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LNG Importation: Evaluating the risks

Western Cape Department of Economic Development and Tourism

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Please note:

This report is based largely on a document produced by PricewaterhouseCoopers under contract to the Department of Economic Development & Tourism in July 2015 (as set out below). Pertinent updates were made to reflect current thinking on project timelines issued by DOE in the period August 2015 – May 2016. It is hereby released by DEDT in June 2016

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Contents

Glossary

Term	Definition
Base-load	Power plants in continuous operation every day of the year
CCGT	Combined Cycle Gas Turbine
COCT	City of Cape Town
Delivered ex Ship (DES)	The seller remains responsible for cargo until it is offloaded from the ship at the destination port.
Distribution (Gas Act)	The distribution of bulk gas supplies and the transportation thereof by pipelines with a general operating pressure of more than 2 bar gauge and less than 15 bar gauge or by pipelines with such other operating pressure as the National Energy Regulator may permit.
DEAT	Department of Environmental Affairs
DEDAT	Dept. of Economic Development & Tourism
DoE	Department of Energy
EIA	Environmental Impact Assessment
Floating Storage and Regasification Unit (FSRU)	A ship which receives LNG from an LNG carrier, stores it in LNG storage tanks, regasifies LNG on-board and provides natural gas through pipelines from the ship to the shore.
Free on-board (FOB)	The seller delivers the cargo to the buyer's ship at the port of departure. The buyer is responsible for shipping the cargo.
Gas-IPP	SA Department of Energy Gas to power procurement programme
Gas price	The price charged for gas molecules by volume or by energy content also referred to "gas energy price".
Gas (Gas Act)	All hydrocarbon gases transported by pipeline, including natural gas, artificial gas, hydrogen rich gas, methane rich gas, synthetic gas, coal bed methane gas, liquefied natural gas, compressed natural gas, re-gasified liquefied natural gas, liquefied petroleum gas or any combination thereof.
GUG	Gas User Group
GUMP	Gas Utilisation Master Plan

Term	Definition
Henry Hub	The reference gas pricing point in the US. It is commonly used as an index in US LNG contracts.
IEA	International Energy Agency
IEP	Integrated Energy Plan
Industrial Development Zones (IDZ)	An IDZ is a purpose built industrial area which contain Customs Controlled Areas (CCA) tailored for manufacturing and storage of goods to boost beneficiation, investment, economic growth and development of skills and employment
IPP	Independent Power Producer
Japanese Crude Cocktail (JCC)	Japanese Customs cleared Crude, it is the average price of customs cleared crude oil imports into Japan as reported in customs statistics. It is commonly used as an index in Asian LNG contracts.
Liquefaction (Gas Act)	Converting natural gas from a gaseous state to a liquid state.
Liquefied Natural Gas	Natural gas that has been cooled from a gaseous state into a liquid by cooling it to -162°C (-260°F). The volume of gas is reduced by a factor of 600 which makes is suitable for long distance transportation.
Load Factor	The percentage time that a power plant is expected to be operating during a year.
Met-ocean studies	Study of location specific wave, wind and current conditions, to determine the impact on offshore operations.
Mid-merit power plant	A power plant that can adjust its power output and be started or stopped as demand for electricity fluctuates throughout the day. In South Africa it is often assumed that a mid-merit plant will operate 5 days a week for 16 hours a day.
MMBtu	Million Metric British Thermal Units. Btu is a unit of heat energy defined as the amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit. One Btu equals 1,055 joules or 252 calories.
Mtpa	Million tonnes per annum
National Balancing Point (NBP)	The reference gas pricing point in the UK. It is commonly used as an index for UK and European LNG imports.
Netback price	The effective price a seller receives for selling to a destination. It is calculated as the market price at the destination less the cost of transportation incurred by the seller.
OCGT	Open Cycle Gas Turbine

Term	Definition
Peaking power plant	Power plants that can be started and stopped quickly and are used to balance peak electricity demand periods.
Production (Gas Act)	The recovery, processing, treating and gathering of gas from wells in the earth up to the boundary of the mine, or the manufacture of synthetic or artificial gas, or the manufacturing of any gases in the refining process up to the boundary of the factory.
RE IPPP	The SA Department of Energy led Renewable Energy Independent Power Producer Procurement Programme.
Regasification	The process of converting LNG from a liquid to a vapour. This is achieved by heating the LNG in a regasification unit.
Reticulation (Gas Act)	The division of bulk gas supplies and the transportation of bulk gas by pipelines with a general operating pressure of no more than 2 bar gauge to points of ultimate consumption.
Sale and Purchase Agreement (SPA)	A contract between a seller and buyer for the sale and purchase of a quantity of natural gas or LNG for delivery during a specified period at a specified price. Also known as GSPA wherein G stands for general.
Service (Gas Act)	Any service relating to the transmission, distribution, storage, liquefaction or re-gasification of gas.
SEZ	Special economic zone
Special Economic Zone (SEZ)	The Atlantis GreenTech Special Economic Zone (SEZ) has financial and environmental and planning incentives to assist the industrial development and employment creation in the Green Economy.
Storage (Gas Act)	The holding of gas as a service and any other activity incidental thereto, but excludes storage of gas in pipelines which are used primarily for the transmission and of gas.
Third Party Access (TPA)	The right for a third party to use a specified pipeline or facility of another company.
Trading (Gas Act)	The purchase and sale of gas as a commodity by any person and any services associated therewith.
Transmission (Gas Act)	The bulk transportation of gas by pipeline supplied between a source of supply and a distributor, reticulator, storage company or eligible customer.
TNPA	Transnet National Ports Authority
WCG	Western Cape Government
U.S. EIA	United States Energy Information Administration

List of Figures

List of Tables

Chapter 1: Study Overview

1 Study Overview

The Western Cape Government's Department of Economic Development and Tourism has acknowledged the importance of the role that natural gas can play in developing the economy of the province, decreasing its carbon footprint and in addressing pertinent issues with regards to energy diversity and security. As a means of exploring the possibility of importing Liquefied Natural Gas (LNG) into the province through the Saldanha-to-Cape Town corridor on the West Coast, the Department has issued a request for this study.

This study consists of a qualitative commercial, financial and regulatory risk assessment for different contracting scenarios across the gas value chain. Suitable mitigation measures to the qualified risks have been identified along with possible bottlenecks in the contracting process. The views of key stakeholders in South Africa's gas market with regard to some of the key elements relating to the scope of this study are included.

1.1 Scope of this study

The scope of this study was to perform a Qualitative Risk Analysis of the commercial, regulatory and financial risks associated with the importation of LNG into the Western Cape.

It was proposed that this analysis be performed in respect to the three contracting scenarios described in the Request for Proposal as follows:

Scenario 1: "Internationally Led", in which gas supply, terminal operation, gas transmission, power generation and other off-take opportunities are all under the control of a single entity;

Scenario 2: "SA dominant", in which a State Owned Company takes on the role of the aggregator of landed gas to service downstream market opportunities, investing in the requisite infrastructure; and

Scenario 3: "Consortium-led", in which a disaggregated consortium of public and private entities comes together to service a diverse market opportunity.

Our analysis describes a plausible contracting model for each of the above scenarios and identifies key risks and responsible parties for these risks. In addition, we indicate possible bottlenecks in the contracting process and mitigation through appropriate stakeholder engagements.

Further to the above scope, feedback from workshops held with the Western Cape Government, requested the following be included:

- An overview of the LNG market as applicable to the Western Cape; and
- Mandates of key stakeholders.

1.2 Sources of information

This report and the findings herein were formulated with the assistance of information obtained from the following sources:

- Literature reviews
- Stakeholder engagements (workshops/interviews)
- PwC local and international expertise

1.3 Importance of this study

The importation of LNG requires the discernment of the different elements along the gas value chain, the different players involved (directly and indirectly) and the contracts present between each of these players. Considering the complexity of such a project, it is important to understand the regulatory, financial, and commercial risks that could potentially arise across different contractual arrangements within the South African context; who assumes those risks and which measures should be put in place in order to mitigate them, if possible. The early identification of bottlenecks to the process enables the WCG to develop plans to proactively address these and thereby ensure that the project progresses timeously.

As a result, the findings of this study will be crucial in providing relevant information that the PGWC can use in developing its risk and mitigation strategy for importing LNG into the Western Cape through the Saldanha-to-Cape Town corridor. Furthermore, the findings of this study will enable the WCG to scope the further development of this project including stakeholder engagement.

1.4 Approach and Methodology

In order to gain an understanding of the LNG value chain in the context of the Western Cape, an investigation was done on the different supply options, the suggested locations, the required terminal and pipeline infrastructure and the various gas market options along the Saldanha-to-Cape Town corridor.

Concepts and types of agreements in the LNG contractual environment were investigated and are presented as an introduction as these are commonly used in the findings and analysis.

The current and potential stakeholders in the South African gas and power market (both in the public and private sectors), that could possibly be involved in such a project, and their mandates/core business were researched and some were interviewed. This was done alongside a review of the various commercial agreements that would take place between each of the players along the value chain.

The regulatory requirements that would have to be taken into consideration for the procurement, construction and operation of infrastructure along the LNG value chain were also investigated.

The financial aspects were unpacked with the aim of identifying risks to the financing of a project of this nature.

The three scenarios proposed by the WCG (private/internationally led; state driven; and consortium/public private partnership) are detailed in respect to each of the elements along the value chain.

A qualitative risk assessment of the commercial, financial, and regulatory risks is performed in respect of each of the three scenarios.

A plausible contracting model is defined for each scenario. Bottlenecks to the development of the plausible models are then described along with key stakeholders required to address.

The conclusory section of the report summarises the key outcomes of the study.

1.5 Structure of the report

This report has been organized into sections that help address the objective of this study. A short description has been provided as to what each section entails.

1. **Introduction**
   Provides basic understanding of Western Cape's energy strategy and the role of LNG as gas source

2. **Contractual Environment**
   Defines the different contracts involved directly and indirectly along the LNG value chain

3. **Key Stakeholders**
   Depicts the key stakeholders in the gas industry, their mandates/core business functions and views

4. **Risk Identification and Qualitative Risk Assessment**
   Identifies the key risks in each Scenario and provides a qualitative risk assessment and mitigants

5. **Plausible contracting scenarios and identification of bottlenecks**
   Identifies the possible bottlenecks in the plausible contractual model and mitigation thereof

6. **Conclusion**
   Highlights the key findings of this study

Chapter 2: Introduction

2 Introduction

2.1 Background

2.1.1 Gas as an alternative

A prefeasibility study for the importation of natural gas into the Western Cape, commissioned by the Department of Economic Development and Tourism, concluded that the importation of LNG is the most viable gas option to address the energy needs of the Western Cape, primarily due to its availability and distance from existing and proposed West and East African natural gas liquefaction projects. The study identified potential market sectors which could be converted to natural gas as the primary energy feedstock and identified power generation as the primary/anchor off-taker.

Several potential alternate off-takers for gas have been identified in previous studies based on areas within the Western Cape region. As can be seen in Figure 1, one group of off-takers are those who use gas a feedstock for chemical and synfuel processes such as gas-to-liquids (e.g. PetroSA GTL plant); and chemical processes to produce various hydrocarbon based products.

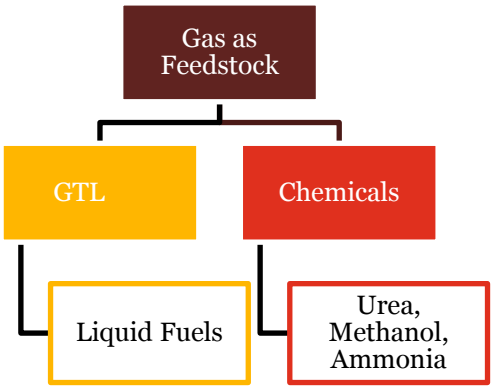

Figure 1: Potential off-taker options for gas as a feedstock to chemical processes

Another group of off-takers are those who will use natural gas as an alternative to carbon-rich fossil fuels, as can be seen in Figure 2. These potential off-takers include gas-to-power using gas fired power generation turbines or gas engines, gas for industrial operations, gas for domestic use and gas as an alternative fuel in transportation.

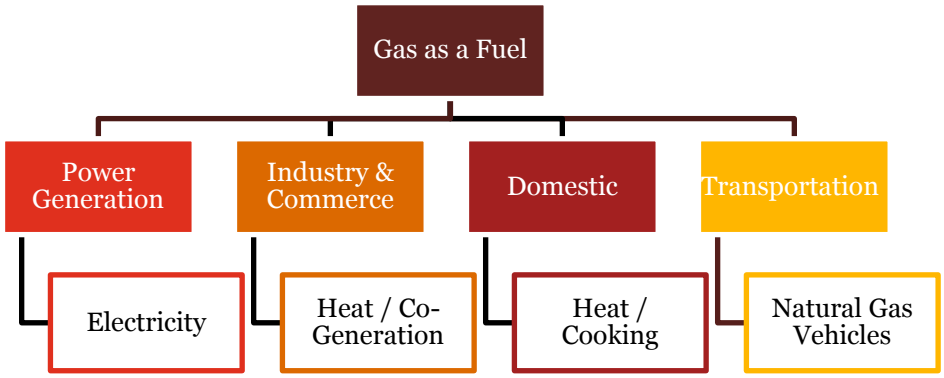

Figure 2: Potential off-taker options for gas as a fuel

The National Development Plan (commissioned by the Presidency in 2008) puts a strong emphasis on gas for power generation as an alternative to nuclear power plants. Relevant national policies such as the Integrated Energy Plan (IEP) and the GUMP, acknowledge the role of natural gas in the economy and in industry. The Western Cape Government's Green Economy Strategy, also considers the use of gas as an alternative fuel in the transport market.

Considering the viability of gas as an alternative, the WCG commissioned a prefeasibility study on the importation of natural gas to the Western Cape with specific focus on the Saldanha Bay – Cape Town corridor (Cape West Coast region). Since this region currently has no developed natural gas business, the establishment of infrastructure required to develop one would classify as a Greenfield gas infrastructure development. In correspondence with the national and provincial government policies & energy plans, the study identified gas-fired power generation and industrial markets as the two market sectors which could be converted to natural gas as their primary energy fuel. The study looked into the gas market potential within different sites along the Cape West Coast region and found that the main existing industrial markets are situated in Saldanha Bay, Atlantis and the Cape Town, Paarl and Wellington regions. However, the attractiveness of these industrial hubs, which have a high value of energy consumption susceptible for conversion to natural gas as an energy source (approximately 87,3 million GJ per annum), was not enough to justify the high costs associated with the required gas infrastructure developments. The commercial viability of the importation project was improved considerably by the inclusion of gas-fired power generation, which would either be through the conversion of Eskom's Ankerlig OCGT power station to a gas-fired CCGT, or through new gas fired power plants in Saldanha Bay and/or Greater Cape Town[1].

Anchor Market – Power generation

Previous studies commissioned by the WCG identified an anchor tenant for LNG importation as the Eskom Ankerlig 1,350MW OCGT plant located at Atlantis north of Cape Town. Its nine diesel fuelled units can be

[1] (The Western Cape Government's Department of Economic Development and Tourism, 2013)

converted to a more efficient CCGT gas-powered plant. Such a conversion would increase the capacity by 720MW to 2,070MW based on a load capacity of 47% (a mid-merit plant running 16 hours per day for five days a week). The Ankerlig power station has been designed so that it can be converted to a CCGT gas-powered plant when natural gas fuel becomes available. The CCGT plant operating on natural gas will be more efficient and emit less carbon than the existing OCGT plant for every unit of fuel consumed.

Eskom's 2012 figures indicated that the Western Cape's peak power demand is approximately 3,864 MW of which it imports about 2,050MW daily, from coal fired power plants in the North and North Eastern part of South Africa, more than 1500km away, in order to meet this peak demand. The conversion of Ankerlig from a diesel fueled peaking power plant to a natural gas fueled mid-merit CCGT plant could significantly reduce imports from coal-powered power stations as well as reduce transmission losses of around 200MW(10%), as Eskom estimates transmission, transformer and distribution losses to be between 6 to 10 percent. Thus there is not only a benefit of improved security of electricity supply in the Western Cape if Ankerlig is converted, but also greater availability of supply up north as transmission losses are instead utilized[2].

Recent studies also investigated the possibility of an 800MW gas-fired power plant being constructed in Greater Cape but upon discussion with the CoCT this has been revised to a 300MW gas-powered plant so that the local peaking demands can be met. It is also envisaged that a further 400MW offtake occur at Saldanha.

Gigajoule Africa (Visagie, 2013) estimated that the technically substitutable portion of the energy feedstock mix of large industry to natural gas as 18.1 million GJ/annum for Cape Town Metropolitan and 2.2 million GJ/annum for the Cape Winelands district and 1.3 million GJ/annum for Saldanha Bay. This total demand would equate to 21.6 Million GJ/annum or 0.42 Mtpa of LNG[3]. These figures were based on a mix of industry surveys and existing commercial realities at that time. It is anticipated that the 2016 demand for natural gas in the West Coast region could be considerably greater, given current volatility in gas pricing.

The Pre-Feasibility report for the importation of natural gas into the Western Cape with specific focus on the Saldanha Bay–Cape Town corridor noted that the Saldanha Bay area has a significant need for affordable electricity with current demand at 310 MWe, and possible future demands increasing by 410MWe to 720MWe. Since 2013, a number of commercially-driven projects for gas-to-power have been proposed for the region. Most of these are aligned with the DOE's current procurement programme (2016).

At present the Koeberg nuclear power plant and the Palmiet hydro-electric pump storage facility supply on average 1,714MWe to the Western Cape. The province's average peak daily demand of 3,864 MWe (Eskom 2012) requires some 2,050MWe (Eskom 2012) of coal-fired power to be imported from Mpumalanga daily[4].

Since October 2015, the DoE has committed through 2 Ministerial determinations to the procurement of an additional 3,126 MW of gas fired power generation capacity from IPPs (October 2015), and additional 600 MW of gas power (May 2016) to involve state owned companies (SOCs). Whilst all natural gas sources are included in these determinations, it is widely acknowledged that LNG importation is likely to be quickest to deliver, will be cheapest, and is the only credible gas source to help catalyse the downstream gas market opportunity across the country. Three LNG importation locations are under consideration… Richards Bay, Coega, and Saldanha. Each has its merits. The final selection will unfold as part of DOE's procurement process, being managed by its IPP office.

[2] (The Western Cape Government's Department of Economic Development and Tourism, 2013)

[3] (The Western Cape Government's Department of Economic Development and Tourism, 2013)

[4] (The Western Cape Government's Department of Economic Development and Tourism, 2013)

2.1.2 LNG as preferred gas source

Since the Cape West Coast region presently does not have sufficient proven natural gas reserves that could commercially be developed in the foreseeable future for industrial usage and/or power generation, alternative potential gas supply options were considered by the pre-feasibility review. The criteria under which the feasibility of the different options was determined is the potential availability of natural gas from these supply options, the distance of the supply source from the Saldanha Bay region and the timing requirement of first commercial gas deliveries. The natural gas importation options considered were:

- Indigenous gas supplies from known gas reserves and resources such as the Ibhubesi and Bredasdorp basin gas fields;
- Pipeline gas from neighbouring or near-neighbouring countries with proven gas reserves such as the Kudu gas field in Namibia; and
- Liquefied Natural Gas (LNG) from existing and planned foreign natural gas liquefaction facilities.

Of the options reviewed, the importation of LNG was found to be the most viable mainly because of the potential availability of LNG from existing and potential future suppliers and the pricing advantages that could be obtained from the shorter distances between potential suppliers from West and East Africa to Saldanha Bay.

Apart from the diminishing supply of gas into PetroSA's Gas-to-Liquids plant in Mossel Bay, no other indigenous natural gas sources are currently supplying the Western Cape. The Ibhubesi field is relatively small (circa 200bcf) and approximately 400kms from the market, thus has limited potential.

The closest current and future potential supply sources for LNG are Angola, Nigeria and Equatorial Guinea in West Africa and Mozambique and Tanzania in East Africa. Other global supply options could be from the USA, Qatar, Iran, Australia, Trinidad & Tobago and a number of other LNG exporting countries.

2.1.3 LNG overview

South Africa is considered as an energy importing country. The country's energy imports are centred mainly on oil which is a key component to the country's energy security. Oil imports make up approximately 20% of the country's total imports[5]. Like oil, LNG is a globally traded commodity and the two are in many ways related. However, LNG is unique in that it plays in gas markets in some geographies and competes with oil in others. In the South African context South Africa imports roughly 500 000 barrels per day of crude oil. To put this in perspective, a 3000MWe mid-merit gas powered power plant fuelled with imported LNG would consume LNG equivalent to about 5% of the countries crude oil imports[6].

Considering how distinctive this relatively young industry is, it is important to gain an understanding of all the elements present in the LNG physical value chain and to get an overview of its market along with the dominant systems therein. This is especially true for parties who could potentially enter as players in this market. As a result, this section aims to provide a basic understanding of the LNG value chain and the global overview of the LNG market.

The LNG value chain

The elements present within the LNG value chain can be classified under three main categories, namely upstream, midstream and downstream, as shown in Figure 3.

