KNOWLEDGE MANAGEMENT AND INNOVATION (KMI) UNIT

NATURAL GAS BRIEFING PAPER

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Table of Contents

Table of Figures

Table of Tables

Abbreviations and Acronyms

bcm Billion cubic metres. 1bcm gas = 0.72 million tons LNG= 0.0353tcf = 37.3PJ

Btu British thermal unit, a traditional unit of work equal to about 1055 joules

CBM Coal Bed Methane

CCGT Closed (or Combined) cycle gas turbine

OCGT Open Cycle Gas Turbine

CNG Compressed Natural Gas

DoE Department of Energy

EIA (US) Energy Information Agency (or Environmental Impact Assessment)

FSRU Floating Storage and Regasification Unit

GHG Greenhouse Gases

GJ Gigajoules, one billion Joules [10^9J] equivalent to 278 kWh

CMG Companhia Limitada de Gasoduto

GTL Gas to Liquids

GPP Gas to Power Programme

GUMP Gas Utilisation Master Plan

HH Henry Hub natural gas trading marker price for the United States of America

IEP Integrated Energy Plan

iGAS Subsidiary of Central Energy Fund responsible for gas infrastructure development

IPP Independent Power Producer

IRP Integrated Resource Plan

JKM Japan Korea Marker – natural gas trading marker price for Asia

LNG Liquefied Natural Gas

mmBtu million British Thermal Units – a unit of energy used internationally for pricing natural gas as in US$/mmBtu.

Mtpa Million tons per annum

MW Megawatt

NBP Natural Balance Point – natural gas trading marker price for UK/Europe

NDP National Development Plan

NERSA National Energy Regulator of South Africa

NG Natural Gas

PJ Petajoule, one million billion Joules 10^{15}J equivalent to 278 MWh

PPA Power Purchase Agreement

ROMPCO Republic of Mozambique Pipeline Company

SNG Synthetic Natural Gas

tcf Trillion cubic feet = 28.3bcm = 1.054PJ

tcm Trillion cubic metres = 724.9 million ton LNG = 35.3tcf = 37.239PJ

1 INTRODUCTION

Natural gas contributes approximately 3.6% of South Africa's primary energy mix at present but a combination of domestic, regional and global factors favoring a greater role for gas is presently unfolding. In pursuit of adding generating capacity, lowering carbon emissions, enhancing energy security and supporting industrial development, South Africa has taken the first steps in a gas to power programme to be executed under the Independent Power Producer programme. Southern Africa's gas potential has been revealed by major discoveries that, when developed, widen options for greater regional energy trade. South Africa's unconventional gas potential remains to be quantified but raises the prospect of possible domestic production in the longer term. Globally the natural gas industry has moved into a supply surplus, favoring a larger role for gas as a clean fossil fuel in many countries' energy policies.

In the lead up to the start of the gas to power programme the Bank has the opportunity to prepare its teams and committees with a knowledge base needed to appraise opportunities as the programme unfolds in the future. The purpose of this report is to provide an overview of natural gas and background to the gas to power programme. It is structured in three parts:

First, an introduction to natural gas sources and uses covering the gas value chain and environmental characteristics.

Second, trends in the global natural gas industry covering liquefied natural gas with a focus on impact on South Africa

Third, a status report on the current state of production, upstream activity and consumption, followed by a summary of the regulatory framework under which gas development takes places and concluding with a background to the gas to power programme.

Information in this report is current as at end September 2016. It is intended that this briefing paper be updated as new information becomes available in order to retain its value as an internal reference source on natural gas for DBSA staff.

2 NATURAL GAS SOURCES AND USES

2.1 COMPOSITION AND ORIGIN OF NATURAL GAS

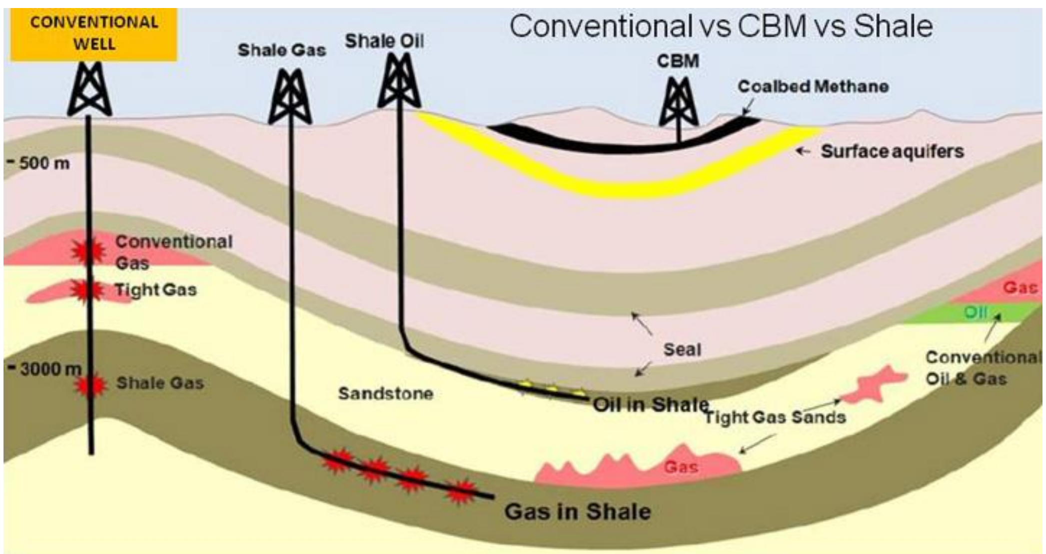
Natural gas is a combustible gas consisting mainly of methane along with varying quantities of other higher alkanes, particularly ethane, propane and butane, plus small quantities of nitrogen, carbon dioxide, hydrogen sulfide and occasionally noble gases. Reserves that are almost pure methane are called 'dry' while those with other hydrocarbons that are present in natural gas are referred to as 'wet'.

As a naturally occurring fossil fuel the composition of natural gas varies from deposit to deposit and it therefore has to undergo processing to produce a consistent quality saleable gas with a constant energy value. Natural gas refineries may produce separate alkane streams in their product slates.

Organic matter is converted to form natural gas in broadly the same ways that the other principle fossil fuels, namely oil and coal, have been formed in the earth's crust. Great heat and compression break down the carbon bonds in organic material over a long time via a thermogenic process to create fossil fuels. Gas associated with oil is typical in shallower deposits while gas only deposits tend to be deeper. Biogenic methane is produced by methanogenic microorganisms found in animal intestines and in landfills. In the latter case it can be tapped to supply natural gas. The eThekwini landfill gas to electricity project was the first such application in South Africa.

2.2 SOURCES OF NATURAL GAS

Natural gas' low density means it rises and will tend to seep into the atmosphere unless trapped to become a natural gas reserve. Gas that becomes trapped by impermeable layers of rock to create a gas reservoir, with or without oil which may be extracted by drilling and is referred to as conventional gas. Unconventional gas is tightly bound to underground rocks, sand or coal or trapped in porous rocks and requires different extraction methods. Advances in technology shift the boundary between conventional and unconventional extraction methods so this distinction should not be regarded as rigid. Principle extraction methods are shown in Figure 1, and each will be briefly discussed in turn.



Source: EIA

Figure 1 Sources of natural gas

2.2.1 Conventional gas

Conventional gas reservoirs

All natural gas formed underground is produced through the interaction of layered depositions of sedimentary rock and geological processes involving igneous rock intrusions and/or faulting to create the conditions for oil and gas formation by trapping organic materials. Typical oil and gas reserves are found in porous sedimentary rock that is overlain with impermeable rock which thereby creates a dome trapping a reservoir underneath. Gas in these reservoirs is typically under pressure, so it can be extracted by allowing it to escape from the reservoir on its own through wells drilled through the impermeable rock. Such oil and gas deposits are exploited both on and off-shore.

2.2.2 Unconventional gas resources

Unconventional gas is not free flowing under its own pressure so the extraction methods applied all involve greater cost to access the resources. Major technical advances in gas drilling and chemistry for liberating tightly bound gas have dramatically changed the economics of natural gas production and converted previously uneconomic gas resources (meaning gas is geologically present) into viable economic gas reserves (meaning the resource can be economically extracted at the prevailing price and state of technology).

Tight gas and shale gas

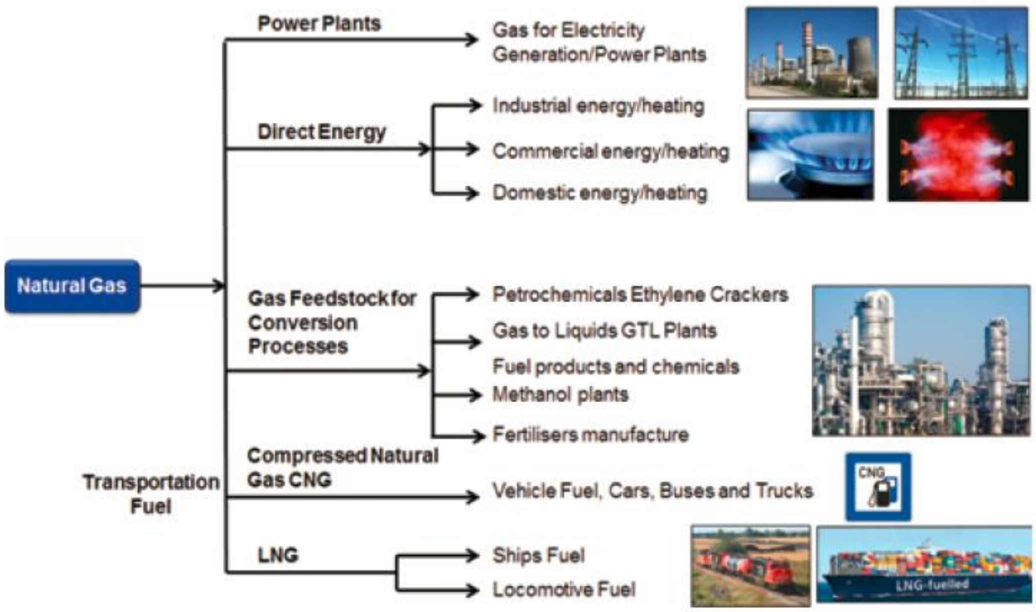
Tight gas is not free to flow because it is natural gas locked in tight formation underground, trapped in impermeable, hard rock, tight sand or limestone formation that is unusually impermeable and non-porous. Extraction requires action to liberate the gas by fracturing or chemically treating the rock. Similarly, shale gas is locked in fine grained shale deposits typically found in narrow seams and must be fractured to create channels for the gas to flow through. Hydraulic fracturing is used for this purpose which involves pumping water and chemicals under high pressure to facture the gas containing rock layers and so liberate the gas.

Coalbed methane

Methane trapped in coal seams can be converted from being a hazard to coal miners – it is a serious explosion and fire risk – into a useful source of natural gas by drilling wells into coal seams and collecting the gas released by reducing pressure on the coal.

