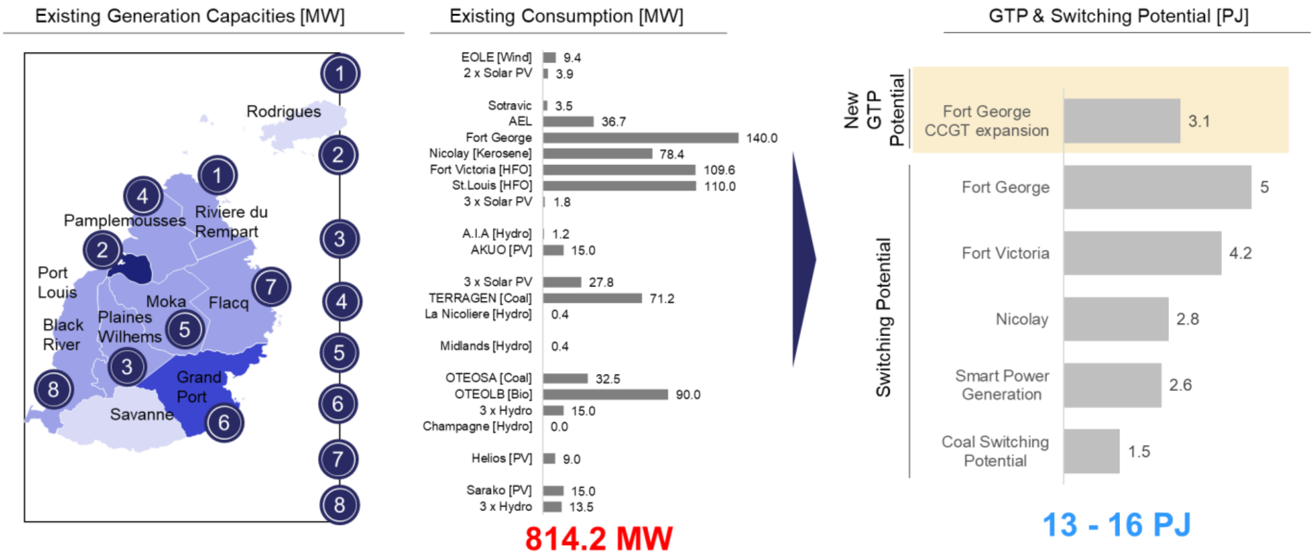


Figure 7-13: Mauritius Electricity Capacity

7.3.5 Mozambique

The Government of Mozambique sets policies and objectives to control the development of the energy and mineral sector. Specifically, the Ministry of Mineral Resources and Energy (MIREME) is responsible for directing & executing natural resource policies. The Energy Regulatory Authority (ARENE) is the governmental consultative body responsible for regulating, controlling & supervising the downstream energy sector. Electricidade de Moçambique is a vertically integrated, government-owned electricity utility responsible for generating, transmitting, and distributing electricity through the national grid. Investors wishing to explore Mozambican oil and gas resources must associate with ENH, the Mozambican NOC. The figure below indicates the key market and regulatory players across the Natural Gas Value Chain.

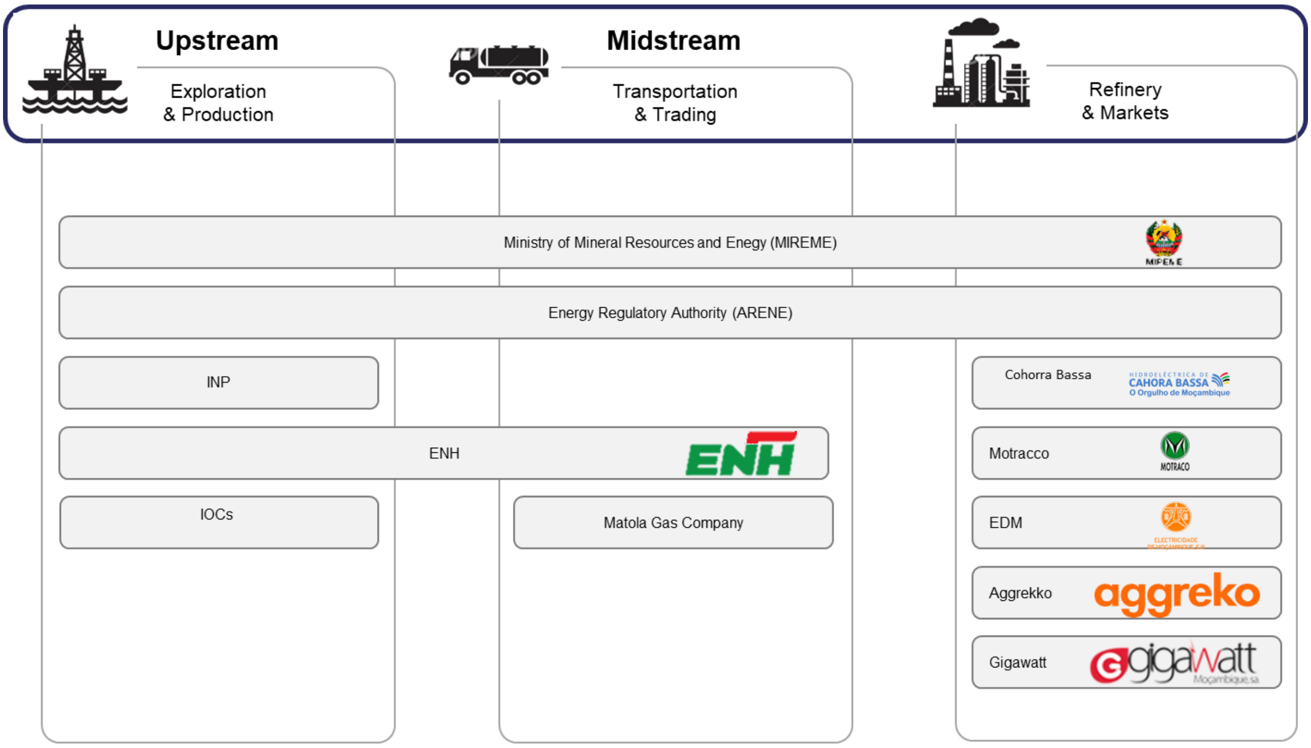


Figure 7-14: Mozambique Energy Market and Governance Structure

Mozambique is a net energy exporter of coal and natural gas products (e.g. LNG), and final domestic consumption accounts for a quarter of national energy production. Bioenergy makes up 41% of the domestic consumption, which largely accommodates residential and commercial energy requirements, as indicated in the figure below. This is because of the socioeconomic context, where 66% of the population resides in rural areas.

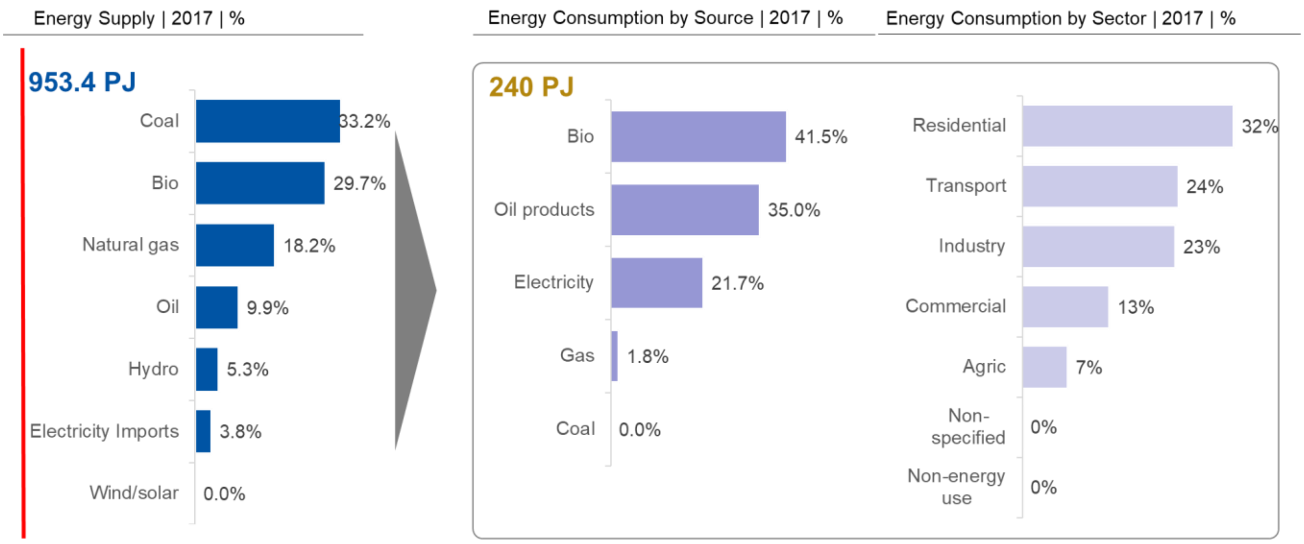


Figure 7-15: Mozambique Energy Profile

Hydropower contributes over 75% of the electricity supply within Mozambique, and natural gas is unlikely to replace it in electricity production. Total natural gas to power potential amounts to 72 PJ by 2030 with a large percentage of that being derived from 2800 MW of gas plant capacity and the switching of existing diesel fuelled capacity of 100 MW to natural gas, which is often structurally more economical than diesel for electricity generation.

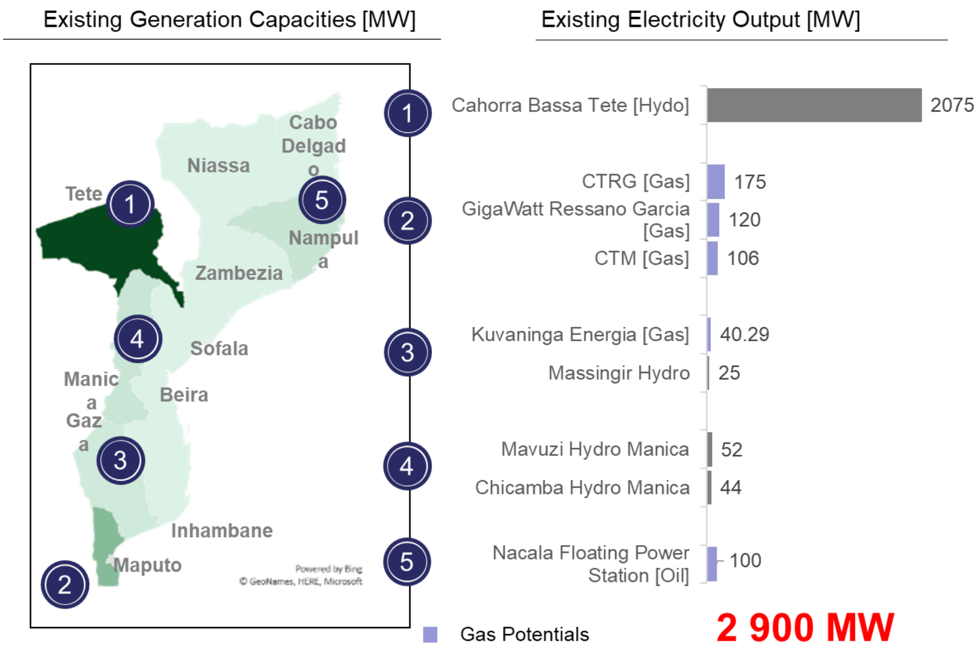


Figure 7-16: Mozambique Electricity Capacity

Mozambique's only source of natural gas has been from the Pande and Temane fields, and the gas is piped south to Ressano Garcia and then to South Africa through the ROMPCO pipeline. Matola Gas Company operates a 100km pipeline to Maputo with a capacity of 8 PJ/a. Currently, natural gas is consumed by several industries within Maputo, which totals approximately 4 PJ/a. There has been little industrial development along the pipeline despite being built in 2004, which represents untapped economic growth potential. An additional 120 PJ of natural gas demand potential could come online by 2025 for the conversion of natural gas to liquid products.

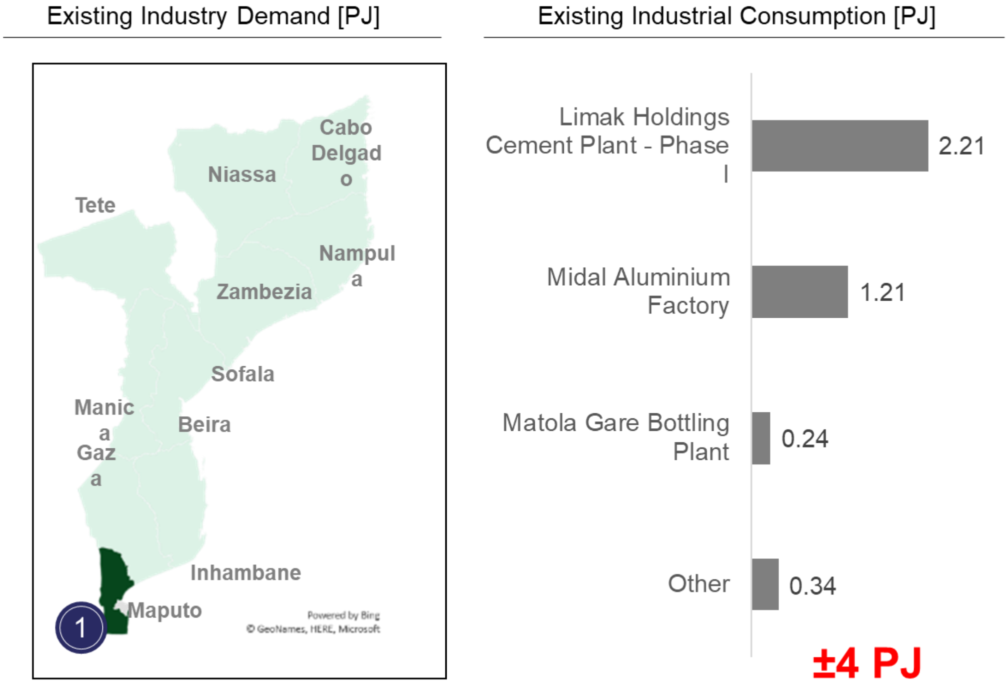


Figure 7-17: Mozambique Industrial Potential

The initiation of petrochemical development in the country, which is expected to start going on-line by 2025, is expected to provide a significant local base demand for natural gas in Mozambique. Ammonia-urea, methanol and GTL projects are all under consideration and are expected to stimulate economic growth and development in the petrochemical sector.

7.3.6 Namibia

The Minister of Mines and Energy introduces energy legislation and is vested with the power to issue reconnaissance, exploration, and production operations licenses. The National Petroleum Corporation of Namibia (NAMCOR), solely owned by the state, is tasked with carrying out upstream operations on behalf of the Namibian government. The vertically integrated state-owned electricity utility, NamPower, generates, transmits, imports and exports electricity. Electricity distribution is decentralised on a regional basis through six Regional Electricity Distributors (REDs). Natural gas and associated commodities are regulated by the Petroleum Commissioner and the Chief Inspector of Petroleum Affairs. The figure below indicates the key market and regulatory players across the Natural Gas Value Chain.

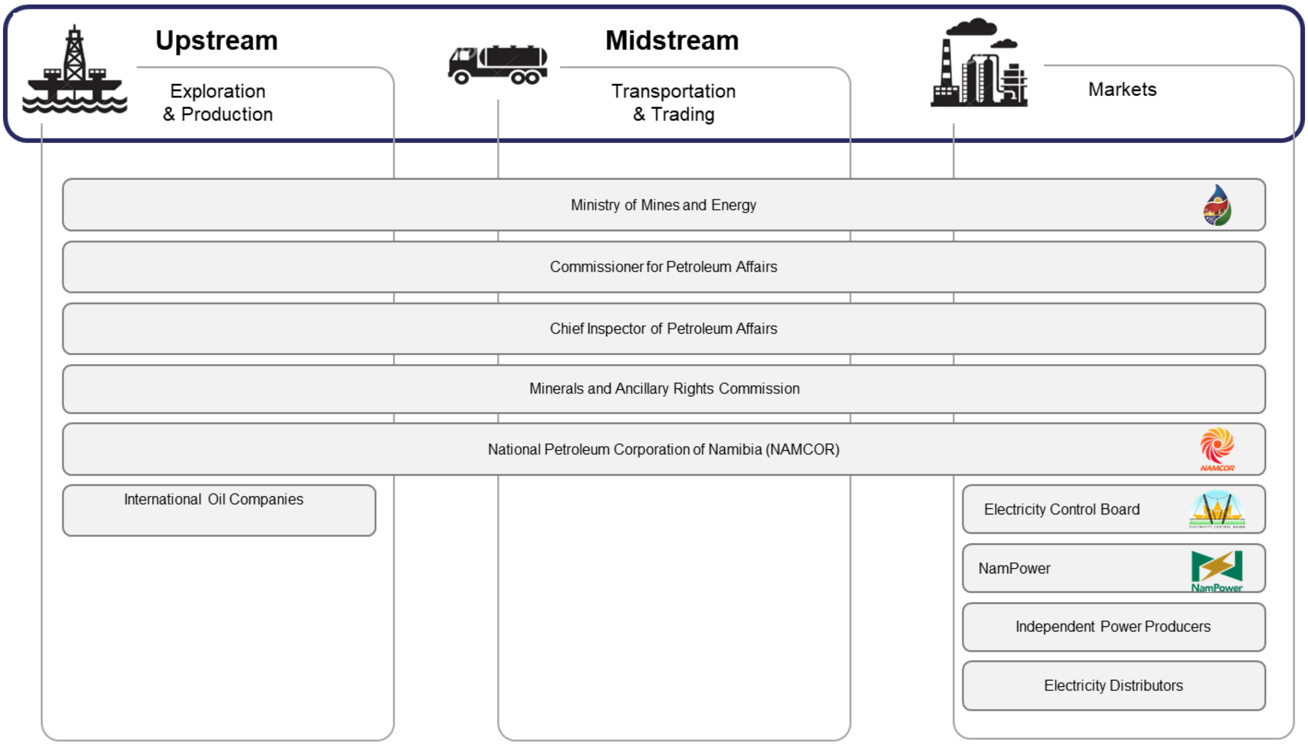


Figure 7-18: Namibia Energy Market and Governance Structure

Namibia is a net energy importer and imports coal, oil products and electricity to power its economy. The relatively large quantity of oil products is consumed in the road transport and agricultural sectors. 36% of the electricity supplied is generated through hydropower while the remainder is imported from Eskom through NamPower. 83% of the bioenergy supplied is consumed in the residential sector for cooking and heating requirements while the rest is consumed in industrial heating applications.

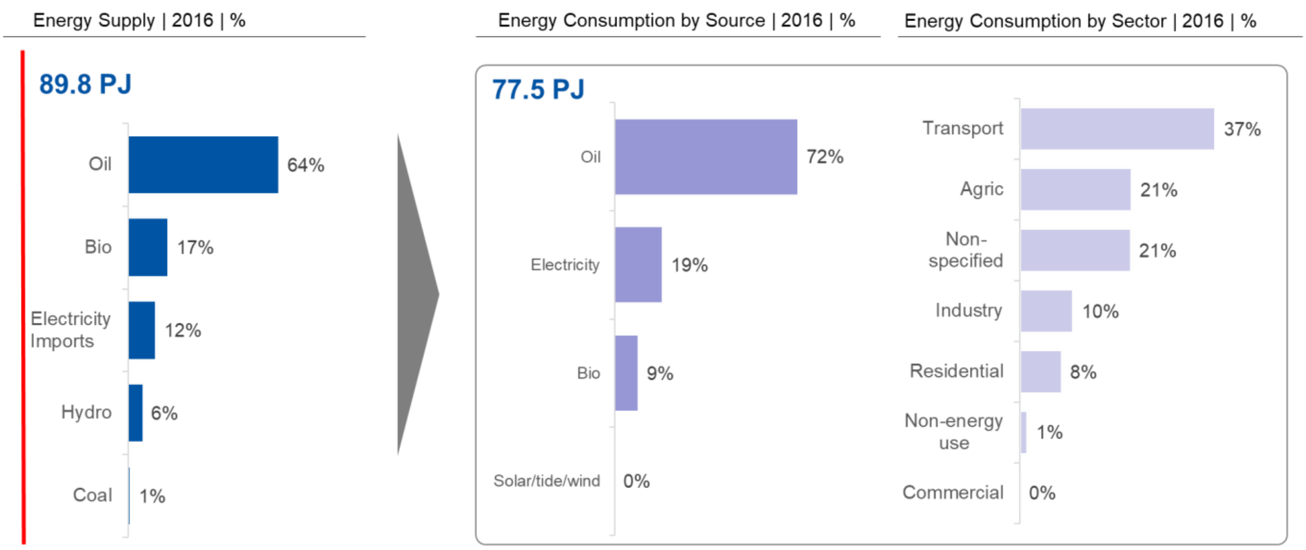


Figure 7-19: Namibia Energy Profile

Namibia has 508 MW of generation capacity with major primary fuel source consisting of hydropower (65%) and coal (24%). Namibia currently has negligible gas consumption, and anchor demand would be required to grow natural gas consumption within the country. By 2030, GTP potential of 1 PJ could be unlocked through the switching of LFO and HFO plants to natural gas, while 21 PJ of new gas to power potential could be realised within the same period to meet electrification requirements.

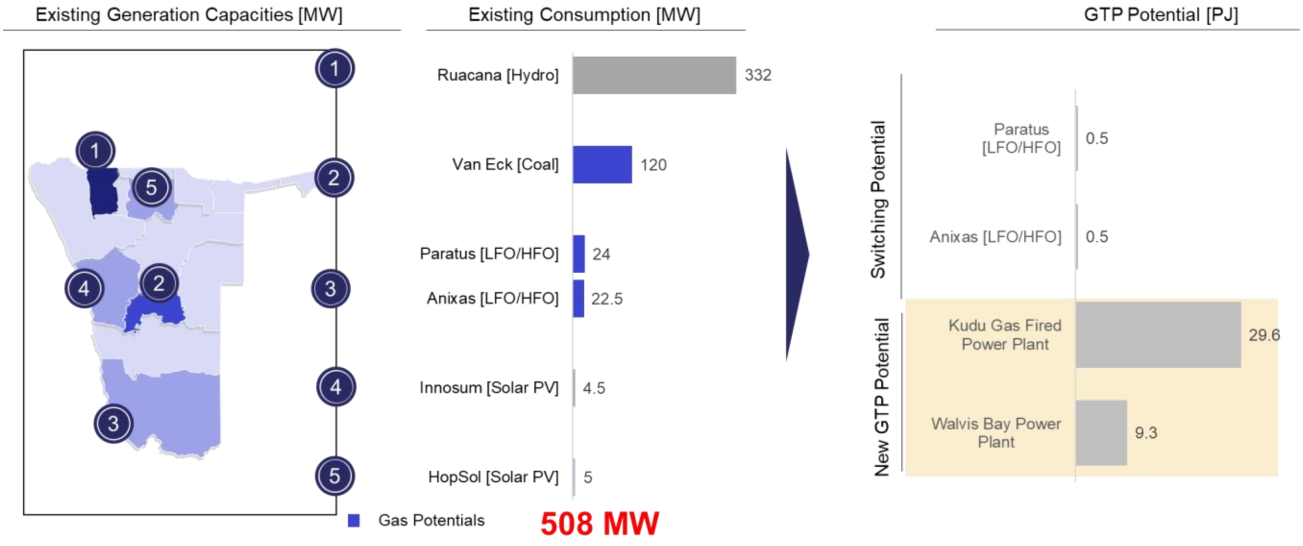


Figure 7-20: Namibian Electricity Capacity

7.3.7 South Africa

The Department of Mineral Resources and Energy (DMRE), Department of Public Enterprises, National Treasury, and Department of Environmental Affairs are all key ministerial players within the energy sector. The DMRE is responsible for the governance of mineral energy resources within South Africa while the Department of Public Enterprises oversees and governs state-owned companies who may be involved in the energy sector (e.g. Eskom). NERSA is the country’s energy regulator and regulates the electricity, piped gas, and petroleum pipeline industries. The Petroleum Agency of South Africa performs an advisory and administrative role, regulates upstream activities, and promotes natural gas exploration and production. Eskom is responsible for the majority of generation, transmission, and distribution of electricity within South Africa, and it holds a dominant position in the market, although private producers have entered the generation space through the Independent Power Producers Programme. PetroSA, the state-owned NOC, is involved in the production of several small oil and gas fields, while Sasol has substantial market power, selling gas to itself, gas traders, reticulators, as well as industrial & commercial clients. The figure below indicates the key market and regulatory players across the Natural Gas Value Chain.

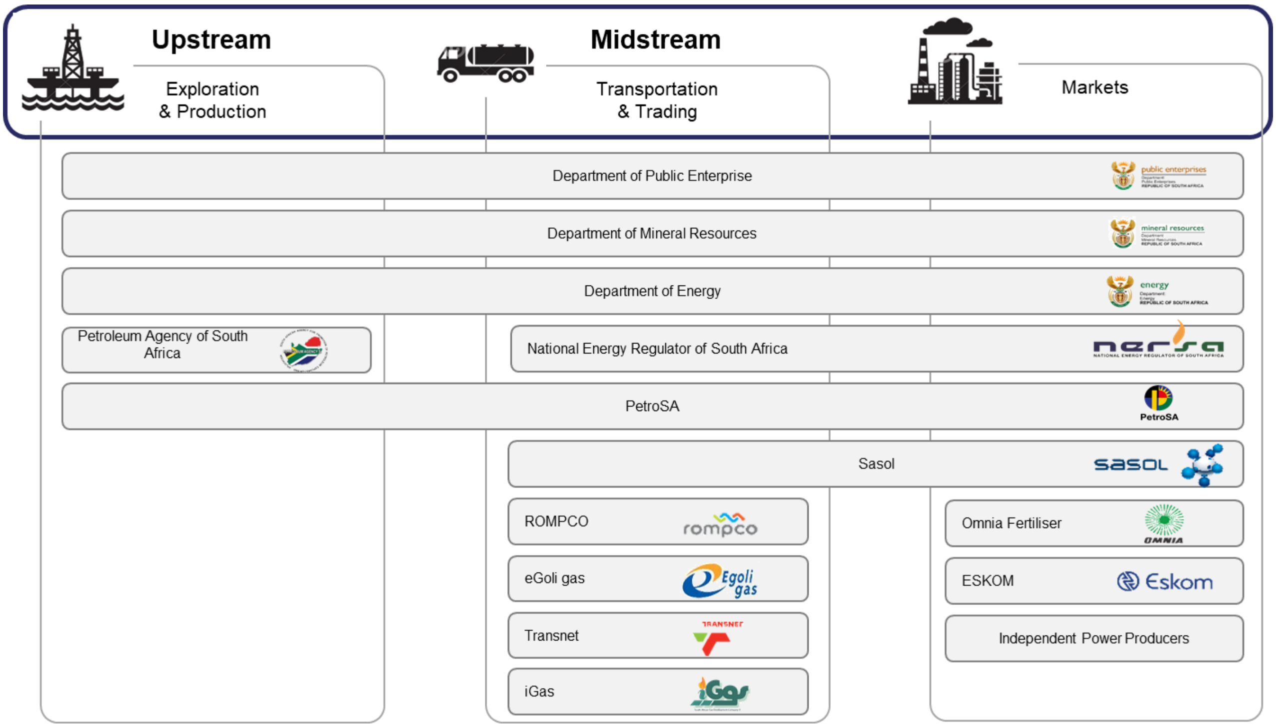


Figure 7-21: South Africa Energy Market and Governance Structure

South Africa is a net energy exporter as the country consumes a third of the energy it produces. 77% of the energy produced is coal that is largely utilised to produce electricity, which powers almost every sector within the economy. South Africa is not endowed with plentiful oil reserves and imports oil (for refining) and oil products to fuel transportation demand. Approximately 80-90% of South Africa's current natural gas consumption is utilised in the petrochemical industry, while the remainder supplements industrial heating requirement alongside coal and electricity depending upon the nature of the industry.

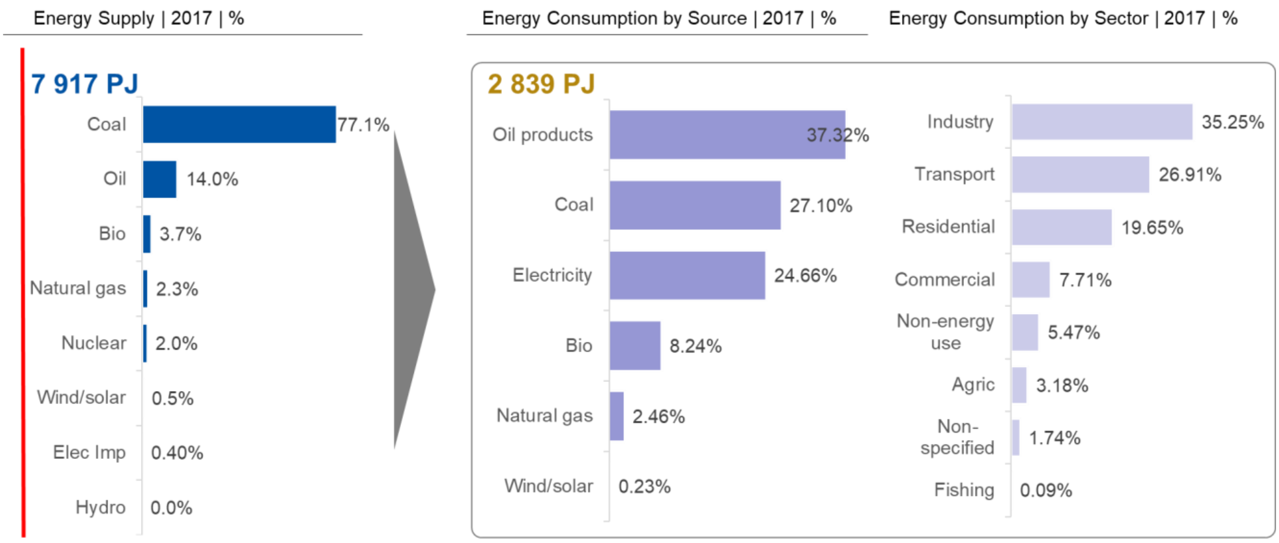


Figure 7-22: South Africa Energy Profile

South Africa has a relatively well-developed electricity value chain within the SADC region. Due to the abundance of reserves, 92% of the primary energy supplied to the 50 GW of electricity generation capacity is coal; as shown in the figure below. Approximately 10.5 GW of coal-fired plants will be decommissioned by 2030 followed by an additional 24.5 GW by 2050[145]. This is largely due to the age of the existing fleet, which is due for replacement soon and opens the door for policy to drive the decarbonising of the energy sector in terms of electricity.

Natural gas has strong potential as a primary energy source for electricity generation as South Africa diversifies its energy mix from coal. Mid-merit natural gas capacity could offset power variations inherent to renewable electricity output. Additionally, natural gas ramps up easily, allowing for load following plant configurations that assist in balancing load requirements across the day. 156 PJ of gas to power potential could be fulfilled by 2030 across three categories:

1. The conversion of the existing 5.2 GW diesel peaking capacity to into a combination of peaking and mid-merit natural gas would demand 97.2 PJ
2. The conversion of 5.4 GW of ageing coal-fired baseload to mid-merit natural gas would demand 44.1 PJ
3. Planned peaking gas capacity of 1,82 GW will demand 14.4 PJ

The economics of converting coal-fired plants to natural gas plants will be impacted by the age of the existing infrastructure and the efficiencies that can be realised.

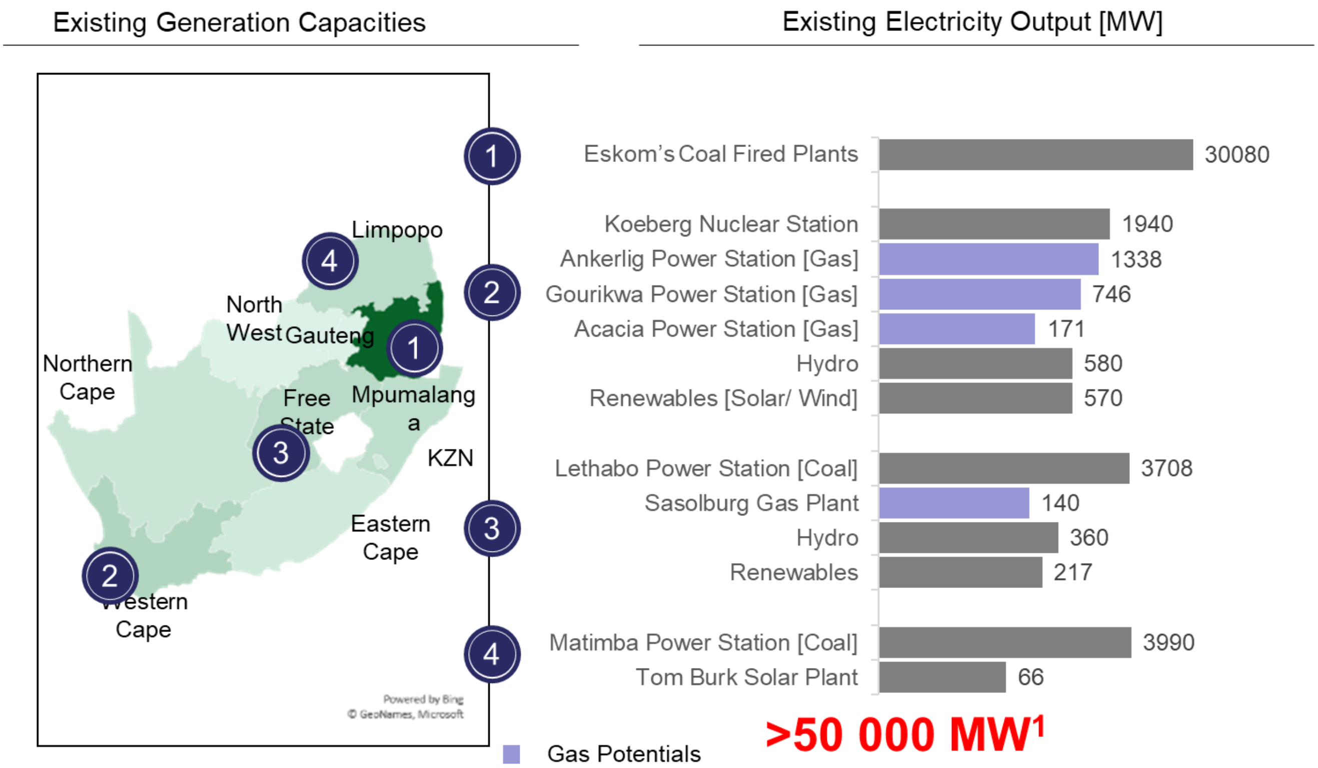


Figure 7-23: South Africa Electricity Capacity

Approximately 25 PJ of industrial heating potential across several energy-intensive manufacturing industries exists. Natural gas would be positioned as an alternative to coal and other sources of heat.

[145] Integrated Resource Plan 2019, South Africa

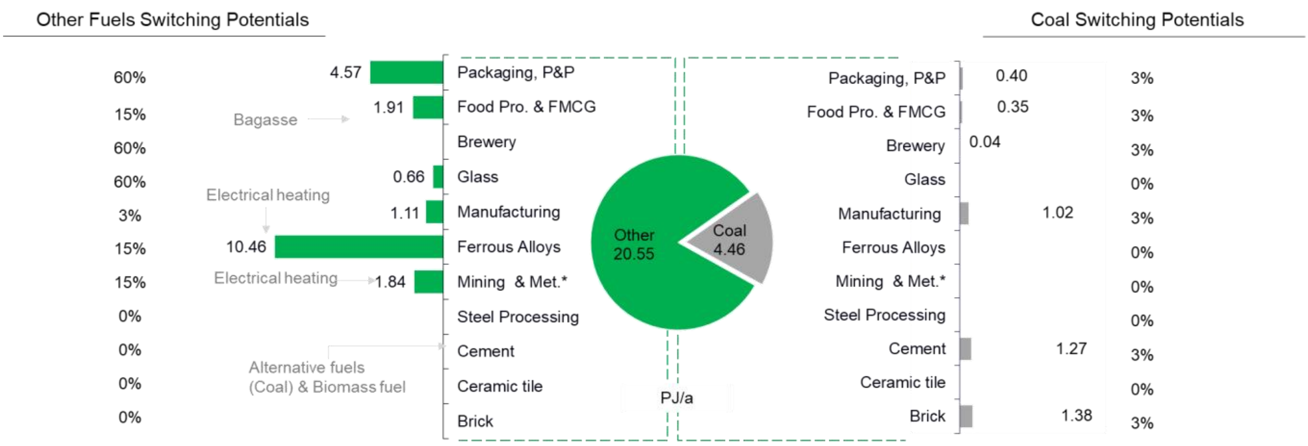


Figure 7-24: South African Industry Switching Potential

South Africa is currently the only petrochemical demand node in the region; this demand is expected to grow as Sasol, the industry leader, is facing increasing pressure to reduce its carbon emissions. The company is targeting reducing CO_2 emissions by 6 million tons by 2030, and the utilisation of natural gas as a replacement for coal, is expected to play an essential role in reaching this goal.

7.3.8 Tanzania

The Minister of Energy is responsible for formulating energy policy and planning and has primary responsibility for the development of the petroleum sector. The Ministry grants licenses for upstream exploration and development. The Tanzania Petroleum Development Corporation is the NOC of Tanzania through which the Ministry of Energy implements Tanzania's commercial aspects of petroleum upstream, midstream, and downstream operation. The Oil and Gas Advisory Bureau advises Cabinet on strategic matters relating to the oil and gas economy, and Petroleum Upstream Regulatory Authority advises cabinet on the granting, renewal, and revocation of license within the Tanzanian petroleum industry. Electricity generation, transmission and distribution are controlled by the vertically integrated, state-owned Tanzania Electric Supply Company Limited. The figure below indicates the key market and regulatory players across the Natural Gas Value Chain.

EWURA is responsible for performing regulatory functions in respect to midstream and downstream oil and gas activities, and PURA is responsible to regulate the upstream petroleum operations as well as advising the Minister on the granting, renewal, suspension, and revocation of license.

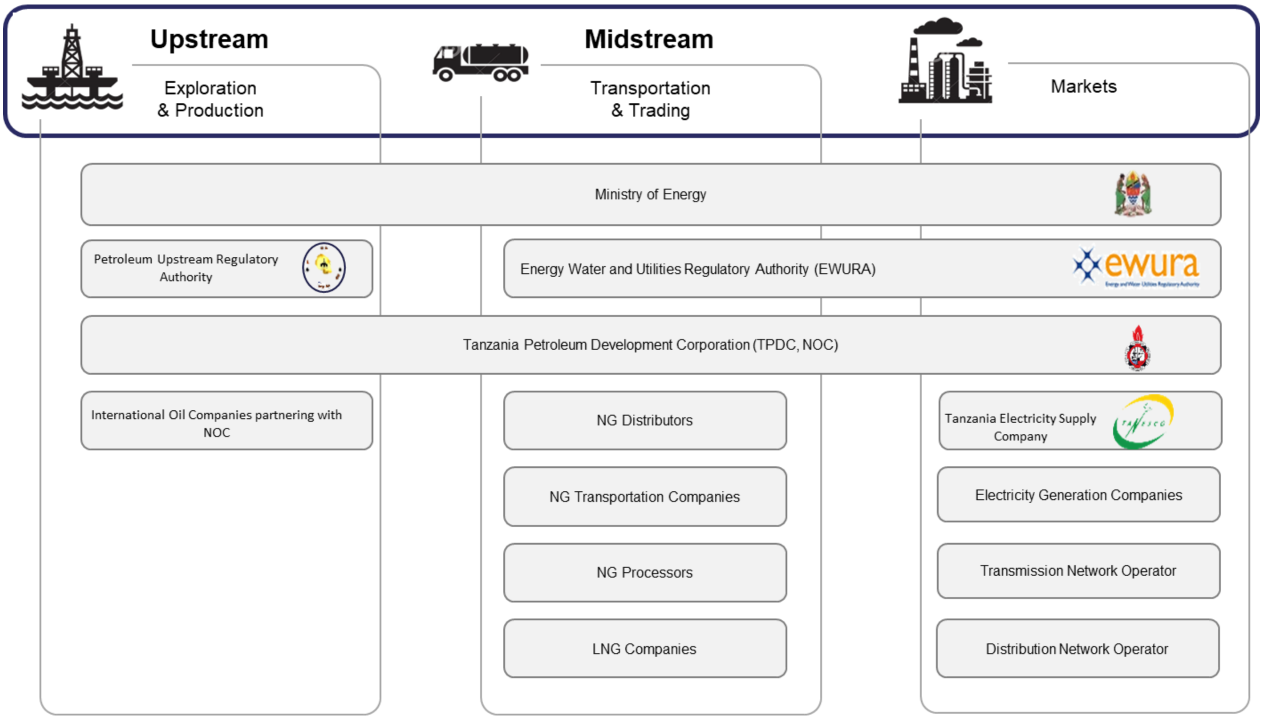


Figure 7-25: Tanzania Energy Market and Governance Structure

Tanzania is a net energy importer with imports consisting of oil products and electricity. As shown in the figure below, bioenergy makes up 82% of the energy produced, where the majority is consumed within the residential sector for cooking and heating requirements, while imported oil-products fuel transportation requirements. Tanzania has proven natural gas reserves with significant uptake potential in terms of LNG trade and gas to power production, which would improve access to electricity through utility-scale and embedded generation capacity.

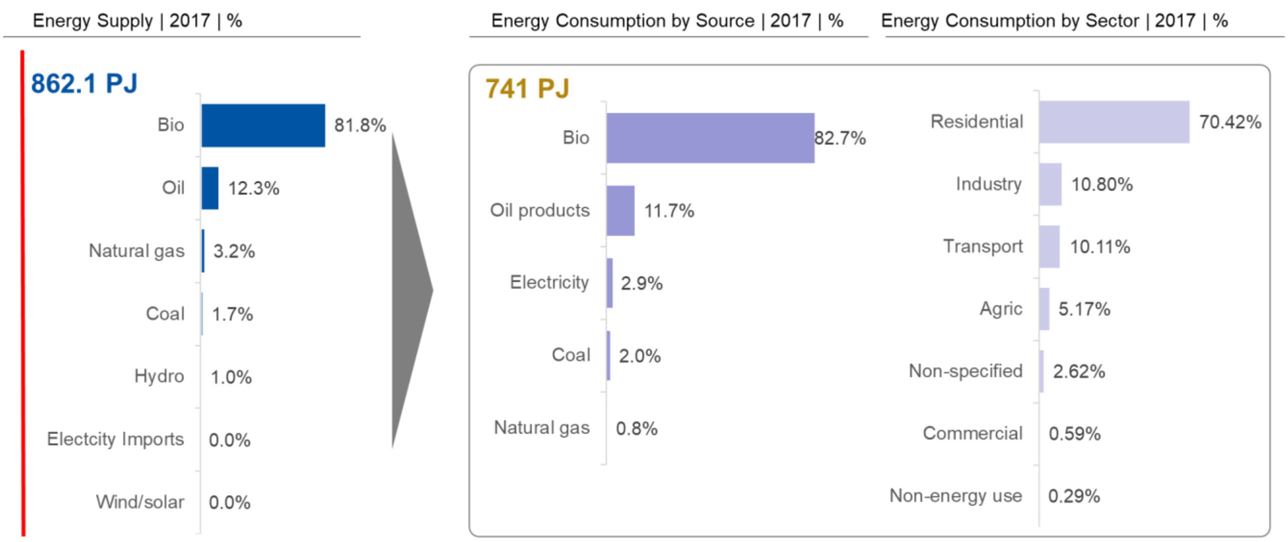


Figure 7-26: Tanzania Energy Profile

Hydropower (36,64%), natural gas (57,02%), oil products (5,67%) and biomass (0,67%) drive electricity generation within Tanzania[146]. By 2030, the existing 24.6 PJ of natural gas demand for electricity generation could potentially grow to 118 PJ. 7.6 PJ would be derived from switching diesel

[146] IEA, Energy Balances

and HFO plants over to natural gas, while the remaining 84.6 PJ would be derived from new gas to power potential, which would generate 3.2 GW of additional power.

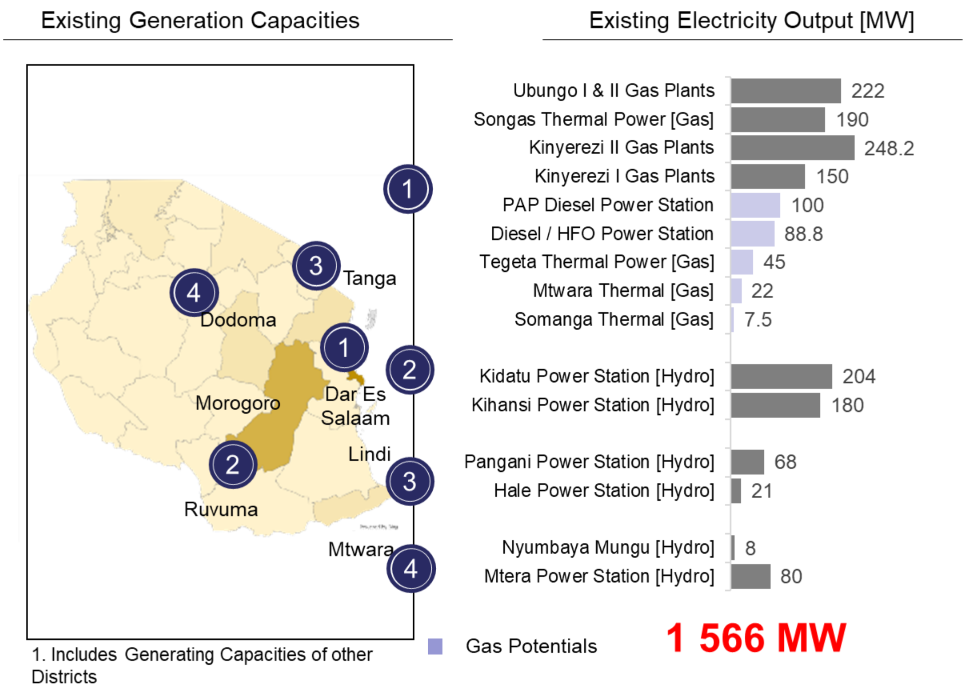


Figure 7-27: Tanzania Electricity Capacity

Short term industrial potential of 14 PJ could be realised by 2030 through fuel switching for industrial heating applications. Fertiliser production could significantly raise the potential for natural gas demand by approximately 200 PJ. This potential is still uncertain as it unlikely that more than one ammonia facility would be developed in the region in order to ensure the maximisation of scale and competitiveness to supply regional markets. In this regard, it would be sensible to aggregate fertiliser demand across the region and develop supply infrastructure that is in close proximity to the source of natural gas for fertiliser production.

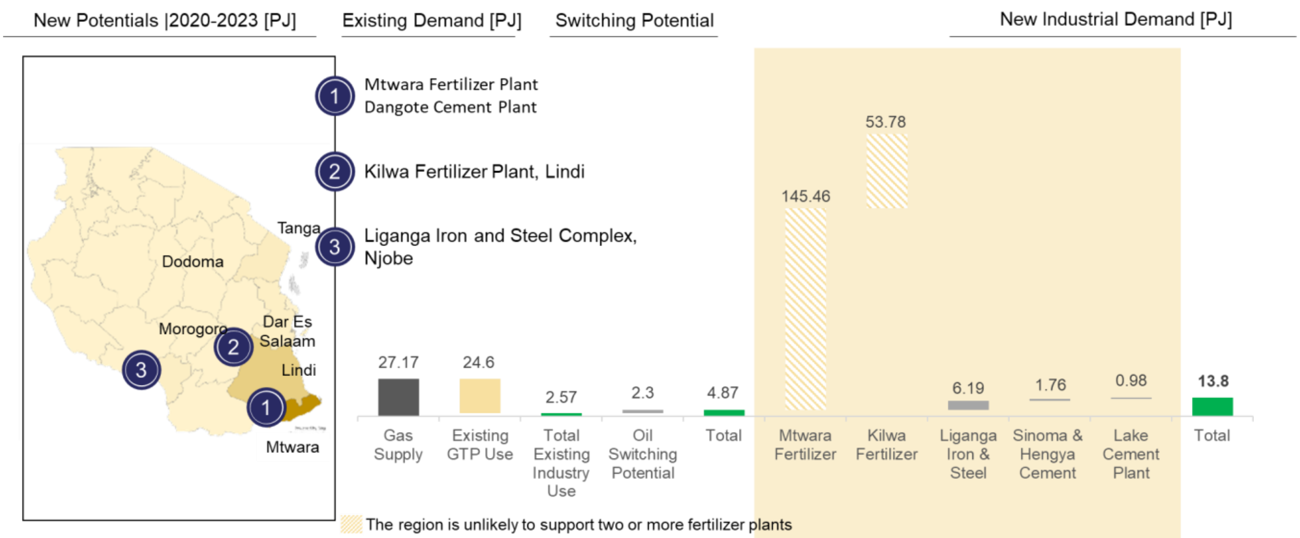


Figure 7-28: Tanzania Industrial Potential

The development of the petrochemical industry in the country, through ammonia-urea, methanol and GTL project initiatives are being considered and is expected to provide strong anchor natural gas demand as well as stimulate economic growth in the country.

7.3.9 Zambia

The Ministry of Energy implements the government policy framework and guidance while the Energy Regulation Board (ERB) is the independent energy regulatory authority within the country. The Zambia Electricity Supply Corporation (ZESCO) has a monopoly within the electricity sector in terms of generating, transmitting, and distributing electricity in Zambia. The private sector also contributes to electricity generation as independent power producers and electricity sell to ZESCO. The Indeni Petroleum Refinery is the only oil refinery in Zambia and there are plans to partner with IOCs to increase the output of petroleum products in the country. Fertiliser production within the country is led by Zambian Fertilisers Ltd and Forestical Fertilisers Zambia Limited. The figure below indicates the key market and regulatory players across the Natural Gas Value Chain.

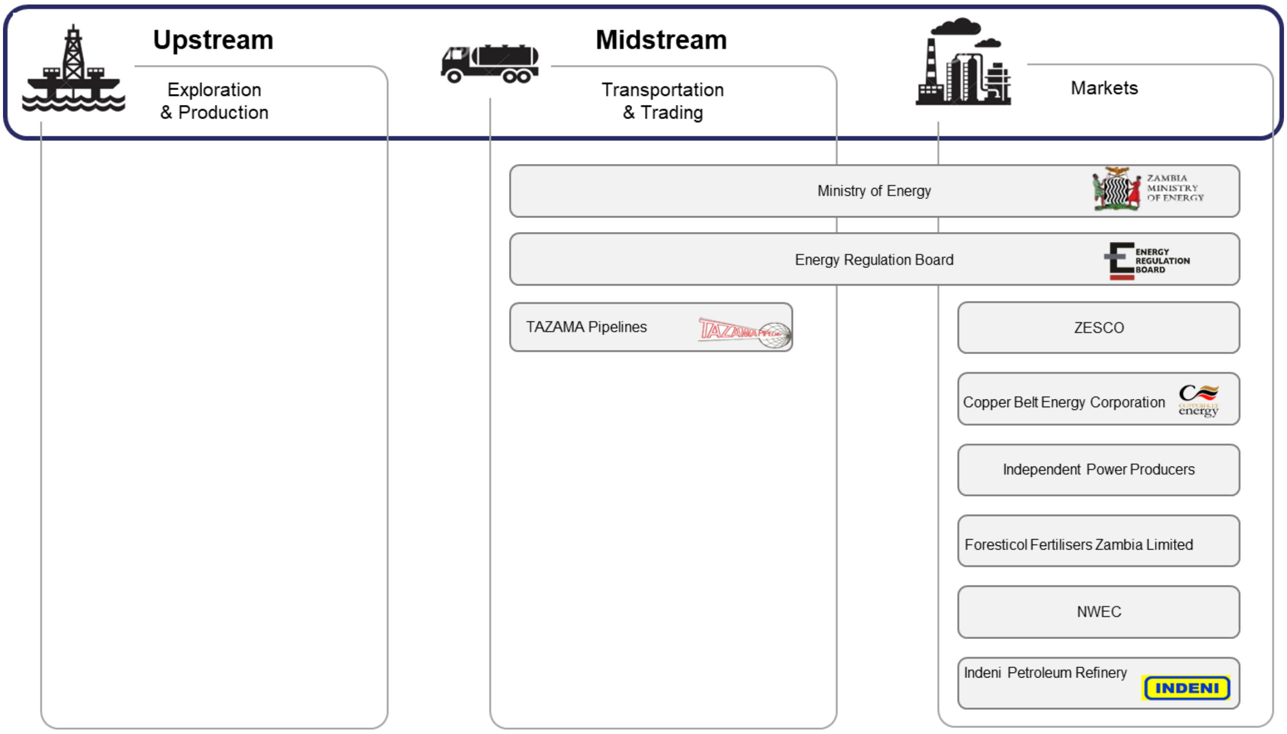


Figure 7-29: Zambia Energy Market and Governance Structure

Zambia is a net energy importer with imports consisting of oil (and oil products) as well as electricity. As shown in the figure below, bioenergy makes up 75% of the energy produced where the majority is consumed within the residential sector for cooking and heating requirements while imported oil products fuel transportation requirements.

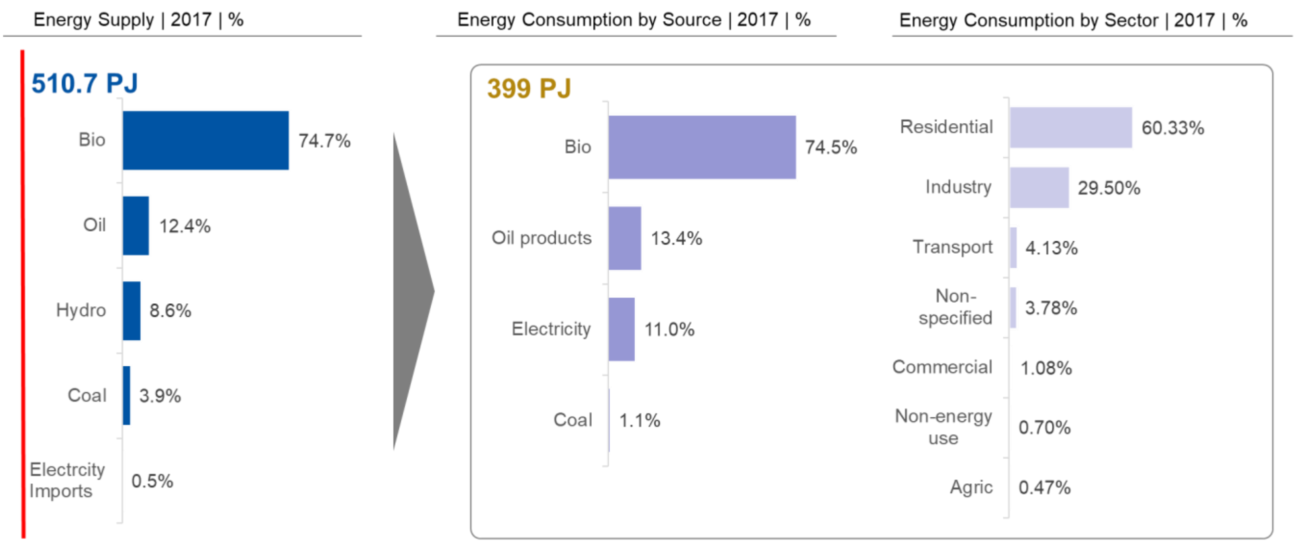


Figure 7-30: Zambia Energy Profile

As shown below, Zambia has 3368 MW of generation capacity with major primary fuel sources consisting of hydropower (68%) and coal (24%). Zambia currently has negligible gas consumption, and anchor demand would be required to grow natural gas consumption within the country. By 2030, natural gas to power generation potential of 13.3 PJ could be unlocked through the switching of HFO and diesel mid-merit plants to natural gas alongside the switching of coal baseload to mid-merit gas.

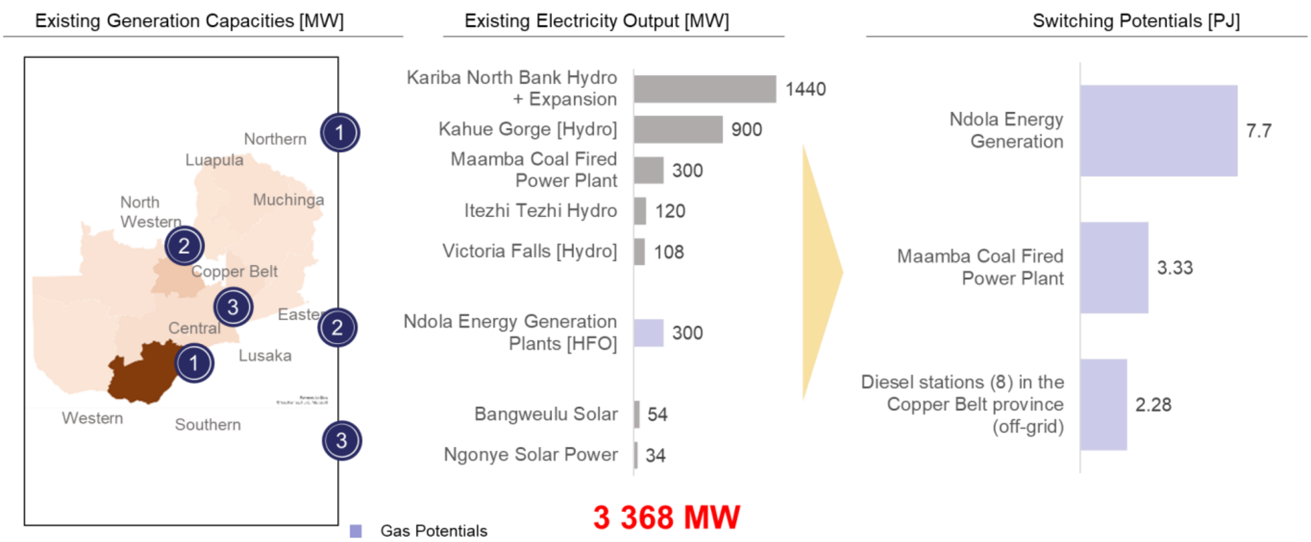


Figure 7-31: Zambia Energy Capacity

7.3.10 Zimbabwe

The Ministry of Energy and Power Development and the Zimbabwe Energy Regulatory Authority have institutional authority over Zimbabwe's energy sector. ZESA Holdings is the state-owned power utility company which generates, imports, and distributes all electricity in the country through its subsidiaries, which are the Zimbabwe Power Company and the Zimbabwe Electricity Transmission and Distribution Company (ZETDC). There are several key players in the local LPG market, including Zuma, Pioneer, BOC gas and Kensys. The National Oil Infrastructure Company of Zimbabwe is a government-owned company that distributes fuel products using the pipeline from Beira in

Mozambique to a depot in Harare. The figure below indicates the key market and regulatory players across the Natural Gas Value Chain.

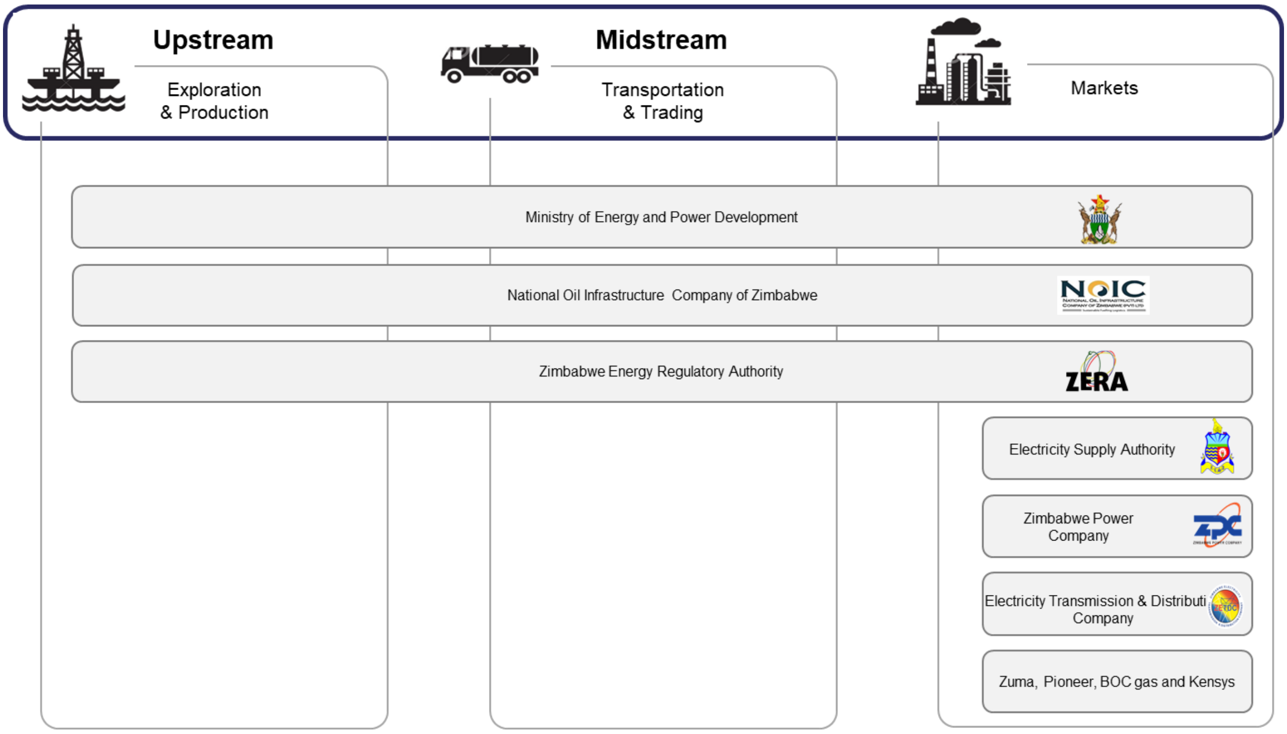


Figure 7-32: Zimbabwe Energy Market and Governance Structure

Zimbabwe is a net energy importer with imports consisting of oil products, coal as well as electricity. As shown in the figure below, bioenergy makes up 68% of the energy produced, where the majority is consumed within the residential sector for cooking and heating requirements, while imported oil products fuel transportation requirements.

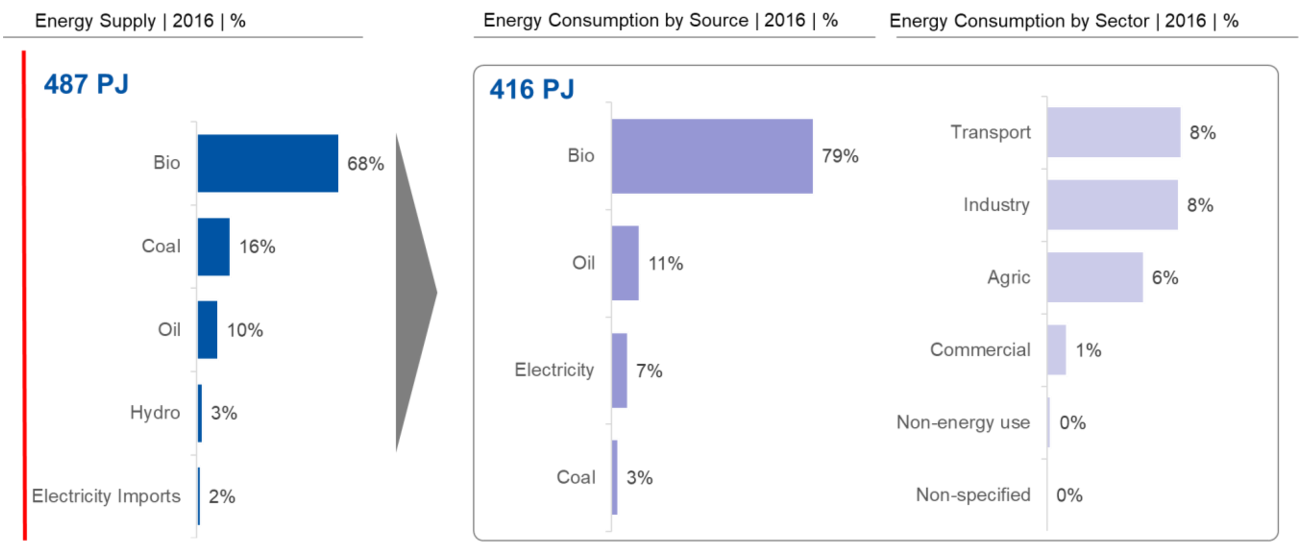


Figure 7-33: Zimbabwe Energy Profile

As shown below, Zambia has 1920 MW of generation capacity with major primary fuel source consisting of hydropower (20%) and coal (76%). Zimbabwe currently has negligible gas consumption, and anchor demand would be required to grow natural gas consumption within the country. By 2030, natural gas to power generation potential of 11.1 PJ could be realised through the switching of diesel mid-merit plants to natural gas as well as an investment in new gas to power capacity in the Matabeleland North Province of Zimbabwe.

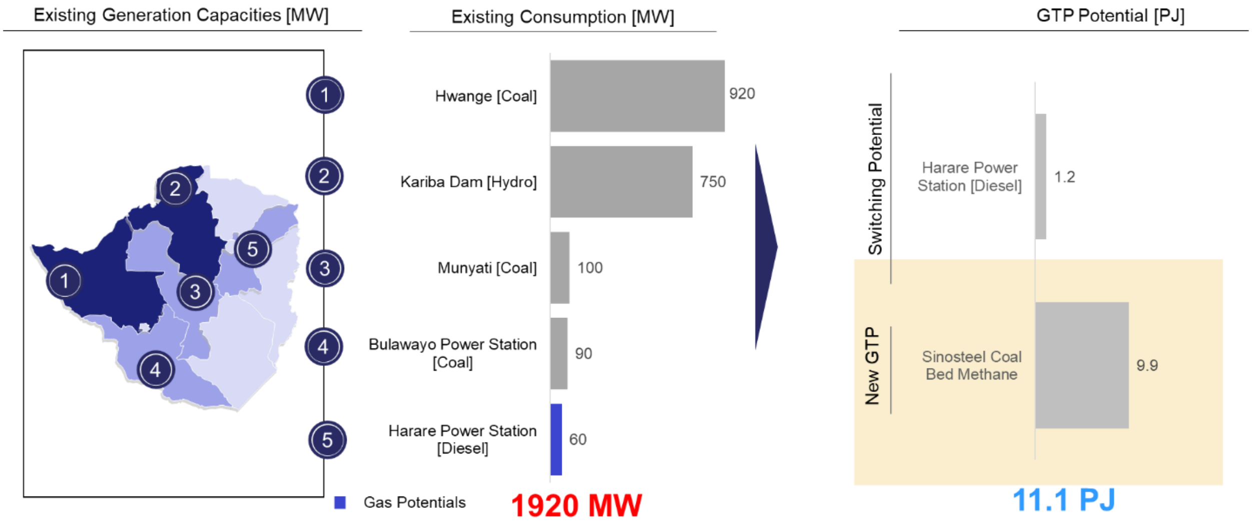


Figure 7-34: Zimbabwe Electricity Capacity

7.3.11 Ethiopia

The role of the Ministry of Mines and Petroleum is to promote the mineral, petroleum, and natural gas potentials of the country. The Ethiopian Energy Authority (EEA) is the energy regulator which issues licences and approves off-grid tariffs (the Ministry of Mines and Petroleum approves on-grid tariffs). The Ethiopian Electric Power Corporation was unbundled into two entities in 2013/14, namely: Ethiopian Electric Power (which is responsible for generation and transmission) and the Ethiopian Electric Utility (which is responsible for distribution of bulk power supply). The Ministry of Agriculture oversees the agricultural and rural development of the country and enacts policies to ensure food security, which includes the use of fertiliser. The figure below indicates the key market and regulatory players across the Natural Gas Value Chain.

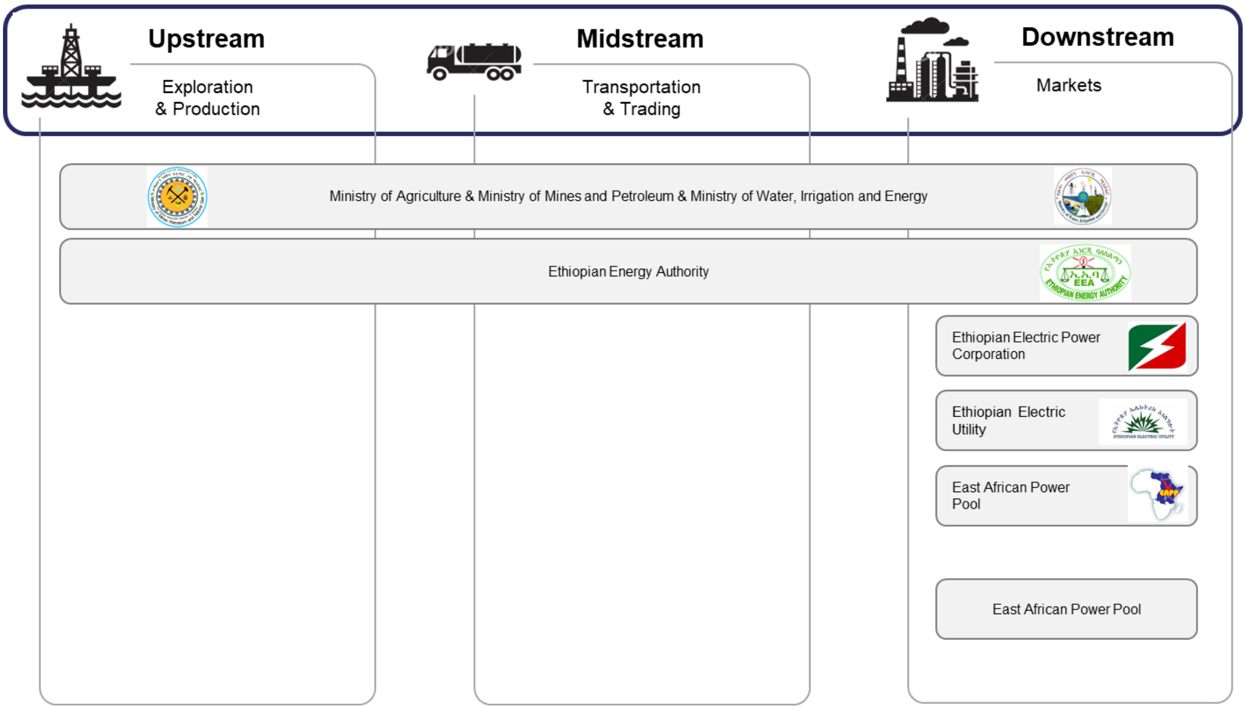


Figure 7-35: Ethiopia Energy Market and Governance Structure

Ethiopia is a net energy importer with imports consisting of oil products and coal. As shown in the figure below, bioenergy makes up 86.5% of the energy produced, where the majority is consumed within the residential sector for cooking and heating requirements, while imported oil products fuel transportation requirements.

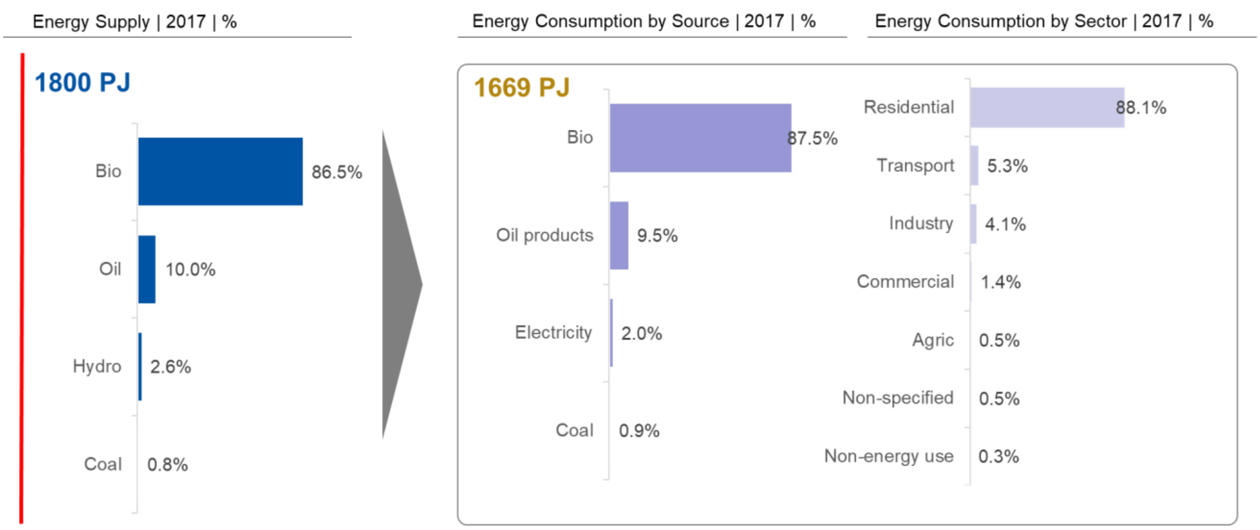


Figure 7-36: Ethiopia Energy Profile

As shown below, Ethiopia has 4344 MW of generation capacity with major primary fuel source consisting of hydropower (93%) and wind (7%). Ethiopia currently has negligible gas consumption, and anchor demand would be required to grow natural gas demand. By 2030, natural gas to power generation potential of 14.5 PJ could be realised through the switching of diesel mid-merit plants to natural gas as well as an investment in new gas to power capacity in Adi Gudem.

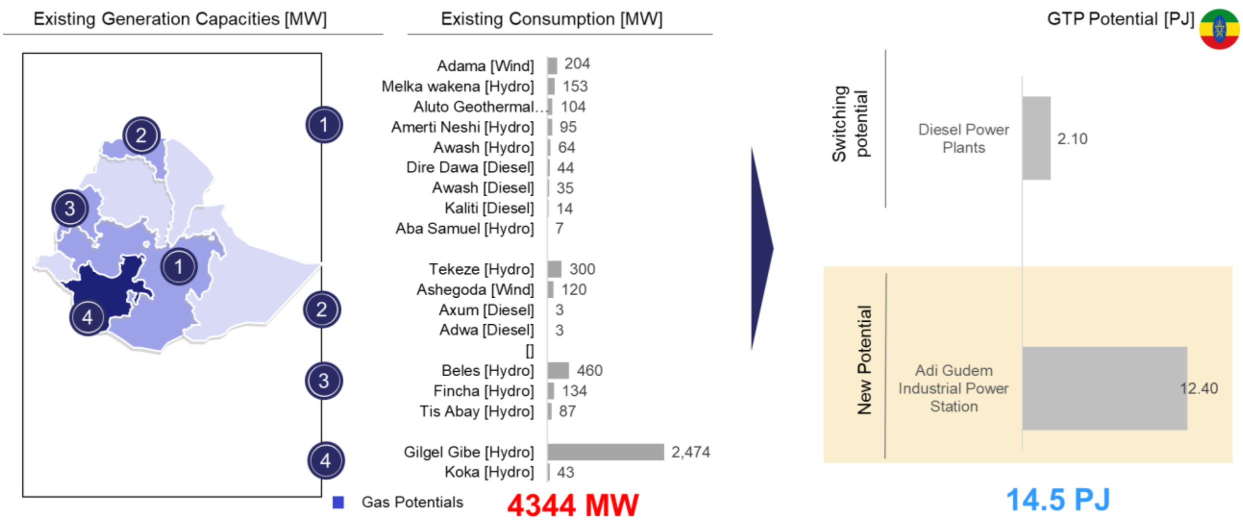


Figure 7-37: Ethiopia Electricity Capacity

7.3.12 Kenya

The Ministry of Energy and Petroleum (MoEP) manages the sector and generates policies that are designed to create an enabling environment for the energy sector. The Energy and Petroleum Regulatory Authority (EPRA) regulates upstream petroleum and coal production industries. Kenya Pipeline Company (KPC) has the responsibility of transporting, storing, and delivering petroleum products to the consumers of Kenya through its pipeline system and oil depot network. The National Oil Corporation of Kenya (NOCK) participates in the petroleum industry, and Kenya Petroleum Refineries Limited supplies a wide variety of oil products. Several organisations are involved in distinct areas of Kenya's electricity value chain (i.e. KenGen, Kenya Power and the Kenya Electricity Transmission Company). The figure below indicates the key market and regulatory players across the Natural Gas Value Chain.

