The Western Cape Government's Department of Economic Development and Tourism

Pre-Feasibility report for the importation of natural gas into the Western Cape with specific focus on the Saldanha Bay-Cape Town corridor

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TABLE OF CONTENTS

Definitions and abbreviations

Bcf	Billions of standard cubic feet
CCGT	Combined Cycle Gas Turbine Power Station
CNG	Compressed Natural Gas
DEDAT	Western Cape Government's Department of Economic Development and Tourism
DES	Delivery Ex Ship
FEED	Front End Engineering Design
FID	Financial Investment Decision
FOB	Freight on Board
FSRU	Floating Storage and Re-gasification Vessel
GSPA	Gas Sales and Purchase Agreement
HFO	Heavy Fuel Oil
HOA	Heads of Agreement
IDZ	Industrial Development Zone
LNG	Liquefied Natural Gas
NERSA	National Energy Regulator of South Africa
MMBtu	Million British Thermal Units
MMScfd	Millions of standard cubic feet per day
MTPA	Millions of tonnes per annum
OCGT	Open Cycle Gas Turbine Power Station
O & M	Operations and Maintenance
US$	United States Dollars
SRV	Storage and Regasification Vessel
Tcf	Trillions of standard cubic feet
WCG	Western Cape Government

List of Annexures

Annexure	Description
Annexure A	Levelized and Normalized Electricity Costs – Saldanha Bay & Milnerton
Annexure B	Economic Model – Assumptions and Parameters

1.0 Executive Summary

The Western Cape Government's Department of Economic Development and Tourism (DEDAT), through the Chief Directorate: Trade and Sector Development, commissioned a pre-feasibility study for the importation of natural gas to the Western Cape with specific focus on the Saldanha Bay – Cape Town corridor. The importation of natural gas to the Western Cape as an alternative energy source partly fulfils the South African Government's objective of introducing natural gas into the economies of the Western Cape and Eastern Cape Provinces and contributes to the realisation of The National Gas Infrastructure Development Plan[1]. Further and in particular, the Western Cape Provincial Government recently adopted the introduction of natural gas as an alternative energy source as a priority to stimulate industrial growth and thus employment opportunities in the province.

The Saldanha Bay – Cape Town corridor (Cape West Coast region) currently has no developed natural gas business. There are no established gas markets or any natural gas infrastructure for the offloading, storage, re-gasification, transportation or distribution of natural gas to any of the potential markets in the region which could be converted to natural gas. The establishment of such infrastructure will therefore classify as a greenfield gas infrastructure development.

The gas value chain for importing natural comprises a number of elements. A review and pertinent issues in each of the main elements are discussed under the following headings:

- Gas Market Potential
- Potential Gas Supply Options
- Infrastructure Development
- Schedule of Implementation

The findings of the above-mentioned elements culminated in an economic evaluation of the viability of importing natural gas to the Cape West Coast region, which together with conclusive remarks, are discussed at the end of the Executive Summary.

Gas Market Potential

The investigation into the introduction of natural gas as a potential alternative energy feedstock to the region resulted in the identification of two market sectors which could be converted to natural gas as their primary energy fuel; gas-fired power generation and

[1] Department of Energy - National Gas Infrastructure Development Plan

industrial markets. Of the identified market potential, power generation was found to be key to any of the natural gas importation options reviewed. Gas-fired power generation typically consumes large volumes of natural gas for its operations over a long period of time making it an ideal anchor for a greenfield gas development.

Power Generation

As a case study, Eskom's existing Ankerlig Open Cycle Gas Turbine (OCGT) power station near Atlantis has been identified as a potential anchor client. The Ankerlig power station is currently utilized as a peak-power generating facility[2] using diesel as its primary fuel source. The opportunity was however identified, should natural gas become available, for Ankerlig to be converted to a gas-fired Combined Cycle Gas Turbine (CCGT) facility, which would not only increase its efficiency from approximately 32 percent to 52 percent, but its generating capacity from 1 350MWe to 2 070MWe.

The Western Cape has a peak daily electricity requirement of approximately 3 864MWe[3]. With its local base load generating capacity by its Koeberg nuclear power plant and the Palmiet hydro-electric pump storage facility, and its electricity export commitments to Namibia, Eskom on average imports about 2 050 MWe[4] of peak power on any given day to the region. The increase in generating capacity by the Ankerlig power station, should it be converted to a gas-fired CCGT facility, could therefore significantly contribute to the reduction of electricity imports to the Western Cape province and at the same time contribute to the reduction in transmission losses, estimated to be in the region of 200MWe[5], during the transmission of electricity to the region.

For the purposes of this study, it was included[6] that the existing Ankerlig power station would be converted to a gas-fired mid-merit[7] CCGT power plant. The total energy requirement for Ankerlig in this configuration equated to approximately 66.5 million Gigajoule per annum, roughly about 75 percent of the total identified gas market potential in the Cape West Coast region.