2.3 Uses of natural gas

The main use of natural gas is in combustion to generate electricity, where it's clean burning characteristics make it environmentally advantageous compared to other fossil fuels, along with industrial, commercial or domestic applications. Natural gas is also used as a transport fuel for fleet vehicles in the form of compressed natural gas (CNG) or liquefied natural gas (LNG). Natural gas also has a large role as a chemical feedstock for the petrochemical industry where it undergoes conversion of gas to liquids (for transport fuels in particular) or used in the production of a wide range of basic chemicals and fertiliser. These applications are depicted in Figure 2.



Source: Transnet LTPF 2015

Figure 2 Uses of natural gas

2.3.1 Gas to electricity in power plants

Combustion in power plants is the main application of natural gas world-wide. There are two types of gas-fired power plants, namely open-cycle gas turbine (OCGT) plants and combined-cycle gas turbine (CCGT) plants. The construction lead time for gas power plants capital costs are shorter and lower than for coal fired generation equivalents but their fuel costs are higher.

OCGT plants consist of a single compressor/gas turbine that is connected to an electricity generator via a shaft. They are used to meet peak-load demand and offer moderate electrical efficiency of between 35% and 42% (lower heating value, LHV) at full load.

CCGT plants are dominant gas-based technology for intermediate and base-load power generation. CCGT plants have basic components that are the same as the OCGT plants but the heat associated to the gas turbine exhaust is used in a heat recovery steam generator (HRSG) to produce steam that drives a steam turbine and generates additional electric power, therefore achieving higher efficiency rates of 52–60% (LHV), albeit with higher capital costs. The proliferation of CCGT plants is due to their flexible operation characteristics. They are designed to respond relatively quickly to changes in electricity demand and may be operated at 50% of the nominal capacity with only a moderate reduction of electrical efficiency (50–52% at 50% load compared to 58–59% at full load).

Gas turbine technology is mature but still undergoing active development into later generation turbines with higher efficiencies and larger outputs for power plants as well as compaction for small power applications and vehicles.

2.3.2 Direct energy

Natural gas has numerous direct applications in industrial, commercial and domestic applications for energy and heating uses. Examples of industrial applications are process heating for steel making, glass making and food processing. Heating ventilation and cooling is a major application for gas in the commercial and domestic sectors particularly in colder regions of North America, Europe and Asia, aided by an installed distribution network.

2.3.3 Chemical feedstock

Natural gas is highly amenable to chemical conversion so it is widely used as a feedstock in gas to liquids plants, for example Mosgas SOC, and in petrochemical plants to produce methanol, ammonia for fertilisers and in the production of pharmaceutical products.

2.3.4 Transport fuel

High utilization vehicles such as buses and freight trucks are candidates for LNG or CNG fuel where there are both distribution facilities for vehicles and emissions controls to encourage their adoption. Gas fueled fleets are common in California and coastal regions of China. The City of Tshwane's A Re Yeng BRT is the first bus fleet to use CNG in Africa. CNG Holdings is trialing CNG for minibus taxis and commercial vehicles from refueling stations in Johannesburg.

2.4 Natural gas transport

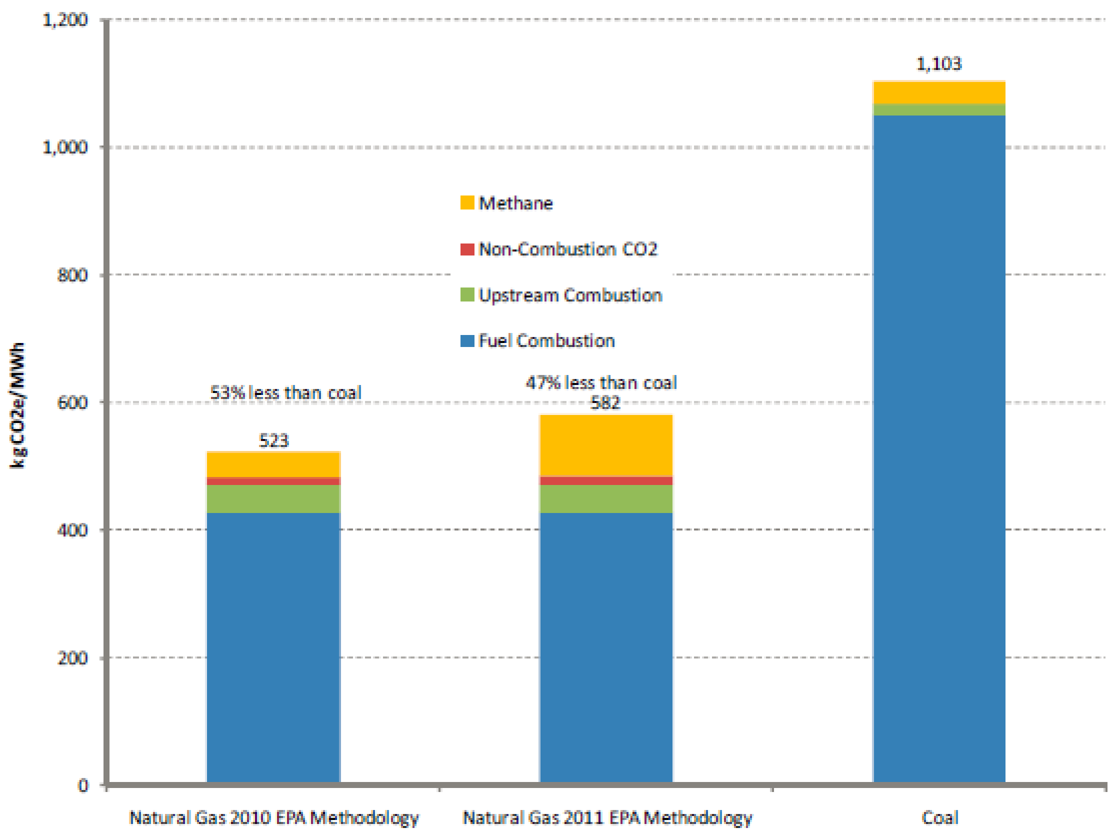
Between the natural gas wellhead and the final customer a transport system is required to purify, store, transport and distribute gas. The principle physical facilities and processes involve the following features, summarised from the US Energy Information Administration.

- Gathering Lines – These small-diameter pipelines move natural gas from the wellhead to the natural gas processing plant or to an interconnection with a larger mainline pipeline.
- Processing Plant – This operation extracts natural gas liquids and impurities from the natural gas stream in preparation for transport.
- Pipeline transmission Systems – These wide-diameter, long-distance pipelines with compressor stations at intervals transport natural gas at high pressure from the producing area to market areas.
- LNG liquefaction/regasification - Involves cooling gas to around −162° and purifying it which increases its energy density to approximately 70% that of petrol, making storage transport by vessels or land tankers economical for gas resources beyond pipeline distances to market (3000km is an upper limit). LNG needs to be regasified to feed into distribution networks.
- Market Hubs/Centers – Locations where pipelines intersect and flows are transferred.
- Underground Storage Facilities – Natural gas is stored in depleted oil and gas reservoirs, aquifers, and salt caverns for future use.
- Distribution transmission systems – Small diameter pipes and lower pressure to customer premises. A gas odorant is added prior to distribution for safety.
- Peak Shaving – System design methodology permitting a natural gas pipeline to meet short-term surges in customer demands with minimal infrastructure. Peaks can be handled by using gas from storage, injecting LNG or by increasing pipeline gas pressure, referred to as line packing.

2.5 Environmental Impacts

Natural gas is efficient, relatively clean burning fossil fuel but the environmental consequences of gas use need to take into account production and distribution impacts as well. Burning natural gas for energy results in fewer emissions of nearly all types of air pollutants per unit of heat produced than coal. Specifically, 43% less carbon dioxide and 99% or less carbon monoxide, nitrogen oxides, sulfur dioxide and ash particulates (EIA – Natural Gas Issues and Trends 1998). This is why gas, albeit a fossil fuel, is seen as a key transition fuel towards a low carbon energy future. Simply comparing the combustion characteristics of gas to other fossil fuels is insufficient to assess the environmental impacts. Carbon dioxide stays in the atmosphere for more than 500 years whereas methane degrades after 12 years, yet its contribution to greenhouse gas insulation per molecule is about 25 times greater.

The correct way to assess the environmental impacts of natural gas compared to other energy carriers is to use a life cycle approach taking into account production, processing, transmission/ storage and combustion/ use. An extensive literature on lifecycle impacts of fuel types is developing, along with improved measurements of fugitive emissions (emissions of gases or vapors from pressurized equipment due to leaks and other unintended or irregular releases of gases). A study by Deutsche Bank, 2011 contrasting natural gas and coal found that in terms of GHG emissions per megawatt-hour of electricity generated from both fuels, after taking into account upward revisions to the carbon dioxide equivalent impact of fugitive emissions made by the EPA in 2011. Gas is 582 kg CO2e/MWh and coal 1,103 kg CO2e/MWh therefore natural gas-fired electricity has 47 percent lower lifecycle GHG emissions per unit of electricity than coal-fired electricity (see Figure 3).



Source: Deutsche Bank 2011

Figure 3 Electric generation natural gas vs coal life cycle GHG burden (kg CO2e/MWh)

In 2013 the US EPA revised the estimate of methane leaks out of the North American natural gas and oil supply chain upwards by 30% (Economist 23 July 2016). Methane emission containment is critical if the environmental advantages of gas over coal are to hold over the full lifecycle. South Africa should be careful to minimize fugitive emissions if a larger role for gas in the energy mix is to significantly reduce environmental impacts of fossil fuels.

2.6 ENERGY EFFICIENCY

Direct use of gas for heating or cooling achieves the highest application of available energy, up to 92% compared to converting it first to electricity where only 32% of usable energy is maintained, states the American Gas Association.

Table 1 Available energy maintained by direct use of gas compared to conversion to electricity

	Source Energy	Extraction, Processing, Transport	Generation	Distribution	Delivered to Customer
Direct use of natural gas	100 MMBtu gas	7% loss 93 MMBtu	N/A	1% loss 92 MMBtu	92 MMBtu
Conversion of fossil fuel to electricity	100 MMBtu coal or gas	5% loss 95 MMBtu	64% loss 34 MMBtu	6% loss 32 MMBtu	32 MMBtu

Source: American Gas Association 2016 based on 2009 actual generation mix of all energy sources

Greater use of gas in South Africa's energy mix will contribute to improving yields from primary energy supplies but the overall impact will be blunted by the gas to power path the country necessarily needs to follow. Promoting natural gas in the medium to longer term will make fuel switching from coal, electricity or diesel possible for industrial and commercial customers and will yield higher energy efficiencies for South Africa. Energy efficiency is a key objective for the development of South Africa's gas industry and consequently requires infrastructure options to bring substantial new gas supplies to the economic hub of the Gauteng City Region.

3 GLOBAL NATURAL GAS INDUSTRY

3.1 2015 PRODUCTION AND CONSUMPTION DATA

Total world production was 3538.6 billion cubic meters (excluding flared gas and GTL production) while total world consumption was 3468.6 billion cubic meters. Natural gas provided 23.8% of the world's primary energy consumed by fuel type, after oil (32.9%) and coal (29.2%). 2015 consumption rose by 1.7%, below the 10 year average rate of 2.3%. Over half of global consumption takes place outside of the OECD countries with strong growth in Iran and China. Among OECD countries consumption rose 3% in the US and 4.6% in the EU. All data referred to in this section are drawn from the BP Statistical Review of World Energy June 2016.