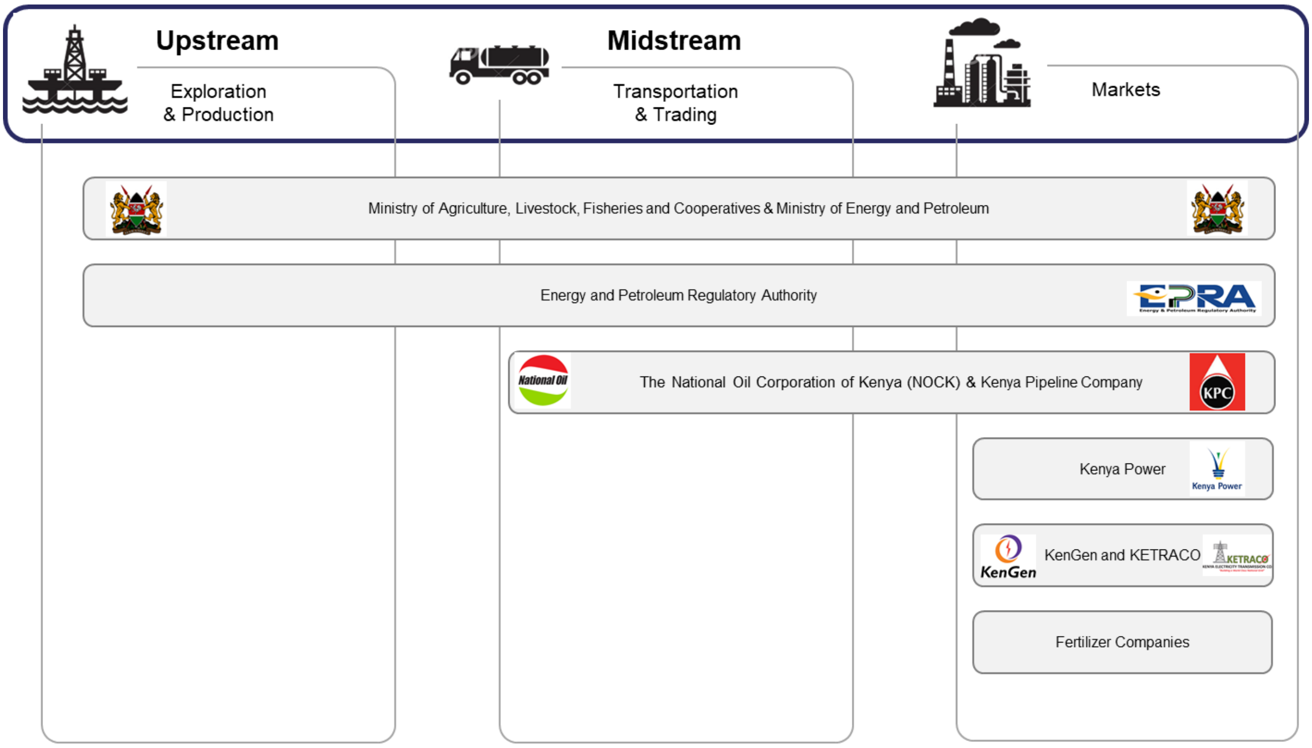


Figure 7-38: Kenya Energy Market and Governance Structure

Kenya is a net energy importer with imports consisting of oil (and oil products), electricity and coal. As shown in the figure below, bioenergy makes up 62% of the energy produced where the majority is consumed within the residential sector for cooking and heating requirements while imported oil products fuel transportation requirements.

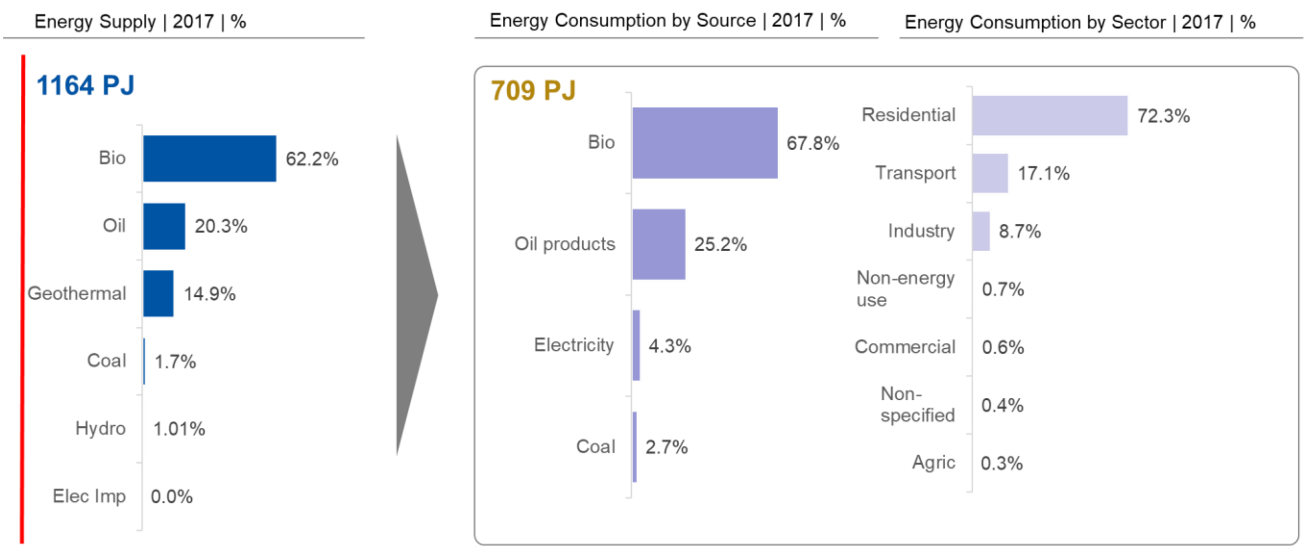


Figure 7-39: Kenya Energy Profile

As shown below, Kenya has 2750 MW of generation capacity with major primary fuel sources consisting of geothermal (82%), hydropower (6%) and oil (12%). Kenya currently has negligible gas consumption, and anchor demand would be required to grow natural gas demand. By 2030, natural gas to power generation potential of 40.6 PJ could be realised through the switching of kerosene and HFO fuelled mid-merit plants to natural gas as well as an investment in new gas to power capacity in Mombasa.

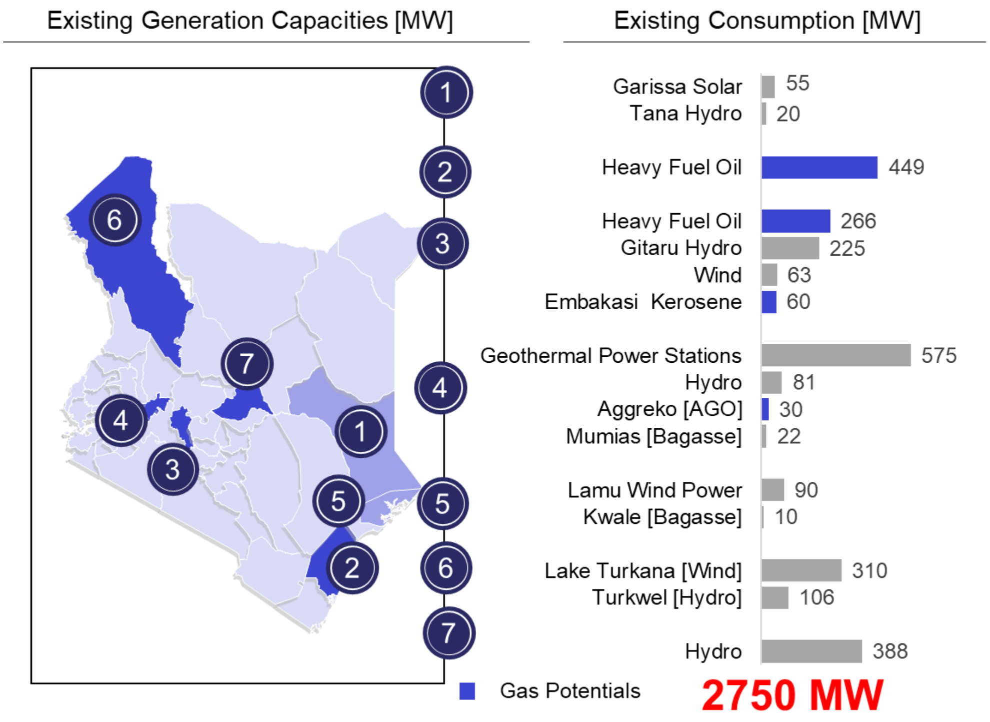


Figure 7-40: Kenya Electricity Capacity

8. LONG TERM GAS DEMAND FORECASTING

8.1 Methodology & Scenarios

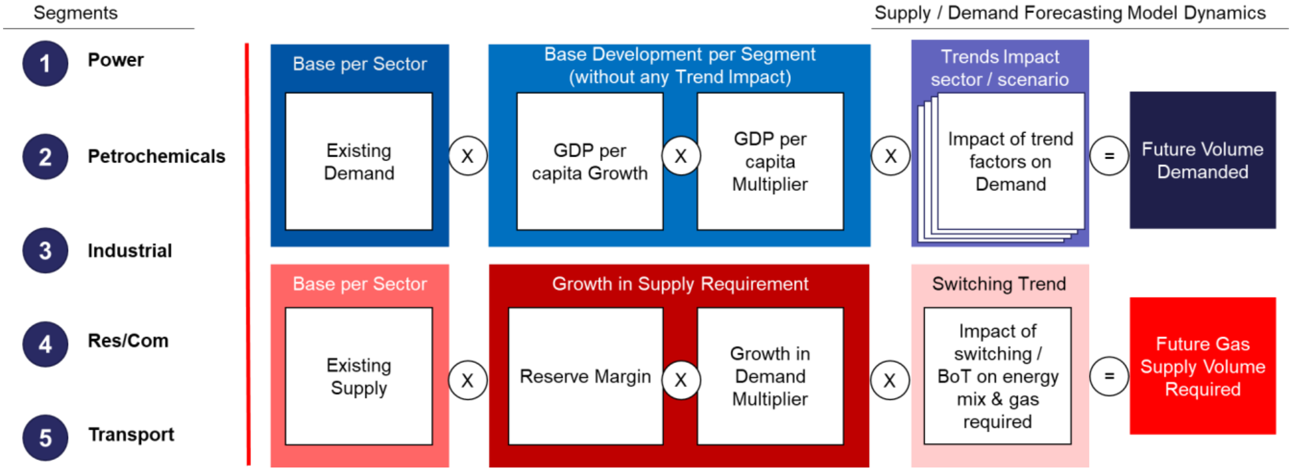
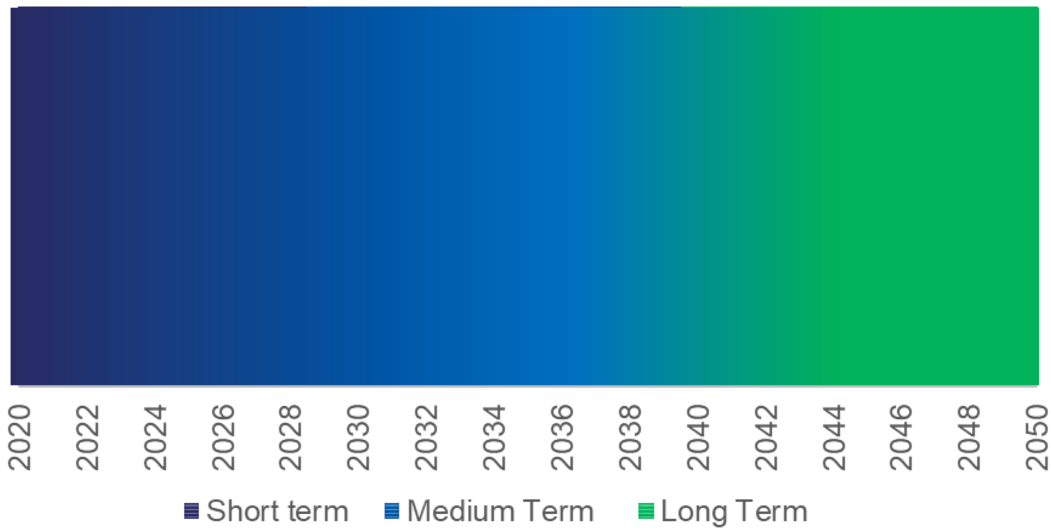


Figure 8-1: Supply Demand Forecasting Model Dynamics

The long-term forecast for natural gas demand within the SADC region is dependent upon two dimensions of analysis across five downstream sectors (i.e. Power Generation, Petrochemicals, Industrial heating, Transportation and Residential & Commercial). As indicated in the figure above, the demand for the outputs of a sector is a function of existing demand as well as two multiplier components to forecast variations in demand, namely:

- Base development which attributes demand growth to fundamental economic factors such as economic activity in the form of GDP per capita.
- Trend impact which estimates the effects of specific industry/sector trends on the potential future demand.



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- Figure 8-2 Breakdown of timeframes relative to forecast period

However, over the long term, sufficient reserve capacity is required within a market system to ensure that short term fluctuations do not hinder market growth and continuity through supply bottlenecks. This is apparent within the electricity market where supply bottlenecks can lead to undesired supply interruptions in the form of "load shedding" or blackouts as electricity grids come under increased strain. Thus, the methodology also considers supply dynamics within the SADC region to determine the adequate supply of natural gas that would be required to sustain overall product supply within each sector. The methodology considers existing supply within each of the downstream sectors as well as two multipliers, namely:

- The growth in the supply requirement, which reflects the required reserve margin for uninterrupted supply as demand for energy and/or products grow within each sector.
- Fuel switching trends which consider the impact of positioning natural gas as the preferred fuel or feedstock in the downstream sectors. This is driven by various factors, including the drive towards lower carbon emissions, the need for flexible electric supply as renewable uptake increases and the balance of trade in terms of chemical products within the region.

For the purposes of this study, the downstream sectors were consolidated in two categories based upon how gas is utilised in each of the sectors, i.e. **thermal energy,** and **chemical transformation**.

Thermal energy consists of sectors that derive benefit from the combustion of natural gas which includes:

- Power generation through various forms of gas cycle turbines,
- Industrial heating in terms of material drying and steam generation,
- Transportation fuel in heavy road vehicles (e.g. buses and trucks) as well as in the maritime industry and, and
- Residential and Commercial requirements in terms of space heating and cooking.

Considering the demand for thermal energy across the region, thermal energy demand was analysed within each of SADC Member States in terms of their particular context.

Chemical transformation occurs in downstream sectors which utilise natural gas as a feedstock to produce higher-value products. These include:

- The production of ammonia to manufacture nitrogen-based fertiliser (i.e. urea),
- The production of methanol as feedstock to for the development of more complex chemical products such as formaldehyde, acetic acid, and olefins, and
- The production of liquid hydrocarbons (e.g. Diesel, Naphtha, Kerosene and Paraffins) through GTL facilities.

Scenarios are employed in this study to determine the impact of the variation in the identified base and trend multipliers on the long-term forecast for natural gas demand. High, base and low cases were identified and applied in the analysis for the base GDP multipliers (see section 0) and the trend multipliers (see section 8.3). The figure below summarises the GDP and Trend Scenarios utilised in the long-term forecast.

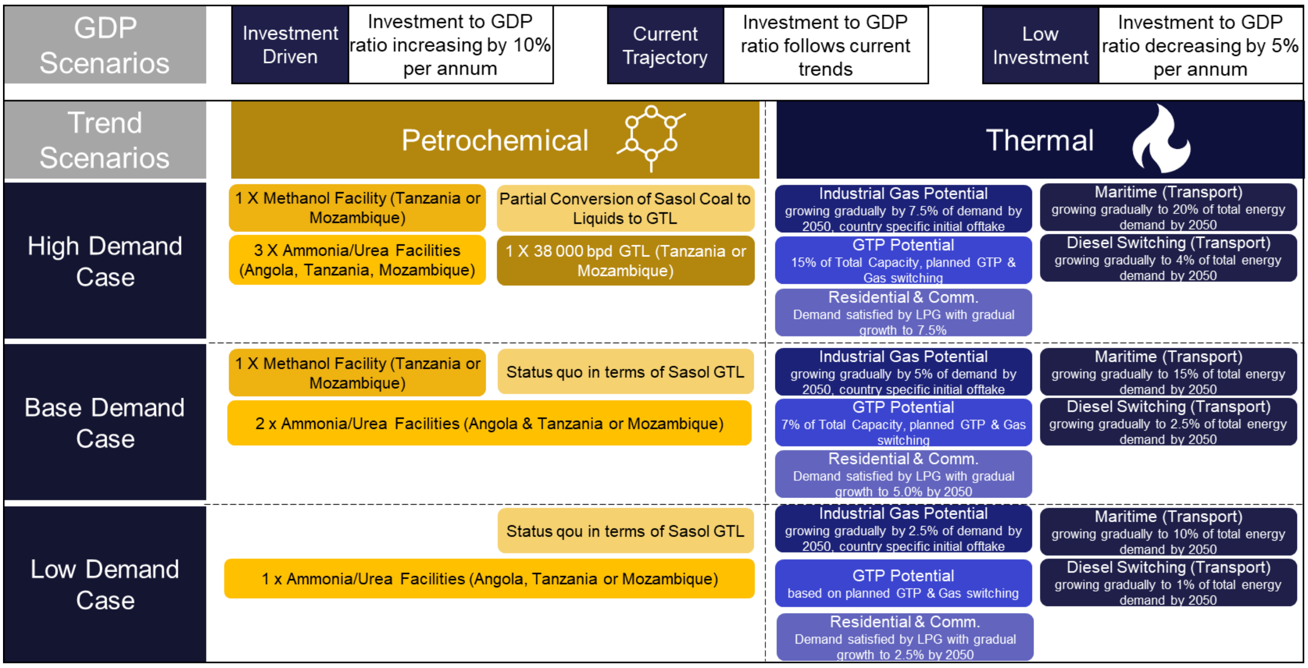


Figure 8-3: GDP and Trend Scenarios variables and assumptions

Results from the analysis are compared with the Indonesian gas market, which has comparable characteristics to the potential SADC regional gas market, as shown in the figure below.

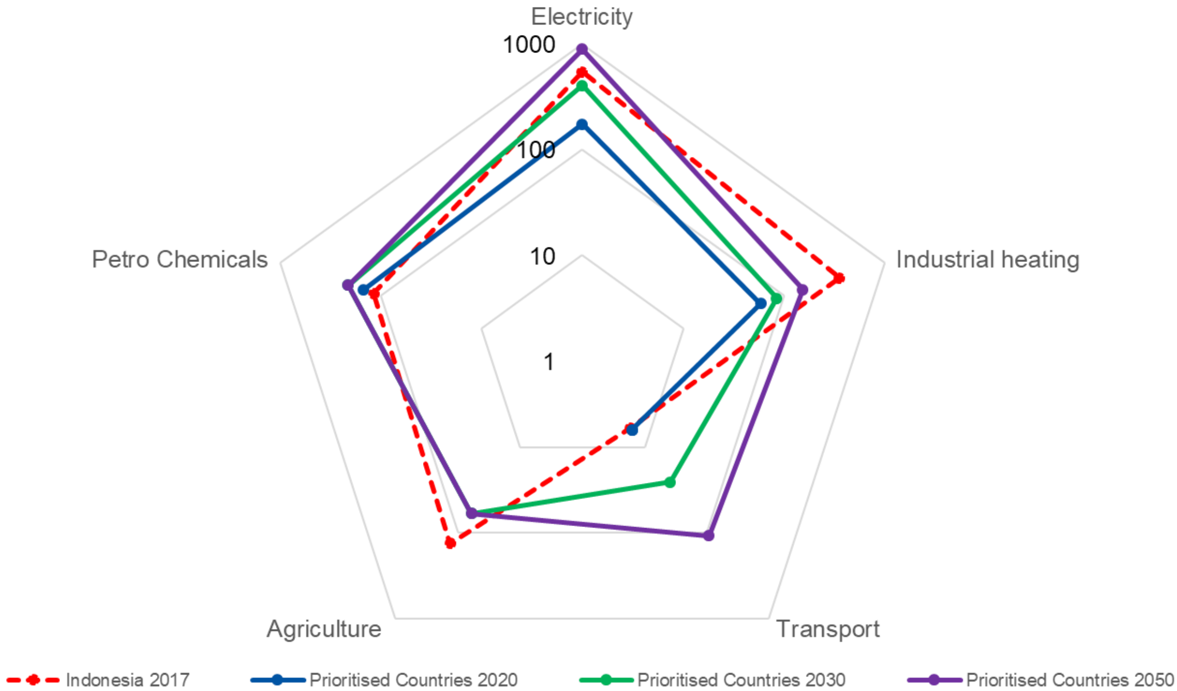


Figure 8-4: 2020, 2030 and 2050 aggregated gas demand in PJ[147]

The Indonesian gas market has transformed from a highly concentrated exporting market to one also focused on supplying local demand, which grows with economic development and availability of gas supply. Indonesia's 2017 GDP of $1,09 trillion is comparable to the combined 2020 GDP of the priority countries which is at $888 billion. Furthermore, Indonesia struggles with similar infrastructure challenges regarding gas distribution, in particular, the major gas reserves are located at considerable distances away from key demand centres. Indonesia also views natural gas as a bridging fuel towards a low carbon energy mix supply, as many countries within the region are trying to achieve.[1]

In order to reach the gas demand levels that would allow the gas market to flourish, the region would require a robust gas market that would only be achievable through integration and aggregation, both on a country and sector level. Indonesia has a well-developed gas industry and their gas demand profile provides a market benchmark which is comparable to the forecasted demand the region is expected to realise.

A multi-sectorial gas market would be essential for the region to achieve this gas demand over the next 30 years, with a gradual build-up of industrial heating and transport demand to supplement the more immediate gas to power, petrochemicals and agricultural demand.

8.2 Macroeconomic Forecasts

Macroeconomic theory suggests that increasing savings/investment ratios are good indicators of positive long-term economic growth potential[148]. The aggregate investment ratio of Sub-Saharan Africa was 17.5% of GDP in 2018 compared to a world average of 25.4%[149]. Low domestic investment rates limit economic growth which necessitates foreign investment to close the funding gap.

Due to the long-term horizon of the demand assessment, the demand for natural gas across the downstream sectors was estimated as a function of economic activity (i.e. GDP). GDP was projected forward through long term real GDP growth forecasts, which were modelled for each of the twelve countries that were prioritised for detailed demand assessment. The model estimated long term GDP growth as a function of the ratio of investment to GDP for a given country. The figure below shows forecasted GDP growth for each of the countries in a scenario where the investment to GDP ratio remains at current levels.

Two additional cases were modelled, an "Investment driven" growth scenario where high GDP growth was forecasted by increasing the investment to GDP ratio by 10% and a "Low Investment" scenario where low GDP growth was forecasted by decreasing the investment to GDP ratio by 5%.

[147] Indonesia figures sourced from the IEA
[148] The Relationship between Savings and Growth in South Africa: An Empirical Study, AT Room, University of the Witwatersrand, 2013
[149] World Bank Economic Data, 2018

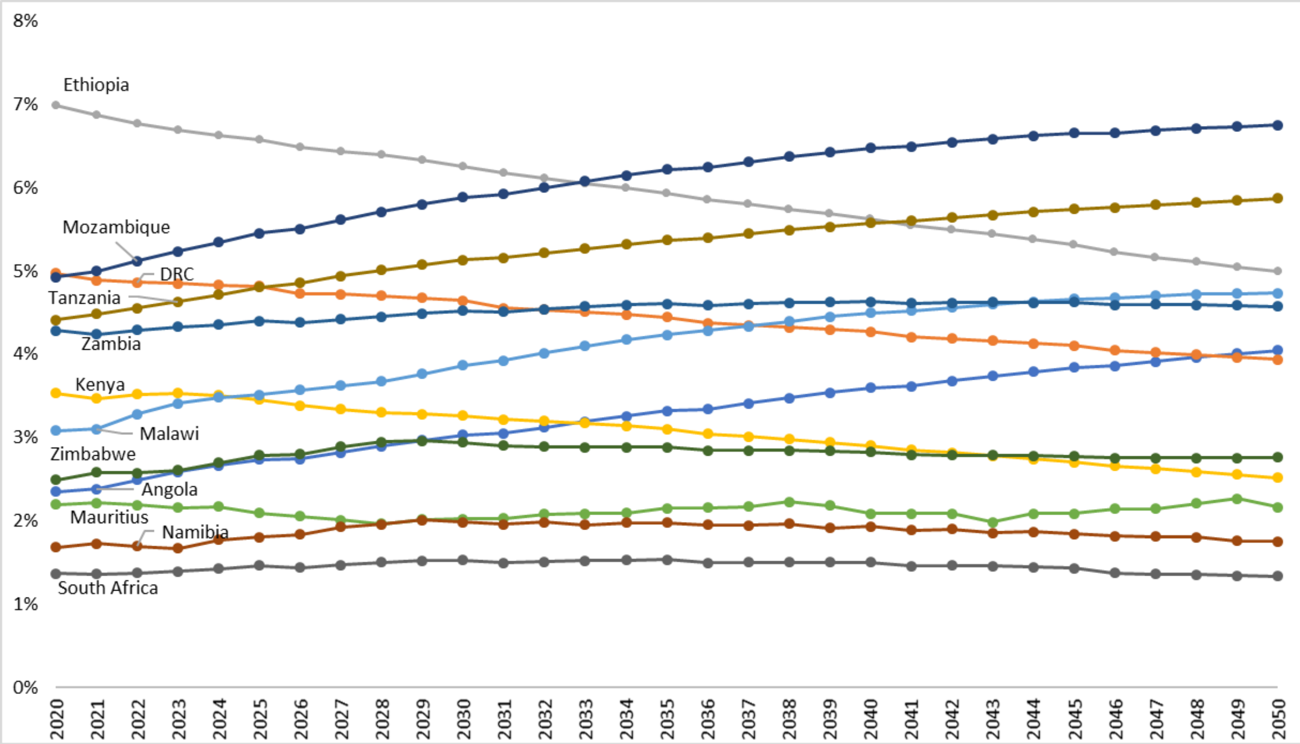


Figure 8-5: Current Trajectory Real GDP Growth Forecasts 2020-2050

The World Bank Long Term Growth Model was used to forecast the economic growth of the prioritised countries. The World Bank Long Term Growth Model, which builds on the Solow-Swan Growth Model and includes data source links, was used to analyse long-term economic growth for the prioritised countries. The model accounts for the building blocks of growth, which are savings, investment, and productivity. The model further analyses human capital, demographics, the external sector (external debt, Foreign Direct Investment (FDI), Current Account Balance (CAB)) and labour-force participation by gender).

The basis of the projection used is founded on growth given investment. The economic growth rate of African countries has grown in recent years with real output increasing from 1.8% in the period 1980-1989, to 2.6% in 1990-2000 and 5.3% in the 2000-2010 period. [150] Recent studies have shown a correlation between the African continent's economic growth and the increase in the productivity of capital. The productivity of capital is significant since it is an essential source of development as well as a substantial determinant of the competitiveness of a country. [123]

The economic growth has gone hand-in-hand with a decrease in the incremental capital-output ratio (ICOR), which measures the degree of inefficiency in the use of capital. The ICOR value in the 1990-1999 period for the continent was 7.4 and reduced to 4.1 the following decade (2000-2011), correlating to Africa's GDP growth. [123]

Real GDP has been used as an economic indicator, which evaluates the economy at constant prices over time. Due to the analysis being done over multiple countries with diverse economic outlooks and being forecasted over a long period, real GDP in constant dollars ensures prices are kept constant across the different countries, with a reference year used to account for time-influenced dynamics.

[150] UNCTAD: Rising Productivity of Capital: The Untold Story of Africa's Recent Growth

The growth rate of capital per worker is a function of the investment share of GDP, together with the capital to output ratio. Initial values for the labour share, capital depreciation rate, and initial capital to output are required and used as the basis to project future trends.

The Penn World Table (PWT) was used to resource information on the assets of each country, including the structures (residential and non-residential), machinery (computers, communication equipment, and other machinery), transport equipment and other assets (including software, other intellectual property products, and cultivated assets). The depreciation rates from PWT9 and the rates used are as follows:[151]

- residential structures 1.1%,
- non-residential structures 3.1%,
- computers 31.5%,
- communication equipment 11.5%,
- other machinery 12.6%,
- transport equipment 18.9%,
- software 31.5%,
- other intellectual property products 15%, and
- cultivated assets 12.6%.

The initial human capital index and total factor productivity values were based on 20-year averages from PWT 9, and these were assumed to remain constant over the forecasted period. External balances were based on CAB using the World Bank's World Development index 20-year average as the initial value, which was kept constant up to 2050 and 15-year historical averages of the net foreign direct investment ratio to GDP were used to allocate for foreign investment factors.

A linear-population growth was used based on the World Bank's World Development Index data and includes gender breakdown as well as accounts for working-age population ratios. Furthermore, the model accounts for poverty effects on economic growth, which were sourced from the World Development Index, poverty line data.

The labour participation, as well as the gender breakdown of participation, was assumed to remain constant and was based on PWT8 (GTAP data accounted for any data gaps). [152]

The ratio of real investment over real GDP was used to create economic scenarios, with the base case using 20-year historical World Development index data and factoring the historical data to produce the low and high case economic scenarios for each country.

8.3 Long Term Demand Modelling

The gas demand for the various potential industry sectors is dependent on availability of supply, geographic location, demand scale and infrastructure requirements. These factors determine the supply mechanisms required to meet the demand.

[151] Penn World Table version 9.1

[152] American Economic Review 2015, The Next Generation of the Penn World Table

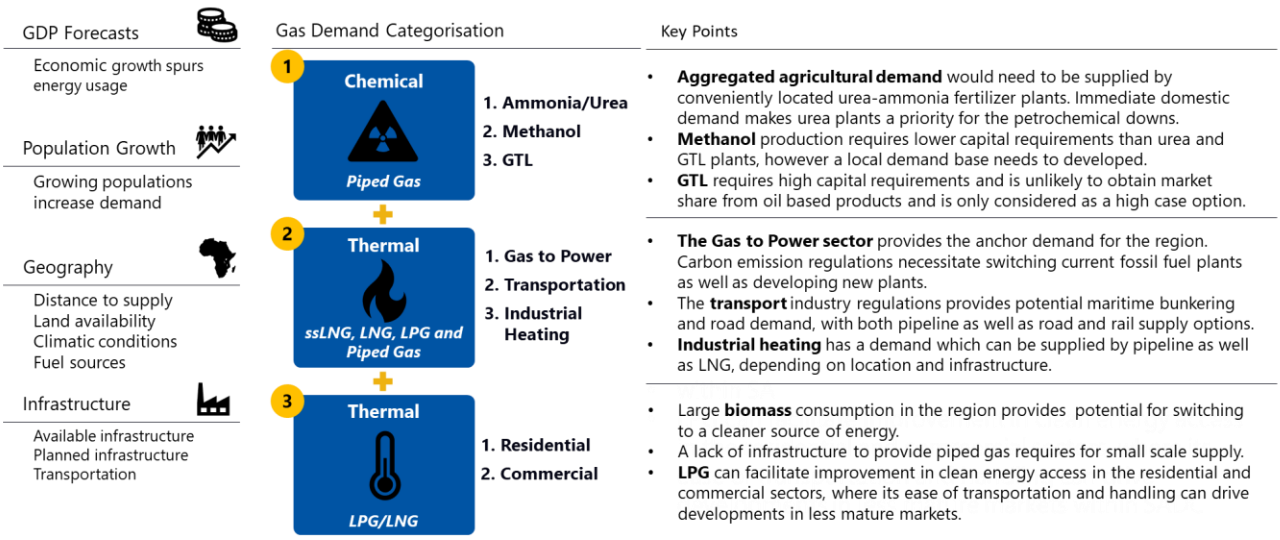


Figure 8-6: Gas demand Profiles

The modelling approach for each of the downstream sectors is indicated in the following and is based upon the methodology indicated in Section 9.1. Appendix E.3 provides greater detail on the modelling approach for each of the sectors. Methanol and GTL demand is excluded (apart from the conversion of Sasol's existing CTL to GTL) from this modelling approach as these two industries have particular nuances which are elaborated in Section 9.5.

8.3.1.1 Electricity Demand Modelling

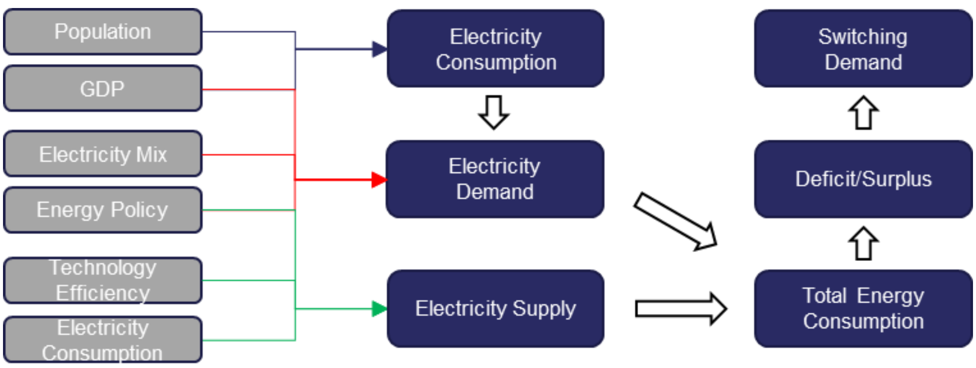


Figure 8-7: Electricity demand model mechanics

Electricity supply is sourced from multiple energy sources and is country dependent. Supply is based on demand projections, which is a factor of economic and population growth as well was electrification rates. The source of power generation is dependent on factors such as political and governing factors, bilateral trade, climatic conditions as well as current infrastructure and infrastructure lifecycles, which requires policy and implementation plan analysis on a country by country basis. The planned builds of power supply infrastructure were used as the basis of expected generation growth in the short to medium term, with the expectation that a more significant share of renewable energy sources would be part of the long-term electricity supply mix.

8.3.1.2 Transportation Demand Modelling

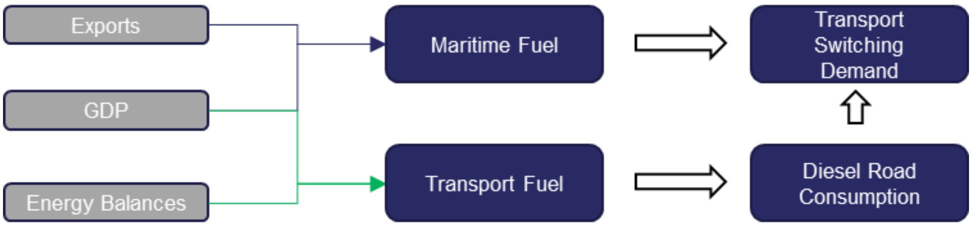


Figure 8-8: Transport demand model mechanics

Transportation demand for natural gas is fundamentally driven by emission and regulatory requirements, particularly in the maritime industry. This creates a switching potential from oil-based fuels to natural gas. A 15% market share is projected to be achieved by 2050 for marine bunkering, whereas the road transport sector has lower market expectations, accounting for 2,5% of market share by 2050, due to strong oil-based infrastructure, together with electrical vehicle market growth expectations.

The maritime industry demand is modelled as a function of export growth, which is driven by the economic growth of the country. Similarly, diesel consumption, which provides the potential switching base for road transport, is also driven by GDP growth.

8.3.1.3 Industrial Heating Demand Modelling

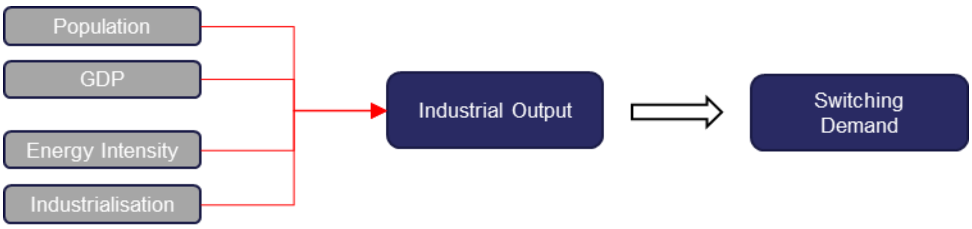


Figure 8-9: Industrial heating demand model mechanics

Industrial heating demand is based on countries industrialisation rates, and growth is driven by GDP and population growth. The energy intensity of the Member State economies, however, is inversely proportional to economic growth, where countries become more efficient as their economies develop, thus reducing fuel required by industry through improved technology and more efficient processes.

8.3.1.4 Residential and Commercial Demand Modelling

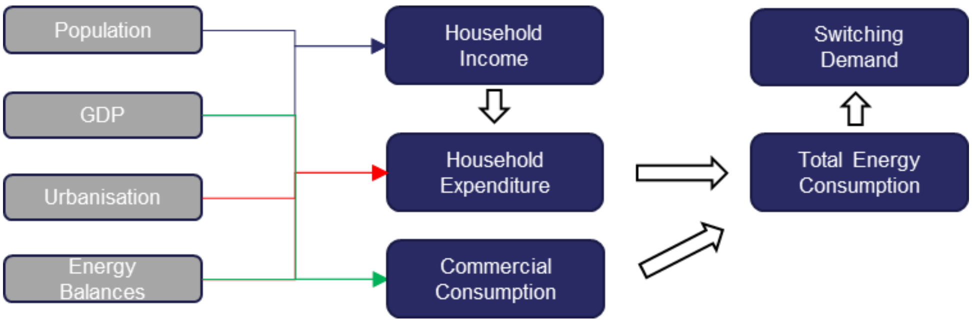


Figure 8-10: Residential and Commercial demand model mechanics

Residential and commercial demand is most likely to be met through LPG due to the lack of pipeline infrastructure and the low probability of investment in the immediate future. Demand is country-based, and supply infrastructure would need to be developed. The residential demand in the region is based primarily on cooking, where heating demand volume is considered negligible due to the climatic conditions within the region.

The residential demand is driven by household expenditure which grows with a country's economy. This increases cooking fuel requirements, together with urbanisation driving the usage of cleaner fuels through improved infrastructure and access to fuel sources.

Similarly, the commercial sector develops with economic growth; however, alternative fuel requirements are not as significant due to the sector being powered through electricity. The switching potential is based on biofuels switching to LPG as a cleaner source of energy.

8.3.1.5 Agriculture Demand Modelling

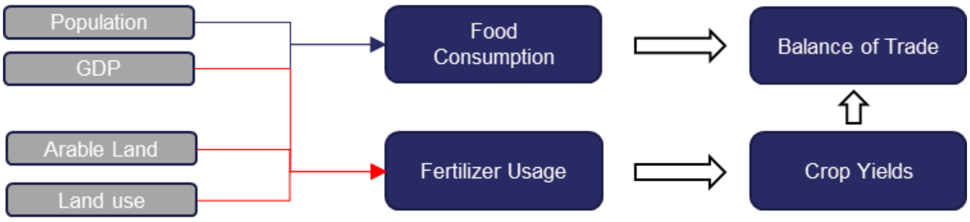


Figure 8-11: Agriculture demand model mechanics

The fertiliser demand is on a country by country basis; however, supply would be through urea fertiliser plants that would be based in countries in close proximity to gas supply fields. The resulting demand is thus concentrated in these countries, and trade mechanisms would need to be in place to ensure supply and demand are aligned.

Population and economic growth drive consumption of food and increase the grain requirements for countries. Developing economies allow for increased infrastructure and access to fertilisers, which increases agricultural yields. The gas demand for agriculture is thus driven by GDP, and agricultural land usage in countries, together with policy and government subsidies, which makes usage affordable to the lower end market.

8.4 Thermal Heating Sectoral Demand Aggregates

In this section, thermal heating sectoral demand aggregates are indicated across High, Base and Low case trend scenarios. All figures relate to the current trajectory GDP scenario while the impact of the high investment and low investment GDP scenarios are shown in Appendix E.2. Overall, the GDP scenarios have a lower impact on the growth of the natural gas market than the trend scenarios which consider the positioning of gas within each of the sectors.

8.4.1 Gas to Power Aggregate Demand

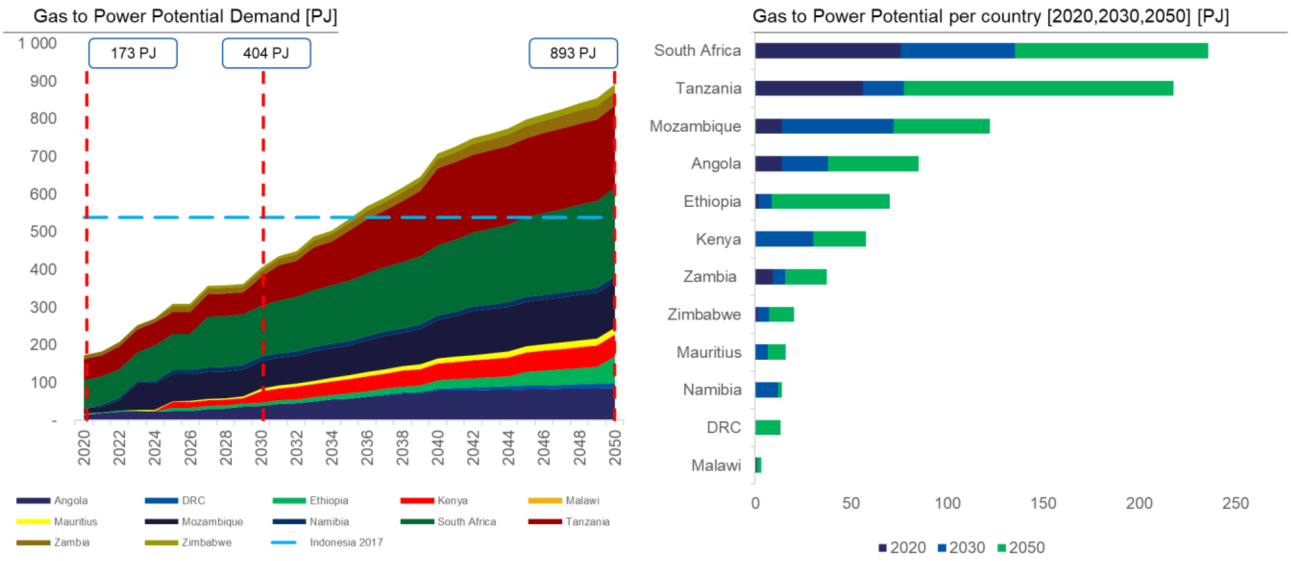


Figure 8-12: Base case projected GTP potential

In the base case scenario, the aggregated GTP potential in the region is expected to reach the Indonesian benchmark by 2035 and will require a supply of 893 PJ per annum by 2050. South Africa is set to lead the deployment of GTP due to the relative size of its economy and generation capacity while gas producing countries within SADC (Angola, Mozambique and Tanzania) are well poised to follow suit as a result of the local availability of natural gas.

GTP is key to anchoring gas demand in the region and demand for gas will increase, particularly in the short to medium term, where a GTP is expected to grow based to both diversify the power supply mix as well as reduce carbon emissions.

Many countries in the region are developing policies and plan to reduce their reliance on fossil fuels (particular coal and oil), and natural gas is seen as a short-to-medium term solution to reduce carbon emissions as natural gas is a relatively cleaner and more efficient fuel source than coal and oil-based fuels. Most countries in the region have included gas as a possible option in their long-term plans and have either committed to GTP projects or have already started construction of GTP facilities.

GTP potential is prevalent amongst all the prioritised countries to some extent, except for the Democratic Republic of Congo, which has a broader focus on hydropower. South Africa has a significant effort on the immediate future in terms of GTP adoption, whereas Mozambique, Angola and Tanzania have considerable long-term investment plans with regard to generating electricity from gas. Gas provides a suitable and implementable alternative power option as a supplement to power generation being affected by climate change, particularly countries with a concentrated hydropower resource base, natural gas also allows for power generation plans to follow the peak load demands.

The primary fuel source for electricity production is dependent upon the indigenous strategic resources available to a country or through trade. Yet, several SADC Member States will require generation flexibility which is inherent to GTP to balance the variability of renewable energy sources and the threat posed by climate change to hydropower generation.

GTP potential in the region is expected to grow over the medium to long term and as renewable energy sources (such as solar and wind supported by affordable utility-scale electricity storage) are anticipated to cover a larger proportion of the energy mix in the region.

The forecasted demand for GTP considered three trend scenarios:

- Low case: GTP is developed according to planned commitments with no changes
- Base case: After 2030, the share of GTP in the planned electricity supply increases to 7% by 2050
- High case: After 2030, the share of GTP in the planned electricity supply increases to 15% by 2050

In the high case scenario (indicated in the figure below), South Africa leads the deployment of GTP and the majority of the growth in GTP in the region occurs from 2030 to 2050 as electricity planning targets the long-term uptake of natural gas. The demand for gas to deploy GTP increases to 1193 PJ by 2050 within high case scenario and the Indonesia benchmark is reached by 2033.

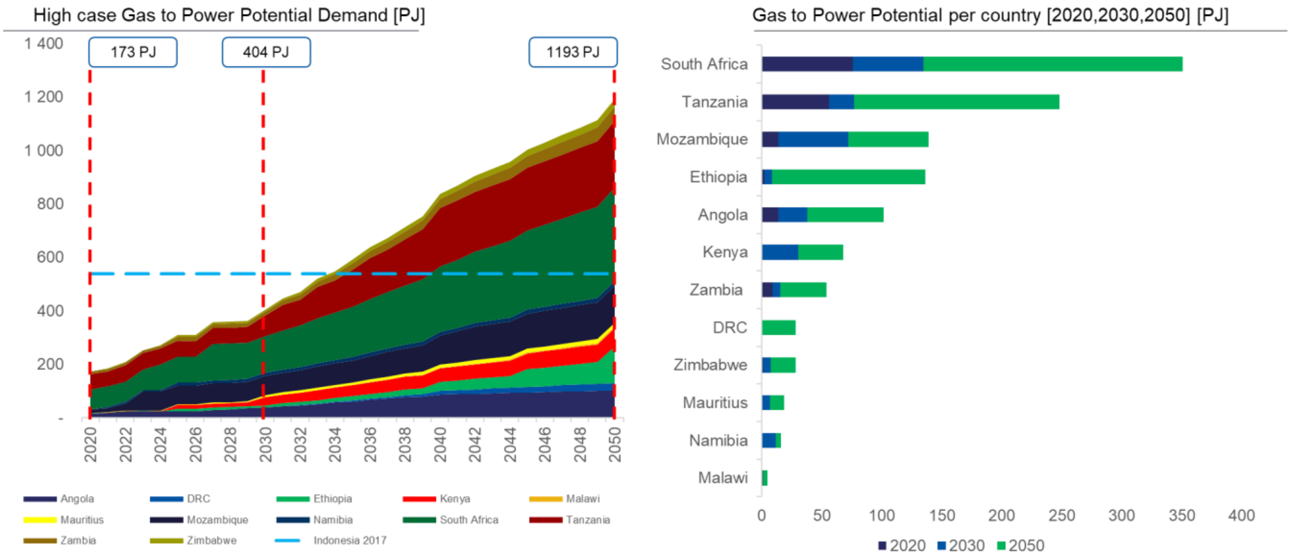


Figure 8-13: High case projected GTP potential

In the low case scenario (indicated in the figure below), Tanzania leads the deployment of GTP as it has the highest level of commitment in terms of capacity planning. Additionally, several SADC Member States have electricity build plans that end in 2030. The demand for gas to deploy GTP decreases to 627 PJ by 2050 within low case scenario and the Indonesia benchmark is reached towards 2039.

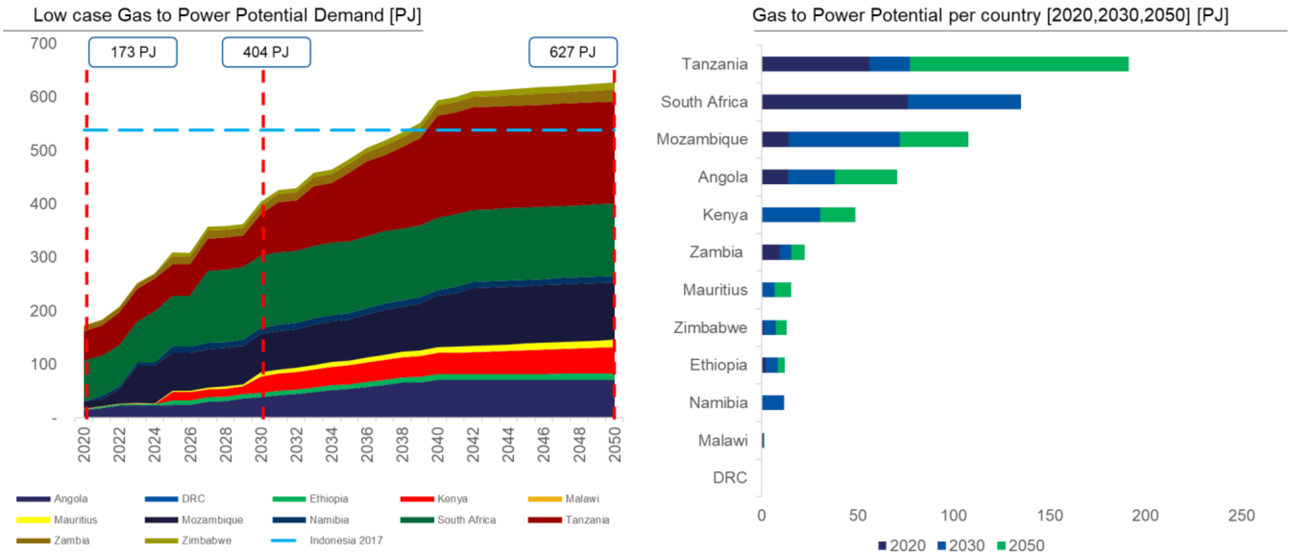


Figure 8-14: Low case projected GTP potential

8.4.2 Transport Aggregate Demand

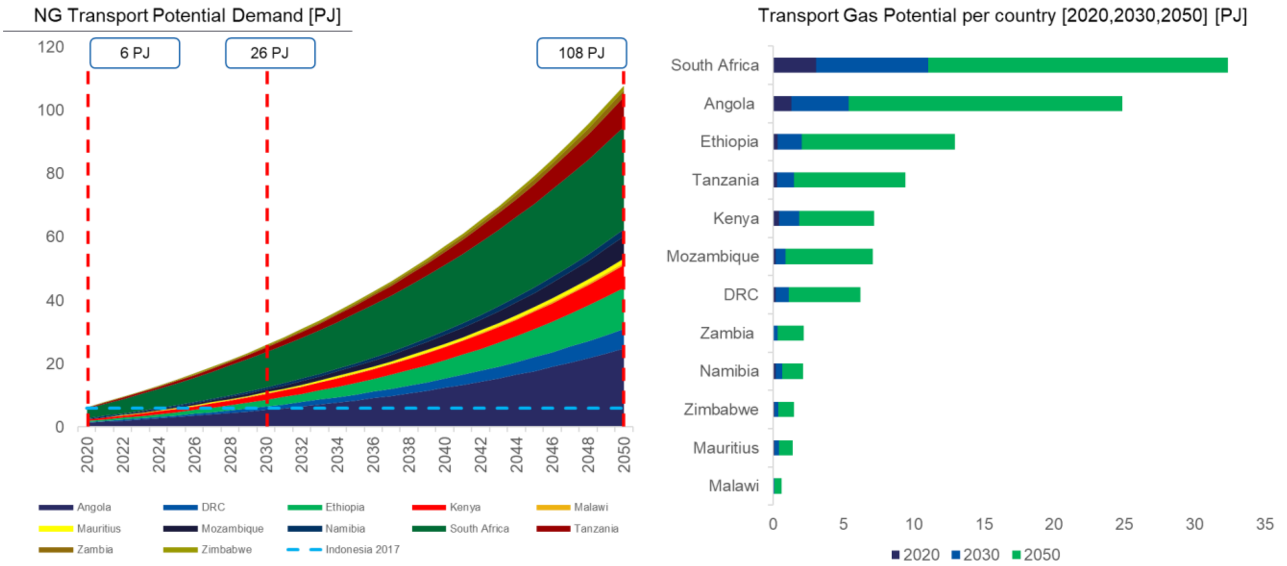


Figure 8-15: Base case projected transport sector gas demand

In the base case scenario, the aggregated transport sector gas demand in the region is expected to surpass the Indonesian benchmark from 2020 and will reach 108 PJ per annum by 2050. South Africa is set to lead demand due to the relative size of its economy while SADC Member States with access to maritime industries have a higher potential for gas uptake in the transportation sector.

The uptake of natural gas in the transport sector within the SADC region considers industrial logistics through maritime and road transportation which generally use bunker fuel and diesel, respectively. The International Maritime Organisation (IMO) emission regulations specified the reduction of sulphur oxides (SOx) and nitrogen oxides (NOx) to 0.1 % in Emission Control Areas (ECA) by 2015, and 0.5% globally by 2020 while the industry sees gas as a key fuel source to combat the current high emission rates. Between 7.5 - 12% of current oil-based fuel used in maritime transportation is likely to shift to gas; in the form of LNG.

Similarly, road transport industry regulations indicated that a reduction in emissions is required, thus enabling natural gas to provide an alternative fuel for diesel vehicles. Governments in various countries are promoting gas-powered vehicles by replacing public transport buses and government fleets to gas through CNG. Mozambique, Tanzania, and South Africa are all actively promoting gas-powered vehicles, with the latter incentivising the taxi industry to shift over to gas.

The forecasted demand for gas in the transportation sector considered three trend scenarios:

- Low case: LNG makes up 10% of bunker fuel for maritime transport and 1% of road diesel consumption by 2050
- Base case: LNG makes up 15% of bunker fuel for maritime transport and 2.5% of road diesel consumption by 2050
- High case: LNG makes up 20% of bunker fuel for maritime transport and 4 % of road diesel consumption by 2050

In the high case scenario, the aggregated transport sector gas demand in the region is expected to surpass the Indonesian benchmark from 2020 and will reach 125 PJ per annum by 2050, as indicated below.

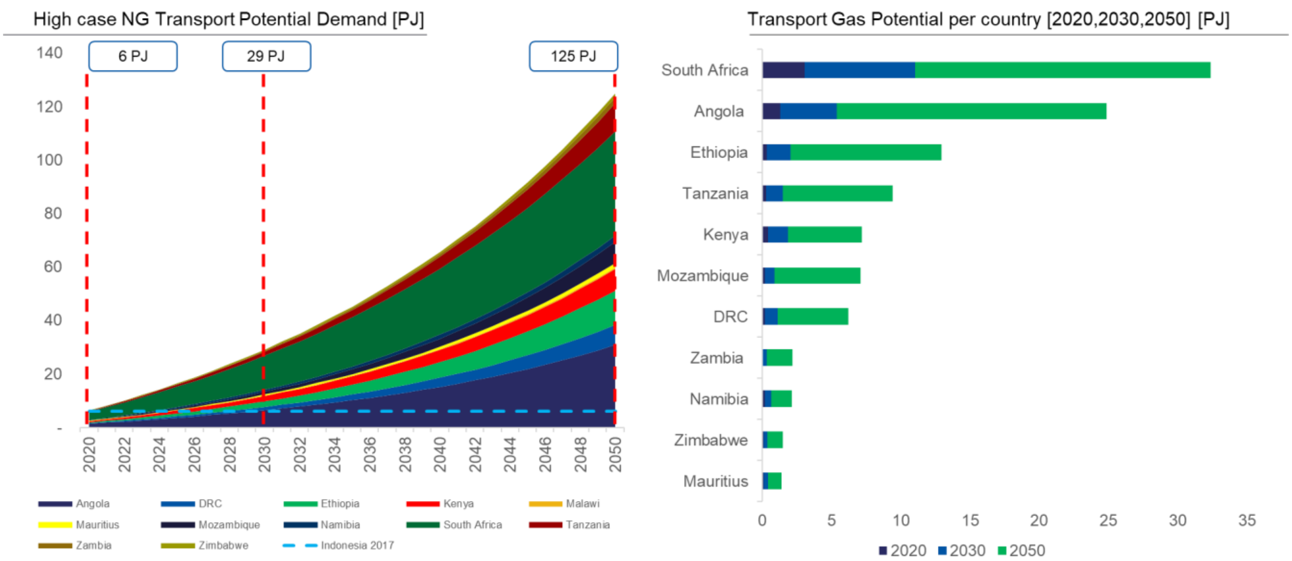


Figure 8-16: High case projected transport sector gas demand

In the low case scenario, the aggregated transport sector gas demand in the region is expected to surpass the Indonesian benchmark from 2020 and will reach 91 PJ per annum by 2050, as indicated below.

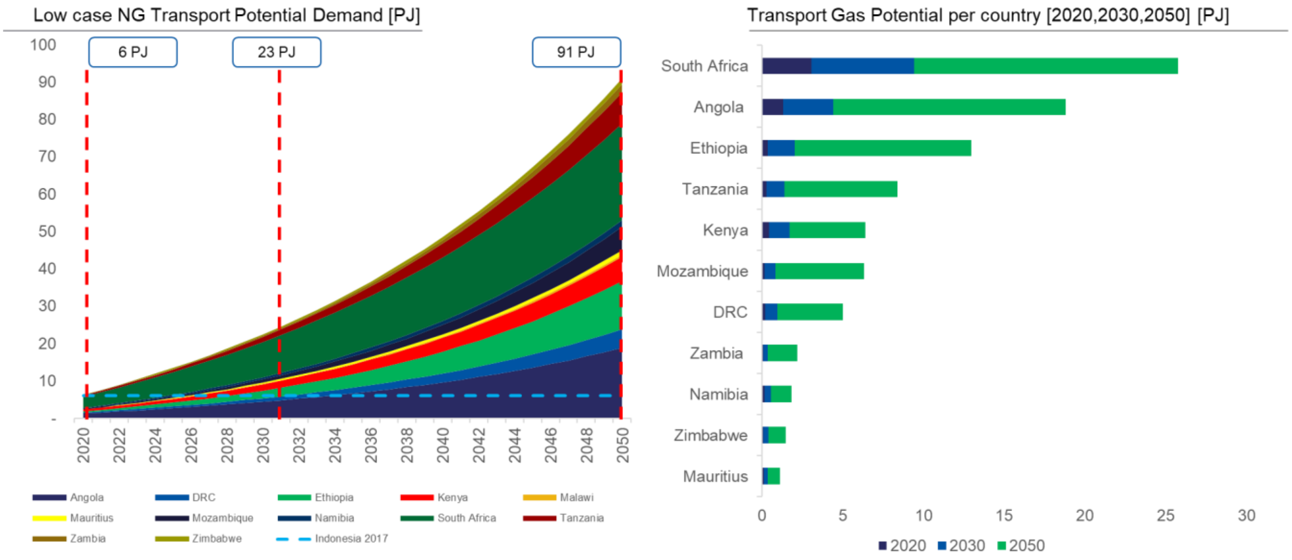


Figure 8-17: Low case projected transport sector gas demand

8.4.3 Industrial Heating Aggregate Demand

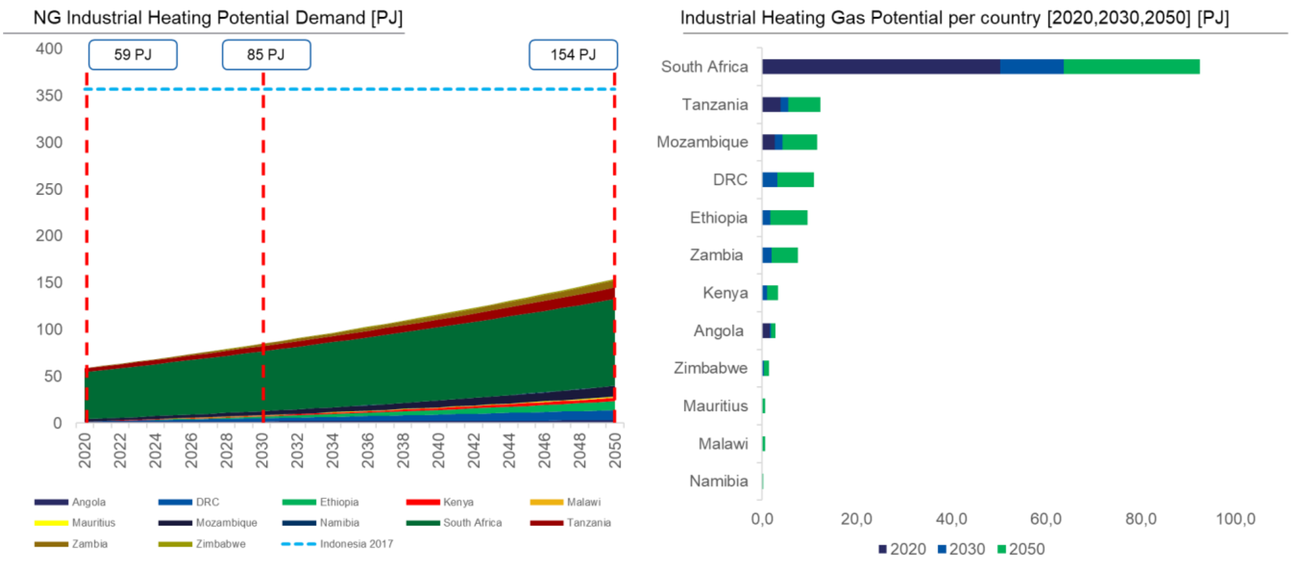


Figure 8-18: Base case projected industrial heating gas demand

Industrial heating requirements are primarily impacted by the level of industrial output and the contribution of heavy industry to GDP. Furthermore, reliable energy infrastructure is an enabler of industrialisation, and the regional gas market has the potential to enable developing industries, particularly in Tanzania, Ethiopia, Mozambique, the Democratic Republic of Congo and Zambia. SADC Member States aim to increase industrial development, and the gas sector is key to providing energy to enable sustained industrial output.

Most SADC Member State economies are driven by large primary sectors while South Africa's strong industrial sector is an exception (alongside the robust tertiary sector within Mauritius). South Africa, therefore, requires the majority of the industrial heating gas share in the region, which is illustrated in the figure above. At 154 PJ by 2050, the region will still be far behind Indonesian industrial demand which is largely a function of the difference in industrial development.

Natural gas will compete with other heat sources including biomass, coal, LPG, and other petroleum products within the region. In a similar vein to GTP, natural gas would be structurally well suited for industrial heating application assuming that the required distribution infrastructure is available and lower carbon emissions are targeted at a policy level to enable competition with higher carbon fuel sources. Biomass utilisation will likely decrease with further industrialisation as industries demand higher value forms of fuel to drive their outputs.

The forecasted demand for gas to fuel industrial heating considered three trend scenarios:

- Low case: Natural gas makes up 7.5% industrial energy supply by 2050
- Base case: Natural gas makes up 10% industrial energy supply by 2050
- High case: Natural gas makes up 12.5% industrial energy supply by 2050

In the high case scenario, industrial demand for natural gas grows to 201 PJ by 2050, as indicated in the figure below.

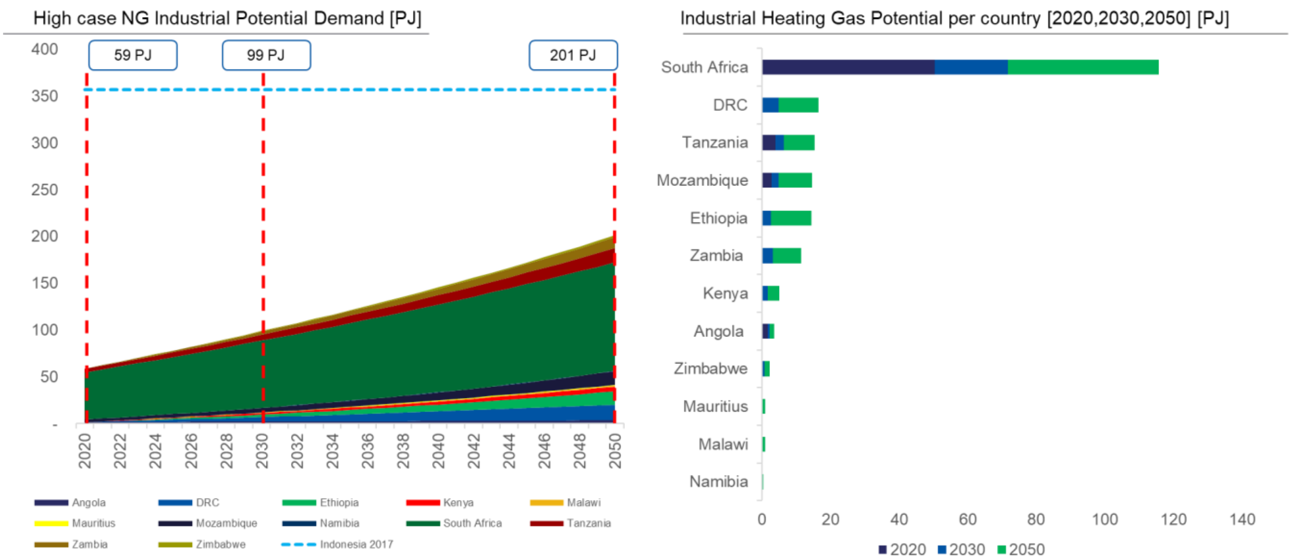


Figure 8-19: High case projected industrial heating gas demand

In the high case scenario, industrial demand for natural gas grows to 107 PJ by 2050, as indicated in the figure below.

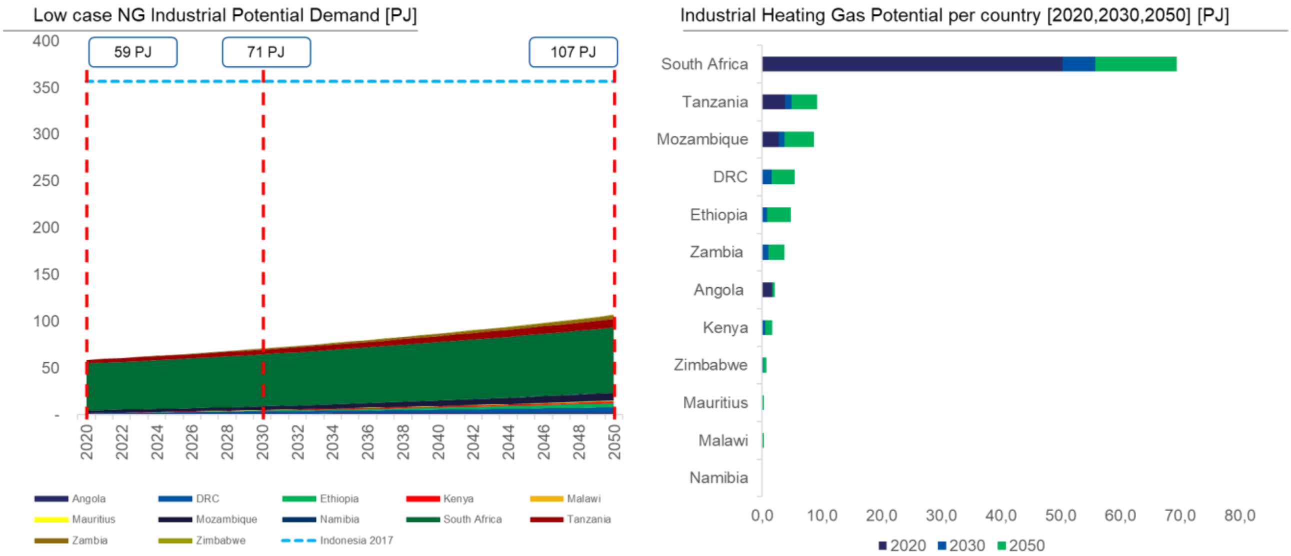


Figure 8-20: Low case projected industrial heating gas demand

8.4.4 Residential and Commercial Sectoral Demand

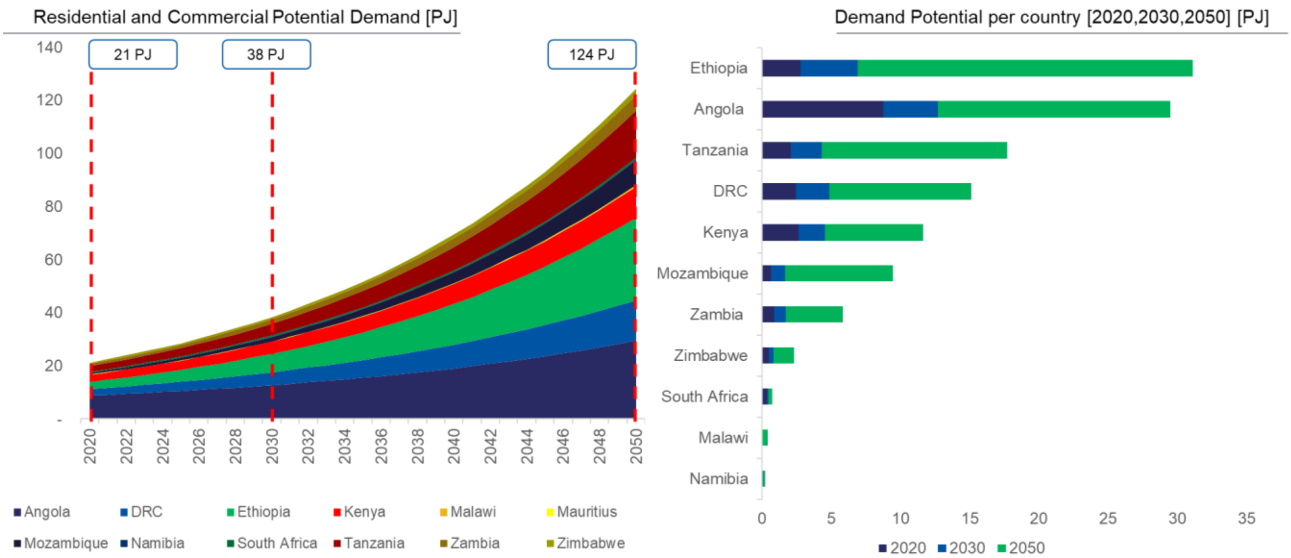


Figure 8-21: Base case projected Residential and Commercial gas demand

In the base case, natural gas demand is estimated at 124 PJ by 2050. Of note is the high potential in countries which consume biomass to drive residential and commercial activities. Biomass consumption within the region has a negative impact on local forestry and biodiversity and is an outcome of the low economic development throughout most parts of the region.

The demand for high-value forms of energy is set to grow in the residential and commercial sectors as a function of overall economic development. In this regard, natural gas would need to compete with alternatives such as electricity and LPG which either have well-established distribution networks through electricity grids and road and rail infrastructure, respectively or commitment to expand the infrastructure. Additionally, the low density of natural gas requires significant scale in terms of demand to afford the distribution infrastructure required to connect households and commercial areas to natural gas suppliers. In this regard, natural gas supply to this sector would be at the tail end of overall gas market development, following on the development and growth of gas uptake in the electricity, industrial and transportation sectors. For this reason, residential and commercial aggregate demand is excluded from the total aggregate demand potential for gas in the region.

The forecasted demand for gas in residential and commercial considered three trend scenarios:

- Low case: Natural gas makes up 2.5% sector energy supply by 2050
- Base case: Natural gas makes up 5% sector energy supply by 2050
- High case: Natural gas makes up 7.5% industrial energy supply by 2050

In the high case, natural gas demand is estimated at 184 PJ by 2050, as indicated in the figure below.

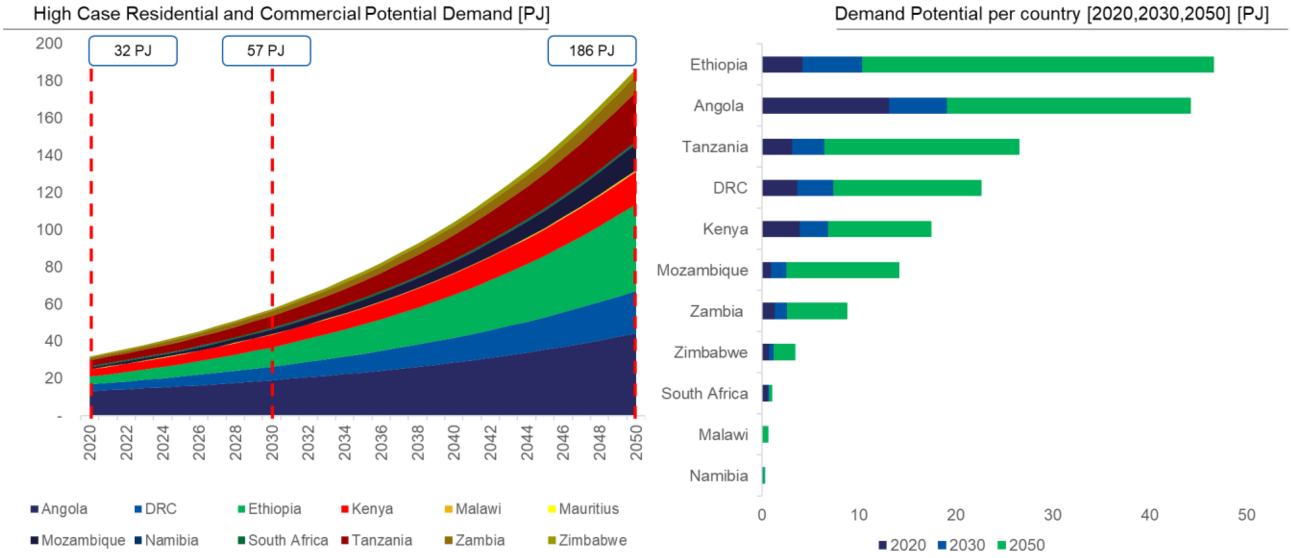


Figure 8-22: High case projected Residential and Commercial gas demand

In the low case, natural gas demand is estimated at 62 PJ by 2050, as indicated in the figure below.

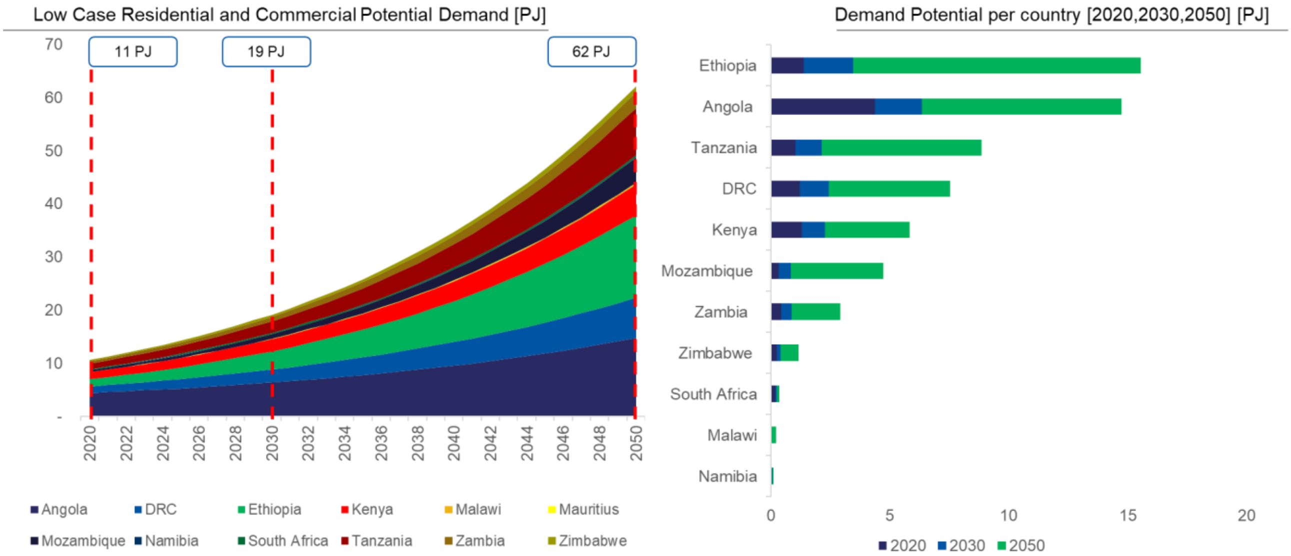


Figure 8-23: Low case projected Residential and Commercial gas demand

8.5 Petrochemical Sectoral Demand Aggregates

8.5.1 Agriculture Aggregate Demand

Fertiliser consumption within the African continent as a whole is projected to be modest in the short term, mainly due to the socio-economic challenges that many of the major economies are facing on the continent, inflating transportation infrastructure costs and security and financial concerns which limit the investment within the sector.[153] The development of the fertiliser market in Africa also faces drawbacks through the lack of enabling policy, human capital and expertise in the agricultural sector.