[5] (Statistics South Africa, 2015)

[6] (Petrie, 2015)

A typical LNG process involves the extraction of natural gas and the transportation thereof to a processing plant where it is purified before liquefaction. During liquefaction, the gas is cooled down in stages until it is converted into a liquid state (referred to as LNG). The LNG is then stored in a terminal, prior to being loaded onto LNG carriers and shipped to a distant destination where it is offloaded, stored and thereafter regasified (sometimes known as vaporised) back from LNG into natural gas. It is then sent by pipeline for distribution or placed in storage until it is needed.

LNG is usually transported to the gas consumer by specially designed refrigerated ships. The ships operate at low atmospheric pressure (unlike LPG carriers, which operate at much higher pressures), transporting the LNG in individual insulated tanks. Insulation around the tanks maintains the temperature of the liquid cargo, keeping the boil-off (conversion back to gas) to a minimum. The ships also use the boil-off gas as engine fuel. On a typical voyage, an estimated 0.1%–0.25% of the cargo converts to a gaseous phase daily.

LNG receiving terminals receive and store the LNG from LNG ships until it is required where upon it regasified and transferred to the local pipeline network. The main components of a regasification facility are:

- The offloading berths and port facilities;
- The LNG storage tanks;
- The vaporisation process equipment to convert the LNG into gaseous phase; and
- The pipeline into the local gas grid.

LNG tankers have a number of ways to offload their cargo:

- The most conventional method is from a berth via a fixed arm linked to an onshore LNG receiving terminal;
- Offshore away from congested and shallow ports a floating mooring system via undersea insulated cryogenic pipelines to an onshore receiving terminal;
- Ship-to-ship transfer. The LNG vessel offloads its cargo into a smaller ship which can berth in the port and either discharge to an onshore receiving terminal or regasify the LNG on-board and pipe the gasified natural gas to shore; and
- LNG can also be pumped directly into cryogenic trucks and transported locally to areas without access to a natural gas pipeline.

Offloaded LNG is stored in storage tanks either above ground or semi-buried, until gas is required by consumers. Semi-buried tanks, which can be spaced closely together, are most common in Japan, where land is scarce. LNG can also be stored on modified LNG tankers that have regasification units on board which provides the ship the ability to discharge gas directly into the local pipeline grid. These facilities are usually known as floating, storage and regasification units (FSRUs).

The diagram below illustrates the LNG supply chain as described

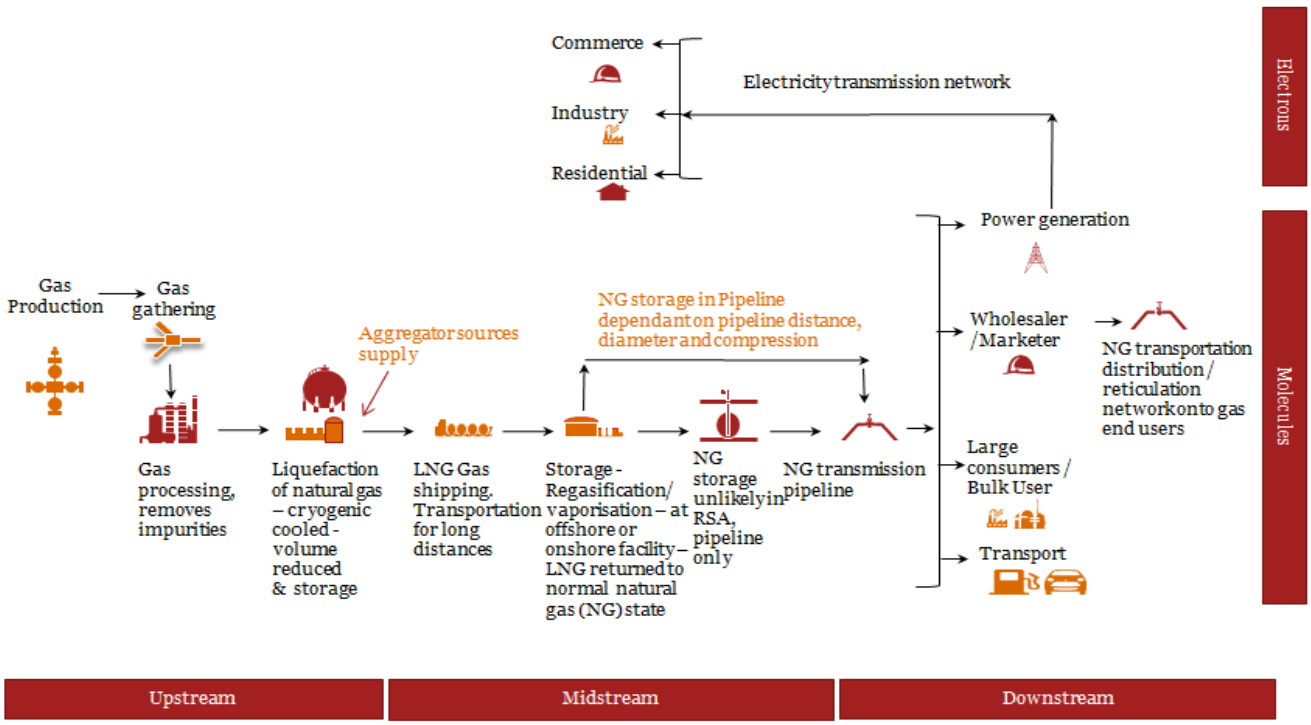

Figure 3: A high-level overview of the LNG value chain

LNG global market view

LNG Trade and markets

The share of LNG in total international gas trade is currently approximated at 30%, which depicts a significant growth over the past two and a half decades.

According to BP's energy outlook 2035, published in February last year[7], the LNG market is poised to experience an eruption of growth in the next 5 years. It forecasts LNG supply growth of approximately 8% every year up to 2020, mainly due to increases in Asian imports.

In North America, the growth in shale gas production has led to an over-supply of gas from 2008 to 2012, causing a plunge in gas prices. During these four years the production of gas is said to have grown at an annual compound rate of 29%. Gas demand, in contrast, was not commensurate with this growth. This lead to gas prices in this region decreasing significantly over this period. This has resulted in the deferral and/or termination of LNG importation projects in the region.

Asia is the largest destination for LNG, importing 73% of the world trade. This is up from 69% in 2012 with Japan and South Korea importing over 50% of the world LNG supply (37% and 17% respectively). LNG demand in Asia is driven by economic growth together with the decision to shut-down most of the nuclear power generation in

7 (BP, 2015)

Japan after the Fukushima incident. However, Asian growth rates have slowed recently due to seasonal and structural factors experienced in South Korea and China particularly[8].

According to BP's Energy Outlook[9], Europe's share of global LNG imports is projected to rise from 16% to 19% between 2013 and 2035. This is despite the current weak demand in Europe for LNG, which dipped for a second year in a row with LNG imports down from 21% in 2012 to 16% in 2013 due to weakness in the Eurozone economies and increased piped gas imports. Europe has also seen an annual decline in total gas demand of 1.6% between 2005 and 2012, which is a result of renewable energy subsidy programmes and efficiency improvements.

According to the International Energy Agency (IEA)[10], Africa holds approximately 74 trillion m^3 of natural gas reserves which can be technically recovered. A report released by U.S. EIA states that South Africa has 390 Tcf (approximately 11.04 trillion m^3) of technically recoverable shale gas resources, making the country the eighth-largest holder of technically recoverable shale gas resources in the world[11]. For the year 2012, Africa accounted for 16.8% of the global LNG export volumes, with Nigeria being the fourth largest exporter of LNG in the world (LNG Industry, 2014). Significant gas finds in Mozambique and Tanzania have caused the world to take note of East Africa as an emerging player in the global industry. This has resulted in a projected growth in African LNG supply to 340 million m^3 per day by the year 2035. Mozambique alone has some of the largest reserves discovered in the last decade, and liquefied natural gas (LNG) exports are expected to begin by 2020. When this occurs, they will be competing with other new entrants such as Australia and Papua New Guinea. Tanzania is also expected to benefit from recent natural gas discoveries with LNG exports expected by 2025. Angola became an LNG exporter in 2013 with the commissioning of the Angola LNG plant in Soyo. The plant has a capacity of 5.2 million tonnes per annum. These developments create significant economic benefits for Africa and provide opportunities for LNG importation into South Africa.

Global Pricing

A decade ago global LNG markets were characterized by stable long term contracts, point to point deliveries with limited interregional trade, segmented pricing regimes and limited markets. Since 2012, the LNG market has changed with off takers often having diversion rights and the liquid markets of the US and Europe allow for flexible volumes. Global (and regional) gas discoveries have resulted in increased availability and in falling gas prices.

There are two basic pricing systems that are generally used for international trade of natural gas: oil-based pricing and gas-on-gas based pricing. The price of natural gas is indexed to competitively determined gas market spot prices which change in response to natural gas supply and demand under the gas-on-gas pricing system. Whereas under the oil-based pricing system, the price of natural gas is determined from oil market spot prices which change in response to oil supply and demand[12].

Figure 4 below displays where in the world each one of these pricing systems is commonly applied.

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[8] (BG Group, 2014)

[9] (BP, 2015)

[10] (International Energy Agency, 2013)

[11] (U.S. Energy Information Administration, 2014)

[12] (U.S. Energy Information Administration, 2014)

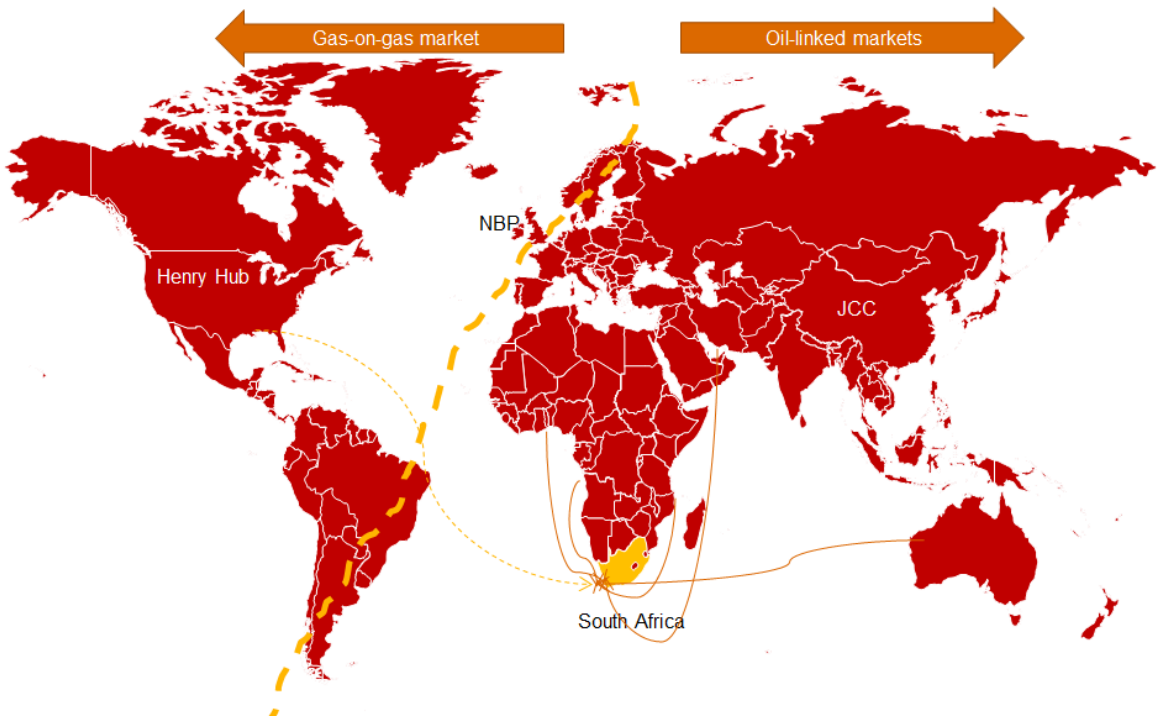


Figure 4: A view of the world's gas pricing systems

Global gas trade has three distinctive markets. These markets are North America (Henry Hub), Europe (NBP) and Asia (JCC).

Henry Hub, serves as the official reference delivery location and pricing point for natural gas futures on the New York Mercantile Exchange (NYMEX). It is the most liquid physical natural gas trading point among the 30 major market hubs in the US[13]. It is a gas-to-gas based pricing system and the factors that affect it include weather, the economy, demand, storage and production.

The UK-based National Balancing Point is also a gas-to-gas based pricing system and is Europe's most mature and liquid virtual trading hub. It is the pricing and delivery point for the Intercontinental Exchange (ICE) natural gas futures contract. The NBP is usually used for LNG spot trading while most European longer term contracts use Brent crude oil as their price reference[14].

The dominant pricing system in the Asia Pacific is the Japan JCC (Japan Crude Cocktail), which is the weighted average price of all crude oils imported into Japan. The JCC is used widely in LNG contracts globally-a reflection of the importance of Japan in the development of the LNG market and as the largest importer. JCC is an oil-based pricing system and is closely correlated with major crude oil indices.

From 2009, a considerable divergence of prices between these distinct regional gas markets across the world has been observed, as can be seen in the figure below. What can also be noted is the declining trend in LNG

[13] (Petronas, 2013)

[14] (Petronas, 2013)

prices across all three markets from 2012. This is due to specific events in each of these regions that have affected their gas market dynamics, consequently affecting the pricing of LNG within each of these regions.

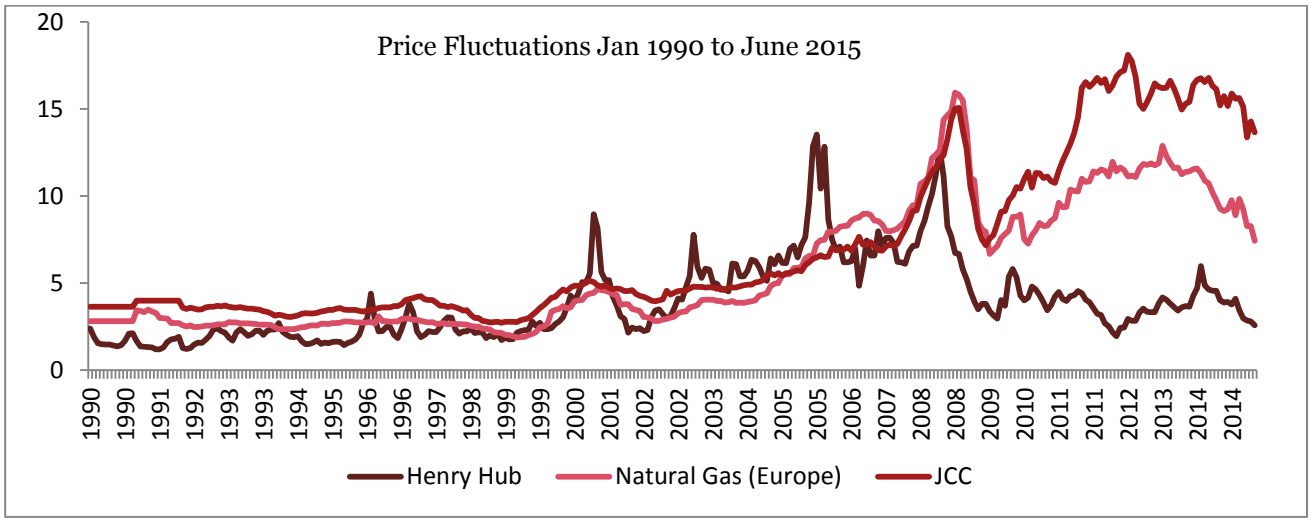


Figure 5: Price fluctuations of the Henry Hub, NBP and JCC

Short-Term/Spot LNG Trading

The evolving characteristics of the global LNG market are most evident in the growth of short term/spot trade. Short term trade is defined as a cargo or a series of cargoes traded with a 90 day to 3 year term. It is a trade in flexible volumes, which are not tied to specific destinations and are divertible. The goal of the suppliers of these volumes is to generate incremental profits from arbitrage opportunities.

In the past, short term trade in LNG was driven by seasonal demand variations and wedge volumes - volumes available from liquefaction projects until their contracted long term buyers could ramp up to take their full volume commitments. Nowadays, short term trade is driven by the following factors:

- 'Equity lifts' (i.e. the share of LNG that equity holders in a liquefaction plant are entitled to offtake) being sold into more lucrative markets, not necessarily to the equity holders' home/primary market;
- Buyers and Sellers agreeing to divert cargoes to higher value markets; and
- Expiry of long term SPAs.

These factors have resulted in the continued growth of the short term LNG market to a point where spot/short term trade accounts for almost 30% of the global LNG volume traded currently. The increase in short term LNG contracts and spot trades, reduces the commercial risk to LNG imports into South Africa in that it allows for increased flexibility and provides an opportunity that shorter duration LNG contracts could be negotiated which enables the country to simultaneously pursue indigenous gas developments and switch to these when/if they're proven to be commercially viable without being locked in to a long term foreign supply option.

Key Trends

The key trends that can be drawn from reviewing the LNG global market are the following:

Shift to a buyer's market

The market environment for the international trade of LNG is becoming increasingly favourable for importers, due to the recent decrease in LNG demand and with supply expected to be in excess until the end of this decade. It remains to be seen if buyers' market will endure or if there will be a return to a sellers' market post 2020.

Spot and short term trading are on the rise

The popularity of these trades is evidenced in that since 2010 this volume has trebled and is likely to continue.

Traditional procurement models are changing

As the LNG spot market grew in the mid-2000's, new procurement models began to emerge that offer more flexibility of supply while maintaining the security of long-term contracts required for project financing.

Chapter 3: Contractual Environment

3 Contractual Environment

3.1 Introduction

This chapter will discuss our findings of the study of the risk elements across the LNG value chain. Accordingly, the chapter commences with an overview of the various contracts in the value chain and thereafter discusses the various commercial, regulatory and the financial risks.

3.2 LNG Contractual Value Chain

The relationships between each of the players across the LNG value chain are characterized by the contracts present between them. The different players present within the LNG value chain and the contracts between each are depicted in the diagram below.

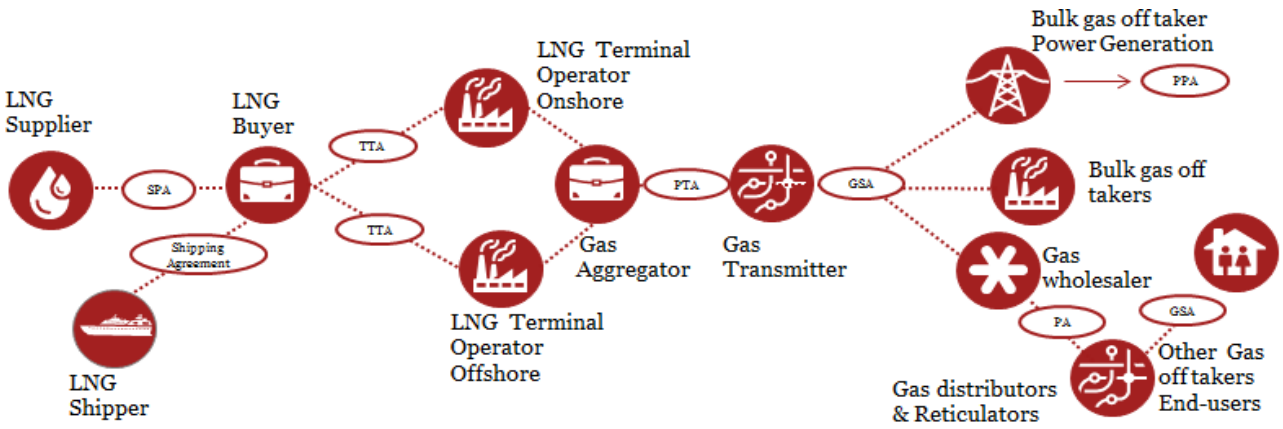


Figure 6: Players within the LNG value chain and their respective contracts

From the above diagram it can be seen that LNG contracts are complex and therefore can present a high level of risk exposure to any given party. LNG contracts have a number of general terms and conditions which are described in the below.

The different contracts present between each of the players, as illustrated in the diagram above are defined in detail below.

Sale and Purchase Agreement (SPA)

The most common agreement in the LNG industry are Sale and Purchase Agreements (SPAs). These are long term contracts between the seller and buyer which describe LNG quantity, quality, price, duration, transportation and the risk and responsibilities of each party. The term of these contracts has typically been for 15-25 years. However, recently the term has been reducing with some contracts of 10 years' duration. The quantity of LNG that the buyer must purchase is usually on a "take-or-pay" basis, in which the buyer must pay for the contracted volumes regardless of whether or not they're able to accept delivery.

The Seller

A take-or-pay contract provides the seller with an assured revenue stream, so that returns on the significant capital investment and risk into a liquefaction plant are controlled. The contract allows a seller to secure substantial external debt financing on a limited recourse basis. Most LNG suppliers will not launch new LNG trains without some firm supply agreements being in place. A seller may allow some flexibility into a contract however, that will come at premium.

Buyer / Aggregator

There are two classes of LNG buyers: those who buy the LNG for their own use (Buyer/Off-taker), and those who buy LNG for resale to the gas-user market (Aggregators). Both need to ensure that they have demand for the volume they intend procuring on a long term contract. For an own use off-taker, for example a power plant, this implies sizing of the deliveries to the consumption rate of the plant. For an aggregator, this may require back to back contracts with gas users to limit the aggregator's risk.