A snapshot of global production and consumption for 2015 shows Europe and Eurasia, the largest consumption region at 28.8% of the world total and similarly sized North America region plus the much smaller South and Central American region roughly balanced regional production and consumption. The Middle East and Africa are net exporters and the Asia Pacific region a net importer. Africa produced 6% of world production and consumed 3.9% of gas used. Africa's largest producers are Algeria, Nigeria and Egypt but Nigeria is not a major consumer. South Africa consumed 5 Bcm of natural gas in 2015, a mere 0.1% of global consumption (see Table 2).

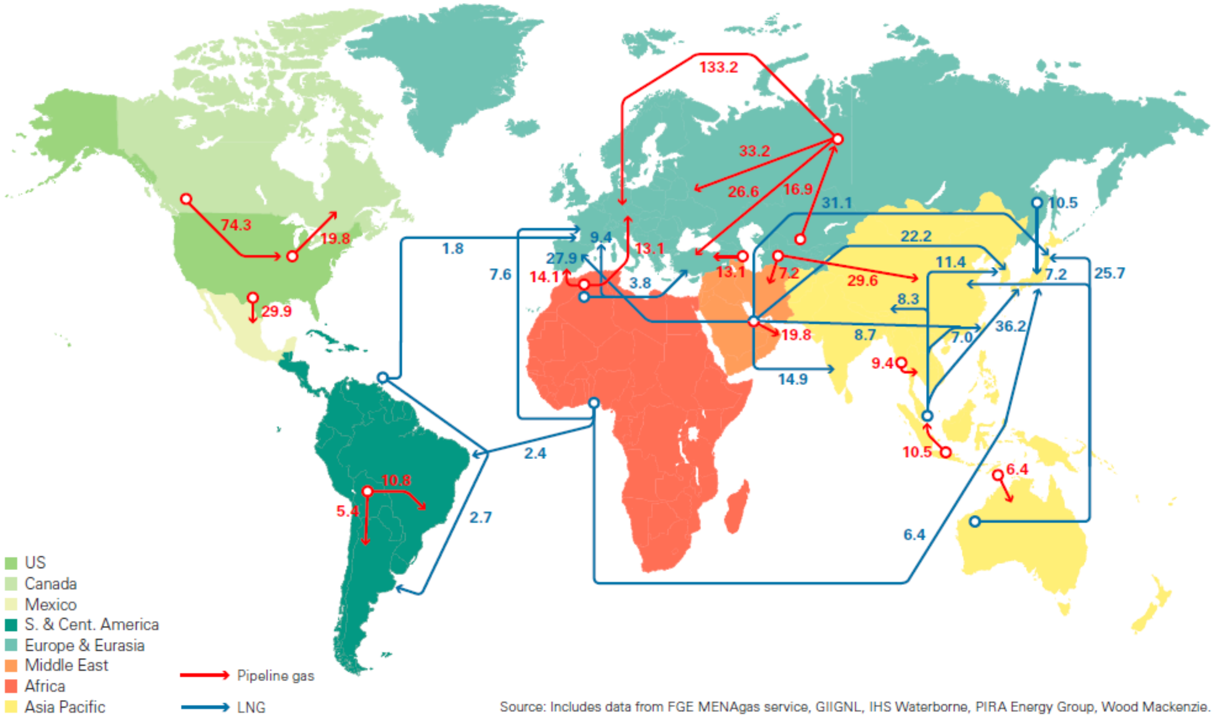
Table 2 Production and consumption of natural gas by region 2015 Bcm

Production			**Consumption**		
Region	**2015**	**2015 share of total**	**2015**	**2015 share of total**	**Region**
North America	984.0	28.10%	963.6	28.10%	North America
S. & Cent. America	178.5	5.00%	174.8	5.00%	S. & Cent. America
Europe & Eurasia	989.8	27.80%	1 003.5	28.80%	Europe & Eurasia
Middle East	617.9	17.40%	490.2	14.10%	Middle East
Algeria	83.0	2.30%	39.0	1.10%	*Algeria*
Egypt	45.6	1.30%	47.8	1.40%	*Egypt*
Libya	12.8	0.40%			
Nigeria	50.1	1.40%			
			5.0	0.10%	*South Africa*
Other Africa	20.4	0.60%	43.6	1.30%	*Other Africa*
Africa	211.8	6.00%	135.5	3.90%	Africa
Total Asia Pacific	556.7	15.70%	701.1	20.10%	Total Asia Pacific
Total World	3538.6	100.00%	3468.6	100.00%	Total World

Source: BP Energy Statistics 2015

3.2 WORLD TRADE IN NATURAL GAS

Pipeline trade moved 704.1 Bcm and LNG 338.3 Bcm of natural gas in 2015, 20.3% and 9.7% of consumption respectively i.e. 30.1% of gas consumed moved through international trade. As depicted in Figure 4, pipeline networks are significant carriers in North America and Eurasia whereas exports from the Middle East and Africa are predominantly by LNG, as are imports to the Asia Pacific region. Transport costs by pipeline are viable for distances of up to 3000 km as a rule of thumb. Monetising gas reserves in Southern Africa will require developing LNG transport facilities to markets for their development.



Source: BP Energy Statistics 2015

Figure 4 Principle gas trade movemements by pipeline and LNG, 2015

3.3 Natural Gas Reserves

Proven reserves of natural gas have risen over the last 20 years by 55% to reach 186.9 trillion cubic meters in 2015, sufficient to meet 53 years of current production. The Middle East holds 42.8% of reserves, Europe and Eurasia 30.4%. Africa holds 7.5% of proven global reserves with Nigeria and Algeria dominating the continent with shares of 2.7% and 2.4% respectively. Africa is relatively under explored for oil and gas so the continent's share of reserves can be expected to grow as the Southern African gas resources are confirmed over time. This is the subject of a separate Southern Africa paper.

Unconventional gas resources are included in the above proven reserves where they are being exploited, particularly in the USA. Globally, unconventional gas resources are far greater than conventional resources, thus a conservative estimate of recoverable reserves from unconventional sources greatly extends the time to depletion of natural gas as a fossil fuel.

3.4 Natural Gas Prices

Transport costs drive the prices of natural gas due to the distances between sources of supply and end markets. LNG economics differ from piped gas due to the material costs involved in liquefaction and shipping. Trading and pricing of natural gas has therefore evolved a number of key marker prices in different geographic markets. Prices shown in Figure 5 (including cost, insurance and freight) are the following:

LNG LNG imports to Japan (cif). Alternatively refer to the Platts Japan Korea Marker (JKM) for the Asian marker as those two countries are the largest LNG importers in Asia.

Germ Gas Pipleline gas from Russia/ Eurasia imported to Germany

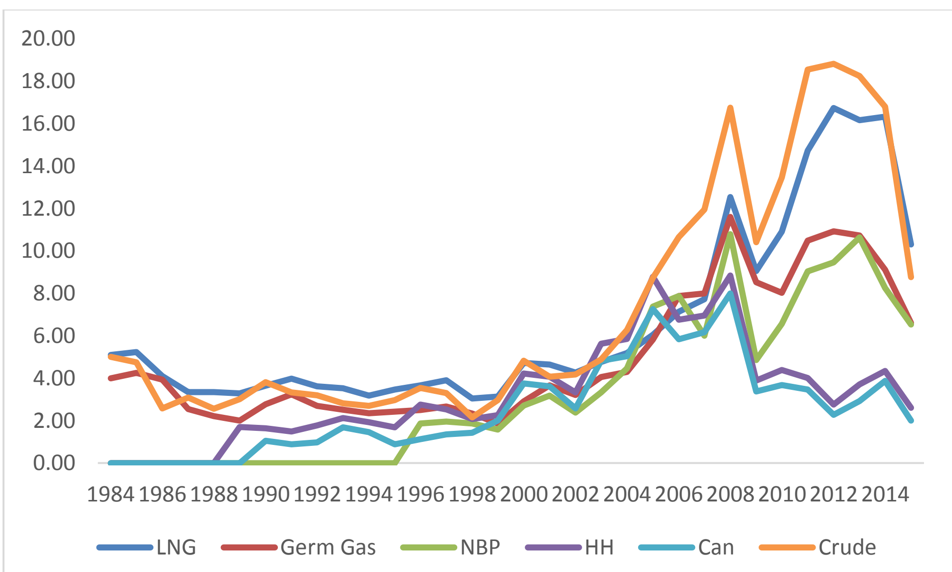
NBP Pipeline gas at the UK National Balancing Point for the UK/West European market

HH Henry Hub North America pipeline gas delivery point for futures contracts traded on the New York Mercantile Exchange

Can Pipeline gas exports from Canada

Crude OECD average crude oil price

Over a thirty year period the data indicate that new pricing paradigm for gas has developed post the 2009 financial crisis. North American and European gas prices moved in step with LNG to Japan and crude oil prices from the 1990s through to the spike in 2008. From 2009 onwards there has been a structural shift in the global gas market. North American prices reflect impact of the ramp up in production from unconventional sources, European gas prices are delinking from oil prices and there is a convergence trend in European gas hub prices and Asian LNG. By mid-2016 NBP and JKM spot prices converged. (BMI Global Industry Overview - Oil & Gas Mid-Year Update: Key Themes for 2016 23 Jun 2016). In response to these shifts the bargaining power of LNG importers has strengthened resulting in the alterations to the terms of long term supply contracts. Fixed off take points have been relaxed, allowing importers to move cargoes to different ports in response to regional demand changes. Volumes moved through the spot market are increasing.