Countries with agricultural driven economies, as well as those with supportive policy and investment (such as Ethiopia, Mozambique, and Tanzania) still anticipate growth in the sector though. This, together with South Africa's developed agricultural sector, provides an anchor demand for urea fertiliser in the region.

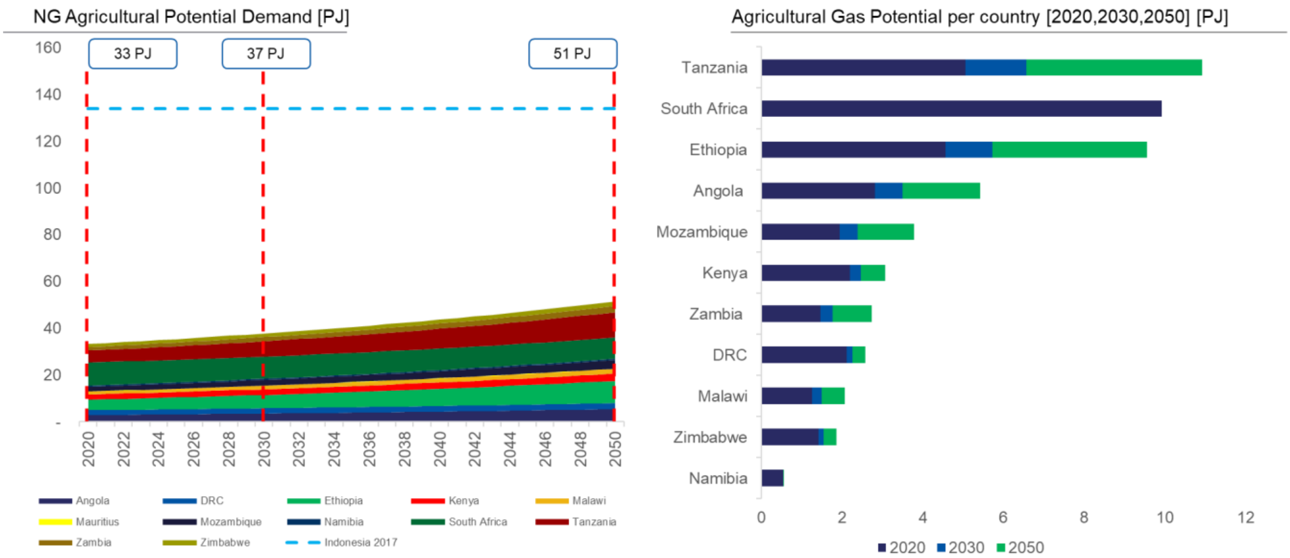


Figure 8-24: Projected agricultural gas demand

The agriculture sector is an industry with strong growth potential throughout the region, forming a key component in many of the countries' economic outlook and social development strategies. South Africa and Mauritius, however, have a decreasing agricultural market growth over the long term due to a decrease in arable land because of urbanisation and development as well as climate change factors.

Tanzania and Ethiopia in particular, with a strong focus on agriculture as an economic enabler, provide long term growth for fertiliser demand. Zambia, Mauritius, and Malawi currently have above-average fertiliser usage per hectare, and the international trends suggest an increase of grain requirement and fertiliser usage with GDP growth, further enhancing the potential market within the developing region.

Under the high investment growth, the agricultural gas demand for 2050 would still be considerably below Indonesia's 2017 demand at 51 PJ per annum. However, Indonesia has a well-developed fertiliser sector which includes exportation numbers and would serve as a benchmark for the

[153] Nexant: Africa Fertiliser Market Outlook: Challenges and opportunities for GCC producers (2018)

agricultural sector in the region as a whole to improve the utilisation and production of fertiliser. The agricultural demand is less dependent on the investment case than the other sectors, with the variability between the high and low investment scenarios being 7,3 PJ/a for the whole region.

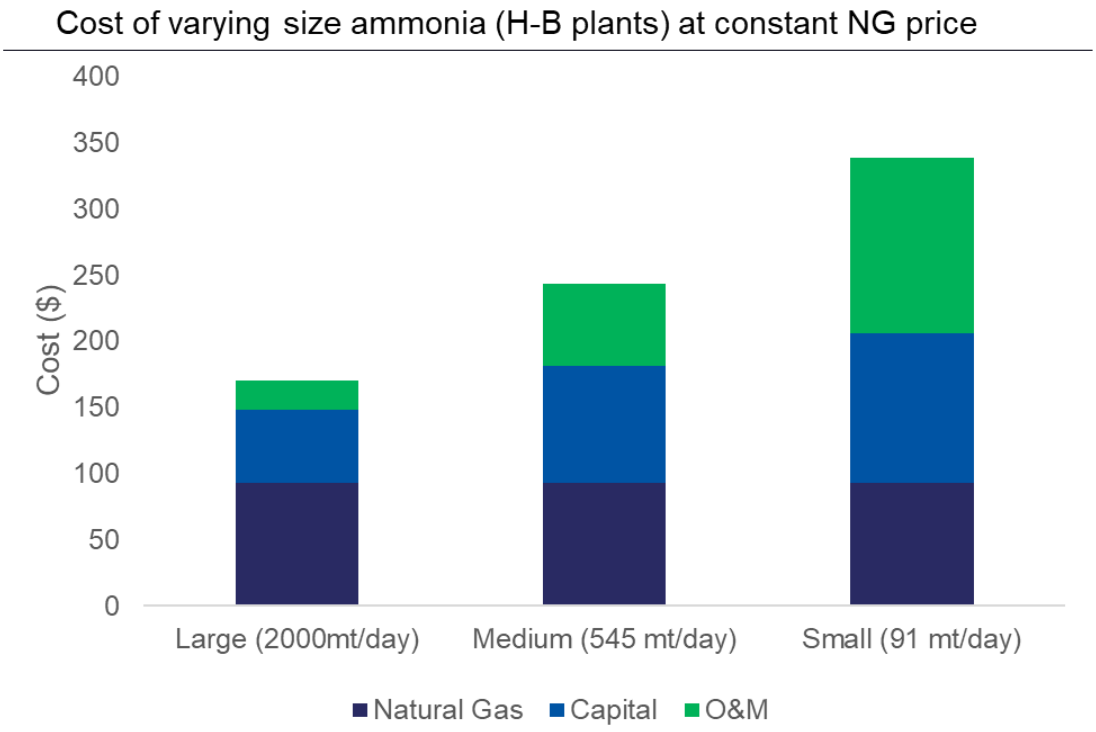


Figure 8-25: Cost of Ammonia plants based on size[154]

Unlike the aggregated demand, which has gas demand for each country for individual sectors, the feasibility of agricultural demand would depend upon clustered demand for multiple countries being supplied by regional plants, most likely in close proximity to the gas sources. The capital costs, as well as Operational and Maintenance Costs (O&M), supports large-scale plant development. Furthermore, plants close to ports would allow for cheaper exportation costs. The costs of H-B plants of varying sizes are shown above, based on recent plants constructed in the United States of America.

Ammonia and urea plants have been planned in Tanzania, Mozambique and Angola, with an expected capacity of 1 400 000, 1 300 000 and 1 200 000 tonnes per year respectively, this would be sufficient to cover not only local demand needs but would also be more than sufficient to account for the demand of the entire region, with additional surplus.[155]

[154] The Potential Economic Feasibility of Direct Electrochemical Nitrogen Reduction as a Route to Ammonia
[155] AfricaFeriliser.org; 2018 Register of Fertiliser manufacturing and processing facilities in Sub Saharan Africa

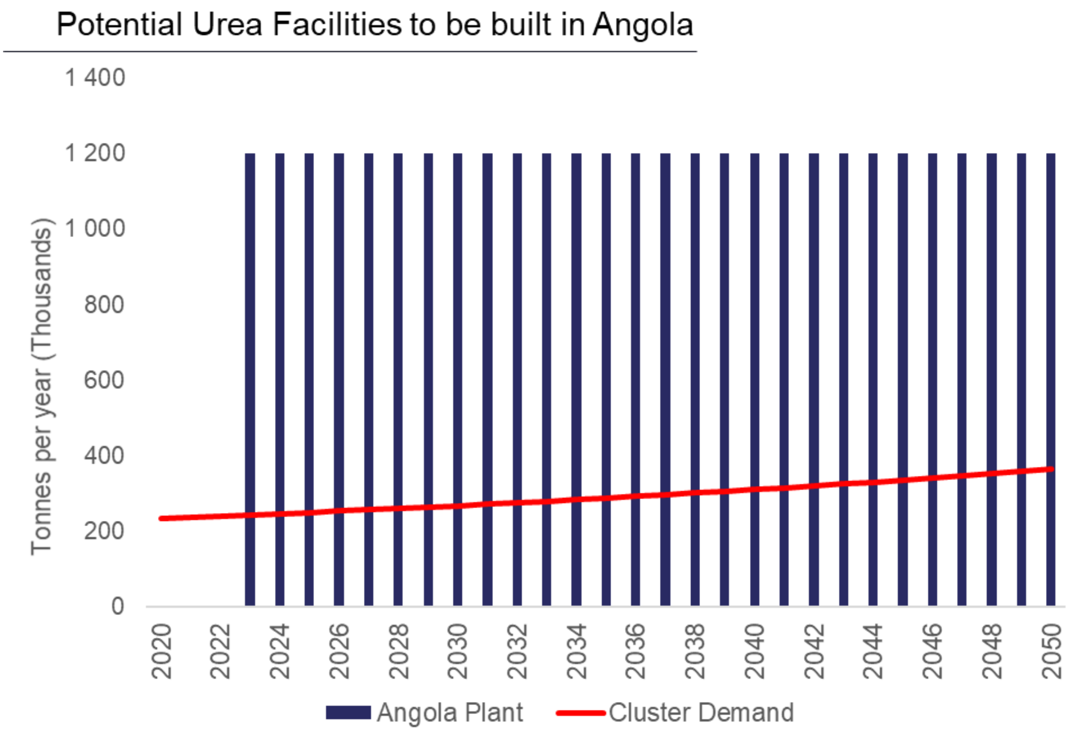


Figure 8-26: Angola Urea plant supply and demand projections

Angola's proposed plant, with a potential capacity of 1 200 000 MTPA, has a potential capacity well advanced of the regional requirements. Due to the proposed plant's northern location, the plant would likely supply the Democratic Republic of Congo and Namibia, together with covering local demand. [156] The proposed ammonia/urea plant would require around 27.2 PJ per annum of gas to meet production targets.

[156] World Fertiliser; Uralchem to build urea production plant in Angola

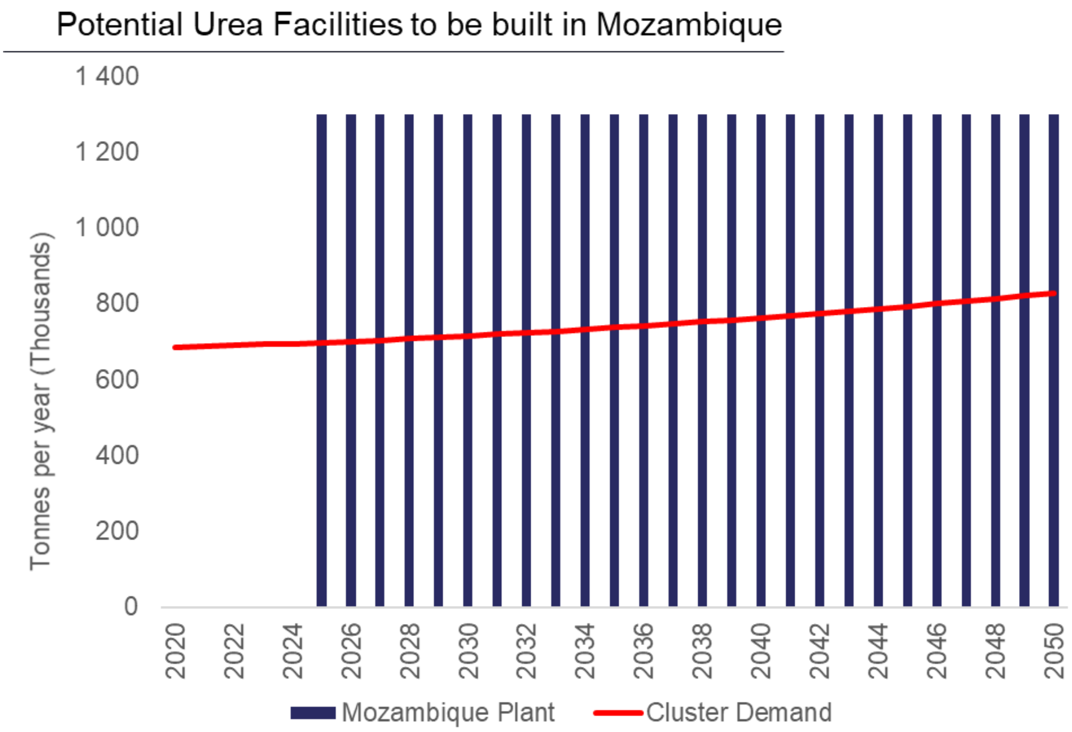


Figure 8-27: Mozambique Urea plant supply and demand projections

The Mozambique plant has been facing challenges regarding implementation, however, is still expected to be completed by 2025, with a capacity of 1 300 000 MTPA of urea production as well as a 50 MW power plant on site. The plant would be ideally situated to supply South Africa, Zambia, Zimbabwe, Malawi, Mauritius as well as supply local fertiliser requirements. Currently, South Africa and Zimbabwe do produce other fertilisers on a smaller scale, but urea is obtained through imports, predominantly from the Asia region.[157] The proposed ammonia/urea plant would require 29.5 PJ per annum of gas to meet production targets.

[157] South African Fertiliser Market Analysis Report 2018

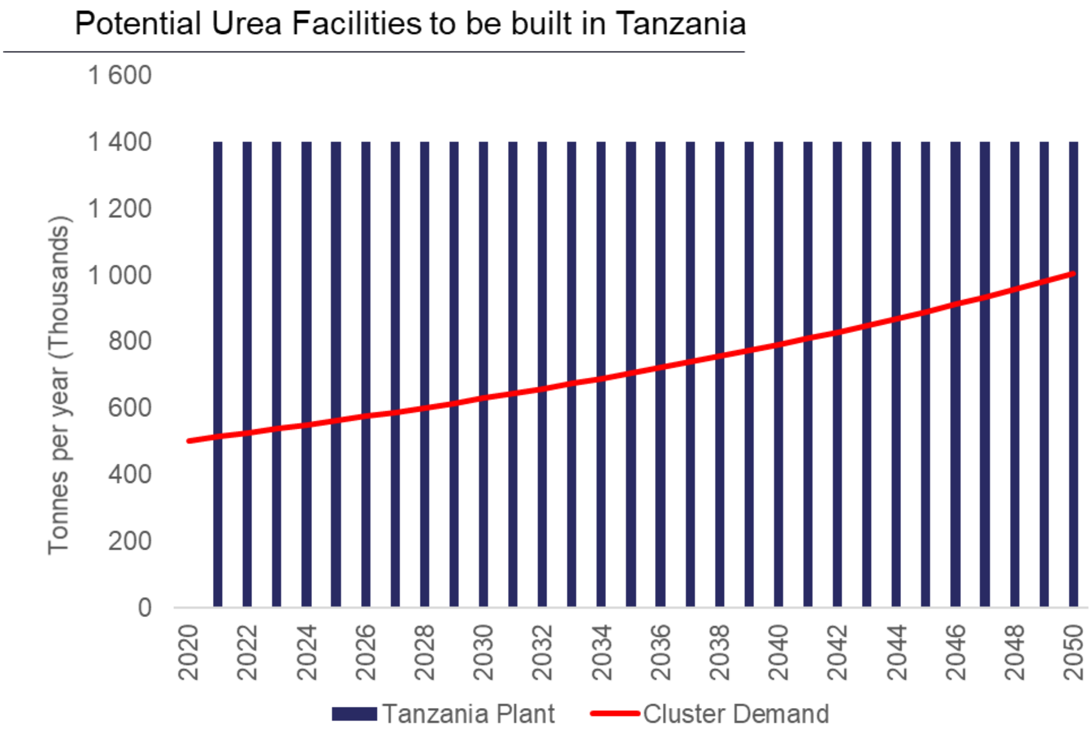


Figure 8-28: Tanzania Urea plant supply and demand projections

The Tanzania ammonia and Urea plant, with a capacity of 1 400 000 MTPA has been planned to be completed before the other two projects in the region and has the capacity to supply the entire region over the short-term; however, development is dependent on resource factors, and delays may be a possibility.

Long-term demand in the eastern region is expected to grow significantly, and the plant would have the capacity to supply Kenya and Ethiopia as well as to accommodate local requirements, with the surplus being exported to regional customers. The proposed urea plant would require 31,7 PJ per annum of gas to meet production targets.

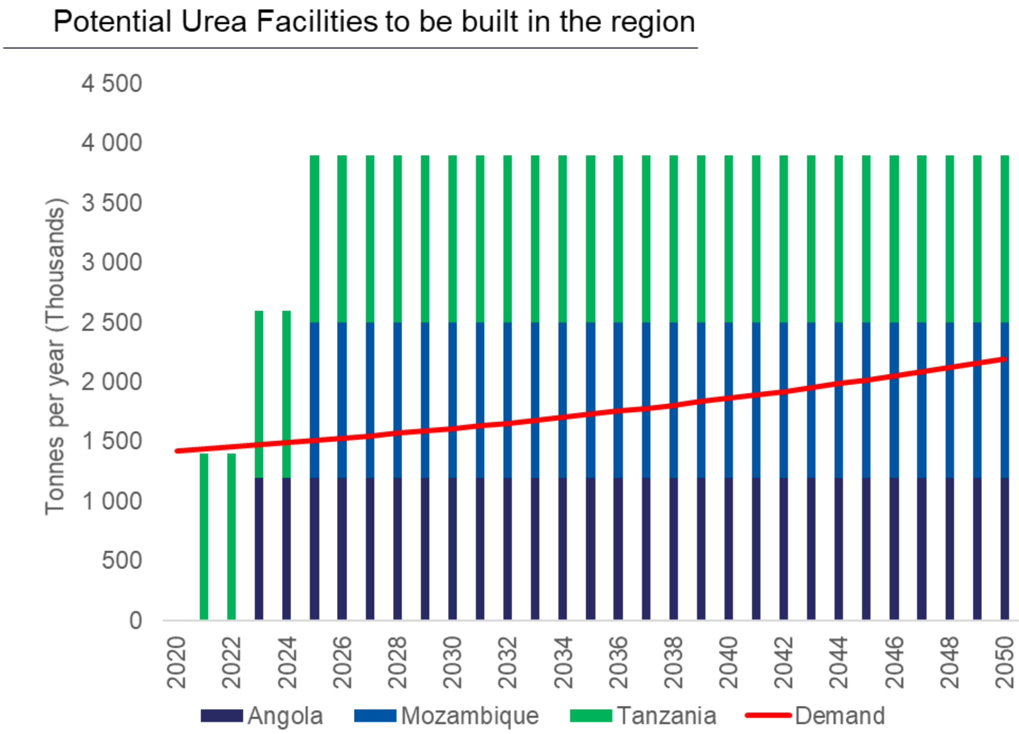


Figure 8-29: Regional Urea plant supply and demand projections

The potential development of urea fertiliser plants will be able to serve the regional demand, while also having the capacity to export fertiliser to the rest of the sub-Saharan region. Although Nigeria and Egypt are already supplying the African market, opportunities to supply neighbouring countries would allow Angola to be able to tap into the West African market and Tanzania/Mozambique to supply the east.

For the base trend case only two plants have been considered to be developed, with one on the east and one on the west coasts of the region. This is because exportation of surplus production is unlikely due to the high gas prices expected in the region in comparison to gas prices in international fertiliser producing countries, thus making more than two plants unviable in the region. The high case scenario, however, considers all three plants being developed in the region as projected within local plans, whereas for the low case, only one plant was considered while imports closed the supply gap within the region.

8.5.2 Methanol Aggregate Demand

Methanol demand in the SADC region is currently limited and Sasol is the only regional producer. The global demand for methanol is consistently growing, with Chinese consumption accounting for a significant share of this growing demand. This is mainly to feed methanol-to-olefin (MTO) facilities, which are typically supplied by captive market coal-derived methanol in China, but there is growing global demand for methanol-based fuels.

Methanol can be an important building block for the development of a downstream chemical industry, particularly if it is coupled with the production of ammonia and urea. Developing downstream industries, such as the manufacturing of formaldehyde, acetic acid, and other chemical products, can provide further impetus to develop the sector and ensure socio-economic development through job creation. Formaldehyde (from methanol) and melamine (from urea) can be coupled to produce the liquid resin urea formaldehyde which is used in a variety of construction and automotive applications – all growing markets in the SADC region. There is also the opportunity to blend methanol with gasoline (as is done in China).

Due to the relatively high expected gas price in the region in comparison to international methanol producers, a world-scale plant would need to be constructed in the region to capitalise on economies of scale. However, current infrastructure, as well as downstream consumption of methanol, is limited in the region. Thus, the exportation of most of the initial supply would be necessary. This would impact economics and so the development of a regional market for methanol and its derivatives is a key success factor for such a plant.

Table 9-1: Estimated Nominal IRR at Alternative Methanol and Gas Prices[158]

Natural gas $/mmbtu	Realised Methanol Price - $/tonne			
	300	350	400	450
5.00		2%	8%	12%
4.00	0%	6%	11%	14%
3.00	5%	9%	13%	15%
2.00	8%	12%	14%	17%

This world scale plant would be in the region of +- 5000 metric tonnes-per-day (mtpd) plant capacity to maintain economic viability, which would require specialised methanol industry developers to invest in the project. The plant would need to be in close proximity to the gas supply, with Tanzania and Mozambique weighing options in the development of a methanol facility as part of their downstream gas development initiatives.

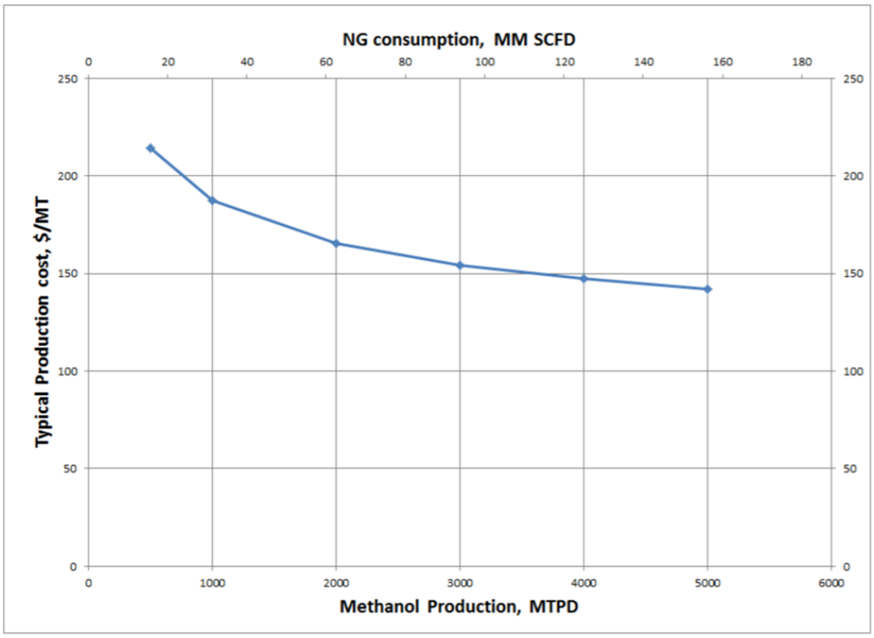


Figure 8-30: Typical Methanol production cost (OPEX+CAPEX)[159]

Petrochemical production growth is predominantly driven by feedstock advantage and robust domestic demand. Gas prices and minimal local demand for methanol may result in a challenging environment for the development of a methanol market within the SADC region. Furthermore, the

[158] Methanex
[159] Haldor Topsoe, 2015

international price of methanol is dependent on supply, which varies based on the cost of production, cost of raw materials including coal and natural gas, freight costs, capital costs and government policies. The development of alternative and renewable energy sources to produce methanol (although currently still unfeasible and contributing less than 1% of total supply) may also have an impact on supply and price competitiveness in the future.

Continuous demand is required for methanol production as storage capacity is limited, and thus a consumer base would be necessary to ensure continual production. The annual gas demand for methanol is projected to be 60 PJ annually for a world-scale plant of 5000 mtpd, with the plant expected to come online by 2030 within the base case for this study.

8.5.3 Gas to Liquid Aggregate Demand

There are two existing facilities within the SADC region that convert natural gas into liquid products and both facilities are located within South Africa. One facility is a dedicated GTL plant in Mossel Bay, South Africa with a feed capacity of approximately 100 PJ per annum. Current natural gas supply shortages to the facility have resulted in a significant reduction in production as the plant consumed less than half of its design capacity over 2018/19[160].The other facilities belong to Sasol. In 2004, the ROMPCO pipeline was commissioned, delivering natural gas from the Pande Temane fields in Mozambique to Secunda and Sasolburg. The justification for the pipeline, which was completed in 2004, was based on Sasol switching its Sasolburg plant from coal to gas as well as taking gas to Secunda to supplement the CTL plant there. The Central Processing facility at Temane was expanded in 2017 to 197 PJ/a and present sales of gas in Mozambique are 32 PJ/a resulting in approximately 165 PJ/a flowing to South Africa. The majority of the gas is used internally in Sasol (110 PJ/a) and approximately 50 PJ/a is supplied externally to customers in Gauteng, Mpumalanga, Free State and Kwa Zulu Natal[161].

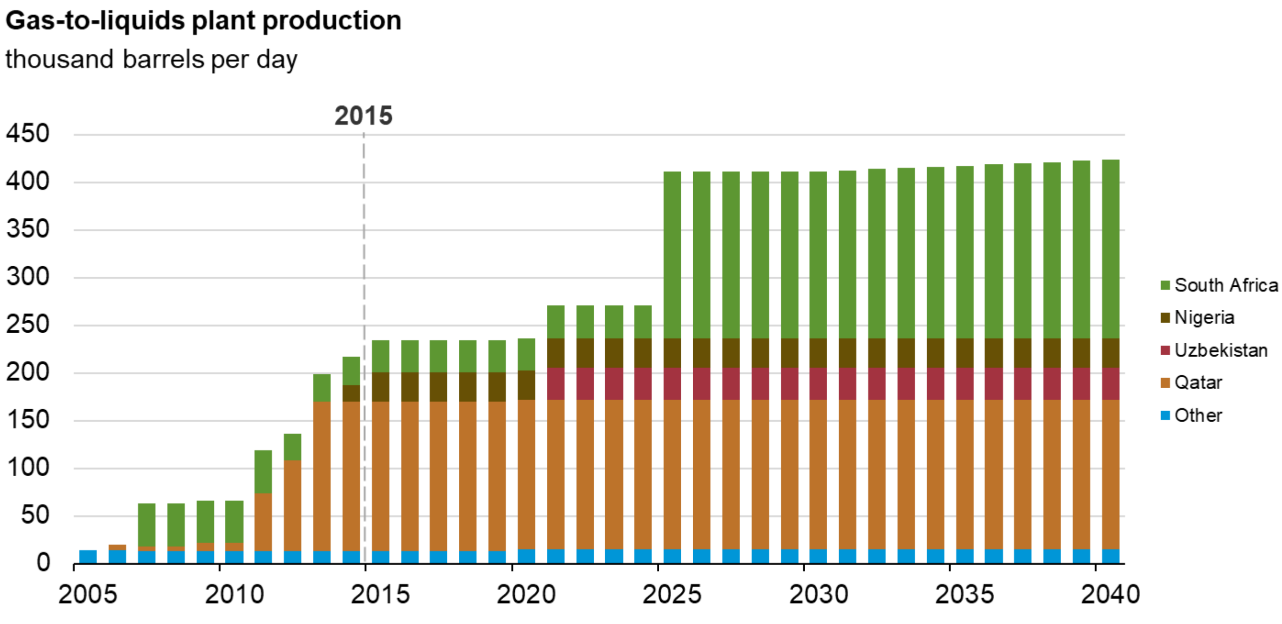


Figure 8-31: Forecasted GTL plant production[162]

[160] PetroSA Integrated Annual Report, 2019
[161] Engineering News "Promoters of Maputo and Richards Bay LNG terminals insist projects can be complementary" December 2019
[162] EIA International Energy Outlook, 2017

There could be a scenario, whereby Sasol converts its entire Secunda facility from coal to gas as indicated in the forecast above from the EIA, [163] but this would be in the high case scenario for gas demand within the SADC region for several reasons. Firstly, Sasol has invested R14 billion since 2009 in a mine replacement programme that added three new coal mines to sustain Sasol's South African operations until 2050[164]. This suggests that coal will remain as the primary feedstock to its operations going forward. Secondly, Sasol's current supply of natural gas through the ROMPCO pipeline has tapered, indicating that long term supply cannot be guaranteed from this source. Alternative sources (either from the Rovuma basin or LNG imports) would need to be secured to enable a full conversion of the Secunda facility. A more likely scenario is a gradual increase in the acquisition of more gas to enable the achievement of Sasol's 2030 goal of reducing its GHG emissions by 10% off its 2017 baseline[165].

The EIA International Outlook for 2017 also indicates that in its low oil price scenario, it does not see further expansion of GTL production, including the conversion of the Secunda facility. This is due to the economics of GTL production (See Section 4.4.2.), which require a high differential in gas and oil prices to afford sustainable productions. In terms of the oil price, reaching the historically high prices that have been observed in the past is unlikely over the long term as oil prices have experienced downward pressure since the peak during the 2008 recession. In recent months, oversupply from OPEC+ countries combined with a global economic slowdown brought on by the coronavirus pandemic resulted in negative crude oil prices in the United States, a first in history. Oil prices have recovered since yet low prices may become the new "normal" depending upon how the global economy recovers from the pandemic. Additionally, climate change awareness has resulted in interventions such as the ongoing technological improvements in internal combustion engine efficiencies to compete with the rise of electric vehicle alternative, which will have a long-term impact on oil demand.

GTL development often responds to a particular use case that leverages not only the right economics but a suite of circumstances that afford the technology's deployment. For example, in 2009, Sasol entered into a joint venture with PETRONAS and Uzbekneftegaz (the National Oil and Gas Company of Uzbekistan) to develop a GTL facility that will consume approximately 3.6 bcm of gas per annum (~115 PJ). Uzbekistan is a particular case for the development of GTL for several reasons, which include the following:

- The country is double landlocked meaning that it is surrounded by landlocked countries which limit its options for trade partners in terms of petroleum products, thus threatening its security of supply.
- The country has substantial (65 Tcf) proven gas reserves which it can exploit to meet its energy demand needs.
- The country is located in a region of the world with a history of instability which impacts upon geopolitics and trade.
- The government has full control of the country's natural gas resources allowing it to dictate pricing and other variables according to its national interests.

With all this in mind, GTL becomes a feasible technology that secures the production of liquid hydrocarbons for Uzbekistan, which is why investment has poured into the country to develop the facility. The same cannot be said for gas producing countries within the SADC region. The identified gas producing countries are not landlocked, and GTL products would need to compete with potentially cheaper imports. Road and rail infrastructure already facilitate the movement of imported and refined

[163] EIA International Energy Outlook, 2017
[164] Sasol Officially Opens Another Coal Mine, Sustaining Jobs, 12 April 2019
[165] Sasol Climate Change Report, 2019

petroleum products and capital would likely be better spent on upgrading existing infrastructure to expand supply where required.

Small scale GTL technology has been developed and deployed in several pilot and commercial projects globally to exploit stranded gas sources or flared gas due to the low or zero pricing of these sources. Often, these projects are designed to respond to a specific or niche use case where the economics make sense for the technology's application. Projects are ongoing, and sustained commercial viability needs to be proven from multiple industry players in the developed world prior to development in the SADC region. For now, scale within a GTL facility is still required to ensure economic feasibility and to limit the shock of oil price volatility.

Thus, from a regional perspective, it would only be in the high case scenario of this study, where gas is abundant within the region, that a world scale GTL facility of ~30 000 to 40 000 b/d would be deployed in the region as a result of the various enabling factors that need to be in place to secure investment in the facility. The GTL facility would need to be in close proximity to substantial reserves of natural gas with high production rates. GTL would struggle to compete with Angola's well-established petroleum industry leaving the Rovuma basin on the border of Tanzania and Mozambique as the most likely location for a GTL facility within the region.

The high case scenario also includes a partial conversion of Sasol's operation from coal to gas, adding approximately 78 PJ of gas demand by 2050. This would be an additional measure towards achieving Sasol's target of reducing 6 million tonnes of CO_2 emissions by 2030. The base and low case consider the status qou being maintained driven by the organisation's recent investments in coal infrastructure as well as threat in exiting gas supply. The figure below indicates the aforementioned scenarios.

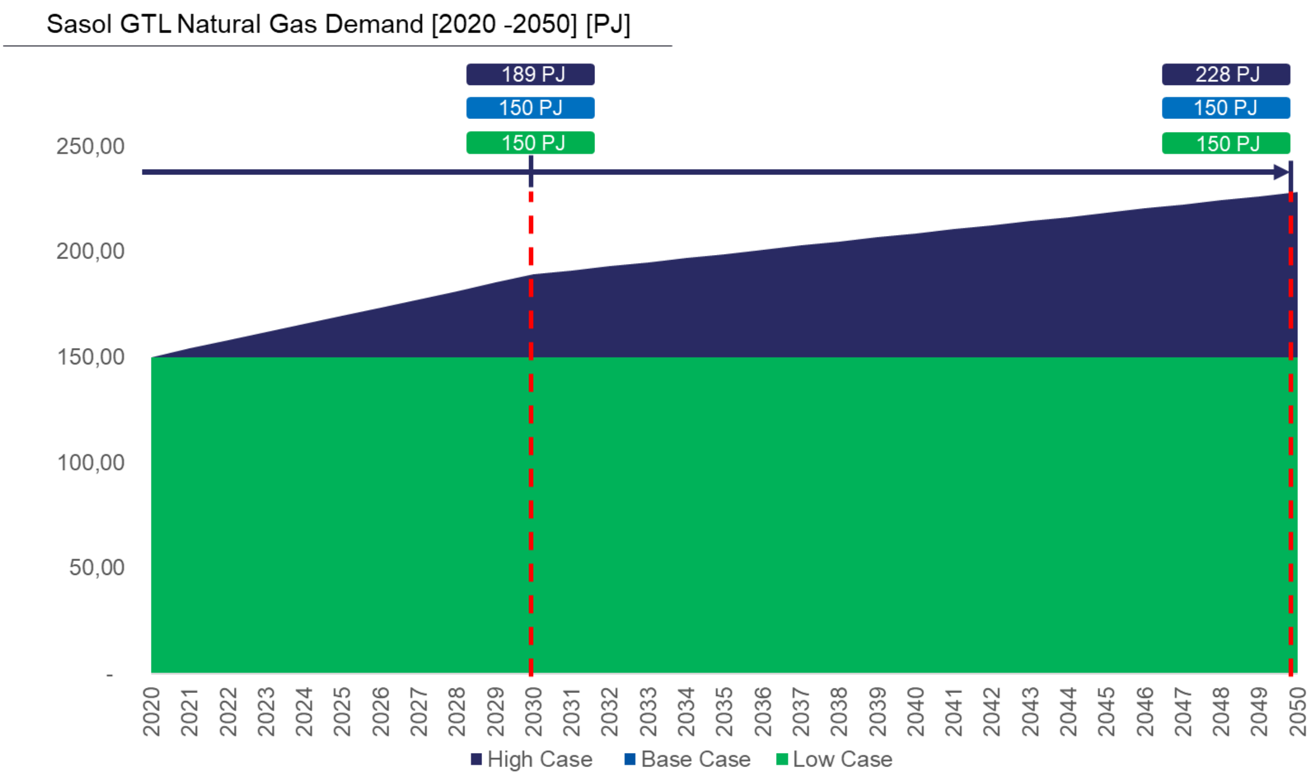


Figure 8-32: Sasol Gas Demand Scenarios

8.6 Total Aggregate Demand

The total aggregated demand for the base case scenario is illustrated in the figure below. Residential and Commercial demand is not included in the total aggregated demand for reasons discussed in Section 8.4.4.

Total aggregated demand is led by the electricity sector through GTP and will anchor demand for natural gas across the region. Existing GTL potential is not set to grow further in the base case as Sasol current coal investments secure the supply of coal to Sasol up to 2050. Industrial heating and transport provide increasing demand potential and are linked to the economic potential in heavy industries and the maritime industry, respectively. Methanol and urea production share the lowest potential, which is largely driven by the scale of the agriculture industry and the scale of demand for chemicals within the region. The Indonesia benchmark is approached towards 2050 as the regional gas market approaches sufficient scale to be robust and sustainable.

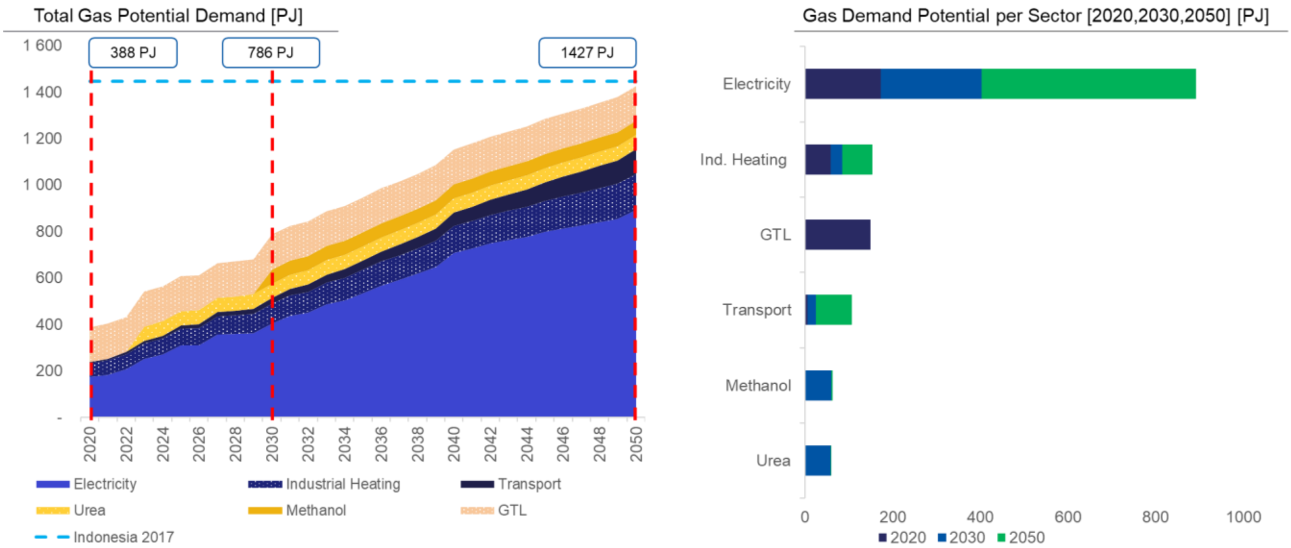


Figure 8-33: Base case total aggregated projected gas demand up to 2050

In the high case scenario (show in the figure below) total aggregate demand is 41% above the base case by 2050. This is a result of a gradual increase in natural gas uptake by Sasol, as it transitions from using coal to produce liquid hydrocarbons. Additional growth is also attributed to GTP growth as the share of natural gas in the electricity supply mix grows as well as an additional urea plant. The Indonesia benchmark is reached by 2040 as natural gas demand doubles by 2030 and an additional demand of ~640 PJ is added by 2050.

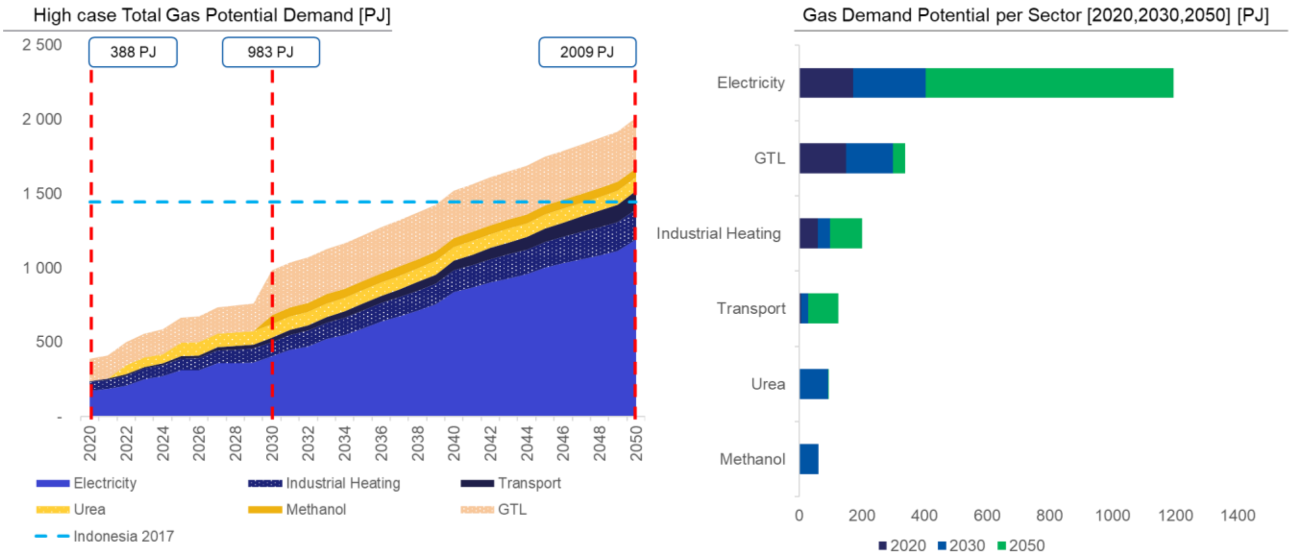


Figure 8-34: High case total aggregated projected gas demand up to 2050

In the low case scenario, total aggregate demand is reduced by 30% from the base case by 2050. Key differences include the lack of a methanol facility within the region and only a single urea plant. GTP potential beyond 2030 is reduced as electricity planning does not adjust to the increased availability of natural gas. GTL production remains unchanged as in the base case facility as current coal investments secure the supply of coal to Sasol up to 2050. In the low case scenario, the region does not reach Indonesia benchmark by 2050 as the potential of the gas market has been constrained.

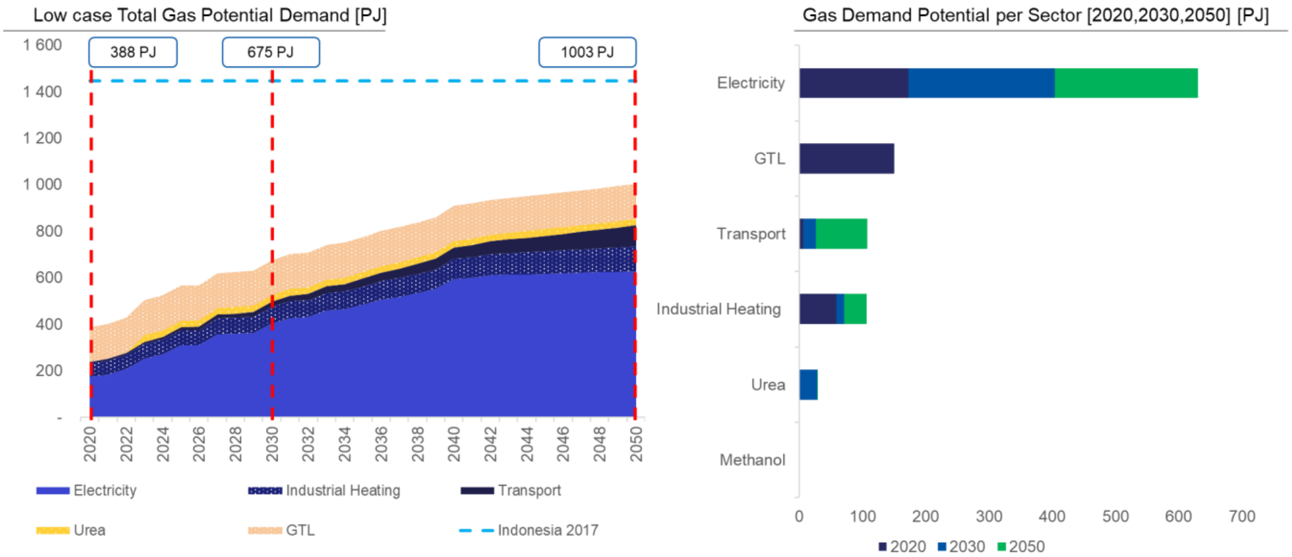


Figure 8-35: Low case total aggregated projected gas demand up to 2050

9. REGIONAL INTEGRATION

All countries in the region, separately and collectively through SADC membership, agree on the need for cooperating and collectively developing projects that are beneficial for the Region, in line with the SADC Protocol on Energy of 1996 (under review). Technically, it is possible, but with multiple political challenges to overcome – including but not limited to issues of sovereignty, sharing of benefits, perceptions of hegemony, long and short-term adverse impacts. These are all considerations that hamper and delay decision making when it comes to developments that transverse national borders.[166]

Multinational projects with regional goals are often difficult to design and implement, with success often being reliant on the structure of the intervention, including the enabling legal framework and tools available, both within the country context and within the regional context.[167] African nations have progressed in overcoming these issues, by approaching projects from a regional perspective. This is believed to be due to the multiple layers of existing enabling legal frameworks (e.g. SADC) in Africa that facilitate the undertaking of regional projects. However, a lack of oversight and enforcement capacity hinders the success of regional projects.

What follows is an analysis of what is required to enable and maximise the benefits of regional integration.

9.1 Regional Market Development

This report has considered the regional gas market as it would facilitate three forms of gas movement: the molecule in the form of natural gas or LNG, the electron in the form of gas generated power, and other products that would be traded within the region, including fertiliser and petrochemicals. Movement (trade) as described, occurs at both the midstream and downstream layers, and requires harmonisation of law and policy, regulation, aggregation, and infrastructure.

The study considers various existing and in-progress mechanisms that must be leveraged in the development of a regional gas market. There should be no replication of efforts, or attempts to 'reinvent the wheel'. What is required for the rapid realisation of the regional gas market, is making it a product of the successful execution of various continental and regional efforts already in existence.

9.1.1 Harmonisation

a) *Member States seek natural market integration, which most seamlessly occurs through the convergence of economic and social parameters. To enable this, countries must attempt to harmonise energy laws and policies across the region.*

However, establishing a common incentive and enforcement structure is difficult. SADC does not have any specific protocols on the harmonisation of sectoral policies, but its thematic areas of cooperation, through the directories, comprise components of policy harmonisation. This establishes the base for SADC to introduce energy policy guidelines that would assist the formulation or amendment of national energy policies by providing guidance on the **contents and methodologies** required.

[166] World Bank Group, 2014. Challenges, Lessons and Prospects for Operationalising Regional Projects in Asia: Legal and Institutional Aspects.
[167] World Bank Group, 2014. Challenges, Lessons and Prospects for Operationalising Regional Projects in Asia: Legal and Institutional Aspects.

SADC has the appropriate mandate to develop Model Energy Guidelines, which would introduce the broad objective for all Member States to provide universal energy security that is environmentally sustainable, affordable, and accessible, i.e. balancing the competing aims of the energy trilemma to achieve energy justice.

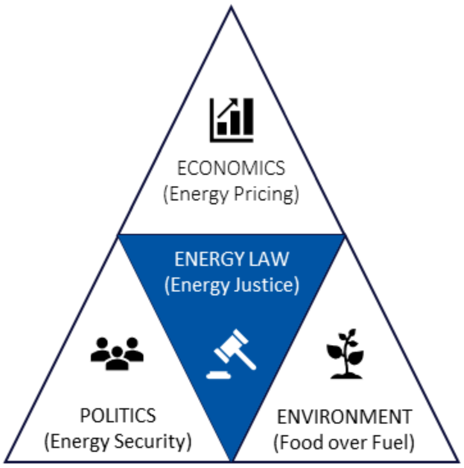


Figure 9-1 The Energy Trilemma. [168]

Such guidelines would encourage Member States to establish an investment friendly regulatory framework that would attract additional investment to the energy sector. This could mean different regulations for different sectors, but for example, the liberalisation of the electricity sector could enable additional investment in transmission, and therefore connection of communities to the grid, where the public sector would otherwise be unable to afford the expansion. Additionally, the guidelines would propose that Member State regulation of the energy sector be autonomous from the policy maker (Government) and service provider (for example, State-owned utility companies).

The guidelines would encourage the use of Integrated Energy Planning (IEP) as a methodology for projecting the demand of different fuel sources. IEP relates to a complex and unique tool of integrated long-term, model-based energy planning. This, in practice, requires analysis of current energy consumption trends within different sectors of the economy (i.e. agriculture, commerce, industry, residential and transport) and projecting future energy requirements, based on different scenarios. An integrated energy approach then determines the optimal mix of energy sources and technologies to meet those energy needs in the most cost-effective manner for each of the scenarios. The complexity of IEP arises from the fact that it accounts for different aspects (e.g. environmental, social, technological), different sectors (e.g. residential, transportation), different energy carriers (e.g. gas, oil, electricity), and diverse technologies required to extract, convert, transport, and distribute energy, where there are several dynamic links among components of the energy system.

If all Member States introduced integrated energy planning into their energy policies, the energy demands of all relevant sectors, for all forms of energy would be fully accounted for and represented, which would make energy planning more efficient and accurate. Having accurate demand projections for a country also facilitate and justify the development of energy generation, transport, and storage infrastructure.

b) *Efficient macroeconomic policy convergence underpins successful cross-border financial and monetary integration that stimulates trade among Member States.*[169]

[168] Heffron et al, 2018. Balancing the energy trilemma through the Energy Justice Metric.
[169] United Nations Economic Commission for Africa, 2020. Macroeconomic Policy Convergence.

A revised regional trade framework which aims for macroeconomic policy convergence as well as financial and monetary integration would therefore facilitate the development of a regional gas market. The development of the regional gas market will, fortuitously, occur in tandem with the negotiation and development phases of the African Continental Free Trade Agreement (the AfCFTA), the goals of which are in direct alignment with the requirements of regional gas market development.

The overarching aim of the AfCFTA is the creation of a single continent-wide market for goods and services and the promotion of the movement of capital and natural persons. Achieving this requires much cooperation and action on the part of Member States and Regional Economic Communities like SADC. According to Article 4 of the AfCFTA Agreement, for purposes of fulfilling and realising the objectives of the Agreement, Member States shall:

- Progressively eliminate tariffs and non-tariff barriers (NTBs) to trade in goods;
- Progressively liberalise trade in services;
- Cooperate on investment, intellectual property rights and competition policies;
- Cooperate on all trade-related areas between State Parties;
- Cooperate on customs matters and the implementation of trade-facilitation measures;
- Design a mechanism for the settlement of disputes concerning their rights and obligations; and,
- Establish and maintain an institutional framework for the implementation and administration of the Continental Free Trade Area

Through the reduction of import prices, the harmonisation of competition laws and the strengthening of regulatory rules, the AfCFTA can improve the protection of consumers by removing anti-competitive practices (price fixing and monopolisation, etc.), the effect being the potential reduction in the prices of gas and gas products. On the supply side, by enabling energy products to flow more smoothly between nations, the AfCFTA will make it possible for suppliers to meet the energy needs of Member States efficiently and affordably.[170]

9.1.2 Infrastructure

The elimination of tariff barriers through the AfCFTA will be futile without dealing with the NTBs that exist, including non-uniform standards and regulations and poor infrastructure that create major bottlenecks. These include poor port logistics, poor roads, many weighbridges, numerous police roadblocks/checks and cumbersome cross-border procedures.

The inter-connectivity of the region will therefore depend on improvements in port facilities and greater investments in roads and rail, which constitute vital arteries in the transport corridors of the region. It is important to utilise existing infrastructure in order to reduce capital expenditure, leverage off existing markets and reduce overall risk, ultimately improving the investment possibility. Existing infrastructure to be leveraged includes:

- Electricity Transmission Infrastructure and Interconnectors,
- Pipeline Infrastructure, and
- Road, Rail and Port Networks

9.1.2.1 Economic Corridors

Corridors, as introduced above, are a collection of routes linking several economic centres, countries and ports with emphasis placed on cross-border trade. On a higher level, however, an economic corridor can be understood as a conceptual and programmatic model to leverage existing population

[170] DLA Piper, 2019. Can AfCFTA solve Africa's energy challenge?

and economic activities to structure development along existing transportation infrastructure. Through creating a dynamic business environment along the corridors, Member States harness sector linkages, enhance cross-border trade, and maximise economic growth. Political boundaries cease to be economic boundaries and thus spatial-economic regional planning takes the lead.

The defining feature of economic corridors is that they provide a platform for integrating investments in infrastructure, a platform for harmonising policy and regulatory frameworks, and a platform for aligning political will and institutional governance. SADC, along with other African RECs, have used and recommended this as a key mechanism to achieving socio-economic development.

Specifically, the revised Regional Indicative Strategic Development Plan (RISDP) 2015-2020 and the recently drafted DISDP 2020-2030 Blueprints, which put an emphasis on industrialisation to facilitate deepening and acceleration of market integration, highlight economic corridors as key interventions towards its achievement. The illustration below highlights the particular strategic objectives, under the four RISDP priorities, that can specifically be achieved through the use of economic corridors.

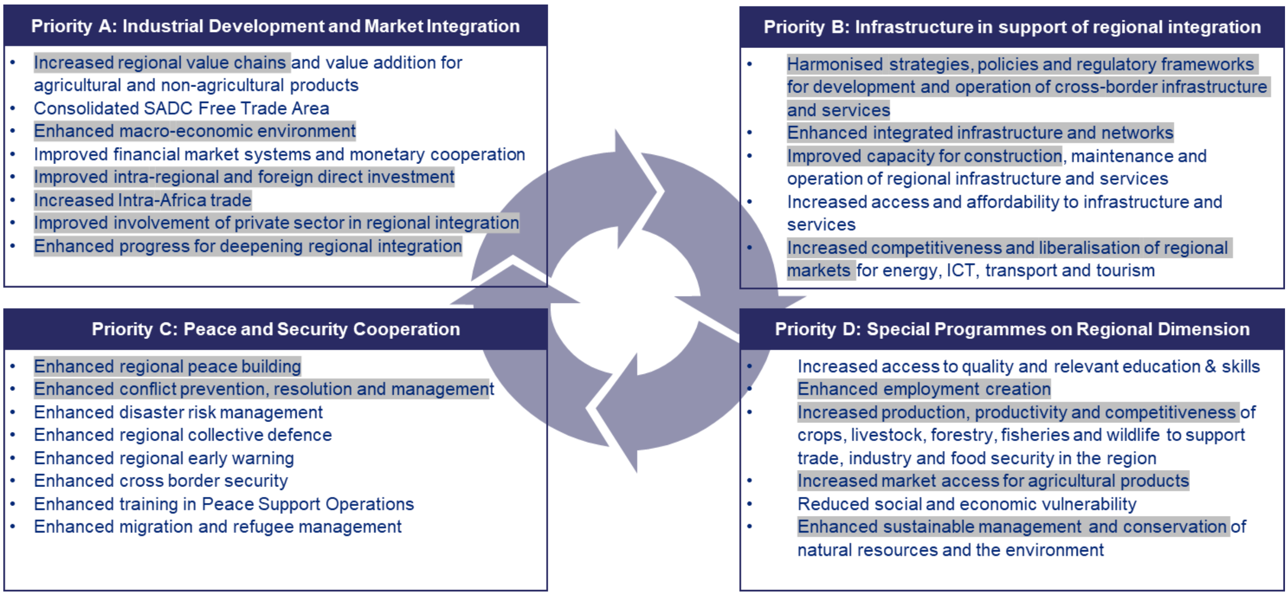


Figure 9-2 Highlighted RISDP strategic objectives that can be achieved through the use of economic corridors.

Over the years, SADC has exercised economic corridors as a development mechanism through the following projects: Bas Conga Development Corridor, Southern Agricultural Growth Corridor of the United Republic of Tanzania, Maputo Development Corridor, and the North-South Corridor.

These corridors were analysed as case studies during this report, with lessons learnt being divided into the following three tools for implementation. These tools are effective in elevating regional projects to economic corridor status, toward the end goal of achieving a regional gas market.

Strategic Planning

Success lies in strategic planning and a strategic visioning. Regional project developers can achieve development outcomes by carefully coordinating the social, economic, and physical development of the corridors and their surroundings. Strategic planning tools are essential to this process, as is close cooperation among the participating Member States, which must harmonise their policies and their social and economic strategies and address other common issues.

Because several countries belong to two or more Regional Economic Communities (RECs), economic corridors within SADC will entail intra-SADC cross border challenges, as well as inter-REC challenges. There may be conflicting border requirements, and a lack of cooperation between countries that are not within the same REC. Regional collaboration and careful planning of the corridors is therefore key. Achieving the free movement of goods, services, labour, and capital requires investments at several levels, namely:

- the development of adequate 'hard' or physical infrastructure, including regional transport links and energy and telecommunications networks, together with institutional arrangements for their management and maintenance.
- 'soft' or institutional infrastructure to facilitate cross-border transactions and allow the integration of national markets. This includes dismantling certain regulatory barriers to trade and harmonising essential policies and institutions among trading partners

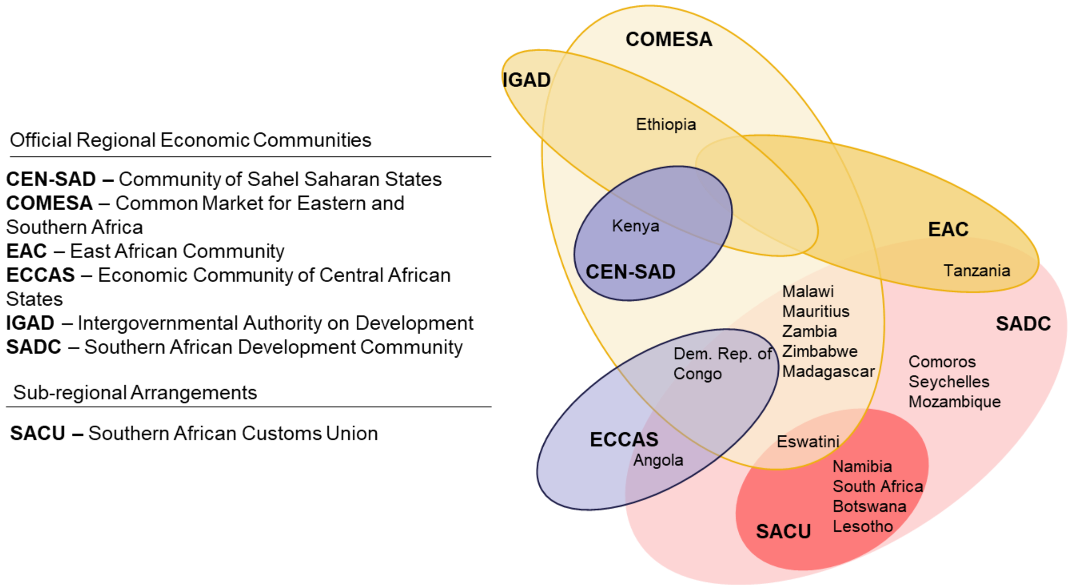


Figure 9-3: Overlapping RECs

Governing Instruments

Energy markets globally are typically governed by Intergovernmental Memoranda of Understanding (MoU) or bilateral treaties focusing on strategic nodes, rather than multilateral initiatives. The case studies conducted regionally and internationally showed the benefit of an MoU being signed in the early stages of development, between all Member States participating in the proposed economic corridor.

The contents of such an MoU vary according to local factors, however, it is a mechanism that establishes agreement that the Member States will cooperate in establishing regional gas market integration between their countries[171] by recognising

- an agreed action plan for enabling a regional market (which, in the SADC case, would be the RGMP),
- the need to foster competition,
- the need to ensure conformity of supply contracts and implementation of energy market rules, and
- the need to better coordinate regional infrastructure projects.

[171] The development of the Baltic Regional Gas Market was considered in this regard.

In addition to the overarching legal agreement provided in an MoU, a corridor requires regulation in the form of various other soft instruments: nation legal instruments, trade facilitation (customs cooperation and incentives), financial and risk management instruments, institutional strengthening and human resource development. These are all additional governing instruments that should be considered in the planning of economic corridors.

Corridor Management

The efficiency and effectiveness of an economic corridor is largely determined by the role played by the Corridor Management Groups or Institutions (CMG or CMI, used interchangeably) that oversees its operations. A CMI typically includes the various government ministries involved in trade such as customs, trade, immigration and transport, while from the private sector it includes the agencies such as the Chambers of Commerce, logistics associations, trade agencies and other individual companies. They facilitate dialogue between corridor stakeholders and RECs such as SADC, in the aim of harmonising procedures and documentation used in transport and transit operations along the corridors, resulting in reduced transit time and cost.[172]

Various institutions have recommended that a semi-autonomous public-private partnership is generally well-suited for this role as this, ideally, would improve efficiency, accountability for the provision and delivery of quality outputs.[173]

Case Study: The Walvis Bay Transport Corridor

The Walvis Bay Corridor (WBC) is an economic corridor under South Africa’s Spatial Development Initiative, initiated by the two governments of South Africa and Namibia. The WBC is a network of routes that links the SADC to the Port of Walvis Bay on Namibia’s southwest coast, offering the region a gateway to transatlantic trade routes and markets. It runs through Namibia, Zambia, Zimbabwe, Botswana, Angola, and South Africa and indirectly to the Democratic Republic of Congo. The corridor system consists of roads, railways, and shipping services; it has a wide catchment area of customers and commodities.

The CMI in this economic corridor is the Walvis Bay Corridor Group (WBCG), a public-private partnership established in 2000 to promote transport and trade along the WBC. The WBCG is governed by a board of directors with day-to-day operations handled by a technical secretariat. The initiative has made significant success in a number of areas, including institutional set-up, the development of infrastructure, and the facilitation of trade.

9.1.2.2 Power Pools

Much like the need for road and border infrastructures to create a regional market to trade goods, the Southern African Power Pool (SAPP) is a necessary regional network and market to trade and transfer electrical power between utilities within SADC. It provides an integrated transmission grid that can create and exploit economies of scale in generation, transmission, and distribution. Unlike most power pools, SAPP does not have a regional regulatory authority, however this is likely to change (see section 9.1.4).

[172] African Corridor Management Alliance, 2017. A Comprehensive Strategy Document to Support the Architecture of the African Corridor Management Alliance.
[173] AfDB, 2013. Regional Integration Paper:

Case Study: The Southern African Power Pool

SAPP was the first power pool created in Africa, following the SADC Summit in 1995, and is currently the most advanced regional power pool in Africa. In 1992, a severe drought hit Southern Africa, which severely impacted SADC's hydropower producers such as Zambia, Malawi, and Zimbabwe. The resulting power shortages fueled the need for energy cooperation between hydro-rich countries in the North and thermal-rich South Africa in the South, at that time an electricity surplus country due to its coal reserves. The convergence of interests, and dynamics of supply and demand therefore fueled its creation. SAPP's objectives are:

a) to promote and increase investments in electricity production, transmission, and distribution infrastructure,
b) to create a regional regulatory framework for pooling energy resources, including the establishment of common standards, rules, and monitoring mechanism of systems performance, with a view to promote power exchanges between utilities,
c) to coordinate the long-term energy development in the region, and
d) to develop regional expertise, training courses and research, with the objective to focus on rural electricity access, and renewable energy.

SAPP has a combination of participants: utility scale companies, whether national producers, fully independent or partially state-owned power producers (IPP) such as Hidroelectrica de Cahora Bassa, as well as independent transmission companies (such as Mozambique Transmission Company - MOTRACO). The pool was first built off of existing bilateral contracts, which in 2001 developed into a regional competitive market platform for energy trade. The following are market mechanisms that have developed over time:

- Day Ahead Market (DAM), a competitive market that trades (via a double-sided auction process) hourly energy contracts for the following day inclusive of existing bilateral contracts (cleared first), transmission capacity constraints and wheeling fees.
- Intra Day Market (IDM) which enables trades up to one hour prior to delivery, which allows utilities to adapt their purchasing volume if they failed to cover their needs in the DAM. The IDM matches market participants automatically on a first-come first-serve basis if a seller's offer price is less than a buyer's bid price and a seller's volume is lower (or equal to) a buyer's volume.

In recent years, responsive market innovations have been developed, including the balancing market and financial markets, and have resulted in an expansion of regional market share from 0% of the total of cross-border trade in 2009 to 21% in December 2019.[174] Flexible regional purchasing agreements (vs. bilateral agreements) can contribute significantly to energy security by providing a solution for peak demand situations and can even go hand in hand with regional solidarity.

In order to enhance the opportunity for gas generated power to be traded through the SAPP, the network must be developed and extended throughout the region, non-operating SAPP members must be connected, and transmission congestion must be relieved. To this end, the SAPP Pool Plan was adopted, which seeks to contribute to the enhancement and stabilisation of generation and transmission infrastructure through short and medium-term interventions.

According to the recently released RISDP 2020-2030 Blueprints, the SADC Secretariat itself will be spearheading the development of a Regional Transmission Infrastructure Program in order to unlock

[174] SAPP Market Monthly Performance Report, January 2020.

transmission constraints.[175] This program will assist in the harmonisation and standardisation of participation on the SAPP network, which is integral to increasing the amount of power traded within it. Specifically, it is stated that the SADC Secretariat will be filling the regulatory gaps such as:

- adopting a uniform, transparent and non-discriminatory regime of open access to the regional transmission grid,
- harmonising grid codes,
- developing an updated transmission pricing methodology for fair benefits sharing mechanisms between the countries, and
- channelling financing from the Cooperating Partners, private and public sector through the establishment and operationalisation of an innovative and sustainable financing mechanism which will focus on addressing both physical (hard) infrastructure and corresponding enabling policy measures (soft) infrastructure pertaining to power transmission.

It is noted that the Secretariat is undertaking the coordination of priority projects under the SAPP Plan, and it will be convening and coordinating inter-governmental and inter power authority platforms to ensure that bilateral and multilateral agreements can be reached on the implementation of SAPP programmes at the national level. This synergistic relationship between SADC and SAPP is hugely beneficial towards the accelerated development of SAPP's capabilities, and therefore increased opportunities for gas to power generation to be added to the grid.

9.1.3 Aggregation

Although different commodities, lessons from the SAPP case study can be applied in the development of a regional gas market. Some countries have more to gain than others from trading regionally and the distinction between energy importers and exporters should be understood. Each countries' needs, interests and constraints or even risks for engaging with their neighbours need to be taken into consideration when working on enabling a regional market.[176] The cost benefit evaluation of participation will ultimately be the determining factor of success. This therefore needs to be made clear to SADC Member States when pitching the regional gas market mechanisms. Different national interests must be represented in a way that complements others, so that collective participation can be combined to achieve the regional goals.

Ultimately, regional markets depend on a critical mass of surplus capacity, which on the African continent has been in short supply. The structural deficit in many of the regions does not make a strong case for expensive infrastructure investments. African regions and countries therefore need to aggregate the demand sufficiently. Once the demand volume is sufficient, and major infrastructure projects are justified, regional energy dynamics can shift relatively quickly.

Research has identified several stages in the development of regional gas markets, as both the supply and demand volumes increase. At the nascent stage of the market, a centralised approach is taken to manage the exploitation of natural gas resources as there are either none or few market participants apart from (centrally) planned end-use projects for natural gas monetisation. As the potential for competition across the natural gas value chain increases, measures are required to open the market for participation by private institutions or individuals, as shown in the table below.

Table 9-1: Natural Gas Market Models[177]

[175] As highlighted in the recently released RISDP 2020-2030 Blueprints.
[176] ECDPM, 2019. African Power Pools: Regional Energy, National Power.
[177] The Emergence of Market in the Natural Gas Industry, A. Juris, 20, 1998

Stage	Model	Description
1.	Vertical Integration	• A single entity produces, transports, and distributes natural gas to end-users as an integrated utility. • Due to the utilities' monopoly in the retail market, a regulator is required to ensure fairness in the setting of natural gas prices
2.	Producer Competition	• Competition is introduced amongst natural gas producers while midstream and downstream components of the value chain are controlled by an integrated utility. • In this sense, supply from various sources is aggregated by the utility (as a wholesaler) who then resells natural gas into the retail market. • Regulation is required to ensure fairness for both end-users and producers; however, regulated pricing mechanisms are often less efficient than price discovery through free markets.
3.	Wholesale Competition	• The mid-stream of the value chain is open to private participants, and several mid-stream players compete for the wholesale of natural gas. • Natural gas utility participates as a wholesaler whilst offering transportation services to large end-users. • Alternatively, the utility only operates the infrastructure (e.g. pipelines) required to transport and distribute natural gas while third parties actively trade natural gas within the wholesale market.
4.	Retail Competition	• Private institutions are active across the entire value chain and less restricted and less regulated natural gas market. • The utility still operates and provides access to transportation infrastructure to facilitate the fulfilment of physical gas transfers. • Regulators are incentivised to maintain a dynamic and efficient natural gas market by enabling competition across the value chain and minimising market failures (e.g. monopolies, collusion, etc.).

SADC is largely in the first to second stage as several countries possess active natural gas value chains. This is likely to stay true in the short term as strategies and policies concerning the utilisation of natural gas are promulgated and additional strategic projects are commissioned to further establish natural gas consumption within the region. The long-term development of the natural gas market within the region will depend upon the sustainability of domestic consumption which can be considered across three factors:

1. Sufficient natural gas needs to be available with the region to meet future demand. To this end, significant quantities of gas are available within the region with gas production set to increase in the short to medium term. The forecasted demand for natural gas within the region could be ~44% of the available supply by 2030, although, the region will need to consider the potential impact of international export trade agreements as a constraint on domestic supply and the growth of the domestic market.
2. Midstream and downstream infrastructure will be necessary for natural gas to be accessible to end-users. Several infrastructure options are available; however, their economics must scale appropriately with the demand potential across the region to ensure adequate returns on investment. The greater the dispersion of end-users across geography, the greater the level of total demand required to offset capital and operational infrastructure costs whilst also minimising the average cost of gas transport services. Capital intensive pipeline infrastructure

transports most natural gas between supply and demand nodes within the SADC region while LNG liquefaction and regasification facilities enable international gas trade. The growth in the application of small-scale LNG in global natural gas trade and distribution indicates the lower barriers to entry required to develop midstream infrastructure to transport gas, which SADC can take advantage of.

3. The affordability of natural gas will depend on the scale of demand present and the pricing mechanisms at play (i.e. regulated pricing or market pricing). The acquisition of natural gas and transportation services is often complex, and for some market participants, it may be too difficult and costly. High transaction costs can even discourage smaller market participants from utilising open access markets, despite opportunities for cost saving. The regional gas market will likely be regulated in terms of price in the medium to long term and will need to consider and balance the utility and value of natural gas to end-users (as it competes with other sources primary energy/feedstock) with the marginal production, transportation, and capital costs of producers. This will be confronted by the socio-economic status of a significant proportion of the SADC population who require economic development to afford the consumption of higher quality energy sources.

The comparison of the current and potential gas market within the SADC region with the current Indonesian market indicated the level of scale required to develop a sustainable market, which is achievable through the aggregation of demand and/or supply with the region. Considering the concentration of supply and the potential distribution of demand (particularly if gas off-takers enter the market), aggregation would be required on a wholesale basis for distribution across downstream sectors. The aggregator would have the function of accumulating and consolidating demand to strengthen buying power when engaging with upstream and/or mid-stream gas sellers in the region. The competitiveness of this trade will be impacted by the level of competition by natural gas producers for market share in the domestic natural gas market and the level of transport infrastructure integration across the region to fulfil the delivery of gas across national borders.

Several models can be utilised to operate an aggregator depending upon the requirements of the market being developed and the regulatory dynamics of the market. The table below summarises several aggregator models.

Table 9-2: Aggregator Models

Aggregator Model	Description
Buyer/Seller Block	The aggregator leverages its dominance within the market to aggregate supply and/or supply. In open markets, this generally applies to companies that have a monopoly or monopsony. In regulated markets, this is often a vertically integrated utility which has some competition in certain areas of the value chain.
Buy/Sell Principle	The aggregator (usually a utility) acts the principle buying and/or selling agent within the market, particularly at a wholesale level. This form of aggregation can occur in two ways:
Brokerage	The aggregator facilitates the sale and purchasing of natural gas without getting involved in the contracting for the commodity.
Government Consolidation	The aggregator plays the role of the regulator with exclusive rights to manage all aspects of the country's gas sector.
Price Consolidation	The aggregator acts as price harmoniser, ensuring that all buyers, no matter the industry or purchasing power, can purchase gas.

Considering these options, the first two models propose an aggregator which actively participates in the market and contracts for natural gas where its strong economic position (whether direct or representative) enables favourable price discovery which is proportional to the volume being traded. The last three models propose an aggregator which does not actively participate but has sufficient powers to facilitate price discovery. The SAPP follows a brokerage model within the regional electricity market as it does not buy or sell electricity while facilitating price discovery through an open bid process between buyers and sellers. This considers interconnector routing requirements to facilitate trade.

The SAPP brokerage model, which has been successful in the region is a key learning tool for the development of regional gas aggregator which would consolidate the demand of national aggregators within the region against supply. This will facilitate cross-border, where transparency, fairness and competitive mechanisms are required to establish trust and cooperation between Member States and their entities.

Price Determination Mechanisms

Contracts for natural gas can be priced against other (non-natural gas) energy commodities. This is commonly done by indexing natural gas prices against existing oil benchmarks (either global benchmarks like Brent or WTI, or regional benchmarks like Japan Customs-cleared Crude) and linking the two by comparing their potential thermal energy output. The benefit of this approach is that pricing broadly reflects prices for other energy commodities in the relevant region.

This approach is not without its downside, however. As trading volumes of LNG increase, it is becoming clearer how distinct it is from other energy products (including oil). Pricing via oil indexation can lead to a variation in gas prices based on factors specific to oil and its sale (including the imposition of sanctions or tariffs, or conflicts in oil-producing regions). In many situations, using this method to price LNG is relatively problem-free, although risk is introduced wherever the fundamentals of oil and gas markets diverge.

Indeed, Europe is transitioning from oil indexation to hub indexation[178]. This is the practice where gas prices are indexed to prices at a well-established gas trading hub. If LNG is being sold into a region that already has an established gas market, pricing can be set according to the local hub, which reflects both the fundamentals of the commodity and local market conditions. However, a sparsity of local hubs means that problems can arise when LNG is priced against those far away, with different economic and market conditions.

The long-term opportunity for the SADC region is to develop a physical gas trading hub, leveraging off existing demand, infrastructure, and supply, thereby creating a mechanism for which price discovery can occur in a transparent, fair, and equitable manner allowing for trading of the commodity. The key risk in establishing a SADC Hub, is that markets without well-developed systems and benchmarks are at risk of relying on pricing systems that do not represent gas trading in the relevant market.

The implication is that a stepwise approach will have to be undertaken in developing the regional market, including relying upon regulatory mechanisms to stimulate market development, while transitioning towards the establishment of a regional hub. The regional market should exhibit the following elements prior to the transition:

- Clear government and intergovernmental support;
- Market liberalisation toward market competition;

[178] A hub, or a trading point, is the place where buyers and sellers exchange the ownership of gas on paper and in physical delivery. The basic role of the hub is the transport of gas from suppliers to consumers as per the contracts at their time of maturity. Gas in a hub has a single price.

- Access to infrastructure;
- Multiple market participants; and,
- Confidence in transparent price formation.