Volume

A typical take-or-pay contract requires the buyer to take or pay for any volumes made available and not taken unless:

(a) the seller failed to make available for delivery;

(b) the volumes were rejected as they did not meet quality specifications; and

(c) the buyer could not take as a result of force majeure.

Gas sales contracts provide the buyer with a right to receive a "make-up" quantity in later years, which preserves the seller's assured annual revenue stream.

Although take-or-pay SPAs are designed to penalise deviation from the planned delivery schedule, most now allow for small deviations as long as these are communicated well in advance and some allow for larger deviations from schedule at a surcharge. With more spot and short term contracts LNG contracting is becoming less rigid and increasingly allows for greater flexibility to both the buyer and seller, where both share in the upside from deviating cargoes to more lucrative destinations.

A fractional quantity refers to small volumes that are under or over delivered due to slight variations in the loaded/unloaded cargo volumes. The surplus/deficit quantity shall then be treated as being acceptable in that year and volume reduced/increased respectively in the following year.

Price

SPAs are typically priced in US Dollars and indexed to either a gas, oil and/or other commodities. As mentioned previously, US destined cargoes are indexed to the Henry Hub gas index, whereas Asian cargoes are referenced to crude oil. This is a significant risk to the buyer in a non-USD referenced country and is further compounded if the indexation is not linked to a locally accepted commodity. In South Africa, the same is experienced with oil imports which are linked to the price of crude oil in USD. A buyer may hedge against the underlying commodity price and currency risks, through the use of financial hedging instruments, however such instruments usually are neither economical nor available for such long term durations. Due to the long term cyclical nature of oil and gas prices and also currency, the buyer may experience years of losses and/or years of windfall profits.

Shipping Agreements

The type of shipping agreement will vary based on whether the buyer/aggregator has a dedicated LNG fleet assigned to it or whether it is company owned or leased/chartered. The detail and costs associated will depend on the size and type of LNG vessel used and the contract flexibility and timelines.

There are two main types of shipping contracts:

- Free on board (FOB) where the buyer bears the risk of any losses during transit and the price quoted does not include freight; and
- Destination ex-ship (DES) where the supplier takes the risk of any losses until the ship docks at the final destination.

Most short term contacts currently are DES, while long and medium term contracts could be either FOB or DES.

The Shipping contracts can also become more complex with multiple supply options and diversion cost allocations being written into a contract.

Tolling agreements

Tolling agreements for terminals and pipelines (TTA, PTA) refers to a contract where a fee is paid for the service provided by a regasification or gas transmission tolling company. The tolling company does not take title to the natural gas that is processes or transports.

The term "tolling facility" implies a unit for which the user pays a fee remunerating for the services provided. The arrangement is one where the infrastructure is built and financed by a special purpose entity that contract its services to the user (which can be more than one in multi-user tolling arrangements) in exchange for a fee. Typically, the off-taker pays a fixed fee for the right to receive the service (LNG storage and regasification or pipeline gas conduit services), regardless of whether the service is used. Commonly the fixed fee contract will also include an additional variable charge that is determined by the actual throughput volume. The fee represents the entity's only source of cash-flow and covers operating expenses, debt service (interest and principal amortisation), taxes and shareholders' return. This is a very common method for financing regasification terminals and transmission pipelines as a certain amount of revenue is guaranteed. While tolling facilities are not able to collect windfall profits, they also are relatively low risk.

Below are the descriptions of the different tolling agreements available.

Terminal Tolling agreements (TTA)

Tolling agreements for an LNG terminal and regasification plant will be an agreement for the storage and regasification of LNG into natural gas and is typically with the buyer. The buyer owns the product, not the terminal owner.

Floating Storage and Regasification Units (FSRUs) are becoming more commonplace in new LNG developments. These are LNG terminals located on a ship which is berthed in or close to the destination port. These vessels receive LNG from an LNG tanker, store the LNG, regasify it and transfer the regasified product into a pipeline which connects to the shore. The tolling model is particularly well-suited to FSRU. The greatest risk to FSRUs is however their uptime which is affected by adverse weather conditions. These result in high demurrage costs and stock-outs with possible diversion of the shipment to another location. The FSRU risks need to be assessed against the benefits of it being cheaper and having a quicker lead time to market than an onshore facility. Detailed feasibility studies are required to determine the tipping point between terminal options for the various identified sites as non-financial elements such as marine conditions, port, environmental and licencing constraints need to be considered. Pipeline Tolling Agreement (PTA)

Tolling agreements for a pipeline will be for the use of natural gas pipeline infrastructure. The pipeline owner will not own the gas molecules inside the pipeline but be responsible to provide the contracted services of storage and transportation via the pipeline to an agreed performance level.

Power Generation / Energy Conversion Agreements (ECA)

Tolling agreements can also be present where a power generator can be compensated for converting a fuel (natural gas) into electricity. These types of agreements are common in the Middle East where the utility sources and provides the feedstock to an independent power plant owner/operator who is compensated to convert the feedstock to electricity.

There are variations of the tolling structure with tolling companies even taking title of the LNG so that they can share in the pricing upside/downside while the tolling fee insulates and guarantees revenue. Tolling agreements generally have a low risk to the entity as the owner of the molecules will take the majority of the risk assuming that volume throughput only provides a small element of the guaranteed revenue stream.

Significant risks for tolling companies are the creditworthiness of the user, unplanned shutdowns, construction cost escalation, tariff mechanisms if applicable and regulatory issues such as EIAs and licencing of projects.

Gas Sales Agreement (GSA)

The GSA is a standard agreement for the sale and purchase of natural gas for delivery into a pipeline network or to facility such as a power station, factory or LNG liquefaction plant- hence, an SPA is a form of a gas sales agreement. The GSA is neither the draft of the seller nor the buyer, but represents a balanced document containing a range of alternative treatments of common issues for both parties to select from and additional optional clauses where necessary. The GSA contemplates sales of gas on the basis of continuous deliveries, rather than discrete dispatches, as might be found under an LNG SPA.

Master Sales Agreements (MSAs)

The LNG spot market has grown wider in terms of the circle of counterparties involved in the trading of LNG. No longer does it consist of only producers and end-users, but now also of LNG aggregators with growing LNG portfolios and traders without equity interests in physical LNG assets. MSAs therefore, act as a common ground for parties to be able to efficiently execute a spot trade. These types of contracts are becoming more popular with almost 30% of the trade in 2014 being LNG spot / short term trade agreements. MSAs on their own do not impose an obligation on the parties to buy or sell LNG from each other, but rather contain a form of confirmation memorandum as an annex which parties will use to execute and record the cargo-specific terms of each particular spot trade. The terms of the MSA and the relevant confirmation memorandum together then represent the agreement for the particular cargo.

MSAs have allowed the gas market to become dynamic with LNG liquefaction projects uncommitted volumes not covered under SPAs now having a developed market in which sales can occur. Suppliers can use MSAs to sell extra cargoes to destinations experiencing seasonal peaks in demand. Buyers can use MSAs to source additional cargoes to meet seasonal or temporary LNG demands.

Since 2009/10 the Association of International Petroleum Negotiators (AIPN) promoted the standardisation of spot sales that are delivered on an “ex-ship” (DES) basis in order to stimulate this market and decrease the complexity associated with short term contracting. Most short term contacts currently negotiated are DES, while long and medium term contracts could be either FOB or DES.

The main areas that this AIPN standardisation covers for spot sales are:

Table 1: AIPN Standardised contract conditions

Contract term	Pricing terms and conditions	Taxes, duties and other charges
Sales obligations	Payment and invoicing	Force majeure
Purchase obligations	Credit support	Dispute resolution and arbitrage
Product quality and delivery tolerances	Measurement and testing	Transportation / unloading terms and conditions

Power Purchase Agreement (PPA)

PPAs are agreements that exist between an electricity provider and an electricity purchaser in order to manage the production and sale of energy between the two parties. PPAs typically consist of the full details of the financing involved as well as the key delivery dates of the project.

LNG requires a large off-taker which in the South African context has been noted to be a power generator in excess of 500MW or significantly larger. The power plant revenue viability and associated tariff implications is the most important part of the value chain as if this is not bankable to investors then LNG importation will not happen. Thus PPAs need to be carefully drafted in order to balance the interest of the all the parties and reduce high levels of associated risks.

For a gas fired power plant, the tariff usually is usually split into three components:

1. A Fixed Capacity Charge which covers the fixed capital costs and debt service of the project;
2. A Variable Charge which covers the variable costs such as operations and maintenance which vary with load factor; and
3. Fuel Costs which can either be included in the variable charge or treated as a separate pass through cost.

Flexibility to accommodate exchange rate movements can put considerable pressure on National Treasury, particularly where a project is committed to fuel purchases denominated in US dollars and linked to an international commodity whilst having to on-sell power in South African Rand and linked to local inflation. The absence of appropriate financial hedging instruments for such long-term contracts leaves the Government with an uncertain financial burden, which is ultimately passed on to the consumer by regulatory mechanisms or the tax payer if mitigated through the fiscus.

Chapter 4: Key Stakeholders

4 Key Stakeholders

Essential to the development of how the scenarios could realistically play out within the South African context, is to discover who the key players are within the industry, their mandates and their views with regards to the role they could potentially assume in a project of this nature. This chapter discusses findings from engagements with several of the relevant stakeholders.

4.1.1 Key Stakeholders and their mandates

The key stakeholders are driven by their mandates, which in the case of private entities is often quite apparent, however state owned companies have broader mandates which may require interpretation.

Table 2: Key industry players and their mandates

Player Type	Examples	Mandate/ Core business functions
International Oil and Gas Companies (IOCs)	BP Chevron Eni ExxonMobil Shell and Total	These companies are engaged in every aspect of the natural gas business. They explore, develop and supply gas for liquefaction. They develop, construct and operate world scale liquefaction plants, and operate a fleet of modern and industry leading LNG tankers. They access premium markets through their direct participation in LNG regasification projects, giving them capacity rights in import terminals.
National Oil Companies (NOCs)	Sonangol (Angola) Empresa Nacional de Hidrocarbonetos (ENH) (Mozambique) Tanzania Petroleum Development Corporation (TPDC) Qatar Petroleum (QP)	These are state-owned enterprises responsible for all phases of the oil and gas industry in their respective countries. Their mandate is to spearhead, facilitate and undertake oil exploration and development in their country.
Shipping Companies	IOCs/NOCs BW Maritime Golar	They are independent owners and operators of LNG carriers. They are progressing plans to grow their business further via Floating liquefaction (FLNG) and further invest in Floating regasification units (FRSU).
Global Offshore terminal (FSRU)	Excelerate Golar Hoegh	Provide floating energy solutions and operate world-wide as owners and operators of floating LNG import terminals; Floating storage and regasification units (FSRUs). Offer a full range of floating regasification services, from FSRU to infrastructure development; they also serve the upstream market through the development of floating liquefaction (FLNG) solutions. They also provide trading and chartering services.
Natural gas transmission pipeline owners (South African)	iGas Sasol Transnet Reatile	Ownership and operation of extensive gas reticulation pipelines for the supply of gas to customers. South African entities listed, however many international companies can also provide this.

Player Type	Examples	Mandate/ Core business functions
	Gigajoule	
Global Power and Gas Utilities	ACS Cobra Centrica EDF ENEL GDF Suez KEPCO SASOL	These are vertically integrated global energy companies with operations spanning electricity generation and the sale of gas and electricity to homes and businesses/ industry. They operate across the entire gas value chain, from exploration to distribution and marketing, including production, liquefaction and transport. They are also involved in the trading and marketing of LNG or natural gas. They also construct and operate gas fuelled power plants.
Independent power producers (IPPs)	Various local and global	Develop and operate gas fuelled power plants which supply electricity to a buyer such as Eskom or a municipality.
Gas Traders	Sasol gas Spring Lights Egoli gas Novo Energy (CNG) NGV Gas (CNG) Virtual Gas Network (CNG)	Ownership and operation of the required gas infrastructure such as gas compression stations, dispensing stations for vehicles and pipelines for the supply of gas to customers.
Main natural gas consumers of gas in South Africa (Bulk consumers)	Members of the Gas User Group (GUG)	The GUG represents 13 large domestic manufacturers- ArcelorMittal, Ceramic Industries, Columbus Stainless, Consol, Corobrik, Distribution and Warehousing Network, Ferro Industrial Products, Illovo Sugar, Mondi, Nampak, NCP Alcohols, PFG Building Glass and South African Breweries. These provide a glimpse of the target industrial market for gas importation.

The above list describes the various global and local private sector players and their anticipated role within an LNG importation project. The list is not exhaustive, and additional players may be relevant to the South African LNG opportunity or express an interest in participating in the local opportunity.

In addition to the above, there are several state owned companies who have expressed their interest in participating in an LNG importation project. These are described below:

Table 3: Government entities and their mandates

Player Name	Mandate/Core business
CEF	The CEF Group mandate is to invest in and develop gas and gas infrastructure in a manner which is commercial and can attract investment. CEF is the holding company for a several state entities including iGas, PetroSA and PASA.
iGas (part of CEF group)	iGas is the official state agency for the development of the hydrocarbon gas industry in South Africa. It represents that State's ownership in the ROMPCO gas transmission pipeline from Mozambique.

Player Name	Mandate/Core business
PetroSA (part of CEF group)	PetroSA is the South African National Oil Company (NOC) and has been mandated by Cabinet to lead developments in gas infrastructure in the Western Cape. Its primary operation is the offshore gas production facility which supplies its Gas-to-Liquids refinery located near Mossel Bay in the Western Cape.
Petroleum Agency of South Africa (PASA)	PASA has the responsibility to promote the exploration and exploitation of natural oil and gas, both onshore and offshore, in South Africa and to undertake the necessary marketing, promotion and monitoring of operations.
Transnet Pipelines (formally Petronet)	Transnet Pipelines is a division of Transnet which owns, operates, manages and maintains a network of 3 000km of high-pressure petroleum and gas pipelines, on behalf of the South African government.
Transnet National Ports Authority	Transnet National Ports Authority is a division of Transnet Limited which is mandated to control and manage commercial ports in South Africa including Saldanha Bay.
The Ports Regulator	The Ports Regulator mainly regulates pricing and other aspects of economic regulation, including promotion of equity access to ports facilities and services and the monitoring of the industry's compliance with the regulatory framework.
The National Energy Regulator (NERSA)	NERSA's mandate is to regulate the electricity, piped-gas and petroleum pipelines industries in terms of the Electricity Regulation Act, the Gas Act and Petroleum Pipelines Act. Its mandate of regulation covers all hydrocarbon gases transported by pipeline, the construction/operation/conversion of gas facilities and gas trading.
Department of Transport	The Department of Transport administers the National Road Traffic Act and the National Road Traffic regulations on the transportation of dangerous goods by tankers. The ports regulator comprises a Chairman and Members that are appointed by the Minister of Transport.
Department of Labour	Administers the Occupation and Health and its regulations as well as the labour relations Act and Basic conditions of employment.
Department of Environmental Affairs (DEAT)	Along with provincial environmental authorities the Department of Environmental Affairs is responsible for the environmental laws and Environmental Impact assessments (EIA) especially on mid and downstream oil and gas sector.
Provincial Government	The Provincial Government of the Western Cape promotes the development of infrastructure in the province including natural gas and renewable energy.
City of Cape Town	The Constitution sets out that the City is responsible for electricity and gas reticulation.
Eskom	Eskom's mandate is to provide electricity in an efficient and sustainable manner, including the generation, transmission and distribution of electricity, the latter including wholesale and retail sales.
Department of Energy (DoE)	Focuses on energy issues and aims to effectively implement policy and to ensure secure and sustainable provision of energy for socio-economic development. The DoE is the driving force behind the GAS-IPPprogramme.
Department of Trade and Industry (DTI)	Focuses on providing a predictable, competitive, equitable and socially responsible environment, conducive to investment, trade and enterprise development; and broadening participation in the economy to strengthen economic development.
Department of Mineral Resources (DMR)	Promotes and regulates the minerals and mining for transformation, growth, development and ensure that all South Africans derive sustainable benefit from the country's mineral wealth

4.1.2 Summary of feedback from stakeholders during engagements

A series of engagements with some of the stakeholders given in the tables above were hosted in the form of a discussion where pertinent questions regarding their views on LNG importation were posed. Their responses are summarised in the table below.

Table 4: Summary of feedback from stakeholders

IOCs and IG&PUs

Position: Can provide full LNG value chain infrastructure - operate and manage it. Can play in any position across the LNG value chain.

What would they require in order to do so?

- A credible buyer - either the state, an A-rated company with a substantial balance sheet or an established gas market. (Form of sovereign guarantees)
- Fully permitted/ licensed sites or a well-defined process for permitting/ licensing with strong adherence to international law
- Minimized country risk
- Like to have third party access restriction on infrastructure
- Long term supply contracts to build a sustainable business

IPPs

Position: Willing to put up and run power plants

What would they require in order to do so?

- Legislation in place allowing them to do these projects
- Have gas supplied on a 'pass-through' basis
- Clarity on and fast tracking of permitting & licensing processes in particular EIA's and power generation & gas use licensing.
- Guaranteed off-take
- Lenders should be comfortable with level of risk
- Less complex wheeling agreements

SOCs

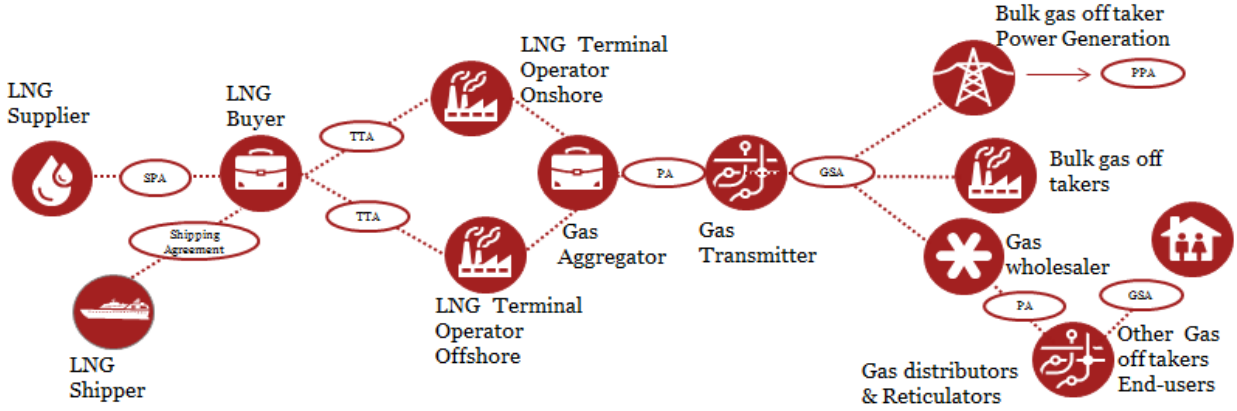
Position: It is unclear which SOE is solely mandated to play the role of being a gas aggregator.

Should an SOC assume this role they would be:

- Interested in developing and managing infrastructure related to building a gas market. Infrastructure may include LNG terminals and gas pipelines, but not power plants
- Keen to play the role of the aggregator in the market- willing to be the buyer of LNG into the SA market-in order to avoid the emergence of a private monopolised gas market.
- Believe BOOT contract would allow greater open infrastructure access.
- The State should own the gas molecules and supply gas to IPPs

4.1.3 Role of key stakeholders in value chain

Figure 7 below displays the generic value chain for the importation of LNG, below which is a table that shows which role the stakeholders described above could possibly assume across each element of the value chain. The third row of the table depicts which SOC could potentially assume that role.



	LNG Supplier	LNG Buyer	LNG Terminal Owner/ Operator Offshore/Onshore	Aggregator / Marketer	Gas pipeline owner/ operators		Off-takers	
					Transmission	Distribution	Power	Other
Stakeholder which can assume role	IOCs NOCs Traders	Aggregator, SOC	IOCs / Global FSRU, SOC, NGC	IOCs / Gas Traders / Global Gas & Power Utilities, SOC	Intl / local Gas Pipeline Co/ Global Gas & Power Utilities, SOC	Gas Pipeline Co, Intl/local Gas Utilities, CoCT	IPPs, Eskom, CoCT	Bulk consumers and wholesalers incl. CoCT
State Owned Company, which can assume role	IOCs NOCs Traders	PetroSA, Eskom	iGas, Transnet	PetroSA	iGas, Transnet	CoCT	Eskom, CoCT,	Bulk consumers and CoCT

Figure 7: The LNG value chain with a table showing the potential players in each element of the value chain

Chapter 5: Qualitative Risk Analysis

5 Qualitative Risk Analysis

This chapter provides an overview of the three scenarios to be analysed and thereafter delves into a qualitative analysis of the commercial, regulatory and financial risks associated with each.

5.1 Scenario Overview

In 2015, the Western Cape government identified three indicative scenarios for LNG importation, namely an internationally led, a public private partnership and a state driven scenario. These scenarios were proposed to cover the range of possible contracting models, and provide a means by which to explore the inherent risks associated with LNG importation. Since that time, there has been clear guidance from DOE favouring a vertically integrated, or "bundled" contracting model for this initial tranche of LNG import projects. As such, the "bundled" model encapsulates elements of all 3 of the scenarios described below.