Source: BP Energy Statistics 2015

Figure 5 Gas and oil marker prices in US dollars per million Btu 1985 - 2015

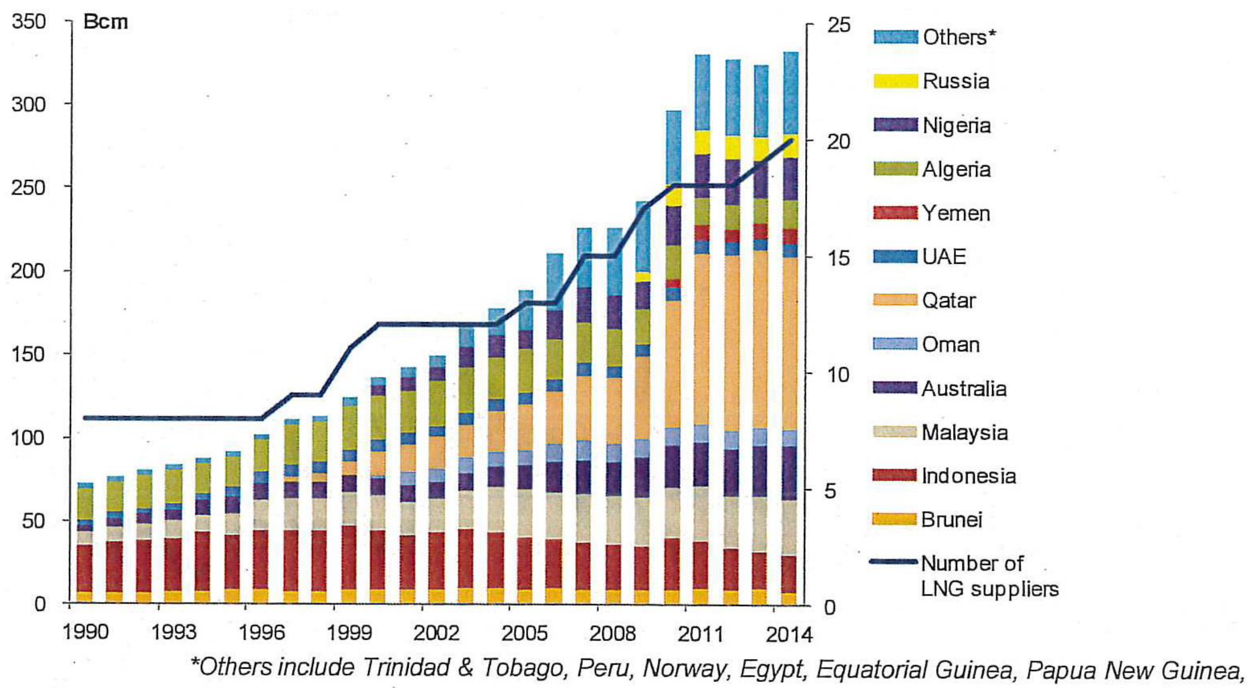
3.5 Liquefied Natural Gas

A bigger role for gas in South Africa's energy mix in the near term is inconceivable without LNG which means that an entirely new LNG industry will have to be built from scratch. As will be seen from the current production and consumption situation examined in section 4.1, future gas supplies will involve limited domestic production, pipeline imports and LNG imports. South Africa is embarking on starting a LNG industry at time when global supply favors importers. This section provides an overview of trends in the world LNG market.

The principle cost components of the LNG supply chain are:

Feed gas	Liquefaction	Shipping	Regassification and storage
32%	47%	13%	8%

Exporters have traditionally founded their supply chains on long term contracts linked to the oil price to fund the capital costs of the upstream processing. Sources of supply are diversifying as existing gas producers are expanding their LNG capacity and new gas fields will require LNG exports to bring them to account.



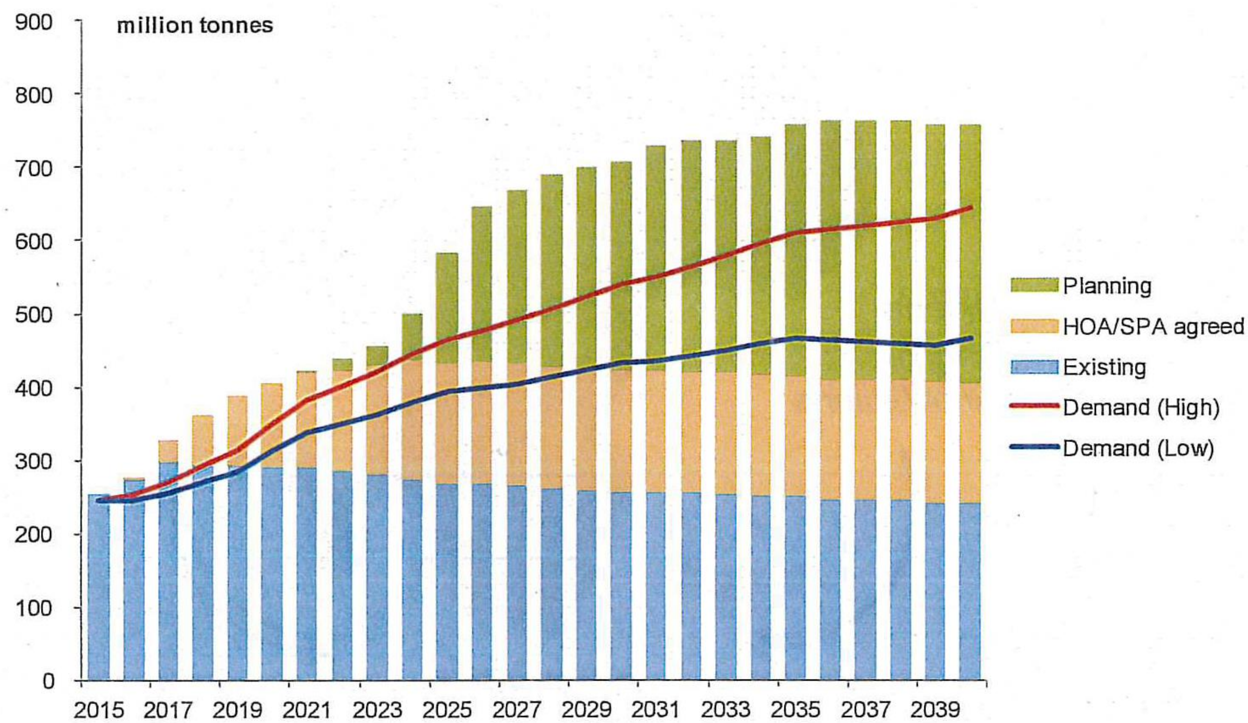
Source: BP in Kobayashi

Figure 6 Historical LNG supply countries

A growing number of countries are starting to import LNG to meet energy demand and lower carbon fossil fuel targets, however, the dominance of Northeast Asia (Japan and Korea are still over 50% of the LNG market) will continue.

The current global oversupply of LNG capacity will widen further as a number of major facilities under construction in the USA, Australia, Malaysia and other gas producing countries come on stream. Committed expansion capacity of over 120 mtpa is planned until 2018. This amount is close to 40% of existing world LNG capacity. While it is likely that some of the expansion will move out beyond 2018 and/or start at lower utilization rates, the supply overhang will contribute to the structural shifts in pricing and contracting referred to in section 3.4.

In the longer term the LNG market could treble in size with the supply surplus maintained to the mid 2020s and very likely beyond. The IEEJ maintains that forecasting LNG prices beyond 2020 is unpredictable due to the uncertainty about macro economic conditions for importing countries, the size and pace of expansion of supply capacity, price movements of energy substitutes – particularly intermittent wind for which gas is highly complementary for system balancing – and polices adopted by LNG consuming countries.



Source: IEEJ estimate

Figure 7 LNG market balance forecast to 2041

3.6 World LNG market implications for South Africa's embryonic LNG sector

South Africa is geographically well positioned to access established LNG supply routes. On the Atlantic coast imports could be sourced from Nigeria, Equatorial Guinea or Angola or from further west in the Caribbean or the USA. Indian Ocean suppliers could be sourced from Qatar, UAE or Yemen or further afield from Australia. As Southern African supplies are developed Mozambique and Tanzania will become nearby exporters. Yoshi Kobayashi from the IEEJ cautioned at a recent symposium on LNG that South Africa should not expect to contract LNG supplies at low prices by virtue of the global supply balance because its embryonic sector will be entering the market at very small volumes and would probably settle on prices at parity with imported pipeline gas.

Commenting on DoE plans to establish an FSRU as a starting point to launch LNG imports Mr. Kobayashi observed that this is a well established route to developing LNG import facilities that are scaled up to onshore facilities as LNG demand grows, recent country examples being Egypt and Jordan. Fleet utilization of FRSU vessels is currently low which confers a charter cost advantage for South African projects, at least in the short term.

4 SOUTH AFRICA'S NATURAL GAS INDUSTRY

Coal has been, and continues to be the dominant energy source for the South African economy. Gas has historically played a minor role. Nineteenth century coke gas plants supplied Cape Town, Port Elizabeth, Kimberly and Johannesburg. Today only Egoli Gas in Johannesburg supplies piped gas sourced from Sasol within a city to residential consumers. In the 1960s off shore gas exploration located gas deposits off the Southern Cape coast. Sasol started production of synthetic gas from coal in 1955 for conversion into liquid fuel and chemicals and has sold pipeline gas from 1964 onwards. Mossgas (later PetroSA) was started for strategic reasons to counter the oil embargo against South Africa using natural gas from the Bredasdorp basin to feed a GTL plant that went into production in 1992. The original fields are now depleted and reserve replacement exploration efforts (Project Ikhwezi) have failed so the plant is feedstock starved and runs below capacity. In 2004 gas from the Pande and Temane gas fields in Mozambique started to flow through an 865 km pipeline to Sasol's Secunda plants for feedstock and pipeline supply to Sasol Gas customers in Gauteng. In 2015, natural gas made up some 3.6% of South Africa's primary energy consumption. Compared to world fuel shares shown in Table 3, South Africa is significantly under served by gas and over reliant on coal.

Table 3 South Africa's primary energy consumption by fuel type 2015

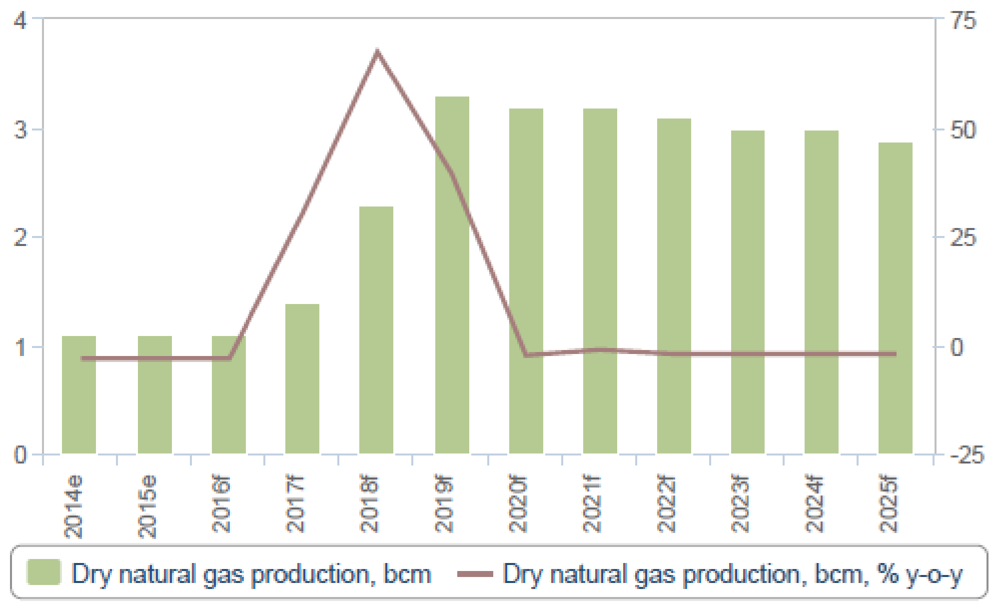
Metric	Oil	Natural Gas	Coal	Nuclear Energy	Hydro electric	Renew-ables	Total
Million tons oil equivalent	31.1	4.5	85.0	2.4	0.2	1.0	124.2
SA fuel share %	25.0%	3.6%	68.4%	2.0%	0.2%	0.8%	100.0%
World fuel share %	32.9%	23.8%	29.2%	4.4%	6.8%	2.8%	100.0%

Source: BP Energy Statistics 2015

4.1 CURRENT STATE OF THE GAS INDUSTRY

4.1.1 Domestic production

South Africa's gas production was estimated at 1.1bcm in 2015, mostly drawn from the maturing offshore F-A and South Complex fields and fed the Mossgas GTL plant. South Africa's current reserves are 27.7bcm. PetroSA is proceeding to develop the F-0 field (Project Ikhwezi) which has thus far only yielded only 10% of the expected recoverable resources. Prospective areas in the Southern Cape could have resources of up to 85bcm which would extend the life of Mossgas. The Ibhubesi gas field near Namibia has confirmed proven reserves of 5.95bcm. Monetisation of Ibhubesi is proceeding via a gas sales agreement with Eskom to convert the Ankerlig power station in Atlantis from diesel to natural gas. This will require the construction of a pipeline traversing the west coast with supply slated for commencement in 2018. BMI forecasts of production expect South African gas to peak at 3.3bcm in 2019, before declining gradually to 2.9bcm by 2025 (see Figure 8).