9.1.4 Regulation

12 SADC Member States out of the 16 have existing electricity regulatory authorities. From these, ten currently hold membership with the Regional Electricity Regulation Association (RERA), and they are shown in Table 9-3.

Table 9-3: RERA member states and respective national regulatory authority

Member State	National Electricity Regulatory Entity
Angola	Institute for Electricity and Water Services Regulation (IRSEA)
Eswatini	Eswatini Energy Regulatory Authority (ESERA)
Lesotho	Lesotho Electricity and Water Authority
Malawi	Malawi Energy Regulatory Authority (MERA)
Mozambique	National Electricity Advisory Council (CNELEC)
Namibia	Electricity Control Board (ECB)
South Africa	National Energy Regulator of South Africa (NERSA)
Tanzania	Energy & Water Utilities Regulatory Authority (EWURA)
Zambia	Energy Regulation Board (ERB)
Zimbabwe	Zimbabwe Energy Regulatory Authority (ZERA)

RERA was formed in 2002 to facilitate the harmonisation of power trading legislation, policies, standards, and practices in Southern Africa. It is a formal association of electricity regulators within the SADC region, with the following strategic objectives:[179]

- Capacity building and information sharing: Facilitate electricity regulatory capacity through information sharing and skills training.
- Facilitation of Electricity Supply Industry Policy, Legislation, and Regulations, focusing on terms and conditions for access to transmission capacity and tariffs.
- Regional Regulatory Cooperation: make recommendations on issues that affect economic efficiency of electricity interconnections, and electricity trade, that fall outside of national jurisdictions.

Currently, RERA plays a recommendatory role without powers to give regulatory directive within the SADC energy sector. This has been seen to cause regional regulatory unpredictability due to lack of clear and enforceable regulations, which has curtailed public and private investment. This has impeded the growth in regional energy trade. To address this, RERA formulated the Regulatory Guidelines for the SADC Power Sector regulators, which would provide certainty for long-term cross border transactions, while offering protection for consumers in buying, selling, and transit countries.[180] However, regulatory authorities voluntarily subscribe to RERA recommendations, which limits implementation, monitoring and enforcement.

Through the adoption of the RIDMP in 2012, SADC Head of States agreed that RERA should be transformed into the SADC Regional Energy Regulatory Authority (SARERA), which would be granted

[179] RERA, 2014. RERA Publication on Electricity Tariffs & Selected Performance Indicators for the SADC Region.
[180] RERA, 2010. Manual for RERA Guidelines for Regulating Cross-border Power Trading.

regulatory power over cross-border energy trade, facilitation of cross-border energy infrastructure investment, and energy regulatory capacity building.[181]

Once this transition has taken place, it is expected that SARERA will be capacitated to provide a methodology for setting of cross-border electricity, natural gas, and natural gas petrochemical products transmission, and products tariffs. It should also provide regulations for non-discriminate access to natural gas pipelines and electricity networks by third parties, as well as standards for natural gas products for the SADC region. Finally, as an institution, it will support and facilitate cross-border energy sector investment initiatives.

As previously mentioned, this Report draws on regional developments already in the works that would facilitate the development of the regional gas market. It is therefore proposed that SARERA would have the role of implementing rules for participation within the SAGP, as well as monitor and evaluate compliance with market rules (fairness, transparency etc. in order to eliminate anti-competitive behaviour). It is further expected that SARERA will oversee power pool operations within SAPP, in charge of regulating regional energy trade and facilitating the harmonisation of regulatory policies, legislation, standards, and practices.

9.2 Domestic Market Development

Regional market development does not happen in isolation. Member States must facilitate the process by ensuring that their own domestic markets provide an enabling environment. What follows is an assessment of the enabling dimensions, as proposed by the World Economic Forum, that must be present in order to attract investment and catalyse development. For purposes of this study, the enabling dimensions were considered based on its centrality to market development and enablement, and for consistency in analysis. This includes:

- Capital and Investment. The availability of capital and the macro-economic and fiscal conditions for investment.
- Policy, Legislative & Regulatory. Policy direction, legislative and regulatory frameworks, with maturity, certainty, and consistency in application.
- Institutions & Governance. Roles and responsibilities of key governance entities within the regulatory, public, and private domains.
- Infrastructure & Market Structure. Quality of infrastructure, market size and 3rd party access.
- People: Capacity & Participation. The necessary skills, competencies, and talent in developing technical value chains and thereby providing the human capital.
- Energy System Structure. Maturity of the market and energy system structure, including energy mix (i.e. fossil fuels, renewable etc.)

The enabling dimensions, as indicated above, have different requirements across the gas value chain. From an upstream perspective, key drivers would include the fiscal regime adopted, while midstream requirements speak to the role of aggregator and infrastructure owner. Finally, downstream elements speak to the market structure entered (e.g. electricity sector), as well as accessibility, affordability, and security of the molecule for end-users. The dimensions indicated are evaluated through quantitative and qualitative analysis for each country.

The analyses of the enabling dimensions for the energy sector were carried out as per the following framework, adapted from World Bank and World Economic Forum Indicators on Competitiveness.

[181] SADC, 2019. Development of a framework and roadmap for the Establishment of a Regional Energy Regulatory Authority for SADC.

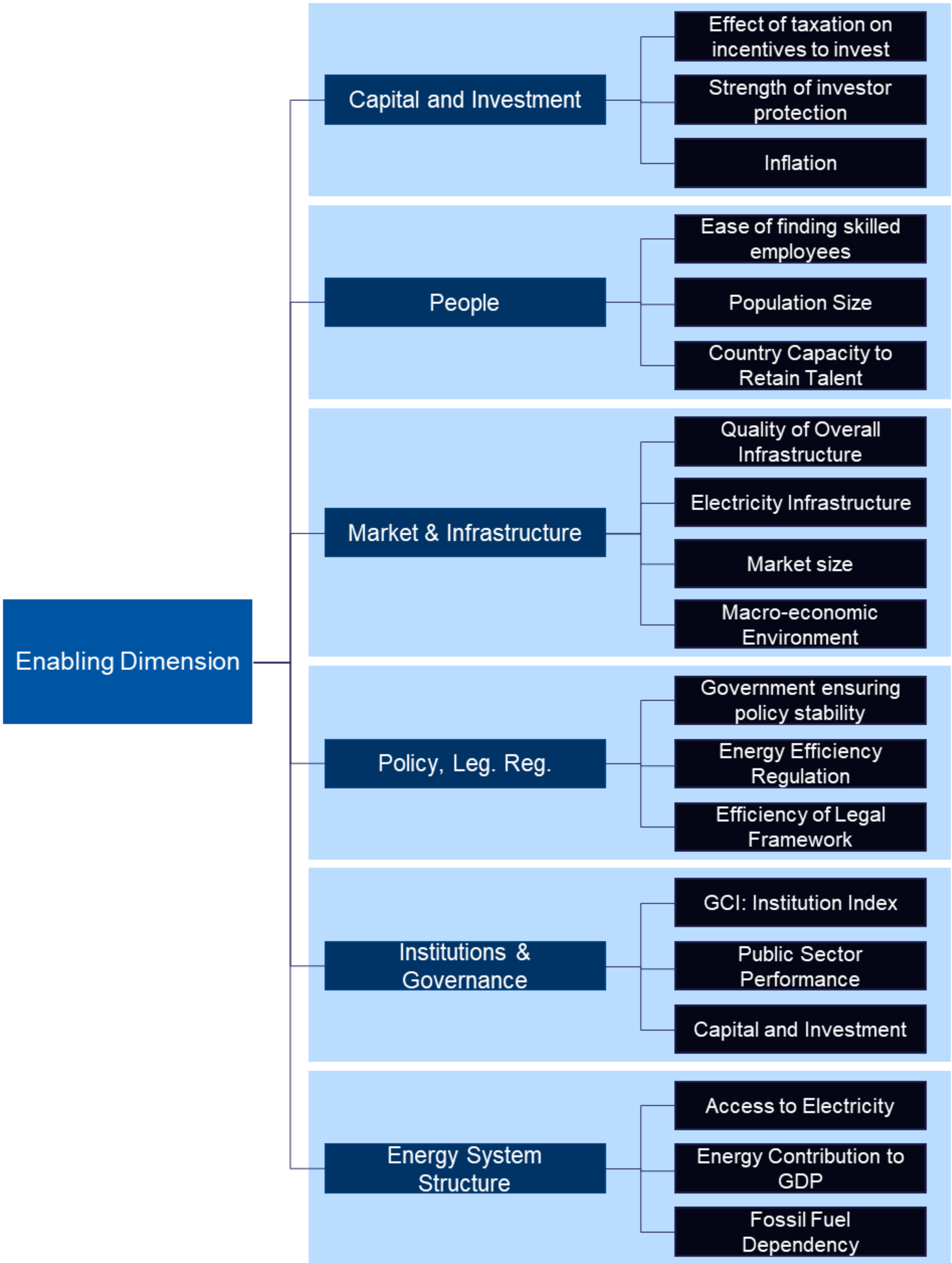


Figure 9-4: Application of Enabling Dimensions and their Indicators (quantitative assessment)[182]

[182] The enabling dimensions and indicators for different sectors (ICT, transport, water) would be largely similar with specific nuances. These have been considered insofar as they support the energy sector.

9.2.1 Capital and Investment

A stable macro-economic environment, with investor protection, is necessary to attract capital flows, which are required for market development and growth, into a country. The effect of taxation on incentives to invest, the strength of investor protection and inflation were considered as proxies for the analysis.

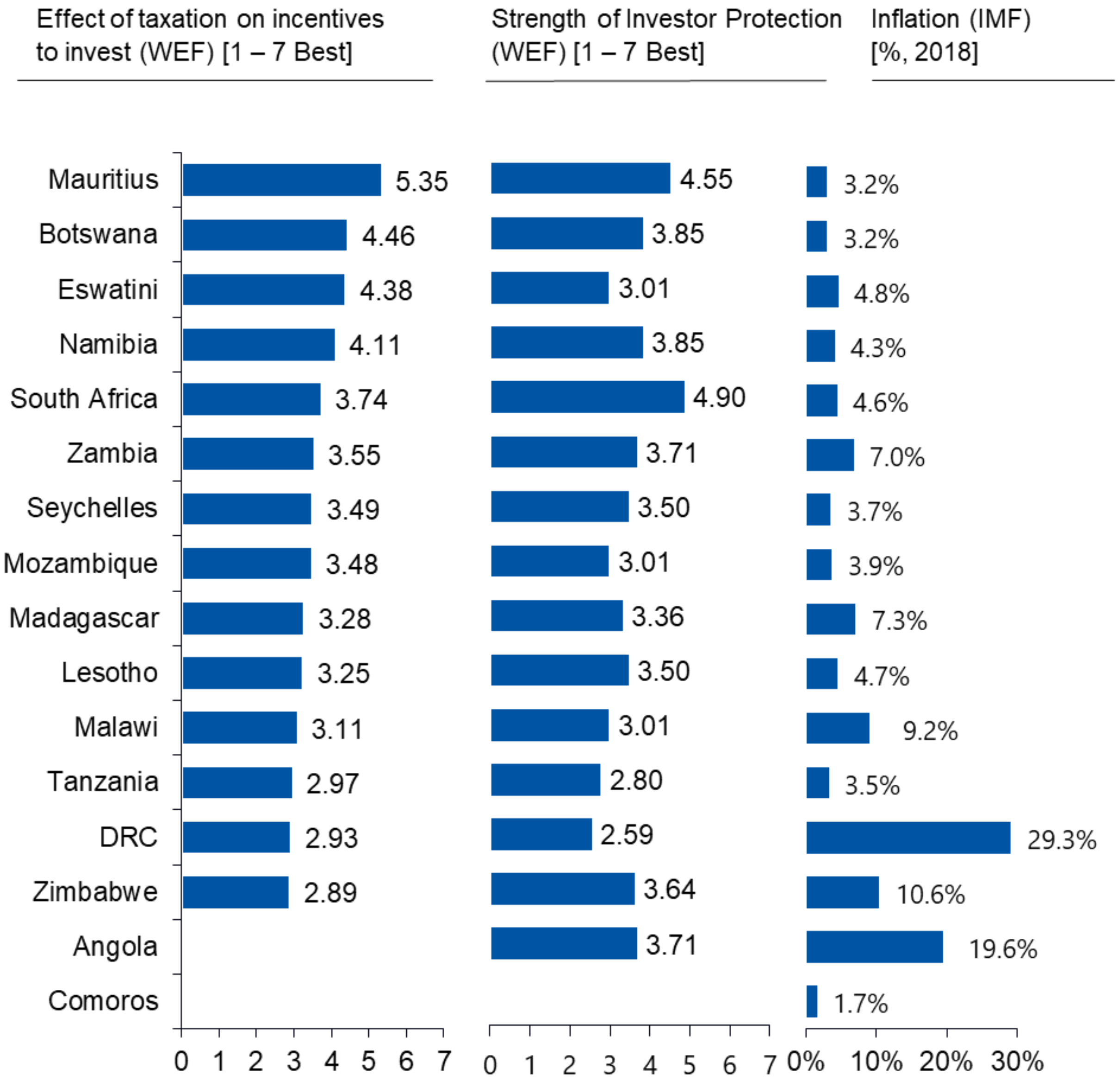


Figure 9-5: Capital and Investment Dimensions[183]

SADC Member States are on the global average, with certain outliers (such as Mauritius), providing moderately attractive environments for investment. The regional average of 3.64 out of 7 shows a general willingness to attract investors through tax incentives, but also indicates that more can be done in this regard. Although tax incentives do represent a cost to countries (in terms of lost revenue), the growth and development generated by the investments that well developed tax incentives attract can far outweigh the costs. Furthermore, given the ease with which capital can move globally,

[183] World Economic Forum Global Competitiveness Index 2017-2018, and the International Monetary Fund, 2018.

countries seeking investment are competing against tax incentives offered in other parts of the world. With room for improvement in terms of electricity access, most SADC Member States require investment in the energy sector.

The payoff from protecting investors is significant. Where expropriation of minority investors is curbed, equity investment is higher and ownership concentration lower. Investors gain portfolio diversification, and entrepreneurs gain access to capital. Without investor protections, markets fail to develop, and banks become the only source of finance. Yet weak collateral or property registration systems block many businesses in poor countries from obtaining even bank loans. The result is that businesses do not reach efficient size for lack of financing, and economic growth is held back.

Inflation, and its effects on interest and exchange rates, is a particularly useful metric for investors. A high inflation rate negatively affects investment as it can lead to cost overruns on projects, while high-interest rates affect the rate of return for investors. Furthermore, the effects of high inflation on exchange rates are well documented, and currency risk can be a significant deterrent to investment. Most of the SADC Member States currently have (and importantly, are expected to have) inflation rates which can be considered to be attractive to investors (ranging between 1.7% and 4.8%). However, inflation in the DRC (29.3%), Angola (19.6%), Zimbabwe (10.6%) and Malawi (9.2%) could negatively impact investment into those countries.

9.2.2 People

Unfavourable labour market conditions can pose a significant hurdle to growth and development. Technical environments, such as the gas value chain, require technical skills. This requires that countries not only develop the required skills but also develop the capacity to retain talent in the country. In this regard, SADC Member States face significant challenges. In terms of the ease of finding skilled employees, the regional average is 3.88/7, however only Mauritius (4.04), Seychelles (4.12), Tanzania (4.29), Zimbabwe (4.38) and Zambia (4.76) score above 4/7. South Africa just falls short with a score of 3.94 for the year 2019. Within the gas value chain specifically, these figures are likely to be even lower.

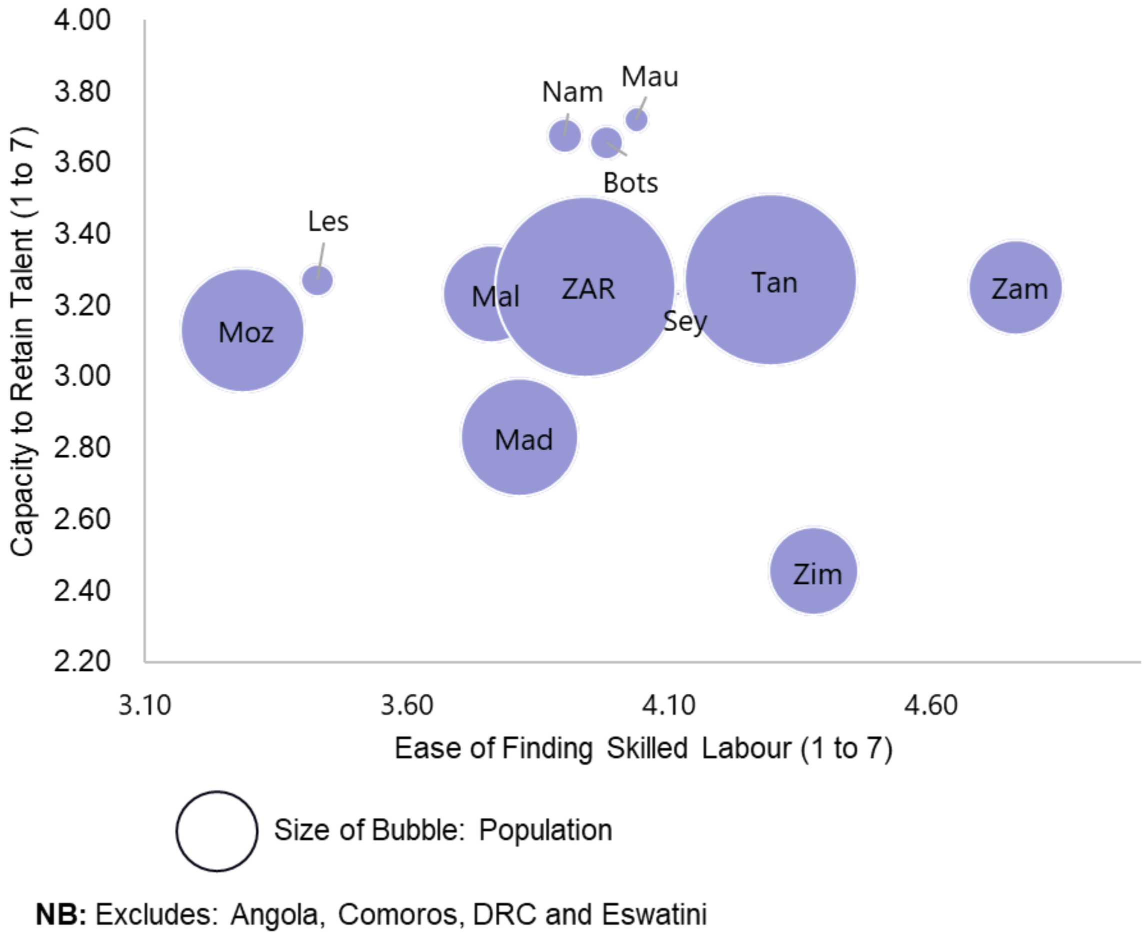


Figure 9-6: People Dimension

Of even greater concern to SADC Member States is the apparent lack of capacity to retain talent. Only Mauritius (3.72), Namibia (3.68) and Botswana (3.66) score above 3.5/7. This indicates that often, skilled individuals within SADC Member States are leaving to seek opportunities abroad.

9.2.3 Market and Infrastructure

The availability of good quality and accessible infrastructure is one of the key enablers for economic development. This attracts foreign and local investors with intent to operate in different sectors of the economy. The Government is largely responsible for the development and governing of infrastructure.

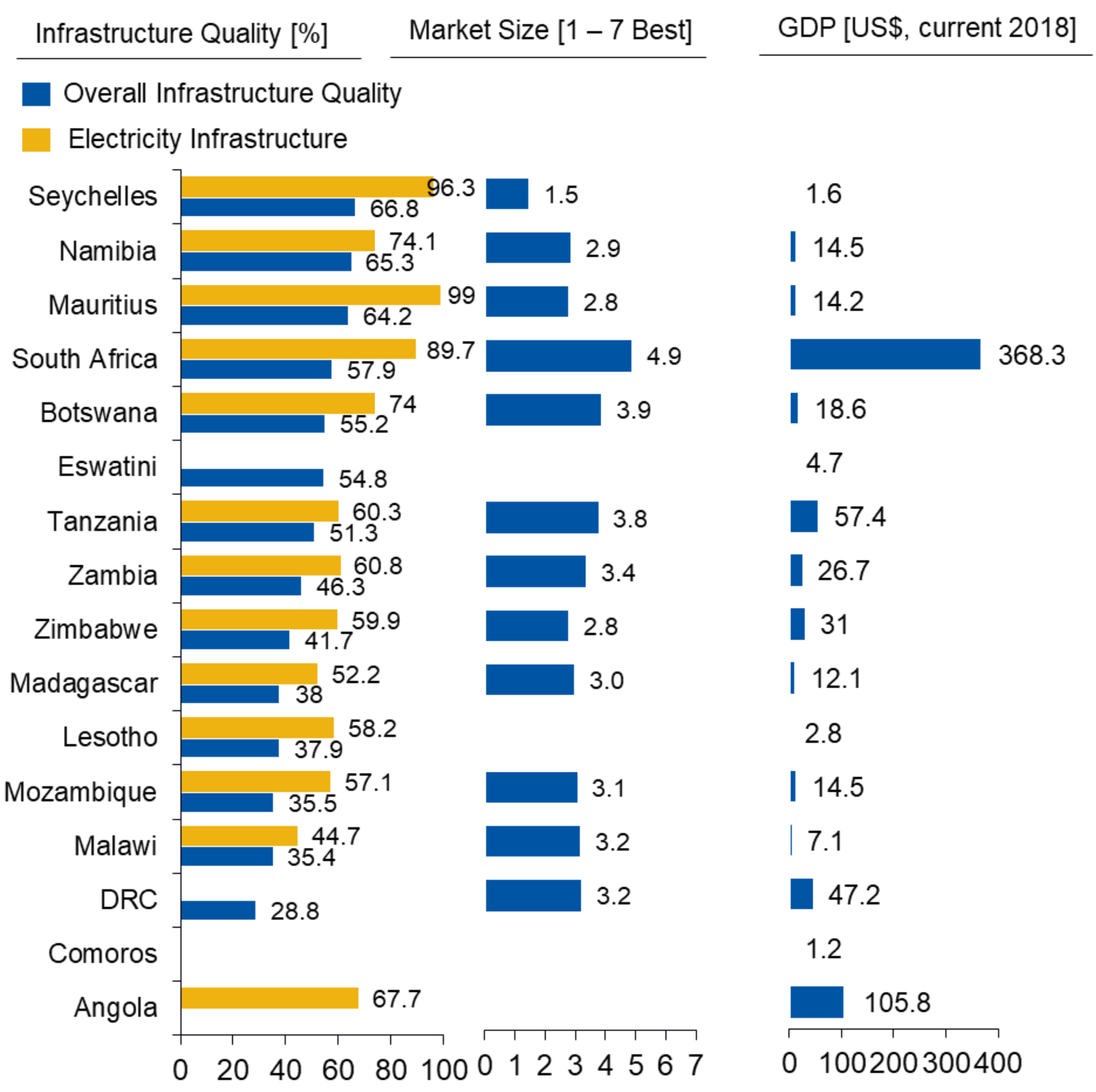


Figure 9-7: Market & Infrastructure[184]

The overall quality of infrastructure within the SADC region is generally poor, with Seychelles being the most advanced with an infrastructure quality of 66.8% (according to the World Economic Forum). Over half of the 16 countries in SADC have an overall infrastructure quality of less than 50% across various sectors, which is a contributing factor toward slow economic growth. Advancement in the necessary infrastructure has the potential to unlock different industries within the different countries, hence further improving the size and conditions of the different markets.

[184] The Quality of Overall Infrastructure is an overall analysis provided by the World Economic Forum based on the following inputs: quality of roads, quality of road infrastructure, quality of port infrastructure, quality of air transport infrastructure, Available airline seat kilometers, Quality of electricity supply, Mobile-cellular telephone subscriptions and fixed telephone lines.

9.2.4 Policy, Legislation and Regulation

The legislative environment within each country plays a key role in energy development. It is the responsibility of governments to provide clear direction within the energy space, ensuring the availability of guiding policies and legislation in a regulated environment and to provide a conducive environment for different industry players.

Policy, Legislation & Regulations

Country	Government Ensuring Policy Stability (WEF) [%]	Energy Efficiency Regulation (WEF) [%]	Efficiency of Legal Framework (WEF) [%]	Overall Efficiency [Rank]
Mauritius	72.32	76.15	61.03	1
Namibia	64.72	76.15	63.44	2
Botswana	66.08	76.15	56.41	3
Seychelles	68.61	76.15	51.67	4
South Africa	47.36	76.15	56.69	5
Lesotho	47.95	28.42	48.47	6
Tanzania	57.91	13.92	50.45	7
Malawi	52.53	14.38	44.08	8
Zambia	53.03	16.08	38.91	9
Zimbabwe	37.59	22.69	36.18	10
Madagascar	39.32	17.38	36.63	11
Mozambique	48.71	5.77	35.40	12
Angola	49.02	10.62		13
Eswatini			45.71	14
DRC			37.41	15

NB: Excludes Comoros

Figure 9-8: Policy, Legislation and Regulation

Although a few of the SADC governments have made positive strides towards ensuring policy stability, much work remains in many of the SADC Member States. The three indices above are connected - the effectiveness of legal frameworks and regulations pave the way for a stable policy environment, aiding in an efficient policy, legislation, and regulatory environment.

9.2.5 Institutions and Governance

Market development is largely reliant of the effectiveness of government institutions mandated with development, public sector performance and corporate governance. The effective functioning of such institutions collectively contributes towards a functional economic environment, offering the relevant support to sector players. Institutions need to have the necessary resilience to keep up with rapid advancements. Most SADC Member States appear to be doing relatively well in this area while struggling in overall public sector performance. There is vast room for much needed improvement in public sector performance, as this influences the speed of execution and decision making. Good public sector performance can enhance the development of the private sector, with the possibility of public-private partnerships being forged to benefit the different parties involved.

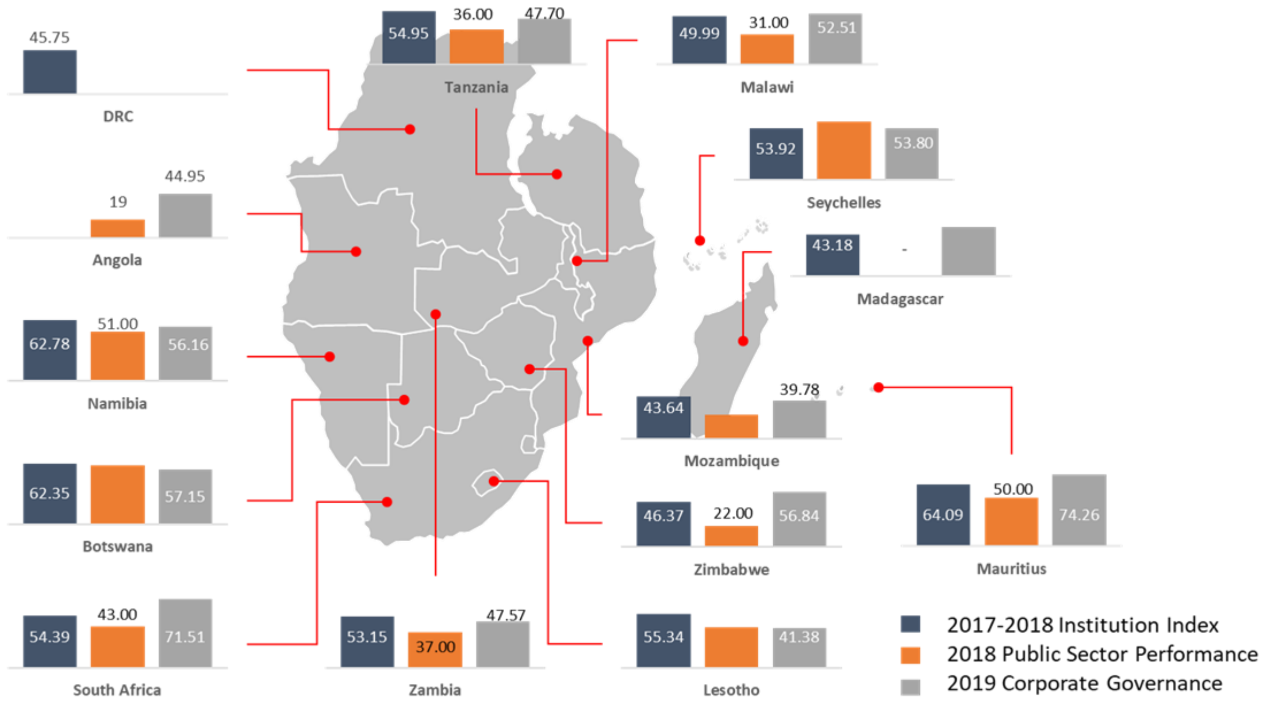


Figure 9-9: Institutions and Governance[185]

Different corporations are key to the overall development of societies, as they are the pillars of economic value creation and employment. Good corporate governance thus has direct implications on a country's development trajectory, with the ability to attract equity capital for domestic growth. Although most SADC Member States appear to be doing relatively well in this area, there is still further room for improvement.

9.2.6 Energy System Structure

The energy system globally is one that is under transition, with the movement towards renewable sources of electricity generation. While the rest of the world makes strides towards this transition, the SADC region is also faced with the challenge of low rates of electricity access. There is thus a significant opportunity for development in the energy system within the region, with more than half of SADC Member States having less than 50% access to electricity, as shown in the figure below. These countries are also marked with relatively high energy intensities, implying a high cost of converting energy into Gross Domestic Product (GDP). This leaves considerable room for improvement in this area and thus a need for energy system development.

The region finds itself in a state where it must answer the global call for cleaner fuels while developing its energy system. Countries with better access to electricity are largely dependent on fossil fuel sources, except for Seychelles. Since a complete transition to renewables in the short to medium term is nearly impossible (due to the variability of supply and energy storage requirements), the use of gas as a mid-merit option appears to be a more attractive alternative in the search for a just transition. Current use of gas for power generation within the region is limited to a few countries like Mozambique and Tanzania, with local availability of the resource. The lack of international

[185] Where there are missing figures, it is due to a lack of data available.

infrastructural links may be a key hurdle towards the utilisation of gas for power generation as most countries are without the resource.

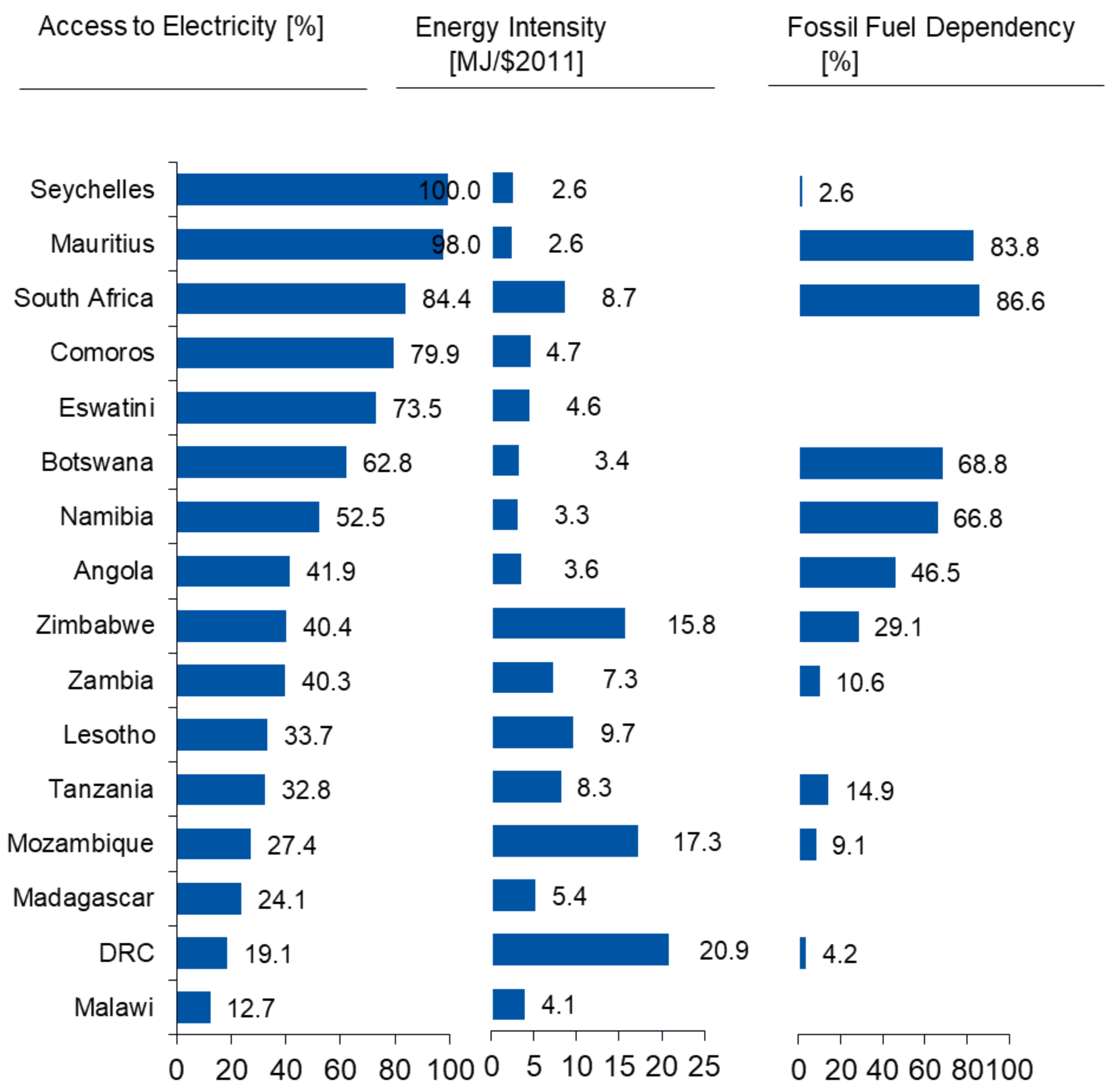


Figure 9-10: Energy System Structure

10. RECOMMENDATIONS

Developing the market requires investments that, typically, SADC Member States cannot cover on public funds alone. Attracting private sector participation and foreign direct investment will be necessary to overcoming infrastructure bottlenecks, developing the market, and boosting long-term economic growth. Establishing a good investment climate that is open and welcoming of both public and private investment, requires interventions within each enabling dimension, as described in Section 10.2 above.

Phase 1 of the RGMP analysed the legislative, policy and regulatory environment of all 16 SADC Member States. It also considered the fiscal regimes of their oil and gas sectors, as well as the institutional and governance frameworks of the energy sector in each country. The analysis is annexed hereto. The findings highlighted that regional market integration requires harmonisation of policies, legislation, regulatory and institutional frameworks at the **regional and national levels**, to facilitate greater coordination and cooperation. The recommendations made herein have been presented and discussed during engagements held with national, regional, and international stakeholders.

10.1 Phases of Market Development

The SADC region is in the nascent phase of gas market development, with majority of the Member States having limited-to-no gas infrastructure, policy, or regulatory structure in place. In order to transition towards a mature gas market, national market development, as well as regional collaboration, is required in terms of regulation, aggregation, policy, and infrastructure congruency. The different phases of the gas market are illustrated in the figure below.

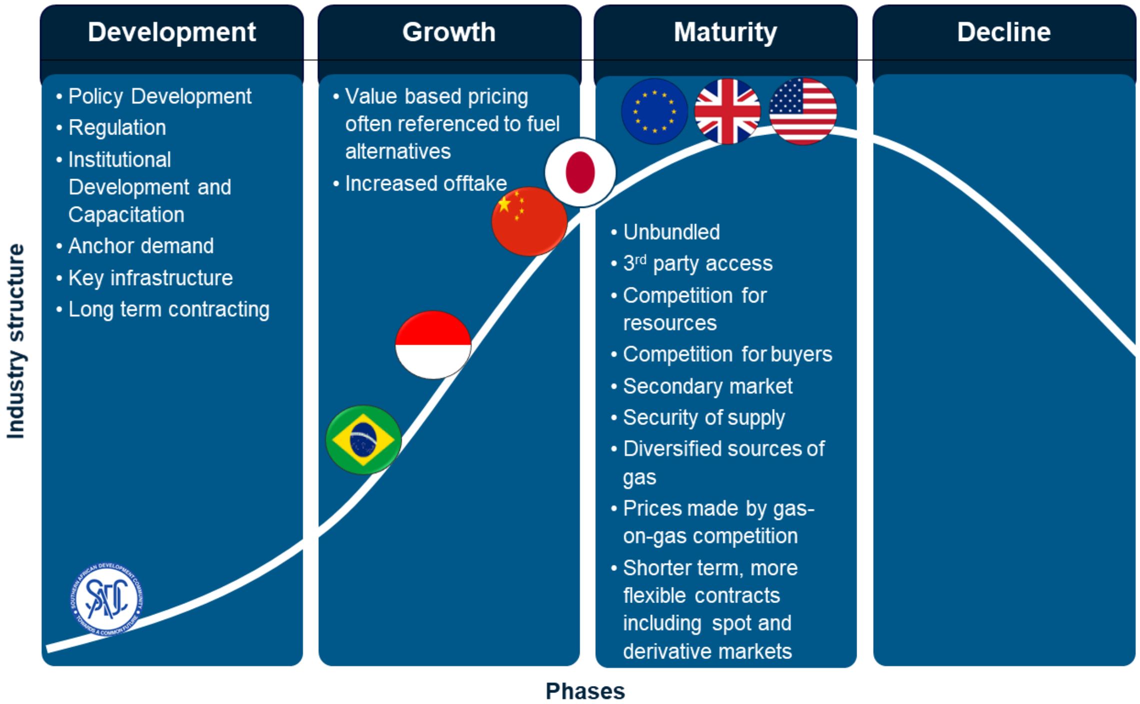


Figure 10-1: Phases in Gas Market Development

During the development phase, securing supply, development of policy and regulation together with regional alignment in terms of infrastructure development as well as securing anchor demand and establishing the foundations for regional aggregation is required to enable growth.

Key developmental projects will be identified and prioritised within the broader market landscape for investment in Phase 2 of the Regional Gas Market Plan, thus establishing midstream infrastructure for gas transportation and anchor projects that consume gas economically. Individual member states should analyse national requirements and develop infrastructure in coherence with regional development plans. The identification of key market nodes with efficient and consistent supply-demand characteristics will allow for supply to be regulated and ensure demand is met economically. Thermal projects, and particularly gas-to-power generally provide the main source of early anchor demand, with comparative infrastructure requirements to alternative sources. Based on regional demand petrochemical plants can provide additional anchor demand to member states with gas reserves. Incentivisation mechanisms can be introduced (through the aforementioned policies) to stimulate domestic gas offtake, thus broadening market participation and the robustness of the regional gas market. Indonesia's fertiliser initiatives highlighted in the case study (appendix C), used favourable gas prices for state-owned fertiliser projects to stimulate the domestic gas market while promoting socio-economic development, through fertiliser utilisation in the agricultural sector. Public investment based on national interest can provide a means for improving socio-economic conditions and allow for strategic development together with carbon emission reductions.

Similarly, the development of LNG plants for countries with gas supply and terminals for consumer nodes are necessary for a regional gas market to develop. Long term supplier-consumer contracts with delivery and purchase obligations provide the foundation to secure partnerships and would fundamentally lead to a competitive regional gas market that benefits all member states.

As a region, policy development should be prioritised and occur at the beginning of the development process to ensure the aggregation of demand can be facilitated to enable competitive pricing and security of supply. SADC must take responsibility for developing a trading environment and provide adequate market surveillance. Developing relationships with international market players early on and creating a dialogue with LNG producers as well as consumers to allow for regional participation in the international market as the region matures.

During the growth phase, where demand is anchored, and supply is stabilised, the expansion of gas markets is necessary to continue development and increase market competitiveness. Diversifying supply sources, advancing infrastructure development and developing regional gas hubs will improve procuring supply, reduce consumer prices as well as ensure supply is met. Pipeline infrastructure and LNG bunkering enable economic and efficient supply, while the utilisation of ssLNG, SNG (substitute natural gas) and LNG to reach a broader market and introduce gas supply in more remote areas will promote regional market growth.

By ensuring coherent development both at a national and regional level, the gas market can be developed, and growth accelerated to transition towards maturity. A mature market requires adequate regional demand and sufficient liquidity in supply to enable a flexible approach to supply and pricing dynamics as well as developing the necessary infrastructure that would allow for broader consumer reach and pricing benefits, this would ultimately lead to deregulation and a sustainable and competitive gas market.

A highly fluid LNG market would require enhancement of tradability; spot pricing options, removal of destination clauses, as well as the continuous development and expansion of the regional market for both natural gas and LNG are required, together with ensuring delivery and cross border trade procedures are smooth and standardised. A phased approach to deregulation can then be implemented to complement market development and promote competitive regional supply to consumers. A well-developed regional market will enable exploration and further development of supply sources. Having the necessary regulation and market capacity in place will ensure resources are utilised effectively to enable economic and social development in the region.

10.2 Regional Developments

10.2.1 SADC

SADC has significant enabling power in facilitating and encouraging harmonisation across the Member States. This report has covered the various strategies and action plans introduced in the context of the energy sector. At the centre of these lies the SADC Treaty – of which the primary purpose is creating an enabling environment for economic cooperation within and between SADC Member States. Instruments that support the Treaty on energy related matters include the Regional Strategic Development Plan (RISDP), the Energy Protocol, the RIDMP Energy Sector Plan and the Energy Monitor. While these documents have paved the way for SADC and its role in facilitating cooperation, it is recommended that Model Energy Guidelines, as described in Section 9.1.1, be introduced.

These guidelines will encourage Member States to introduce integrated energy planning into their energy policies, so that the energy demands of all relevant sectors, for all forms of energy, would be fully accounted for and represented. This would make energy planning more efficient and accurate. Having accurate demand projections for a country also facilitate and justify the development of energy generation, transport, and storage infrastructure.

The report also recognises efforts made by SADC towards enhancing trade, particularly through the SADC Trade Protocol. Especially in the establishment of a Trade Monitoring and Compliance Mechanism for monitoring the implementation of the Free Trade Area, with a specific mechanism for identifying and eliminating non-tariff barriers which will facilitate movement of goods. It is recommended that the teams involved in the development and monitoring of the Trade Protocol be involved in the development of a regional AfCFTA Implementation Strategy and prepare actionable plans to implement the agreement effectively. This is aligned with the RISDP 2020-2030 Blueprint which recommends that there should be agreement on how the gains made under the Tripartite Free Trade Agreement will be leveraged to fast track and further the AfCFTA among SADC Member States.

A SADC Implementation Strategy could provide Member States guidance on the negotiation of tariff concessions between African countries, specific commitments that need to be made, as well as the steps that can be taken toward liberalisation over the next 10-15-year period. The framework could also provide guidance on new trade mechanisms, including the proposed Africa-wide digital payment system being introduced to domesticate intra-regional payments.

10.2.2 SAPP

As mentioned in Section 9.1.2.2 above, one of SAPP's objectives is to create a regional regulatory framework for pooling energy resources, including the establishment of common standards, rules, and monitoring mechanism of systems performance, with a view to promoting power exchanges between utilities.

Some power pools on the African continent, for example, ERERA under ECOWAS, enforce regional legislation/regulation by adopting directives introducing obligations for members. SAPP, while mandated to create a regional regulatory framework, currently only requires utilities to abide by market rules and grid codes.

The report echoes the RISP 2020-2030 Blueprint in recommending that SADC take a role in spearheading the development of a Regional Transmission Infrastructure Program in order to unlock transmission constraints. As mentioned above, this would assist in the harmonisation and standardisation of participation on the SAPP network, by introducing and adopting a uniform, transparent and non-discriminatory regime of open access to the regional transmission grid, harmonising grid codes, developing an updated transmission pricing methodology for fair benefits sharing mechanisms between the countries, and establishing and operationalising an innovative and sustainable financing mechanism for hard and soft infrastructure.

The fact that SAPP is currently unregulated does pose a challenge to the implementation of some of its aims. This challenge may be overcome through the transformation of RERA into SARERA, as discussed below.

10.2.3 SARERA

RERA's current role as an association of national regulators is an important one as it formalises the avenue for engagement and dialogue between the national regulatory authorities. RERA has also supported SAPP in the development of a market platform for competitive trade in electricity.

As introduced in Section 9.1.4, a RERA Report was released in 2019 detailing the establishment of a regional energy regulatory authority for SADC, by transforming the existing RERA (the Transformation Report). Consultations with RERA highlighted the important role that SARERA could play in monitoring and enforcing market rules for the regional power pool and regional gas market.

On the power regulatory front, it is expected that SARERA will develop the following instruments: [186]

a. Network Access (non-discriminatory): The proposed instrument is a SARERA regulation for access to the grid needed to enable cross-border trade. The regulation will provide the minimum requirements but will allow national regulators to implement these through national regulations.
b. Wheeling Charges: The proposed instrument is a high-level regulation for setting transmission charges (to achieve tariffs that are cost-reflective and cost-recovering). It will leave open scope for implementation by national regulators, to conform with existing methodologies or approaches while being consistent with the SARERA principles. Where cross border trade uses the transmission networks of third countries, SARERA will guide the tariffs through separate regulations.
c. Anti-competitive behaviour: The proposed instrument is the ability, where necessary, to intervene to modify SAPP trading rules to obligate company behaviour, e.g., bidding at marginal cost rather than prices which earn additional profits. Market surveillance will be effected through appropriate software tools used to monitor the wholesale energy market for anti-competitive behaviour.
d. Governance of SAPP market rule development: three instruments are proposed to contribute to the development of SAPP rules and their adoption at a national level, including technical standards that facilitate unhindered energy trade and national grid codes specifically related to cross-border trade.[187]

On the gas regulatory front, the Transformation Report indicates that RERA's role in the regulation of cross-border trade of other energy products such as petroleum products and gas will develop similarly

[186] ECA, 2019. RERA Transformation Report.
[187] There are some overlaps in the proposed role that the SADC Secretariat will play and that of the transformed SARERA, and it is recommended that Phase 2 of the RGMP aim to assign clear roles and responsibilities for speedy implementation.

as it has for regional electricity trade.[188] This would include similar measures as those mentioned above, and will be applied to the regional gas market as it is to the regional power pool.

10.2.4 SAGP

As introduced in Section 9.1.3, introducing a regional aggregator is key to achieving the scale required to develop a sustainable gas market. The recommendation is that using the lessons learnt from the creation of the SAPP, Member states within the SADC region agree on the development of a regional institution that would aggregate demand to strengthen buying power when engaging with upstream and/or mid-stream gas sellers in the region. Specifically, the report recommends a wholesale competition market model where the mid-stream of the value chain is open to private participants and several mid-stream players compete for the wholesale of natural gas in the medium to long term. For ease of reference, this report refers to this institution as the Southern African Gas Pool (SAGP).

Much like the SAPP developed over the last two decades, it is envisaged that in the short to medium term, the SAGP will facilitate the establishment of bilateral long-term contracts between supply nodes and national anchor projects in the region, with national aggregators representing the interests of each participating country. Likewise, as SAPP enforces rules of conformity, the SAGP would introduce the market codes and standards for national aggregators and private sector players to abide by in order to participate in the regional gas market.

The competitiveness of this system would develop, much as the SAPP developed over the last two decades, with the introduction of transmission infrastructure, to enable the gas molecule to travel to each SADC country, whether this be through pipeline, road, rail, or LNG options. Additional functions include:

- Analyses and reporting on local and foreign gas trading dynamics to inform the region on best practice and areas of improvement in the market. This would enable the SAGP to advise on future infrastructure projects that would grow the markets and improve the accessibility of gas within the region.
- Investigating and potentially implanting a local pricing index for natural gas trade that speaks to the unique dynamics of the SADC region. The European Network of Transmission System Operators for Gas (ENTSOG) functions as a gas aggregator within Euro-zone and has implemented a methodology to standardise the calculation of tariffs for gas transportation across the network that it operates.

10.2.5 REPGA

The Regional Infrastructure Development Master Plan for the Energy Sector recommends the introduction of operationalisation of the Regional Petroleum and Gas Association (REPGA) to advise policy makers in harmonising gas policies and fostering trade between the SADC Member States. There may be a potential overlap between REPGA, RERA and the SAGP, and it would be advisable to develop mandates and function that are clearly segregated to avoid confusion.

10.3 National Developments

Under the direction provided by SADC and in the formalisation of cooperation, Member States have developed different legal instruments, essentially aimed at improving economic and social areas, regulating security interests, providing food security, enhancing trade etc. in a more effective and

[188] A Petroleum, Gas and Biofuel Regulation Sub-Committee has already been established within RERA which will develop guidelines for gas tariff and price setting to be applied by member countries. Further tasks and responsibilities will be developed.

concerted manner. It, therefore, is envisaged that the Model Guidelines would encourage Member States to develop national energy policies including IEP, as well as sector specific policies to encourage the increased uptake of natural gas demand within different parts of the energy sector, i.e. LPG, electricity, fertilisers and petrochemicals.

Our recommendation considered the approach taken by South Africa in developing the draft Integrated Energy Plan and includes the following elements:

1. An IEP should provide the overall energy sector landscape of the country (policy and regulatory, infrastructure requirements etc.), but it should be supported by sector specific plans that provide in-depth information on infrastructural matters, i.e. an Integrated Resource Plan (electricity), Liquid Fuel Roadmap and Gas Utilisation Masterplan.
2. Ongoing data collection needs to be prioritised to support evidence based IEP development. Member States should partner with national energy organisations to collect data on energy technologies, as well as aggregated energy balances.
3. Because of the cross-cutting nature of IEP, government ministries need to be provided with guidance and clear mandates in cooperating, sharing information, establishing reporting lines, and clearing any ambiguities that may arise from the overlapping of functions across ministries.
4. To adequately address the concerns from provincial and local levels of government that experience energy issues 'on the ground', national governance structures must enable information sharing and accountability between levels.

Additionally, it is our recommendation that the contents of the Model Energy Guidelines be workshopped among Member States to ensure that it can, practically, ensure harmonisation across energy sectors.

10.3.1 Natural Gas and LPG

The global shift toward cleaner and more efficient fuels has created an impetus for governments to incentivise the switch from biomass to LPG (or from paraffin to LPG, in some cases).[189] LPG is generally considered an aspirational fuel source in many low-income countries, but with the right economic supports in place, the switch can be affordable. In addition to the above proposal that Member States establish a Liquid Fuel Roadmap (or an LPG Masterplan) to guide the penetration of LPG in the country (define investments and policy interventions), a few policy proposals have been taken from the large-scale adoption within Indonesia and India.[190] Member States should:

1. develop technical plans and financing structures to achieve LPG expansion targets. Upstream supply issues need to be addressed as a priority, with the investment required being mapped out for potential investors. This includes infrastructure (import, bulk storage, transportation, and filling facilities and LPG cylinders) and expanded distribution and retailing networks.
2. appoint an inter-ministerial committee to ensure that pricing regimes, taxes, and subsidies are tailored to enable access to the poorer communities on a sustained basis.
3. roll-out education campaigns to help households understand the cost, safety, health, and environmental benefits, as well as risk (SHERQ) associated with switching to LPG.
4. provide assistance in the initial purchasing of cylinders and first refills – making the switch more affordable.

[189] Propane, butane, bottled gas, or cooking gas.
[190] World Bank Group, 2017. Increasing the Use of Liquified Petroleum Gas in Cooking in Developing Countries.

5. encourage financial institutions to provide consumer financing mechanisms, such as microfinance and pay-as-you-go options

The above mechanisms assist in ensuring high LPG retail density, and global practice has shown that where LPG use has become widespread, natural gas often follows.[191] LPG use typically precedes natural gas use because LPG infrastructure is much less costly and much faster to deploy than natural gas infrastructure. Therefore, in encouraging Member States to roll-out LPG roadmaps, it is enabling the long-term sustainability and success of the regional gas market.

10.3.2 Natural Gas and Electricity

In affecting the RISDP, the SADC Climate Change Strategy and Action Plan of 2015, the SADC Regional Green Growth Strategy and Action Plan of 2015, the Africa Union Agenda 2063, the SDGs, as well as meeting Nationally Determined Contributions under the Paris Agreement, Member States are making changes to their energy mixes in order to ensure the reduction of GHG emissions.

The widely known policy proposals for countries to do so include that Member States should

1. consider adopting renewable energy, energy-efficiency strategies, and carbon offsetting to mitigate carbon footprints.
2. consider using natural gas as a bridge to a renewable energy future in countries currently using higher-carbon fuels, including coal, oil, and diesel for cooking, power generation, or heating and cooling. Unlike hydroelectric power, which is dramatically impacted by drought and climate change, natural gas provides consistent and reliable power.[192]
3. the above considerations should be mapped out and included in national IEP and electricity roadmaps.

Electricity, being an important downstream market, was considered in the context of regional trade policies. The SAPP has been clear, through recent documentation, on what is required in order to standardise electricity for ease of trade across borders.

10.3.3 Natural Gas and Fertilisers

Policies and institutions are instrumental in helping to provide an enabling environment for increased productivity and market development, and incentives to use fertiliser and other improved technologies. Policy proposals herein have been drawn from a study done by the International Food Policy Research Institute which discussed policy options for improving regional fertiliser markets in West Africa.[193] Member States should:

1. provide a certain and consistent policy environment.
2. encourage better integrated supply chains through the establishment of farmer organisations, producer associations, or cooperatives that increase farmer access to input and output markets. Agro-dealers should be distributed to rural and peri-urban areas to ensure that remote areas have access to inputs.
3. establish a coordinating body to improve market coordinating mechanisms (e.g. the implementation of interlocking contracts between farmers and buying firms).
4. convert existing fertiliser subsidies into targeted purchasing-power-support subsidies for the most vulnerable but viable smallholder farmers. Ideally, such support should be fiscally

[191] World LP Gas Association, 2014. Guidelines for the Development of Sustainable LPG Markets Transitioning-Stage Markets.
[192] Power Africa, 2016. Understanding Natural Gas and LNG Options.
[193] International Food Policy Research Institute, 2011. Policy Options for Improving Regional Fertiliser Markets in West Africa.

sustainable and have clear sunset clauses to avoid creating the dependency syndrome among beneficiaries. Ultimately, the goal for national governments should be to refrain from interfering in national and regional fertiliser markets in such a way that crowds out private importers and agro-dealers.

5. introduce fertiliser standards and enforce them at point of sale. However, mandatory inspections by government should be done on a case by case basis so that it does not add costly delays during quality control inspections (for example, international inspection companies have already done quality checks prior to shipping).

The presence of existing national tariffs, nontariff controls, and taxes at border crossings prevents the free flow of goods across national boundaries - adding to the costs of inputs, especially for landlocked countries. SADC's efforts to liberalise and harmonise the market should therefore involve:

5. harmonising subsidy rate policies across Member States so that fertiliser can be traded without borders, and implementing a zero duty on imported fertiliser;
6. convincing national governments to exempt fertiliser from other unnecessary taxes and levies at national levels;
7. encouraging Member States to standardise their quality control standards so as not to prevent the movement of products from one country to another. A regional regulatory framework on fertiliser quality control should be introduced;
8. the establishment of a fertiliser market platform for market information to be shared so that different segments of the market can be integrated, and traders can be linked up with one another, thereby benefiting from lower prices. Market transparency and connectivity is essential in establishing a well-functioning regional market.
9. education for Member States on the opportunity-cost in foregone crop output as a result of high fertiliser costs due to tariffs and taxes.

10.3.4 Natural Gas and Petrochemicals

The IEA, in a presentation on the future of petrochemicals, recognised the importance of petrochemicals in oil and gas demand (accounting for 8% of global gas demand in 2018), and introduced a set of policy recommendations for the increased production of petrochemicals.

Taking into consideration the required emissions reductions from the chemicals sector, these policy recommendations aimed at the production of chemicals included the following. Member States should:

1. directly stimulate investment in the research and development of sustainable chemical production routes and limit associated risks.
2. establish and extend plant-level benchmarking schemes for energy performance and CO2 emissions, and incentivise adoption through fiscal incentives.
3. pursue effective efforts to reduce CO2 emissions across all sectors.
4. pursue stringent air quality standards, including for industry.
5. fuel and feedstock prices should reflect the actual market value.[194]

10.4 Market and Infrastructure

Sub-Saharan Africa has several power pools that interconnect Member States' power systems, where the delivery of energy resources relies on power interconnections and supporting infrastructure requiring a balanced and relevant approach towards infrastructure and energy route to market options given the regions existing infrastructure challenges.

[194] International Energy Agency, 2018. The Future of Petrochemicals.

From a gas/electricity integration perspective:

- It may be both easier and more economical to import power from neighbouring countries than the gas molecule itself, especially for landlocked countries with no direct access to LNG,
- With many issues surrounding pipeline projects in the region, the use of existing electricity transmission infrastructure may be a more reasonable option,
- Not all the export of power would come from gas-fired plants, but the flexibility of importing LNG would allow the power pools to optimise their systems so it could be an attractive option. For countries like DRC this may also be true because of multiple power pool memberships

Appendix G illustrates the appropriate technologies required to satisfy gas demand based on the distance of the market from the gas field and the scale of the market. In Mozambique, Tanzania, and Angola natural gas pipeline would be appropriate to satisfy gas demand, due to existing in-country gas fields. While in satisfying South Africa's gas demand, a pipeline and LNG are both competitive. Due to the low scale of gas demand, ssLNG would be the appropriate technology to satisfy the other prioritised countries gas demand.

Pipeline infrastructure includes the ROMPCO, and in-country South African and Mozambique pipeline networks, including the Sasol, Matola Gas Company and Transnet Lily pipelines. Developing gas supply infrastructure to connect and expand these networks is a low risk opportunity. This includes LNG regasification in Maputo and possibly LNG regasification in Richards Bay.

Finally, existing economic and transport corridors should be strengthened to deliver either small scale gas or gas product (e.g. fertilisers) to end markets. The African Development Bank provides guidelines on the elevation of a transport corridor to an economic corridor that extends past the objective of transporting goods, but aims to facilitate socio-economic development across the value chain of goods and services connecting to the transport route.

10.4.1 Regional Aggregation

Transactions in the wholesale natural gas market are typically conducted on a bilateral basis, however the nascent stage of gas market development in the SADC region calls for an intermediation of these transactions, i.e. an aggregation of demand in order to facilitate the movement of the molecule to the market.

The acquisition of natural gas and transportation services is often complex, and for some market participants it may be too difficult and costly. High transaction costs discourage smaller market participants from utilising open access, despite opportunities for cost saving. Natural Gas Traders, or Energy Traders (such as Energy Exchange of Southern Africa) aggregate demand and supply for smaller market participants by purchasing natural gas and transportation services on their behalf.

The long-term movement has been towards market liberalisation, encouraging 3rd party access, and competition. The viability of competition in the natural gas industry is determined by three factors: technology, the size of the market, and entry barriers. Technology determines economies of scale and scope where recent advances in ssLNG has begun altering this dynamic. However, as highlighted, scale is still a key driver, and therefore natural monopolies will emerge specifically in the midstream infrastructure segment of the value chain. Furthermore, the size of the market will determine how many firms can efficiently compete in it.

Finally, entry barriers determine whether an additional firm can enter the market if the opportunity to do so exists. These three underlying factors determine the efficient configuration of the industry.

10.4.2 Gas Hubs

The long-term opportunity for the region is to develop a physical gas trading hub, leveraging off existing demand, infrastructure, and supply thereby creating a mechanism for which price discovery can occur in a transparent, fair, and equitable manner allowing for trading of the commodity.

However, setting up a Natural gas/ LNG pricing hub requires key elements to be in place, and even so is complex. Some of the requirements include:

- Clear government and in the case of SADC, intragovernmental support,
- Market liberalisation,
- Access to infrastructure,
- Many market participants and
- Confidence in transparent price formation.

This includes gas-to-gas/LNG competition and demand side responses such as coal/oil switching capabilities with gas. However, Japan, currently the largest LNG market globally, is central for global LNG price formation, yet even after three decades it has failed to develop a domestic framework.

Liberalisation is providing momentum for competition, but so far only at the retail level, with limited third-party access to infrastructure to facilitate wholesale gas price competition or fuel competition within local power producers.

Asia-Europe price spreads are increasingly being driven by transportation differentials, where Atlantic traders are using European gas hubs' liquidity and financial instruments to trade arbitrage opportunities between Atlantic and Pacific basins. Effectively, this establishes Europe as a global benchmark for LNG spot prices.

Development of a regional market is therefore contingent upon there being market liquidity and if there is the required storage and reticulation infrastructure.

In this regard liquidity is an important measure in determining a market’s ability to achieve its main purposes: **provide price discovery, transparency, and allow for efficient risk transfer between participants**. A liquid market also fosters **efficient competition**, encouraging the **optimal allocation** of an asset. A market is considered liquid if participants can easily transact large volumes with limited impact on asset prices and low transaction costs. Liquidity also dictates decisions around whether to trade — the size of an order that can be executed, order sizes available at different price levels, and the ability to execute a timely trade to minimise slippage losses.

A well-functioning, and efficient Spot Market helps develop the futures market. As currently seen within the SAPP environment, developing towards a true spot-market can allow for the development of financial instruments to be developed off the market.

Europe has liquid spot and futures markets for natural gas, coal, carbon, and electricity, which facilitate fuel switching in its electricity-producing sector.

Tokyo Gas recently signed a long-term deal with Royal Dutch Shell, in what was believed to be the first time a coal pricing index was used with an LNG contract.

While benchmark contenders may emerge, liquidity will continue to coalesce around a few key benchmarks — and other hubs or markers will trade as a basis to these, in the absence of a breakdown in market fundamentals. In addition, the existing network of major gas hubs and markers is sufficient for global liquidity, now connected by LNG freight movements across continents.

Amid market upheaval — the liberalisation of LNG, a shift towards gas-on-gas pricing, and the decoupling of oil and natural gas markets — TTF and JKM are emerging as robust and distinct global benchmarks.

The price of liquefied natural gas (LNG) usually reflects the energy market into which it is sold. LNG sold into well-established gas markets, such as Europe, is priced to compete with alternative sources of gas, whereas in Asia it is usually linked to the price of crude oil.

Oil indexation. Contracts for natural gas can be priced against other (non-natural gas) energy commodities. This is commonly done by indexing natural gas prices against existing oil benchmarks (either global benchmarks like Brent or WTI, or regional benchmarks like Japan Customs-cleared Crude) and linking the two by comparing their potential thermal energy output. The benefit of this approach is that pricing broadly reflects prices for other energy commodities in the relevant region.

This approach is not without its downside, however. As trading volumes of LNG increase, it is becoming clearer how distinct it is from other energy products (including oil). Pricing via oil indexation can lead to a variation in gas prices based on factors specific to oil and its sale (including the imposition of sanctions or tariffs, or conflicts in oil-producing regions). In many situations, using this method to price LNG is relatively problem-free, although risk is introduced wherever the fundamentals of oil and gas markets diverge.

Foreign hub-based pricing. To avoid the problems of differing fundamentals, gas prices can be indexed to prices at a well-established gas trading hub. If LNG is being sold into a region that already has an established gas market, pricing can be according to the local hub, which reflects both the fundamentals of the commodity and local market conditions. However, a sparsity of local hubs means that problems can arise when LNG is priced against distant ones.

The key risk for the Regional Hub, is that markets without well-developed systems and benchmarks are at risk of relying on pricing systems that do not represent gas trading in these markets.

The implication is that a stepwise approach will have to be undertaken in developing the market, including relying upon regulatory mechanisms to stimulate market development, while transitioning towards gas trading hubs.

10.4.3 Economic Corridors

Economic corridors being used as a mechanism for market development and integration, as described in 9.1. The success of this proposal lies in strategic planning and strategic visioning. This requires detailed designing of the social, economic, and physical development of the corridors and their surroundings. It is recommended that each of the three proposed economic corridors below be workshopped within each set of stakeholders to ensure that maximum cooperation between states and entities is achieved.

In addition to the physical development of multinational infrastructure development, participating Member States also need to agree on the process taken in harmonising social and economic strategies, as well as the standardisation required to remove non-tariff barriers at border points.

Design Considerations

The grouping of the economic and trading clusters was considered beneficial as a mechanism to initiate development in the short term, leading to broader longer-term integration. Economic corridors are proposed that would link clusters.

Geography, economic characteristics, existing and planned infrastructure, route-to-market, trade dynamics, economic relatedness, the location of supply and projected demand were all factors considered when proposing the designs below. From a gas utilisation perspective, LNG was considered an important delivery mechanism, with a Hub and Spoke model being utilised for the aggregation of demand.

The following is a representation of the projected gas production and aggregated gas demand with a 20 to 30-year projection. The aggregate gas demand indicated below refers to the base case scenario which is elaborated in section 9 of this report.

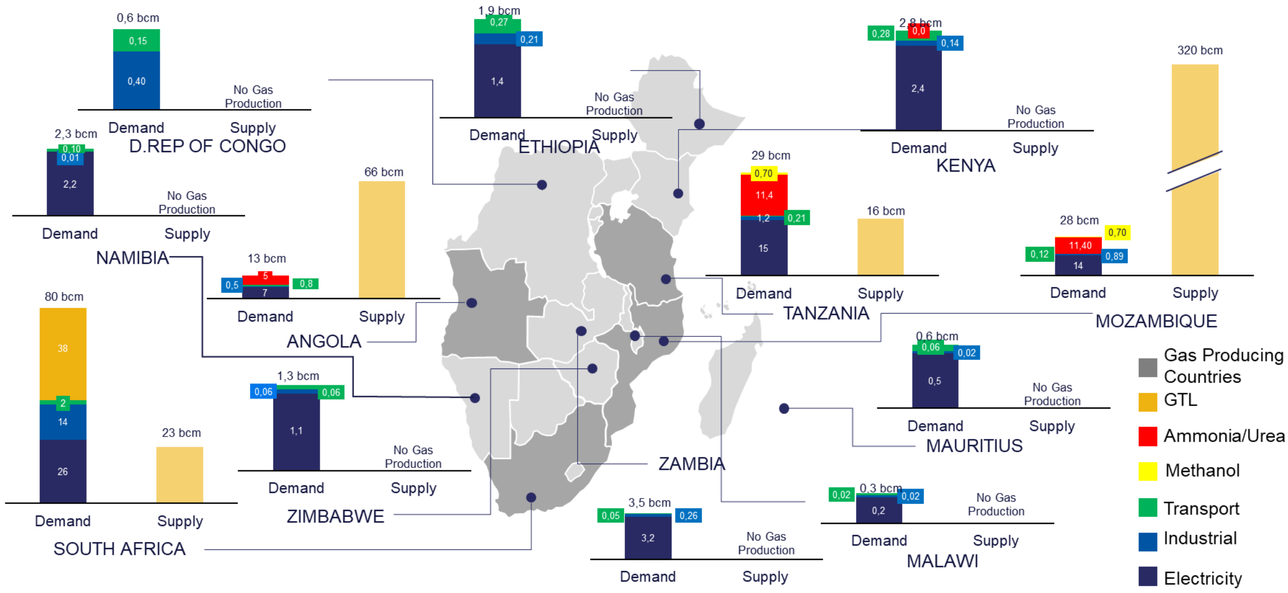


Figure 10-2: Aggregated Gas Demand '20-'30 and Projected Gas Production '20-'30 (bcm)

Considering all factors above, three clusters were identified, largely separated by position within SADC, into East and West.

10.4.3.1 South East Cluster

In the 2020 to 2030 period, Petrochemical, and electricity constitute a large share of demand, accounting for 83% of total natural gas demand in the South East Cluster. Figure 10-3 shows the projected demand and supply balance in the South East cluster, with Mozambique, and Tanzania as the largest supply nodes. The satisfaction of demand is thus driven by infrastructure capability in gas delivery and strengthening of power trading through the development of electricity transmission interconnectors.

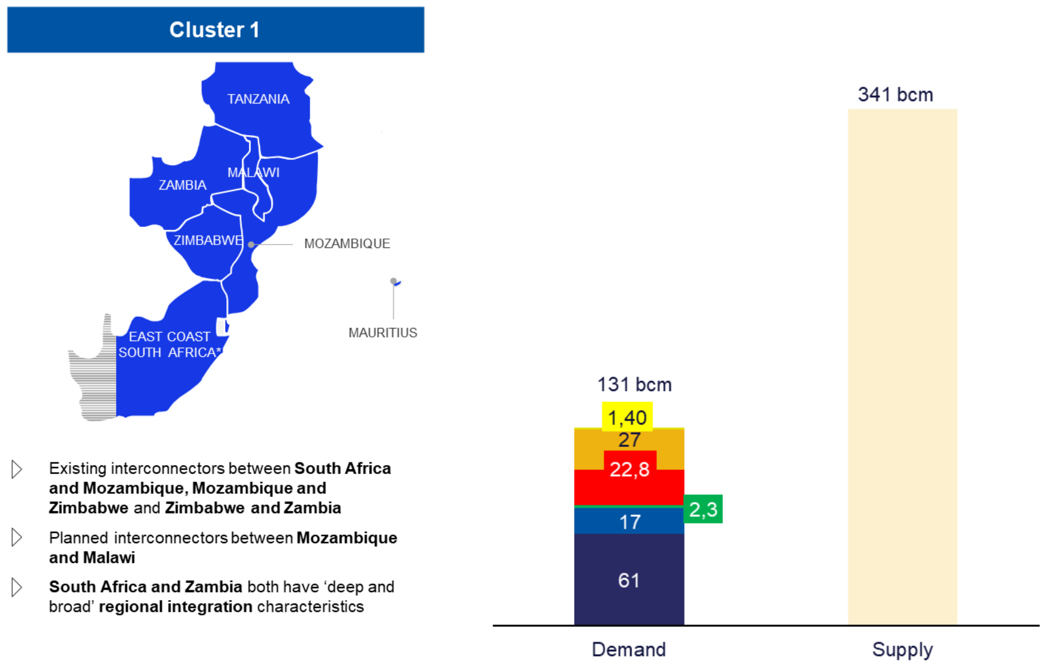


Figure 10-3: Cluster 1: South East Cluster (comprising 7 countries) with aggregated '20 – '30 demand and supply.

Infrastructure

The development of the South East corridor gas market will require leveraging existing gas infrastructure. Existing gas pipeline infrastructure in the South East corridor includes the ROMPCO pipeline which supplies gas to the South African and Mozambican market, the South African Lily pipeline, and the pipeline stretching from Mtwara to Dar es Salaam, Tanzania.

In the short to medium term, LNG will play a crucial role in the supply of gas to demand nodes within the South East corridors. The recommended infrastructure development pathway within the South East corridor is based on projected demand and building around existing infrastructure, and is as follows:

- Develop LNG facilities in Tanzania and Mozambique in the short term, for supply within the economic corridor, and to facilitate the exportation of surplus natural gas.
- Due to the low-scale natural gas demand for inland countries (see Appendix G), gas demand would need to be satisfied by ssLNG. This will require the strengthening of road and rail infrastructure for these regions.
- The development of an LNG storage and regasification facility in Maputo, which will supply gas to planned GTP and other industries. This is in consideration of the tapering gas supply in Temane and Pande.
- The development of LNG storage and regasification facilities in Richards Bay, and Coega. Natural gas from the Richards Bay facility would be transferred to the Mpumalanga through the Lily pipeline to supply petrochemical, gas to power, and industrial anchor demand in the region. While in Coega anchor demand currently exists through existing GTP facility.
- Develop Mozambique North-South pipeline connected to the ROMPCO pipeline. This would facilitate the development of industries along the pipeline, increase the security of supply to South African market while complementing LNG storage and regasification facilities.

- Fertiliser demand deficit in this corridor will be satisfied by planned facilities in Tanzania and Mozambique.

Though there are existing Tanzania-Zambia and Zimbabwe-Mozambique oil pipelines which could facilitate gas pipelines being developed alongside them, the demand analysis illustrates that the low-scale Zambia and Zimbabwe gas demand would not be sufficient to support a gas pipeline. Thus, for these markets, ssLNG is recommended

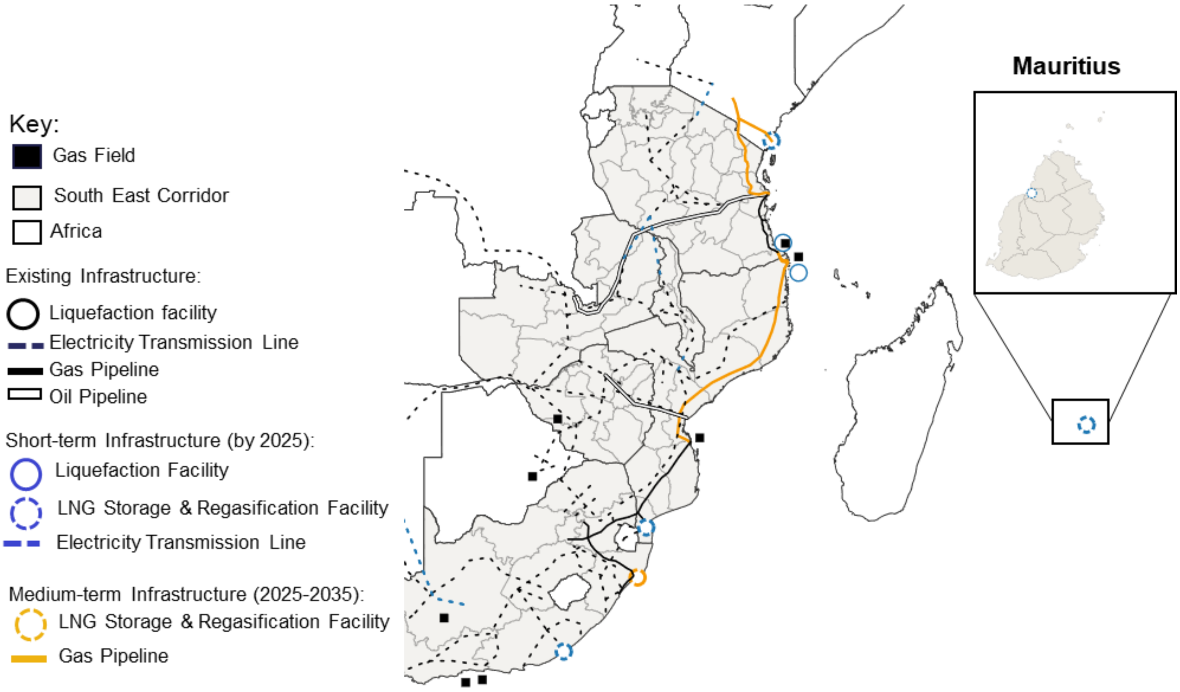


Figure 10-4: South-East corridor infrastructure development pathway.

Gas Value Chain Segment	Region	Infrastructure project (s)	Stakeholder	Phase	Expected Startup	Role of SADC Secretariat
Midstream	Mozambique	Mozambique LNG (12.9 MTPA)	Anadarko (26.50%); Total (26.50%) Bharat PetroResources (10.0%) ENH (15.0%) Mitsui (20.0%) PTTEP (8.50%) Oil India Ltf (4.0%) ONGC Videsh (16.0%)	FID reached in 2019	2025	Create links between LNG suppliers, and LNG demand nodes to establish supply agreements
	Mozambique	Rovuma LNG (15.2 MTPA)	-	FID TBD	2021 – 2025	
	Mozambique	Coral South FLNG (3.40 MTPA)	KOGAS ENI CNPC Galp Energia ENH	FID reached in 2017	2023	
	Tanzania	Lindi LNG (10.0 MTPA)	Pavilion Energy Shell Ophir Energy Equinor Exxon Mobil TPDC	FID TBD	2028	

Gas Value Chain Segment	Region	Infrastructure project (s)	Stakeholder	Phase	Expected Startup	Role of SADC Secretariat
Midstream	Mozambique	North to South Pipeline linked to ROMPCO	-	-	2025 – 2035	Advocate for pipeline development, and coordinate commencement of prefeasibility studies
	Tanzania-Mozambique	Tanzania-Mozambique Pipeline	-	-	2025 – 2035	
	Mozambique – South Africa	ROMPCO Looplines	Sasol Companhia Mocambiçana de Gasoduto S.A iGas	-	2025 – 2035	
	South Africa	Coega LNG storage and regasification facility	Transnet DOE (RSA)	Feasibility	2021 – 2025	Coordinate investment mobilisation
		Richards Bay LNG storage & Regas facility	Transnet DOE (RSA)	Feasibility	2025 – 2035	
	Mauritius	Port Louis LNG Storage & Regas facility		Feasibility	2025 - 2035	
	Mozambique	Maputo LNG storage & Regas facility		Feasibility		
Downstream	Tanzania-Malawi	Tanzania-Malawi transmission interconnector	TANESCO ESCOM SAPP	-	2021-2025	Advocate for transmission interconnectors, and coordinate commencement of prefeasibility studies
	Tanzania-Zambia	Tanzania-Zambia transmission interconnector	TANESCO ESCOM SAPP	-	2021 - 2025	
	Mozambique-Malawi	Mozambique-Malawi transmission interconnector	EDM ESCOM SAPP	FID	2021 - 2025	

Mainland SADC Member States within this cluster have a few established National Oil Companies and major gas in players including Sasol, PetroSA (CEF, including iGas), and Transnet (South Africa), ENH (Mozambique) and TPDC (Tanzania).