- The international driven scenario envisages that a single entity would provide a full turn-key private solution driven by a single entity that has the capability to provide or source all the elements of the value chain from LNG supply to electricity generation. This would be sourced though an open tender procurement process (such as the DoE Gas-IPP procurement programme) and funding would be sourced through the private sector. It is not clear how NERSA would licence the internationally driven scenario if the price is not split into the separate elements.
- The State driven scenario has a greater focus on developing a full gas market strategy that is funded and procured by the state through its mandated SOCs. This approach would take the form of national interest projects and imply centrally led co-ordination of state entities. DoE and NERSA are familiar with this scenario given their current oversight and regulation of state owned companies such as CEF, PetroSA, iGas and Eskom. DoE has indicated through the IRP that the majority of new gas to power projects will be sourced from IPPs, thus this scenario may be limited to specific projects, or require a policy shift.
- The Public Private Partnership scenario envisages that multiple entities would be involved in a complex contracting structure that could be bundled within a single project company or unbundled into separate elements. PPPs allow for some State participation and can access either state or private funding. DoE may consider this scenario as a means to gaining IPP participation whilst also securing national interests in a strategic sector of the economy.

The table below highlights the salient features and potential benefits of each scenario.

Table 5: Overview of the 3 scenarios

Scenario Characteristic	Scenario 1 (International led /Private sector driven)	Scenario 2 (State driven)	Scenario 3 (PPP driven)
Project development	Fully private sector developed	Part of the Developmental agenda - in the National interest	State partners with private sector (PPP)
Main benefits to government	Minimise risk to government. Allows for accelerated timelines and competition	Allows for government to government transactions. Maximise the use of RSA resources	May allow for government to government transactions. Skills and knowledge transfer between internationals and locals
Funding	Funded by private sector	Funded by the State	Access private sector funding
Procurement structure	Competitive open tender procurement for a private sector provided	SOCs mandated to perform distinct roles within the gas value chain	Government to procure private sector partner(s) through open tender to form a consortium. The

	full value chain solution	and will procure within state procurement regulations	consortium provides the full value chain solution.

5.1.1 Scenario 1 – International /Private sector driven

The contractual and player arrangement for Scenario 1 can be illustrated as shown in Figure 8. In this scenario a full value solution is supplied by private players, through either a consortium or a vertically integrated company or collection of individual private entities. The grey represents the elements where the private players, either within a consortium or as single entities, would be involved.

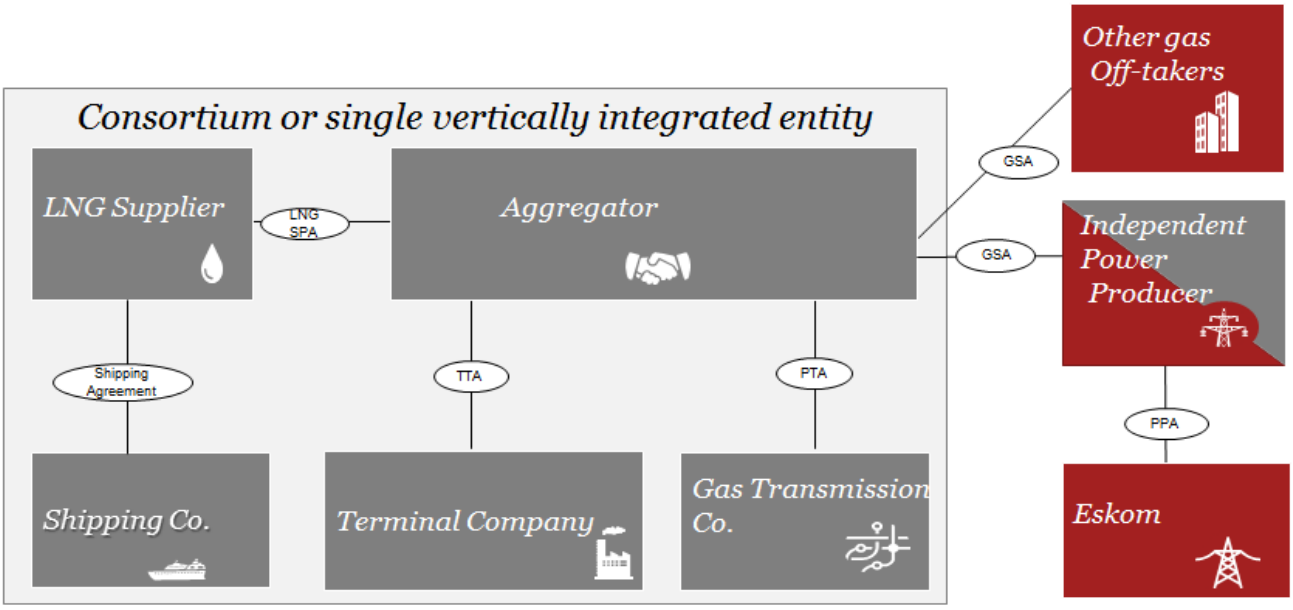


Figure 8: Contractual arrangement for Scenario 1

The players capable of performing the lead role for the above scenario are described in the table below:

Table 6: Players for Scenario 1

Players in consortium or Single vertically integrated entity (providing full value-chain solution)	**Gas Off-takers**	
	Power	**Other**
IOCs NOCs Global Gas & Power Utilities	IPPs Eskom CoCT	CoCT Bulk consumers

It is assumed that the contracts from the area of exploration and production are in place and the supply of natural gas to the liquefaction plants are in place; hence they are not depicted in Figure 8. This contractual arrangement assumes that the natural gas sent to the liquefaction facility is owned by the producer, who then sells it after liquefaction.

In this scenario it is envisaged that an IOC could aggregate demand and supply and operate infrastructure through to the regasification on-shore or offshore facility and then source another international or local gas pipeline company to operate the pipelines and the power plants. It is possible that a vertically integrated energy company such as Sasol or Centrica could provide all the elements along the value chain. There are a number of large global gas and power utility companies that could participate in being the buyer /aggregator of power and provide all the elements along the value chain to power generation.

The above scenario might not align with the horizontal integration and development of the entire gas market, as this scenario might focus only on gas for power generation.

A further risk is that there are only three potential sites for LNG importation in South Africa and it is unclear how the DoE's procurement programme will be applied to these sites. This may lead to a concentration risk whereby only one IPP entity may be procured for each site assuming each site can accommodate only one LNG receiving facility.

There is a risk of monopolistic behaviour by the vertically integrated private sector player, which may be mitigated by the DoE in its structure of the procurement programme, in particular through prescribing a ceiling price.

LNG supplier risk is considered low, however the contract should provide a second source of supply in-case of an event at the upstream liquefaction facility.

The advantages of this scenario are firstly that it promotes a privately funded solution with a less complex contracting structure and accelerated timelines while limiting the risk to government. This view is premised on the assumption that capable international companies/consortia will be invited to apply and provide a full turnkey solution through a well-defined tender process.

There is a possibility that this will provide an option for more competitive pricing as the integrated company may supply LNG cheaper through bulking from its global portfolio, build on its global gas infrastructure experience and leverage its supplier relationships to procure and provide cheaper services.

5.1.2 Scenario 2 – State Driven

The contractual and player arrangement for Scenario 2 can be illustrated as shown in Figure 9. The grey represents the elements where the state would be involved.

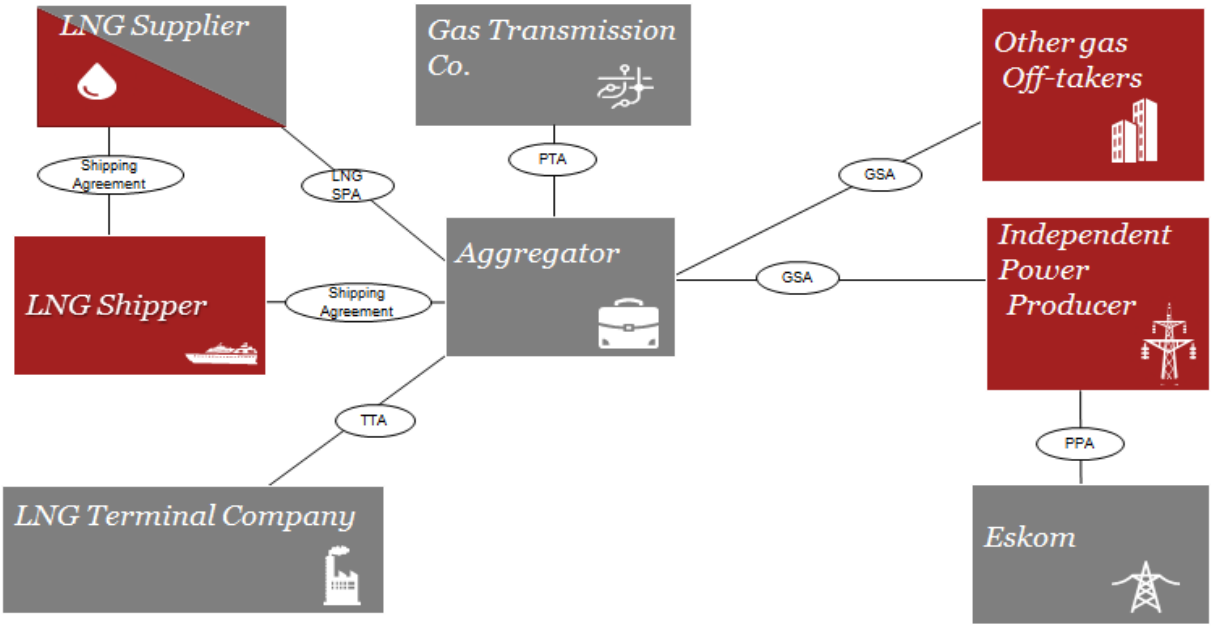


Figure 9: Contractual arrangement for Scenario 2

The table below describes the potential players for each of the elements of the value chain for this scenario.

Table 7: Players for Scenario 2

LNG Supplier	LNG Buyer	LNG Terminal Owner/Operator	Aggregator / Marketer	Gas pipeline owner/ operators		Off-takers	
		Offshore/Onshore		Transmission	Distribution	Power	Other
IOCs NOCs Traders PetroSA	PetroSA Eskom	iGas Transnet	A number of SOCs, possibly PetroSA	iGas Transnet	CoCT	IPPs Eskom CoCT	Bulk consumers and CoCT

As in the previous scenario the contractual arrangement assumes that the natural gas sent to the liquefaction facility is owned by the producer, who then sells it after liquefaction. The liquefaction owner could be an NOC, be part of a joint venture or an international private player. PetroSA has previously indicated interest in participating in an upstream LNG liquefaction project, however it is unclear how this investment might be financed.

In this scenario it is envisaged that a state owned company (possibly PetroSA) would be the buyer and aggregate supply to the market. Eskom may also jointly participate as a buyer or have a direct back to back arrangement for its own gas supply requirements. An IPP would possibly have a back to back agreement with the aggregator or a fuel cost pass through agreement with the electricity off-taker.

The aim of the aggregator would be a focus on the country's best interest and the development of a fully integrated gas market, rather than just focusing on gas to power and self-interest.

The advantage of the a State owned entity being an aggregator is that government to government transactions may be possible especially with other African trading countries via their NOCs.

The terminal and regasification facilities and transmission pipelines infrastructure would be typically handled by iGas or Transnet who both own and operate long gas pipelines in country (iGas is the holding company of the SA Government's 25% share of the ROMPCO gas pipeline from Mozambique to Secunda and Transnet owns the Lily pipeline from Secunda to Durban). The companies would levy a tariff via a tolling arrangement for the regasification, storage and distribution services provided.

The natural gas sold to off-takers would be to Eskom for power generation, IPPs under the Gas-IPP programme and possibly other IPPs and Municipalities if they have been identified by a ministerial determination. The reticulation and marketing of the gas could be performed by the CoCT independently, or through a joint venture to generate income, however it needs to be determined if the CoCT could reticulate the gas profitably. The natural gas could also be distributed to bulk end users and marketers who could also assume the reticulator role.

The biggest advantage to a state driven scenario is the influence of the government especially with other governments in negotiating supply agreements and the focus on developing an integrated gas market where gas demand is created prior to commercial development of indigenous supply sources. It is envisaged that the State driven scenario will better facilitate broader gas market development and support the development of indigenous gas reserves which if successful will enable a reduction in the balance of trade through reduced reliance on foreign oil and gas. A State driven scenario will maximise South African resources and an emphasis on the economic benefits that gas can have on the fiscus at large. The state driven scenario is likely to have a higher number of South Africans employed than in the other scenarios and be focussed on providing a full gas to market solution.

The disadvantage to a state driven scenario is that there is some ambiguity in the mandates of the various SOCs, leading to confusion in the marketplace as to who is the designated National Gas Company, National Gas Pipeline Company and National Gas Aggregator. This has led to each developing their own projects independently and issuing conflicting statements to the market regarding LNG importation to Saldanha Bay.

The creditworthiness of SOCs is quite topical given Eskom and Transnet's major capital asset build programmes and the dim outlook on PetroSA's future revenue given its challenges in securing feedstock for its primary asset. The increased borrowing costs, combined with investor concerns over operational and financial issues, have led to downgrades to various SOCs' credit ratings in the past year. Eskom was downgraded by Standard and Poor to BB+ (junk speculative status), and Transnet to Baa2 by Moody's at the lower end of investment grade stock. Fitch has rated South Africa as a country at BBB. PetroSA with its recent ZAR14.9 billion loss is likely to be significantly downgraded by credit agencies. The cost to borrow money and the risk of further downgrades of SOCs and the State provide a risk that any projects developed and under-written by the State will cost more than projects developed by the private sector.

Furthermore, the state has no experience in procuring LNG and its associated infrastructure though it has studied this extensively and consulted widely. Recent experience on major infrastructure projects at most of the SOCs raises concern about the states' ability to execute projects on schedule and within budget.

For a state driven scenario to be realised, a centrally co-ordinated effort is required where the respective SOCs are clearly mandated and tasked to deliver the appropriate components of a national interest programme. The release of the national Integrated Energy Plan (IEPl) that is meant to be the guide for future energy infrastructure investments and development and the GUMP which is meant to provide clarity and direction to potential investors regarding the gas infrastructure and utilisation strategy for South Africa have been delayed. This results in uncertainty on the future role of SOCs in the local gas to power market.

5.1.3 Scenario 3 – Public Private Partnership (PPP) Driven

The contractual arrangement for Scenario 3 can be illustrated as shown in Figure 10. The grey area represents the elements where a PPP would most likely be formed to assume that role.

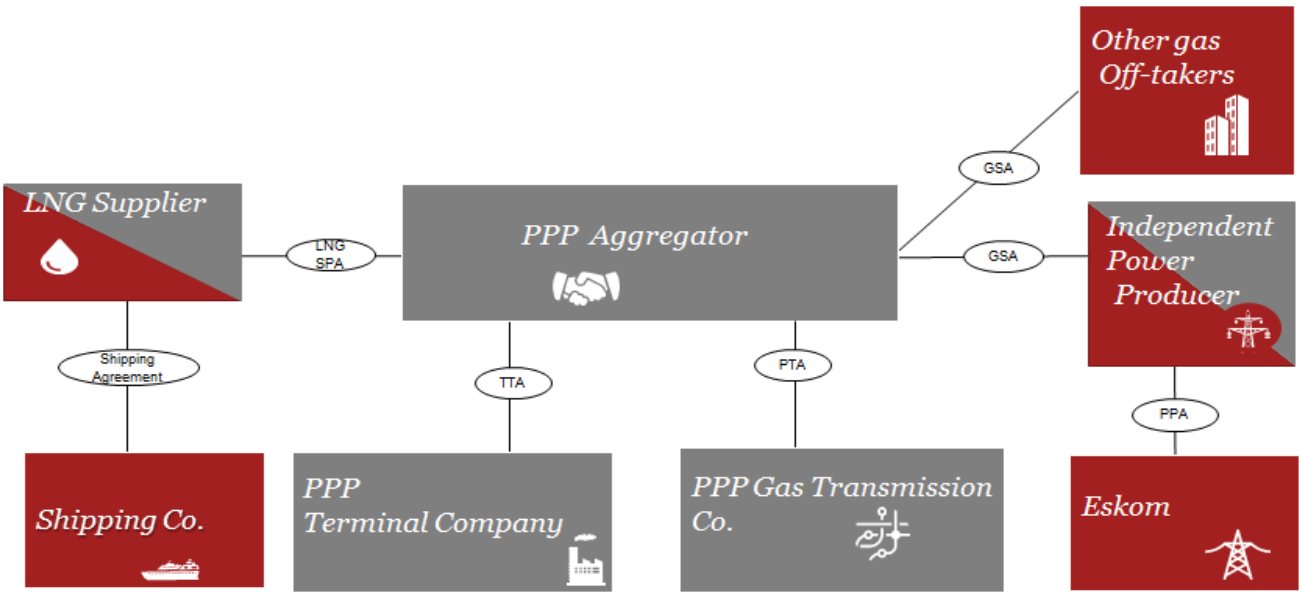


Figure 10: Contractual arrangement for Scenario 3

Table 8: Players for Scenario 3

LNG Supplier	LNG Shipper	Consortium (LNG buyer), Terminal owner, operator, Aggregator/marketer	Gas pipeline owner / operators	Off-takers	
				Power	Other
IOCs NOCs Traders	International shipping Company	SOC or CoCT & IOCs / NOCs / Global Gas & Power utilities	IGas Transmission pipeline owner	IPP Eskom CoCT	Bulk consumers CoCT

As in the previous scenario the contractual arrangement assumes that the natural gas sent to the liquefaction facility is owned by the producer, who then sells it after liquefaction.

A public private partnership scenario has the advantage of partnerships which can create synergies. PPPs require some type of performance by the private entity to the state institution or involve the use of the state's property by the private entity for commercial purposes.

IOCs, NOCs, global power utilities and traders are likely to be the suppliers of gas and can contract or control the most cost effective LNG supply shipping options to the South African market.

The buyer may not necessarily be the gas aggregator although it could be both. Typically, the government and private sector gas demand could be aggregated at the buyer level. Such a PPP based on strategic objectives could be a buyer of gas for individual or multiple projects.

Once landed it is possible that either that a special purpose entity can subcontract out or could construct, own and operate its own infrastructure. The advantage of PPPs is that they provide an enabling environment to increase market competition with the opportunity for participation by a larger number of participants. It is possible that the gas molecules and land used for development is held by the state and specialised companies provide the capital and expertise to manage the construction and operation of facilities and infrastructure, such as off and onshore facilities, pipelines and power plants.

PPP's management structures can provide a conduit for both public and private funding, creating robust energy equity markets. In most circumstances the funding will be privately driven.

PPPs are attractive to state institutions that may not have the skills and expertise nor the capital to construct or operate and maintain infrastructure such as gas reticulation networks, but would like to participate in the benefits directly or indirectly. PPPs have the ability of attracting both large and small stakeholders along the value chain thus it has the ability to more easily develop a horizontal integrated gas market for both electrons and molecules. The advantages are that the correct skills and expertise can be contracted to expedite the development and timelines through efficient structures and good governance.

The duration and type of PPP contracts can vary considerably. However they must all provide sufficient time within which the original funders are able recoup their investment. PPPs may find it acceptable to have shorter contract times, on the expectation that indigenous gas resources in (or close to) the Western Cape could, on a best case scenario, feed into the market and replace imports within 10-15 years.

The state will claim that it should be the aggregator and owner of the gas molecules to ensure the development of a fully integrated gas market and to maximise its economic development contribution; and PPPs should be used for the building, construction and ownership of infrastructure for a specific time, which can be done on a build, own, operate and transfer (BOOT) basis.

The disadvantage of this model is its inherent complexity, and the number of contracts that may be required for each element of the value chain. There is also a view within government, based on some PPP experiences, that with PPPs the private sector reaps the benefits whilst passing the risks to state.

5.2 Commercial Risk

The main issue influencing the commercial aspects of a project of this nature is the procurement process itself under which the importation of LNG will take place. Aspects of concern include the different contracts, agreements, association and licences required along the entire value chain.

Since "gas-to-power" is considered as the anchor gas off-taker for the importation of LNG, from the perspective of an IPP or Eskom, according to regulations the process for new generation planning and procurement can be as per the New Generation Regulations which were published in August 2009. The main aims of these are to:

- Provide rules and guidelines applicable to the procurement of an IPP for new generation capacity; and
- Facilitate the development of an Integrated Resource Plan (IRP) by the Department of Energy (DoE) which sets new generation capacity requirements.

All IPP procurement programmes are therefore to be executed in accordance with the IRP. IPPs however may also apply directly to NERSA for gas-fired power generation licences outside of the GASIPP process. However this would require ministerial determination and approval through NERSA's licensing process which includes detailed reviews, a public participation process and executive and Board level approvals. Future iterations of the IRP should also consider capacity increases from existing plants such as Eskom's and GDF Suez's diesel-fired OCGT plants converting to gas-fired CCGT plants.