Source: BMI

Figure 8 Gas production forecast 2014 - 2025

4.1.2 Upstream activities

South Africa's oil and gas resources, suggested by its geology, are a potential for substantial offshore conventional oil and gas and unconventional onshore shale and CBM. Exploration interest is, however, muted due to challenging deepwater high cost and high risk conditions, low oil prices and regulatory uncertainty.

A separate regulatory framework for oil and gas has been proposed which necessitates splitting oil and gas legislation from the Mineral and Petroleum Resources Development Act (MPRDA). This process has not been smooth, with early indications of excessive government discretionary powers fueling regulatory uncertainty.

The Petroleum Agency of South Africa has licensed over 20 offshore blocks for exploration, granted onshore rights, mostly for CBM, and has a number of applications under evaluation (see a petroleum exploration map in Appendix 2). A number of international majors are involved in offshore exploration but are moving slowly due to the factors cited above.

4.1.2.1 Unconventional shale

Fracking in the Karoo has elicited a public debate that has generated more heat than light. Attention turned to potential of South African shale gas when in the EIA estimates there were 11tcm of reserves in the Karoo which raised the specter – in a context of economic growth severely constrained by power shortages - of South Africa emulating the US shale gas revolution turning natural gas to a game changer for the country. Fundamental geological work is required to understand this reserve argues respected geologist Maarten de Wit (2016). No production from this resource can be expected for at least another decade for the following reasons.

- Resource estimation models remain highly uncertain. June 2016 estimates by the US Geological Survey estimated undiscovered, technically recoverable mean resource of 33.5 tcf (1.246 tcm) of shale gas in the Karoo Province (USGS 2016-3038).
- Regulatory uncertainty due to the incomplete revision to the MPRDA and continued political risk linked to terms for exploration companies.
- Lack of infrastructure increases costs and lead time to monetise the gas.
- Lack of major foreign participation means that the exploration work is being conducted by companies with more limited capacity.
- Water scarcity, a potentially fatal flaw for highly water-intensive hydraulic fracturing techniques that will be required.
- Environmental risks, the greater Karoo biome is highly sensitive which will require extensive mitigation measures.
- Weak commodity price outlook directs attention of upstream oil and gas companies to more prospective areas elsewhere in Southern Africa.

BMI notes that Royal Dutch Shell pulled back from its plans for shale gas exploration in South Africa in 2015 and has indicated that an oil price in the range of USD60.0-80.0/bbl -coupled with significantly more attractive fiscal and licensing terms - would be needed for the company to resume its operations.

4.1.2.2 Other unconventional gas

Coal Bed Methane resources are under active development by several companies including Anglo Operations, NT Energy Africa, Molopo Exploration & Production, Badimo, Umbono Coal, Kinetiko (see Appendix 2). These developments are likely to bring small volumes of gas into production on shorter timeframes and could therefore play a beneficial role in developing the domestic gas market.

Major players like Sasol and Eskom have trailed other technologies for monetising coal deposits that are fragmented or unsuitable for conventional mining, notably underground coal gasification. Eskom has conducted a UCG pilot at Majuba. Sasol terminated UCG trials judging them unviable at the current level of technological development and prevailing resource prices.

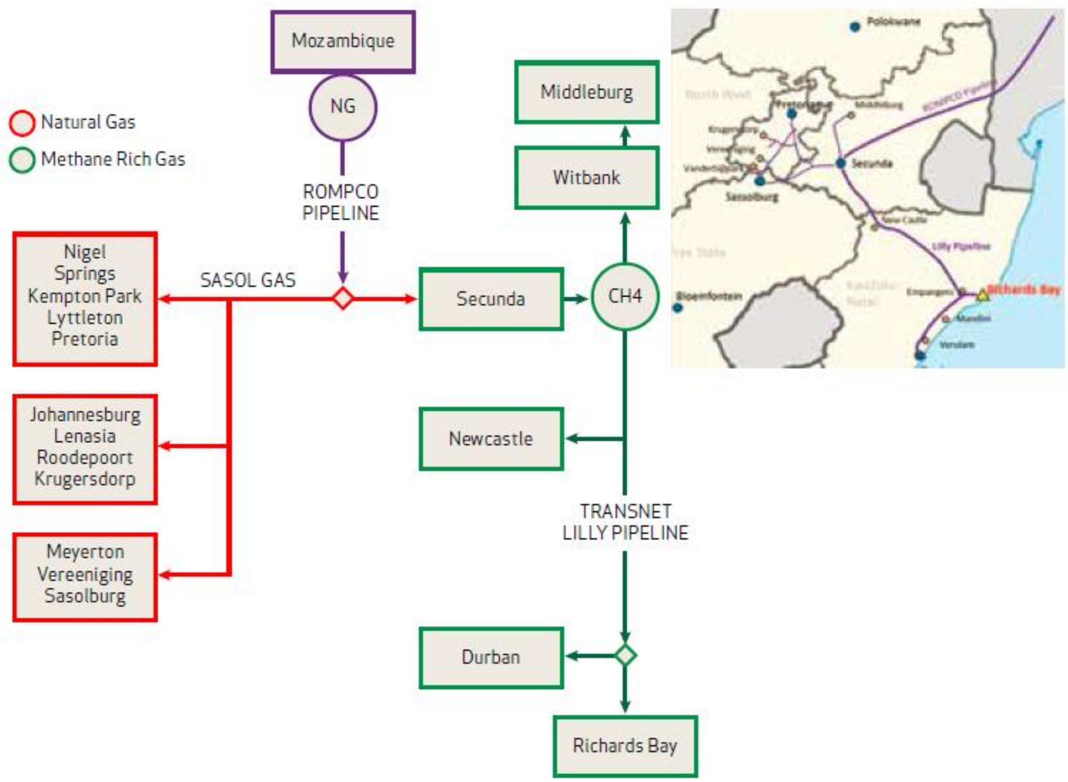
4.1.3 Gas consumption

South Africa currently consumes some 5.0 bcm of gas pa, slightly over 1.0 bcm domestic natural gas production, and 4.0bcm of imported natural gas. BMI forecasts gas consumption to increase by 54% from an estimated 5.0bcm in 2015 to 7.7bcm in 2025.

Imports are delivered by the Republic of Mozambique Pipeline Company (ROMPCO) pipeline from Mozambique to Secunda. ROMPCO is a joint venture between the national gas development companies of Mozambique and South Africa Companhia Limitada de Gasoduto (CMG), South African Gas Development Company (iGas) respectively and Sasol Gas Holdings. The ROMPCO pipeline has been upgraded to a current annual capacity of 183 PJ. 50% of this gas is supplied to Gauteng and Free State customers, 42% used in GTL/chemicals in Sasol plants and 8% supplied as methane rich gas to customers in KZN and Mpumalanga (see the Appendix 5 for Sasol gas specifications).

South Africa's main gas pipelines infrastructure comprises four parts, the first three are shown in Figure 9 (not to scale).

1. ROMPCO pipeline from Mozambique to Secunda ;
2. Transnet operated Lilly pipeline from Secunda to Richards Bay and Durban feeding methane rich gas;
3. Pipeline network from Secunda to Sasolburg and industries in Gauteng and Mpumalanga; and
4. Subsea pipeline from the southern offshore gas fields to the PetroSA GTL plant in Mossel Bay.



Source: Transnet LTPF 2015

Figure 9 Principle gas nework infrastructure

South Africa gas industry structure is highly concentrated. Only Sasol Gas and PetroSA are involved in upstream and mid-stream activities. The following companies are active in downstream activities serving commercial, industrial and retail markets: Egoli Gas, Reatile Gas, Novo Energy, Spring Lights Gas, CNG Holdings, Virtual Gas Networks. Several of these companies also distribute LPG, a market where new entrant Sunrise Energy is in the process of constructing an LPG import and storage facility at Saldanha Bay.

4.2 Gas Regulation

Natural gas regulation is governed by South Africa's energy policy framework, energy legislation and sector legislation for gas, which will be briefly summarised here. Attention is directed to proposed changes and policy issues that will influence the regulatory environment for future gas developments.

The 1998 Energy White Paper (see Appendix 3) amongst other objectives promotes diversification of South Africa's energy mix. Natural gas was recognized as an attractive option for the country, regional integration was sought and encouraged for the industry to develop, and it was also recognised that regulation was needed to deal with monopolistic supply characteristics. These principles were carried through into the gas and energy regulation Acts that followed.

The Gas Act, 2 no. 48 of 2001 (see appendix 4) set out to promote the orderly development of the piped gas industry and to establish a national regulatory framework implemented through a gas regulator. To facilitate the construction a gas pipeline from Mozambique Sasol was granted a ten year exemption from certain conditions which expired in March 2014. The Gas Regulator is now incorporated in the Energy Regulator, enacted by National Energy Regulator Act, 2004 (Act No. 40 of 2004) implemented by the National Energy Regulator of South Africa (NERSA) authority. The Energy Regulator, assisted by NERSA's secretariat, issues licenses, makes tariff decisions and performs the functions assigned in the Gas Act. The guiding framework for these functions are given by the Piped Gas Regulations 2007, Rules in terms of the Gas Act issued in 2009, Guidelines on Approving Piped-Gas Transmission and Storage Tariffs in South Africa 2009, Methodology to approve Maximum Prices for Piped-Gas in South Africa 2011, Allocation Mechanism to Sasol Gas Ltd's Transmission Pipelines dated 2012 and NERSA price determination methods and or guidelines.

Energy Regulator functions germane to this paper are licensing and infrastructure planning for construction, operation and trading of piped gas and the setting of gas tariffs and monitoring of compliance. In the absence of gas on gas competition in South Africa a transparent market price for gas does not exist, therefore the Energy Regulator generates a price for gas based either on relevant energy sources (i.e. coal, electricity, Heavy Fuel Oil, Liquefied Petroleum Gas and Diesel) or on a pass-through of costs approach. Only the maximum price is approved by the Energy Regulator (made up of gas energy price, transmission tariffs, distribution, trading and service margins) per applicant. Customers falling into one of four different volume classes negotiate prices they pay suppliers as discounts on the maximum price.