The Island Member States would be represented by the State Trading Corporation (STC) in Mauritius.[195]

10.4.3.2 West Coast Cluster

A second cluster exists with Angola as a key supply node to the rest of the cluster through its existing liquefaction facility.

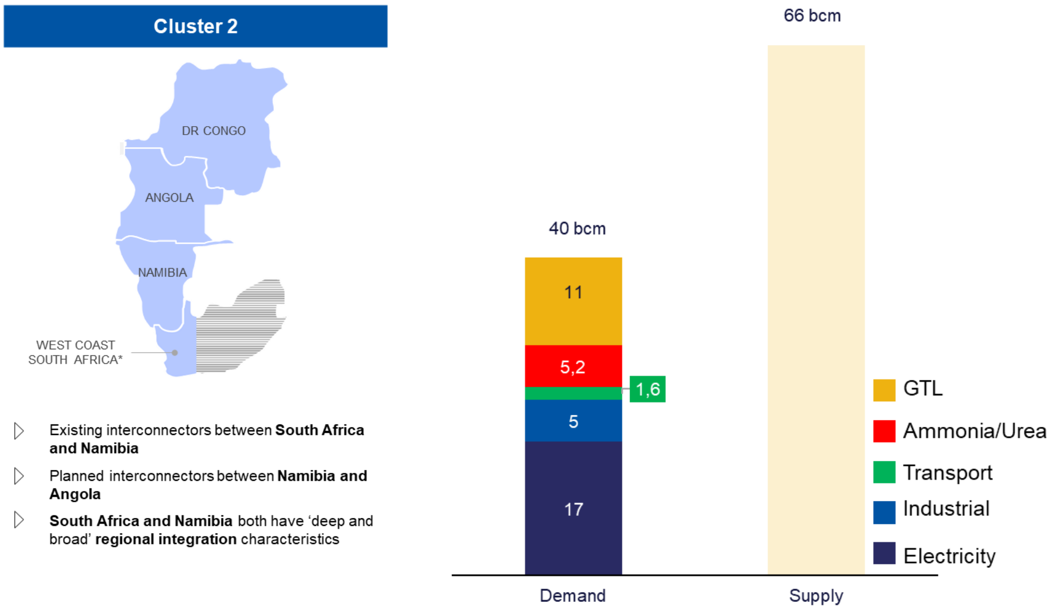


Figure 10-5: South / West Cluster (comprising 4 countries) with aggregated '20 – '30 demand and supply.

In the West cluster, Angola is currently the only country with an existing gas market. The 5.2 MTPA liquefaction facility in the north of Angola will be key in supplying gas to the rest of the region.

For the DRC, two gas delivery options exist: a pipeline stretching from the Soyo gas field to supply adjacent demand nodes, and ssLNG as a supply mechanism for markets further from the Soyo gas field. The evaluated low-scale gas demand in the DRC would be appropriately satisfied by ssLNG. While the gas demand in Namibia, and the west coast of South Africa can be satisfied by the development of LNG storage and regasification facilities. Fertiliser demand in this corridor would be satisfied by planned fertiliser plant in Soyo, Angola.

[195] In line with its mandate as the trading arm of the Government, the STC is responsible for the importation of strategic commodities such as petroleum products including LPG. The development of LNG in Mauritius is coordinated by the LNG Steering Committee chaired by the Economic Development Board (EDB). As per decision of the Steering Committee, the STC has recruited a consultant to assess, inter alia, the feasibility and viability to develop Port Louis as a hub for LNG. The STC and EDB have jointly followed up the work of the consultant. At the present point in time, the involvement of the STC might be in terms of coordination without any financial and infrastructural development commitments. The LNG Steering Committee would need to assess the potential impact of decisions of the CEB and the Ministry of Energy and Public Utilities (MEPU) on the national energy policy and its potential impact on the LNG study. Thereafter, the SADC Secretariat will be informed of any material change in the LNG strategy of Mauritius.

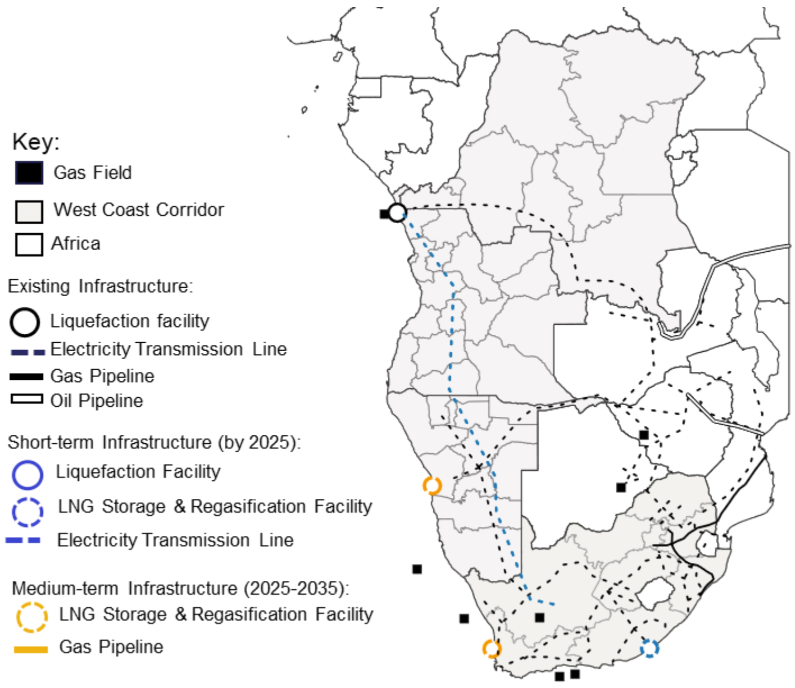


Figure 10-6: West coast corridor infrastructure development pathway.

Table 10-1:Key stakeholders in infrastructure projects[196] indicating the role of SADC Secretariat

Value chain segment	Country	Corridor Infrastructure	Stakeholder	Phase	Expected startup	Role of SADC Secretariat
Midstream	South Africa	Saldanha Bay LNG storage and regasification facility	Transnet DOE (RSA)	Feasibility	2025 - 2035	Coordinate investment mobilisation
	Namibia	LNG storage and regasification facility	-	FID	2025 - 2035	Coordinate LNG supply agreements with Angola liquefaction facility
Downstream	Angola – Namibia – South Africa	Angola – Namibia – South Africa transmission interconnector	ESKOM Nampower RNT (Angola) SAPP	Planning	2021 – 2025	Coordinate investment mobilisation

[196] Relevant infrastructure based on the corridors. Not all infrastructure may be included, although existing or planned i.e. refineries.

The potential market players in this corridor would include National Oil Companies and major gas players in the region including Sonangol (Angola), Namcor (Namibia) and Sasol/CEF/Transnet (South Africa).

10.4.3.3 North East Coast Cluster

A third cluster exists, which includes Tanzania as a pivot to the rest of East and Central Africa. As illustrated in Figure 10-7, at natural gas supply projections between the 2020 to 2030 period, this cluster would have a natural gas supply deficit. The planned Lindi Liquefaction facility would increase cluster natural gas production; however, this is expected to start later in the decade, in 2028. To meet demand in the short to medium term, this cluster will require positioning for natural gas imports.

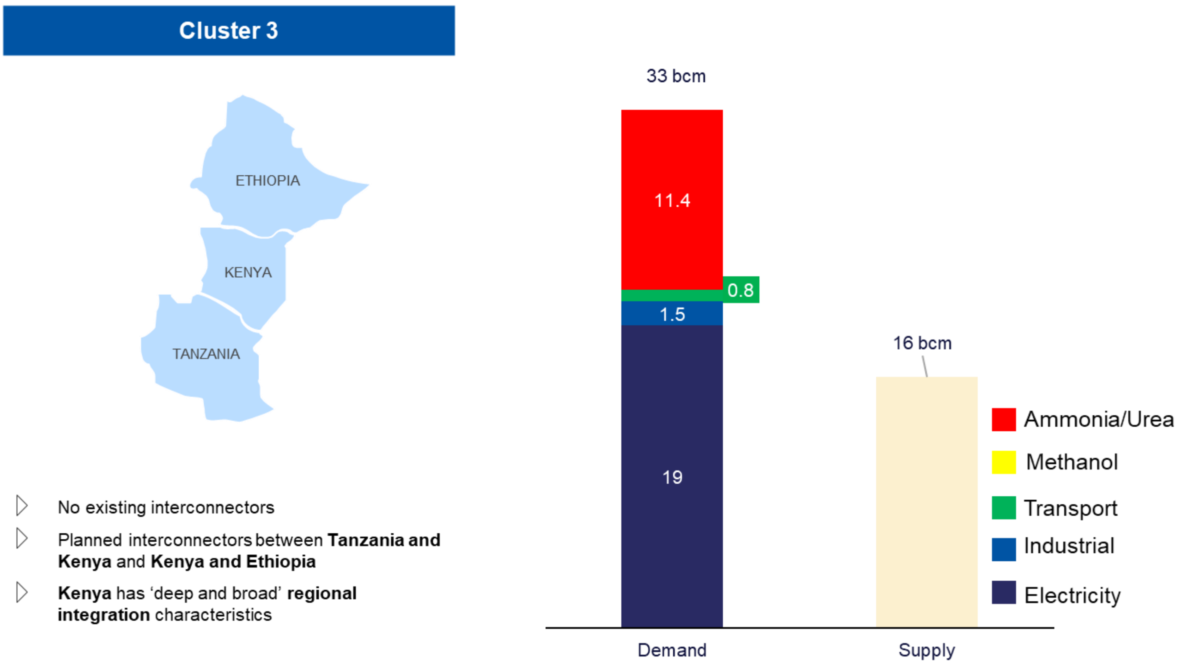


Figure 10-7: SADC and East Africa Cluster (comprising 3 countries) with aggregated '20 – '30 demand and supply.

Infrastructure

Within the North East economic corridor, Tanzania is currently the only producer of natural gas. Over the 2010 to 2030 period it is projected that there would be a natural gas supply deficit within this corridor, requiring the importation of natural gas. Existing gas infrastructure lies only within Tanzania, through the gas pipeline from Mtwara to Dar es Salaam.

To develop the North East corridor, the following infrastructure pathway is recommended:

- In the short-term develop LNG facility in Lindi, Tanzania.
- Develop LNG storage and regasification facility in Kenya, within the short-term. This will serve the domestic market, and act as a vehicle for ssLNG transfer to Ethiopia.
- Expansion of existing Mtwara to Dar es Salaam pipeline to meet domestic demand with further expansion to Kenya.
- Fertiliser demand in this cluster would be satisfied by planned fertiliser facility in Tanzania.

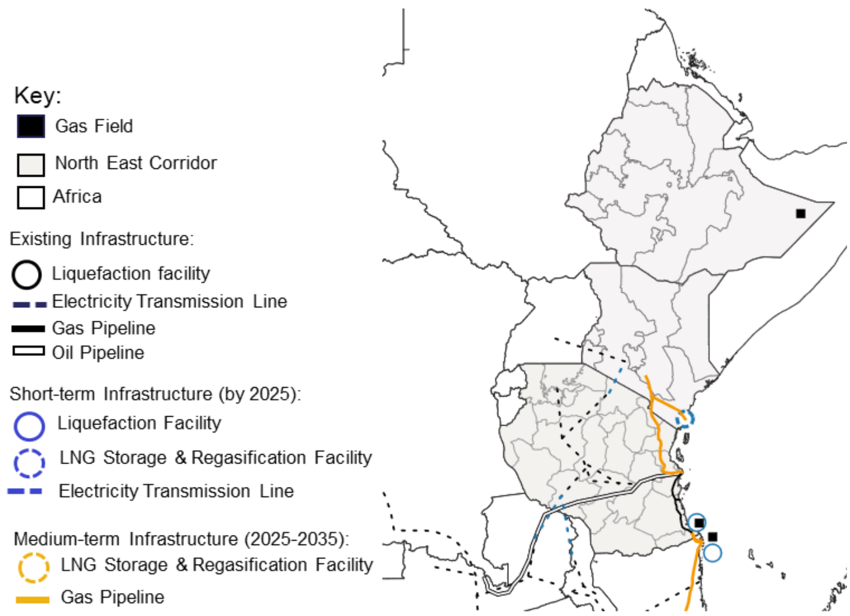


Figure 10-8: North / East corridor infrastructure development pathway.

Table 10-2:Key stakeholders in infrastructure projects indicating the role of SADC Secretariat

Gas Value Chain Segment	Country	Corridor Infrastructure requirement	Stakeholder (s)	Timeframe	Role of SADC secretariat
Midstream	Tanzania	Lindi Liquefaction Facility	Pavilion Energy Shell Ophir Energy Equinor Exxon Mobil	2021 – 2025	Create links between LNG suppliers, and LNG demand nodes to establish supply agreements
	Kenya	LNG storage & Regas facility (Mombasa)		2025 – 2035	
	Tanzania – Kenya	Dar es Salaam to Kenya Pipeline		2025 – 2035	Advocate for pipeline and coordinate commencement of prefeasibility studies
Downstream	Tanzania – Kenya	Tanzania – Kenya transmission interconnector		2021 – 2025	

Tanzania and Kenya are the two prominent players in this cluster, so National Oil Companies in these two countries would have a potential role to play, namely the TPDC in Tanzania and the National Oil Corporation of Kenya.

10.5 Capital and Investment

As analysed above, some factors that contribute to a country's investment climate are the effect of taxation on incentives to invest, the strength of investor protection and inflation. In terms of strengthening investor protection, it is helpful to consider this from the investor's perspective. Risk mitigation is a key component when deciding on pursuing investments in Africa; market structure and a country's legal, social, economic, and political stability are all factors that are considered during due diligence and risk assessment practices.

SADC Member States play a balancing act in providing a degree of protection to investors while protecting state interests. Investor protection may be provided through international treaties or conventions, bilateral investments treaties (BITs) between investors and host states, domestic legislation that deals with investor-state relations, and by contractual agreement. Typical protection that investors seek relates to the physical security of property (against expropriation or unfair and inequitable treatment), national treatment and allowing the repatriation of funds.

Dispute resolution mechanisms are also important, with investors typically preferring the option to refer disputes with the host government to the International Centre for Settlement of Investment Disputes (ICSID) (or similar such institutions) for international arbitration. Many governments, however, feel that subjecting matters of national interest to international arbitration is concerning to constitutional and democratic policy making.[197]

It is our recommendation that the SADC model guidelines provide best practice on matters relating to foreign investment, dispute resolution, institutional capacity development and establishing a non-discriminatory framework for energy imports and exports.[198] All these factors are crucial from the perspective of gas market development and provide the certainty that market participants need to operate in the market. Further, the functions of SADC or SARERA be elevated to include a mechanism for regional energy related dispute resolution. This seems to not be too far a stretch since it is proposed that the transformed SARERA provides a forum to mediate disputes over access to facilities relating to cross-border trade.

10.6 People

As described in section 9.1 above, the measurements used to rate SADC Member States on their people dimension include the ease of finding skilled labour and the capacity of countries to retain that talent. Another measurement that should be considered in this regard is the quality of education that is provided. Where schools and universities are not adequately supplying the quality of education required to supply skilled labour to the natural gas market workforce, solutions need to be found to upskill workers in different ways.

During stakeholder engagements, the Consultants spoke with various national and regional institutions that have the capacity to encourage skills development in the sector, develop curricula and offer courses to both public and private sector institutions wishing to upskill their employees. It is

[197] Speaking in July 2012, the South African Minister of Trade and Industry highlighted concerns about investor-state arbitration.
[198] As is provided for in the ECOWAS Treaty

our recommendation that a SADC Skills Development Plan be created for the natural gas sector, to provide a roadmap for Member States which addresses challenges in skills development, key knowledge gaps that need to be filled and a solution to skills development. Our recommendation is to offer a regional skills development solution. Existing institutions[199] have the potential to enhance their offerings in the natural gas space, obtain finance for the development and running of courses, and essentially be transformed into hubs of knowledge development (both technical and institutional).

As the gas market is in its nascent stages of development, governing institutions need to be capacitated to better inform national policy decisions around gas, while executing the guidelines. Energy sector personnel, in addition to receiving adequate resources, manpower and training, require clearly defined mandates and incentives for the efficient execution thereof.

10.7 Energy System Structure

Energy system structure as an enabling dimension has been measured by factors such as the percentage of the population with access to electricity, the dependency of the country on fossil fuels and energy efficiency. These are all areas that the Regional Infrastructure Development Master Plan for the Energy Sector seeks to address and improve. Our recommendations are therefore aligned to the existing solutions, i.e.:

- Assist SADC Member States in enabling a just transition from fossil fuels to renewable energy and position gas as an alternative and cleaner fossil fuel that would enable that transition, particularly in the power sector.
- Promoting and enabling the development of electricity transmission and distribution infrastructure through SAPP and positioning Gas to Power as a flexible power source of electricity which can respond to trade dynamics within the regional gas market. The relatively short start-up time for gas plants makes them well suited for markets such as the Day Ahead Market where gas plants can respond to supply shortages as required.

[199] The Kafue George regional Training Centre, RERA, SADC, SACREEE, for example.

11. IMPLEMENTATION PLAN

The table below indicates a high-level implementation programmes which respond to the recommendations within the report. Other strategic documents were considered in developing the programmes. Appendix F contains a consolidated list of projects that are various stages within the region as well as stakeholders of those projects.

Table 11-1: High Level Implementation Programme

Outcome	*Strategic Interventions*	*Timeframe*	*Responsibilities*	*Link to Strategic Documents*
Economic corridors that maximise regional integration and trade	*5. Formalise regional clusters and cooperation modalities* *6. Strengthen existing interconnecting road, rail, port, and power transmission infrastructure which enables the movement natural gas and/or natural gas products* *7. Establish a Corridor Management Group or Institutions to oversee existing and developing economic corridors* *8. Strategic planning between all stakeholders*	*2021 - 2023*	*1. SADC Secretariat/ Member States* *2. Member States* *3. SACD Secretariat/Member States* *4. Member States*	*All enabling mechanisms link in some respect to the key SADC strategic documents, including:* *Regional Indicative Strategic Development Plan (2015-2020)* *Regional Infrastructure Development Master Plan: Energy Sector 2012 – 2027*

Outcome	Strategic Interventions	Timeframe	Responsibilities	Link to Strategic Documents
Effective trade of natural gas and its downstream products	*6. Investigate key revisions to the SADC Trade Protocol which would foster trade of natural gas and derivative products* *7. Facilitate the development of intergovernmental trade agreements that reduce the cost of trading natural gas and derivative products* *8. Develop a natural gas aggregation framework which enables the establishment of demand aggregators across the clusters* *9. Develop sector specific recommendations to standardise downstream products within the Gas Value chain*	*2021 - 2025*	*1. SADC Secretariat* *2. SACD Secretariat/Member States* *3. SADC Secretariat* *4. SADC Secretariat*	*SADC Industrialisation Strategy and Roadmap of 2015* *Related Action Plan of 2017* *Energy Monitor of 2018* *SAPP Plan of 2017*
Enabling Policy Environment	*4. Develop Model Energy Policy Guidelines to capacitate member states in developing Integrated Energy Plan and Integrated Recourse Plans* *5. Reinforce outcomes of the SADC Industrialisation Strategy* *10. Analyse critical public sector performance gaps which would impact the development of a natural gas market*	*2021 - 2025*	*1. SADC Secretariat* *2. Member States* *5. SADC Secretariat*	
A highly skilled and innovative workforce	*4. Assess key skills requirements within the natural gas value chain* *5. Recommend skills development initiatives targeted at the natural gas value chain* *11. Develop sector skills plans that close the skills gap*	*2021 - 2025*	*1. SADC Secretariat* *2. SADC Secretariat* *6. Member States*	

Outcome	*Strategic Interventions*	*Timeframe*	*Responsibilities*	*Link to Strategic Documents*
Investment driven economic growth	*3. Ensure policy certainty to foster investment within the region* *6. Analyse policy alignment measures to drive domestic investment and private-public partnership*	*2021 - 2030*	*1. Member States* *3. SADC Secretariat*	

12. SCOPE OF WORK FOR FUTURE ACTIVITIES

As a starting point, the Scope of Work envisioned for Phase 2 of the Regional Gas Market Plan are developed from the title provided in the Phase 1 Terms of Reference, i.e.:

> *Phase 2: Master Planning (Visioning and Mapping the Strategic Location of Natural Gas Based Industries/Projects) and Final Master Plan and Investment Blueprint*

In planning the delivery of this work, we have divided the proposed set of deliverables and milestones for the appointed consultants into two work streams: preparation and design. It is envisaged that these processes happen alongside one another, with constant reiteration as the environment is developed.

Table 12. 1 An illustration of the proposed two workstreams that will be carried out during Phase 2 of the RGMP.

Policy Recommendations	**Infrastructure Investment Blueprint**
Includes the work that must be done to provide firm policy recommendations for SADC and its Member States while improving factors across enabling dimensions, which will improve the investment climate and lower the risk rating of projects within the RGMP.	Includes the finalisation of the mapping process that was conducted during Phase 1. This involves in-depth detailing of the infrastructure, stakeholders, and finances requires to develop the clusters and economic corridors.
Deliverables and Milestones	**Deliverables and Milestones**
Developing the RGMP Strategic Framework	Price dynamics
Defining the key outcomes and steps for implementation	Scoping of Infrastructure Projects: Project Portfolio
Allocating of Roles & Responsibilities	Economic Assessments for Clusters
Defining the nature of institutions that will be required for implementation	Investment Portfolio with particulars
Workshops and stakeholder engagement to solicit input and validate outcomes	Workshops to confirm the design and implementation of corridors
Designing the Implementation Plan	Discussion of roles for institutions to play and assessments of their readiness to take on the responsibilities

Finally, the implementation plan of the Final RGMP must include elements that speak to the following:

- Establishment of the Regional Gas Aggregator
- The drafting of SADC Model Energy Guidelines
- Capacitation of Member States Energy Ministries and Implementation Assistance (practical and financial)

- Enhancing Energy Sector Governance and Investment Protection through the utilisation of international instruments
- Intergovernmental MoUs between participating Member States for enhanced cooperation
- Stakeholder buy-in (private sector, public sector etc)

The two workstreams of Phase 2, together with the implementation plan, will complete the strategic planning of the integrated regional market.

It must be noted that the opportunity for natural gas is an immediate one – with there being a requirement to adequately capacitate SADC and its member states in the execution and development of a regional market, which can benefit the region by improving energy access, energy affordability and environmental sustainability.

APPENDIX A: CONVERSION FACTORS

		Conversions read across only															
		Gas							Energy				Oil Equivalent		Electricity		LNG
		cm (m3)	bcm	tcm	cf	bcf	tcf	mmscf	MJ	GJ	PJ	mmBTU	boe	bbl oil	kWh	GWh	MTPA of LNG
cm	→	1.00E+00	1.00E-09	1.00E-12	3.53E+01	3.53E-08	3.53E-11	3.53E-05	4.33E+01	4.33E-02	4.33E-08	4.11E-02	7.10E-03	7.08E-03	1.20E+01	1.20E-05	7.69E-10
bcm	→	1.00E+09	1.00E+00	1.00E-03	3.53E+10	3.53E+01	3.53E-02	3.53E+04	4.33E+10	4.33E+07	4.33E+01	4.11E+07	7.10E+06	7.08E+06	1.20E+10	1.20E+04	7.69E-01
tcm	→	1.00E+12	1.00E+03	1.00E+00	3.53E+13	3.53E+04	3.53E+01	3.53E+07	4.33E+13	4.33E+10	4.33E+04	4.11E+10	7.10E+09	7.08E+09	1.20E+13	1.20E+07	7.69E+02
cf	→	2.83E-02	2.83E-11	2.83E-14	1.00E+00	1.00E-09	1.00E-12	1.00E-06	1.23E+00	1.23E-03	1.23E-09	1.16E-03	2.01E-04	2.01E-04	3.41E-01	3.41E-07	2.18E-11
bcf	→	2.83E+07	2.83E-02	2.83E-05	1.00E+09	1.00E+00	1.00E-03	1.00E+03	1.23E+09	1.23E+06	1.23E+00	1.16E+06	2.01E+05	2.01E+05	3.41E+08	3.41E+02	2.18E-02
tcf	→	2.83E+10	2.83E+01	2.83E-02	1.00E+12	1.00E+03	1.00E+00	1.00E+06	1.23E+12	1.23E+09	1.23E+03	1.16E+09	2.01E+08	2.01E+08	3.41E+11	3.41E+05	2.18E+01
mmscf	→	2.83E+04	2.83E-05	2.83E-08	1.00E+06	1.00E-03	1.00E-06	1.00E+00	1.23E+06	1.23E+03	1.23E-03	1.16E+03	2.01E+02	2.01E+02	3.41E+05	3.41E-01	2.18E-05
MJ	→	4.33E-05	4.33E-14	4.33E-17	1.53E-03	1.53E-12	1.53E-15	1.53E-09	1.00E+00	1.87E-06	1.87E-12	1.78E-06	3.07E-07	3.07E-07	5.21E-04	5.21E-10	3.33E-14
GJ	→	2.31E+01	2.31E-08	2.31E-11	8.15E+02	8.15E-07	8.15E-10	8.15E-04	1.00E+03	1.00E+00	1.00E-06	9.49E-01	1.64E-01	1.64E-01	2.78E+02	2.78E-04	1.78E-08
PJ	→	4.33E+04	4.33E-05	4.33E-08	1.53E+06	1.53E-03	1.53E-06	1.53E+00	1.87E+06	1.87E+03	1.00E+00	1.78E+03	3.07E+02	3.07E+02	5.21E+05	5.21E-01	3.33E-05
mmBTU	→	2.43E+01	2.43E-08	2.43E-11	8.59E+02	8.59E-07	8.59E-10	8.59E-04	1.05E+03	1.05E+00	1.05E-06	1.00E+00	1.73E-01	1.72E-01	2.93E+02	2.93E-04	1.87E-08
boe	→	1.41E+02	1.41E-07	1.41E-10	4.97E+03	4.97E-06	4.97E-09	4.97E-03	6.10E+03	6.10E+00	6.10E-06	5.79E+00	1.00E+00	9.97E-01	1.69E+03	1.69E-03	1.08E-07
bbl Oil	→	1.41E+02	1.41E-07	1.41E-10	4.99E+03	4.99E-06	4.99E-09	4.99E-03	6.12E+03	6.12E+00	6.12E-06	5.81E+00	1.00E+00	1.00E+00	1.70E+03	1.70E-03	1.09E-07
kWh	→	8.31E-02	8.31E-11	8.31E-14	2.93E+00	2.93E-09	2.93E-12	2.93E-06	3.60E+00	3.60E-03	3.60E-09	3.42E-03	5.90E-04	5.88E-04	1.00E+00	1.00E-06	6.39E-11
GWh	→	8.31E+04	8.31E-05	8.31E-08	2.94E+06	2.94E-03	2.94E-06	2.94E+00	3.60E+06	3.60E+03	3.60E-03	3.42E+03	5.90E+02	5.89E+02	1.00E+06	1.00E+00	6.39E-05
MTPA of LNG	→	1.30E+09	1.30E+00	1.30E-03	4.59E+10	4.59E+01	4.59E-02	4.59E+04	5.63E+10	5.63E+07	5.63E+01	5.34E+07	9.23E+06	9.20E+06	1.56E+10	1.56E+04	1.00E+00

A. 1 Conversion Factors.

APPENDIX B: POLICY, LEGISLATIVE AND REGULATORY ANALYSIS

Please see Appendix B: Policy, Legislative and Regulatory Analysis

APPENDIX C: CASE STUDIES

12.1 Indonesia Gas Market Development Case Study

12.1.1 Natural Gas Background

Indonesia has a mature gas supply industry, with natural gas being discovered in the 18th century and the first gas pipeline dating back to the Dutch colonial era in 1859.

From a gas market perspective, the first economic use of natural gas in Indonesia was as fuel in 1958 to conserve excess gas, Shell laid a 10 km pipeline from Prabumulih to the Plaju refinery. In 1961 gas production was used for the first fertiliser industry in Palembang, South Sumatra, which signified a critical moment in the development of the Indonesian natural gas business. Subsequently, in 1974, the construction of gas piping systems from Limau field to Prabumulih and from Prabumulih to Palembang, together with gas from the Java Sea offshore gas fields and Cirebon being supplied to the industrial area in West Java.

Natural gas was then distributed in Jakarta City in 1978 and Bogor City in 1981 and later expanded to other cities. The operation of the Grissik-Batam-Singapore gas transmission pipeline began in 2003 and the transmission pipeline from South Sumatra to West Java in 2007.

Indonesia energy policy sought to exploit exportation demand for natural gas while depending on coal, geothermal and hydropower for domestic needs. The low price of natural gas for state enterprises further discouraged the domestic sale of gas by foreign companies. This resulted in little market and infrastructure development. Plans for petrochemical plants in the 1980s were expected to materialise; however, due to the high cost of development and the limited market in Asia at the time resulted in implementation being continuously delayed. By 2000, only a small amount of natural gas had gone to local fertiliser plants, primarily as a result of a lack of foreign investor confidence. [200]

12.1.2 LNG Infrastructure and Market Structure

The Indonesian LNG market was initiated with the discovery of gas reserves in Badak field in East Kalimantan and Arun field in Aceh in the early 1970s, and, which was followed by LNG plant construction in both regions. In 1977 a first LNG shipment was sent to Japan from Badak LNG plant, followed by the first shipment from Arun LNG plant in 1977. Japan was the only country with the capacity to invest and offtake natural gas from Indonesia in the region prior to the economic development of other East Asian countries. In 2009 the first shipment was sent to Fujian, China, via the LNG Tangguh Plant in Papua.

A brief history of Indonesian natural gas industry development is shown in the figure below:

[200] WIJARSO, I. (1985). *Natural gas development in Indonesia. Energy, 10(2), 231–236*

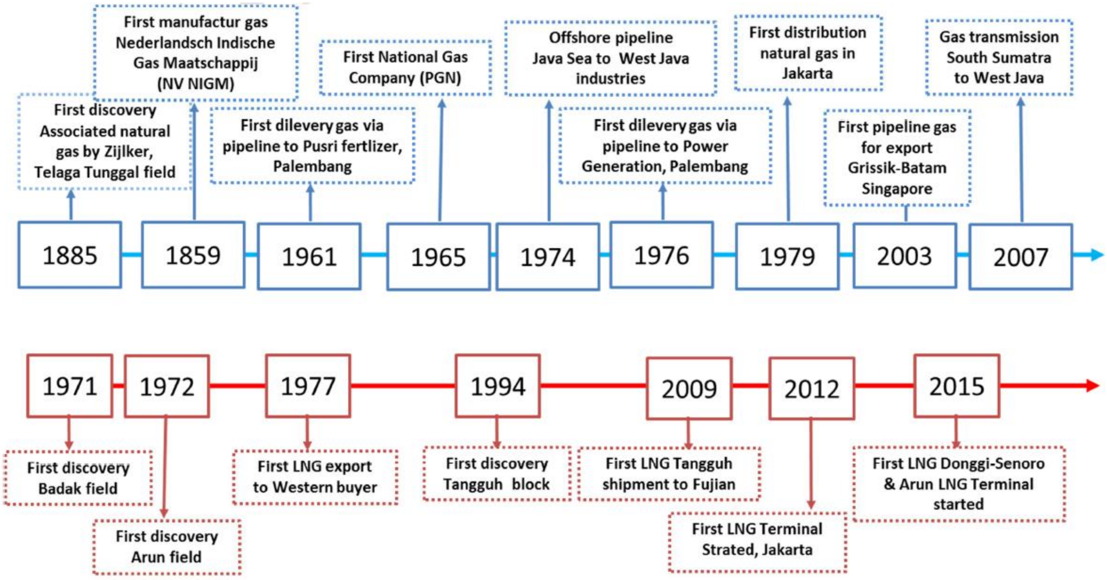


Figure 0-1: Brief History of Indonesian Natural Gas[201]

The renewal of liquefaction infrastructure has been continuously pursued with five plants currently (or scheduled to be) in operation (Badak, Arun, Tangguh and Donggi-Senoro, Abadi Masela) with a total capacity of 50 million tons per annum. The largest LNG plant, Badak LNG, had dramatically decreased production, from eight trains to four trains operating, due to a shortage in the gas supply.[202]

Table 2: Summary of LNG plants in Indonesia[203]

Field	**Reserve (TCF)**	**LNG Plant**	**Capacity**	**Start-up year**	**Status**
Arun	19,7	Train 1,2,3 Train 4,5 Train 6	5.1 4.4 2.5	1978 1983 1986	Stopped Stopped Stopped
Badak	14 & 26	Train A,B Train C,D Train E,F Train G,H	6.4 4.6 2.5, 2.5 2.9, 3.3	1977 1983 1989, 1994 1998, 1999	4 of 8 trains stopped
Tangguh	17	Train 1 Train 2 Train 3	3.8 3.8 3.8	2009 2009 2019	Operation Operation FEED
Donggi-Senoro	3	Train 1	2	2015	Operation
Abadi, Masela	18	Train 1	2.5	2020	FEED

The first LNG Terminal located in the Java Sea began operation in 2012 to counter the domestic gas supply shortage and limited pipeline infrastructure. 5 LNG terminals are in operation, including the first floating storage and regasification unit (FSRU) in Jakarta Bay, which started operating in 2012, with a capacity of 3.8 MTPA. The Lampung FSRU, located in South Sumatra, began operation in 2014 with a capacity of 1.8MTPA, and the Arun LNG terminal, with a capacity of 3 MTPA, opened in 2015. LNG supply has been used to alleviate the increasing domestic demand growth,

[201] Widodo Wahyu Purwanto (2015), Status and outlook of natural gas industry development in Indonesia
[202] Widodo Wahyu Purwanto (2015), Status and outlook of natural gas industry development in Indonesia
[203] Widodo Wahyu Purwanto (2015), Status and outlook of natural gas industry development in Indonesia

Table 3: LNG Terminals in Indonesia[204]

Terminal Name	**Capacity (MTPA)**	**Start-up year**	**Type**	**Status**
Nusantara Regas	3.8	2012	Floating	Operation
Lampung LNG	1.8	2014	Floating	Operation
Perta Arun Gas	3	2015	Onshore	Operation
Cilacap, Central Java	1.5	2018	Floating	Planned
Banjarnegara	4	2017	Onshore	Operation

The demand centres in Indonesia are situated at considerable distances from gas reserves, making pipeline infrastructure development challenging. The pipeline networks were developed based on business projects, resulting in a fragmented system, with the interfaces located mostly near consumer centres. The country's combined pipeline transmission and distribution network have a total length of approximately 8,363 km, which includes 3,700 km of distribution networks and 4,336 km of transmission networks and is operated by a state-owned gas company. [205]

12.1.3 Pricing Dynamics

From a pricing perspective, Indonesia adopted a marginal cost pricing policy approach was adopted to ensure further gas supply and market development as well as to provide sufficient for natural gas switching to ensure domestic development and stimulate the industrialisation process and enhance socio-economic development. As an example, in the 1960s, the pricing mechanism adopted for the Pusri fertiliser plant was lowered based on the fact that the plant was government-owned and to enable the fertiliser plant to provide a cheap product to stimulate widespread utilisation.[206]

Natural gas pricing affects supply and demand dynamics; the figure below provides a breakdown of the recent Indonesian natural gas price of LNG Badak and Tangguh. Export prices are generally higher than domestic gas prices for all sectors, and the drastic increase in LNG prices are due to contract renewals.

[204] Widodo Wahyu Purwanto (2015), Status and outlook of natural gas industry development in Indonesia

[205] Widodo Wahyu Purwanto (2015), Status and outlook of natural gas industry development in Indonesia

[206] WIJARSO, I. (1985), *Natural gas development in Indonesia. Energy, 10(2), 231–236*

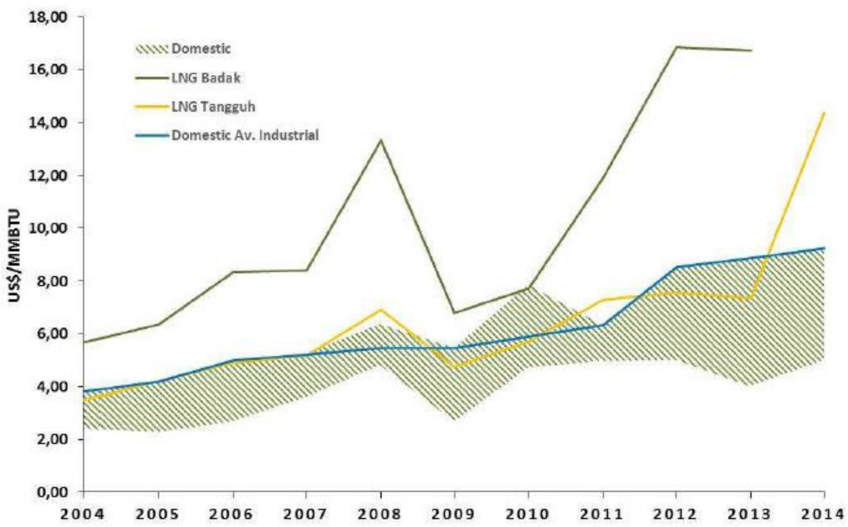


Figure 0-2: Export and Domestic Gas Prices[207]

The domestic market development strategy resulted in a gap between export market prices and domestic prices, which creates challenges when alternative gas supply sources need to be acquired. As economic development in Indonesia increased so did the energy and natural gas demand, the domestic demand for natural gas increased above locally allocated gas provisioned for supply, to ensure export contract requirements were fulfilled, natural gas was imported to account for the supply-demand gap.

12.1.1 Domestic Gas Demand Assessment

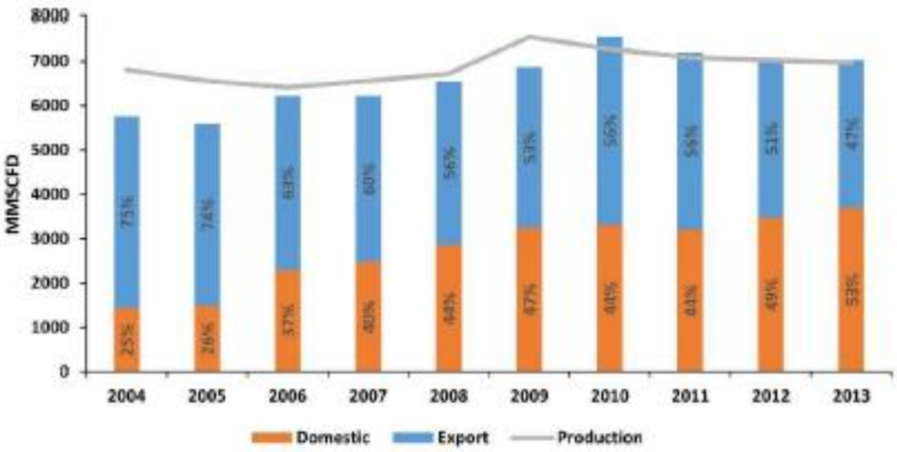
Indonesia, has been a gas producing nation, commercialising natural gas since the 1970s and is one of the leading LNG exporting nations in the world. The gas industry contributes to economic development, has a positive impact on emission rates and reduces reliance on petroleum fuels. Recent developments in the gas market have resulted in a shift in dynamics for the Indonesian gas market together with increased local gas demand, which follows the country's rapid economic growth.

Indonesia's rates of GDP growth (at 3-4% per year) remained largely unchanged in the period from 2001 to 2016 (IISD).

The country, however, experiences infrastructure challenges in terms of gas transportation as well as a fragmented gas market. These factors provide similar implementation challenges to the Southern African region in terms of meeting local demand which is sparsely located with insufficient transportation infrastructure required to transport gas from the main gas supply fields.

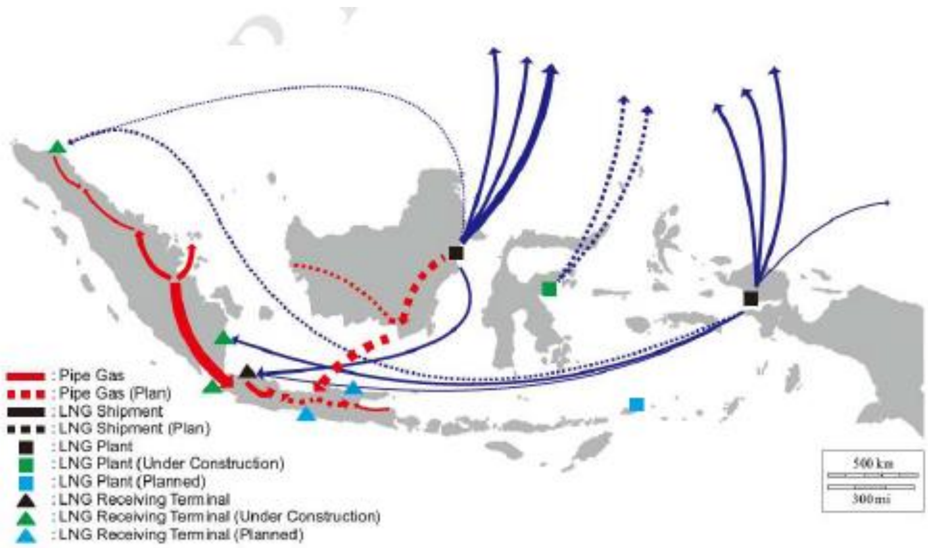
The Indonesian government is aiming to incorporate natural gas into the energy mix, targeting a 22% share on the national energy mix by 2025.

[207] Widodo Wahyu Purwanto (2015), Status and outlook of natural gas industry development in Indonesia



C 1.1 Indonesian natural gas demand and production, 2004-2013[208]

Indonesian gas production is rated 11th largest in the world, with proven reserves of 96 trillion cubic feet (TCF) in 2018 and an estimated 1% of the worlds gas consumption.[209] The Indonesian gas local gas market has grown in line with the country's economic growth and the local demand has accounted for an increasing share of the countries gas production supply since 2004. In 2013, the local demand comprised of fertiliser (31%), electricity sector (14%) and private use and enhanced oil recovery accounted for 5%; with the other half of the total production being exported. Gas utilisation for transportation and households had marginal share of the demand, accounting for 0,04% and 0,01% respectively.[210] This demand is expected to shift significantly, particularly in the Maritime industry due to regulatory requirements being implemented from 2020 onwards.

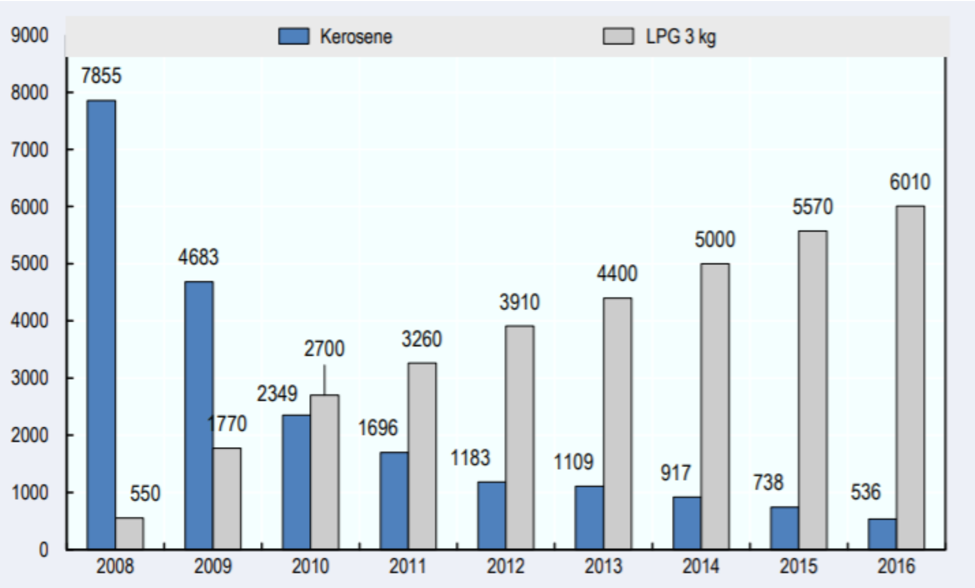


C 1.2 Domestic natural gas flow distribution routes and exports.[211]

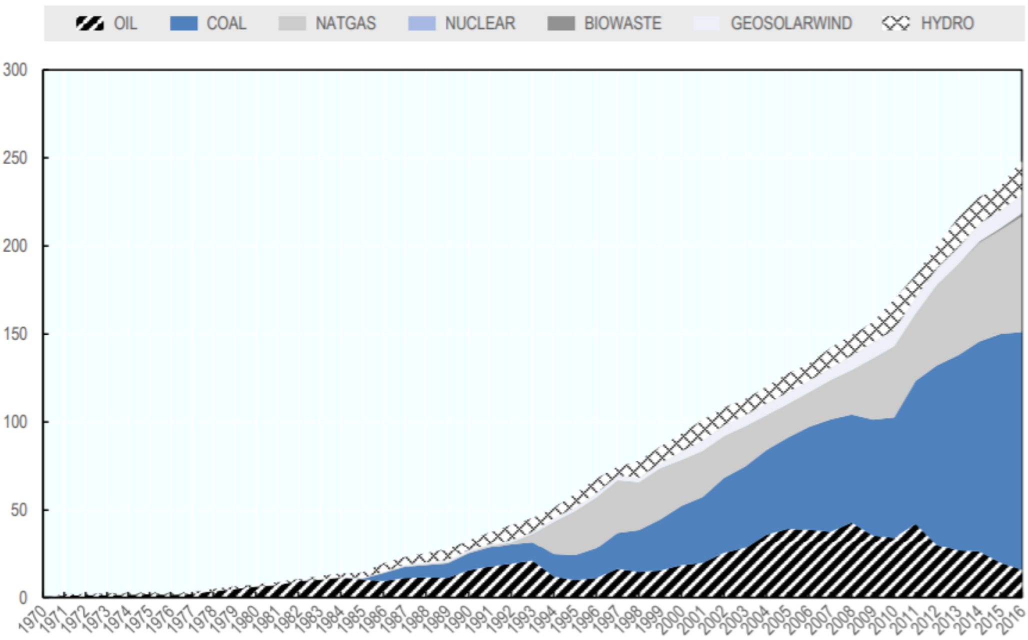
The geographic makeup of Indonesia, as well as the misalignment of gas supply and demand nodes, provides a good comparative assessment for the prioritised countries being analysed. The Southern African region, similarly, has demand nodes as major cities with limited transportation infrastructure

208 *Journal of Natural Gas Science and Engineering,* Status, and outlook of natural gas industry development in Indonesia
209 PWC, Oil and Gas in Indonesia Investment and Taxation Guide
210 *Journal of Natural Gas Science and Engineering,* Status, and outlook of natural gas industry development in Indonesia
211 *Journal of Natural Gas Science and Engineering,* Status, and outlook of natural gas industry development in Indonesia

availability and the coastal nature of the majority of countries allows for LNG shipping to remain an option for supply to major ports.



C 1.3 Kerosene and 3 kg LPG canister consumption in million kg, 2008-16[212]



C 1.4 Indonesia electricity consumption by type in ktoe.[213]

The majority of Indonesia's electricity generation is through fossil fuels, accounting for around 88% of electricity generation, more than half from coal. Natural gas makes up 25% and 6% is generated through oil, the remaining 14% is generated through renewable sources, including hydro.

The subsidising of LPG has been used to reduce kerosene subsidy expenditure and reduce emissions, which has resulted in a significant reduction of kerosene usage with a corresponding

212 OECD, Indonesia's effort to phase-out and rationalise Its fossil-fuel subsidies
213 OECD, Indonesia's effort to phase-out and rationalise Its fossil-fuel subsidies

increase in the subsidised 3 kg LPG canisters, further policy amendments were made to ensure the subsidies were focused on the target groups, by limiting it to households with an income threshold. Similar strategies would allow for the SADC region to reduce kerosene usage in the region over the long term. [214]

Indonesia currently faces a situation whereby domestic prices are below export prices, together with increasing domestic consumption of gas as well as a decline in gas production, which requires a shift in policy as well as foreign gas trade, with the expectation that the country will become a net gas importer in the near future.

12.1.2 Regulatory Framework

In the 1960s, Pertamina was set up to function as both an oil and gas company and as a state energy regulator in Indonesia. In 1966, a price-sharing contract was signed, the first of its kind in the petroleum industry, between Pertamina and the Independent Indonesian American Oil Company. Pertamina both controlled and supervised oil and gas activities under various production sharing contracts for the rest of the century.

In 2001, the regulatory function of Pertamina was limited to oil and gas operations through the introduction of regulation law on oil and gas; the regulatory functions were transferred to BP Migas, an independent Upstream Oil and Gas Implementing Agency. The downstream activities were regulated through licenses supervised by BPH Migas, who was tasked with assuring sufficient supply and safe operations of downstream oil and gas activities. In 2012, several provisions of this law were annulled, and BP Migas was disbanded, as the Constitutional Court deemed that supervision of oil and gas should not reside with an independent regulatory body, but rather should reside with the state. A temporary regulatory agency SKK Migas was installed.

In 2015, an amendment to the oil and gas law was drafted in response to the decision, to enhance the state's role in controlling and exploiting oil and gas resources, satisfying domestic consumption and performing the business licensing and supervision functions of upstream oil and gas activities directly through the Ministry of Energy and Mineral Resources.

The law provisions the instalment of a state-owned business entity, BUMN-K, responsible for cooperation with a private oil and gas company for exploration and production. Local companies were also provisioned to have business license priveledges, and no changes were made to downstream regulations. The new law also creates a buffering business entity, BUP, to act as an aggregator, centralising the purchase and sale of oil and gas for the domestic market.

12.2 Japan Gas Market Development Case Study

Japan has a long history with natural gas, with discoveries as early as the 1600s; early use was limited to the residential sector, and in 1872 gas was used for lighting. Due to limited gas reserves and geographic constraints, production and transmission infrastructure development were limited, resulting in feedstock being delivered and distributed to consumers over land.

In 1969, Tokyo Gas and Tokyo Electric Power Company jointly began importing LNG from Alaska, mainly due to the environmental benefits of switching from higher carbon-emitting fuels, even though prices were significantly higher, due to liquefaction costs at the exporting site and transportation costs - including the cost of constructing a ship equipped with low-temperature storage vessels. The switch to natural gas was seen to boost the achievement of economies of scale concerning LNG transportation and terminal construction and secure a cleaner energy source to meet environmental

[214] OECD, Indonesia's effort to phase-out and rationalise Its fossil-fuel subsidies

requirements to reduce air pollution.[215] The anchor demand for natural gas was thermal and more specifically gas to power; however, many power companies were only willing to switch to natural gas if the government would cover the high capital costs. The sale price was set in the purchase agreement with the inclusion of a supply scenario clause whereby price adjustments will be made if additional supply alternatives come online, the clause stated: "If in the future another Liquefied Natural Gas project is placed into operation to supply Japan with natural gas from foreign gas sources, such as Alaska, Canada, Australia, Brunei and the Middle East under similar conditions such as volume, distance, liquefaction and ocean transportation techniques, contract term and so forth, Sellers will hold a discussion with Buyers concerning the price as herein set forth, and shall endeavour to find a solution satisfactory to all parties concerned." [216]

The early gas market consisted of two sectors under the Gas Utility Industry Law, general city gas and simplified gas business, which consisted of simple gas production facilities for small residential areas. These were supplemented by LPG which supplied small businesses and domestic users.

Japan's LNG supply is dominated by long term contracts, with the obligation to buy over 15-25-year contracts, while ensuring end-user delivery obligations. Most of Japan's entities are not state-owned, but operate internationally under government guidelines, while the government is involved in the local supply of natural gas throughout the value chain. The gas market is dominated by a mix of large electric utilities, gas distribution utilities, and large industries. In 2014, electric utilities and city gas companies accounted for 60% and 35% of market share. [217]

12.2.1 Infrastructure Development

In the 1990s supply was fragmented into monopoly areas, with a large number of distribution companies supplying different areas; with three major companies accounting for 75% of total sales, resulting in varied calorific outputs, which inconvenienced consumers. Regional connection via large-scale transmission pipeline was not deemed essential due to the differing gas supply characteristics in different areas. A 300km pipeline connecting indigenous supply from Niigata to 32 gas utilities, up to Tokyo, owned by a major gas producer and wholesaler, was completed in 1962 and was the exception.

In 1992, the national gas committee recommended connecting three major cities (territories of the major gas companies) and the LNG terminals which they operate to develop the gas market and reach a broader consumer base. The aim was also to alleviate electricity supply issues and increase opportunities for gas usage.

In 1997 the volume of Japanese LNG imports stood at 64.3 BCM, 57.8 percent of total world LNG trade. In comparison with the total amount of gas consumed, trunk line network development remains relatively low (1,366km), with demand focused around the 22 LNG terminals.

The Japan Gas Association (JGA) announced its plan on national pipelines constructing a 1,200 km pipeline from Tokyo to Osaka through Nagoya, in March 1993, which was planned to start in 2000 and be completed by 2010.[218]

The development of LNG bunkering base is the latest LNG infrastructure development in Japan, and consists of optimising truck-to-ship bunkering, followed by the introduction of ship-to-ship bunkering

[215] ASIA NATURAL GAS PIPELINE DEVELOPMENT
[216] King & Spalding LLP; Japan's pivotal role in the global LNG industry's 50-year history
[217] Japan's Gas and Electricity Market Reform: The Third Revolution
[218] The Gas Industry in Japan, Hideo Taki; Working Paper No. 117 (1996)

and as sufficient demand is realised, strengthening and expanding of the ship-to-ship bunkering operations.[219]

12.2.2 Security of Supply

Security of supply was anchored on long term supply contracts and political agreements and partnerships; as the market developed, diversifying import sources became more prevalent together with gas utilities investing in research to develop Substitute Natural Gas to diversify supply, as well as, obtaining concession rights for natural gas exploration and production internationally, such as Indonesia, and establishing a company to build and own tankers for its own use. Initially, suppliers were responsible for delivery, and often third parties were used to mitigate risk.

When energy supply sources are diversified, the power controlled by a single supplier is diminished. Diversification of supply has been used by Japan to improve energy security and enhance bargaining power. Since 2010 Japan has increased its spot price and short-term LNG contracts. Furthermore, increased importation from the USA is seen as a mechanism to pressure the current oil-indexation in Asia.[220] In partnership with the business sector, the Japanese government are planning to invest $14.4 billion in liquefied natural gas development in Mozambique.[221]

Japan and India are currently working together to address higher LNG prices in Asia than in Europe and North America to develop a globally competitive and stable LNG market environment, through improved LNG procurement prices and mechanisms.

12.2.3 Market Reform

Japan’s city gas and electric power industries are undergoing unprecedented but somewhat anticipated structural changes brought about by the recent regulatory restructuring. The process dates back as far as 1995 when an amendment of the gas utility industry law in 1995 allowed for gas sales to the most significant industrial customers with contracted amounts of more than 2 million m3/year was opened for competition. The following provisions were made:

- Gas utilities could compete outside their service areas;
- Non-city gas suppliers were allowed to supply to large industrial customers; and
- Gas tariffs were free of regulation in principle.

In 1999, a further amendment to the Gas Utility Industry Law was made in an attempt to enable:

- Further opening of the gas market;
- Gain further benefits for consumers;
- Strengthen the competitiveness of utilities; and
- Minimise government involvement.

Finally, in 2016, the government officially announced a policy of de-linking the LNG price from crude oil prices and an LNG pricing mechanism was introduced, based on the Japan Over-the-Counter-Exchange (JOE).

Furthermore, the liberalisation of the electricity market took place and was followed by the liberalisation of the domestic gas market in 2017. The ensuing competition had a significant impact on the large gas companies and ensured competitive prices for consumers. A phased approach was used leading to complete liberalisation in 2017 as shown in the figure below.[222]

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[219] METI: Japan's LNG Market Strategy
[220] Energy Policy; Natural gas in Asia: Trade, markets, and regional institutions
[221] RT: https://www.rt.com/business/493723-japan-bets-big-mozambique-lng/
[222] Japan's Gas and Electricity Market Reform: The Third Revolution

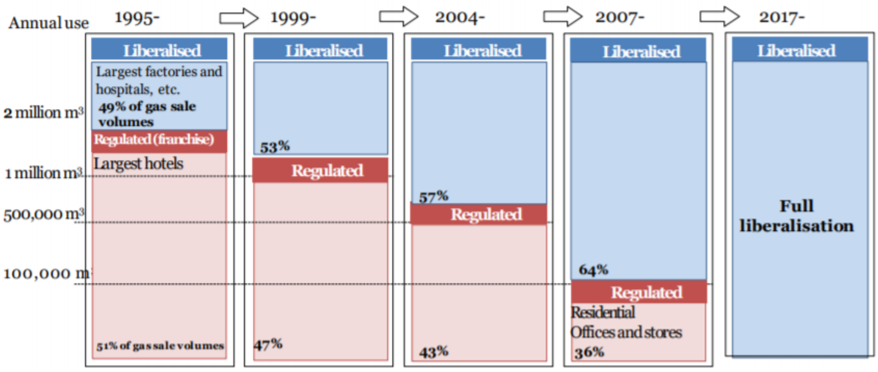

Figure 0-3: Brief History of Japans City-Gas Liberalisation[223]

12.3 Norway Gas Market Study

Norway has become one of the most prosperous economies in the world, despite being a small, peripheral, and costly market. Their story of success can be explained by abundant natural resources (with oil and gas production beginning in 1971), sound and stable macroeconomic policies, strong public institutions, remarkably high productivity and labour utilisation, equality across its homogeneous population, and overall social stability. The dynamics behind Norway's successful oil and gas sector model are further considered across the six enabling dimensions as a basis for comparison.

12.3.1 Energy System Structure

Norway is one of the most significant energy producer and exporters among Europeans. Norway has the highest share of electricity produced from renewable sources in Europe, and the lowest emissions from the power sector. At the beginning of 2018, the installed capacity of the Norwegian power supply system was 33 755 MW, and normal annual production was 141 TWh. Norway is now developing more renewable power production capacity than it has for decades.[224]
The Norwegian energy system is unique in that virtually all electricity is generated through hydropower. Unlike other Nordic countries with significant thermal electric and heat production and district heating systems, Norway has electrified its energy system to a much greater extent.[225]

One special feature of the Norwegian hydropower system is its high storage capacity. Norway has half of Europe's reservoir storage capacity, and more than 75% of Norwegian production capacity is flexible. Production can be rapidly increased and decreased as needed, at low cost. Like its significant exports of oil, Norway also exports electricity through the Nordic grid, and through goods created in power-intensive industries. Oil powers most transport, and together with gas it powers the offshore extraction industry.

The power market in Norway was deregulated in 1991, when few countries had market-based power systems. The market is now a fundamental element of the Norwegian power supply. Energy Norway represents the renewable energy industry in Norway, i.e. companies producing, transporting, or trading renewable energy. Their members produce 130-140 TWh annually, which is some 99 per cent of all power production in Norway. Energy Norway members have approximately 2.5 million grid

223 Energy Policy; Natural gas in Asia: Trade, markets, and regional institutions
224 Energifaktanorge, 2020. Norway's Energy Supply System.
225 Norway: An electrified energy system.

customers, which is about 90% of Norway's grid customers. The members of Energy Norway have some 15 000 employees and have a gross annual turnover of about $9 billion USD.[226]

12.3.2 Capital and Investment

Norway has successfully managed to avoid the so-called Dutch disease (a decline in other exports due to a strong currency) for a number of reasons. The country decided to do what Iraq and many other oil-producing states never do: deliberately limit how much oil revenue enters the economy.

Initially, the government decided to take all the profits generated by its state-owned oil companies and reinvest them in searching for and producing more oil. But by 1990s, the flood of income had grown beyond what this could absorb[227]. In response to this, Norway created a special buffer fund to keep the oil profits out of the economy by declaring them the property of future generations of Norwegians. In 1990, the precursor of the Government Pension Fund – Global (GPFG), a sovereign wealth fund, was established for surplus oil revenues. The government limited itself from using more than 4 percent of the money for current infrastructure and other public projects and invested the rest in financial markets abroad, effectively sending it into exile. Through these measures, Norway has avoided hyper-inflation, and has been able to sustain its traditional industries.[228]

At present the total investment level on the Norwegian Continental Shelf (NCS) is relatively high. In 2019, investment in oil and gas activities, excluding exploration, reached more than 140 billion Norwegian kroner, an increase of 13 per cent when compared to 2018. Investment in the petroleum sector accounts for about 25 per cent of total investment in productive capital in Norway.

12.3.3 Policy, Legislative and Structure

The policy of the domestic natural gas sector is set by the parliament and the government, while the overall responsibility to execute the resource management is vested in the Ministry of Petroleum and Energy (MPE). The Norwegian petroleum industry is based on a principle of sustainable development that strives to facilitate long-term profitable production benefiting the country as a whole. As part of this principle, the government also focuses on increased recovery from producing fields, and increased exploration in both mature and unexplored areas. A petroleum fund is established to ensure that the revenue from petroleum activities (including the natural gas sector) will be available for future generations. All activities must comply with comprehensive safety regulations and high environmental standards (zero-pollution policy).

The MPE has overarching responsibility for managing petroleum resources. It is also responsible for the state-owned companies Petoro AS (Petoro) and Gassco AS. Petoro manages the state’s direct financial interest (SDFI) in petroleum activities and is organised as a private limited company. Petoro is not empowered with any regulatory authority and conducts activities on the same terms and conditions as the other licensees. The NPD is administratively subordinate to the MPE and plays a key role in the management of petroleum activities.

Pursuant to the Petroleum Act of 29 November 1996 No. 72 (the Petroleum Act), and the analogous Onshore Petroleum Act of 4 May 1973 No. 21, the state has a proprietary right to all petroleum deposits and the exclusive right to resource management. The MPE is, however, empowered to grant

[226] About Energy Norway. EnergiNorge.
[227] Hsieh, Esther. What Norway did with its oil and we didn’t. May 11, 2018. The Globe and Mail
[228] Torres, Cesar Said Rosales. Norway’s oil and gas sector: how did the country avoid the resource curse? revista tempo do mundo . rtm. v. 1, n. 1, Jan. 2015

licences pertaining to exploration and production of petroleum. The granted licences contain criteria the licensees must comply with, and are given for a limited time period within a predefined area.

The state participates in petroleum activities on the NCS through the state's direct financial interest (SDFI). The participating interest held by the SDFI in production licences, transportation pipelines and specific land-based plants are managed by the state-owned limited company, Petoro AS (Petoro). Petoro is a licensee in selected licences and participates on equal terms and conditions as other licensees. There are no limitations on the maximum participating interest to be reserved to the SDFI, but Petoro's share will normally be less than 50 per cent. Petoro does not hold operatorships.

12.3.4 Institutions and Governance

The State has historically played a critical role in the economy of Norway. Excluding petroleum, public expenditure is the highest in the OECD as a % of GDP. There are extensive SOEs. The rationale for maintaining SOEs can be grouped in 4 main categories:

i) Industrial development and sectorial policies,
ii) Control of strategic natural resources,
iii) Norwegian ownership, head office location and preservation of strategic national competence and
iv) Financial returns.

Norway has undertaken important reforms in its ownership policy over the last 15 years, separating the policy, commercial, and regulatory functions. Within each area there are state-controlled institutions with their own distinct roles. The Ministry of Petroleum and Energy is a policy-making body working with the political leadership on setting goals for the sector, making assumptions for the realisation of these goals and framing the licensing process. Commercial functions are ceded to the partly state-owned company Statoil which carries out operations both in
Norway and oversees. All regulatory and technical guidelines are within the competences of the Norwegian Petroleum Directorate with a wide range of duties from setting regulations related to resource management, collecting fees from oil operators and compiling data on all hydrocarbon activities on the Norwegian Continental Shelf.[229]

In general, Norwegians have a high level of trust in their fellow citizens and those they elect to hold office. Norway routinely tops surveys ranking the world's countries in citizens' trust in their government and institutions as well as for general contentment with their lives. This could mean that the Norwegian model would not work as well in many countries where there is a less strong sense of social contract, but Norway's experience could still provide some valuable lessons.[230]

12.3.5 Infrastructure and Market Structure

Oil and gas projects are often located in remote areas with limited local pools of skilled labour. The need to import foreign construction workers affects not only the labour rate but also infrastructure costs. In addition, the logistical challenges of building in remote areas can reduce overall productivity and prolong construction schedules, especially for plants located in regions with geopolitical instability or extreme weather conditions[231]. The harsh Norwegian climate did not allow for easy access to the

[229] Dośpiał-Borysiak, Katarzyna. Model of State Management of Petroleum Sector – Case of Norway. International Studies. Interdisciplinary Political and Cultural Journal, Vol. 20, No. 1/2017
[230] Recknagel, Charles. What Can Norway Teach Other Oil-Rich Countries? November 27, 2014. RFERL
[231] Dediu, Dumitir et.al. Setting the bar for global LNG cost competitiveness. October 2019. McKinsey Insights – Oil and Gas

offshore oil and gas fields but compared to their onshore oil and gas producing counterparts they do have a geological advantage. The construction of roads and rail roads for improved access and transportation of resources is an expensive endeavour. Norway has largely bypassed this financial burden as all their oil fields are offshore which allows for near immediate storage and export via ship or series of complex, interconnecting pipeline networks. Several submarine pipelines transport petroleum from Norway to delivery points in landing terminals in continental Europe and the United Kingdom. The Norwegian petroleum transport infrastructure also includes several receiving terminals located on the territory of foreign countries[232]. These activities and facilities are regulated by the Petroleum Act and are pursuant to specific bilateral agreements between Norway and the relevant state where the terminal is located.

Unlike other oil-producing countries, Norway has been able to develop a supplier cluster that supports oil and gas production. The critical success factors were existing capabilities in the maritime industry, sophisticated demand conditions, and balanced policy intervention. Today, the Norwegian supplier companies are leading players that are strategically positioned in many of the most dynamic oil provinces of the world.

Several important policy decisions in the 1970s enabled Norwegian suppliers to develop competences. The government implemented protectionist procurement policies. In Section 54 of the Norwegian Petroleum Code, operators, such as Phillips Petroleum, were legally required to inform the Ministry of Petroleum and Energy about supplier bids. The Ministry could then demand that specific Norwegian firms be included on the bidder list. Foreign firms could not be excluded from the list, but the Ministry had the authority to change who was awarded the contract. Informally views were exchanged with the Ministry on which company should be awarded the contract[233].

As part of the licensing process, foreign operators had to come up with plans to develop the competences of the local suppliers. The Norwegian government subsidised the local development costs with tax deductions. This is another distinguishing feature of the Norwegian policy model. There were location-based directives to keep R&D activities in Norway. In the 4th licensing round in 1978--1979, authorities introduced a requirement that at least 50% of R&D necessary to develop a field had to take place in Norwegian institutions. Later this 50% requirement was replaced with “goodwill agreements” under which foreign operators had to make an effort to conduct as much oil and gas R&D in Norway as possible. However, these protectionist policies only targeted industries where Norway was already world class (e.g. shipping but not steel)[234]. These policies were removed as Norwegian firms developed competences and were phased out in 1994, when Norway entered into a free trade agreement with the EU, which prohibited these practices.

12.3.6 People: Capacity & Participation

Norway has a high level of education allowing a high participation in the labour force. Despite this, their oil and gas industry is following the global industry trend and currently facing a skills shortage. This is due to several factors, including skilled workers retiring or leaving the sector and a lack of younger people who want to fill those roles. The volatility of the price of oil has led to some workers deciding to seek more stable employment as cuts to graduate recruitment and apprenticeships during the oil downturn were implemented. There are a number of recommendations to address the skills gap which threatens the growth of the industry[235]. The three most prevalent recommendations are:

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[232] Oil and Gas in Norway. Lexology. 7 June 2018
[233] Leskinen, Oliva. Norway oil and gas cluster. May 2012. Microeconomics of competitiveness Harvard Business School
[234] Heum, P. Local Content Development - Experiences from Oil and Gas Activities in Norway. SNF. Bergen, 2008.
[235] Skills shortage constrains Norway's oil industry: Study. November 28, 2012. Reuters

- Introduce more technology - Automation and the use of technology could help to make up for the current shortage of skilled workers. Technology applications can make the oil and gas industry more efficient, allowing companies to produce more with fewer workers
- Foreign Labour - Attract skilled foreign labour. Following the example of the Partnership between Statoil and the University of Texas at Austin, firms could increase cooperation with top foreign universities

Improve Incentives - Firms should better align results and rewards (career development, recognition, pay) for entry and mid-level managers. They should invest in culture---building programs that make their companies attractive. Firms should position themselves as being on the cutting edge of the sustainability trend and sell the opportunity to innovate around clean technologies.

12.3.7 Electricity Sector

Norway was amongst the first countries globally (after Chile and England) to restructure its electricity sector. It is a fascinating example, as its industry is highly efficient and competitive but large elements of the sector remain in public ownership.

12.4 India Gas Market Study

Over the last several decades India has been among the world's fastest growing economies. India is now at a crossroads in its energy transition journey. Its energy needs are primarily met by fossil fuels (with implications for environmental sustainability and increasing energy import costs) but a large share of the Indian population still lacks access to electricity and clean cooking fuel.[236] Recent initiatives to improve electricity access have experienced some success and the outlook is positive; however, the road to continuous access to power and clean cooking fuel for all is long.[237]

12.4.1 Energy System Structure

The Indian power sector is characterised by a multiplicity of players across all segments of the energy value chain. There are more than 600 generating stations, 30+ transmission licensees, about 70 distribution licensees, 2 power exchanges, 40 odd trading licensees, load dispatchers at the centre, in each of the five regions and in each of the 29 States. The total installed generation capacity is 346 GW with a mix of 57% coal, 13% hydro, 21% renewables, 7.2% gas, and 2% nuclear[238].

Currently 87% of India's electricity is transacted through long-term (25-year) fixed power purchase agreements (PPAs) between distribution companies (discoms) and generators. To meet the majority of their daily power needs, discoms "self-schedule" generation from the portfolio of generators with whom they hold these long-term contracts. Self-scheduling refers to the practice followed by the discoms to requisition power from the generating stations with which they have contracts. The discoms are not obliged to inform the system operator of the variable cost of such contracted generators.

The remaining power is traded through bilateral transactions between utilities, through power exchanges and traders. The decentralised self-scheduled manner of power procurement between discoms and generators offers little visibility and therefore flexibility for discoms to choose from cheaper generators from outside their portfolio. Lacking this visibility and the ability to accurately

[236] India ranks 78th on WEF Energy Transition Index. GKToday. March 15, 2018.
[237] Fostering Effective Energy Transition, A Fact-Based Framework to Support Decision-Making. WEF Insight report. March 2018
[238] Market Based Economic Dispatch of Electricity: Re-designing of Day-ahead Market (DAM) in India. Central Electricity Regulatory Commission (CERC). December 2018.

anticipate and adjust for future demand, variable generation sources like renewables are often curtailed[239].

The energy industry in India is set for a systemic transformation with the recent developmental ambitions of the Government of India – 175 GW of installed capacity of renewable energy by 2022. Moreover, the aim is to achieve 100 smart cities, a 10% reduction of oil and gas import dependence by 2022 and provision of clean cooking fuels. This translates to India initiating the largest government-mandated renewable energy programme globally.[240]

Capital and Investment

Between April 2000 and June 2019, the power sector attracted US$ 14.54 billion in Foreign Direct Investment (FDI), accounting for 3 per cent of total FDI inflows in India.[241] India is further anticipating an influx of investment in oil and gas exploration as well as investments in establishing the natural gas infrastructure over the next few years as the country prepares to meet the needs of a fast-growing economy.

According to the Ministry of Petroleum and Natural Gas, a cumulative investment of $40 Bn is expected in the Indian Energy & Petroleum sector in the near to medium term horizon. This will largely be driven by a host of favourable policy measures benefiting the sector players and other industry incumbents. Furthermore, with the recent recovery in the crude oil prices globally, the sector activity, in general, is likely to pick up and garner more interest from global players looking into India. Oil Field Services and Equipment (OFSE) Investments worth $102 billion are expected in upstream equipment and services over the next 10 years.[242]

The minister further estimates close to USD 136 Bn investments in the Indian gas sector by 2025, a large part of which includes strengthening of infrastructure – RLNG terminals, pipeline projects etc. - and expansion of City Gas Distribution network. The government's push towards a gas-based economy has given significant thrust to LNG imports, given the low domestic natural gas output, which in turn will inevitably lead to significant investment towards infrastructure development.

India has emerged as a *refining* hub in Asia, serving a large domestic market for refined petroleum products and even exports. Some of the key areas of focus in the downstream value chain include overall energy efficiency, upgrading the quality of fuel while upgrading facilities to produce compliant fuels. Petrochemicals also offer a great opportunity for the incumbents and the sector is likely to grow at a CAGR of ~10% over the next five years to reach the USD100 billion mark by 2022.

The Government of India (GoI) has recognised the potential in this area and it is one of the priority sectors under the *Make in India* program. The government has launched several schemes and initiatives to encourage growth in the sector which include:

- Petroleum, Chemical and Petrochemical Investment Region (PCPIR): a cluster approach to promote petroleum, chemicals, and petrochemical sectors in an integrated and environmentally friendly manner on a large scale. PCPIRs have already received investments worth $ 24.68 Bn until now and are expected to attract investment in the tune of USD 117.42 Bn over a long-term horizon.

[239] Creating a National Electricity Market: India's Most Important Power Sector Reform. Center for Strategic and International Studies. August 19, 2019.
[240] Niti Aayog. Energising India.
[241] Power Sector in India. India Brand Equity Foundation. December 2019.
[242] The Evolving Energy Landscape in India: Opportunities for investments. The International Energy Forum, New Delhi 2018.

- Plastic parks: cluster development scheme aimed at setting up need based plastic parks, an ecosystem with state-of-the-art infrastructure and common facilities. Under this scheme GoI provides grant funding up to 50% of project cost with a celling limit of USD 5.97 Mn per project. 10 parks have been approved by central government and "in principle" approval has been given to 8 more in 2015.

Given the robust growth of LPG, increasing market share of LPG in India and neighbouring regions can be considered. Consumption expanded more than 8% to nearly 23 million tons last year, with imports making up more than half those requirements. India raised its target for providing free cooking gas connections to the poor by 60% to 80 million families.

GoI is further encouraging global players to have a hand in the retail growth story. Retail sales have become more viable for private-sector refiners ever since the current government abandoned the diesel price controls in October 2014. Pricing freedom coupled with record oil consumption is increasing competition in what International Energy Agency (IEA) predicts will be the world's fastest-growing oil consuming nation through 2040.