The process for new generation planning and procurement as per Regulations is illustrated in the following diagram:

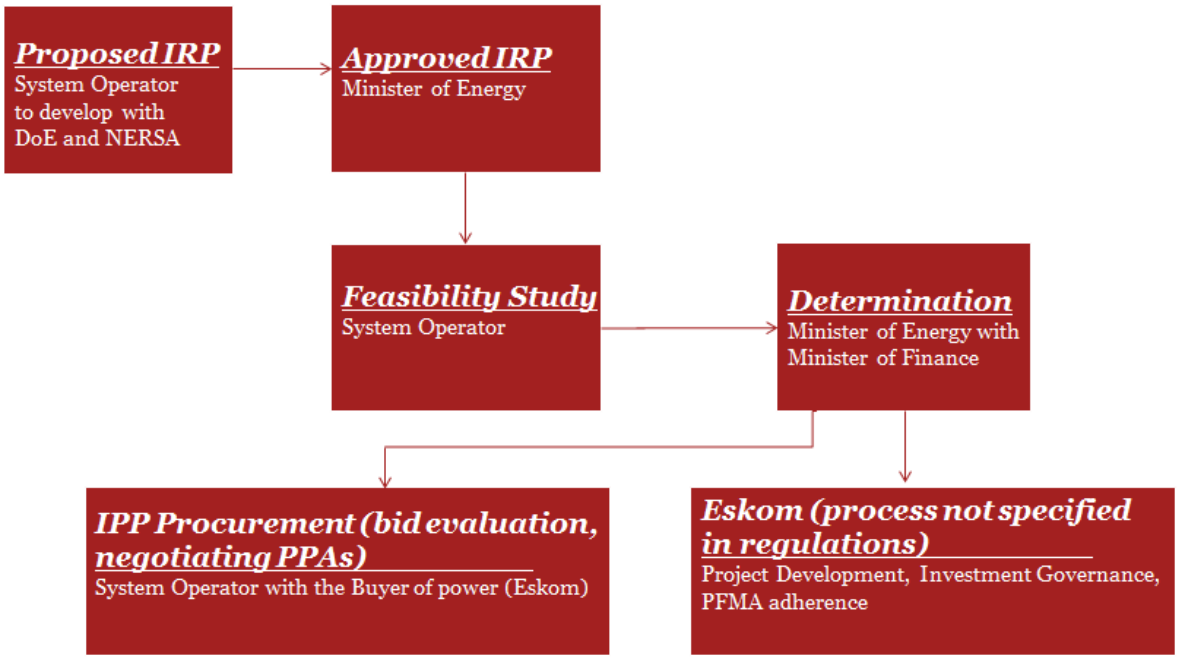


Figure 11: Process for procurement of new electricity generation capacity

All bid programmes have the following prescribed stages during the IPP procurement process:

1. Request for Information (RFI).
2. Request for proposals (RFP):

DOE has expanded this bid process for "gas-to-power" to include a formal pre-qualification step (RFQ) in order to address the inherent complexity of the gas value chain. Using the Renewable Energy IPP Procurement Programme as a reference, the RFP is usually divided into three sections detailing: 1) general requirements, 2) qualification criteria, and 3) evaluation criteria. The documents also include a standard Power Purchase Agreement (PPA), an Implementation Agreement (IA) and Direct Agreement (DA).

The PPA is to be signed by the IPP and Eskom as the designated off-taker. PPAs should specify the currency of the transactions and the length of the contracts tenures from the date of commercial operation.

The IAs are be to be signed by the IPPs and the Department of Energy (DOE) and could effectively provide a sovereign guarantee of payment to the IPPs, by requiring the DTI/DoE to make good on these payments in the event of an Eskom default. The IA could also place obligations on the IPP to deliver economic development targets. The DAs role is to provide step-in rights for lenders in the event of default.

The PPA, IA and DA are non-negotiable contracts and are developed after an extensive review of global best practices and consultations with numerous public and private sector actors.

The REIPPPP process has proven to have been transparent and well managed with only preferred bidders being able to enter in to contracts with Eskom. Projects once at the preferred bidder status are highly bankable and the risk of not being funded is extremely low.

Government regards the initial period of the development of South Africa's gas industry to be anchored on the demand provided by its Gas to Power Programme. In mid-2015, the DoE issued a formal Request for Information (RFI) for the Gas to Power programme that was intended to solicit information from participants in the gas to power industry. All information submitted has assisted the DoE to structure the Gas to Power Procurement Programme. This will now follow a 2-stage process (a formal RFQ preceding an RFP). The RFQ will itself be preceded by the release of a Project Information Memorandum to assist potential project developers to understand the full complexity of the proposed natural gas-to-power opportunity.

5.2.1 Sovereign Guarantees

Strong political will within a clearly defined policy framework, and support in the form of sovereign guarantees are essential elements for gas-IPPs, due to the capital expenditure requirements and the signing of long term supply agreements. Without a sovereign guarantee and minimum volume offtake agreements by a creditworthy off-taker, the risk to most projects is deemed too high and funders will be unwilling to provide funding unless high returns on investment can be negotiated commensurate with the project risk. For the Gas-IPP programme to be successful, the National Treasury's Fiscal Liability Committee will need to formally approve the government guarantees, as well as scrutinize each transaction.

The decline in South Africa's international credit standing means that banks and investors might accept sovereign country risk, but may also require some political risk insurance similar to that in other African countries. Eskom's poor investment credit rating and its current financial standing, maintenance backlog and the possible future unbundling of the utility mean that such a guarantee must come from the National Treasury. The major cost is not the infrastructure but the long term fuel supply contract. LNG sellers will be insistent on a sovereign guarantee or similar. Lenders to each of the infrastructure projects along the value chain (terminal, pipeline, power plant) will possibly also seek sovereign guarantees.

The REIPPP programme provided a sovereign guarantee in case of the Eskom as the counterparty to the PPA defaulting. The Gas-IPP programme is considerably more complex as there are more elements along the value chain along with the implications of an imported global commodity as the primary feedstock. Thus it is envisaged that IPPs would seek guarantees to provide sufficient comfort to their principals and lenders.

Guarantees could also be provided by the SOCs, however apart from Transnet whose credit rating is the same as the State, it would appear that the other SOC guarantees would still require national treasury approval.

Whilst there is no reason why the CoCT or other large municipalities cannot provide guarantees to project investors due to their better credit ratings, the quantum of the guarantees required may have a negative impact on their financial standing.

It is not possible to assess project premiums based on different types of sovereign guarantees as these depend on the profile of the bidder/consortium, its project specific risks, its contracting structures, etc.

5.2.2 Price Risk

The challenge for commercial contracts is to address the mismatch between gas and electricity pricing. LNG fuel is purchased in US$ and linked to an international gas or crude oil index; whereas with new coal base-load and/or co-generation, as well as with utility scale renewables, electricity is priced in ZAR as ZAR/kWh.

Historically, the approach employed by the DoE for the procurement of electricity from diesel fuelled Open Cycle Gas Turbines was for a capacity payment in ZAR/MWh and an energy payment as a variable ZAR/MWh with fuel costs as a pass-through. Management of this then becomes a regulatory issue around dealing with the pass through cost. This approach is manageable when the plant is intended to provide peak load at low load factors with high flexibility. It may be more difficult to manage when several gas or peak plants are connected to the grid, each with the aforementioned pricing risk as this may have a significant swing on the overall electricity price in country. In this regard the mitigation of price risk needs to be considered as discussed in the table below.

Table 9: Price risk and risk mitigation measures

Description	Risk Mitigation measures
The regulated electricity tariff does not align to the gas price with fluctuations leading to large investor risks	New regulations to allow for Basic Gas Pricing similar to the Basic Fuel Price where under and over recoveries in the gas price are passed onto the consumer in the following month. New electricity pricing structures to accommodate for a fluctuating electricity price based on the fluctuating gas price. This would require municipalities and Eskom to be able to pass on the price increases without affecting their revenues. The establishment and use of an equalisation fund to smooth the impact of over/under recoveries on a longer term basis. This would require an appropriate operating model and management structure and the size of the fund would be dependent on commodity and currency movements. Taking equity in the upstream gas field and liquefaction facility to reduce the impact of global commodity indexation – physical hedge. Hedging the fuel supply for the upcoming 12 months and getting regulatory approval for the hedged position in the tariff for the next year. Regulatory approval for retrospective clawback through the tariff of over/under recoveries.

The price risk is likely to be very high for any international investor and without a contract guaranteeing price risk mitigation (e.g. pass through) it is unlikely they would be willing to participate in the project.

State entities may seek means to minimise any price risk impacts through engaging NERSA to provide them with adequate means to protect against price risk as described above.

Eskom as the grid-owner and sole buyer may opt not to enter into long term gas contracts due to its current financial position and/or its view on the future supply and demand position. In the future, an independent system and market operator (ISMO) may focus on securing more dispatchable mid-merit generation and thus

pursue gas as an alternative. The impact of an ISMO and a deregulated market are not covered in this report as at present it is unclear which market models South Africa will pursue into the future.

5.2.3 Volume Risk

The Gas-IPP RFI indicated a low load factor for mid-merit gas-fired power stations over their lifespan, however this could mean that some years are much higher and other years much lower. If power supply fluctuations are expected then higher levels of storage would be required to meet this profile. The DoE may also envisage gas-fired plants having higher load factors in their initial years of operation prior to when "new coal" or "new nuclear" power comes online. Thus there is uncertainty over the dispatch profile of these plants which creates a significant volume mismatch risk.

LNG contracts are typically "take-or-pay" agreements. Thus buyers will try and closely match their demand requirements to their purchase schedules. A volume mismatch may incur penalties and even the possibility that shipments are forgone and diverted to another location. If a buyer wants a flexible contract, then a cost benefit analysis needs to be undertaken to assess if the flexibility provided is worth the additional cost for such.

Mitigation strategies for this risk are described in the table below.

Table 10: Volume risks and risk mitigation measures

Description	Risk Mitigation measures
Volume could not be supplied by the supplier or the off-taker is unable to accommodate the shipment.	**Supply Side** Contract obliges supplier to supply and penalises non-performance. The supplier may be able to supply from other sources. Supplier is obligated to buy on spot market at own expense to ensure supply in case of normal supply location disruptions. The use of a trader with multiple shipping options provides for cargo diversions. Storage has an adequate buffer to cover late delivery. **Buy Side** Contracts provide for shipments with flexible destinations, diversion options. Aggregator who manages the short and long term supply schedules to ensure that neither stock outs nor the inability to accommodate shipments occurs. Negotiate a more flexible take or pay arrangement. Flexible shipping arrangements. Storage facility has enough buffer space to cover late deliveries as well as the ability to accommodate additional stock holding during lower than expected local demand consumption. Size and locate the regasification facility appropriately to take into account environmental conditions. For example an FSRU may have periods of time where LNG cannot be offloaded and it would have been better to locate offshore elsewhere or incur higher capital costs and build an onshore regasification facility.

The volume risk could be lower in the internationally led scenario – i.e. Scenario 1, where a single entity is in charge of the supply chain and has a greater awareness of supply issues anywhere along the value chain. This is especially relevant if the international is a vertically integrated gas and power company with a global portfolio. Such a player will have greater flexibility, due to its scale, to re-direct cargoes to alternative locations.

The State and PPP scenarios would require robust communication and scheduling between the parties as any deviations/amendments to the contracted schedule needs to be communicated via the agreed process under the terms of the contract. These communication processes are generally well detailed and applied rigorously

In the case of government to government deals with the State driven scenario, there is a risk that other sources of supply may not be included, exposing the project to a single country and/or project.

5.2.4 Country Risk

Even though attractive rates of return may be possible through the Gas-IPP programme, investors could still be concerned about political risk, with issues such as the ability to repatriate profits, changes to tariffs and changes in the regulatory and tax regimes. Whilst the REIPPPP has addressed these issues, the gas industry is not as clearly defined with a number of pieces of legislation such as the Mineral and Petroleum Resources Development Act (MPRDA), the Gas Act and GUMP still being promulgated / amended. The greater the political risk, the higher the required rate of return on capital will be.

Table 11: Country risk and risk mitigation measures

Description	Risk Mitigation measures
Investors do not want to invest, or put a large risk premium on their investment due to the political risk in country	Sovereign guarantees. Clearly defined procurement programme with appropriate country risk mitigation. Regulation certainty with the promulgation of all requisite acts and policies which enables well informed decision making. Only with clarity on all policies and regulations can investors model impacts and make decisions with confidence. Assurances of adherence to local and international laws and providing protection against changes in law and taxation. Country risk decoupled from other commercial risks

The country risk is viewed as highest for an internationally led scenario as it carries an external viewpoint and does not want exposure to political risk. The shareholders under this scenario have global portfolios, and their willingness to embrace country risk will be different to participants in the other scenarios, which include varying degrees of state participation.

The wholly state-driven scenario has the least country risk.

The PPP scenario is more complex. However their reliance on government institutions and the ability of other entities to more easily step into the value chain reduces the risk to the overall nature of the project.

5.2.5 Integration Risk

Unlike the REIPPPP, the procurement of LNG to power has many elements in the value chain. There is a possibility of breakdown along the chain and thus risk mitigation processes need to be put in place to ensure that any single point of failure does not compromise a project irredeemably.

This is further compounded in South Africa, where specific procurement requirements such as local content, Broad Based Black Economic Development and local Community involvement may differ across each element of the value chain; e.g. an SOC will require PFMA approvals and compliance with PPPFA and its own internal procurement rules, whereas DoE may institute a bespoke set of requirements and selective procurement devised for the specific procurement programme. Furthermore, the Department of Trade and Industry has committed to facilitating an attractive gas-based industrialisation programme, the requirements of which will need to be addressed in the respective procurement.

The DoE IPP bid processes have required an exemption from the PPPFA as the normal 90/10 split favouring the price was adjusted to a 70/30 split with 30% allocated to non-price "economic development" for REIPPPP bidding rounds. The 30 points for Economic Development scoring in previous bid submission is weighted as noted below in the table below. The DoE has yet to state what the Gas-IPP RFP economic development criteria might be, and it is possible that it might be different from the other IPP bidding programmes.

Table 12: Economic Development elements from previous DoE IPP bidding rounds

Economic Development Elements within previous bidding rounds - The Balanced Scorecard with sub-elements, weighting and point allocation.		Weighting
1	Job Creation Obligations	25%
2	Local Content Element Obligations	25%
3	Ownership Element Obligations	15%
4	Management Control Element Obligations	5%
5	Preferential Procurement Element Obligations	10%
6	Enterprise Development Element Obligations	5%
7	Socio Economic Development Element Obligations	15%
	Total	**100%**
	Points	**30**

Some bidders may find it difficult to prepare proposals with stringent local procurement requirements further exacerbated by a tight deadline from RFP issue to bid submission. The impact of this would be that competition is reduced and the outcome of the bidding process may be somewhat subdued. The first REIPPP bidding window had a similar outcome where due to the limited number of compliant bidders in the first window relative to the capacity on offer, bidders may have priced higher knowing that competition is limited. In the subsequent rounds, competition was more intense as bidders had more time to prepare their projects, there were more bidders and relatively less volume on offer. This resulted in a remarkable decline in prices offered.

The community trust stakeholder element on the REIPPP programme was between 2.5% and 5.0%. The local content minimum requirement threshold for Concentrated Solar with storage increased from 25% to 40% and the actual target increased from 45% to 60% over the bidding rounds. It is yet unknown what this criterion will be in the Gas-IPP. Regardless, DOE is committed to ensuring that all bids are evaluated against a robust set of criteria, to ensure maximum competition and preferred socio-economic development.

Thus IPPs will endeavour to structure their projects in a manner which addresses the various procurement requirements whilst limiting risk exposures of the primary shareholders. The figure below illustrates the structure for a typical IPP company with a main (possibly international company) shareholder, local (power project development Company) shareholder and a local BEE shareholder. It also indicates how the project company is separated from the shareholders and engages equipment suppliers, lenders and the community:

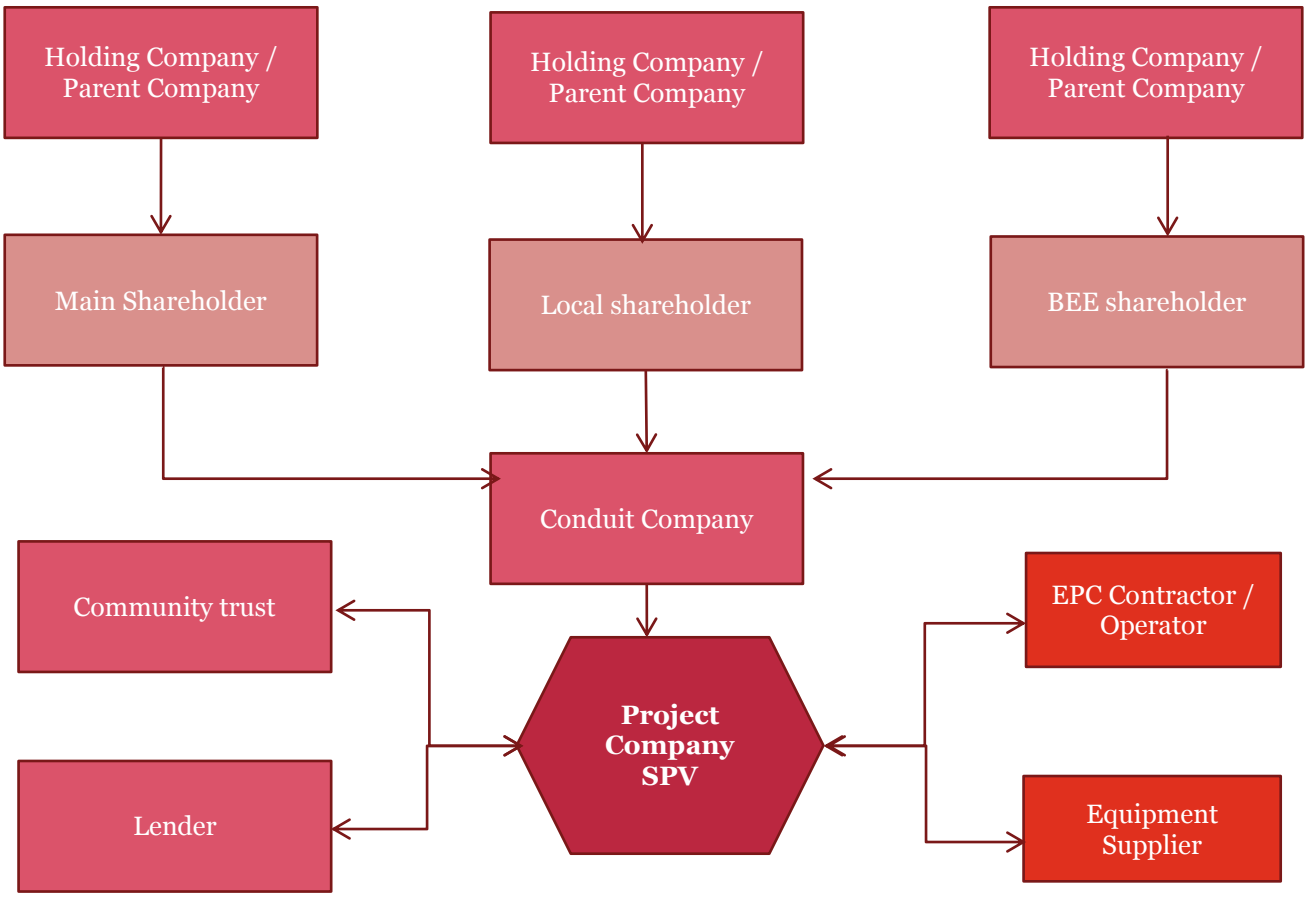


Figure 12: Typical IPP SPV contracting structure

5.2.6 Specification / Quality Risk

LNG contracts detail product specifications which are tailored to the use of the product and the design of the related infrastructure. Product outside of the specifications may be rejected or incur penalties/price discounts.

Table 13: Specification/Quality risk and risk mitigation measures

Description	Risk Mitigation measures
Product quality is outside the acceptable tolerance levels	Contracts negotiated on identified legislated minimum quality standards. Contracts negotiated to ensure that any loss of product quality from supply to end user is accommodated for. Contracts identify and penalise party for products that are out of specification. Contracts terms ensure that additional costs associated with demurrage and resupply are borne by the transgressor. DES shipment contracts pass the risk back to the supplier. Product quality is surveyed at port of origin, port of delivery and regasification plant to ensure quality.

It is envisaged that this risk applies equally to all three scenarios and is typically covered in the contractual terms.

5.2.7 Risk of delayed procurement

The 2012/13 revision to the IRP is described below. In this revision new CCGT capacity is anticipated to be in commercial operation from 2019. Assuming a year for procurement and progression to financial close and three years for construction, the below commitment to the 2019 date for the first units will not be met. Procurement has been delayed beyond 2016. The most recent timeframe for the commercial operation of the first gas-to-power station is 2022/23.

Furthermore, the 3,126MW envisaged to be procured under the initial procurement programme may differ from what is proposed below as OCGT and CCGT with other technology options such as gas engines and fuel options such as HFO and underground coal gasification also being promoted. The incorporation of these various technologies also poses a risk of delay.