Examples of recent decisions

- Sasol Gas has been granted a trading margin of R8.97/GJ for the period 01 July 2016 to 30 June 2017;
- Approval of the extension on the approved maximum price of R249.44/GJ applicable for period 01 July 2014 to 30 June 2015 by NOVO Energy Pty Ltd.
- ROMPCO gas transmission tariff for 2016 Q3: R13.34/ GJ.

Intention to change current regulations were announced by the Minister of Energy Ms Tina Joemat-Pettersson, MP in her Budget Speech on 11 May 2016 through three bills:

1 Gas ammendment bill

- The Bill will largely introduce a mechanism that allows the Minister of Energy to direct the development of new gas infrastructure including pipelines, storage and regasification technology for imported liquefied nation gas (LNG). The Bill will encompass the midstream elements of the gas value chain, whereas the upstream will be covered under amendments to the Mineral and Petroleum Development Act. The plan involves separating from the mineral regulatory framework those elements that relate to the petroleum value chain.

2 Upstream Gas Bill

- The Gas Amendment Upstream elements of the gas values chain, including the exploration and concessioning of conventional and unconventional gas will fall under the purview of the Upstream Gas Bill, the legislation which will be derived from the MPRDA separation process.

3 IPP Office Establishment Bill

- The IPP Office Establishment Bill will formally create the Independent Power Producer Office and define its role and mandate in regard to private-public sector programmes in the power sector. This has become necessary due to the lapse in the agreement that gave effect to the creation of the project office responsible for the procurement and contract management of the 15 to 20 year IPP projects that the Department of Energy has entered into. It has become incumbent that the department must manage its obligations under these contracts in a more structured manner.

Substituting gas for coal will help cut South Africa's carbon intensity and greenhouse gas emissions argues the National Development Plan (2012). It points out that natural gas is an important transition fuel to a low carbon economy which is particularly important given South Africa's huge reliance on coal for primary energy. The NDP advocates confirming resources and perusing sources from off-shore natural gas, coalbed methane, shale gas resources in the Karoo basin and imports of liquefied natural gas. The NDP proposes that natural gas should be used for power production in a phased way and concludes "South Africa should seek to develop these resources, provided the overall economic and environmental costs and benefits outweigh those associated with South Africa's dependence on coal, or with the alternative of nuclear power. The national value of this resource needs to be maximized." (NDP 2012:167-168)

4.3 Gas Infrastructure Planning

Efforts by Government to develop gas infrastructure planning has been underway since at least 2005 (DME 2005) but a definitive plan has yet to emerge. The current focus is on a Gas Utilisation Master Plan (GUMP) which started as an initiative from the National Planning Commission and is being developed for the DoE by the IPP office as a component of Integrated Energy Planning by the Department. The GUMP envisages using the Gas to Power Programme to aid the development of South Africa's gas sector.

"The GUMP is a roadmap for the development of a gas economy. It analyses the potential and opportunity for the development of South Africa's gas economy and sets out a plan of how this could be achieved. One of the key objectives of the GUMP is to enable the development of indigenous gas

resources and to create the opportunity to stimulate the introduction of a portfolio of gas supply options." (source: IPP Office)

GUMP is envisaged as a long term – 30 year plan for the full development of the South African gas industry considered holistically. It is tightly coupled to the gas IPP programme but eagerly awaited by all interested parties as the framework for development to guide the nascent gas industry so delays in finalising it add to the uncertainty for gas development. Developing a gas industry in South Africa has to overcome a number of hurdles argues the GUMP project manager (Fichardt 2014):

- Limited indigenous supplies. Reserves in the Bredasdorp basin are declining and potential off-shore plus shale gas resources still have to be explored and proven.
- Significant gas offtake or demand does not exist, as yet. Financing gas infrastructure is therefore difficult.
- Gas infrastructure is limited. South Africa lacks LNG import facilities and existent pipeline and transmission network is limited.
- Demand – supply gap locked in place by the above three factors.
- Planning uncertainty awaiting the finalisation of GUMP.

Increasing flexibility of the South Africa's power system is a core theme for the GUMP and reason for natural gas being inextricably linked to power production. Introducing renewables in the generation mix increases the need for system balancing to managing intermittent generation by means of flexible, dispatchable generation – a role gas is ideally suited for. A larger role for gas in generation is highly complementary to greater wind and solar capacity because of its system flexibility and balancing effects. Natural gas applications the GUMP is expected to address include gas to liquids, transportation fuels and industrial and commercial uses.

When finalised, the GUMP is expected to detail the regulatory framework for gas industry development kick started by a gas to power programme, that in the short term, will require LNG imports. In the medium term imports via pipeline may be viable along with the development of domestic supply from conventional off shore gas and unconventional shale and CBM resources (Fichardt 2014).

Release of the GUMP has not been given a timeframe. The Minister of Energy referred to energy planning in her budget speech, only stating that the Integrated Energy Plan, which has been under development since 2012 has been reviewed by a Ministerial Advisory Council and will be tabled for further consultation. The Minister stated that the updated Integrated Resource Plan (IRP) process is well underway, and will be submitted to the economic sector and infrastructure development cluster in the second quarter of this financial year. On gas she stated "similarly the Gas Infrastructure Plan will take its lead from the IEP, in regard to the gas pipelines, storage and other infrastructure that is necessary for meeting the energy demand through gas supply". Minister Tina Joemat-Pettersson: Energy Department Budget Speech Vote 2016/17 11 May 2016. Milestones for the gas policy framework given in the budget speech are shown in Table 4. Communication with the IPP office has confirmed that the first draft of the GUMP is final but is unable to say when the report will be made public. Taking this into account it is assumed that the GUMP will probably be released with the IEP, when that plan is finally unveiled.

Table 4 Minister of Energy Policy Framework and milestones regarding gas in 2016/17 budget vote speech

Document	Timetable
Integrated Energy Plan (or IEP) represents the overarching energy policy and strategy statement that has been under development since 2012. Reviewed by Ministerial Advisory Council.	No date. A final version will then be tabled for further consultation.
Integrated Resource Plan (IRP) and the Gas Infrastructure Plan	Will be submitted to the economic sector and infrastructure development cluster in the second quarter of this financial year.
Preliminary information memorandum on the 3126 MW gas-to-power programme	Make available to the market in the second quarter of the 2016/17 financial year, prior to commencing with the formal procurement process later in the year. *****

Note

***** The DoE has announced that the preliminary information memorandum for gas-to-power programme will be released at the Gas Options conference to be held 3 – 5 October 2016.

4.4 GAS TO POWER PROGRAMME

Based on the 2010 IRP, the Minister of Energy directed in two 2012 determinations that new generation capacity should be procured from hydro, coal and gas sources to support South Africa's base load energy mix and generation from gas and cogeneration as part of the medium-term risk mitigation project programme. The Determinations require that 3126MW of baseload and/or mid-merit energy generation capacity is needed from gas-fired power generation to contribute towards energy security. The second 2012 determination stipulated that this should be a LNG to power IPP programme and mandated the DoE to commence with an LNG to IPP procurement programme.

Looking back on the 2010 IRP, with the benefit of hindsight from 2016, it is interesting to observe that the new build planning for gas envisaged 711MW from natural gas CCGT and 2415 MW from diesel OCGT technologies by 2025 out of a total of 2370MW and 3910MW by 2030 respectively (IRP 2010). It tellingly points to the difficulties faced by energy planners and underscores the need for flexibility to accommodate significant fuel price changes and technology disruptions and this is precisely why the IRP is supposed to be updated every two years.

4.4.1 Designing a gas to power programme

The Gas to Power Programme (GPP) IPP programme commenced with an RFI issued by the DoE in May 2015, inviting potential bidders to provide information to help design an appropriate procurement framework and prompt clarification of regulatory issues. At the outset it anticipated that ministerial determinations would be amended for respondents to plan for the procurement of 3126 MW of generation capacity from any gas type or source generated using any appropriate technology.

The nub of the issue stands as follows:

A challenge in developing the gas sector is to bring gas demand and supply on stream at the same time and spread geographically to stimulate broader localised demand through South Africa. Without such localised gas demand it is difficult to develop distributed gas supply and without such distributed gas supply it is difficult to develop localised gas demand. One way of breaking this impasse is to create significant "anchor" gas demand through the development of a Gas to Power Programme. The demand from the Gas to Power Programme will provide a market for a potential supply of gas. It will also provide long term gas demand sinks for future indigenous gas supplies. (DoE RFI 2015 para 3.4)

In the absence of available natural Gas within South Africa and to ensure new capacity is delivered in timescales commensurate with the objectives of the medium term risk mitigation project it is recognised that it will be necessary to import Gas, *inter alia*, in the form of LNG or CNG. As a consequence, the Gas to Power Programme could be designed as a potential means to catalyse the importation of such Gas (DoE RFI 2015 para 3.6)

In respect of the Power Generation Facility, where a Respondent anticipates providing a power generation solution (a) supplied by LNG or (b) with an installed capacity in excess of 500MW, then, based on analysis of a number of least-cost dispatch scenarios for the South African power system for the years 2020, 2025 and 2030, it is anticipated that such solution will provide Mid-Merit Energy and the following annual average load factors may be expected (DoE RFI 2015 para 3.9):

Year	Installed Capacity	Load Factors
2020	3 000 MW or 1 000 MW	35% or 50%
2025	3 000 MW	35%
2030	3 000 MW	35%

In South Africa's presently constrained power supply environment the Department would like to investigate early gas power generation opportunities. As such, the Department encourages respondents to provide potential solutions to deliver gas fired power generation as expeditiously as possible. The generation of such early power may come from reducing the timeframes to build out and develop the gas to power value chain or it may come from an interim Early Power Generation Facility as part of the development of the longer term gas to power value chain (DoE RFI 2015 para 3.11).

4.4.2 Additional 600MW programme

In May 2016 the DoE published a call for Expressions of Interest from the private sector to partner with State Owned Entities for the development of a 600MW generation facility, intended as an addition to the LNG to power programme (DoE, 2016).

Through this EOI, the Department intends to determine the private sector's interest in seeking appointment as a Strategic Partner to one or more State-Owned Company/ies to implement the Project. The role of the Strategic Partner will be to provide the necessary technical and financial support for the implementation of the Project, in conjunction with the State-Owned Company/ies. Such support may include, inter alia, the design and development of a 600MW gas-fired power generation plant and the identification and establishment of opportunities for manufacturing within the gas to power value chain (DoE, 2016 RFI para 4.1).

Project details set out in the RFI state the Strategic Partner will partner with one or more State-Owned Company/ies who will be minority equity participants to implement the Project (holding not specified and economic role, apart from rent taking, difficult to discern). The Strategic Partner's role is to be the lead developer, undertaking, amongst others:

- Site selection and securing land tenure;
- Completing all permitting and authorisations;
- Settling all agreements required to construct, finance, commission, operate and maintain the Power Generation Facility for the term of the PPA;
- Contributing or securing the required equity;
- Procuring all the required debt;
- facilitating the equity participation of Black Enterprises and/or Black People;
- ensuring the project is completed on-time and on-budget;
- facilitating the establishment of manufacturing facilities to supply the generation facility.