12.4.2 Policy, Legislative and Structure

The sector is prominently guided by the Electricity Act 2003 (EA 2003) or (the Act), National Electricity Policy 2005 and National Tariff Policy 2006 and 2016. The Government of India (GoI) has emphasised that an efficient, resilient, and financially robust power sector is essential for growth of the Indian economy. A series of reforms in the 1990s and the EA 2003 have moved the power sector towards its vision of a competitive market with multiple buyers, sellers supported by regulatory, and oversight bodies. In context to this, organisations have been formed both at the central and state government levels to facilitate development of the power sector[243]. The policy framework increasingly leans towards empowering the states more and decentralising the decision making for funding. Some of the sector policy reforms include[244]:

- *Hydrocarbon Exploration & Licensing Policy (HELP)* replaces the present policy regime for exploration and production of oil and gas, known as New Exploration Licensing Policy (NELP). HELP provides a uniform licensing system to explore and produce all hydrocarbons such as oil, gas, coal bed methane, shale oil/gas, etc. under a single licensing framework
- With an opportunity to increase domestic production of oil and gas, the GoI in September 2015, in consultation with ONGC and OIL, approved the *Discovered Small Field Policy*. This policy aimed for monetisation of 69 discovered small fields/discoveries of ONGC and OIL, which had not been put into production. Under the Discovered Small Field Policy Round-II, on 9 August 2018, Government of India has offered 59 discoveries clubbed under 25 contract areas for bidding[245]
- Under the New Domestic Gas Pricing Policy, a transparent new gas pricing formula linked to the global market is made effective from 1 November 2014
- Policy framework for relaxation, extensions and clarifications at the development and production stage under PSC regime for early monetisation of hydrocarbon discoveries approved on 10 November 2014
- Policy for grant of extension to the PSCs of 28 Small and medium-sized discovered blocks approved on 10 March 2016

[243] The Evolving Energy Landscape in India: Opportunities for investments. The International Energy Forum, New Delhi 2018.
[244] Make in India – Oil and Gas Sector.
[245] Press Information Bureau - Ministry of Petroleum & Natural Gas, Approval of 69 Discovered Small Field/Discoveries Under the Discovered Small Field Policy,

- Policy on Testing Requirements for discoveries in New Exploration Licensing Policy (NELP) blocks approved on 29 April 2015
- Hydrocarbon vision 2030 for North East India has been released in February 2016
- Pooling of gas in fertiliser (Urea) industry was approved on 31 March 2015. Mainly to supply gas at a uniform delivered price to all fertiliser plants, through a pooling mechanism of domgas with R-LNG
- The Petroleum and Natural Gas Regulatory Board Act 2006 regulates refining, processing, storage, transportation, distribution, marketing and sale of petroleum, petroleum products and natural gas
- The National Biofuel Policy 2009 promotes bio-fuel usage. The GoI has provided a 12.36% concession on excise duty on bioethanol and also exempted biodiesel from excise duty. The Union Cabinet has approved National Policy on Biofuels – 2018[246]
- The Government is implementing an Ethanol Blending Petrol program under which OMCs are mandated to sell Ethanol blended petrol with up to 10% Ethanol. The mechanism for procurement of ethanol by OMCs to carry out Ethanol Blended Petrol program approved on 10 December 2014. The Government of India has enhanced the Ethanol Procurement Price and opened an alternate route like cellulosic and lignocellulosic materials, including Petrochemical route
- Direct sale of biodiesel by private manufacturers/suppliers to bulk consumers like Railways and State Transport Corporations permissible on 10 August 2015
- The milestone set in Auto Fuel Policy 2003 is already achieved. Ministry of Petroleum and Natural Gas has issued a statement to all the concerned stakeholders including OMCs. The statement is for implementation and expansion of the supply of BS-IV auto fuels in phases by 1 April 2017, as per the road map is given in Auto Fuel Vision & Policy-2025
- The Policy on Shale Gas & Oil, 2013 allows companies to apply for shale gas and oil rights in their petroleum exploration licenses and petroleum mining leases

The drive for regulatory, policy and administrative reforms over the past few years have allowed for an improved investment environment and overall strong sector growth impetus

12.4.3 Institutions and Governance

India is the second-best performer in resource governance in the Asia-Pacific region, trailing only Australia. The Directorate General of Hydrocarbons is responsible for the development of the oil and gas sector. It is guided by the Hydrocarbon Exploration and Licensing Policy, which reformed licensing procedures and changed the fiscal regime from production-sharing to revenue sharing 2016.[247]

The Oil & Gas industry in India is closely regulated by the Ministry of Petroleum and Natural Gas, Government of India subjected to each link in the chain including Energy and Petroleum, refining, marketing, and distribution; and import, export, and conservation of petroleum products and LPG. There are several leading Public Sector Undertakings (PSUs) and private players across the value chain. The pricing of petroleum products and natural gas continued to be controlled and regulated by the government. The Petroleum & Natural Gas Regulatory Body (PNGRB) is the regulatory body, responsible for regulating the refining, processing, storage, transportation, distribution, marketing and sale of petroleum, petroleum products and natural gas excluding production of crude oil and natural

[246] Press Information Bureau, Government of India, Cabinet, Cabinet approves National Policy on Biofuels – 2018.
[247] Natural Resource Governance Institution. India Oil & Gas.

gas so as to protect the interest of consumers and entities engaged in specified activities and to ensure uninterrupted & adequate supply and to promote competitive markets.[248]

12.4.4 Infrastructure and Market Structure

In the recent years, India's energy consumption has been increasing at one of the fastest rates in the world due to both population growth and economic development. Primary commercial energy demand grew at the rate of six per cent between 1981 and 2001 (Planning Commission 2002). India ranks fifth in the world in terms of primary energy consumption, accounting for about 3.5% of the world commercial energy demand in the year 2003. Despite the overall increase in energy demand, per capita energy consumption in India is still very low compared to other developing countries.

India is well-endowed with both exhaustible and renewable energy resources. Coal, oil, and natural gas are the three primary commercial energy sources. India's energy policy, up until the end of the 1980s, was primarily based on availability of indigenous resources. Coal was by far the largest source of energy. However, India's primary energy mix has been changing over the last few decades.

Despite increasing dependency on commercial fuels, a sizeable quantum of energy requirements (40% of total energy requirement), especially in the rural household sector, is met by non-commercial energy sources, which include fuelwood, crop residue, and animal waste, including human and draught animal power. However, other forms of commercial energy of a much higher quality and efficiency are steadily replacing the traditional energy resources being consumed in the rural sector. Resource augmentation and growth in energy supply has not kept pace with increasing demand and, therefore, India continues to face serious energy shortages. This has led to increased reliance on imports to meet the energy demand.[249]

The Indian Oil & Gas industry is instrumental in fueling the rapid growth of the Indian economy. The sector meets more than two third of the total primary energy needs of the country. The oil & gas sector has been actively involved in putting India on the world map. With high rate of economic growth, India has become a major consumer of energy resources. India is fourth largest consumer of oil in the world. Despite the economic crisis, India's energy demand continues to rise steadily. India ranks 21st in terms of global oil reserve. However, their demand-supply gap is very high. The country imports more than one-third of its oil requirements.[250]

India's high dependency on crude oil imports makes the country susceptible to external forces such as supply disruptions and international prices.[251] To shield India from global oil supply disruptions and to reduce its overall crude oil import levels in the longer term, the Indian government decided to set up strategic storage of 39 million barrels of crude oil at three locations (Visakhapatnam, Mangalore, and Padur) as part of its first phase of strategic petroleum reserves development. The Indian Strategic Petroleum Reserves Limited (ISPRL), a special-purpose legal entity owned by the Oil Industry Development Board, would manage the proposed facilities, which are expected to be completed in 2016. The Visakhapatnam facility came online in June 2015 and began filling its facilities. The

[248] Sakariya, Sanjay. Indian Oil and Gas Industry - An Overview. January 2011.
[249] Indian energy sector: An overview. India energy portal.
[250] India 2020: Energy Policy Review. Country report.
[251] U.S. Energy Information Administration (EIA) India Overview

government unveiled plans to increase reserves to cover 90 days' worth of imports and add another 91 million barrels to the state's strategic crude oil capacity in a second phase by 2020.[252]

The national attempt is to bridge the ever-increasing gap between demand and supply of petroleum products by intensifying exploratory efforts for oil and gas products. An extensive increase in the domestic supply of natural gas and reduced prices of LNG in the country, are likely to encourage the consumption of gas in power, fertilisers, city gas distribution and other industrial segments. Given the commencement of production from RIL's KG Basin fields, the commencement of Cairn India's production and the potential development of the discoveries, the sector is poised to see considerable activity in the near future.

Gas is fast becoming a preferred fuel for retail user segment as a cheaper and cleaner fuel for domestic and transportation purposes. The growth of Auto CNG and Piped domgas in major Indian cities has sparked off a new demand spurt for NG. The fast pace of growth can be assessed from the fact that in the next few years, at least 30 cities would be embraced for city-wide gas coverage by private and public players, supported by regulation, as compared to the six cities today.[253]

12.4.5 People: Capacity & Participation

India’s achievements in the energy sector in recent years have been outstanding. Led by Prime Minister Shri Narendra Modi and his ministers, the Government of India is implementing reforms towards a secure, affordable, and sustainable energy system to power a robust economic growth.

The country has made huge strides to ensure full access to electricity, bringing power to more than 700 million people since 2000. It is pursuing a very ambitious deployment of renewable energy, notably solar, and has boosted energy efficiency through innovative programmes such as replacing incandescent light bulbs with LEDs (under the Ujala scheme).[254]

Whist India has managed to make great strides in developing its energy market, ongoing participation of local and international actors through fair and transparent policies is necessary. A collaborative effort towards ensuring greater integration, developing infrastructure, and ensuring a conducive fiscal and regulatory landscape will be instrumental in attracting continued investments across India’s energy sector. Considerations towards participation in the following areas should be addressed in order to continue to attract investments in the sector:[255]

Industry Associations

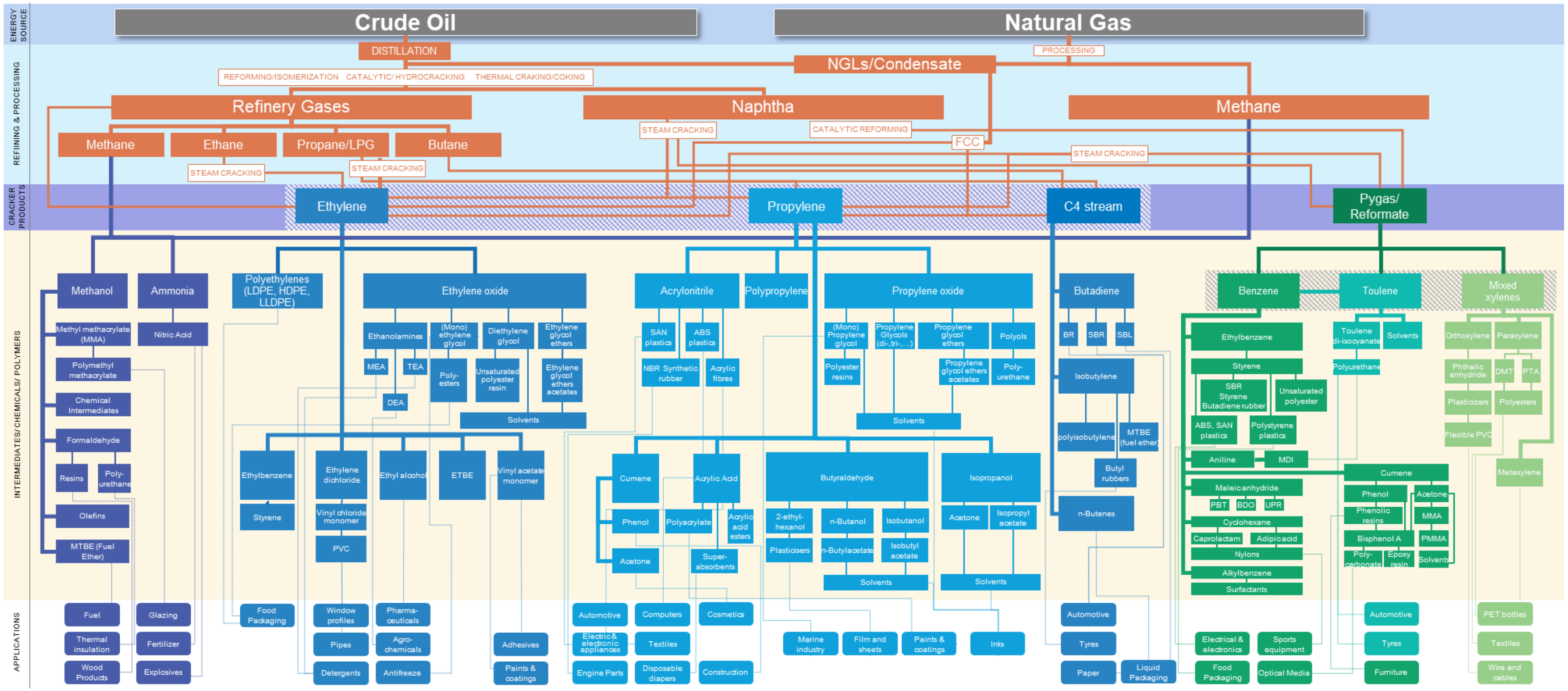
- Creating a platform for stakeholders to come together and deliberate on challenges; ensure representation to the authorities on various matters
- Ensuring learnings from global markets is translated effectively to Indian counterparts
- Need for a collaborative effort from the Government, Academia, Corporates, and Industry Associations to work with communities to educate them about the benefits of using Renewable Energy and generally increase awareness
- Government to push for more rural electrification and using renewable energy to power schools, colleges, and other institutions

[252] Bloomberg, "Petroleum Reserve to Cut Import-Shock Risks: Corporate India," September 2, 2014; Newsbase, AsianOil, "Indian oil ministry seeks SPR funding," February 10, 2016, page 8.
[253] Oil and Gas in India, 2020. KPMG in India – Infrastructure and Government division.
[254] International Energy Agency, 2020. India 2020 Energy Policy Review.
[255] The International Energy Forum, New Delhi 2018. The Evolving Energy Landscape in India: Opportunities for investments.

Academia

- Institutional ecosystem is essential to support economic growth and they play a vital role in stitching the social fabric to support development
- As employment levels increase, institutions need to ensure availability of skilled resources locally.

APPENDIX D: DETAILED PETROCHEMICAL PRODUCTS



D 1.1 Detailed Petrochemicals Value Chains[256]

[256] www.petroleumchemistry.eu

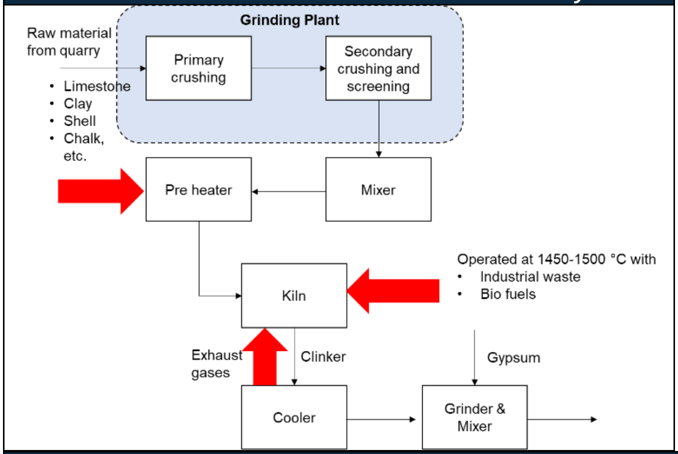
APPENDIX E: DEMAND ANALYSIS, ASSUMPTIONS & CALCULATIONS

Appendix E.1: Project-based Demand Mechanics

Cement

The following gives an overview of the cement manufacturing process, highlighting the units that require heating.

Process Overview — Cement Industry



Industry Fact Sheet and Assumptions

Average Energy per process [GJ/tonne]	
Dry long process	4.6
Dry with 1 cyclone preheater	4.2
Dry with 4 cyclone preheater	3.8
Dry with 5 cyclone preheater	3.0

Comments

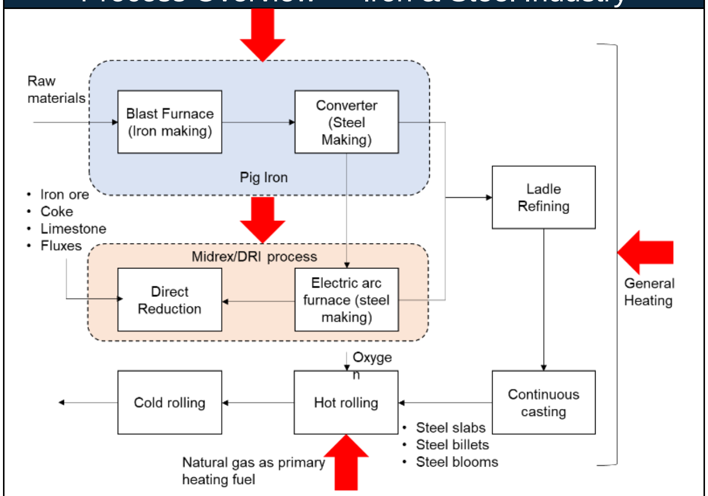
- In computing natural gas requirement for cement plants, a 5-cyclone preheater was assumed.

E 1.1 Cement manufacturing process

Iron and Steel

The following grants an overview of the Iron and Steel making process, highlighting the units that require heating.

Process Overview — Iron & Steel Industry



Industry Fact Sheet and Assumptions

Average Energy per process [GJ/tonne]	
Iron making	17.4
Steel-making	0.3
Hot and cold rolling	2.5

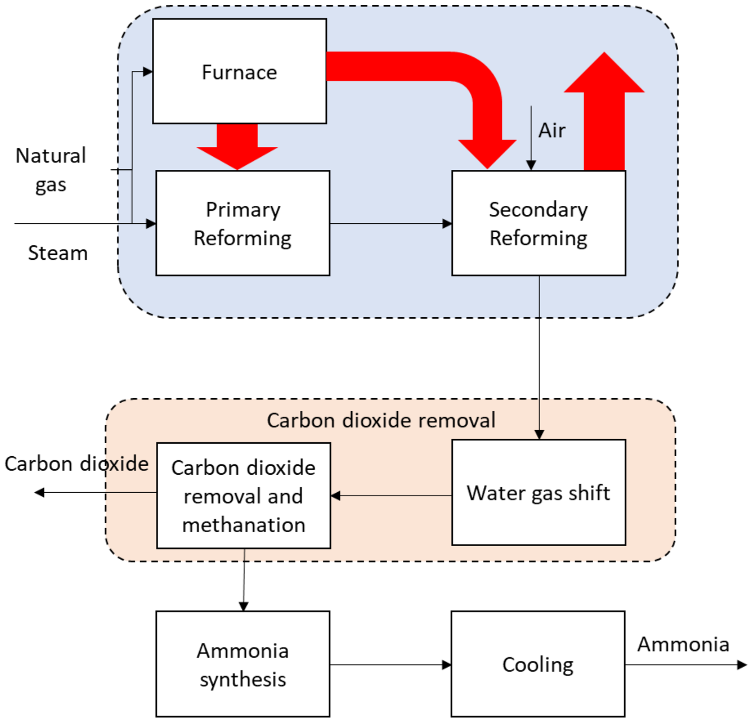
Comments

E 1.2 Iron and Steel manufacturing process

Fertiliser

The following is an overview of the energy requirement for Ammonia production. It should be noted that natural gas is used as both a heating fuel, as well as a feedstock in the process.

Process Overview — Ammonia



Comments

- Natural gas is used as both a fuel and feedstock in the ammonia production process.
- Natural gas requirement for ammonia production was set at 32.7 GJ/tonne of Ammonia[257].

E 1.3 Fertiliser manufacturing process

Electricity

Short term gas to power electricity potential was based on existing gas demand, switching potential, and planned gas to power stations. The following indicates the assumptions made to compute the gas requirement for each of the categories, where the efficiency and the plant load factor was considered.

[257] J. Ruddock, T.D. Short. Energy integration in ammonia production, 2003.

	As-Is				Conversion to				Comment/Assumption
	Type	Load Factor	Fuel	Efficiency	Type	Load Factor	Fuel	Efficiency	
Existing Potential	Peaking	10%	Gas (OCGT)	38%	Peaking	10%	Gas (OCGT)	38%	-
	Mid-merit	47%	Gas (CCGT)	60%	Mid-merit	47%	Gas (CCGT)	60%	-
Switching potential	Peaking	10%	Diesel/HFO /Kerosene	58%	Mid-merit	47%	Gas (CCGT)	60%	Capacity increase due to efficiency increase
	Mid-merit	47%	Diesel/HFO /Kerosene	58%	Mid-merit	47%	Gas (CCGT)	60%	Capacity increase due to efficiency increase
	Base	80%	Coal	38%	Mid-merit	47%	Gas (OCGT)	60%	Gas requirement computed based on the 'as-is' capacity. Coal conversion was only assumed in South Africa for decommissioned plants
Planned					Mid-merit	47%	Gas (CCGT)	60%	Planned plants were assumed to be midmerit CCGT, unless

E 1.4 Potential electricity demand

Computation

Capacity change for conversion of Diesel/HFO/Kerosene/Gas(OCGT):

$$\text{New Plant Capacity [MW]} = \frac{eff_{new}}{eff_{old}} * \text{Old PC[MW]}$$

Gas Requirement:

$$Gas\ requirement\ [MWh] = \frac{24 \times 365 \times \text{LF} \times \text{PC}}{\text{eff}_{\text{new}}}$$

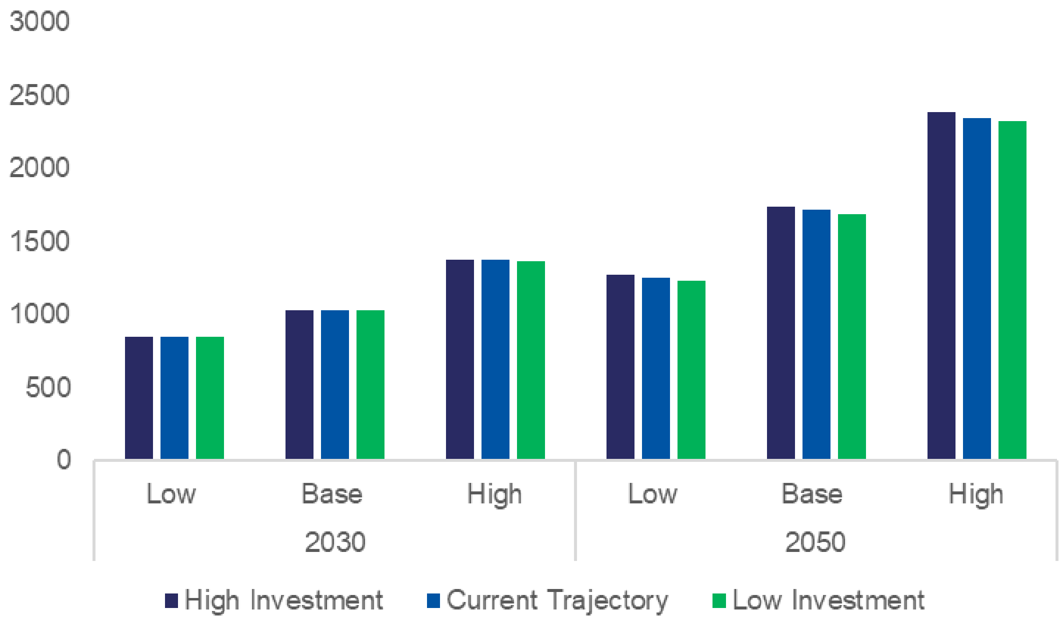
Where,
eff is plant efficiency, %
PC is installed plant capacity, MW
LF is load factor, %

E 1.5 Electricity gas demand computation

Appendix E.2: Demand Analysis

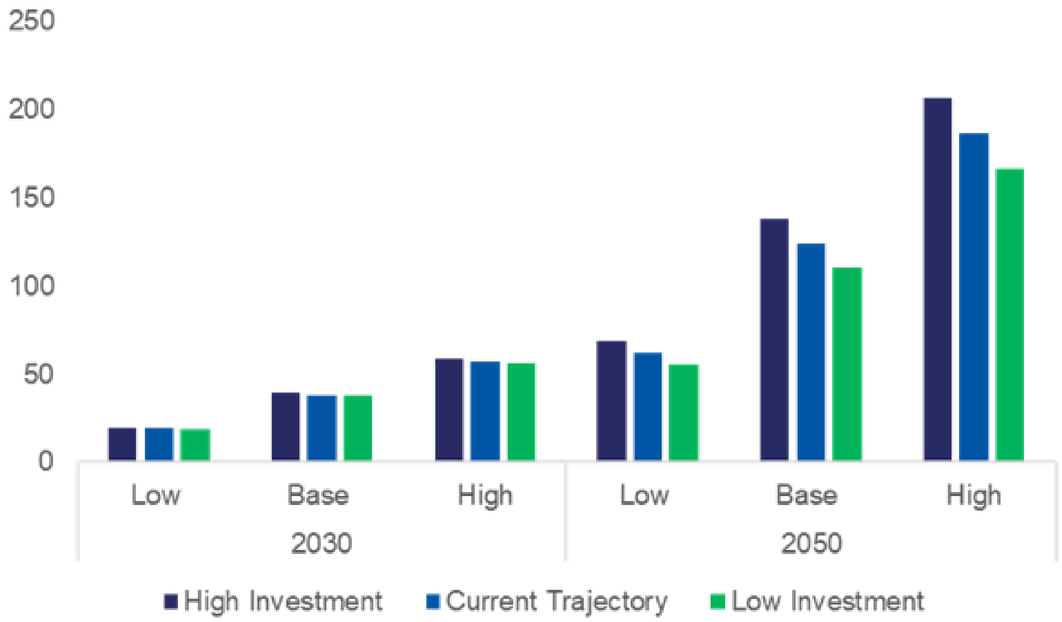
The impact of the GDP scenarios was significantly less than the trend scenarios for the demand of natural gas in the region, as illustrated in the graph below. This was predominantly due to the fact that the most impactful sectors, gas to power and petrochemicals, were based on planned builds and their demand was affected by sector trends. Thus, the overall change in demand was negligible for the short to medium-term, with 2030 changes for the high investment scenario ranging between 0.25% to 1.54% for the different trend scenarios, while the low investment scenario ranged from 0.14% to 0.20%.

The long-term GDP scenarios had a greater influence on regional demand; however, the impact was still minimal in comparison to the trend scenarios. The change in total demand for the region for the high investment scenarios were 24.1 PJ, 26.4PJ and 35.4PJ for the low, base, and high trend cases respectively, with a maximum of 1.54% change for the base case. The low investment scenario had a similar impact, with the reduction from the current trajectory demand being 44.0 PJ, 29.7 PJ and 29.2 PJ for the low, base, and high case trend scenarios. The low case reduction was the highest for the trend cases, reducing by 3.52% from the current trajectory.



E 2.1: Impact of GDP scenarios on regional demand [2030/2050] [PJ]

The economic growth and development of countries had a significant impact on the growth of the industrial heating and transport sectors; where growth was dependent on consumption. The gas to power and petrochemical sectors were more reliant on infrastructure requirements and investments and were thus less dependent on GDP growth factors. The residential and commercial sectors were analysed independently from the other sectors, due to the likelihood of LPG being used ahead of natural gas as the energy source for the sector.

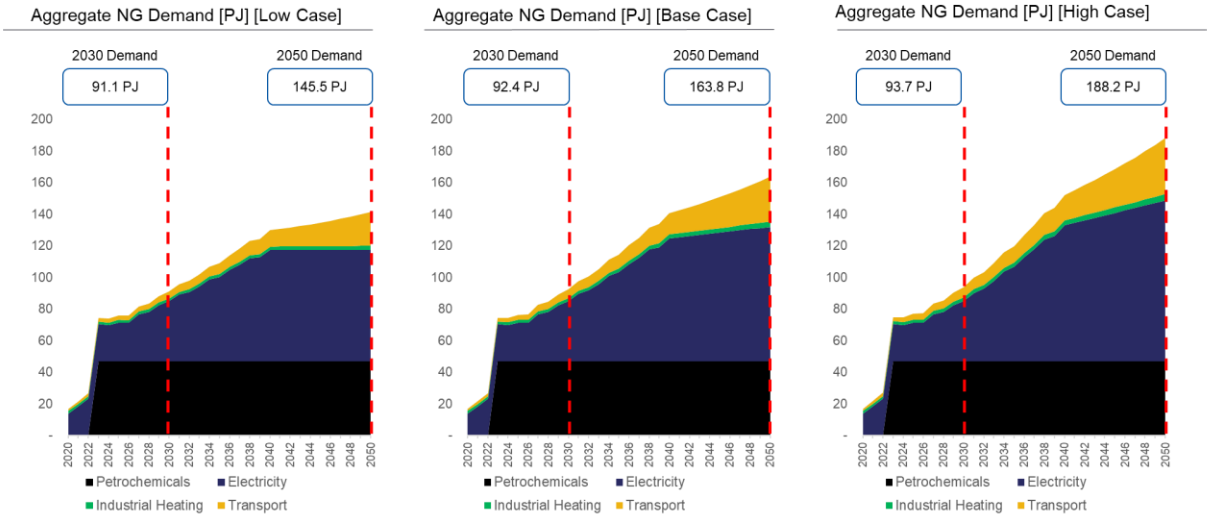


E 2.2: Impact of GDP scenarios on regional ResCom demand [2030/2050] [PJ]

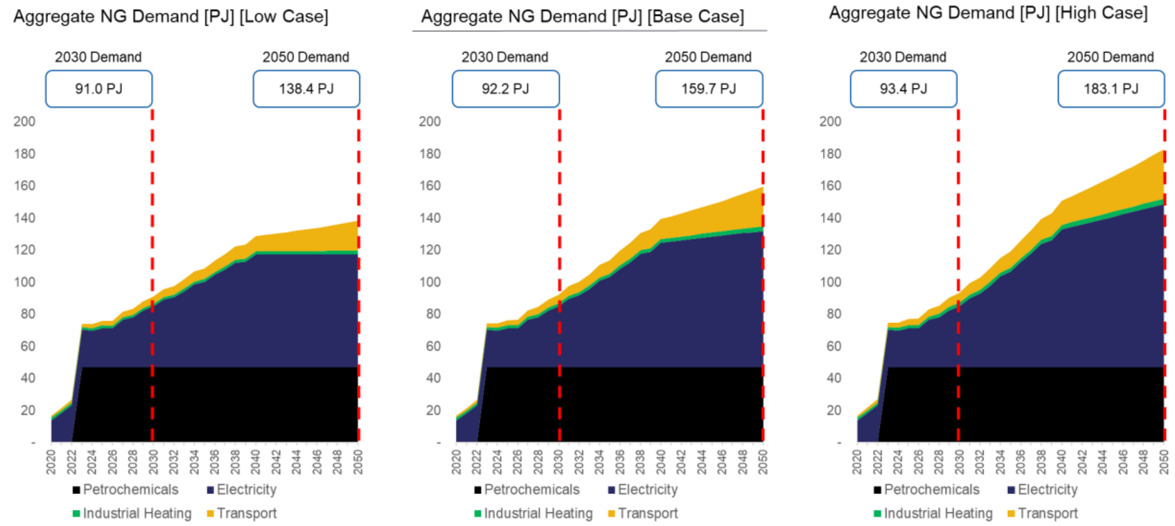
The residential and commercial demand is impacted considerably by economic factors in the long-term, while short to medium-term effects are less pronounced. The 2030 high and low investment differentials are below 2% for all the trend cases, while for 2050, the high and low investment differentials are between 6-7%, 13-14% and 20-21% for the low, base, and high cases, respectively.

Angola

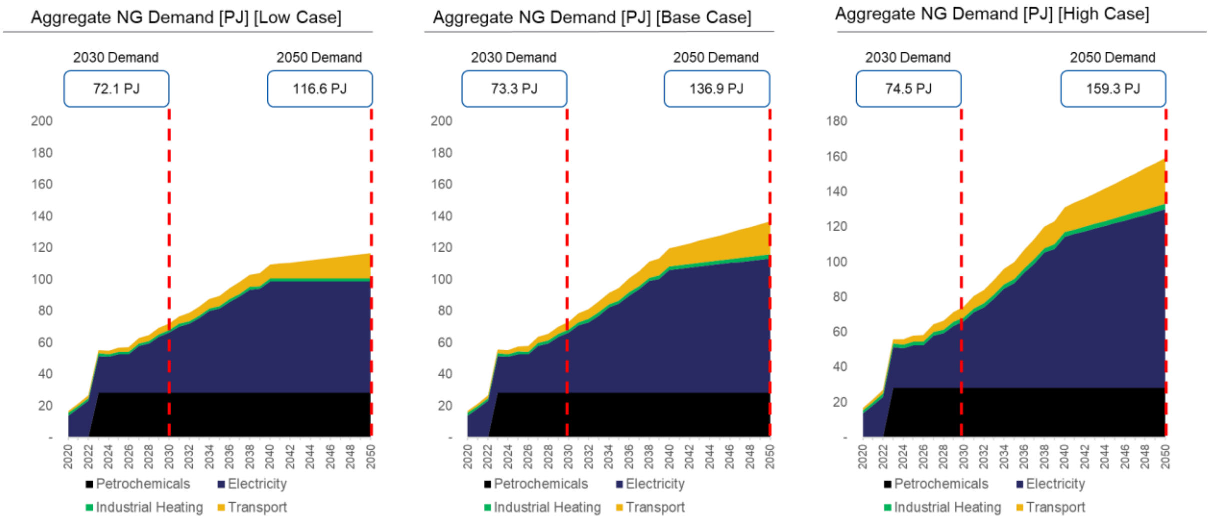
The economic development of Angola over the next 30 years has an impact on the expected demand for gas. A 3-6% differential from the current economic trajectory has been projected for the investment driven and low investment scenarios. The relatively large transport sector growth in comparison to other countries accounted for the economic growth scenario dependency.



E 2.3 Angola Investment driven Scenario

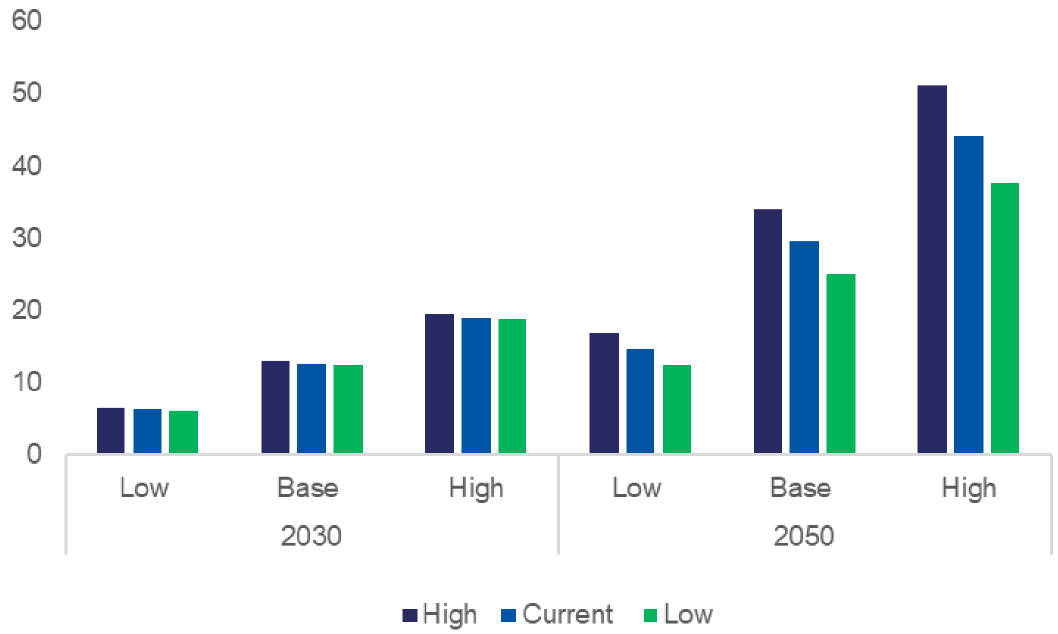


E 2.4: Angola Current Trajectory



E 2.5: Angola Low Investment Scenario

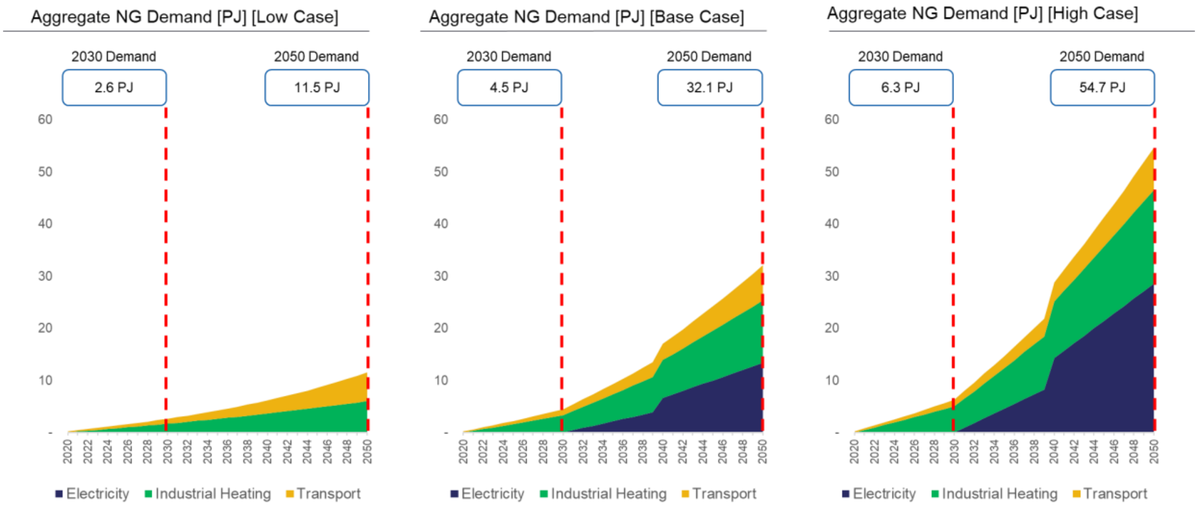
Angola's residential and commercial sector demand is expected to have around 15% variance for the high and low investment scenarios compared to the current trajectory for 2050. The short to medium-term is less affected by the scenarios and has a 3% increase for the investment driven scenario and a 2% decrease for the low investment scenario.



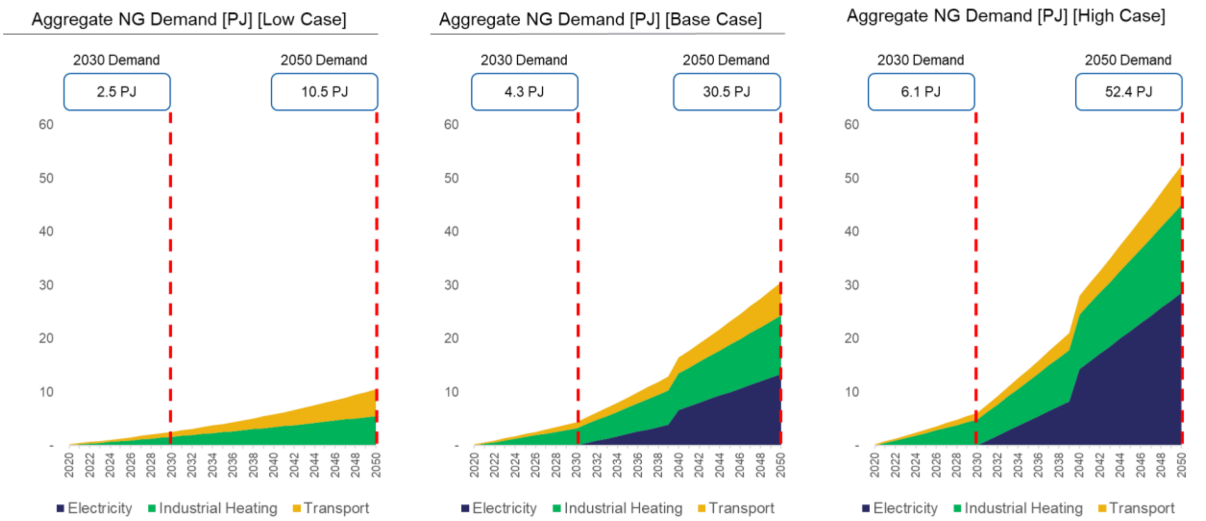
E 2.6: Impact of GDP Scenarios on Angola's Residential and Commercial demand [2030/2050] [PJ]

Democratic Republic of Congo

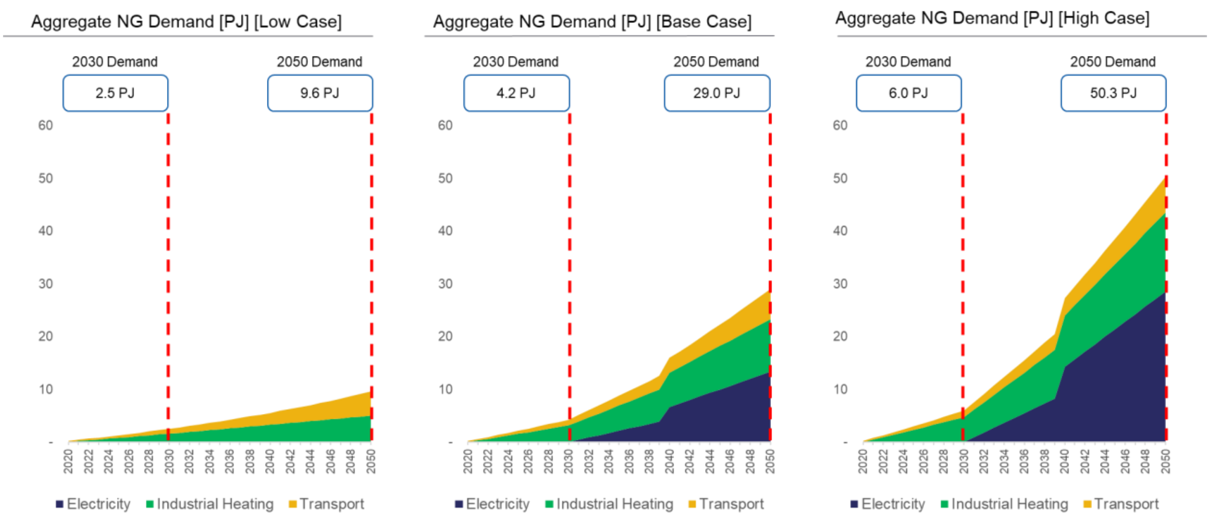
The Democratic Republic of Congo is most significantly influenced by economic development factors, due to the industrial heating and transport sectors accounting for significant shares of the gas demand. For the low trend case, where gas to power has no demand share, the gas demand increases by 9.5% for the high investment scenario and decreases by 8.6% for the low investment scenario. For the base and high trend cases, between 4% and 5% differentials from the current trajectory is projected.



E 2.7: Democratic Republic of Congo Investment Driven Scenario

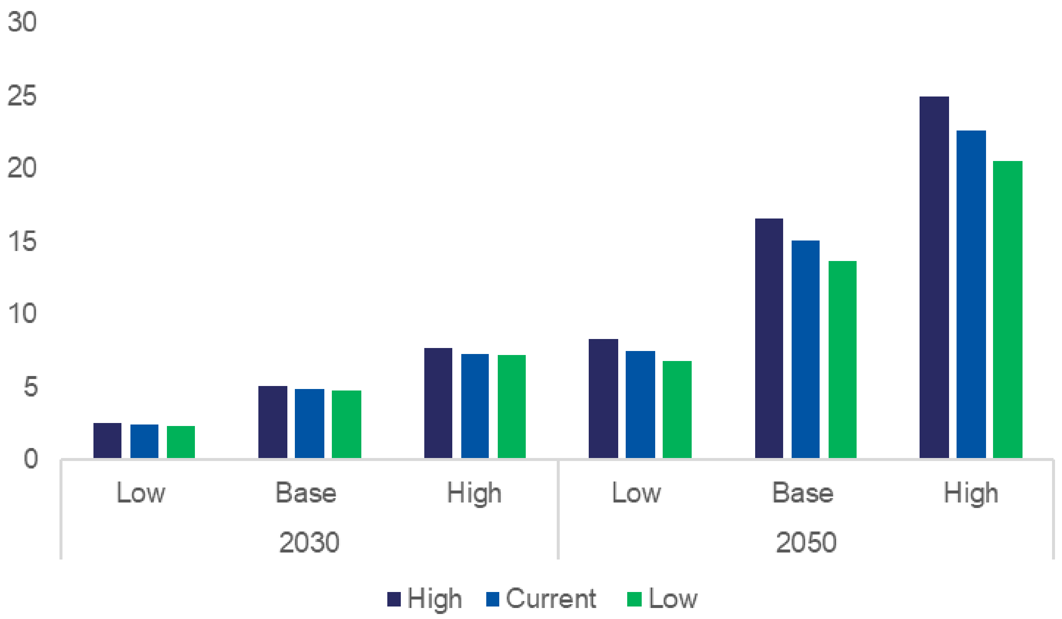


E 2.8: Democratic Republic of Congo Current Trajectory



E 2.9: Democratic Republic of Congo Low Investment Scenario

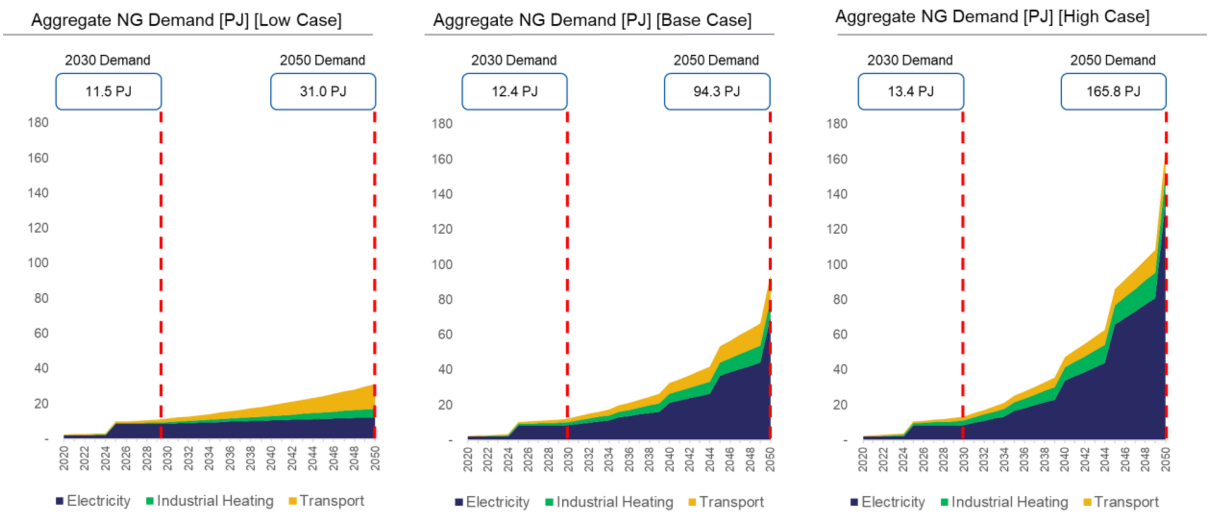
The long-term economic growth and development of the Democratic Republic of Congo impacts the consumption of energy of the residential and commercial sectors. Under the high investment scenario, the demand for gas has a 10% differential for the high and low investment scenarios in comparison to the current trajectory scenario.



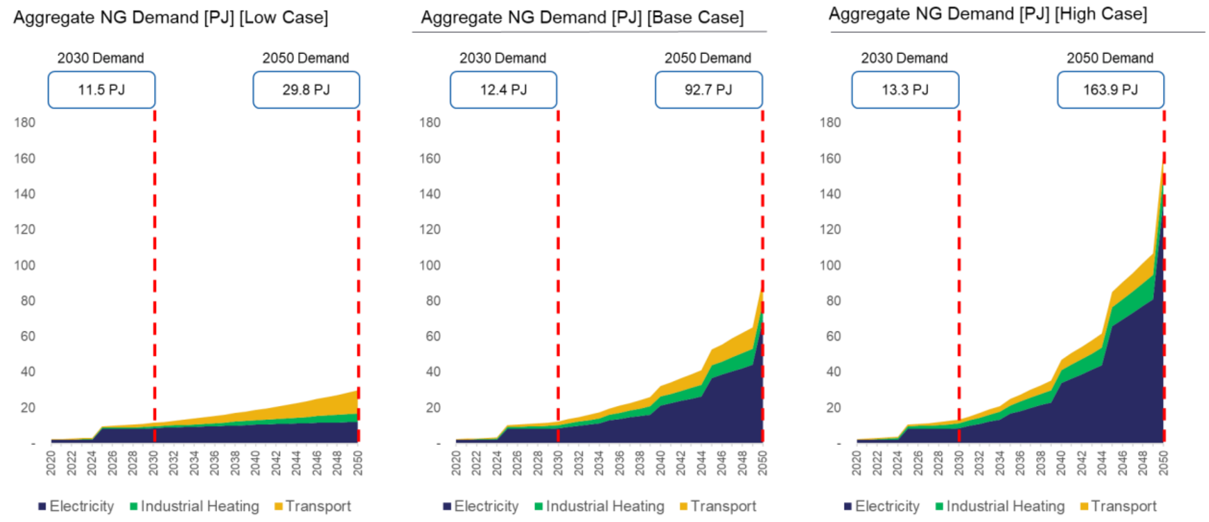
E 2.10: Impact of GDP Scenarios on the DRCs Residential and Commercial demand [2030/2050] [PJ]

Ethiopia

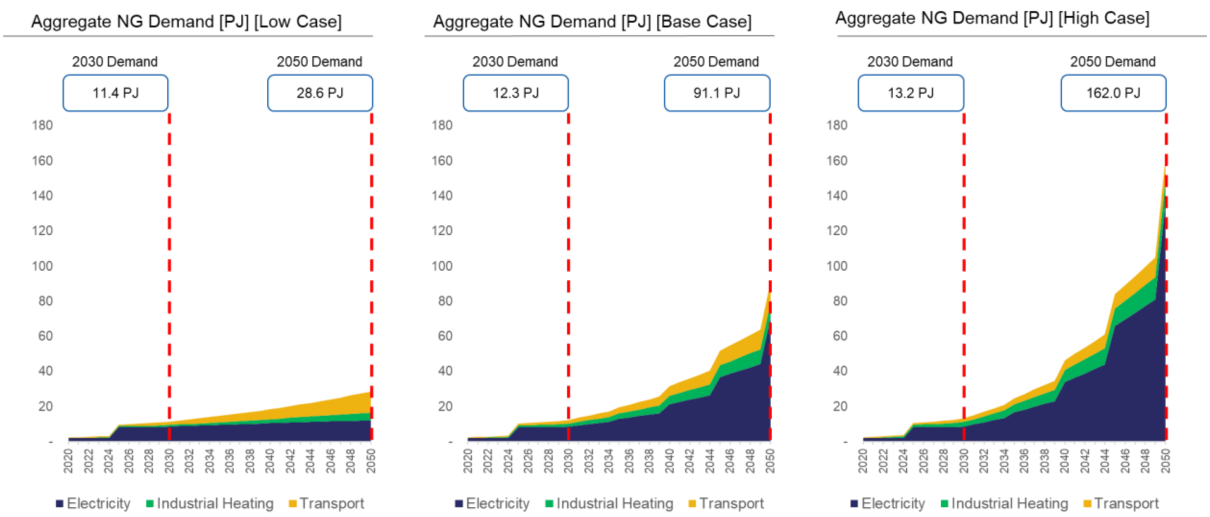
The 2030 economic differential for Ethiopia is below 1% for the GDP scenarios, whereas the 2050 adjustment is more substantial. For the low case, where gas to power accounts for a lower share of the gas demand, the increase and decrease from the current trajectory is 4%. While, for the base and high cases, electricity demand accounts for a larger share of the gas demand and the change due to economic factors is thus reduced to between 1% and 2% for the different cases.



E 2.11: Ethiopia Investment Driven Scenario

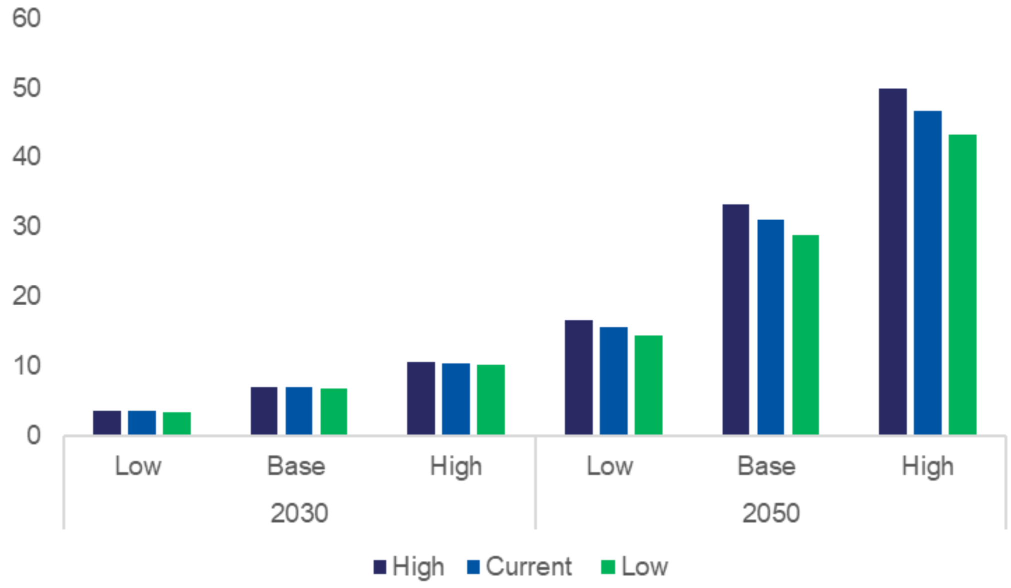


E 2.12: Ethiopia Current Trajectory



E 2.13: Ethiopia Low Investment Scenario

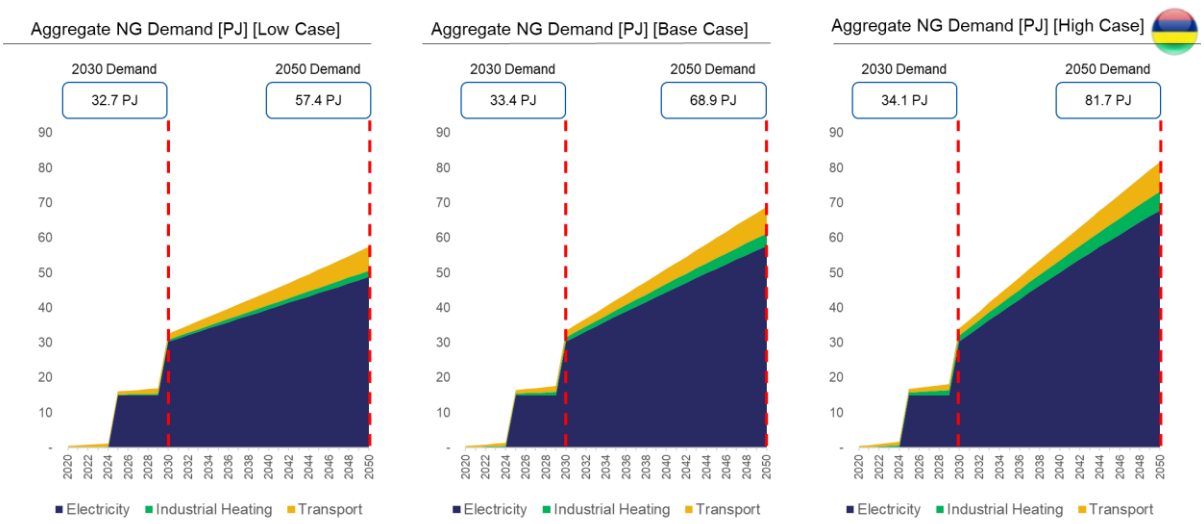
The 2030 residential and commercial demand variance is about 2% and the 2050 demand variance is around 7% for both the investment driven and low investment GDP scenarios. This equates to a 4.4 PJ difference between the investment driven and low investment scenarios for the trend base case in 2050 for Ethiopia.



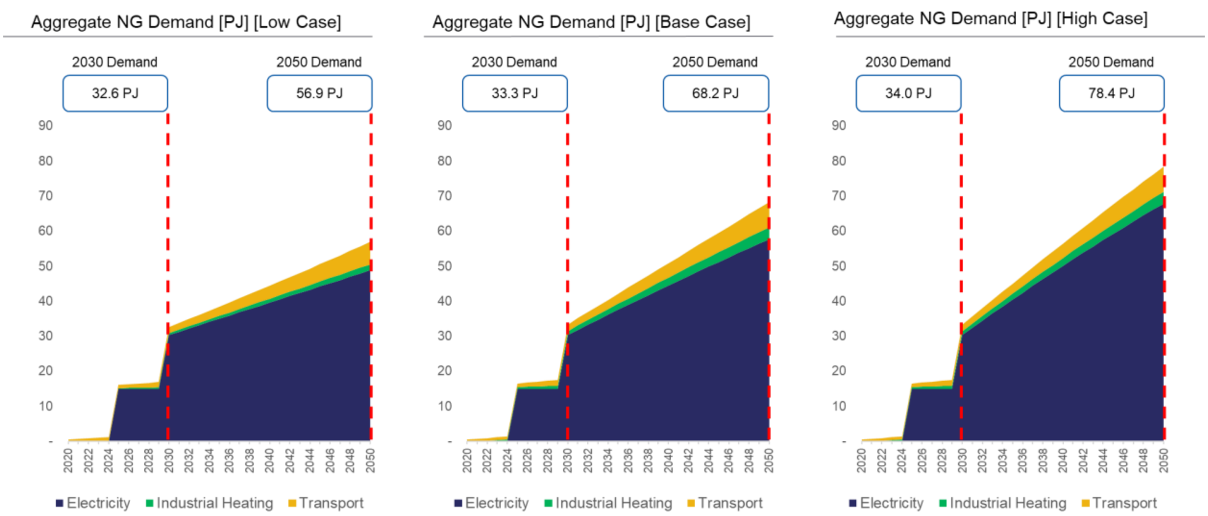
E 2.14: Impact of GDP Scenarios on Ethiopia's Residential and Commercial demand [2030/2050] [PJ]

Kenya

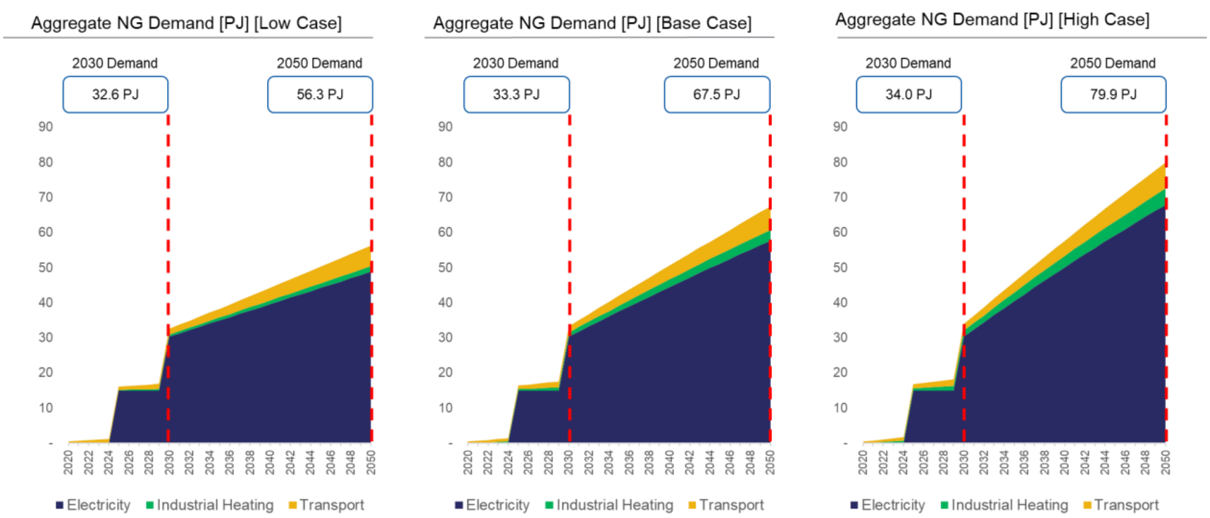
The demand for gas in Kenya is less dependent on the economic outlook of the country in the short to medium-term, with a deviation of between 0-0.3% for the low and high investment scenarios respectively in 2030. However, in 2050, the differential increases to between 1-4% for the high investment scenario and between 1- 2% for the low investment scenario. This is due to the long-term growth expected in the transport and industrial heating sectors.



E 2.15: Kenya Investment Driven Scenario

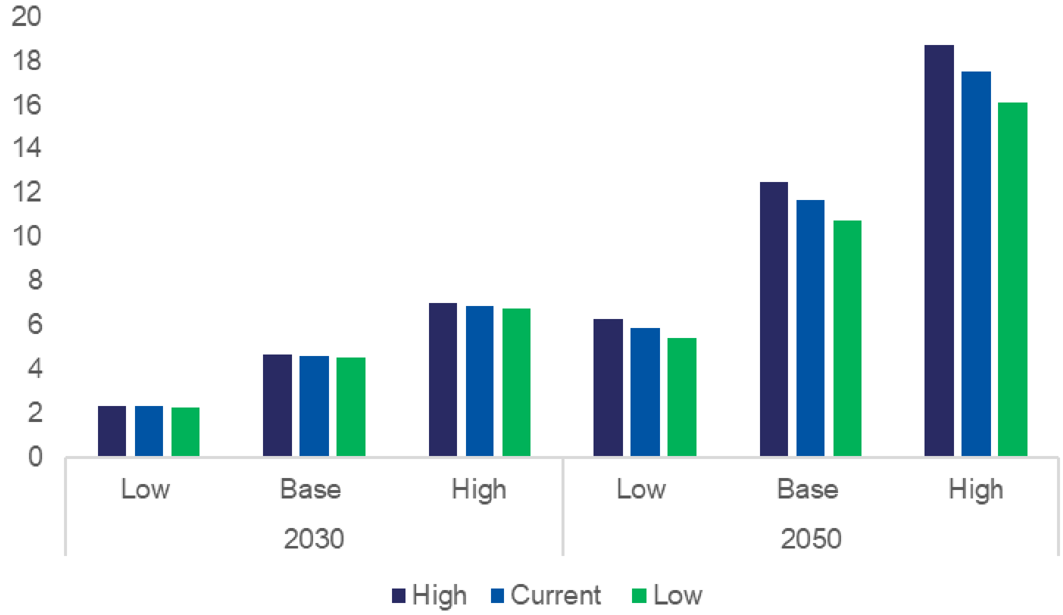


E 2.16: Kenya Current Trajectory



E 2.17: Kenya Low Investment Scenario

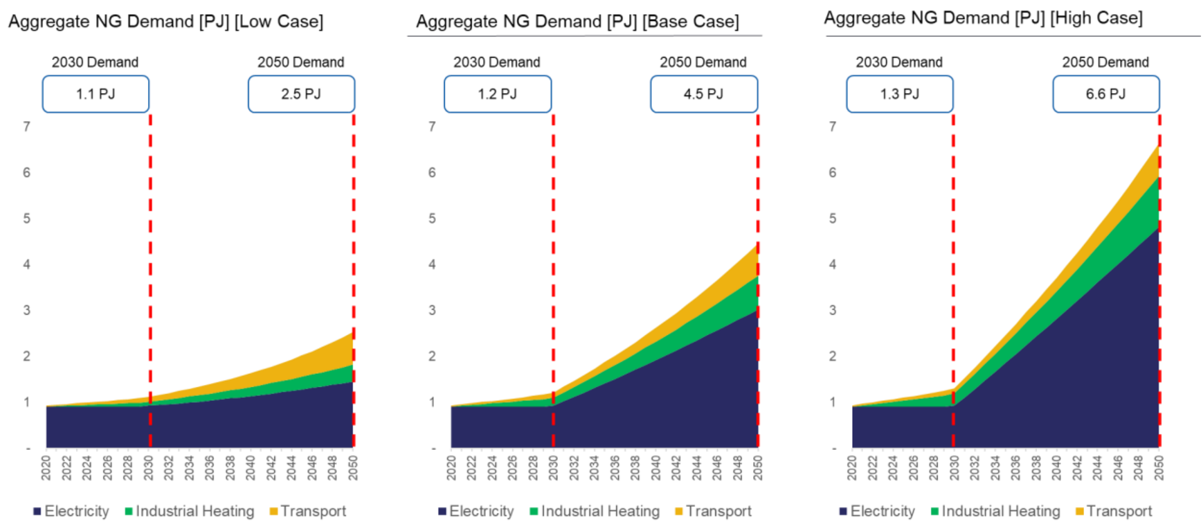
The 2030 demand variance for the residential and commercial sectors is about 2% and the 2050 demand variance is around 7% for both the high and low GDP scenarios for Kenya. This equates to a 1.8 PJ range between the investment driven and low investment scenarios for the trend base case in 2050.



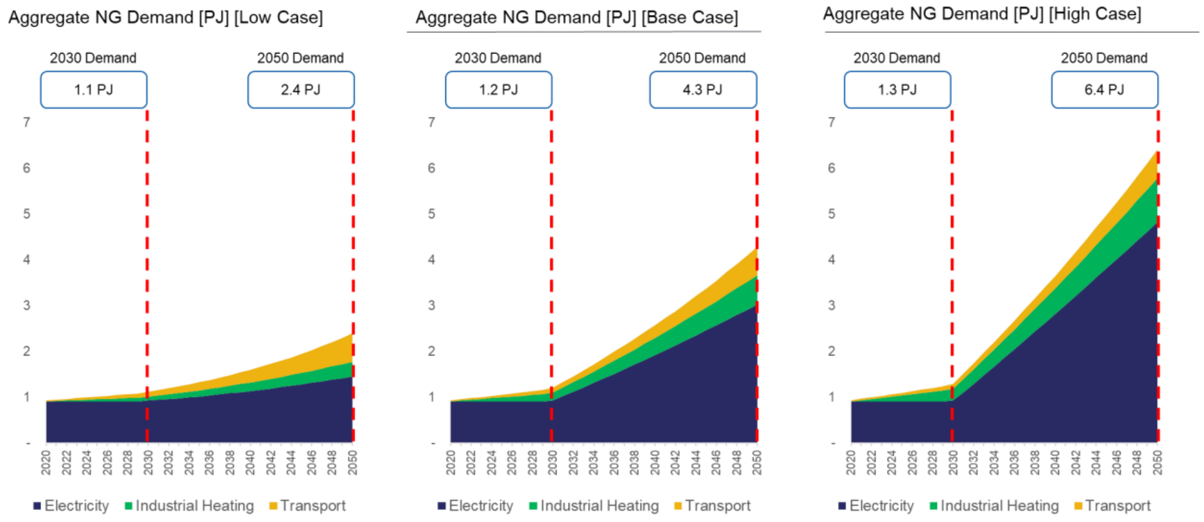
E 2.18: Impact of GDP Scenarios on Kenya's Residential and Commercial demand [2030/2050] [PJ]

Malawi

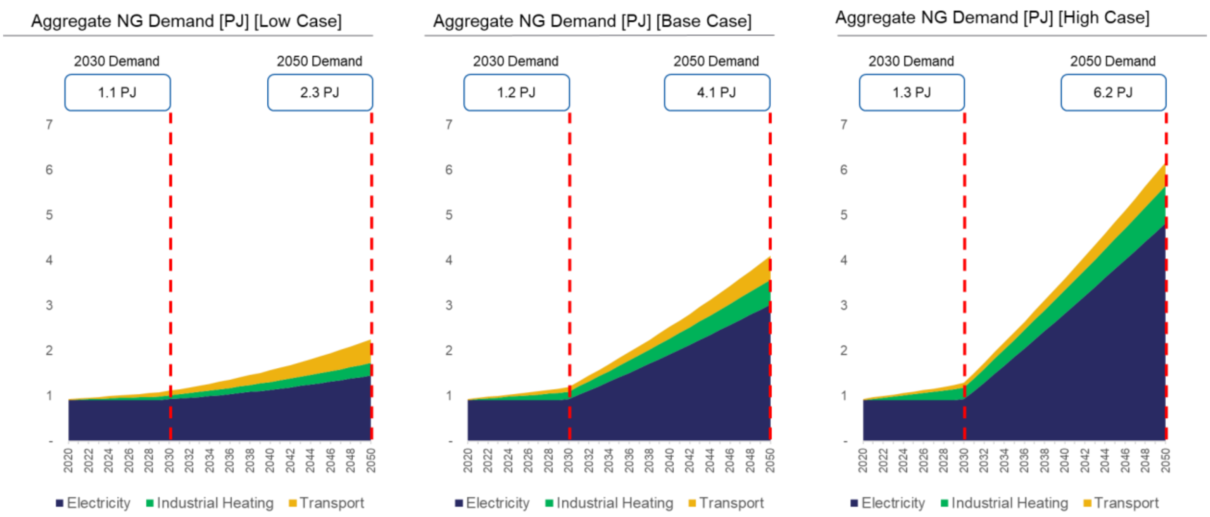
Malawi's gas demand is not affected by economic growth scenarios in the short term, as gas to power dominates the gas demand requirements up to 2030. However, in the long-term, industrial heating and transport gas demand growth accounts for a larger proportion of the demand mix, thus increasing the impact of GDP growth on the aggregated gas demand. The increase and decrease based on low and high investment conditions are between 3% and 5% for Malawi by 2050.



E 2.19: Malawi Investment Driven Scenario

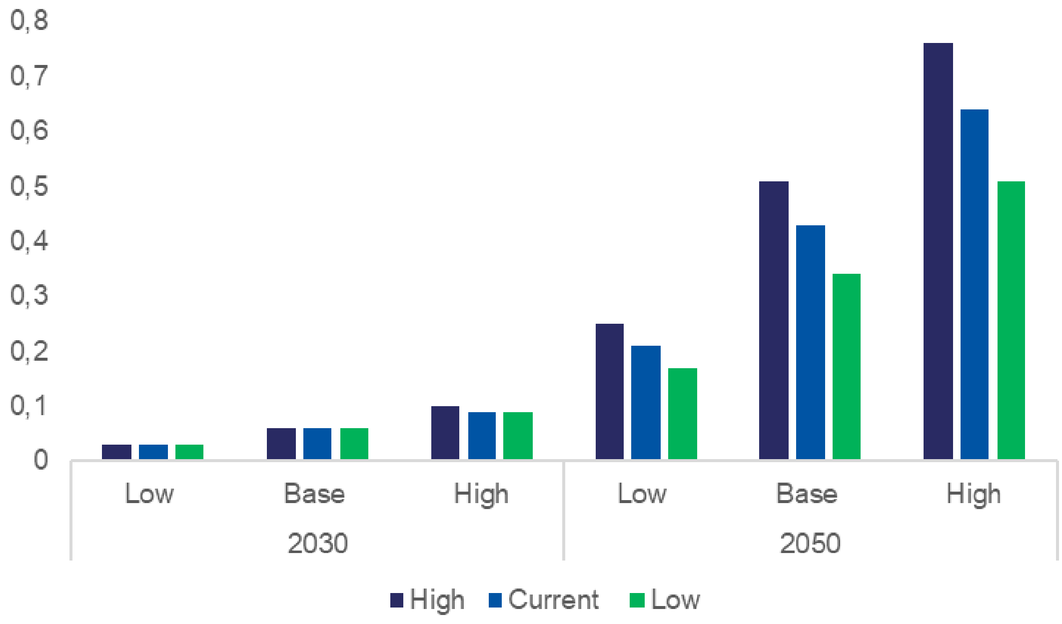


E 2.20: Malawi Current Trajectory



E 2.21: Malawi Low Investment Scenario

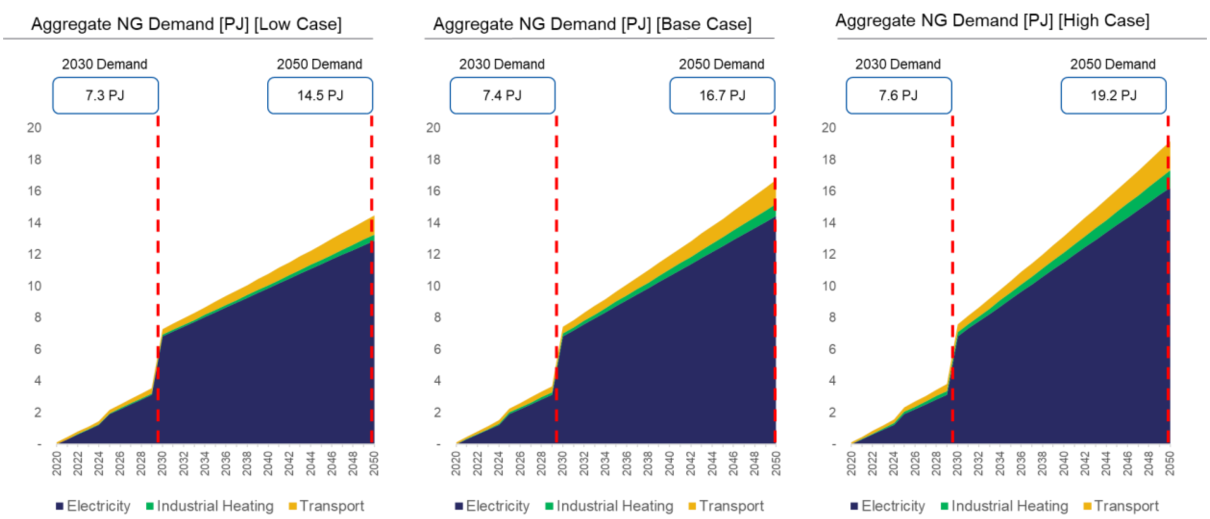
The 2030 demand has minimal dependence on economic conditions in Malawi for residential and commercial demand. However, the long-term demand has an 18% to 20% variance from the current trajectory scenario for the investment driven and low investment scenarios. The difference between the low investment and investment driven scenarios are 0.1 PJ, 0.2 PJ and 0.3 PJ for the low, base, and high case trend scenarios, respectively.



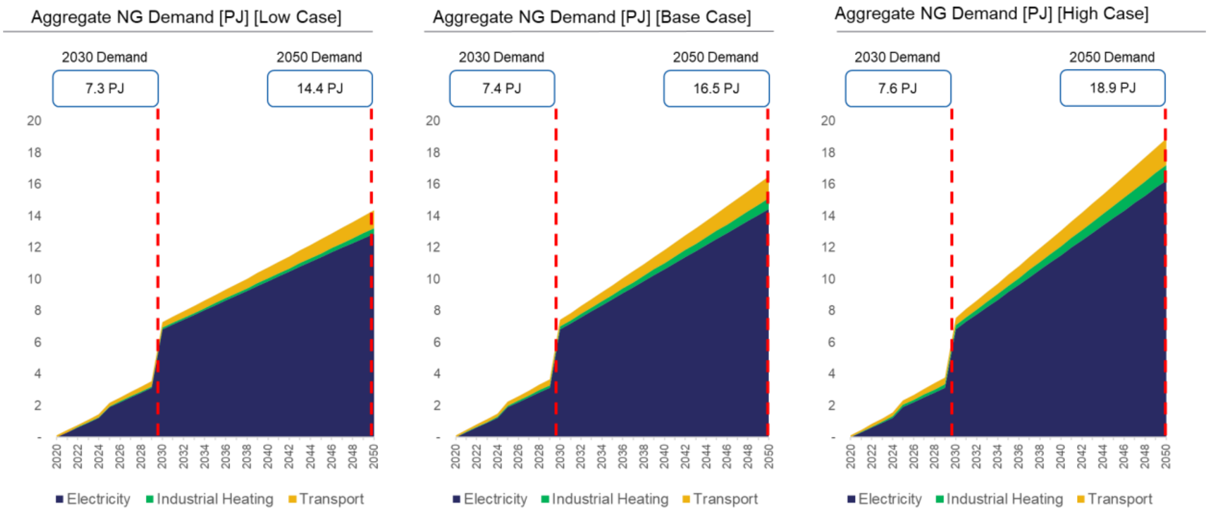
E 2. 22: Impact of GDP Scenarios on Malawi's Residential and Commercial demand [2030/2050] [PJ]

Mauritius

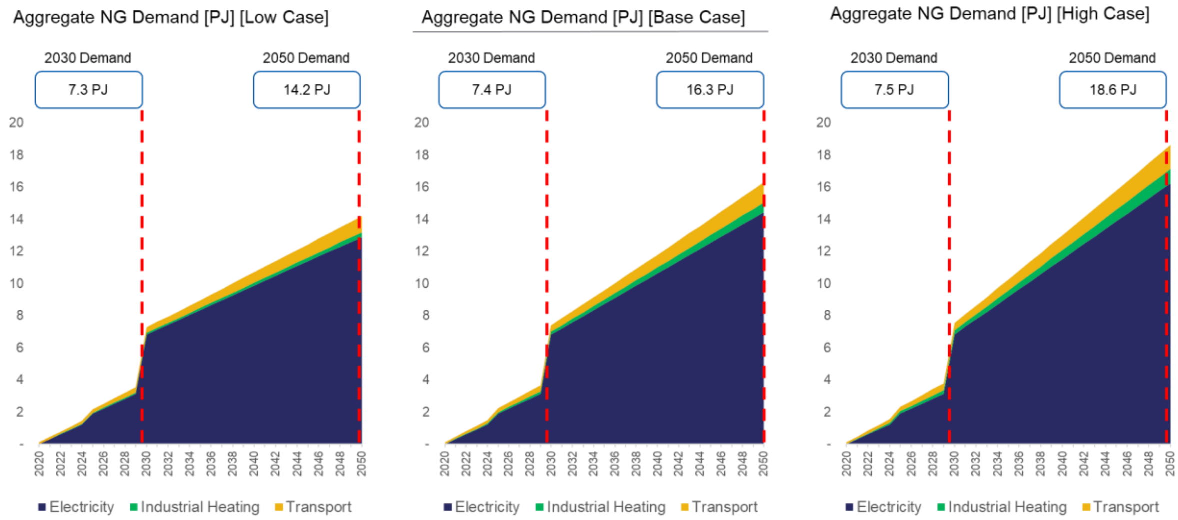
The gas demand in Mauritius is relatively constant regardless of economic conditions up to 2030; however, the growth of industrial heating and transport in the long term, results in more variable effects due to GDP growth by 2050. For the high investment scenario, the aggregated demand increases for the low case by 0,7%, 1,2% for the base case and 1.6% for the high case, whereas the base trend case is unaffected. The low investment scenario reduces the aggregated demand by 1.4%, 1,2% and 1,6% for the low, base, and high trend cases, respectively.