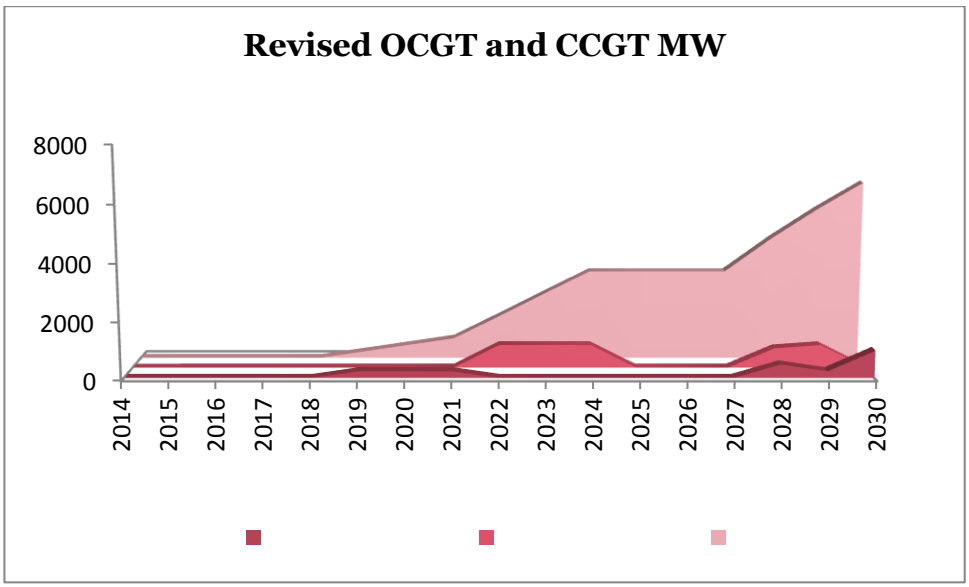


Figure 13: Revised OCGT and CCGT MW

Table 14: New build capacity generation capacity in MW as per the revised IRP2010

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
CCGT	0	0	0	0	0	237	237	237	0	0	0	0	0	0	474	237	948
OCGT	0	0	0	0	0	0	0	0	805	805	805	0	0	0	690	805	0
Total	0	0	0	0	0	237	474	711	1516	2321	3126	3126	3126	3126	4290	5332	6280

Assuming the forecasted new electricity generation build in the revised IRP for CCGT and OCGT is all powered by natural gas then 6,280MW or 14.8% of the new build between 2010 and 2030 will be supplied by natural gas. It is expected that 7% of the total generation capacity will come from natural gas by 2030.

There is a possibility of delays due to uncertainty of regulations, the complex nature of the gas market, key stakeholders' concerns and the lack of a developed gas market. The amount of contracts and stakeholder agreements that are required in combination with the number of elements along the value chain make alignment difficult and delays highly probable.

Table 15: Risk of delayed procurement and risk mitigation measures

Description	Risk Mitigation measures
Gas projects are delayed due to the complexity of the gas value chain and the number of contracts and regulations that need to be adhered to.	Alignment of parties, especially SOCs and DoE. Clear understanding of what key stakeholders require and why.

Further to the above, delays are more likely in the state driven scenario where some government departments and State owned players are still to resolve and obtain sign off on their mandates. It should be noted that the regulators and licensing/permitting authorities in most respects do have clarity on their mandates

The nature of PPPs is that due to the complexity and number of contracts and agreements involved between private and public entities there is a risk that contracting could delay the process.

The internationally driven scenario may have the lowest risk of delay as it has international contracting experience and should know how to navigate this risk.

5.2.8 Siting Risk

Unlike the REIPPPP which has an abundance of sites, an LNG importation development is very specific in terms of location, with only three harbours designated as potential import locations. These are Richards Bay, Coega and Saldanha Bay. This implies that developers who proactively acquire prime sites and servitudes around these harbours may position themselves advantageously for a competitive bidding process. The DoE has yet to formally indicate how the issue of potential land sterilisation would be dealt with. A consideration would be to identify a limited number of good sites and design the procurement programme around these sites to ensure greater pricing competition. It is envisaged that multiple parties might be allowed to bid on the same site, which might limit the number of technology options. The possible bias of the sites selected need to be open for robust discussion to ensure the country and fiscus maximise the benefits of any site chosen. It is not clear until the DoE RFP is released probably in early 2016 what proportion will be allocated to LNG and where these sites might be geographically.

The WCG at present is pre-qualifying sites at the Atlantis Special Economic Zone (SEZ) to reduce this sterilisation risk, and working closely with the Saldanha Bay IDZ licensing company to maximise the value of the gas-to-power opportunity in that location.

5.2.9 Impact of procurement model on technology selection and gas market development

There is a view that if the country wants to develop large LNG importation options that can meet the current and future demand forecast, then this requires a clear gas market agenda linked to broader economic development policy. As such, the state will be required to assume some risk and play a market maker / aggregator role until the market develops to a level where such risk under-writing is no longer required. At present there is no clarity on the mandate of the State owned companies that would participate in this vision.

Transnet, parts of the CEF group and Eskom have different perspectives on their roles. The present situation has resulted in a lack of movement in developing the gas market and there is a risk this may continue unless a consolidated approach is adopted where the SOCs act together in the national interest.

Under a dedicated Gas-IPP programme based on Scenario 1 an IPP would size the terminal and associated infrastructure to meet only the power generation requirement and not that of the larger market opportunity. Thus IPPs may look to FSRUs as discrete solutions to meet their sole and immediate need and design pipelines to the size that is required to operate the power plant. The IPP would in this case be the only gas off-taker, and thus it would have little interest in greater terminal or pipeline capacity for the market as it would make its own pricing less competitive. DoE will mitigate this by ensuring that all infrastructure is "open access", and that a fair return to anchor customers is ensured by subsequent pricing for other off takers.

As of March 2016, DOE has committed to an FSRU option for this first round of LNG importation projects. Specific details of mooring infrastructure, on-shore tankage etc are awaited from DOE.

5.3 Financial Risks

The financial considerations and their impact will be the driving factors behind the development of gas projects.

The capital costs of the LNG infrastructure, pipelines and power generation is relatively cheap when compared to other baseload power plants, such as coal and nuclear power. However, the cost of the fuel is highly volatile and can significantly impact overall cost viability.

Funding can be either through on balance sheet corporate financing or through the use of project financing, where the project is funded through its returns. The ability to raise funding at reasonable rates will depend on factors such as price, currency, contract duration, technical and financial feasibility assessments, political risk, regulatory risk, scale of the project, government incentives, environmental risks and the certainty of the return.

The EPRI table[15] below compares the various power generation technologies, and demonstrates the suitability and benefits of natural gas for power generation. It should be noted that the EPRI figures are distorted by the lower gas input price and more costly renewable energy in the US.

	Coal	Coal w/CCS*	Natural Gas	Nuclear	Hydro	Wind	Biomass	Geothermal	Solar
Construction cost *New* plant with equivalent amount of generating capacity	5	7	4	0	6	5	6	7	6
Electricity cost Projected cost to produce electricity from a *new* plant over its lifetime	4	6	4	5	7	6	6	6	7
Land use Area required to support fuel supply and electricity generation	6	6	5	4	6	7	0	5	7
Water requirements Amount of water required to generate equivalent amount of electricity	0	0	6	0	6	4	0	6	4
CO2 emissions Relative amount per unit of electricity	0	5	6	4	4	4	5	5	4
Non-CO2 emissions Relative amount of air emissions other than CO2 per unit of electricity	0	0	6	4	4	4	7	5	4
Waste products Presence of other significant waste products	0	0	4	6	4	4	7	5	4
Availability Ability to generate electricity when needed	4	4	4	4	6	0	4	4	0
Flexibility Ability to quickly respond to changes in demand	6	6	4	7	4	0	6	5	0
	More favourable ←4---5---6---7---0→ Least favourable								

Figure 14: Choosing electricity generation technology reference card EPRI

[15] EPRI 2012

Technology considerations

The decision of what type of technology is to be utilised will affect the financial profitability of any gas powered plant. Newer high efficiency combined cycle gas turbines use much less fuel to generate the same amount of power, however are larger in size and more costly than open-cycle units. Thus capital cost, operational cost, ease and speed of deployment, size and efficiency of the plants need to be considered when making a financial decision on what technology to use. Whether such plant is used in load-following or base-load power generation is also a critical decision.

Balance of trade impact

It is often argued that LNG importation will affect South Africa's balance of trade. Whilst this is true, there are also arguments that not importing LNG results in more detrimental alternatives. For example, if the Eskom Ankerlig power station was converted into a combined cycle plant and operated with LNG, at an exchange rate of ZAR 12/US$ and assuming a LNG price of $10MMBtu then its fuel bill would be approximately ZAR 7.6 billion. This would affect the annual trade deficit in a positive manner when compared to the current diesel usage of these two Eskom plants which have been quoted as ZAR 10.5 billion over a recent 5 month period.[16].

Apart from the possible financial trade implications in importing LNG, there is a significantly greater financial risk to the economy if enough power is not generated to sustain the economy without load-shedding. Green Cape have estimated that the economic growth and investment are negatively impacted by power shortages. The cost of unserved energy is estimated at around R75/kWh[17]which is used in performing calculations to determine the impact of loadshedding.

5.3.1 Credit Risk

LNG fuel suppliers will usually look through to the creditworthiness of the off-taker in order to guarantee that the off-taker is creditworthy and able to pay for the gas supplied. A buyer of LNG must consider the upfront working capital required to pay for a scheduled cargo as it is common practice that the shipment is paid for through the use of a margin account. For a DES contract, the buyer deposits the payment for the next shipment prior to it leaving the port of origin into a margin account, where the funds are held until the cargo is delivered to the destination port. Thus if the buyer is not the off-taker, the buyer would need to ensure that this upfront payment is covered through an appropriate back to back agreement or priced in.

Table 16: Credit risk and risk mitigation measures

Description	Risk Mitigation measures
All elements of the value chain will be unwilling to provide the required service without a guarantee that the final off-taker is creditworthy	Sovereign guarantees. Robust financial model and agreement that the off-taker guarantees supply. Regulation that each element of the value chain is profitable as a stand-alone.

[16] (Fin24, 2015)

[17] (Petrie, 2015)

In all scenarios the off-taker's creditworthiness is assessed and most participants would require a sovereign guarantee for any investor to be willing to participate in a project. This includes the state driven scenario as the current financial position of a number of State owned companies suggests these will require guarantees from the Treasury to enter into LNG purchases.

The risk of not having a contract guaranteed by a credit worthy off-taker would be too risky for an internationally led/private sector company.

5.3.2 Tariff Risk

NERSA regulates the electricity and gas market and prescribes infrastructure tariffs based on standard regulatory parameters. The terminal and pipeline are two elements in the chain which carry a tolling fee which would typically be a cost plus based tariff. However such infrastructure whilst seemingly low risk, may be exposed if it incurs cost excursions on its capital and/or operational expenditures which cannot be recouped through the tolling tariff. The same risk applies to all elements along the chain, including power generator and gas reticulators who may have a fixed tariff agreed upfront early in the project.

Table 17: Tariff risk and risk mitigation measures

Description	Risk Mitigation measures
IPPs, Eskom, CoCT, Terminal and pipeline operators may be unable to charge appropriate tariffs due to mandated maximum approved tariffs.	Proper project definition and thorough cost estimation. Use of fixed-price turnkey contracts for the infrastructure. Fixing the interest payments on the funding of capital infrastructure by swapping from a floating to a fixed rate. Maintain a detailed set of accounts to enable the regulator to perform prudency reviews without any risk of findings.

This risk is expected to affect all scenarios, though state owned companies may get a more lenient response from the regulator than private entities as in Scenario 1 who may be held to their contractual position.

In terms of the IPP, the tariff cost and expected average cost of supply into the grid needs to be recalculated based on the cost of new coal projects, renewables and the cost increases to the generation base as old coal fired power plants are decommissioned. This new cost base may be much higher than previously envisaged thus lower capital cost options like gas-fired power stations become increasingly competitive against the future generation base cost, including new coal and nuclear power plants.

NERSA regulates tariffs for both electricity and gas. Its mandate is described in the table 18 below.

Table 18: NERSA's mandate

NERSA uses acts of parliament to regulate the gas industry	
Regulates activities - Licence	Licences the construction, operation and conversion of transmission, distribution, storage, liquefaction & re-gasification facilities and gas trading activities. Covers all hydrocarbon gases transported by pipelines. Distribution licences are exclusive for a geographical area for a particular range of gas specifications for 25 years. Associated trading licences only exclusive for a period determined by NERSA
Registration	Registration of gas production operations and gas importation.
Encourage competition	Encourages horizontal integration and competition into the market, through the enforcement of third party access to existing infrastructure
'Monitor and Approve	Monitor and approve and if necessary regulate transmission and storage tariffs.
'Approve' max gas price	Approve max gas price for distributors, reticulators and all classes of customers In terms of S21(1)(p) Sasol Regulatory agreement took precedence over the Gas Act until March 2014. NERSA monitored gas prices charged to reticulators
Compliance monitoring	Enforcement, investigation and dispute resolution

NERSA's aim is to be an independent body that approves licences, monitor and approves tariffs that are reflective of costs, risks and economic value of the product while facilitating investment, entry and promoting industry growth.

5.3.3 Currency Risk

Stakeholders along the value chain may be able to bring a variety of financing options to gas infrastructure investment, including private equity, development finance, export credit finance, vendor finance and possibly other international financing. Under the REIPPPP, the funding is largely driven by local banks as the contracts are primarily ZAR denominated. International players tendering on the Gas-IPP programme may be similarly averse to bring foreign funding if the tendering process seeks ZAR pricing for most elements of the chain, which is quite likely. This would require active participation of local development banks and commercial banks.

Currency risk is pervasive in all LNG options as fuel is sourced in US$ and recovered in ZAR/kWh for power and ZAR/MMBtu for energy uses. Infrastructure technology and refined steel, which make up a considerable amount of the construction costs, are sourced in US$ thus even fixed contracts will be affected as the DoE will likely fix and guarantee an exchange rate so that all projects are evaluated equally. The currency rate continually changes as seen by the 17% depreciation of the ZAR to the US$ in 2015. International investors will want to have guaranteed returns in US$, but at present the local electricity and gas infrastructure tariffs are set and mandated by NERSA in ZAR. The contracting risk is that, without exchange rate guarantees or hedging in a Rand mandated fixed gas market, currency risk will render these projects unattractive.

At present Eskom uses the regulatory clearing account mechanism to retrospectively address its exposure to movements in the diesel price across a financial year.

Table 19: Currency risk and risk mitigation measures

Description	Risk Mitigation measures
Current exchange rate fluctuations provide construction cost and fuel price uncertainty thus deterring capital project investment.	Procurement programme, recognises and accommodates currency movement from bid submission to financial close and a beyond. Construction costs hedged for forex movements. Greater local institutional investor, lender and state entities participation who are not affected by returns in ZAR will have lower exposure to uncertainty in revenue streams.

If currency risk is not managed players are in effect speculating on market movements.

This risk is applicable to all three project development scenarios.

5.3.4 Revenue Risk

There are several alternatives to LNG which, if materialised, may render an LNG importation project uneconomic and pose a risk to long term project revenues if these are unsecured.

Such alternatives may include shale gas and nearby offshore gas field developments.

Table 20: Revenue risk and risk mitigation measures

Description	Risk Mitigation measures
Supply of gas from alternative sources make LNG capital investment unlikely	The offshore proven reserves are small and may not be significant enough to supply the full gas market. The Ibhubesi field off the West Coast of South Africa has 0.2Tcf P1 reserves, which is around 23 times less than the Pande/Temane fields that supply gas from southern Mozambique to South Africa. The lead time for shale gas developments is long with uncertainties over the regulation, licensing and royalty regime still remaining.

This risk is equal to all scenarios; however the state-led scenario may be best positioned to assume such a risk, whereas private sector parties in the other scenarios may opt to exit.

5.3.5 Volume / Load Factor Risk

Gas power stations are the most flexible type of energy source as these can be used for baseload, balancing, peak and mid-merit electricity supply processes. The Gas-IPP programme anticipates that only peak to mid merit solutions will apply, as indicated by the low 30-50% load factors referred to in the RFI released by DOE in mid-2015. This poses a risk that, at such load factors, infrastructure is not adequately utilised and will thus come at a higher cost due to poor economies of scale.

Table 21: Volume/Load factor risk and risk mitigation measures

Description	Risk Mitigation measures
Low load factors make gas solutions expensive and cannot be profitable without high tariff costs	Provide for a portion of a power plant to be operated at high mid-merit or baseload, thereby guaranteeing a portion of the required revenue stream. Commit to taking a minimum volume on a monthly or fortnightly basis to ensure no risk of oversupply of LNG.

In all cases an increased load factor will allow the cost per unit of power produced to be lower and benefit the tariff charged to the End user. PPPs and international driven scenarios may prefer higher load factors as these would allow the power plants to be more profitable.

The state driven scenario will have a greater focus on supplying peak to mid merit power for balancing support to the grid, especially with increased renewables which have an intermittent profile.

It is also envisaged that gas fired power plants could have a high load factor over the first few years of operation while other supplies of power such as coal and nuclear are under construction. It may then decrease significantly to lower load factors as these new power plants start supplying the grid. The DoE needs to evaluate the cost benefit to consumers and guaranteed revenue benefits to operators for higher load factors.

5.3.6 Performance Risk

Plant and equipment are designed to achieve a certain level of performance and thus post construction and commissioning, a performance test is conducted. If the particular plant or equipment does not perform to specification, this leads to a risk that the full potential of the asset may never be realised. Typical examples include power plants which don't achieve the specified power generation output which leads to reduced output and consequently reduced revenue. Terminals and pipelines might not achieve design insulation levels or flow rates which poses a risk of increased losses or reduced throughput and consequently revenue risk. Performance risk normally arises through shortcomings in design, procurement and/or construction

Table 22: Performance risk and risk mitigation measures

Description	Risk Mitigation measures
Plant does not perform to design specification levels	Procure best of breed and standardised / proven technology Source best available contractors and experienced labour Contract on a turnkey method using standard forms of contract (e.g. FIDIC silver book or NEC3) with appropriate performance guarantees

This risk is common to all, however may be reduced in Scenario 1 as the internationally led consortium can leverage its experience from similar projects it has undertaken in other countries and bring in skilled expatriate professionals

The state driven scenario carries the highest risk, due to its relative inexperience in procuring LNG infrastructure. However, SOCs have good experience in procuring and operating power plants and pipelines.

Scenario 3 enables the state to access international experience through a partnership approach and thus reduce performance risk in a similar manner to scenario 1.

5.4 Regulatory Risks

There are a number of policies, plans and regulations that affect the Gas sector in South Africa. The main regulations will be discussed below.

The IRP Ministerial Baseload determination has stated that 6,280MW of gas-fired power will be produced in South Africa by 2030. The Gas-IPP programme is to procure 3,126 MW new gas power between 2019 - 2025 and a further 3,154 MW between 2026-2030. As of May 2016, a further DOE Ministerial Determination of 600 MWe of gas-fired power has been declared, with specific reference to the direct involvement of one or more SOCs. The IRP 2010 which was updated in 2012/13 has a base case scenario of 3,550MW OCGT / Gas Engines and 7680MW CCGT indicating that the gas scenario could be increased up to 11,230MW. The levelised cost comparison in the IRP indicated that at the then market fuel cost assumptions CCGT is preferred at load factors below 46%. The recent downturn in global economies and fall in oil and gas prices indicates that if the IRP model is re-run on today's LNG prices, it will probably yield a larger capacity and higher load factor for CCGT plant and possibly even defer the next baseload coal or nuclear plant.

The GUMP which has yet to be legislated will direct the development of gas infrastructure and the creation of an appropriate institutional environment. It looks at gas to electricity, LNG importation, piped gas, indigenous gas resource development and gas market dynamics up to 2050. The draft has noted that gas demand is to primarily come from electricity generation although the transport and industrial sectors could also be key drivers in the future.

A high level summary of the legislation that will affect the gas industry is highlighted below:

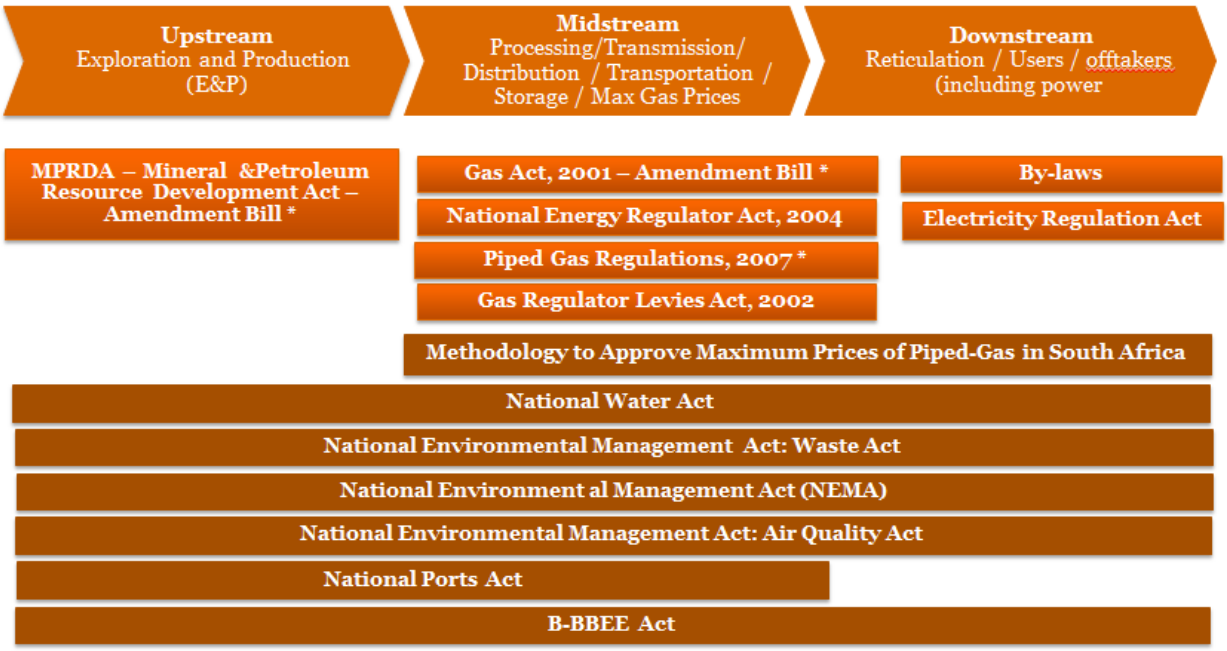


Figure 15: High level summary of the legislation that will affect the gas industry

5.4.1 Licences for the importation of natural gas

A number of licences will be required along the entire value chain for imported LNG and at any point the granting of a licence can cause a delay and in the case of the IPP process actually stop a bid from being selected. The Gas Act is of particular importance as numerous licences will be required if an integrated project from the importation through to trading of gas is to operate legally.