Generation is anticipated to be either baseload or mid-merit plant with the timeframe to commercial operation set to be finalized IRP. The RFI states "it is anticipated that the Project will be located within the proximity of one of the major ports, that is, Coega, Richards Bay or Saldanha Bay, with the highest probability of achieving the earliest commercial operation date" (DoE, 2016 RFI para 5.4).

Discrepancy with Ministerial Determination to be clarified.

In the Ministerial Determination for the additional 600Mw gas programme a specific supply point is named which contradicts the DoE 2016 RFI, namely "5. the new generation capacity shall be supplied into the transmission network in the area between Ankerlig Power Station and Saldanha.." notice 602 Government Gazette no 40023, 27 May 2016.

4.4.3 Other government gas initiatives

4.4.3.1 Operation Phakisa

A gas Phakisa ('quick – fast') initiative has been started drawing upon inter-departmental task teams and involving SOCs coordinated through the national infrastructure development planning structures. Its task is to create an enabling, supportive environment for oil and gas exploration, six key areas were identified as work streams to focus on evaluation of the current status and recommendations to support exploration and developments in the future, paying attention to capacity building.

These key areas or work streams are:

- A – Gas infrastructure;
- B – Environmental management;

- C – Supply chain – leveraging local content;
- D – Local skills development;
- E – Institutional governance; and
- F – Legislative

4.4.3.2 Gas Industrialisation Unit

The Department of Trade and Industry launched a Gas Industrialisation Unit (GIU) in May 2016 designed to maximise the multiplier effects of natural gas for power generation in South Africa. The GIU includes senior officials from government departments, supported and advised by industry experts and civil society representatives to oversee the development and implementation of appropriate gas industrial policy for South Africa and the Southern African region. It will support the LNG-to-power procurement programme by assisting in driving the development of gas markets and non-IPP gas utilisation within the three ports identified for LNG importation, focusing on possible gas-to-liquids and fertilizer applications.

4.4.4 Timetable for gas to power programme

Addressing Oil and Gas council on 17 May 2016, the Minister Tina Joemat-Pettersson announced a timetable for the implementation of the gas to power programme.

Table 5 Timetable for gas to power programme announced 17 May 2016

Event	Timeframe
Expressions of Interest from the private sector to partner with our State Owned Entities with the development of a 600MW Additional Gas Determination	Issued 12 May 2016, closed 20 June 2016
Preliminary information memorandum on the 3125 MW gas-to-power programme	second quarter of the 2016/17 financial year *****
Start of formal procurement process in gas to power programme	Later 2016/17 financial year
Request for Qualifications for the supply of a Floating Storage and Regasification Unit vessel or FSRU-based bundled natural gas-to-power solution of up to 3126 MW to be sited at Ngqura (Coega), Richards Bay or Saldanha Bay	quarter 3 of financial year 2016/17.
Request for Proposals to the market	quarter 4 of financial year 2016/17.
bid submission and evaluation process	quarter 3 of financial year 2017/18.

Note

***** The DoE has announced that the preliminary information memorandum for gas-to-power programme will be released at the Gas Options conference to be held 3 – 5 October 2016.

The timeframe given in will be updated as new information becomes available.

5 CONCLUSION

Developing the natural gas industry in South Africa through a gas to power programme and the intention to establish an entirely new LNG industry is official government policy.

Important components of policy and the regulatory framework for natural gas are, however, incomplete. Furthermore, the lack of certainty regarding the stabilisation of the policy environment increases risks across all of the initiatives discussed in this briefing paper. Progress with the gas to power programme and broader natural gas ambitions for the country will remain weighed down by these risks until there is sufficient consensus among policy makers to reach finality on outstanding points.

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7 APPENDIX 1 NATURAL GAS MEASUREMENTS

Natural gas can be measured in terms of its volume or its energy content. Metric and imperial measures are frequently both used, a legacy effect of the United States of America influence on the petroleum industry.

Measures of Volume	Measures of Energy Content
Cubic metres (Cm) [m^3] Billion cubic metres (Bcm) [$10^9m^{3]}$ Cubic feet (cf) [f^3] Trillion cubic feet (Tcf) [$10^{12}f^3$]	Gigajoules (GJ) British thermal units (Btu) Million British thermal units (MMBtu)

Metric measurements

Measures of Volume	Measures of Energy Content
Cubic meter A cubic metre (m^3) is a measurement of gas volume. The standard reference conditions for measurement are a temperature of 15°C and an atmospheric pressure of 101.325 kilopascal (kPa). Note "standard conditions" must be referenced to a measuring system	Gigajoules A gigajoule (GJ) is one billion Joules [10^9J] The amount of energy represented by one GJ is equivalent to 278 kWh. Petajoules A petajoule (PJ) is [10^{15}J] frequently confusingly referred to a million gigajoules mGJ or worse MGJ.

Imperial measurements

Common volume measurements are based on multiples of cubic feet, with reserves measured in trillions (Tcf). Cubic feet is the imperial measurement unit for gas volume at standard reference conditions (at a pressure base of 14.73 pounds standard per square inch absolute and a temperature base of 60 degrees Fahrenheit)

British thermal units (Btu) are the imperial measurement of energy content in natural gas commonly referenced in Million Btu (MMBtu). One Btu is the amount of energy required to heat one pound of water at maximum density by one degree Fahrenheit. A common multiple is a therm equal to 100,000 BTU. It is approximately the energy equivalent of burning 100 cubic feet or 105.5 megajoules 105,505,600 joules

Gas metering

Users are interested in the heat energy that combusting the gas will generate. Gas is priced in units of energy content, Gigajoules or MMBtu but it is delivered to most industrial and residential customers via a pipeline connection and metered by the volume of gas delivered. This volume measurement is subsequently converted, using the average energy value per volume factor, into number of energy units consumed by the end user. Variation in the energy content of the gas and delivery pressure require adjustments to the conversion factor used.

Unit Conversions

Convert from	Convert to	Multiply by
1 Cubic metre (m^3)	Gigajoules (GJ)	0.038
1 GJ	m^3	26.137
1 m^3	Cubic feet (cf)	35.314
1 cf	m^3	0.028
1 GJ	Million British thermal units (MBtu)	0.948
1 MBtu	GJ	1.055
1 therm	GJ	0.1055056

Note on standard conditions

Standard conditions for temperature and pressure are referenced differently under different authorities and reference system.

Metric

The International Standard Metric Conditions for natural gas and similar fluids are 288.15 K (15.00 °C; 59.00 °F) and 101.325 kPa.

International Union of Pure and Applied Chemistry (IPAC)

standard temperature and pressure (STP): a temperature of 273.15 K (0 °C, 32 °F) and an absolute pressure of exactly 100 kPa (1 bar)

National Institute of Standards and Technology (NIST)

normal temperature and pressure (NTP): a temperature of 20 °C (293.15 K, 68 °F) and an absolute pressure of 1 atm (14.696 psi, 101.325 kPa)

8 APPENDIX 2 PETROLEUM EXPLORATION MAP

Petroleum Exploration and Production Activities in South Africa, September 2016

Petroleum Agency of South Africa map

9 APPENDIX 3 EXCERPT FROM WHITE PAPER ON ENERGY POLICY

White Paper on the Energy Policy of the Republic of South Africa

December 1998

Part 3 Supply Sectors, section 7.5 Gas

7.5 *Gas*

7.5.1 *The existing gas industry*

Natural gas, produced from the F-A field in the Mossel Bay area, supplied 1,6% (or 72 PJ) of total South African primary energy supply during 1997, as a feedstock to the Mossgas synthetic liquid fuels plant. Piped coal gas, manufactured in Sasol's chemicals and liquid fuels plants and marketed by Sasol Gas, a division of the Sasol subsidiary Sasol Oil, supplies 1,1% (or about 30 PJ) of net energy consumption, largely to industrial consumers in the Gauteng and Mpumalanga provinces. The pipelines are owned by Gaskor. Sasol Gas markets both high energy content methane-rich gas (to Witbank, Middelburg and the Richard's Bay/Durban areas) and low energy hydrogen-rich gas in Gauteng. Both Mossgas and Sasol were state initiated and financed. Sasol has subsequently been privatised while Mossgas remains state owned. The Mossgas project was developed for purely strategic reasons and has been unable to re-coup its R11 billion capital cost. The Sasol gas business developed largely as a by-product of Sasol's synfuels business and remains inextricably linked to it. Sasol's gas production capacity is unknown.

7.5.2 *Gas resources and industry development*

South Africa has relatively small known gas resources of 30 billion cubic metres (bcm) off the south coast and some very small recent discoveries (3 bcm) off the west coast. However, the potential natural gas resources have not yet been fully investigated. To date South Africa has undertaken limited exploration for oil and natural gas leading to twenty gas and nine oil discoveries. Limited exploration for coal-bed methane is underway. This section on the downstream gas industry does not distinguish between natural gas and coal-bed methane.

Despite the relatively low level of known domestic gas resources it is probable that the South African gas industry is on the brink of significant expansion, due to natural gas field discoveries and development in neighbouring Mozambique and Namibia, as well as the potential development of South African natural gas and coal-bed methane resources.

Based on the results from three wells drilled, the current recoverable reserve in the Kudu field in Namibia is 56 bcm. An upside potential of 230 bcm is likely. This amount of gas is sufficient to satisfy current levels of demand for gas in both the Western Cape and Gauteng markets. The Pande field in Mozambique is the most mature of the gas fields, with current proven reserves of 65 bcm, and is likely to be developed first. The utilisation of this gas in South Africa will require the construction of an international gas transmission pipeline, up to 900 km in length, from Pande in Mozambique to Mpumalanga and Gauteng. The project has attracted significant international interest in recent years.

Potential gas development projects entail huge capital investments, locked into immovable assets with long term returns, and investors therefore require stable policy conditions. In the absence of stability, increased investment risks lead to lenders requiring higher returns, which pushes up the price of capital and hence the gas price. This has the dual effect of making some projects non-viable, and allocating an unnecessary portion of the rent to risk capital for those projects that are viable.

Given that both the Pande and Kudu fields are located in neighbouring countries the development of these projects has important implications for regional economic development. The harmonisation of gas policies within the region, particularly regarding bi-national gas trade, is required to facilitate this process. Considerable progress has already been made in this regard with Mozambique.

Strong potential thus exists for significant growth in South Africa's gas industry, based largely on regional gas trade. Recent developments in the local gas industry have seen Petronet, the state-owned fuel pipeline company, converting a liquid fuels pipeline to transport gas more than 500 km from Sasol's Secunda plants to the Richard's Bay and other Natal markets. Sasol has also recently built a 119 km pipeline from its Secunda plants to the Witbank area, thereby significantly expanding its market access.

7.5.3 *Environment*

Environmental benefits arising from the use of natural gas as a source of energy include:

- reduced carbon dioxide emissions relative to equivalent energy other fossil fuels;
- low particulate emissions;
- high energy efficiency in combined-cycle applications;
- negligible sulphur content in regional deposits; and
- gas-fired generation plants require less space than conventional coal-fired plants of the same capacity.