E 2.23: Mauritius Investment Driven Scenario

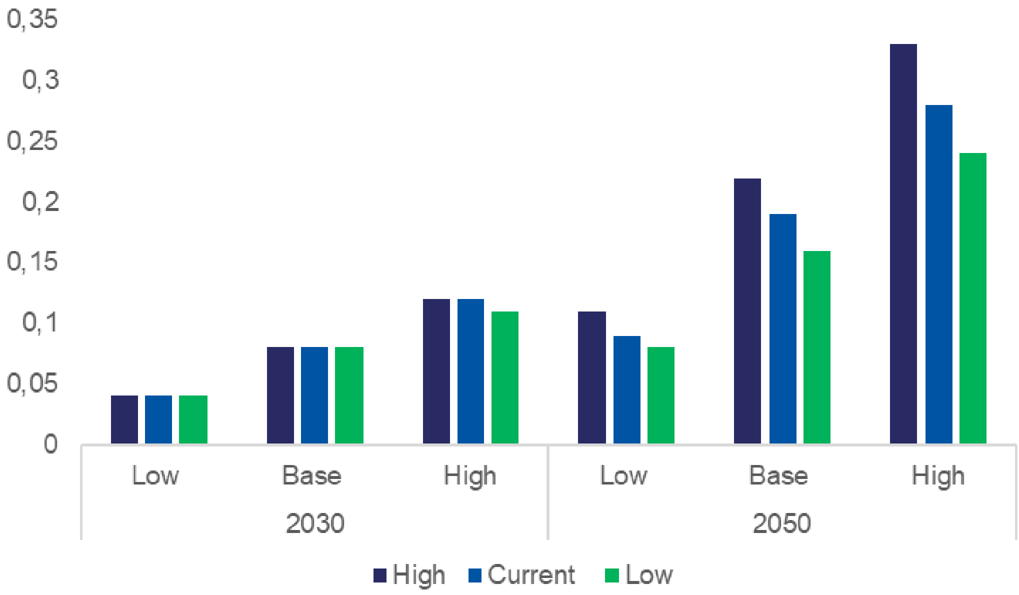


E 2.24: Mauritius Current Trajectory



E 2.25: Mauritius Low Investment Scenario

The impact of the GDP scenarios on the residential and commercial demand for Mauritius is significant, however, the total demand for the sector is limited. The investment driven scenario has a demand of 0.22 PJ, while 0.16 PJ is projected for the low investment scenario for the base case. The investment driven and low investment cases range between 11% and 22% from the current trajectory.

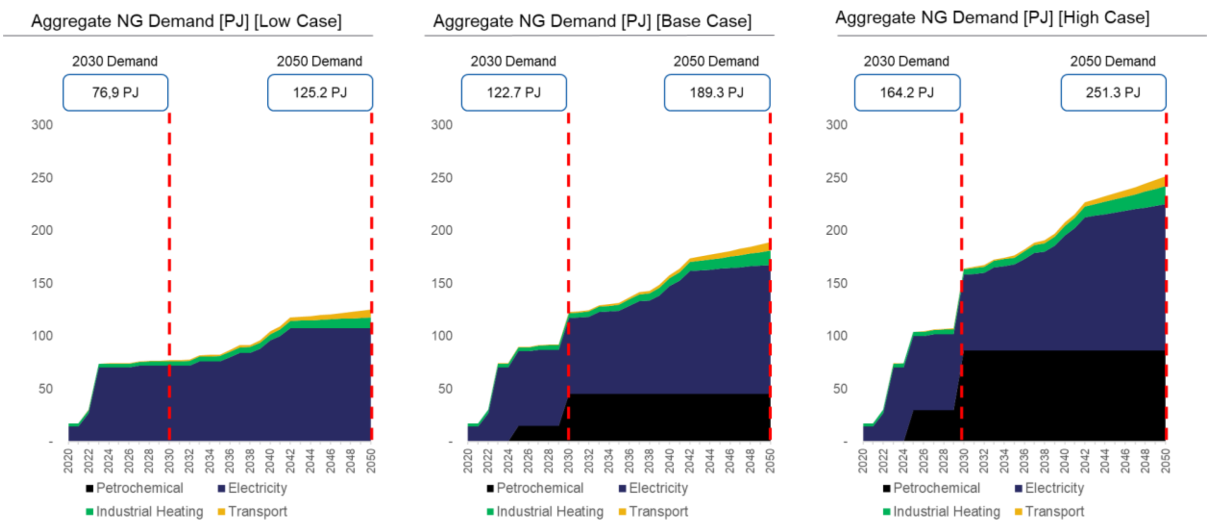


E 2.26: Impact of GDP Scenarios on Mauritius' Residential and Commercial demand [2030/2050] [PJ]

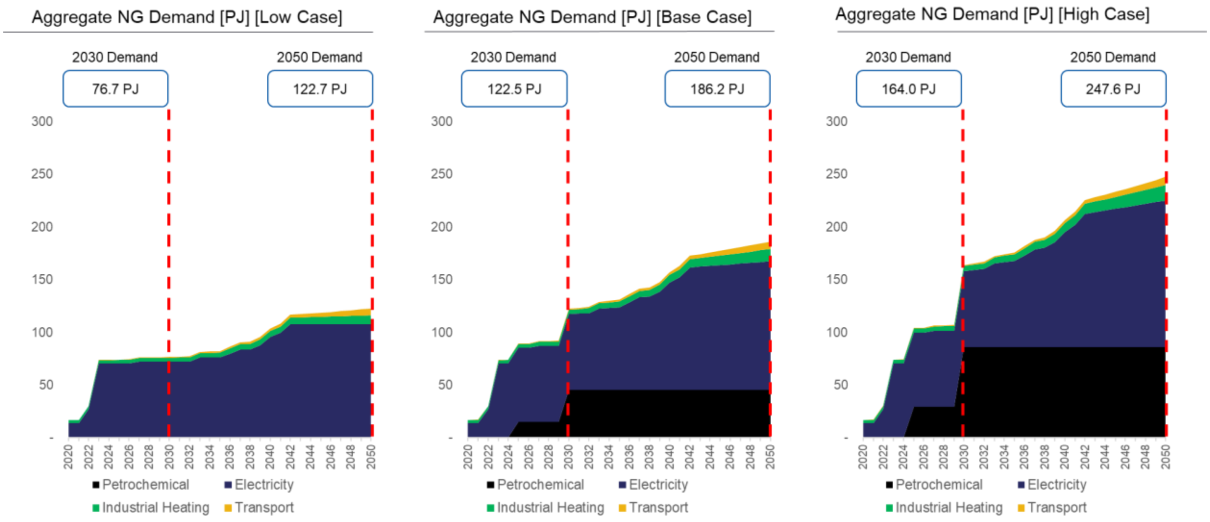
The gas demand in Mauritius is relatively constant regardless of economic conditions, with less than 2% average change from the base case for both the lower and upper case scenarios, however, the sector based scenarios have a fluctuation of around 12-14%, due to the country's long term growth in gas to power, industrial and transport gas demand.

Mozambique

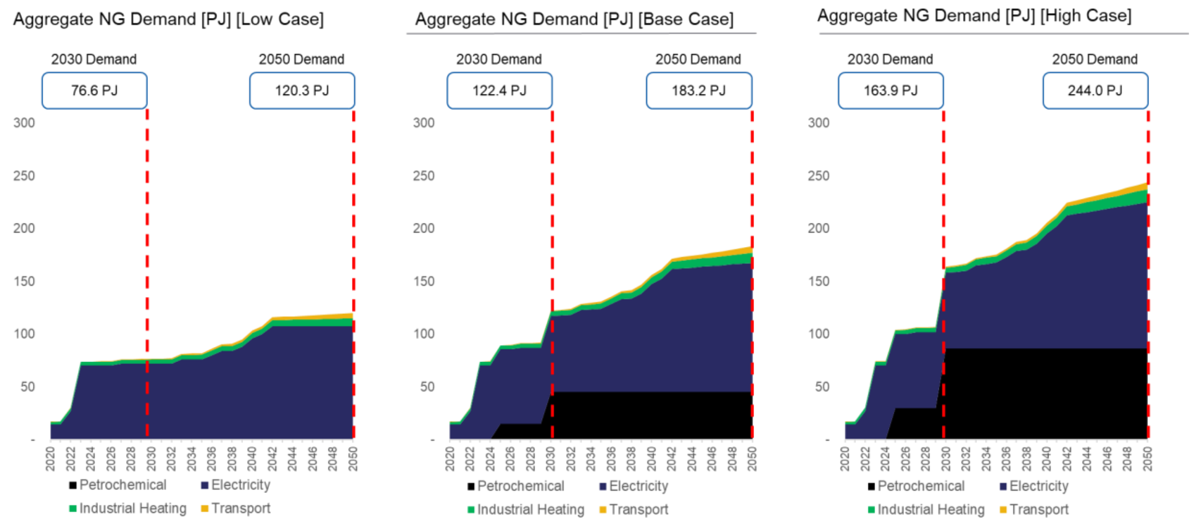
Demand for gas is not significantly affected by the economic conditions. A maximum of 2.0% change from the current trajectory demand is expected by 2050, with 2030 demand remaining almost constant; this is due to the strong anchor demand base in petrochemicals and gas to power.



E 2.27: Mozambique Investment Driven Scenario

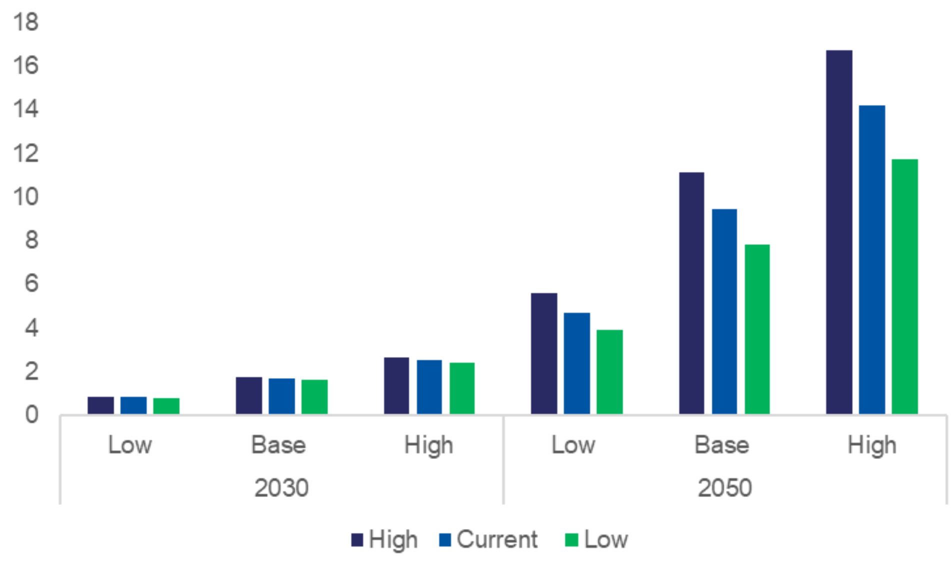


E 2.28: Mozambique Current Trajectory Scenario



E 2.29: Mozambique Low Investment Scenario

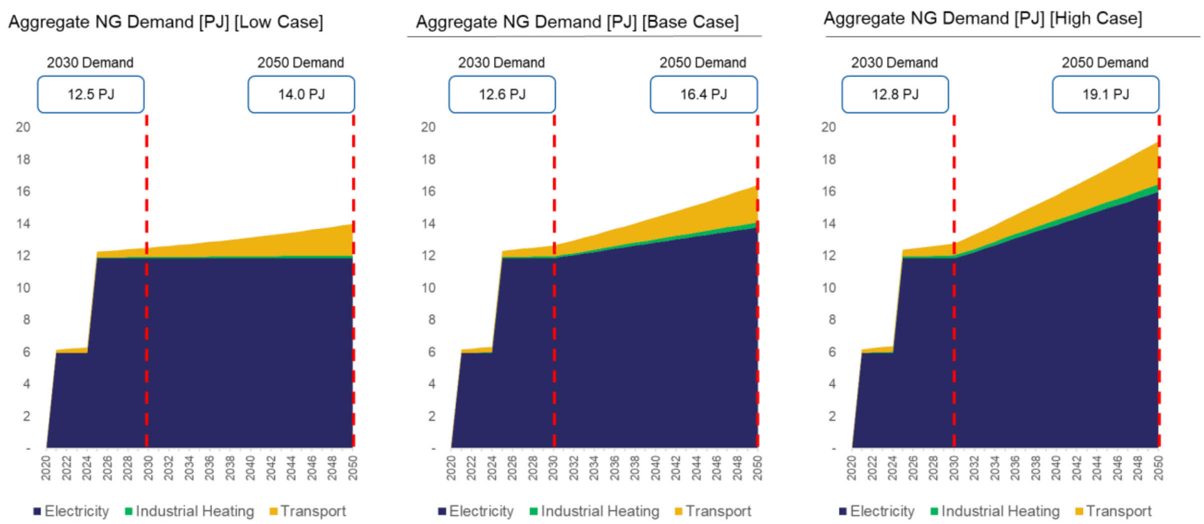
The Mozambique residential and commercial energy demand are dependent on economic conditions to a large degree. The investment driven and low investment scenarios increase and decrease by between 17% to 18% respectively in 2050. The base case results in a 3.3 PJ differential between the low and high investment cases.



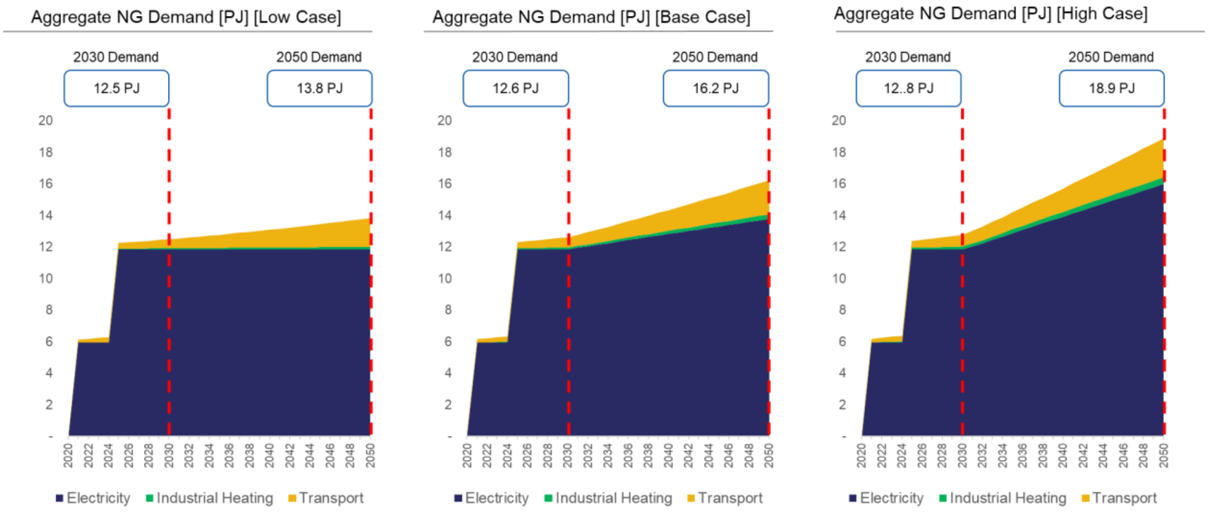
E 2.30: Impact of GDP Scenarios on Angola's Residential and Commercial demand [2030/2050] [PJ]

Namibia

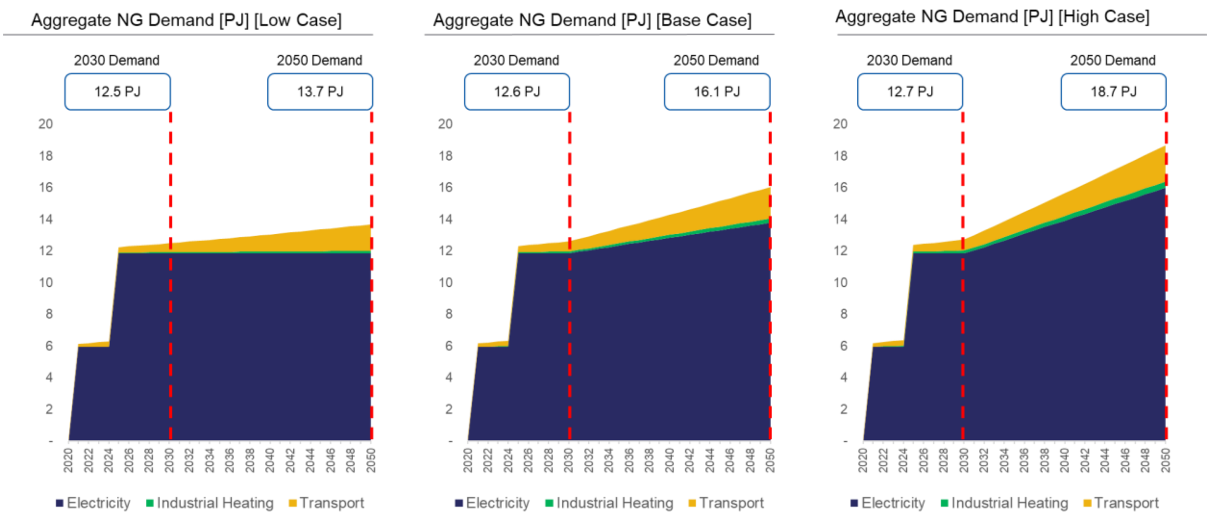
Namibia's gas demand is minimally dependant on the economic scenarios, having an average of around 1% deviation from the current trajectory forecast for GDP forecasts. For the base case, the total aggregated gas demand ranges between 16.1 PJ and 16.4 PJ for the different investment scenarios.



E 2.31: Namibia Investment Driven Scenario

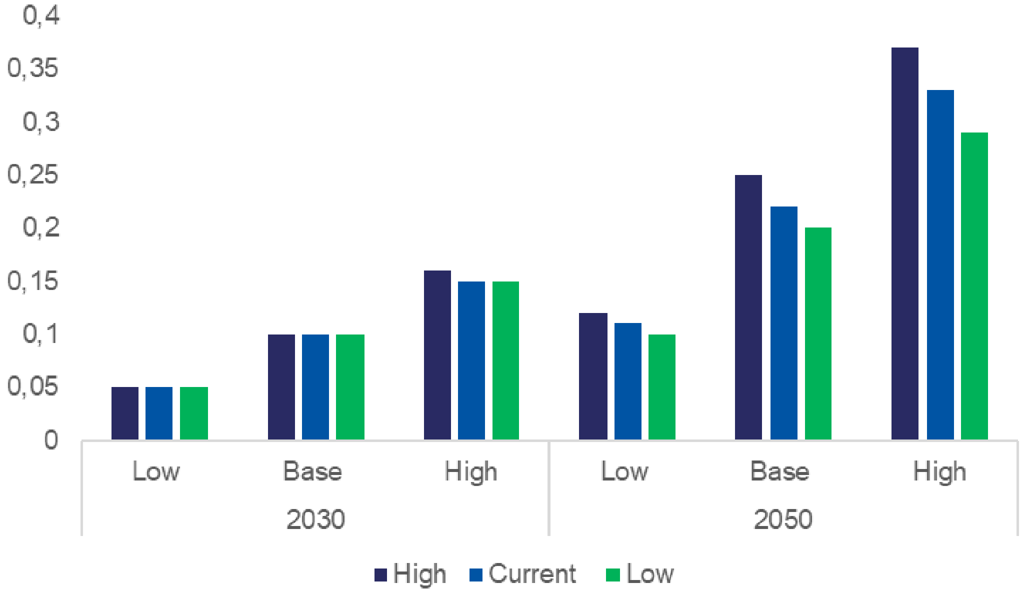


E 2.32: Namibia Current Trajectory



E 2.33: Namibia Low Investment Scenario

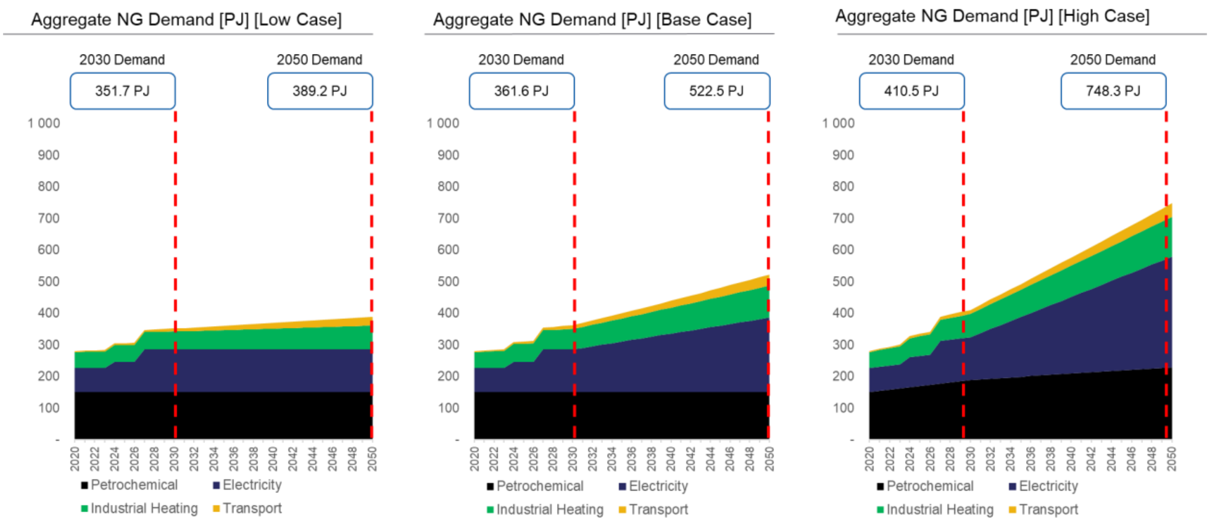
The variance in residential and commercial demand for Namibia for the base case is 0.05 PJ, which results from a 14% increase and a 9% decrease for the investment driven and low investment scenarios from the current trajectory. The variance ranges between and 9% and 12% for the low and high case scenarios.



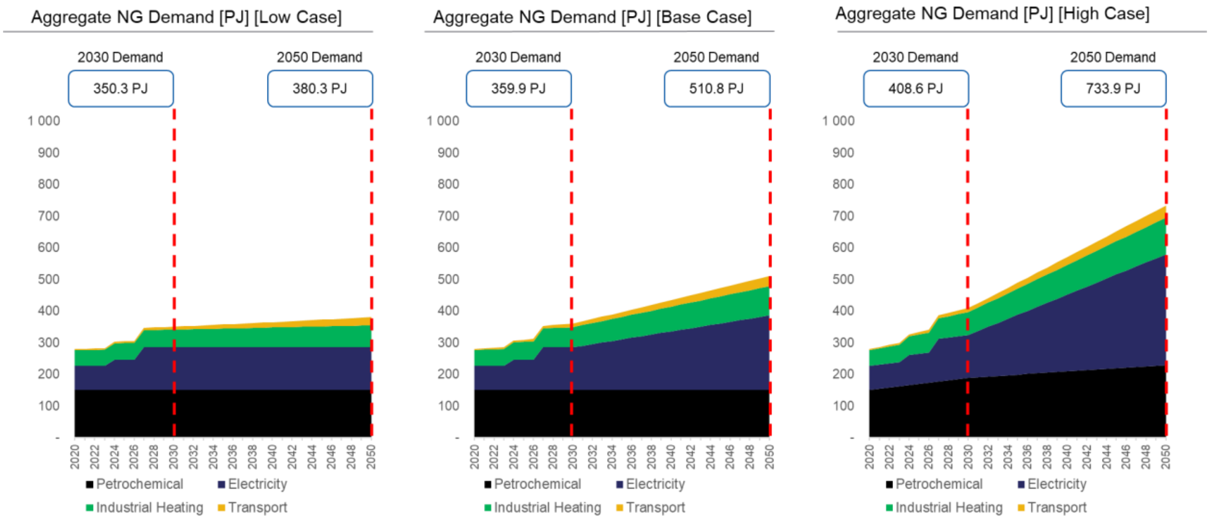
E 2. 34: Impact of GDP Scenarios on Namibia's Residential and Commercial demand [2030/2050] [PJ]

South Africa

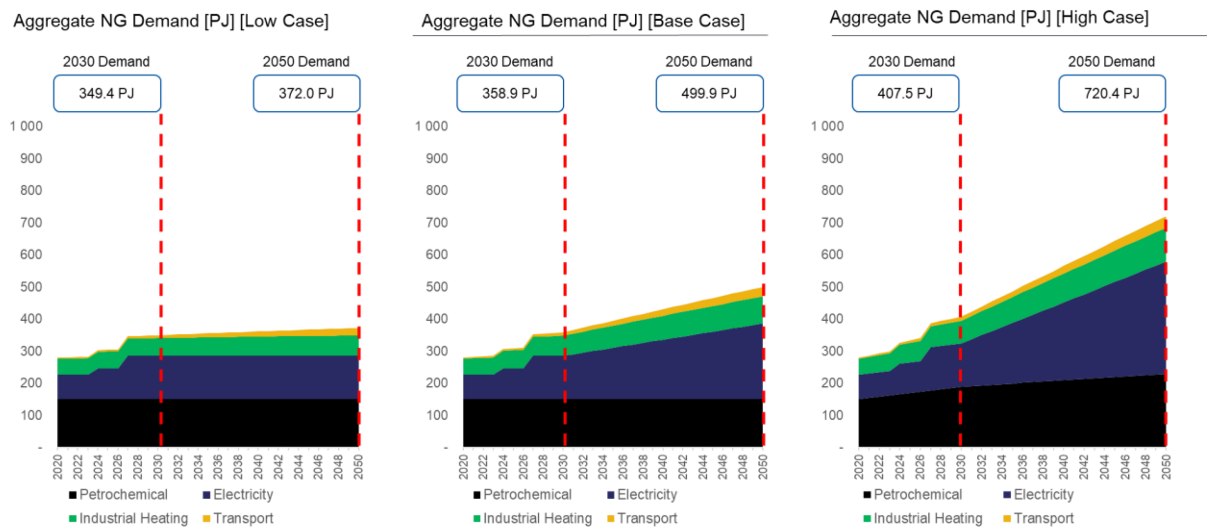
South Africa's aggregated natural gas demand is not significantly changed by the different GDP scenarios in the short to medium-term, with the high investment differential from the current trajectory being around 0.4% and a decrease of 0.3% for the low investment scenario by 2030. The 2050 impact of GDP is around 2% for both scenarios. The industrial heating demand growth from 2030 to 2050 is the main factor in this increase, with the strong gas to power and petrochemical demand providing an anchor base.



E 2.35: South Africa Investment Driven Scenario

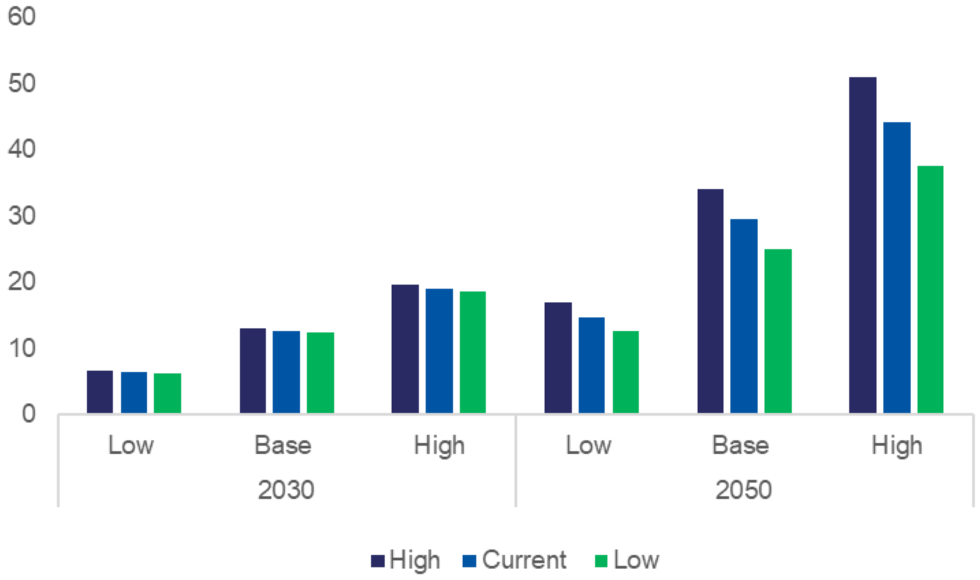


E 2.36: South Africa Current Trajectory Scenario



E 2.37: South Africa Low Investment Scenario

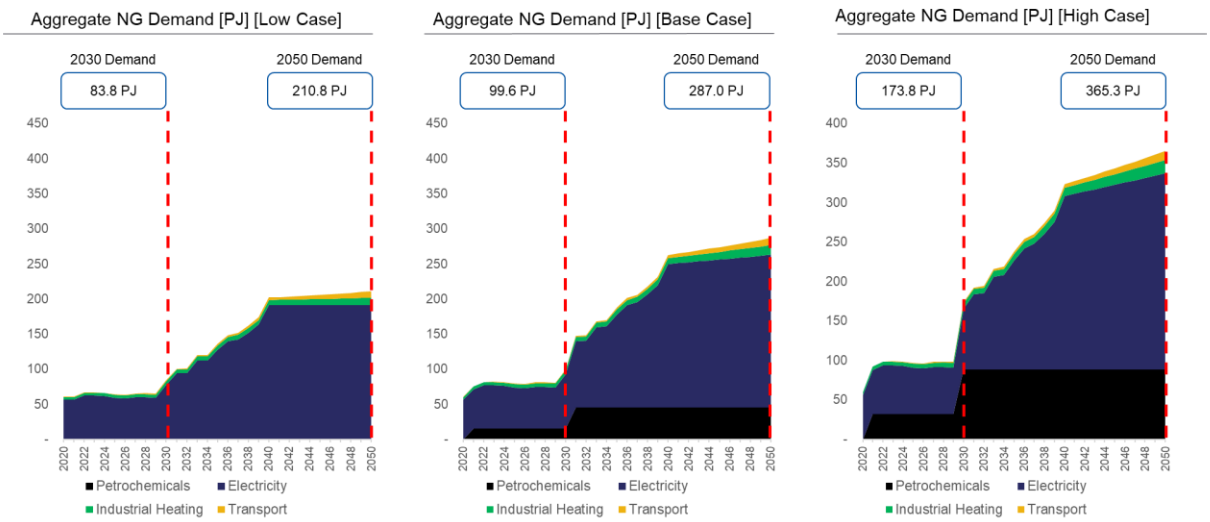
The 2030 residential and commercial demand variance due to the GDP scenarios compared to the current trajectory is between 0% and 4% in 2030. The variance range increases to between 8% and 11% for 2050; this results in a difference of 0.13 PJ for the low investment and investment driven scenarios.



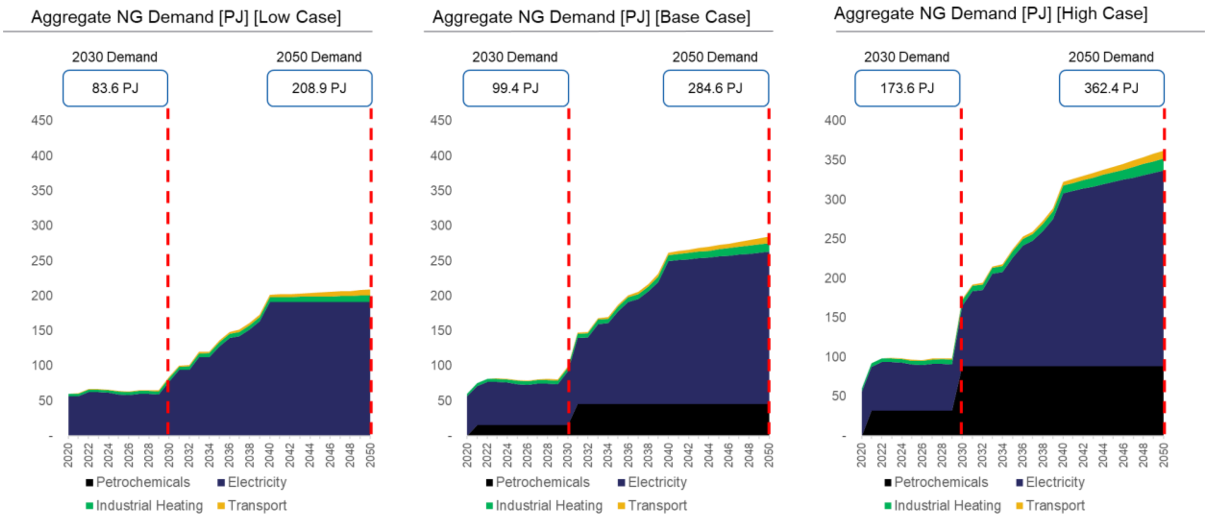
E 2.38: Impact of GDP Scenarios on South Africa's Residential and Commercial demand [2030/2050] [PJ]

Tanzania

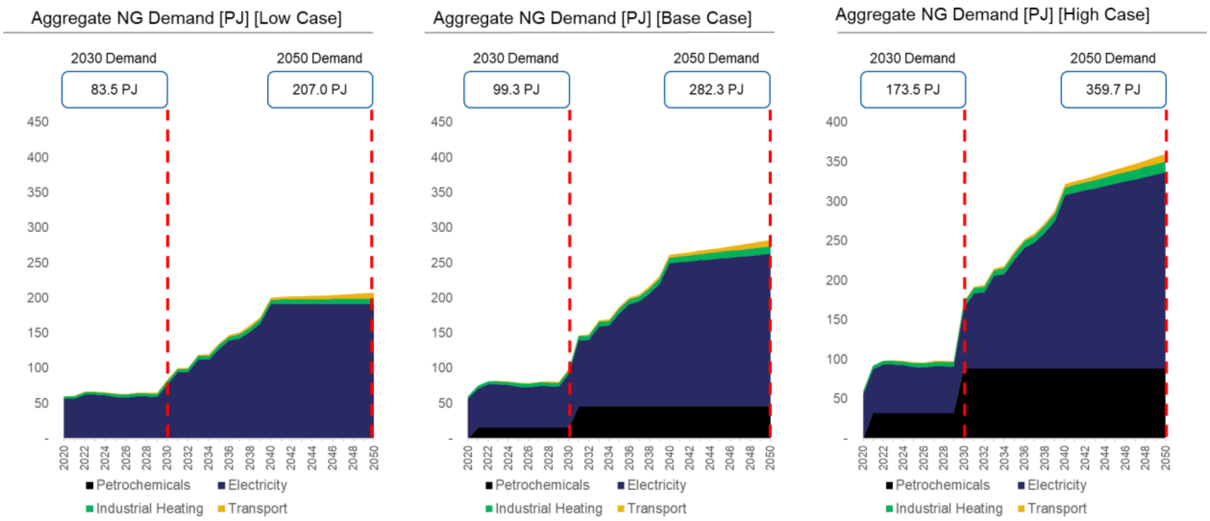
Tanzania's aggregated natural gas demand is not significantly impacted by the economic development scenarios, due to a strong gas to power and petrochemical demand providing an anchor base. The gas demand differential from the current trajectory is negligible, between 0.1% and 0.2% by 2030. The 2050 impact of GDP increases to between 1% and 2% for both scenarios.



E 2.39: Tanzania Investment Driven Scenario

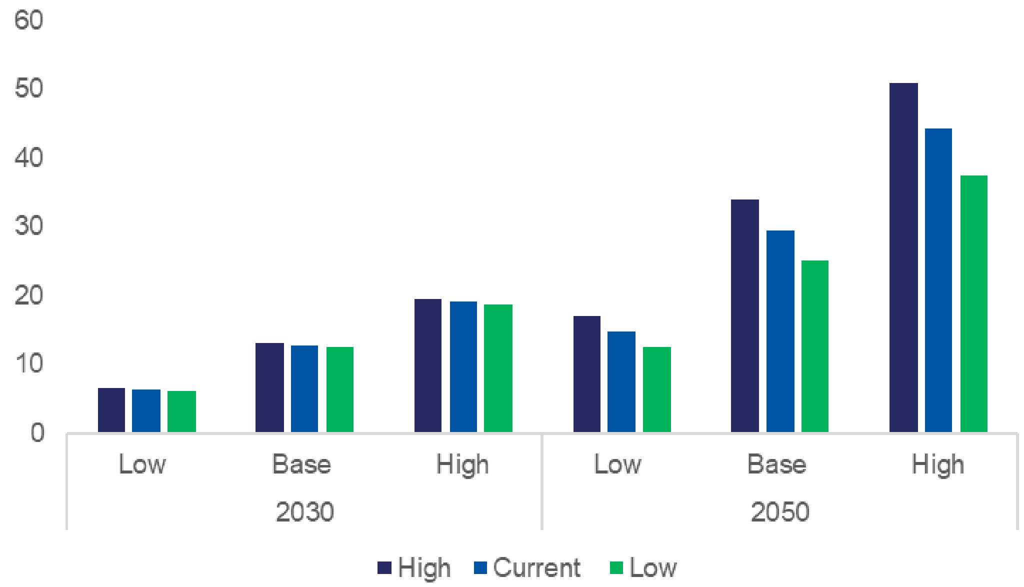


E 2.40: Tanzania Current Trajectory



E 2.41: Tanzania Low Investment Scenario

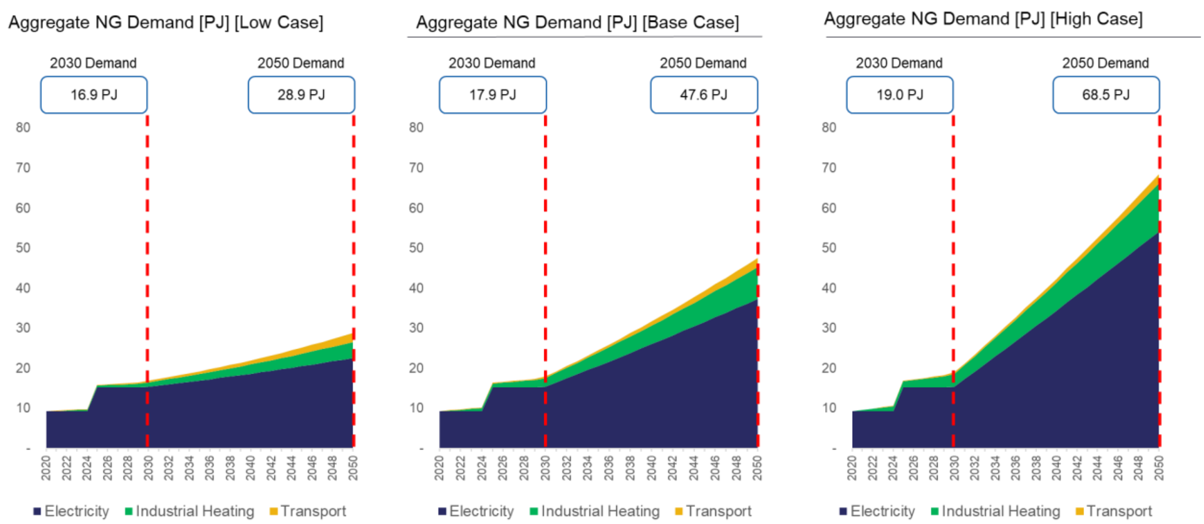
Tanzania's residential and commercial demand in 2050 ranges between 11% to 12% variance from the current trajectory for the low and high investment scenarios. This results in a 2.0 PJ differential between the low and high investment scenarios for the low case, 3.9 PJ for the base case and 5.9 PJ for the high case; thus, accounting for a significant adjustment to the demand base.



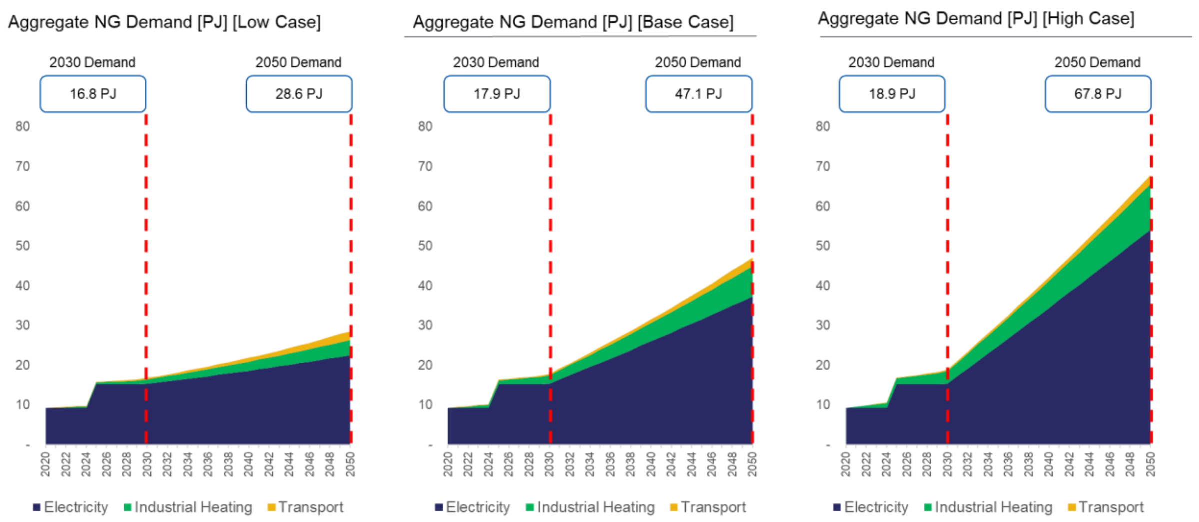
E 2.42: Impact of GDP Scenarios on Tanzania's Residential and Commercial demand [2030/2050] [PJ]

Zambia

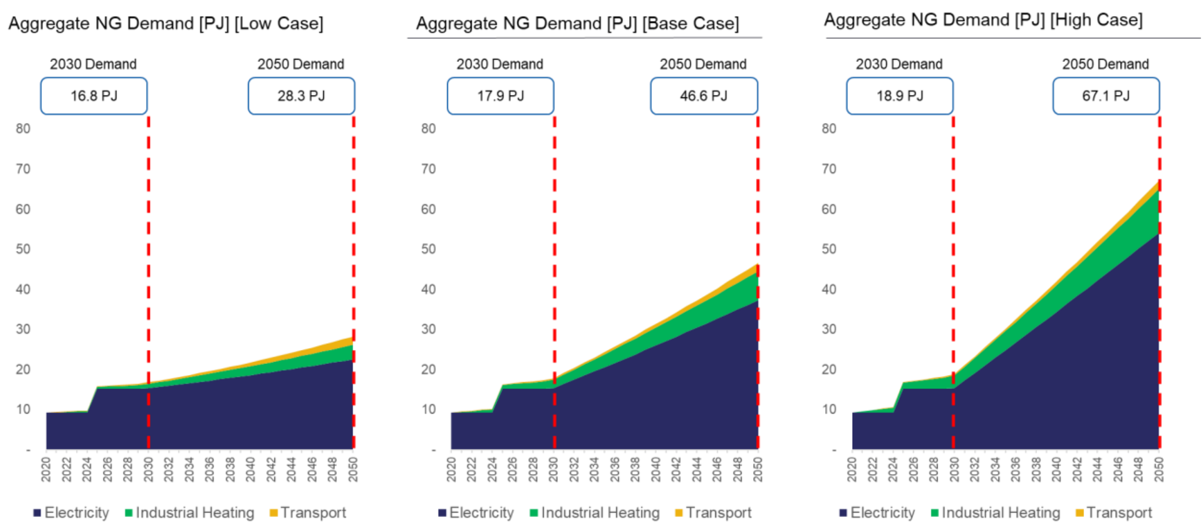
The gas demand is minimally affected by economic activity over the forecasted period, a 1% change in demand is projected for both the low and high investment scenarios. A 1 PJ difference is projected for the base case between the low and high investment scenarios.



E 2.43: Zambia Investment Driven Scenario

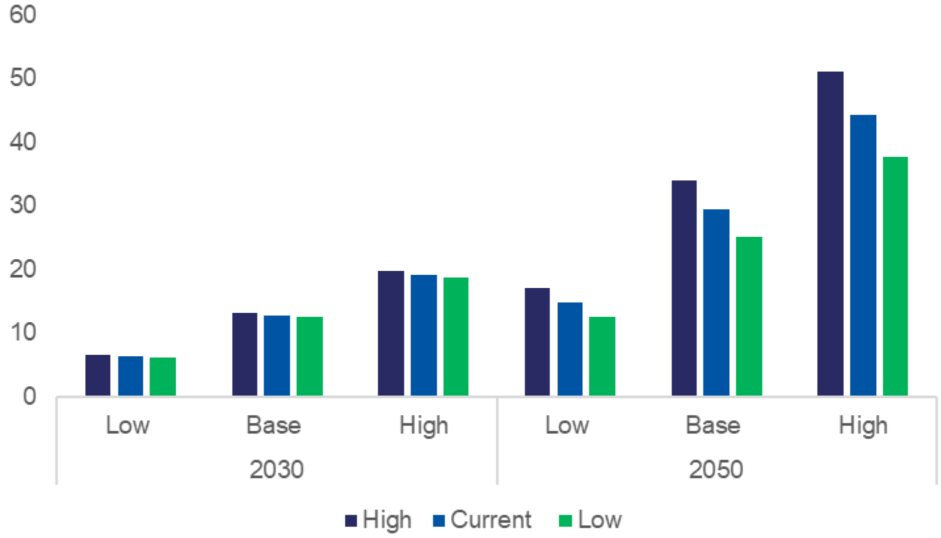


E 2.44: Zambia Current Trajectory



E 2.45: Zambia Low Investment Scenario

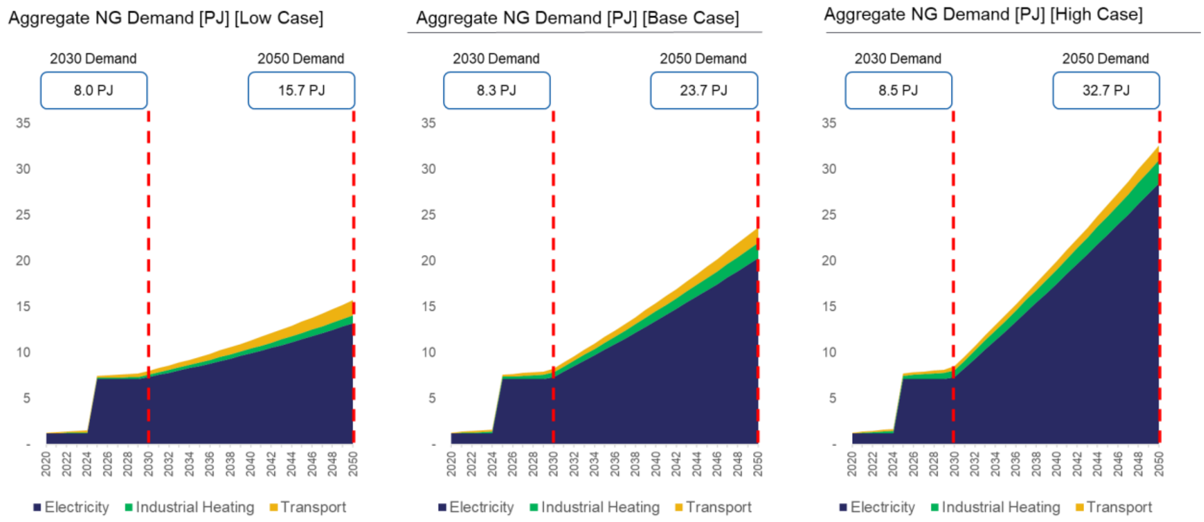
The economic scenarios have a relatively low impact on Zambia's residential and commercial sector in comparison to the other countries in the region. The 2050 variance between the low and high investment scenarios to the current trajectory is between 5% and 6% for all the trend cases. This equates to 0.6 PJ for the base case in 2050.



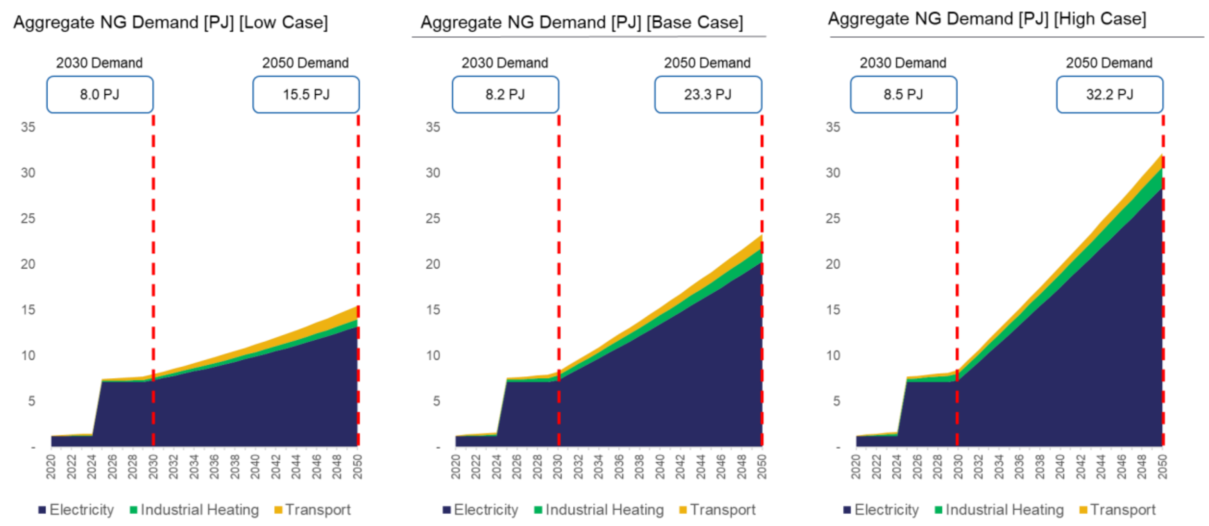
E 2. 46: Impact of GDP Scenarios on Zambia's Residential and Commercial demand [2030/2050] [PJ]

Zimbabwe

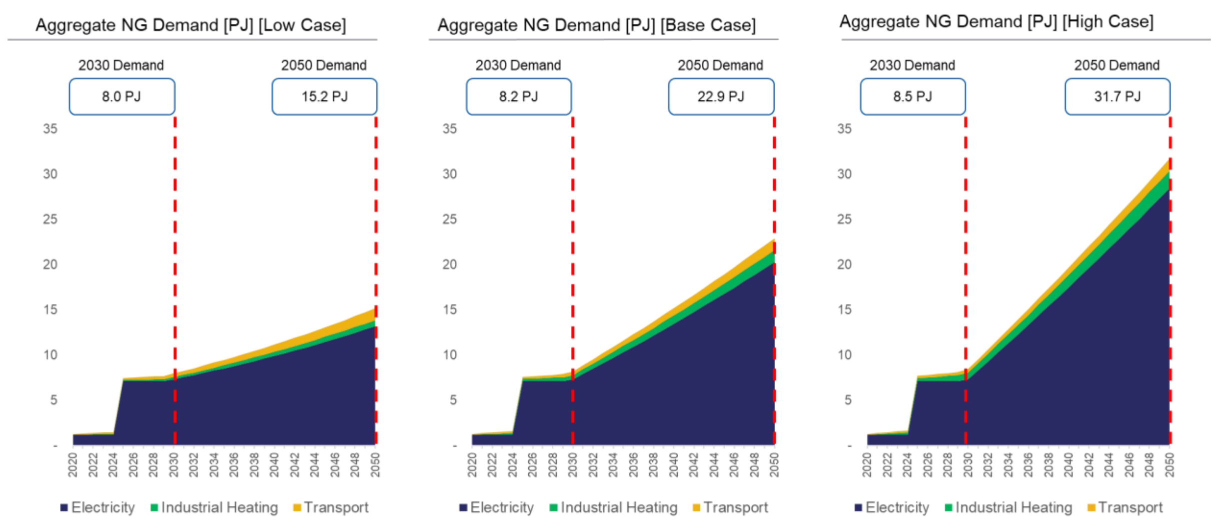
Zimbabwe's gas demand is minimally affected by economic development conditions up to 2030. The long-term effect is only slightly more considerable with a 1 PJ differential between the low and high investment cases. The gas to power demand provides an anchor and thus the changes in transport and industrial heating are less impactful to the aggregated gas demand.



E 2.47: Zimbabwe Investment driven Scenario

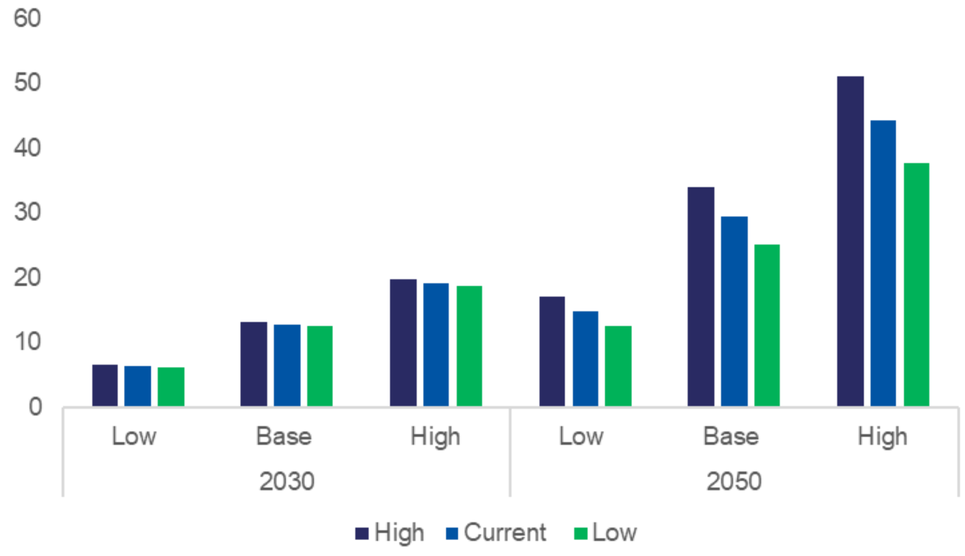


E 2.48: Zimbabwe Current Trajectory



E 2.49: Zimbabwe Low Investment Scenario

The residential and commercial demand variance based on GDP growth scenarios is between 2% and 4% for 2030 and rises to between 14% and 16% by 2050. This equates to a difference between the low investment and investment driven scenarios of 0.35 PJ for the low trend case, 0.7 PJ for the base case and 1.1 PJ for the high trend case.



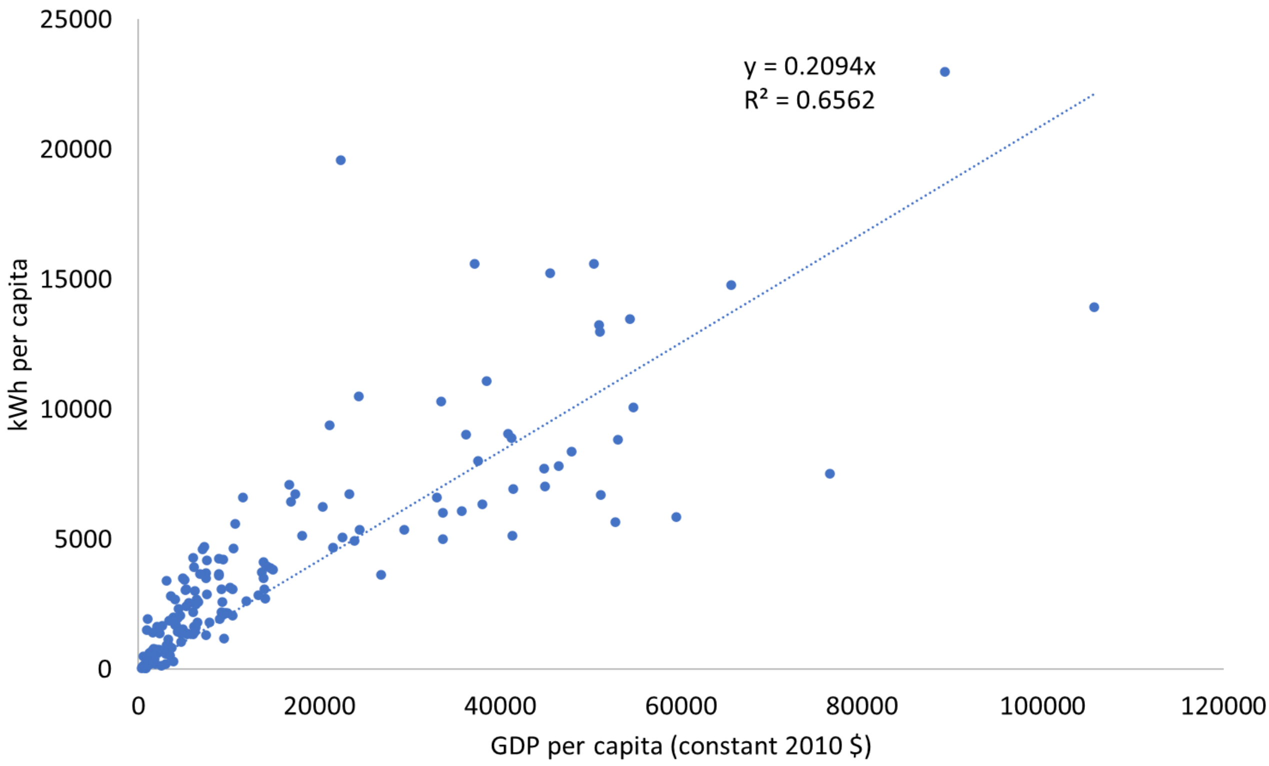
E 2.50: Impact of GDP Scenarios on Zimbabwe's Residential and Commercial demand [2030/2050] [PJ]

Appendix E.3: Demand Model Mechanics

Electricity Model Methodology

Gas to power comprised of electricity consumption and electricity supply. The electricity consumption of countries was analysed and a correlation between economic growth, population growth and electricity consumption were found. Thus, the GDP per capita growth was used as the basis of forecasting the electricity consumption of each of the prioritised countries.

Together with the economic growth, an electrification factor was used for each country's electricity consumption for the forecasted period, accounting for planned electricity supply growth rates. Furthermore, the countries projected energy intensity and electrification rates were included as factors to project electricity demand up to 2050. A 20% reserve margin is added to the demand requirement for which electricity supply is expected to meet. The planned builds and energy mix projection plans were used as the basis to build up the supply analysis. All current and planned HFO and Diesel power plants, have been switched to GTP plants in the model, with gradual switching of total capacity from 2020 or planned commission to the end of the analysis period. The gas share in the demand mix was also incrementally increased up to 7% and 15% of the total planned builds from 2030 to 2050 for the base and high trend cases, respectively.



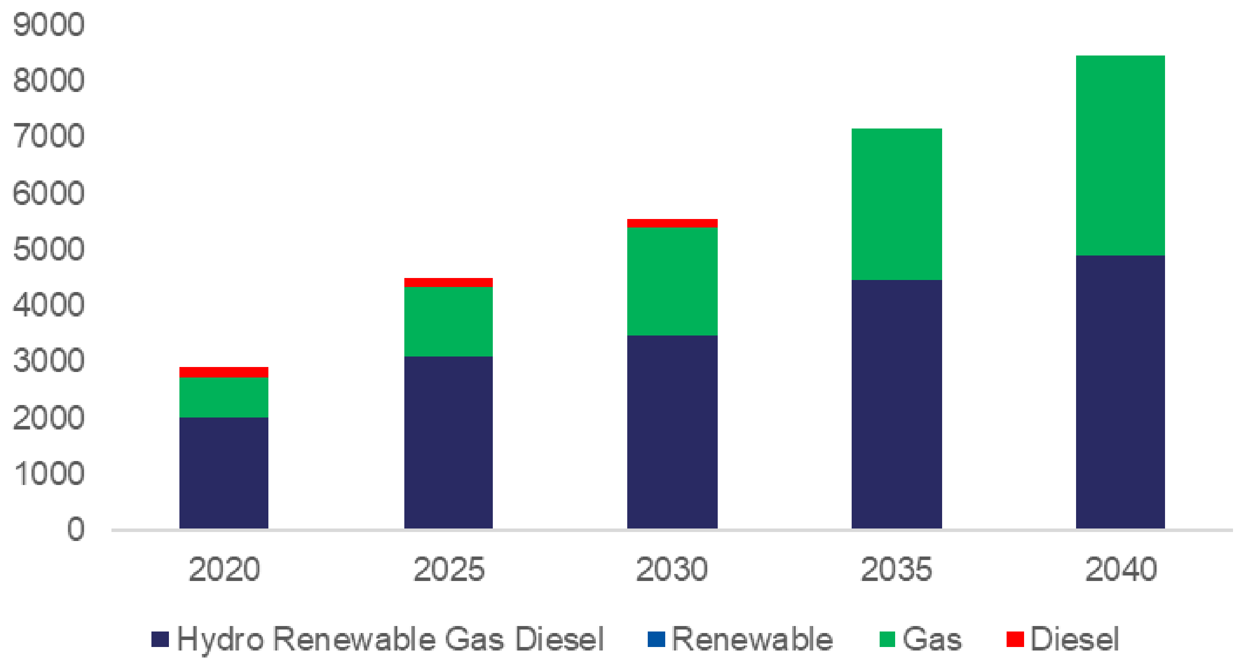
E 3.1: GDP per capita vs Electricity consumption (kWh per capita) of countries worldwide

Electricity supply projected data was sourced from various source documents depending on availability of policy, such as IRPs, Energy Roadmaps and similar infrastructure and economic development studies. Where information on future developments was not readily available, information was obtained from documentation from energy studies or regulatory and oversight bodies within the energy and governing sectors. More recent plans to implement gas projects were incorporated into the demand analysis. A breakdown of different energy mix forecasts, based on these sources, for each country, are provided below.

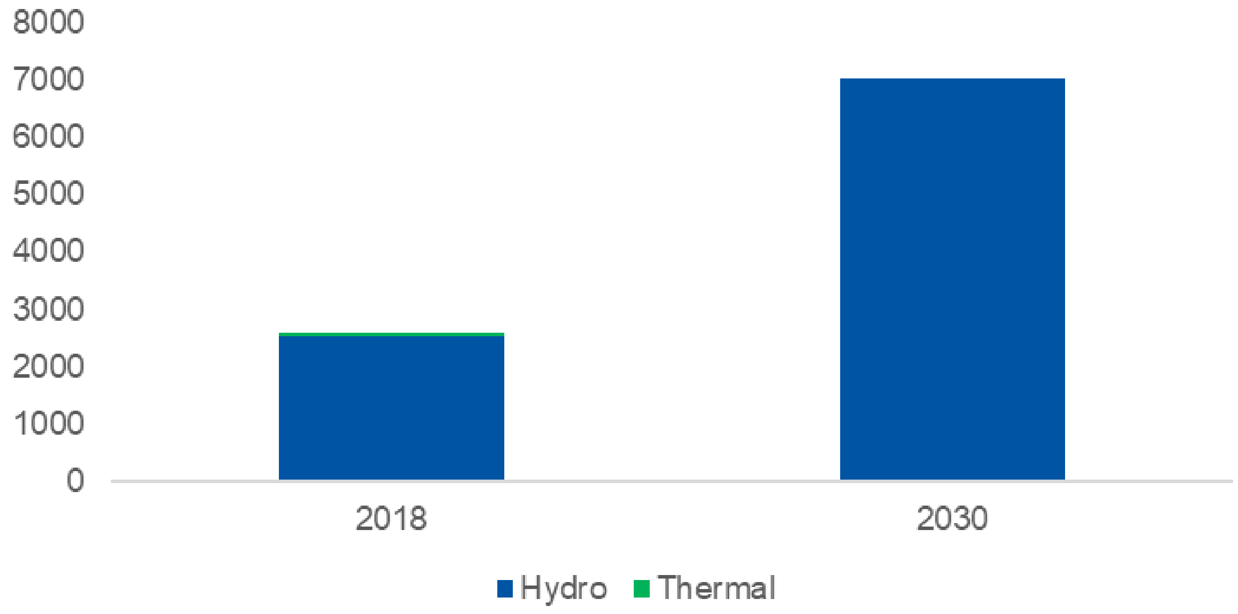
Table 4: Breakdown of Country Electricity Plan Sources

Country	Energy Demand Source	Year Developed
Angola	Angola Power Sector Masterplan 2018	2018
Democratic Republic of Congo	Mini Grid Market Opportunity Assessment: Democratic Republic of the Congo; 2017	2017
Ethiopia	Ethiopian Electric Power Corporation Energy Report; Ethiopian Electric Power- Power Sector Development	2014
Kenya	Kenya Vision 2030	2008
Malawi	Malawi Sustainable Energy Investment Study, 2019	2019
Mauritius	Mauritius 2025 gas masterplan; Mauritius Central Electricity Board	
Mozambique	Integrated Master Plan Mozambique Power System Development, 2019	2019
Namibia	IRP 2016 Review and Update	2016
South Africa	IRP 2019	2019
Tanzania	Power system master plan, 2016 (update) {40% gas scenario}	2016

Country	Energy Demand Source	Year Developed
Zambia	IRP 2016-2020	2016
Zimbabwe	IRP 2016-2020; Zimbabwe Infrastructure Report 2019	2016; 2019

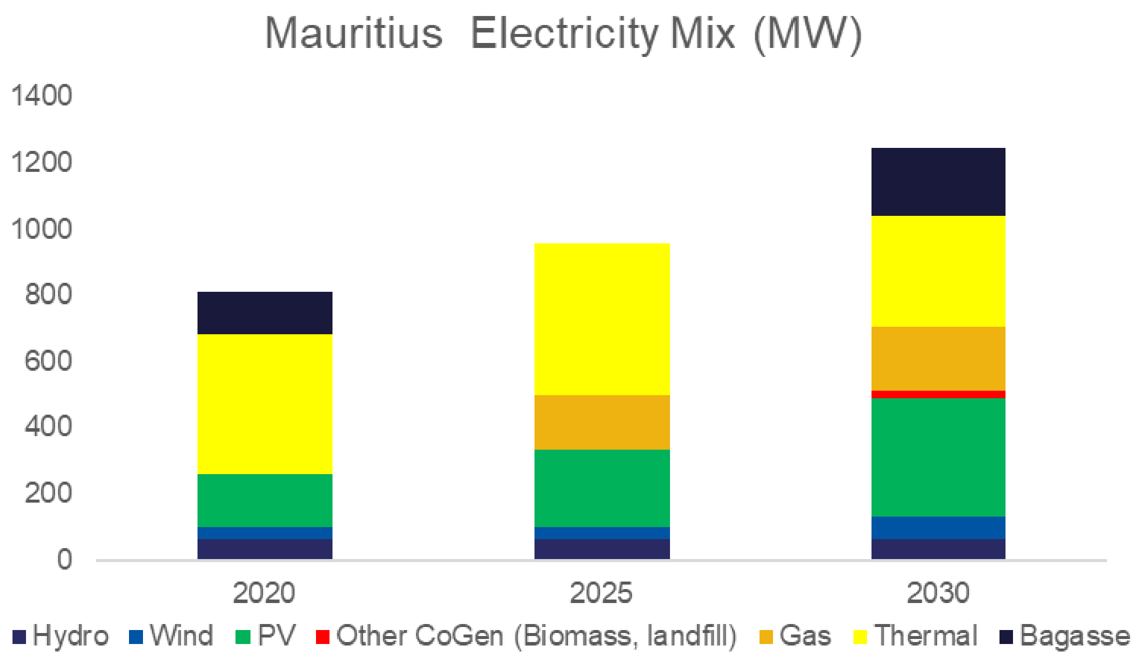


E 3.2: Angola Electricity mix [MW][258]

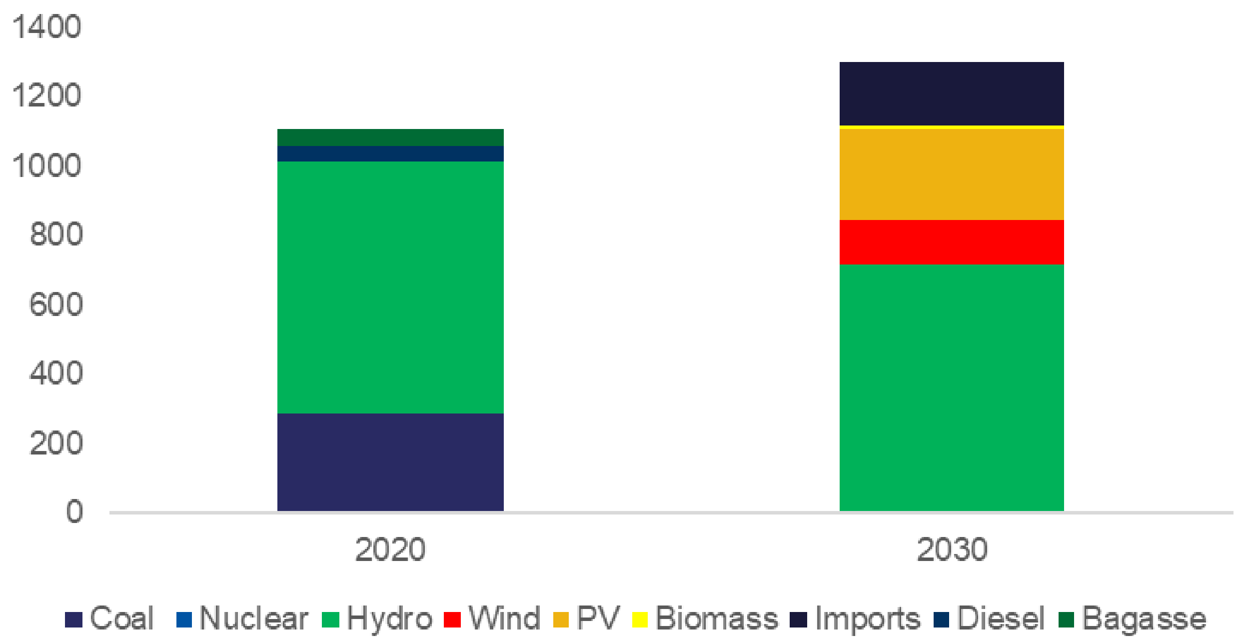


E 3.3: Democratic Republic of Congo Electricity mix [MW][259]

[258] Angola Power Sector Masterplan 2018
[259] Mini Grid Market Opportunity Assessment: Democratic Republic of the Congo; 2017.