The table overleaf highlights a number of licences and permits that may be required.

Table 23: License and permits required for importation of natural gas

Gas Act – Regulated by NERSA
Construction and operational licences for regasification plant (on-shore and off-shore)
Construction and operational licence for gas storage
Construction and operational licences for gas pipeline transmission infrastructure
Construction and operational licences for gas distribution infrastructure/ facilities
Gas trading licence for traders
Other licences outside the Gas Act
Exploration and Production permits – PASA
MRPDA - DMR
Gas Importation Registration with DoE – ITAC
Shipping Permits and licences – locally and internationally
National ports Authority – TNPA
Gas electricity generating licence from NERSA under the ERA
National Environmental Management Act –Environmental Impact Assessment regulations EIAs
National Water Act
National Air Act
National Waste Act
B-BBEE Act – certification

5.4.2 Relevant Acts

A number of Acts are of significant importance for a successful importation of LNG into the Western Cape.

An updated IRP, Gump and IEP are all important as they will provide the guidance on the future energy mix of gas in the economy, although the IRP will only focus on gas to power. The Gas Act and its amendments will have the greatest effect on the gas industry at large since it is the main gas regulation in South Africa in respect to mid and downstream activity. The MPRDA will be the main legislation to affect indigenous upstream gas exploration and production. The gas-IPP programme will be the driving force of procuring gas power generation and LNG importation and without this programme it is unlikely that gas development will happen.

The National Environmental Management Act and the associated Environmental Impact assessments have significant impact on the gas infrastructure development at a port, pipeline servitudes and power plant sites.

Environmental Impact Assessments (EIAs) can take 12 to 18 months and even be held up indefinitely by stakeholder objections or the inability to satisfy all the EIA conditions.

All projects have the risk that an EIA will not be granted, thus if a municipality has approved EIAs for any of the infrastructure elements such as the regasification and storage facilities, servitude and gas power plant sites then they will become a preferred location for IPP and gas infrastructure developer.

National Ports Act

National Port Act (section 56) allows for provision of port services and port facilities and use of land for activities such as LNG Importation and regasification as long as the process is in accordance with a procedure that is fair, equitable, transparent, competitive and cost-effective.

The National Ports Act (section 79) also allows for Ministerial direction to a ports authority to perform a specified act if it promotes the national, strategic or economic interests of the Republic and allows for compensation to the authority for any such activity. This Act would provide the minister a possibility of approving / direct the ports authority to accept LNG importation at designated desired locations.

The Municipal Systems Act

The Municipal Systems Act (section 23) provides guidelines for the development and planning of energy as an essential issue for people in the Republic.

Section 25 requires municipalities to produce Integrated Development Plans which identify critical areas for development which includes energy planning, security and economic development thus providing a way for the municipality to motivate gas infrastructure and power generation capacity.

The Integrated Resource Plan

The 2010 IRP only covers power generation capacity that is sold to Eskom, designated the deemed sole buyer. Private and municipal buyers and any power production for "own use" will not fall under the IRP. Although the IRP does not per se place constraints on power purchasing it would seem probable that the gas-IPP programme will be the driving force for gas-to-power generation for the foreseeable future.

A municipality, CoCT and an IPP can apply for a power generation licence directly from NERSA, however complex wheeling agreements, guaranteed offtake and a lack of sovereign guarantees has made it unpalatable for entities. Wheeling costs and distribution costs charged by Eskom have discouraged IPP investment and new power purchasing models need to be investigated such as an ISMO who buys electricity.

IPPs can operate outside the IRP with a willing buyer, willing seller arrangement, however the process is difficult and not common.

The IRP assumptions and the IRP need to be continually updated to take into account construction and current market conditions if it is to remain relevant.

The IRP is focussed on electricity which creates a risk that gas market development may not be fully considered.

The PFMA and MFMA

The PFMA and MFMA are similar in principle. They only differ in the level of authority and in the conditions under which a procurement process becomes a formal tender process. All elements of the LNG value chain, if procured by a municipality, would require a formal tender process with multiple approvals. The MFMA procurement process could provide an alternate route to procure LNG without going through the DoE Gas-IPP programme.

It is possible for municipalities to participate in gas to power projects; however these may require a number of conditions to be met.

Procuring generation capacity outside of the IPP applies to small scale generation capacity with short term contracts of three years or less; however a number of pieces of legislation provide support for the municipality to have longer term contracts associated with power generation. These are listed in the tale below:

Table 24: Municipal procurement of power generation

Reasons why the WCG / CoCT can contract power generation
S33 of the Municipal Finance Management Act (MFMA) provides an option for NT approval on contracts over three years. A contract that is over three years must prove that the price paid for electricity is lower than Eskom's and has that there are no long-term negative budgetary implications.
NERSA would need to approve tariffs and related yearly increases.
Chapter 5 of the MFMA requires electricity price increases to be submitted to NT and SALGA.
A Ministerial determination identifying the CoCT or an IPP that the CoCT contracts to would need to be in place for electricity generation directly to the City. The case would need to be motivated as in the case of the Darling wind farm.
Any tariffs implemented that are more than Eskom's are possible, but would need a signed resolution from City treasurer, City manager, Head of Legal and Head of infrastructure procurement.

The Gas Act

The Gas Act is the most influential act concerning Gas in South Africa and the most important section of the **Gas Act** that requires compliance with is section 21.

Section 21

1. The Gas Regulator may impose licence conditions within the following framework of requirements and limitations:

(b) licensees must provide information to the Gas Regulator of the commercial arrangements regarding the participation of historically disadvantaged South Africans (HDSA) in the licensees' activities as prescribed by regulation and other relevant legislation;

(c) the gas transmission, storage, distribution, trading, liquefaction and regasification activities of vertically integrated companies must be managed separately with separate accounts and data and with no cross-subsidisation;

(d) third parties must in the prescribed manner have access on commercially reasonable terms to uncommitted capacity in transmission pipelines;

(h) licensees must allow interconnections with the facilities of suppliers of gas, transmitters, storage companies, distributors, reticulators and eligible customers, as long as the interconnection is technically feasible and the person requesting the interconnection bears the increased costs occasioned thereby, which must be taken into account when setting their tariffs;

(m) a distributor will be granted the construction, operation and trading licences for its exclusive geographic area. The construction and operation licences will be exclusive for the period of validity of such licences, and the trading licence will be exclusive for a period determined by the Gas Regulator;

(o) gas must be supplied by a licensed distributor within its exclusive geographic area to any person on request, if such service is economically viable;

(s) all customers in a licensed distribution area, except eligible customers and reticulators, must purchase their gas from the distribution company licensed for that area;

The other important section is **Section 23** in terms of a licence in the Gas Act ensures that a licence is valid for a period of time exclusively for that licensee and:

1. Any licence issued in terms of this Act is valid for a period of 25 years or such longer period as the Gas Regulator may determine.
2. Licensee may apply for renewal of licence
3. A licensee may not assign its licence to another party.

The **Gas Act** requires both licence and registration of gas activities along the value chain as highlighted below:

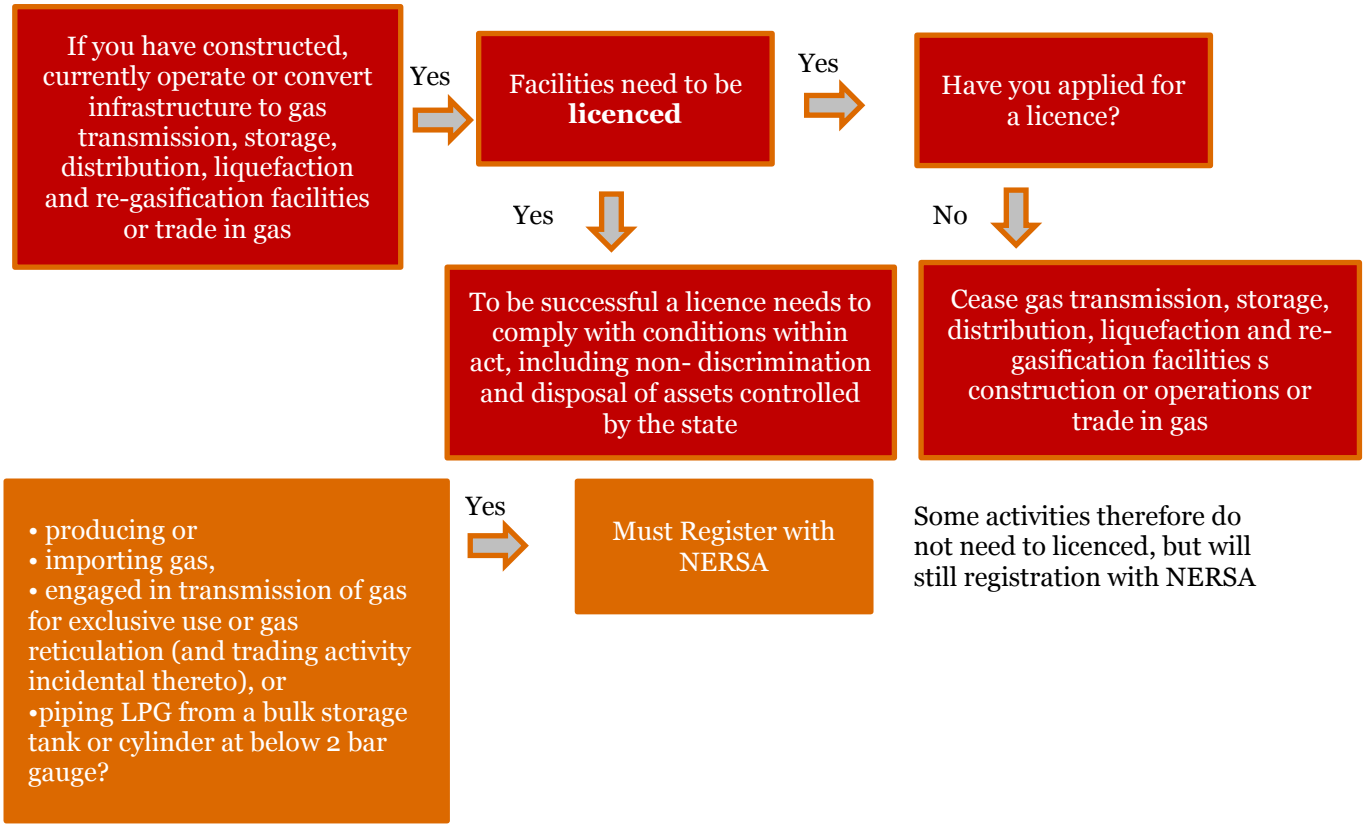


Figure 16: License and registration of gas activities along the value chain (Gas Act)

A large number of licences and permits may be required in respect to S21 of the Gas Act. At the same time, gas power stations fall under the Electricity Regulation Act.

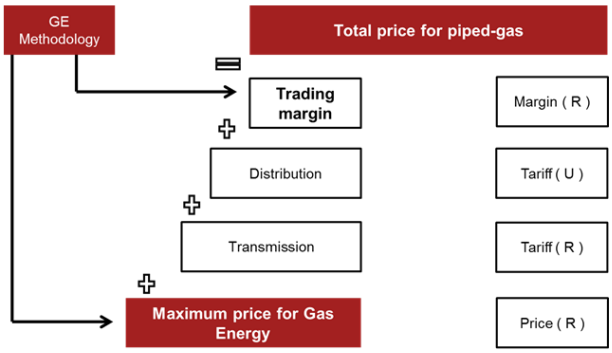
The Gas Act aims to create an environment for horizontal integration and market development; however the risk is that the requirements allowing third party access may lead to investors failing to invest in South Africa unless they can get an exemption for a number of years to enable project bankability.

In Europe gas projects have been successfully funded through Projects of Common Interest (PCI) exemptions that have recognised that third party access can be restricted for a period of time to ensure that initial investment allows sustainable businesses to be built. This would not be in line with the Gas Act, however. Internationally it has been a proven way to develop the initial infrastructure required to develop a gas market and thus the gas-IPP and the legislation may require companies to have an exemption if South Africa wants to attract investment.

NERSA approves the maximum gas energy price in South Africa using two approaches: 1) the use of Energy Price Indicators to determine the Gas Energy (GE) price and 2) the pass through (or build up) cost price method.

The maximum price approach as per the Gas Act S21(1)(p) has indicated that the pass-through cost method will apply to new entrants, such as importers of LNG and any new gas infrastructure developments.

The below diagram shows a gas energy price and a pass through method example of the total gas price traders would be allowed to charge off-takers.



Reference – Pass through method	Information to be supplied by the applicant / licensee
1. Cost of imported gas	R120.00
2. Transport cost	R10.00
3. Re-gasification (network) tariff	R11.00
4. Liquefaction (network) tariff	Not applicable
5. Trading margin	R10.00
6. NERSA levy	R3.00
TOTAL GAS ENERGY PRICE (GE)	R154.00

Reference	Information supplied by applicant/ licensee
1. Gas Energy Price (GE)	**R 123.20**
2. Maximum prices for each customer category	List per customer category
3. Gas trading margins	R10.00
4. Discounts applied to each customer category	R10.00
5. Transmission tariff	R4.00
6. Distribution tariff	N/A
7. Storage tariff	N/A
8. NERSA levy	R3.00
6. TOTAL MAXIMUM CHARGES FOR GAS	R130.20

Reference – Price Indicator Approach Max price of piped gas	Information to be supplied by the applicant/ licensee
1. Price Indicators used (NERSA)	Price indicators
2. Weights of the different price indicators	Weight of Coal is 37% Weight of Diesel is 24% Weight of Electricity is 37% Weight of HFO is 1% Weight of LPG is 1%
3. Conversions of the energy indicators (the calorific energy value equivalents) to gas	Conversion of Coal: 27 GJ/tonne Conversion of Diesel: 0.0381 GJ/litre Conversion of Electricity: 0.0036 GJ/kWh Conversion of HFO: 43 GJ/tonne Conversion of LPG: 0.0267 GJ/litre
4. Average price for the preceding 12 months of each of energy indicators	Average price of Coal: R27.91 Average price of Diesel: R192.21 Average price of Electricity: R171.40 ETC
5. Average forex for preceding 12m	R/$ R8.72 - GPB R13.15
6. TOTAL GAS ENERGY PRICE (GE)	**R123.20**

Figure 17: Gas energy price and pass-through method example

The gas price approved by NERSA would vary depending on the cost base and structures of the entities applying for a licence.

One of the risks of the evolution of the gas market into a fully competitive market is that the Gas-IPP programme is likely to create an oligopoly where geographical areas are controlled and access by third party to spare capacity is difficult unless the common infrastructure has open access, which is a declared intention of DOE. This open access may be more likely if held by a state owned company as the State is more likely to look at developing a full gas market whereas the international and PPP scenario will aim to protect their market via control over the infrastructure. This is still possible even with NERSAs policy of allowing third party access to infrastructure spare capacity.

Wheeling rules and the associated contracts are under review from NERSA. A wheeling agreement is required when an IPP wishes to supply energy into the grid. The wheeling process is quite complex and difficult to navigate. It is not clear what the cost of wheeling contracts with Eskom will be. In theory, these should be reflective of costs of providing and maintaining the electricity transmission and distribution network. The consequences of the delay in providing an environment for wheeling arrangements is that it makes it difficult for merchant trade of power between willing buyers and sellers.

The main aim of the Gas Act is to promote the orderly development of the piped gas industry; establishes a National Gas Regulator as custodian and enforcer of the national regulatory framework.

Table 25: NERSA mandate in respect to Gas Act

Gas Act
Promote development the efficient, effective, sustainable and orderly development and operation of gas transmission, storage, distribution, liquefaction and re-gasification facilities and trading services
Facilitate investment in South Africa's gas industry
Ensure safe, efficient. economic transmission, distribution, storage, liquefaction & re-gasification of gas
Promote HDSA owned or controlled companies by means of licence conditions so as to enable them to become competitive
Equitable services interests and needs of all parties concerned are taken into consideration
Promote skills and employment equity within gas industry
Promote development of competitive markets for gas and gas services
Facilitate trade between the Republic and other countries
Promote access to gas in an affordable and safe manner

Petroleum Products Act

The LPG maximum refinery gate price and maximum price supplied to residential customers is regulated under the Petroleum Products Act. The LPG gas price is not regulated under the Gas Act as LPG is not considered a natural gas, but rather a by-product from the crude refinery process. Market competition between LPG and natural gas is likely to be primarily a function of volume and convenience.

Regulators in South Africa

In the gas value chain there are six different economic regulators (excluding Health, Safety and Environment affairs departments) that would regulate the industry with NERSA having the greatest influence, PASA and the DMR would not have involvement in LNG importation. These regulatory bodies are:

- The Department of Mineral Resources;
- The Department of Energy;
- The Petroleum Agency of South Africa (PASA);
- The National Energy Regulator (NERSA);
- The Transnet National Ports Authority; and
- The Ports Regulator. (Department of Transport)

Currently three have their status under review, which creates confusion and lack of alignment and synchronization of the Acts relating to Gas.

Reticulation by-laws

Reticulation is a responsibility of Local Government and as such local municipalities should create their own by-laws. At present only the Greater Johannesburg Metro has by-laws in place. NERSA at present only monitors gas prices charged to reticulators by Sasol Gas Ltd.

The reticulation of gas by a municipality could provide a revenue stream similar to electricity reticulation. The CoCT by itself or in a joint venture could own the molecules within the pipeline and charge a tariff to customers. Customers could be industrial, commercial and residential and municipal reticulation of gas could be a pro-active approach to supplement income as users move away from electricity. The Municipality may not need to own the infrastructure. The focus on gas has always been on gas to power and municipalities should start engaging with stakeholders in order to ensure that they can benefit from the future transmission of gas to end users.

5.4.3 Regulatory Considerations

The two main regulatory risks identified above is the lack of regulations identifying gas market development outside the IRP and a clear hierarchy of government authority and accountability. The Gas-IPP programme does not take into account planning and delivery with State involvement, nor does it consider the development of an integrated gas market.

National Treasury, Eskom, DoE, DMR, DPE, TNPA, CEF, NERSA and other state entities have unclear and overlapping mandates which has created a level of uncertainty and stagnation in gas development.

The GUMP which is the roadmap to an integrated horizontal development of a diverse market in South Africa has yet to be promulgated into law.

Single Buyer Risk

Due to the lack of a developed gas market, and in order for gas to power projects to be viable, IPPs will seek strong off take agreements (Power Purchase Agreements). Eskom is the designated single buyer of power and as with the REIPPPP programme, IPPs participating in the Gas-IPP programme will seek sovereign guarantees.

Table 26: Single buyer risk and risk mitigation measures

Description	Risk Mitigation measures
The ERA and Gas-IPP programme have identified Eskom as the sole buyer	Ministerial determination allowing identified buyers such as municipalities to buy directly from an IPP may allow greater market diversity. Establishment of a framework for the wheeling of energy to enable merchant gas and power markets. Longer term shift towards deregulated gas and power markets.

South Africa may be able to foster a more competitive gas and power market similar to those in the USA and Europe by enabling a merchant market where willing buyers and sellers can participate. This will stimulate the international led scenario where developers may seek to import LNG on a willing buyer/seller basis.

The current structure with Eskom as the single buyer reduces the competitive landscape and promotes reliance on sovereign guarantees.

Regulatory uncertainty

Table 27: Regulatory uncertainty risk and risk mitigation measures

Description	Risk Mitigation measures
Regulatory certainty over Acts, policies and ways to pass through the prices of fuels priced in US$ are required to provide guidance on future market development	GUMP roadmap should be promulgated into law to identify the road map ahead. NERSA should mandate a tariff that accommodates market dynamics such as forex movements. Ministerial determination should allow gas price pass through.

The uncertain regulatory environment is most likely to affect the internationally led scenario as international entities will require high levels of confidence that they can recover their capital investment costs.

PPPs are also likely to require high levels of certainty, but due to stronger government participation, this risk is lower.

State owned companies would require mandate certainty, however the risk of changes in regulations would not be that high.

Approval Processes

The EIA approval process, the issuing of permits, getting stakeholder agreement, and Eskom connection agreements are risky, time consuming and can deter investment. Putting out a tender where the bidder is required to secure the relevant permits and EIA approvals could result in a poor response from the market, as was the case in Taiwan with the Taipower tender process (2001-2003).