7.5.4 *Key policy challenges*

Gas has a number of attractive characteristics from an energy policy perspective. The development of the gas industry will stimulate inter-fuel competition, provide environmental benefits through lower emissions in contrast to oil and coal, provide greater options for industrial thermal applications, and increase the diversity of fuel supplies and hence improve 74 South Africa's energy security. Other important uses of gas are as a reductant in the metallurgical industry or as a feedstock in the chemical industry. Government is therefore committed to the establishment of an appropriate climate to facilitate the development of the gas industry.

Key policy challenges facing government are the following:

- to ensure conditions conducive to a stable investment climate, so as to encourage economically viable development and thereby limit the risks to capital lenders and improve project viabilities;
- to ensure that gas transmission, storage and distribution operators do not adopt monopolistic behaviour and to limit the opportunities for dominant operators to abuse their market power;
- to deal effectively with the international aspects of gas transmission pipelines and international gas trade; and
- to develop appropriate gas governance systems and the necessary capacity for these to operate.

7.5.5 *Regional issues*

The Department of Minerals and Energy is currently in the process of developing a gas regulatory structure and addressing the harmonisation of regional gas polices through binational agreements. Studies by the World Bank, the International Energy Agency, and South African bodies are assisting this process.

The Government shall in consultation with relevant stakeholders endeavour to harmonise gas issues with neighbouring states.

This will facilitate cross-border gas trade and enhance regional socio-economic development.

7.5.6 *Regulatory regime*

South Africa's small gas industry is expected to expand and provide a significant component of national primary energy. Indications are that the existing participants in the industry, potential participants and potential investors would all welcome a regulatory environment in which government policies for the gas industry are stated explicitly. This will increase investor confidence and promote the rapid development of the industry.

A Gas Regulatory Authority will be established to implement a minimal regulatory regime consistent with orderly development of a competitive gas industry through granting licenses for the transmission, storage, distribution and trading of piped gas.

Government recognises that the existing gas industry is relatively small, but growing rapidly. The regulatory environment will be conducive to the development of the industry and will provide investors with confidence to invest in the required infrastructure by establishing clear, stable legislation to facilitate investment. Legal requirements will be phased in where appropriate.

Due regard will be given to the needs of all stakeholders.

The functions of gas transmission, storage, distribution and merchandising will be implemented as separate undertakings and will require separate licences. The regulatory system will facilitate pipeline routing, pipeline sizes and capacities, and the interconnection of pipelines. A facility will be made for phasing in of regulations, and where a monopoly exists a price control mechanism will be instituted.

75 7.5.7 ***Industry structure***

Integration of companies operating in more than one of the gas chain elements, namely production, transmission, storage and distribution, can result in anticompetitive behaviour. On the other hand, the security of gas supply/demand to encourage development of the industry may require some form of vertical participation by the principle players.

Interests in more than one element may be permitted in order to facilitate project development from producer, through transmission to distribution. . In the event of common interests in the control of vertically-related companies, the licensing of such companies will be subject to proof of functional separation and arm's-length relationship between the companies.

The government will facilitate efficiencies which accompany economies of scale.

Large gas consumers will be permitted to purchase gas directly from the transmission system. [Small gas consumers in licensed distribution areas will purchase gas through a distribution system.]

7.5.8 ***Transmission***

The natural monopoly characteristics of gas transmission pipelines presents the potential for the exercise of market power, including restricted access of gas industry competitors and maintenance of high prices.

The gas regulatory regime will inhibit monopolistic abuse of pipelines by requiring pipelines to provide non-discriminatory open access to uncommitted capacity, transparency of tariffs, and disclosure of cost and pricing information to the Gas Regulatory Authority.

Where a third party requests access to a transmission pipeline, decisions will be made on a reasonable basis, and at the expense of the applicant who requests the upgrading.

7.5.9 ***Distribution***

A distributor's function is to supply lower volume consumers whose consumption is too small or too irregular to warrant purchasing from a producer/merchant. Distributors are vulnerable to predatory actions by producers, who can attract the steady-demand medium-sized consumers, thus destroying the distributor's ability to aggregate sales and enter into a take-or- pay contract with the producer. This chain of events would limit the expansion of the gas industry into the household market. The distribution system world-wide is reliant on a distributor's ability to aggregate customers and exclusive rights to an area to prevent duplication of the distribution grid.

Distributors will be awarded licenses for exclusive geographic areas in order to market a class of gas to small gas consumers. This will be subject to price approval by the Gas Regulatory Authority.

Licensed distributors will be required to satisfy specific customer service standards and to disclose operating information to the regulatory body responsible for the gas industry,

7.5.10 ***Fiscal matters***

Depreciation on pipelines is currently not allowable for tax purposes. This is a fiscal policy which discourages investment. The Department of Minerals and Energy has made representation to the Department of Finance to allow tax deductibility on gas pipelines.

7.5.11 ***Technical standards***

The Department of Minerals and Energy will assist the Department of Labour with the development of health and safety standards for the construction and operation of transmission and distribution pipelines, storage and metering.

Where existing standards are deemed acceptable, even if they do not conform to the new national standards, these will be permitted for indefinite use, but new or replacement work will have to conform to the national standards. Where existing standards are deemed unsatisfactory, a transition period will be allowed for institutions to bring equipment up to standard without undue financial hardship.

7.5.12 ***Gas utilisation***

Some countries have chosen to restrict the usage of gas to certain applications, based on the understanding that gas reserves were limited and that this commodity should be conserved while alternative commodities were available. Such constraints on usage have tended to limit the growth of gas markets and hence the rate of exploration. International experience now shows that, in general, gas reserves are far larger than had been expected and that no limitations should be placed on gas utilisation.

No restrictions will he placed on the use of gas, or on the amount of national primary energy sourced from gas that may be imported from SADC countries.

Efficient-energy practices will, however, be encouraged.

10 APPENDIX 4 OBJECTS OF GAS ACT, NO. 48 OF 2001

Objects of Act

2. The objects of this Act are to-

(a) promote the efficient, effective, sustainable and orderly development and operation of gas transmission, storage, distribution, liquefaction and regasification facilities and the provision of efficient, effective and sustainable gas transmission, storage, distribution, liquefaction, re-gasification and trading services;

(b) facilitate investment in the gas industry;

(c) ensure the safe, efficient, economic and environmentally responsible transmission, distribution, storage, liquefaction and re-gasification of gas;

(d) promote companies in the gas industry that are owned or controlled by historically disadvantaged South Africans by means of licence conditions so as to enable them to become competitive;

(e) ensure that gas transmission, storage, distribution, trading, liquefaction and re-gasification services are provided on an equitable basis and that the interests and needs of all parties concerned are taken into consideration;

(f) promote skills among employees in the gas industry;

(g) promote employment equity in the gas industry;

(h) promote the development of competitive markets for gas and gas services;

(i) facilitate gas trade between the Republic and other countries; and

(j) promote access to gas in an affordable and safe manner.

Functions of Gas Regulator

4. The Gas Regulator must, as appropriate, in accordance with this Act-

(a) issue licences for –

(i) construction of gas transmission, storage, distribution, liquefaction and re-gasification facilities;

(ii) conversion of infrastructure into transmission, storage, distribution, re-gasification facilities;

(iii) operation of gas transmission, storage, distribution, liquefaction and re-gasification facilities;

(iv) trading in gas;

(b) gather information relating to the production, transmission, storage, distribution and re-gasification of gas;

(c) issue notices in terms of section 26(1) and, if necessary, take remedial action 30 (d) undertake investigations and inquiries into the activities of licensees;

(e) consult with government departments and other bodies and institutions regarding any matter contemplated in this Act;

(f) consult with government departments and gas regulatory authorities of other countries to promote and facilitate the construction, development and functioning of gas transmission, storage, distribution, liquefaction and re-gasification facilities and services;

(g) regulate prices in terms of section 21(l)(p) in the prescribed manner;

(h) monitor and approve, and if necessary regulate, transmission and storage tariffs and take appropriate action when necessary to ensure that they are applied in a non-discriminatory manner as contemplated in section 22;

(i) expropriate land or any right in, over or in respect of such land as is necessary for the performance of a licensee's functions;

(j) promote competition in the gas industry;

(k) promote the optimal use of available gas resources;

(l) take decisions that are not at variance with published Government policy;

(m) publish from time to time a list of other legislation applicable to the gas industry;

(n) perform any activity incidental to the performance of its functions;

(0) make rules in accordance with section 34(3); and

(p) exercise any power or perform any duty conferred or imposed on it under any law.

11 Appendix 5 Sasol gas specifications

Sasol Natural Gas Marketing specification

Property	**Units**	**Limits**		**Notes**
		Min	Max	
Energy content (HHV)	MJ/m^3_n	38.1	43.5	1
Wobbe index		50.9	55.1	2
Relative density		0.55	0.70	3
Total Sulphur	mg/m^3_n	-	15.0	
Composition of gas				
Methane	vol%	88.0-	98.0	
Carbon dioxide	vol%	-	2.0	
Nitrogen	vol%	-	3.0	
Total inerts	vol%	-	5.0	
Hydrogen Sulphide	$mg/^3_n$	-	4.0	
Odourizing Agent (Spotleak 1005)	mg/m^3_n	11.0	20.0	

Addendum to specification

Component	***volume%***
Nitrogen	2.06
Carbon dioxide	0.00
Methane	94.28
Ethane	2.03
Propane	0.83
i Butane	0.21
n Butane	0.24
Component	***volume%***
i pentane	0.07
n pentane	0.06
neo Pentane	0.01
Hexane	0.06

Heptane	0.12
Octane	0.02
Nonane	0.00
Total	100.00

Sasol Methane Rich Gas Marketing Specification

Property	Units	Limits		Notes
		Min	Max	
Energy content (HV)	MJ/m^3_n	33.57	37.90	1
Relative density		0.56	0.66	3
Wobbe Index		37.9	50	2
Total Sulphur	Mg/m^3_n	4.3	9.0	
Composition of gas				
Hydrogen	vol%	-	3.0	
Methane	vol%	82.5	94.0	
Carbon Monoxide	vol%	-	4.0	
Nitrogen + Argon	vol%	-	16.0	
Ethane and Ethylene	vol%	-	2.0	
Odourizing Agent (Spotleak 1005)	mg/m^3_n	12.0	25.0	

Addendum to specification

Component	***volume%***
Nitrogen	6.6
Carbon Dioxide	0
Carbon Monoxide	2
Methane	88
Ethane	0.4
Hydrogen	3
Total	100.00

Notes

1. 'NORMAL CUBIC METER' (m^3_n) shall mean a cubic meter , the reference conditions of measurement being 0 degrees Celsius at a pressure of 101.325 kilopascals and free of water vapour at these conditions.
2. 'RELATIVE DENSITY' (relative molecular weight), shall mean the ratio of the average molecular weight of gas to that of air (28.97)
3. 'WOBBE INDEX' shall mean the index obtained when the energy content of the gas in (MJ/m^3_n) is divided by the square root of the relative density of the gas calculated by WN_o = HHV