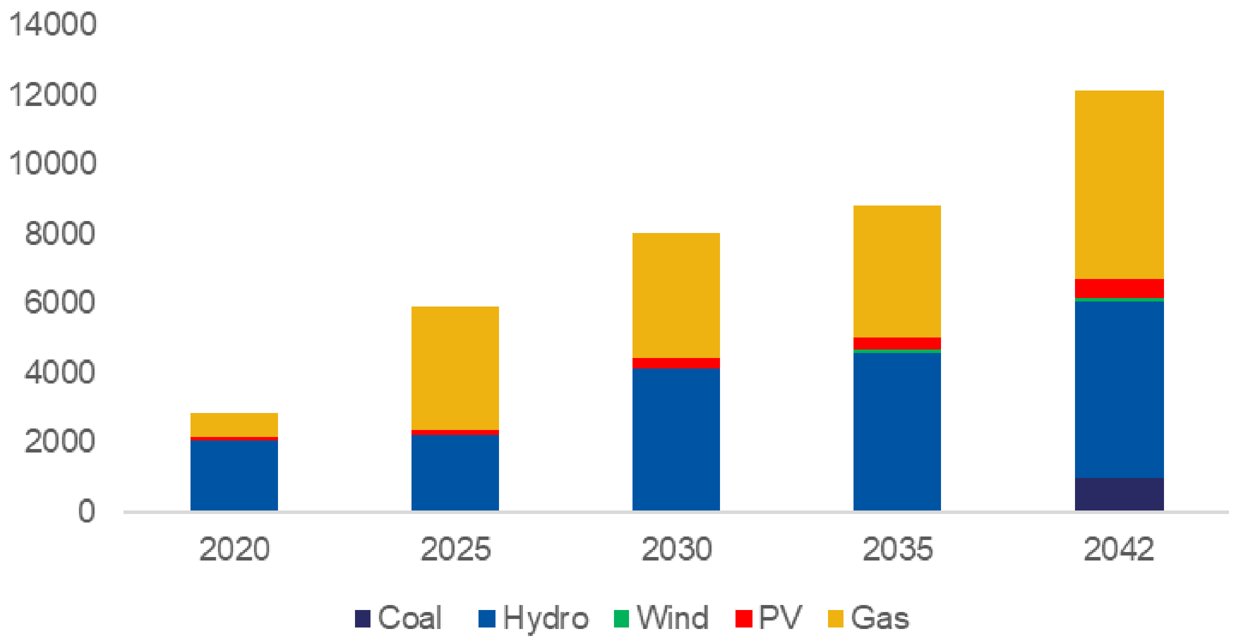


E 3.4: Mauritius Electricity mix [MW][260]

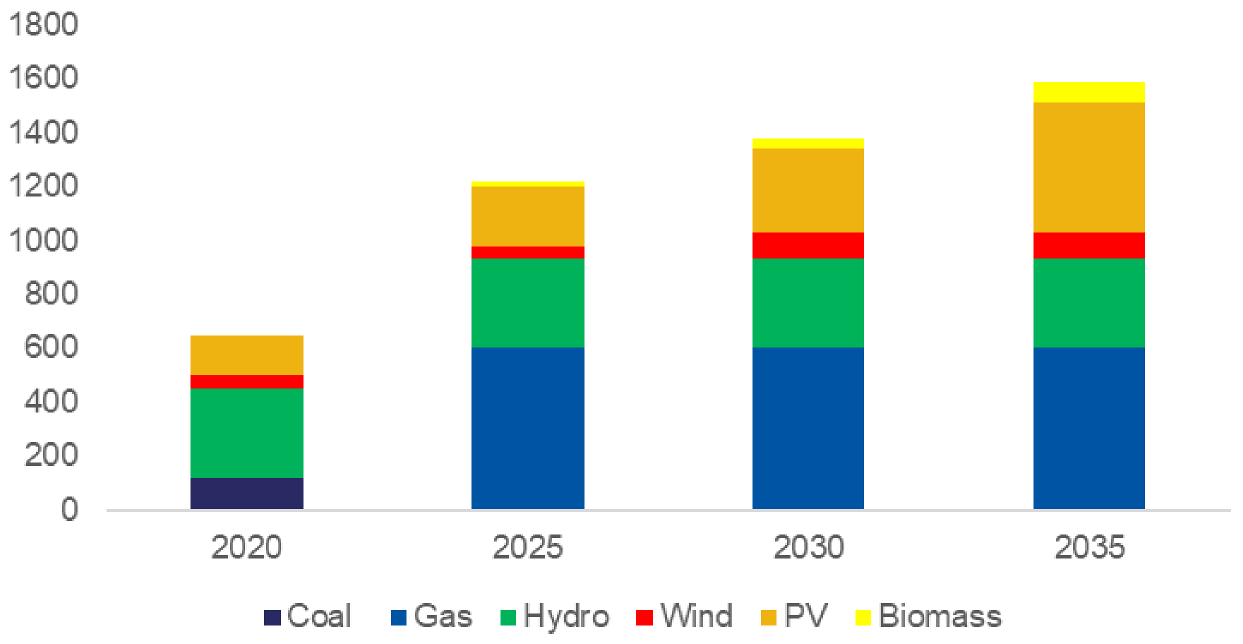


E 3.5: Malawi Electricity mix [MW][261]

[260] Mauritius 2025 gas masterplan.
[261] Malawi Sustainable Energy Investment Study, 2019

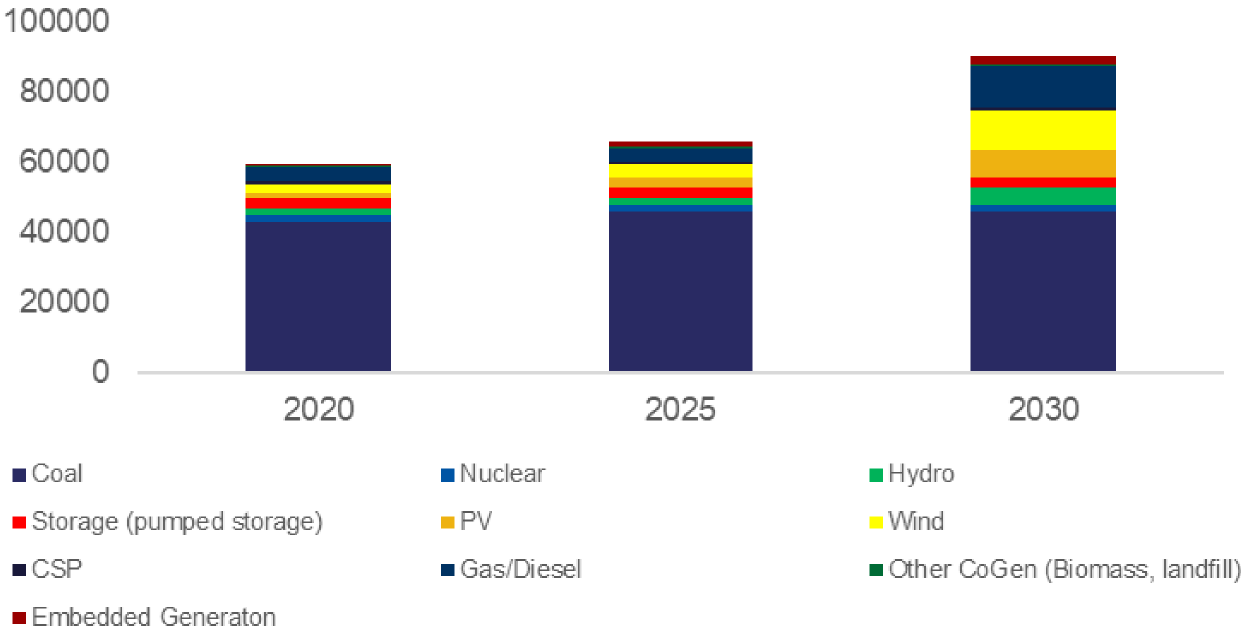


E 3.6: Mozambique Electricity mix [MW][262]

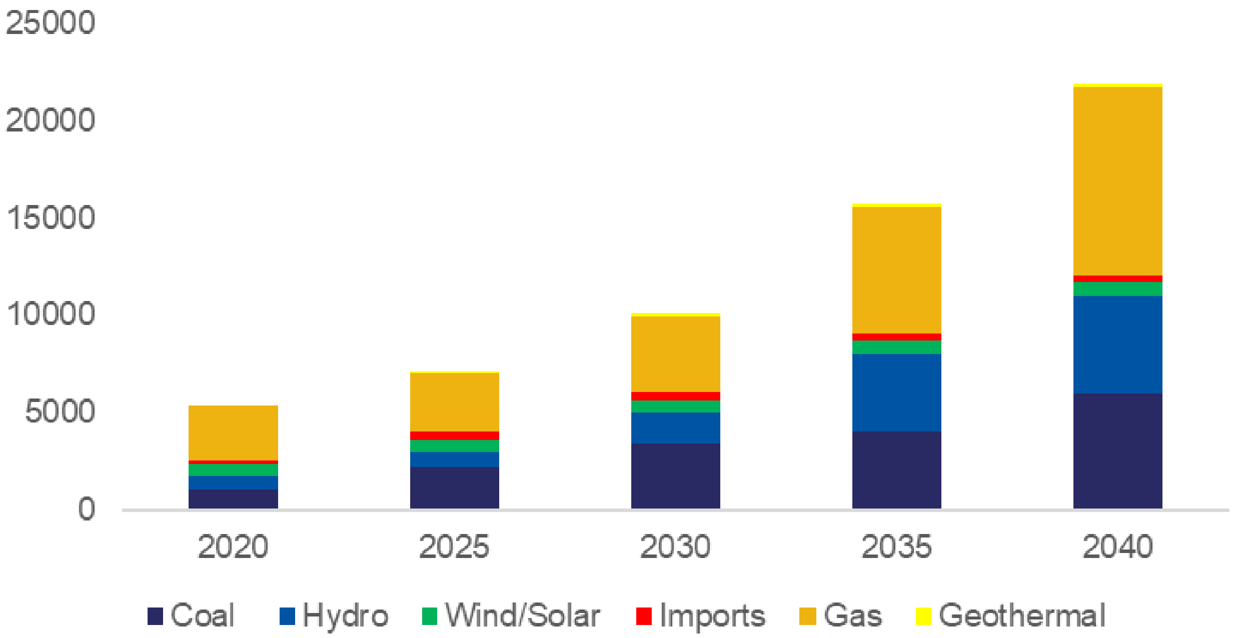


E 3. 7: Namibia electricity mix [MW][263]

[262] Integrated Master Plan Mozambique Power System Development, 2019
[263] IRP 2016 Review and Update

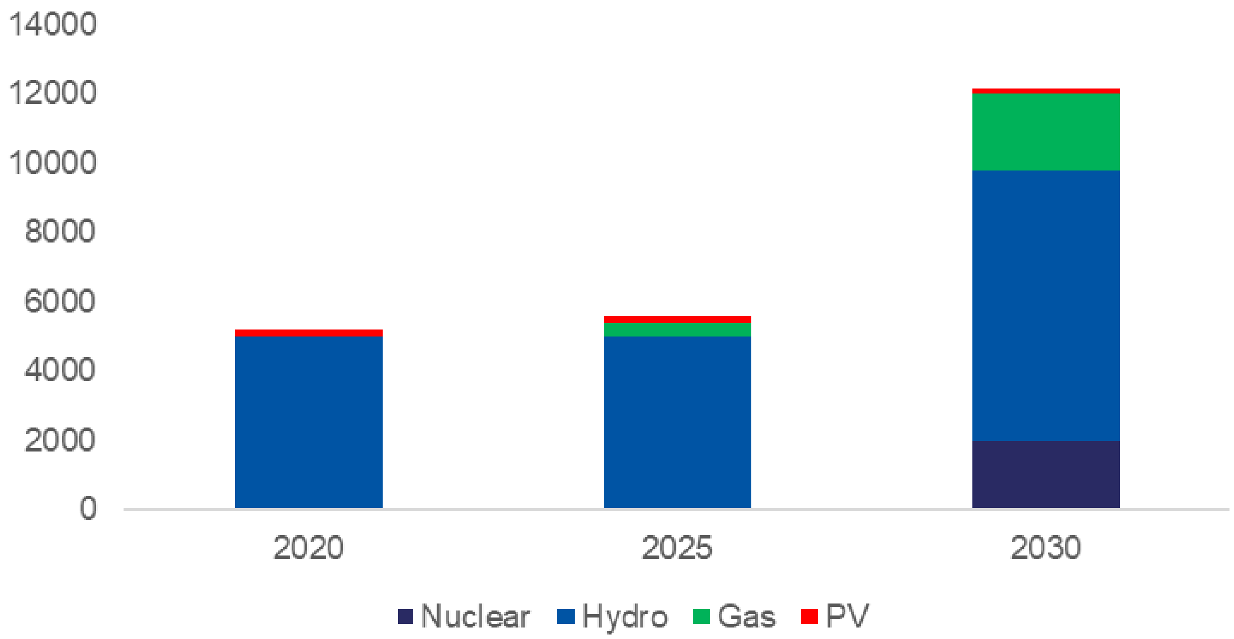


E 3.8: South African Electricity mix [MW][264]

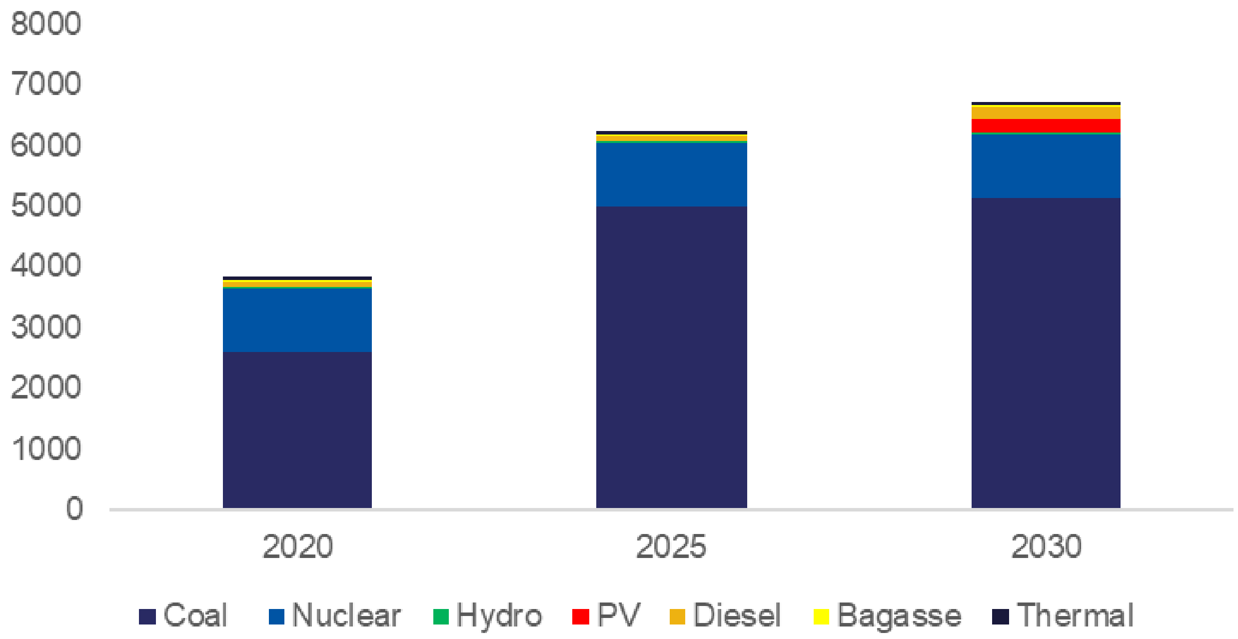


E 3.9: Tanzania Electricity mix [MW][265]

[264] IRP 2019
[265] Power system master plan, 2016 (update) {40% gas scenario}

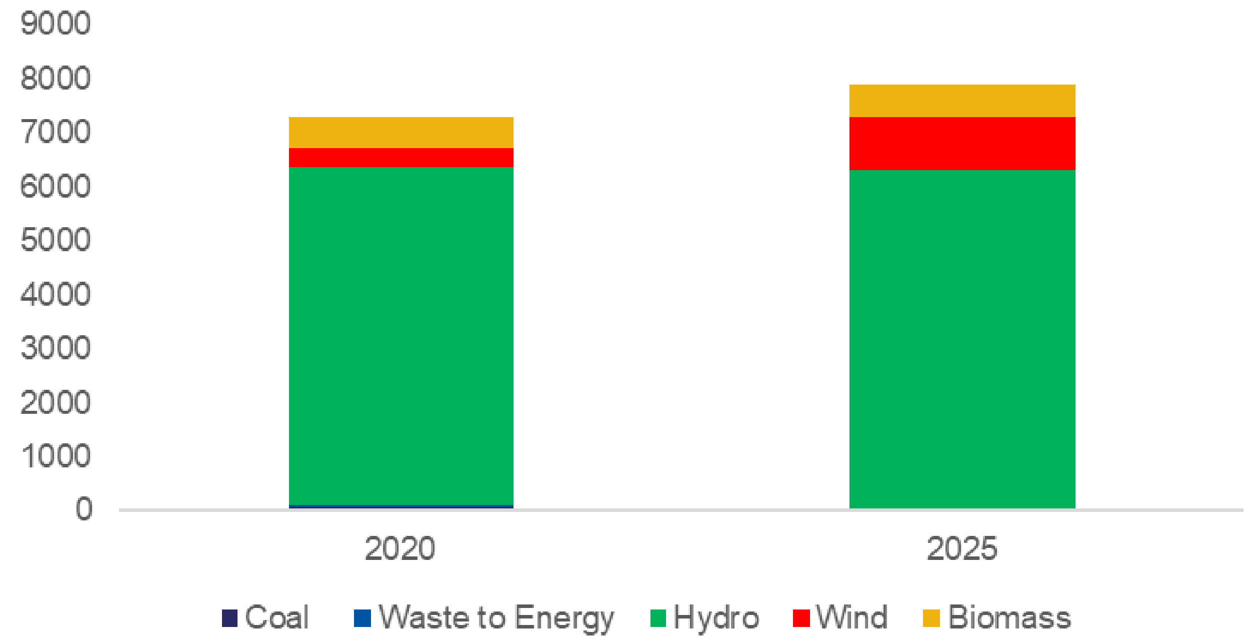


E 3.10: Zambia Electricity mix [MW][266]

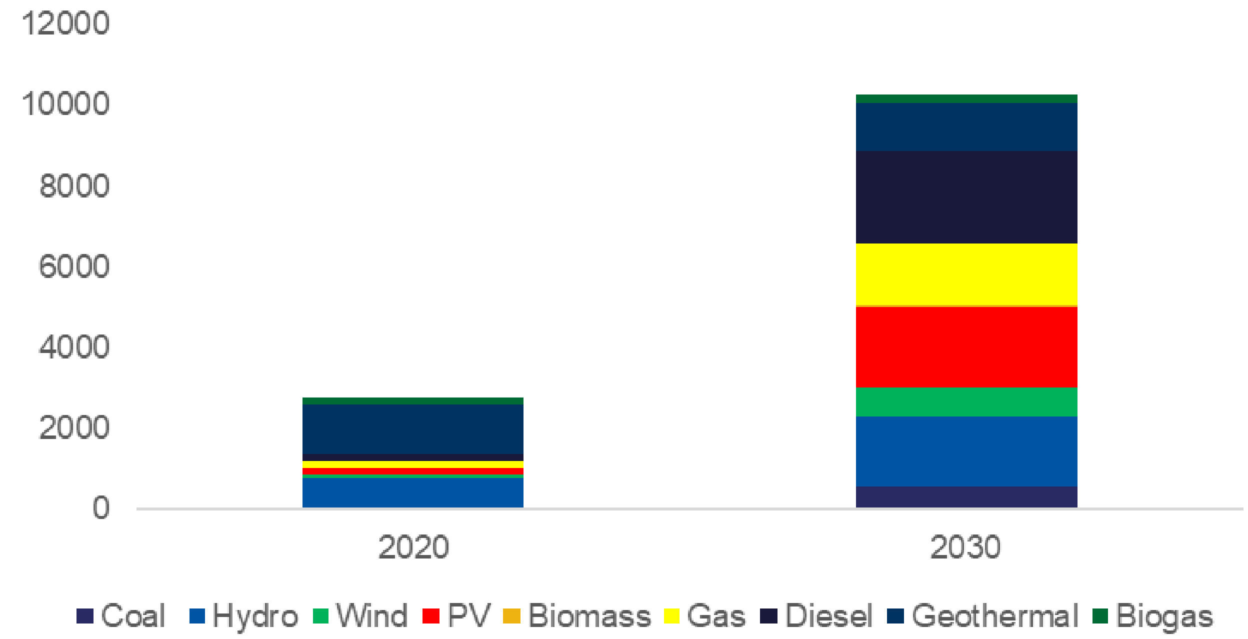


E 3.11: Zimbabwe Electricity mix [MW][267]

[266] IRP 2016-2020.
[267] IRP 2016-2020; Zimbabwe Infrastructure Report 2019.



E 3.12: Ethiopia Electricity mix [MW][268]

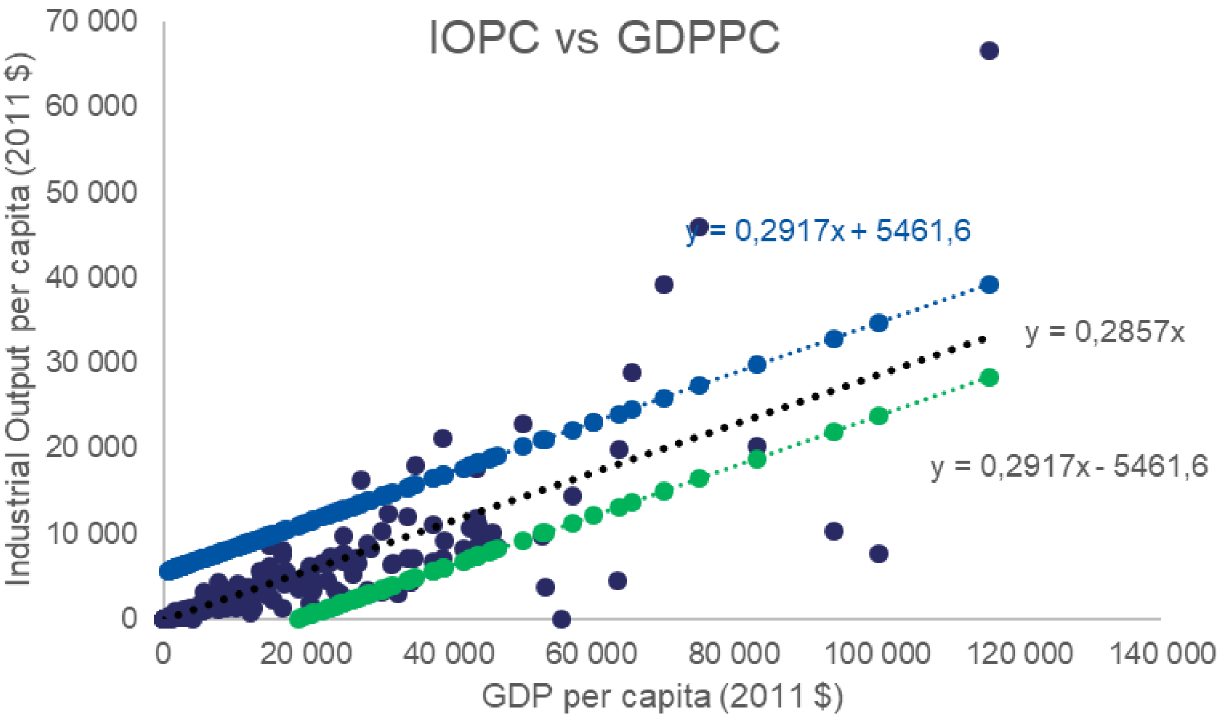


E 3. 13: Kenya Electricity mix [MW][269]

[268] Ethiopian Electric Power Corporation Energy Report; Ethiopian Electric Power- Power Sector Development
[269] Kenya Vision 2030

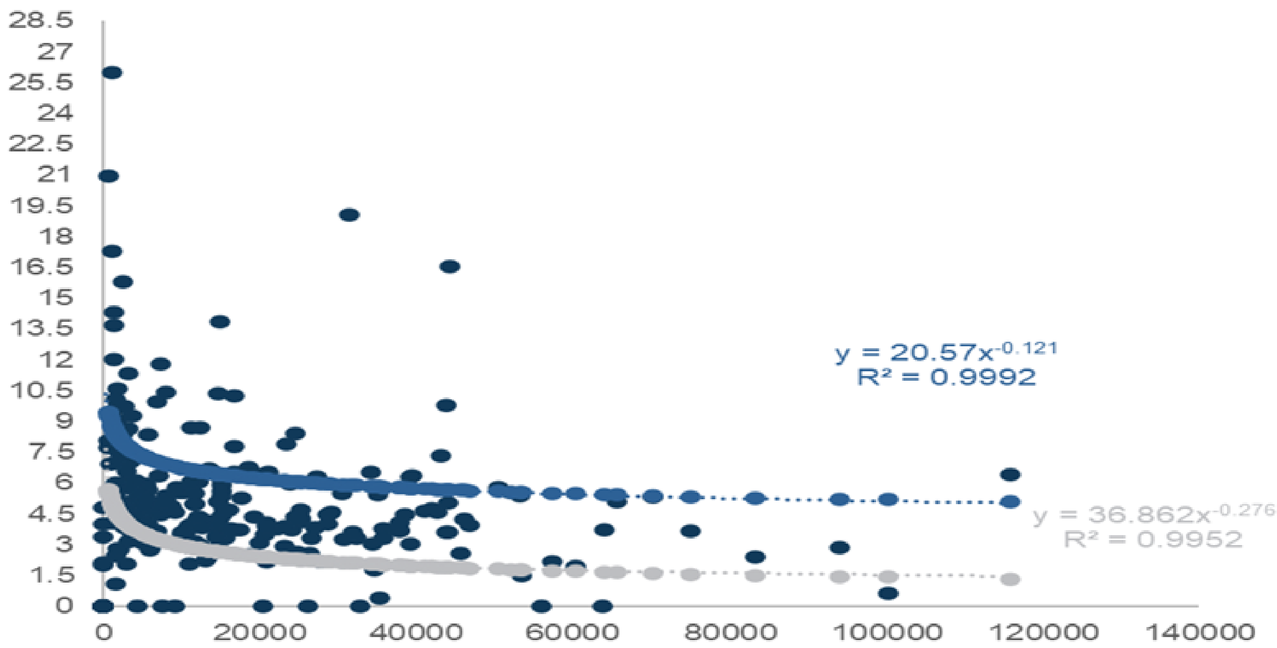
Industrial Heating Model Methodology

With the exception of South Africa, the industrial heating sector within the region is underdeveloped due to the developing nature of the economies. On a global outlook, the industrial output per capita increases in correlation to GDP per capita growth. The projection of the countries' industrial output towards 2050 is based on this relationship.



E 3. 14: Industrial output per capita vs GDP per capita for countries internationally

As countries' economies grow in relation to population growth, the industrial output increases proportionally. In a similar fashion, the energy intensity, which is the measure of the efficiency of an economy decreases with GDP per capita growth, a decrease of 1% per annum, is assumed over the projected period. The total industrial energy demand is thus calculated using the countries projected industrial output based on economic growth, decreasing energy intensity, and is factored by current industrialisation output capacities.

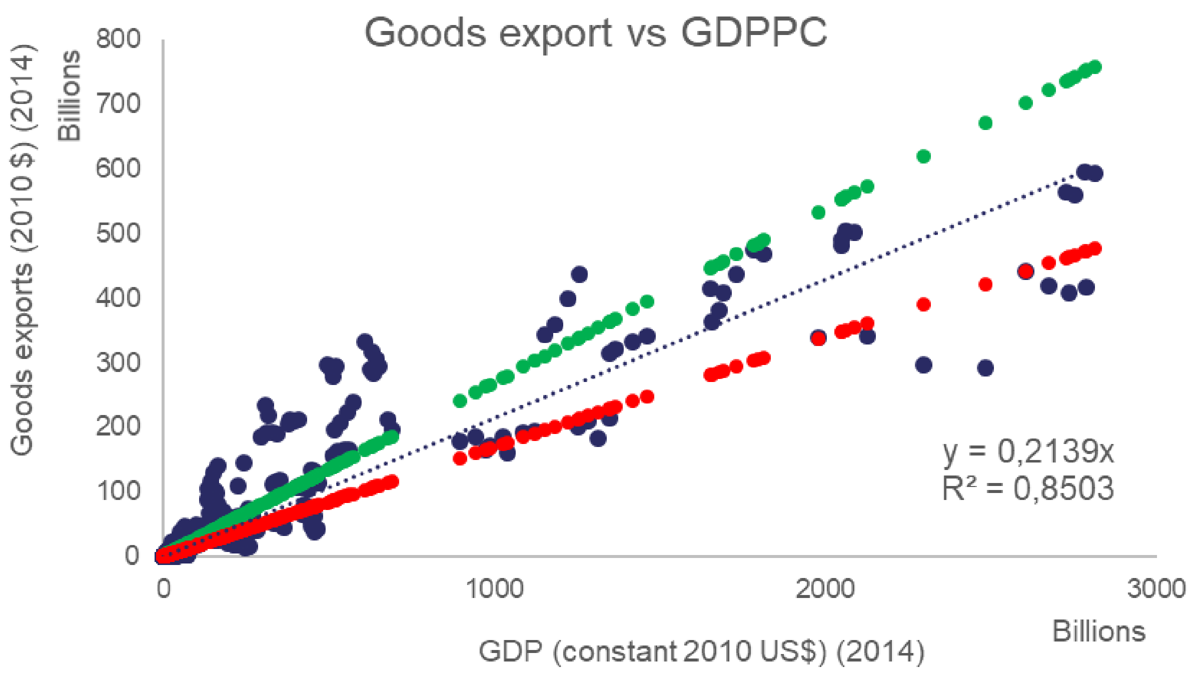


E 3.15: Energy intensity vs GDP per capita

The switching potential to natural gas was accounted for as a percentage of the total industrial energy demand. The switching factors were assumed to start with country specific initial offtakes based on industrialisation factors, with a gradual increase up to 2050, of 2.5% for the low case, 5% for the base case, and 7,5% for the high case scenarios.

Transport Demand

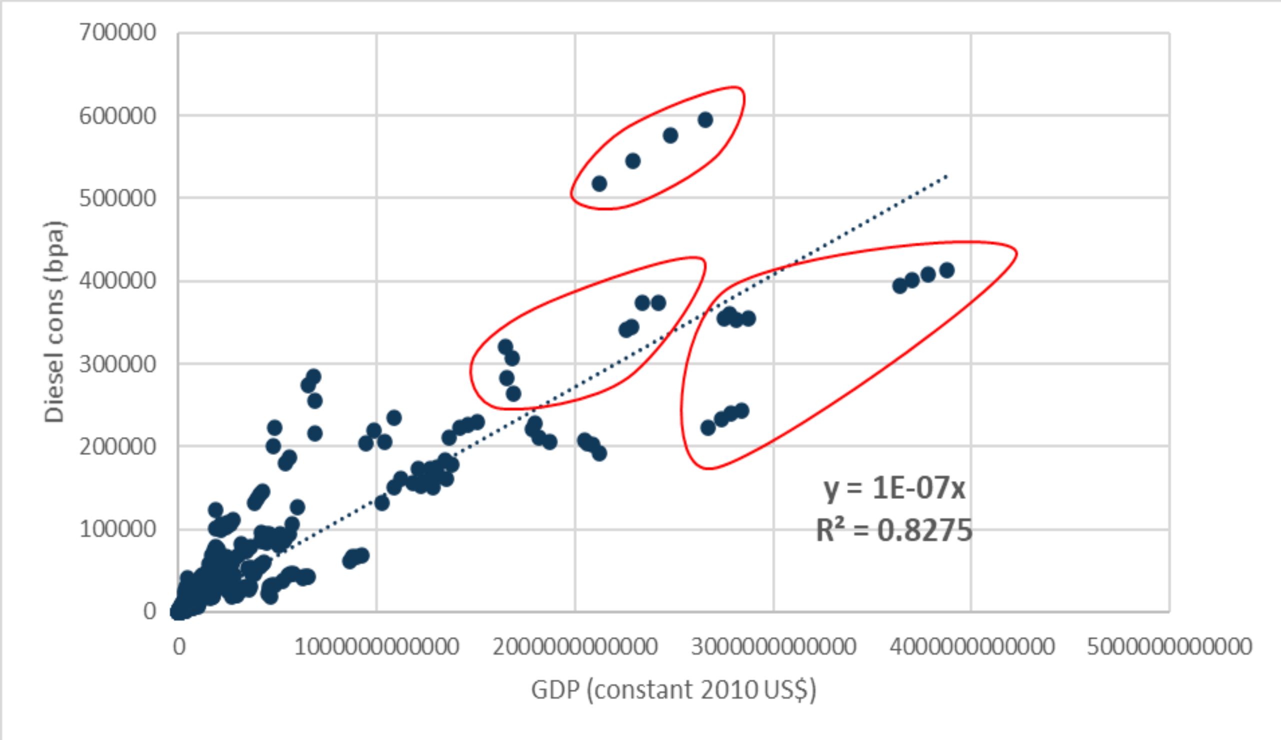
The transport demand for natural gas comprises of two markets, the fuelling of the maritime industry and the road industry. The maritime sector is interrelated to the exportation requirements of countries and, in particular, to goods shipped to overseas markets, which was assumed to be 90% of the total goods exported; whereas the potential road demand for natural gas as a fuel source, is based on the switching potential of diesel fuels.



E 3.16: Goods exports as a function of GDP

The maritime industry growth can be seen to correlate to increased economic prosperity, through the development of the exportation market, illustrated in the graph above. The total value of exported goods was projected based on the countries' projected growth. The total exportation requirement was then converted to the equivalent of LNG fuel required to ship those goods.

The switching potential for marine fuel to natural gas was assumed to be a percentage of the total fuel required. The 2050 gas share in the maritime industry was assumed to be 15% of the total market share, gradually cumulating to that share over the projection period from an initial 2% offtake .



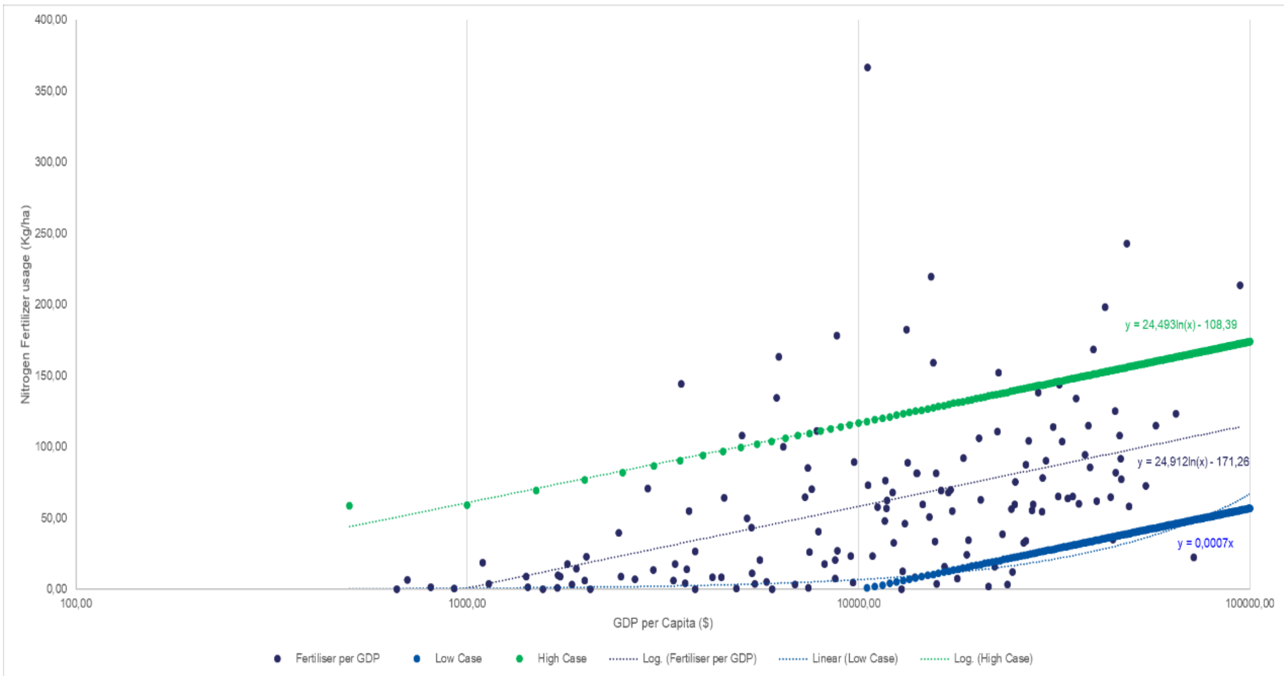
E 3.17: Countries (international) Diesel consumption vs GDP

Similarly, for the road transport fuel demand, the diesel consumption of countries was correlated to GDP growth. The future consumption of diesel could then be projected based on the country's economic growth for the next 30 years. Road-based transport was assumed to account for 50% of a country’s total diesel consumption, which was used as the basis for the potential switching pool. The likelihood of natural gas penetrating the road market in a meaningful way is less likely than for the maritime industry, due to the growth in the electric car industry as well as the improved efficiency of vehicles and enhanced refining process of oil-based fuels. However, over the short term, an impetus has been placed on incorporating gas-powered vehicles into the market by countries in the region. A 1%, 2.5%, and 4% switching potential is assumed to be achieved by 2050 starting from an initial offtake of 0.5%, from diesel to gas as a road vehicle fuel for the low, base, and high case scenarios, respectively.

The total transport demand, thus, comprises of the marine bunkering fuel as well as the switching of diesel to natural gas for road-based transport, and a gradual growth for both sectors for the projected period is expected.

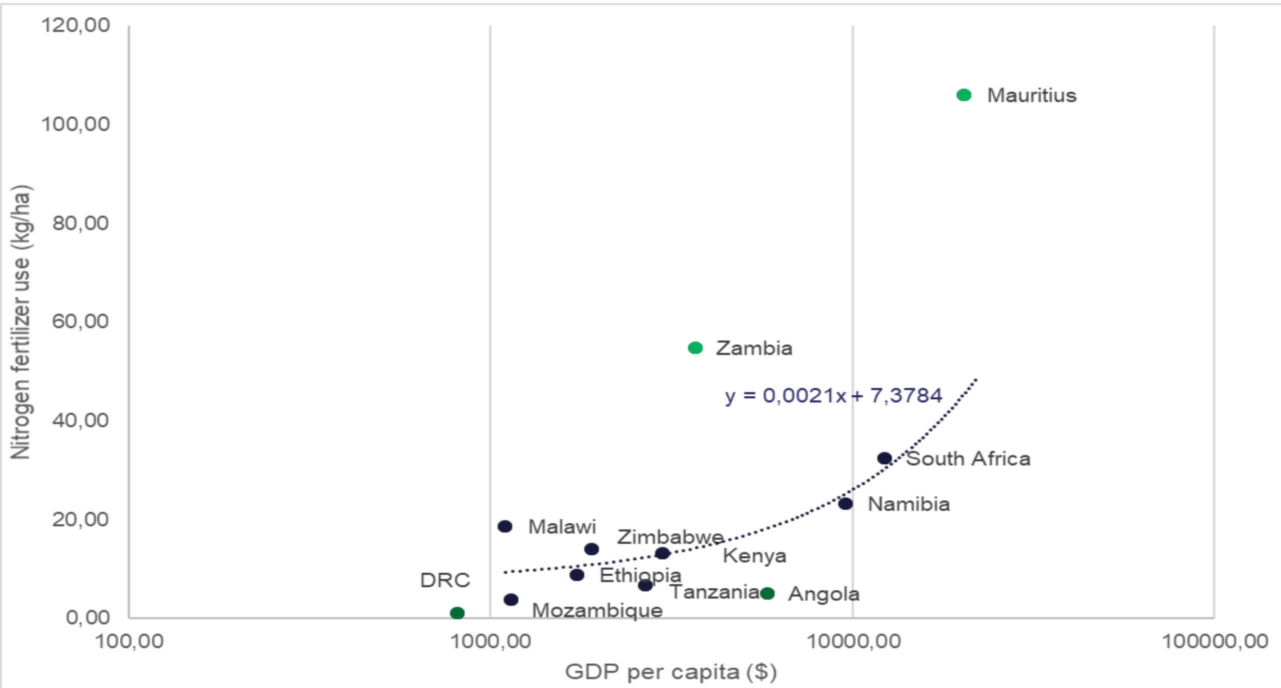
Agriculture Model Methodology

The SADC region is comprised of strong agrarian economies with South Africa having a stronger industrialised economy, however, the agricultural sector is still strong. The model was based on the strong correlation on fertiliser usage based on economic development. On an international level, the ratio of fertiliser usage to land increases with an increase in GDP per capita, as can be seen in the figure below.



E 3. 18: International Nitrogen Fertiliser usage vs GDP per capita.[270]

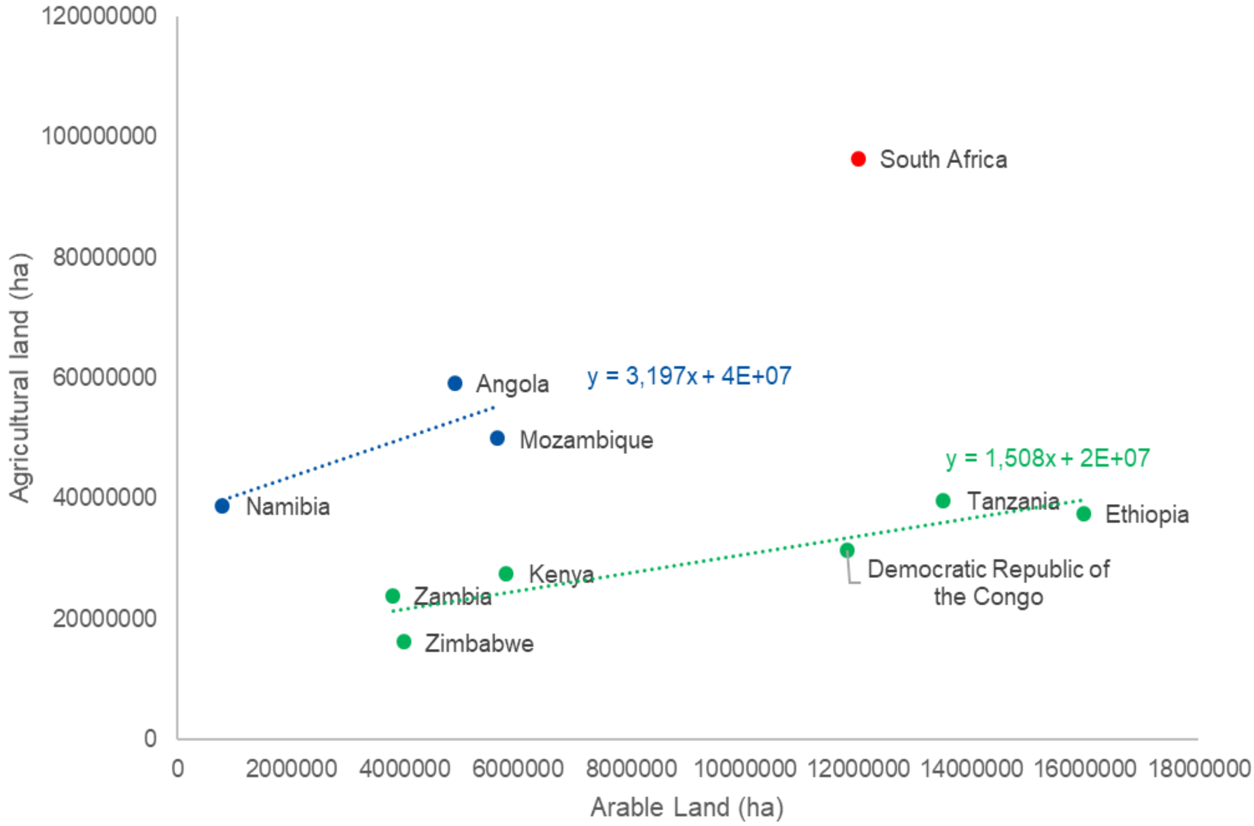
The prioritised countries were then isolated, and a similar trend was found, whereby the fertiliser usage directly correlated to GDP growth. The trend was used to forecast fertiliser usage for the majority of countries, with the exception of the outlier countries; Zambia and Mauritius are already high consumers of fertiliser and were grouped together, with Zambia's expected projection aligned to Mauritius, while at the low end DRC and Angola have lower projected growth.



E 3.19: Prioritised countries nitrogen fertiliser usage vs GDP per capita. [271]

[270] Our World in Data
[271] Our World in Data

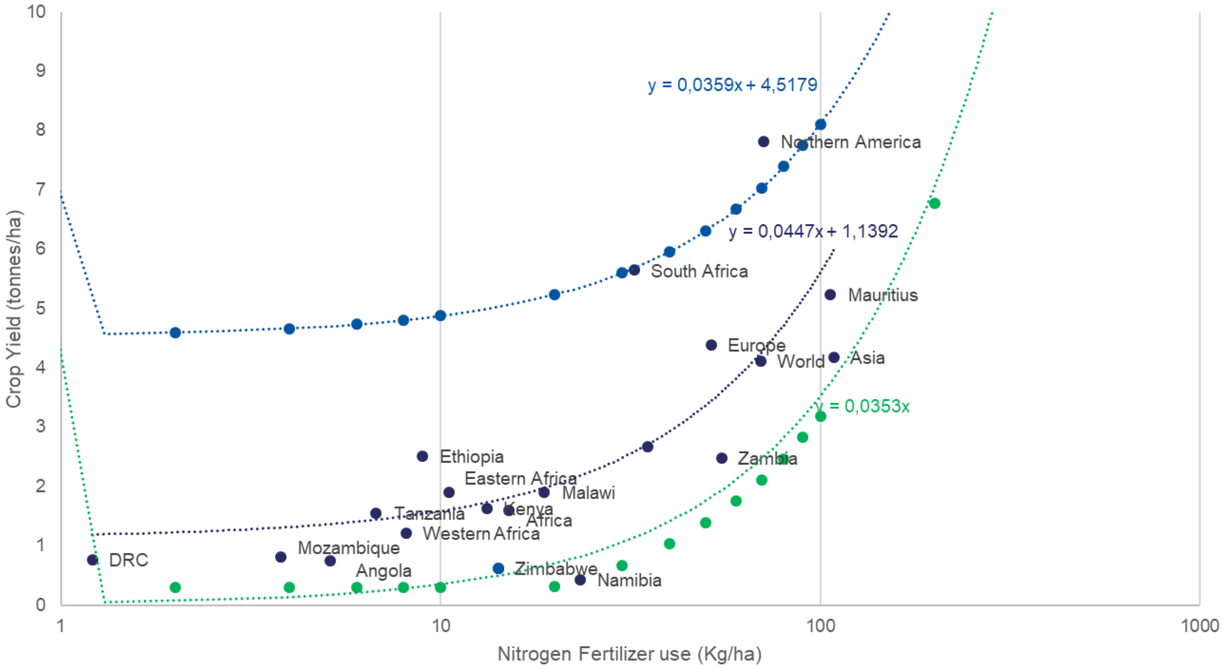
To account for agricultural land usage, which affects the amount of fertiliser usage for each of the countries, a correlation between agricultural land and arable land was obtained. This allowed for countries to be grouped based on agricultural production based on land potential; and the current trends, illustrated below, were used to project expected growth, based on land availability. South Africa was an outlier due to an expected decrease of arable land over the projected period and agricultural land was thus kept at a constant rate.



E 3. 20: Prioritised countries arable land vs agricultural land. [272]

An increased usage of fertiliser shows a clear correlation to increased crop yields, as seen in the figure below. This correlation was used to predict crop yield as countries develop over the projected period, which suggests a growth in the agricultural sectors, especially in countries with encouraging policies.

[272] World Bank, World Development Index



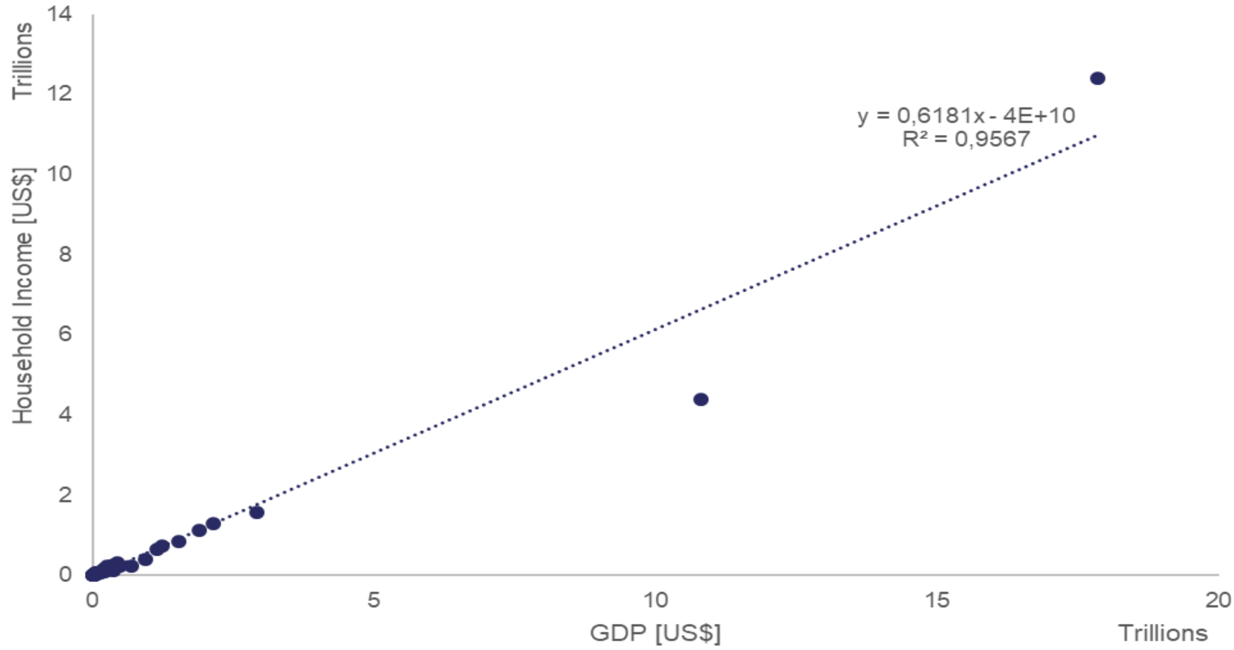
E 3.21: Nitrogen fertiliser usage vs crop yield. [273]

The expected grain production based on arable land is then compared to food consumption trends which provides a balance of trade on agriculture up to 2050. Food consumption is expected to grow in proportion to economic development, both in terms of total calorie consumption as well as meat consumption, which can be seen in the graphs below. This has a significant impact on food requirements and the agricultural sector, particularly the requirement of increased land for animals as well as grain for feed. The total calorie consumption, which comprises of grain and meat, was projected based on expected GDP growth rates, and provides the overall requirement per capita. The projected meat consumption was subtracted from total calories to obtain the grain consumption per capita and the combination of the two was used to calculate total grain requirements for each country, accounting for the fact that meat production requires 20-25 Kg of grain feed to produce a Kg of meat.

Residential and Commercial Model Methodology

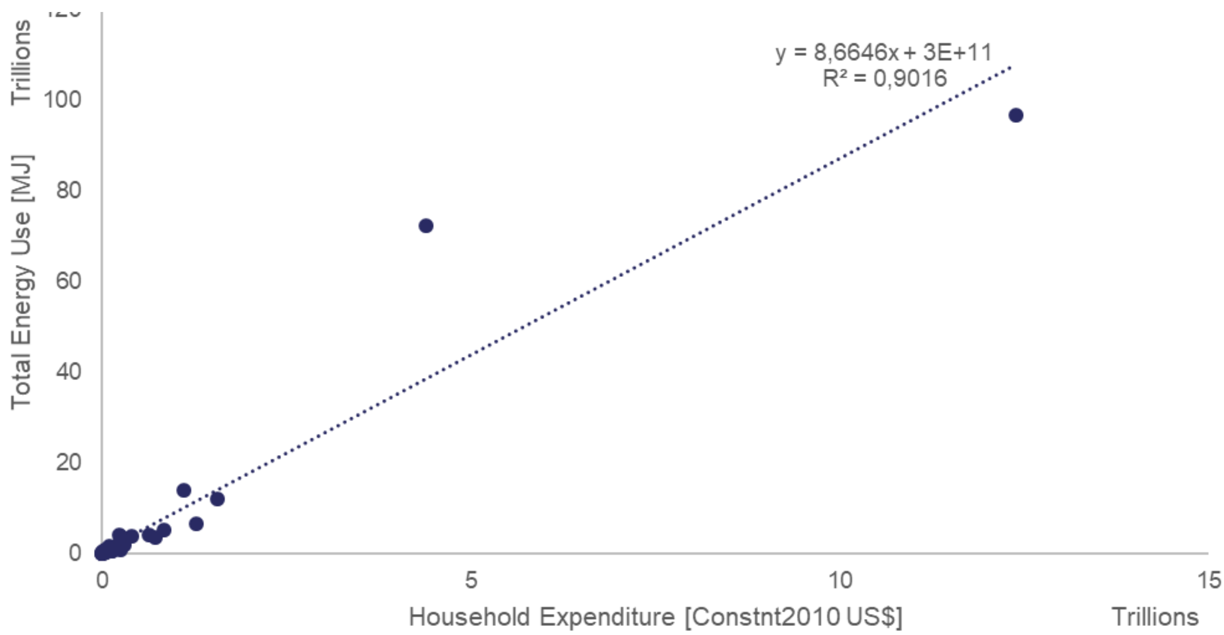
The residential energy sector consumption in the SADC region is primarily based on cooking fuel requirements, where climatic conditions does not necessitate heating and cooling to contribute to overall fuel requirements.

[273] Our World in Data



E 3.22: GDP v Household Income, 2018 [Constant 2010 USD]

The economic growth of the prioritised countries allowed for a projection of household income and household expenditure based on international trends, the correlation between household income growth and GDP growth was used to estimate household expenditure as countries develop.



E 3.23: Energy consumption [MJ] based on Household expenditure [Constant 2020 USD]

The correlation between household expenditure of countries and energy intensity could then be used to estimate the total cooking fuel required, which was assumed to be 90% of total household energy consumption.

Energy balances and the diverse use of source energy for cooking fuel was taken into consideration on a country per country basis, where the percentage breakdown of cooking fuel was assumed to remain constant over the projected time-period.

The switching potential of gas was then based on the rate of urbanisation of the prioritised countries. The natural gas demand for the residential sector was thus limited to urban areas, where accessibility would allow for a percentage of current energy use, to be transferred to natural gas usage. Switching factors of 2.5%, 5.0% and 7.5% for the low, base, and high case scenarios were used respectively for the residential demand.

For the commercial sector, a similar approach was followed. The sector's energy is predominantly supplied through the electricity grid. Other sources of energy are oils and to a smaller extent and limited to a few countries, biomass is also used. A switching factor of 2.5%, 5.0% and 7.5% was used for the low, base, and high case scenarios respectively, of the total oil and biomass energy usage to be substituted to natural gas.

APPENDIX F: LIST OF PROJECTS AND STAKEHOLDERS

Table F-1: Identified LNG Projects

Country	Name	Location	Category	Existing/New	Proposed Capacity (MTPA)	Start Date
Kenya	Kenya Regasification	Mombasa	Regasification	Planned	TBC	TBC
Mauritius	Port Louis	Port Louis	Regasification	Planned	TBC	TBC
Mozambique	Maputo Regasification	Maputo	Regasification	Planned	2	2022
Mozambique	Mozambique LNG	Rovuma	Liquefaction	Planned	12.9	TBC
Mozambique	Coral South FLNG	Rovuma	Liquefaction	Planned	3.4	2022
Mozambique	Rovuma LNG	Rovuma	Liquefaction	Planned	15.2	2024
Mozambique	Matola	Matola	Storage	Planned	0.7	TBC
Namibia	Walvis Bay	Walvis Bay Port	Regasification	Planned	TBC	TBC
South Africa	Richards Bay Port	RB Port	Regasification	Planned	1	2024
South Africa	Coega	Coega Port	Regasification	Planned	2	TBC
South Africa	Saldhana Bay	Saldhana Bay Port	Regasification	Planned	2	TBC
Tanzania	Lindi LNG	Lindi	Liquefaction	Planned	10	2022

Table F-2: Identified Gas to Power Projects

Country	Project Name	Existing/ New	Project Type	Load Type	Size	End date	Companies [Role] (Share) {Country}
Mozambique	Central Termica de Ressano Garcia (CTRG), Maputo	Existing	Gas (OCGT)		175 MW	2023	• Ncondezi Energy Limited [Sponsor] {Virgin Islands, British} • China Machinery Engineering Corporation [Operator] {China} • General Electric [Sponsor] {United States}
Mozambique	Ressano Garcia Gigawatt Gas-fired Power Plant, Maputo	Existing	Gas (OCGT)	Baseload	120 MW		• ATP Mocambique Engenharia e Consultoria Lda[Sponsor] {Mozambique} • Mozambique Ministry of Energy [Sponsor] {Mozambique}

Country	Project Name	Existing/ New	Project Type	Load Type	Size	End date	Companies [Role] (Share) {Country}
							• Electricidade de Mocambique [Sponsor] {Mozambique} • Sonipal [Sponsor] {Mozambique} • Rutland Holding [Sponsor] {Mauritius}
Mozambique	Palma Gas Fired Power Plant, Cabo Delgado	New	Gas (CCGT)	Mid-merit	75 MW	2020	• Electricidade de Mocambique [Sponsor] (12.5) {Mozambique}
Mozambique	Maputo Combined Cycle (CTM) Power Plant, Maputo	Existing	Gas (OCGT)	Baseload	106 MW	2016	• Government of Zambia [Sponsor]{Zambia} • Government of Mozambique [Sponsor] {Mozambique} • Karpowership [Sponsor] {Turkey}
Mozambique	Temane Thermal Power Plant Expansion, Inhambane	New	Gas (CCGT)	Mid-merit	95 MW	TBC	• Government of Mozambique [Sponsor] {Mozambique} • Sasol [Sponsor] {South Africa} • Electricidade de Mocambique [Sponsor] {Mozambique} • Globeleq [Sponsor] {United Kingdom} • eleQtra [Sponsor] {United Kingdom}
Mozambique	Temane Gas-fired Power Plant, Inhambane	New	Gas (CCGT)	Mid-merit	400 MW	TBC	• Government of Mozambique [Sponsor] {Mozambique} • Reputacao Moz [Sponsor] {Mozambique} • Phanes Group [Sponsor] {United Arab Emirates}
Mozambique	GLAE Nacala Gas-fired Power Plant, Nampula	New	Gas (CCGT)	Mid-merit	250 MW	TBC	• Termoelectrica de Benga [Sponsor] (35) {Mozambique} • Kibo Energy PLC [Sponsor] (65) {Ireland}
Mozambique	Beluluane Thermoelectric Project, Beluluane Industrial Park, Maputo	New	Gas (CCGT)	Mid-merit	2000 MW	2022	• Government of China [Sponsor] {China} • China Energy Investment Corporation (CEI) [Construction] {China}

Country	Project Name	Existing/ New	Project Type	Load Type	Size	End date	Companies [Role] (Share) {Country}
Tanzania	Ubungo II Natural-gas Power Plant, Dar es Salaam	Existing	Gas (OCGT)	Mid-merit	129 MW	2014	• SolarReserve [Sponsor] {United States} • Kensani Group [Sponsor] {South Africa} • Intikon Energy [Sponsor]{South Africa} • Development Bank of South Africa [Financier] {South Africa} • Google [Sponsor] {United States} • Ingeteam [Equipment] {Spain} • Yingli Green Energy [Equipment] {China} • Iberdrola [Construction] {Spain} • Group Five Energy [Construction] {South Africa} • Rand Merchant Bank [Financier] {South Africa} • Public Investment Corporation – PIC [Sponsor] {South Africa} • WorleyParsons [Consultant/Project Management] {Australia}
South Africa	Dedisa Open-Cycle Turbine Power Plant, Port Elizabeth, Eastern Cape	Existing	Gas (OCGT)	Peaking	335 MW	2015	• Grassridge Winds of Change Community Trust [Sponsor] (26) {South Africa} • Industrial Development Corporation [Sponsor] (14) {South Africa} • InnoWind [Sponsor] (60) {South Africa} • PPC Ltd [Construction] {South Africa} • Vestas Wind Systems [Equipment] {Denmark}
Tanzania	Kilwa Gas fired Power Plant, Lindi	New	Gas (CCGT)	Mid-merit	318 MW	2018	• Japan International Cooperation Agency (JICA) [Financier] {Japan} • Sumitomo Mitsui Banking Corporation [Financier] {Japan} • Development Bank of Southern Africa [Financier] {South Africa) • Japan Bank for International Cooperation [Financier] {Japan} • Government of Tanzania [Sponsor] {Tanzania} • Toshiba Plant System and Service Corporation Limited [Construction] {Japan}

Country	Project Name	Existing/ New	Project Type	Load Type	Size	End date	Companies [Role] (Share) {Country}
							• Mitsubishi Hitachi Power Systems (MHPS) [Construction] {Japan} • Sumitomo Corporation [Construction] {Japan} • TANESCO [Sponsor] {Tanzania}
Tanzania	IV II Gas-fired Power Plant, Dar es Salaam	New	Gas (CCGT)	Mid-merit	240 MW	TBC	• Kuyasa Mining [Sponsor] {South Africa} • Jones & Wagener (J&W) [Consultant/Project Management] {South Africa}
Tanzania	Dangote Thermal Power Station, Mtwara	Existing	Gas (OCGT)		45 MW	N/A	• SEPCO III Electric Power Construction Corporation [Construction] {China} • Kibo Energy PLC [Sponsor] {Ireland}
South Africa	Port Elizabeth CCGT Power Plant, Coega Industrial Development Zone, Eastern Cape	New	Gas (CCGT)	Mid-merit	1000 MW	TBC	• Clean Energy Finance Corporation [Feasibility] {Australia} • NextGen Solar [Sponsor] {Tanzania} • The U.S. Trade and Development Agency [Financier] {United States}
Tanzania	Mkuranga Gas Fired Power Plant Project, Pwani	New	Gas (CCGT)	Mid-merit	300 MW	TBC	• Sterling and Wilson [Sponsor] {India} • Development Bank of Southern Africa • [Financier] {South Africa} • Standard Bank [Financier] {South Africa} • Solar Capital [Operator] {South Africa} • JA Solar Holdings [Equipment] {China}
South Africa	Avon Open-Cycle Turbine Power Plant, KwaZulu-Natal	Existing	Gas (OCGT)	Peaking	685 MW	N/A	• Electricity Supply Corporation of Malawi Ltd. (ESCOM) [Sponsor] {Malawi}
Tanzania	Kinyerezi III Gas-fired Power Plant, Dar es Salaam	New	Gas (CCGT)	Mid-merit	600 MW	TBC	• Poly Technology Co Ltd [Financier]{China} • TANESCO [Sponsor] {Tanzania}
Tanzania	Kinyerezi IV Gas-fired	New	Gas (CCGT)	Mid-merit	330 MW	TBC	• African Development Bank (AfDB) [Financier] {Cote d`Ivoire} • TANESCO[Sponsor]{Tanzania}

Country	Project Name	Existing/ New	Project Type	Load Type	Size	End date	Companies [Role] (Share) {Country}
	Power Plant, Dar es Salaam						
Tanzania	Somanga Fungu Gas fired Plant, Lindi	New	Gas (CCGT)	Mid-merit	320 MW	TBC	• Faber Capital [Sponsor] {United States} • China State Construction Engineering Corporation (CSCEC) [Sponsor] {China} • China New Energy [Sponsor] {China} • Sunbird Bioenergy Africa Limited [Sponsor] {Mauritius}
Tanzania	Dar es Salaam Gas Fired Power Complex, Dar es Salaam	New	Gas (CCGT)	Mid-merit	900 MW	TBC	• ACWA Power [Operator] {Saudi Arabia} • Department of energy - South Africa [Sponsor] {South Africa}
South Africa	Sasolburg Gas-fired Power Plant, Free State	Existing	Gas (CCGT)	Peaking	140 MW		• Eurus Energy Holdings [Sponsor] {Japan} • Windlab [Sponsor] {Australia}
Tanzania	Mtwara Gas Fired Power Plant Project, Mtwara	New	Gas (CCGT)	Mid-merit	300 MW +300 MW addition	2015	• TANESCO [Sponsor] {Tanzania} • Jacobsen Elektro [Construction] {Norway} • General Electric [Equipment] {United States}
Tanzania	Kinyerezi I Gas-fired Power Plant, Dar es Salaam	Existing	Gas (OCGT)	Mid-merit	150 MW	2016	• Nava Bharat Ventures [Sponsor] (65) {India} • Absa Bank Limited [Financier] {South Africa} • Africa Finance Corporation [Financier] {Nigeria} • Development Bank of Southern Africa [Financier] {South Africa} • ZCCM Investments Holdings PLC [Sponsor] (35) {Zambia} • SEPCO Electric Power Construction Corporation [Construction] {China} • Industrial Development Corporation - South Africa [Financier] {South Africa} • Standard Chartered [Financier] {United Kingdom}

Country	Project Name	Existing/ New	Project Type	Load Type	Size	End date	Companies [Role] (Share) {Country}
							• Industrial and Commercial Bank of China (ICBC) [Financier] {China} • Bank of China [Financier] {China} • Barclays Plc [Financier] {United Kingdom}
Tanzania	Kinyerezi I Gas-fired Power Plant, Dar es Salaam	New (extension)	Gas (OCGT)	Mid-merit	185 MW	TBC	TBC
Tanzania	Kinyerezi II Gas-fired Power Plant, Dar es Salaam	Existing	Gas (OCGT)	Mid-merit	248.2 MW	TBC	TBC
Mozambique	Kuvaninga Energia Gas-fired Power Project, Chokwe, Gaza	Existing	Gas (OCGT)	Mid-merit	40.29 MW	TBC	• TBC
Mozambique	Temane Electrical Expansion and Fuel Gas Superheater Project, Zambezia	New	Gas (CCGT)		420 MW	TBC	• TBC
South Africa	Port Rex Power Station	Existing	Gas (OCGT)	Peaking	171 MW	TBC	• TBC
South Africa	Newcastle Cogeneration Plant	Existing	Gas (CCGT)	Peaking	18 MW	TBC	• TBC
South Africa	Acacia Power Station	Existing	Gas (OCGT)	Peaking	171 MW	TBC	• TBC
South Africa	Ankerlig Power Station	Existing	Gas (OCGT)	Peaking	1338 MW	TBC	• TBC
South Africa	Gourikwa Power Station	Existing	Gas (OCGT)	Peaking	746 MW	TBC	• TBC

Country	Project Name	Existing/ New	Project Type	Load Type	Size	End date	Companies [Role] (Share) {Country}
Tanzania	Ubungo I Thermal Power Station	Existing	Gas (OCGT)	Mid-merit	102 MW	2011	• Tanesco
Tanzania	Tegeta Thermal Power Station	Existing	Gas (OCGT)	Mid-merit	45 MW	2008	• Tanesco
Tanzania	Mtwara Thermal Power Station	Existing	Gas (OCGT)	Mid-merit	22 MW (Mtwara 1= 18MW, Mtwara II= 4MW)	2010	• Tanesco
Tanzania	Somanga Thermal Power Station	Existing	Gas (OCGT)	Mid-merit	7.5 MW	2011	• Symbion Power Limited
Tanzania	Songas Thermal Power Station	Existing	Gas (OCGT)	Mid-merit	190 MW	2012	• Symbion Power Limited
Mozambique	Inhambane	Existing	Gas (OCGT)		4.6 MW	TBC	• TBC
Mozambique	GTG3 Maputo	Existing	Gas (OCGT)		24 MW	TBC	• TBC
Mozambique	GTG Beira	Existing	Gas (OCGT)		14 MW	TBC	• TBC
Mozambique	Termoeléctrica de Temane	Existing	Gas (OCGT)		11.2 MW	TBC	• TBC
Mozambique	Termoeléctrica de Maputo	Existing	Gas (CCGT)		121 MW	TBC	• ZESCO
South Africa	IRP 3000MW	New	Gas (CCGT)	Mid-merit	1821 MW	TBC	• TBC
Zimbabwe	Sinosteel Coalbed Methane Gas (CBM) Power Plant	New	Gas (CCGT)	Mid-merit	400 MW	TBC	• TBC
Namibia	Kudu Gas Fired Power Plant,	New	Gas (CCGT)	Mid-merit	800 MW	TBC	• TBC

Country	Project Name	Existing/ New	Project Type	Load Type	Size	End date	Companies [Role] (Share) {Country}
	Oranjemund, Karas						
Namibia	Walvis Bay Natural Gas Power Plant, Erongo	New	Gas (OCGT)	Mid-merit	250 MW	TBC	• TBC
Angola	Soyo Combined Cycle Power Plant, Zaire	New	Gas (CCGT)	Mid-merit	750 MW	TBC	• TBC
Angola	Belem Power Plant, Huambo	New	Gas (CCGT)	Mid-merit	50 MW	TBC	• TBC
Angola	Soyo Combined Cycle Power Plant, Zaire	New	Gas (CCGT)	Mid-merit	750 MW	TBC	• TBC
Angola	Belem Power Plant, Huambo	New	Gas (CCGT)	Mid-merit	50 MW	TBC	• TBC
Angola	Luanda OCGT Power Station	Existing	Gas (OCGT)	Mid-merit	148 MW	TBC	• TBC
Democratic Republic of the Congo	Muanda	Existing	Gas (OCGT)	Mid-merit	1.6 MW	TBC	• TBC
Kenya	Mombasa Gas Fired Power Plant, Mombasa County	New	Gas (CCGT)	Mid-merit	500 MW	TBC	• TBC
Kenya	Dongo Kundu Gas Fired Plant, Mombasa	New	Gas (CCGT)	Mid-merit	700 MW	TBC	• TBC
Ethiopia	Adi Gudem Industrial Power station	New	Gas (CCGT)	Mid-merit	500 MW	TBC	• TBC

Table F-3: Identified Transmission and Gas Pipeline Projects

Country 1	Country 2	Country 3	Type	Distance (km)	Existing/ Planned	Description
Tanzania	Malawi		Transmission Interconnector	TBC	Planned	
Tanzania	Zambia		Transmission Interconnector	TBC	Planned	
Mozambique	Malawi		Transmission Interconnector	218	Planned	North of Mozambique
Angola	Namibia	South Africa	Transmission Interconnector	TBC	Planned	
Mozambique			Gas Pipeline	1200	Planned	North Pipeline connecting to Rompco Pipeline
Mozambique	South Africa		Gas Pipeline	865	Existing	ROMPCO Pipeline
South Africa			Gas Pipeline	600	Existing	Lilly Pipeline
Tanzania			Gas Pipeline	533	Existing	Mtwara to Dar es Salaam

Table F-4: Identified Industrial Projects

Country	Project Name	Project Type	Status	New/ Existing	Gas Input [PJ]	Value ($m)	End date	Companies [Role] {Country} (Share)
Mozambique	Limak Holdings Cement Plant, Maputo	Cement	At planning stage	New	7.0	150	TBC	• Limak Holdings [Operator] {Turkey}
Mozambique	Sasol Oil Processing Plant, Inhassoro	GTL	In tender/ Tender launched	New	170.3	TBC	TBC	• Sasol [Sponsor] {South Africa}
Mozambique	Iron and Steel Factory, Rovubue	Iron and Steel	At planning stage	New	9.3	950	TBC	• ABB Group [Feasibility] {Switzerland} • Metallurgical Corporation of China (MCC) [Feasibility] {China}

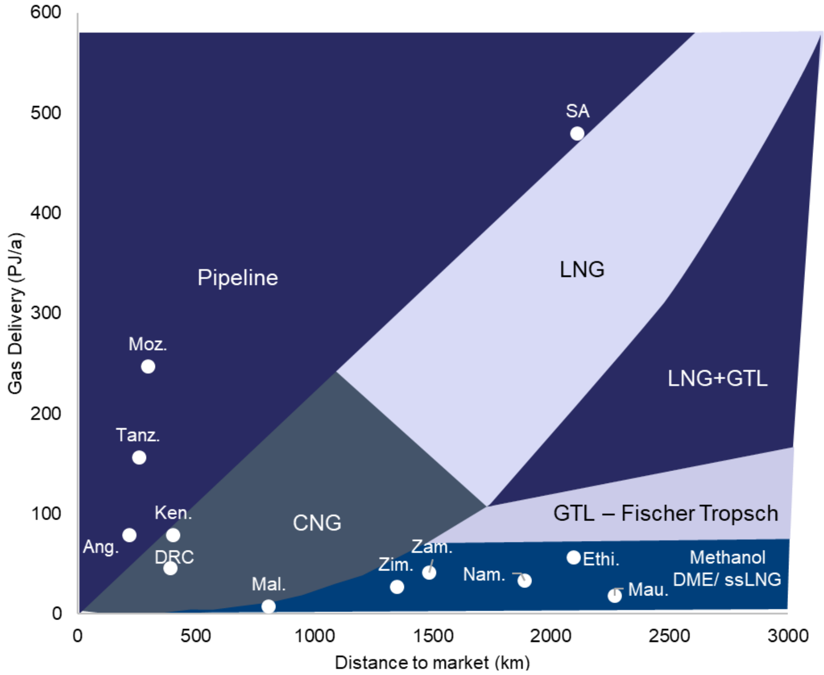
Country	Project Name	Project Type	Status	New/ Existing	Gas Input [PJ]	Value ($m)	End date	Companies [Role] {Country} (Share)
	Industrial Free Zone, Tete							• International Finance Corporation (IFC) [Sponsor] (13) {United States} • Baobab Resources [Sponsor](87) • Government of Mozambique [Sponsor] {Mozambique}
Mozambique	Iron and Steel Factory - Phase II, Rovubue Industrial Free Zone, Tete	Iron and Steel	At planning stage	New	6.2	TBC	TBC	• ABB Group [Feasibility] {Switzerland} • Metallurgical Corporation of China (MCC) [Feasibility] {China} • International Finance Corporation (IFC) [Sponsor] (13) {United States} • Baobab Resources [Sponsor] (87) • Government of Mozambique [Sponsor] {Mozambique}
Mozambique	Yara Fertiliser Plant, Cabo Delgado	Fertiliser	At planning stage	New	35.8	2000	TBC	• Government of Mozambique [Sponsor] {Mozambique} • Yara International ASA [Sponsor] {Norway}
Mozambique	Cabo Delgado Cement Factory, Cabo Delgado	Cement	Approved	New	0.0	120	TBC	• TBC
Mozambique	Limak Holdings Cement Plant - Phase II, Maputo	Cement	At planning stage	New	4.9	100	TBC	• Limak Holdings [Operator] {Turkey}
Zambia	Chilanga Cement Plant, Lusaka	Cement	At planning stage	New	5.3	420	TBC	• Dangote Group [Operator]{Nigeria} • Sinoma International Engineering Co.,Ltd [Construction] {China}
Tanzania	Kilwa Fertiliser Plant, Lindi	Fertiliser	At planning stage	New	53.8	1920	TBC	• Tanzania Petroleum Development Corporation (TPDC) [Sponsor] {Tanzania} • Ferrostaal Industrial Projects [Sponsor] {Germany} • Haldor Topsoe [Sponsor] {Denmark}

Country	Project Name	Project Type	Status	New/ Existing	Gas Input [PJ]	Value ($m)	End date	Companies [Role] {Country} (Share)
								• Fauji Fertiliser Company Energy Limited [Sponsor] {Pakistan}
Tanzania	Sinoma and Hengya Cement Plant, Mkinga, Tanga	Cement	At planning stage	New	8.8	1000	TBC	• Sinoma International Engineering Co.,Ltd [Sponsor] {China} • Hengyuan International Engineering Group [Sponsor] {China}
South Africa	Clinker and Cement Production Facility, Dwaalboom, Limpopo	Cement	At planning stage	New	3.8	265	TBC	• Sephaku Cement [Sponsor] {South Africa} • Africa Geo-Environmental Services [Consultant/Project Management] {South Africa}
Mozambique	Shell GTL, Cabo Delgado	GTL		New	141.7	TBC	TBC	• TBC
Zimbabwe	Lafarge Cement Plant	Cement	Feasibility studies/EIA underway	New	0.0	300	TBC	• Lafarge S.A. [Operator] {France}
Angola	Secil Lobito Cement Plant, Benguela	Cement	At planning stage	New	0.0	187	TBC	• Government of Angola [Sponsor] (49) {Angola} • Secil Group [Sponsor] (51) {Portugal}
Zimbabwe	Dangote Cement Plant	Cement	At planning stage	New	1.7	400	TBC	• Dangote Group [Operator] {Nigeria}
Angola	Soyo Fertiliser Factory, Zaire	Fertiliser	Announced	New	25.1	2000	TBC	• Haldor Topsoe [Sponsor] {Denmark}
Congo (DRC)	Nyumba Ya Akiba Cement Plant, Bas-Congo	Cement	Completed	New	1.4	270	TBC	• TBC
Zimbabwe	Lafarge Cement Plant	Cement	Feasibility studies/EIA underway	New	0.0	300	TBC	• Lafarge S.A. [Operator] {France}

Country	Project Name	Project Type	Status	New/ Existing	Gas Input [PJ]	Value ($m)	End date	Companies [Role] {Country} (Share)
Kenya	Nooleleshuani Cement Plant, Kajiado	Cement	At planning stage	New	0.0	TBC	TBC	• East African Portland Cement Company [Operator] {Kenya}
Kenya	Pokot Cement Factory, West Pokot	Cement	Under construction	New	1.4	151	TBC	• Sanghi Group [Operator] {India} • China Investment Trustee International Corporation China (CITIC) [Construction] {China}
Zambia	Chilanga Cement Plant, Lusaka	Cement	At planning stage	New	1.7	420	TBC	• Dangote Group [Operator] {Nigeria} • Sinoma International Engineering Co.,Ltd [Construction] {China}
Zimbabwe	Dangote Cement Plant	Cement	At planning stage	New	1.7	400	TBC	• Dangote Group [Operator] {Nigeria}
Kenya	Mombasa Cement Vipingo Factory Expansion, Kilifi	Cement	At planning stage	New	2.5	73	TBC	• Mombasa Cement Limited [Operator] {Kenya}
Kenya	Mariakani Cement Plant, Kilifi	Cement	Project finance closure	New	865.2	290	TBC	• Devki Steel Mills [Sponsor] {Kenya} • International Finance Corporation (IFC) [Financier] {United States}
Angola	Secil Lobito Cement Plant, Benguela	Cement	At planning stage	New	1.4	187	TBC	• Government of Angola [Sponsor] (49) {Angola} • Secil Group [Sponsor] (51) {Portugal}
Angola	Soyo Fertiliser Factory, Zaire	Fertiliser	Announced	New	25.1	2000	TBC	• Haldor Topsoe [Sponsor] {Denmark}

APPENDIX G: INFRASTRUCTURE DEVELOPMENT PATHWAY

Figure G1.1[274] below shows the appropriate technologies required to satisfy gas demand based on the distance of the market from the gas field and the scale of the market. In Mozambique, Tanzania, and Angola natural gas pipeline would be appropriate to satisfy gas demand, due existing in-country gas fields. While in satisfying South Africa's gas demand, a pipeline and LNG are both competitive. Due to the low scale of gas demand, ssLNG would be the appropriate technology to satisfy the other prioritised countries gas demand.



G1.1: Market Infrastructure requirements to satisfy country demand. Based on gas demand in 2050.

[274] US AID, 2018. Power Africa Gas Roadmap to 2030.