If land, servitudes and EIAs can be fast tracked and /or pre-approved, investors will respond more favourably. The CoCT has for example put in place a rapid land disposal process for the development of green manufacturing SEZ in Atlantis. (This fast tracking processes is an exception within the normal regulatory environment). The Atlantis SEZ office has commissioned an EIA for this land, after discussion with WCG and City officials. The commissioning of the EIA at this early stage would reduce the lag time before a gas-fired power station could be built in Atlantis, thus benefiting the national Gas-IPP programme as well as potentially attracting other investment to the area.

Table 28: Approval process risk and risk mitigation

Description	Risk Mitigation
Regulatory approval processes for projects will cause significant delays and/or may affect the viability of projects	Areas identified for possible development to be earmarked and pre-permitted where possible. The Gas-IPP programme could allow multiple bidders to bid using the same approved location in respect to land rights and EIA. Municipalities and related government departments must have in place processes to accelerate land and EIA process related to Gas-IPP bids.

Private sector players in Scenario 1: Internationally led may opt not to participate if the regulatory approvals prove to be excessive.

Mandate Uncertainty

Uncertain mandates of State owned entities have created confusion with SOCs' agendas misaligned.

Table 29: Mandate uncertainty risk and risk mitigation measures

Description	Risk Mitigation measures
State owned entity mandates are unclear and may not be aligned to the best socio-economic benefit for the Republic of South Africa	Central co-ordination of State Owned entities mandate so that all stakeholders roles are clearly defined. This will be within CEF group, TNPA and others. The potential sites for LNG need to be identified based on the socio-economic benefits to the fiscus. Collaboration of State owned Entities and related departments, such as port authorities, land owners such as public works, municipalities, etc. need to be engaged; and ministerial determinations need to be prioritised and fast tracked for development.

The state driven scenario has a risk of the gas sector development being stifled by uncertain mandates.

Both the PPP and international scenario will be affected by uncertain SOC mandates especially in respect to LNG regasification facilities where different positions could delay development.

Anticompetitive Behaviour

There is a possibility that the appointed parties under any of the above scenarios may seek protection over use and control of their infrastructure assets to the extent that it may be viewed as restricting open and fair participation in the sector.

Table 30: Anticompetitive behaviour risk and risk mitigation measures

Description	Risk Mitigation measures
Policies on ownership of strategic assets may stifle competition	Regulations should allow for acceptable capital returns and the establishment of a sustainable business but thereafter must allow for increased participation.

The risk of monopolies and oligopolies is that these may result in limited market development outside power generation and stifle future competition.

The risk to state driven companies can be lower as they may be able (as an aggregator) to more easily monitor and influence market development and supply.

The risk of not allowing a period of exclusivity is that companies may opt not to invest.

Municipal Tariffs

There is a belief that if power producers enter into a PPA with a municipality that the price charged per kWh must below Eskom's rates charged.

Table 31: Municipal tariff risk and risk mitigation measures

Description	Risk Mitigation measures
Municipalities cannot procure directly from IPPs if the cost of power produced was higher than Eskom's as it would be in contravention of the MFMA and NERSA tariff	The municipality can motivate for a higher price than Eskom if it is deemed to be in the best interest of the country and ministerial determination, such as in the case of the Darling Wind farm. A municipality must motivate the reason for higher tariffs if above base load costs, in particular if they are above new coal costs. A financial model that highlights the benefits of gas, non-financial implications such as the support for renewable energy, the reduction in load-shedding occurrences, reduction in carbon emissions, etc. could achieve this. NERSA should clarify how they intend to regulate LNG fuel and terminal costs

The risk that NERSA will not issue an operating licence due to a higher tariff would be most applicable to the internationally led scenario.

Table 32: Reticulation risk and risk mitigation measures

Risk	Risk Mitigation measures
Municipalities do not have a reticulation gas by-law in place as required.	The CoCT, Saldanha, Drakenstein areas should create and promulgate a gas by-law for gas reticulation.

Ministerial Determination

There a number of areas where ministerial determination or direction could be required along the LNG importation value chain.

Table 33: Ministerial determination risk and risk mitigation measures

Description	Risk Mitigation measures
Ministerial determinations that would be required to proceed with LNG import may be delayed or not issued.	The Minister should gazette decisions to ensure that LNG importation development occurs such as in the cases below: The Electricity Regulations Act -S34(2) allows for the identification of a buyers to develop, buy and apply for permits and licences. This determination could be applied to the CoCT or to an IPP. The section also expedites the establishment of a public or private owned electricity generation business. A fractionally higher tariff than Eskom could be approved by a Ministerial determination, if LNG importation was declared as a strategic imperative for economic development and could be justified. The National Ports Act S79 allows the Minister in the promotion of the national, strategic or economic interests of the Republic to direct the ports authority to accept LNG importation at designated desired locations such as Saldanha or other sites.

Ministerial determinations would assist all three scenarios.

The main areas where the provincial government and CoCT can have an influence on IPP development in the Western Cape is by providing land and approved EIAs for gas infrastructure development.

The CoCT can become an IPP or contract to an IPP outside the DoE Gas-IPP programme, but it will need to apply directly to NERSA.

Chapter 6: Plausible Contracting Models

6 Plausible Contracting Models for each scenario

6.1.1 Scenario 1 – International Driven

The table below depicts the most plausible players that would be involved in an LNG to power project in the context of Scenario 1.

Table 34: Most plausible players for Scenario 1

LNG Supplier	Terminal	Pipeline	Power Plant
LNG could be supplied by an IOC. Each of these players is capable of supplying as a single vertically integrated entity, or as a stakeholder in a consortium.	Given the regulatory complexities with developing an onshore terminal, the most likely terminal option for this scenario is an offshore terminal in the form of a FRSU, which can be leased from companies such as Golar, Hoegh and Excelerate.	The pipeline infrastructure would most likely be developed by a local or international pipeline company.	The power plant would be developed by IPPs, being either global gas and power utilities, or local developers.

The procurement process for this scenario could occur in the following ways:

The first is through the Department of Energy (DoE), which would issue an open tender for a full end to end solution for the supply of gas to power, from LNG (i.e. the Gas-IPP programme). The tender would include the construction of an LNG supply terminal and the associated delivery of gas through the terminal. The tender would be within a fixed timeframe and all of the risk would be transferred to the bidder. The tender would be backed with an Eskom PPA and a sovereign guarantee from the DoE.

The second option would be where Eskom is seeking to procure gas delivered to its facility as a privately driven solution. In this option, Eskom would engage the market for the supply of gas from LNG to its plant, Ankerlig. The successful bidder would be required to develop the necessary infrastructure (i.e. LNG receiving and regasification terminal and natural pipeline) to Eskom's Ankerlig power plant.

The third option is through a full merchant model. This would require creditworthy private sector off-takers and private sector developers. This option is least likely at present given the lack of creditworthy private sector players but could change if the South African gas and electricity markets are radically reformed to be private sector driven. This option is thus not considered in the assessment below.

In any of the above procurement approaches, it is assumed that the international / private sector entity would assume the infrastructure construction and performance risk. They will seek to pass this on to their EPC contractors though they ultimately carry this risk.

The international entity as the Buyer of LNG will enter into a take or pay contract with a specified price formula, currency and volume requirements. The Buyer will seek to pass these risks onto the state through mirroring the LNG SPA terms in the IPP offtake agreement. This may be an iterative process as the terms and duration of the SPA and other infrastructure contracts (e.g. The Terminal Tolling Agreement) need to match those of offtake agreement. From an operations perspective, the private sector consortium will require the off-taker to commit to a minimum and maximum dispatch profile aligned with the LNG delivery schedule and terminal storage capacity.

To minimise their construction and operational risk, the international consortium will seek to use standardised contracts and proven technology. They may even outsource the operations and maintenance through long term service contracts with experienced operators.

The international consortium will seek to pass on to the state any risks which are outside of their direct sphere of control, e.g. grid connection, industrial action, permitting delays and/or adverse weather, and may even walk away from the project if these risks are not transferable. An example of this is Taipower which ran a procurement programme for the supply of LNG and a terminal which required the bidder to undertake the permitting of the terminal. Internationals did not respond as they viewed the risk of Taiwanese EIA and land permitting requirements as too onerous. Thus international players will seek exemption from permitting and environmental legislation or where these are required will expect well defined approval processes for such and adherence to timelines by the regulatory authorities.

International players will focus on credit risk and the credit worthiness of the off-taker. Eskom and South Africa's downgraded credit ratings make credit worthiness a significant issue and project will require the provision of sovereign guarantees.

In addition, international players will seek protection from changes in law that may affect their operations, returns, and ability to transfer their dividends. As such they will look at tax regimes, withholding taxes on dividends, expatriate requirements and proposed changes to environmental and labour laws.

6.1.2 Scenario 2 – State Driven

The table below depicts the most plausible players that would be involved in an LNG to power project in the context of Scenario 2.

Table 35: Most plausible players for Scenario 2

LNG Supplier	Terminal	Pipeline	Aggregator	Off-takers
LNG could be supplied by an IOC, or PetroSA, if it takes equity in an upstream liquefaction facility	An onshore terminal is likely to be developed by either iGas or Transnet. There is still the option to consider an offshore terminal with a tolling arrangement with a private FRSU company.	The pipeline infrastructure would be developed by either iGas or Transnet.	PetroSA is positioning itself as a Gas Aggregator, and would therefore most likely fulfil this role.	The main off-takers focused on are Eskom, CoCT and IPPs.

For this scenario, the necessary infrastructure would be developed as a National Programme approved by Cabinet and the state ultimately carries the entire project risk. The state driven scenario is aimed at development of an integrated gas market and not just a gas to power market and thus the planning and sizing of the infrastructure will based on the larger market and long term estimated demand.

Independent Power Producers have expressed their comfort with this structure for the gas supply as they would see the state as taking the LNG procurement risk, however they are concerned about timelines, since a state driven project of this nature may take much longer to be realised.

As a state driven model, procurement for the elements of the value chain will be in accordance with the PFMA/ PPPFA and hence will require a competitive tender process or ministerial determination. Being a National Programme it will require the coordination of different state owned companies.

The State owned companies will each develop, design, procure and build their respective infrastructure component of the value chain. This can be via turnkey or multi-package contracts depending on the level of complexity and the specific each SOC's skills, experience and capacity.

Price, currency and volume terms of an SPA between a global LNG Seller and an SOC as the Buyer would more than likely be passed through an offtake agreement through to the end-user assuming NERSA continues to use the pass-through method with cost reflected tariffs. If the state, through a SOC, invests in the upstream liquefaction facility it may be able to provide a physical hedge and thus fix the price at a certain level, however this is unlikely. State owned companies responsible for the terminal and gas transmission pipelines are likely to propose tolling agreements for these services (storage, regasification and transportation of gas).

In comparison to scenario 1, it is anticipated that the State driven model will focus to a greater extent on national skills development and supply chain localisation. As such opportunities to develop the local industry for the manufacture of components of the works will be promoted. Typically, these could be quite extensive for the civil works, piping, electricals and the more labour intensive activities. SOCs are experienced at supplier development and will use this experience to develop local industries to supply this programme. Whilst the SOCs

will seek to limit their risk exposure, project delays caused by industrial action and other inefficiencies are likely to be ultimately carried by them and eventually passed onto the end consumer.

SOCs are very familiar with the regulatory environment and will work within the existing regulatory framework to get the necessary approvals where required.

SOCs also would not seek protection against any changes in law; however, they would seek National Treasury support to comply with any new legislation which has a significant cost impact.

Under this scenario, the City of Cape Town may be able to lobby via a national gas market development programme for capital investment into the associated downstream infrastructure to reticulate gas to industry, commercial, agricultural and residential end consumers.

6.1.3 Scenario 3 – Public private Partnership (PPP) Driven

The table below depicts the most plausible players that would be involved in an LNG to power project in the context of Scenario 3.

Table 36: Most plausible players for Scenario 3

LNG Supplier	Terminal	Pipeline	Aggregator
Similar to the State Driven scenario, the LNG could be supplied by an IOC or PetroSA, if it takes equity in an upstream Liquefaction facility.	The terminal could be developed by a partnership formed by the LNG supplier, such as an IOC, and iGas/Transnet. The supplier would be offering their terminal construction and operation experience to the partnership.	The pipeline infrastructure could be developed by an international pipeline company and iGas or Transnet. Here again, the international pipeline company would be offering his experience with regards to the construction and operation of pipelines to the partnership.	The aggregator role could be assumed by a consortium that could be between PetroSA and others, e.g. IPPs and gas traders. This enables some sharing of volume risk, where some of the members within the consortium will have committed volumes of off-take which they can potentially divert to other processes downstream. Since they are part of the off-takers, being members of this consortium will prevent them for being gas price-takers, and will enable them to schedule their committed volumes in an appropriate manner.

This scenario will most-likely be a state-led process. The state would form partnerships with private companies that would develop and operate the infrastructure required along the different elements of the value chain. An open tender would be issued in order to procure these partners.

The PPP would assume infrastructure construction and performance risk. The partner selection will be driven by technical capability and experience in delivering similar projects in other countries. The partner will also need to bring funding to the project and furthermore share in the revenue risk, though in several PPPs, these have been largely passed onto the state by the private sector partners.

It is expected that the consortium company (SPV) will own the product once shipped to South Africa and will have to take price, currency and volume risk, though the consortium would seek to pass these risk on through back to back offtake agreements.

The consortium contracts can become quite complex with several state entities possibly interested in such a structure and several private sector players who would be keen to partner for elements or the whole value chain. Thus the establishment of the PPP may be cumbersome and time consuming.

The City of Cape Town can also be a participant in the PPP and/or be an off-taker. The private sector partners should be capable to support the City with the rollout of gas infrastructure including the associated metering and billing systems.

The risk with this approach is both public acceptance as well as national government acceptance given the recent experience with PPP based toll roads in Gauteng and PPP projects by other government departments.

Chapter 7: Identification of Bottlenecks

7 Identification of Bottlenecks

Based on the analysis performed on the importation of LNG into the Western Cape, several elements which could serve as bottlenecks to the progress of the projects have been identified. This chapter aims to elaborate on each of those elements, and provide recommendations on what the Western Cape Government/ City of Cape Town can do in order to address these bottlenecks.

7.1.1 Bottlenecks

Land and servitudes

Developers would require land in order build power plants, pipelines, the LNG terminal and related infrastructure, and electricity transmission power lines. Obtaining land, or servitudes entitling developers the right to use land, could address a major bottleneck to the development.

Permits and consents

As mentioned in previous chapters of this report, Environmental Impact assessments have significant impact on the development at a port, pipeline servitudes and power plant sites. Thus, the process of obtaining EIAs approved for the development of such infrastructure could be a bottleneck since it is possible that EIAs may not be granted for these projects. Furthermore, developments at a port require consent from the National Ports Authority, which may be a lengthy process.

With the development of terminal, pipeline and power plant infrastructure, the municipal government in the selected locations for these developments would plausibly change the terms of property use on those sites. The process of rezoning these sites may be simple or complex depending on the demands and requirements of the city. The level of complexity is commensurate to the delay in the progress of the project.

Another possible bottleneck for the power plants is that of a grid connection for connection to the electricity transmission system, which could be an extensive process.

Pricing model

Considering that the price of LNG is indexed differently in different markets and that it is traded in a currency different to the ZAR (i.e. the USD), NERSA and Government may need to develop a different tariff structure for gas and electricity generated by gas sourced from LNG. Furthermore, as mentioned previously, a more flexible tariff recovery method allows for LNG importation LNG costs to be recovered similar to the fuel BFP mechanism that provides for crude and forex movements to be recovered on an under and over recovery basis, would have to be developed. This can also be in the form of an equalization fund as used previously by CEF/PetroSA and Sasol or a regulatory clearing account with an annual clawback as used currently by Eskom. The authorization of such a mechanism could be an extensive process, thus delaying the progress of the project.

Financing

The creditworthiness of the buyer may significantly affect the supplier's decision to supply LNG. To address this, the involvement of local debt funding from institutions such as the Industrial Development Corporation (IDC) and the Development Bank of Southern Africa may be required. Considering the magnitude of the costs involved in procuring LNG, sourcing local debt funding may be a protracted process, unlike with the RE IPPPP programme.

7.1.2 WCG's role

Scenario 1

In the context of Scenario 1, the Western Cape Government could offer their support to international players in addressing the bottlenecks mentioned above in the following ways:

- The Western Cape Government/ City of Cape Town could administer the site selection, the zoning and permitting of property or land belonging to or in the control of the Western Cape Government or the City. This may relate to possible power plant sites at Saldanha, Atlantis and Milnerton (as an example of a metro location), as well as distribution and reticulation infrastructure. This would make the Gas-IPP tender more attractive to international bidders, since the risk to them would be significantly reduced, and galvanise the progress of the project. It should be noted that most of the land in the Saldanha area identified for the siting of a potential plant is privately owned and potential terminal sites are on TNPA land. In this instance, the WCG or City may facilitate participation amongst the respective land owners and gas to power project developers.

- Alternatively the WCG could take out options on privately owned land and apply for its permitting and licensing with the requirement to transfer such to the preferred bidder from a gas to power procurement process. However, this possibility needs to be explored with the DoE IPP office and the Department of Environmental Affairs. The WCG would need to investigate if this process can be performed on the same EIA basis as the Atlantis SEZ.

- In addition to the options mentioned above, the Western Cape Government/ City of Cape Town could charge a development fee to the preferred bidders that would compensate the cost of administering/ obtaining the necessary licensing and permits on the bidders' behalves in order for them to develop infrastructure on the relevant sites. The bidders would then compete based on the price of their technological offers.

Scenario 2

Since, Scenario 2 is a state-driven model; the Western Cape Government could offer their support to the state in the following ways:

- The Western Cape Government could be a facilitator to getting State Owned Companies (SOCs) to commit to an integrated solution across the different elements of the LNG value chain. This could be achieved through a forum with the different SOCs or through getting the Department of Energy (DoE) and/or the Department of Public Enterprises (DPE) to commit to this project in the national interest.

- In addition, the Western Cape Government could assist in structuring the programme between SOCs and support them to progress the programme through cabinet and in supporting the SOCs to drive a consolidated project development programme, in the National Interest.

Scenario 3

In the context of the Private-Public Partnerships that would be formed in Scenario 3, the Western Cape Government could play the facilitator role between Government and private/ international companies. The WCG could also support the progress of the project through liaising with the relevant state institutions and assisting internationals in navigating the South African regulatory landscape. The recommendations mentioned in the Scenario 1 context regarding what the Western Cape Government could do, are also applicable in this scenario.

To execute on the above, the WCG may opt to setup a purposefully designed entity which shall act as a facilitator to promote the development of LNG infrastructure and gas to power projects. Such an entity would perform typical investor support functions and be the single point of contact for interaction between developers, SOCs and the WCG/CoCT.

Conclusion

8 Conclusion

Current global market conditions are favourable for LNG importation as demand for the product in the US and Europe has been affected by increased local shale gas production, increased regional piped gas supply and renewable energy subsidies.

The development of an LNG importation facility requires the co-ordinated development and construction of the LNG infrastructure value chain which includes the sourcing of LNG, procurement of a terminal, construction of pipelines and power plants. This co-ordination of the various elements of the chain poses to be major risk which can be addressed in various ways through each of the three scenarios described.

For Scenario 1: The internationally led (private sector developed) approach. The key consideration for WCG is how to enable the developers to fast track their project development activities. This can be through identifying and pre-permitting sites and servitudes for the projects. This is especially so in the case of port infrastructure, where WCG will look to TNPA and DEAT for support in defining and licensing the sites for onshore and offshore terminals. Similarly for pipeline servitudes, the same will be required.

For Scenario 2: The state driven approach. The main finding is that various state entities are developing similar projects as they have overlapping mandates. WCG can facilitate the co-ordination of state entities to ensure the seamless integration between the elements of the value chain which will also enable the development of a realistic schedule for the project development with associated commitments to the programme at a national level.

For Scenario 3: The Public Private consortium approach. WCG can play the role as described in Scenario 2 and furthermore, support state entities to identify appropriate partners for the various infrastructure components.

The WCG can proactively engage the DoE to ensure that the imminent RFQ / RFP process and programme deliver maximum benefit to the growth and development of the Western Cape. This may include considerations around how the programme is structured, whether sites are to be identified and developed by the developer or allocated, whether the state owned companies will provide infrastructure and services or whether the private sector will be called upon to develop an end to end solution.

There is potential value in having a state owned company as an equity participant in the gas aggregator and in the primary infrastructure development as this will enable the state to promote the sizing of the infrastructure to accommodate future growth.

It should be noted that for all the above scenarios, the need for a sovereign guarantee is consistent. It is envisaged based on the REIPPPP experience that a fully private procurement will also be dependent on sovereign guarantees and political risk safeguards.

The City of Cape Town can also participate as a buyer and off-taker of gas which would be within its mandate, however it would need to engage the DoE to ensure its requirements are accommodated within an IPP procurement programme.

In conclusion, WCG and the City of Cape Town are key stakeholders and influencers of the development of LNG importation in the Western Cape, which has significant medium to long term benefits to the province. The following months are essential to engage the DoE and other key stakeholders to ensure that such benefits are adequately covered through a holistic LNG market development programme of which the solicitation of IPPs is a component.

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