[2]Peaking power facility - efficiency of 32.7 percent with utilization less than 6 percent per year
[3]Source: Eskom 2012
[4]Source: Eskom 2012
[5]Transmission, transformer and distribution losses are estimated to be between 6 to 10 percent - Eskom
[6]DEDAT Assumption
[7]Mid-merit power operations – operational 5 days per week, 16 hours per day with an efficiency of 51.7 percent and utilization of 47 percent

For evaluating the effect that new power generating capacity could have on the viability of importing natural gas to the Cape West Coast region, option selections for various sizes of gas-fired plant have been included in Saldanha Bay and/or Milnerton in the accompanying economic model.

An estimated normalized cost[8] of electricity from Ankerlig and the different power station options at Saldanha Bay and Milnerton under the various LNG importation options have been calculated in a manner to be comparable to the bid prices received by the Department of Energy during the second bidding window for the supply of renewable energy and the estimated cost[9] of electricity from the Medupi coal-fired power station currently under construction. Tables 1, 2, & 3 summarizes of the comparative electricity prices.

Renewable Electricity

Average Bid Prices for Renewable Electricity 2nd Bid Window	
Type	**Cost/kWh**
Concentrating Solar Power (CSP)	**ZAR 2.51**
Solar Photo-voltaic (PV)	**ZAR 1.65**
Wind	**ZAR 0.90**
Small Hydro	**ZAR 1.03**

Table 1

New Coal-fired Power Generation

Estimated Normalized Electricity Costs – New Coal-fired Power Generation (Medupi)		
Capacity	**Type**	**Cost/kWh**
4 800 MWe	**New Coal-fired Power Generation - Medupi Power Station**	**ZAR 1.10-1.30**

Table 2

[8]Internal cost estimation
[9]mg.co.za/article/2012-08-24-00-eskom – August 2012

Gas-fired Power Generation

Estimated Normalized Electricity Costs - Gas-fired Power Generation (Ankerlig CCGT Conversion)				
	Offshore LNG Terminal (Between Duynefontein & Yzerfontein)		Onshore LNG Terminal (Saldanha Bay)	
Capacity	LNG Landed Price (US$10/MMBtu)	LNG Landed Price (US$15/MMBtu)	LNG Landed Price (US$10/MMBtu)	LNG Landed Price (US$15/MMBtu)
2 070 MWe	ZAR 0.84-R0.95/kWh	ZAR 1.18-1.34/KWh	ZAR 0.92-1.04/kWh	ZAR 1.27-1.43/kWh

Estimated Normalized Electricity Costs - Gas-fired Power Generation (Saldanha Bay)				
Capacity	Offshore LNG Terminal		Onshore LNG Terminal	
	LNG Landed Price (US$10/MMBtu)	LNG Landed Price (US$15/MMBtu)	LNG Landed Price (US$10/MMBtu)	LNG Landed Price (US$15/MMBtu)
350 MWe	ZAR 1.14-1.28/kWh	ZAR 1.48-1.67/KWh	ZAR 1.08-1.22/kWh	ZAR 1.42-1.61/kWh
450 MWe	ZAR 1.12-1.27/kWh	ZAR 1.46-1.65/kWh	ZAR 1.08-1.22/kWh	ZAR 1.42-1.61/kWh

Estimated Normalized Electricity Costs - Gas-fired Power Generation (Milnerton)				
Capacity	Offshore LNG Terminal		Onshore LNG Terminal	
	LNG Landed Price (US$10/MMBtu)	LNG Landed Price (US$15/MMBtu)	LNG Landed Price (US$10/MMBtu)	LNG Landed Price (US$15/MMBtu)
800 MWe	ZAR 1.09-1.23/kWh	ZAR 1.43-1.62/KWh	ZAR 1.10-1.25/kWh	ZAR 1.44-1.63/kWh
1 000 MWe	ZAR 1.09-1.23/kWh	ZAR 1.43-1.62/kWh	ZAR 1.09-1.23/kWh	ZAR 1.44-1.62/kWh

Table 3

Industrial Markets

The existing industrial markets which could potentially be converted to natural gas were found to be mostly concentrated in the Cape Town, Atlantis and Saldanha Bay regions. Cape Town, Paarl and Wellington have the largest concentration of “switchable” industries and accounted for about 23 percent, or 20 million Gigajoule per annum, of the approximately 89 million Gigajoule per annum market potential within the Saldanha Bay - Cape Town corridor. Coal and fuel oil users dominated the current energy consumption in the area’s industrial hubs where coal usage constituted approximately 60 percent and fuel oil approximately 20 percent of the existing energy mix. The remainder of the energy consumption was spread between waxy oil, diesel, LPG and paraffin.

The potential industrial markets in the Atlantis region which could be converted to natural gas amounted to a little over 1 million Gigajoule per annum. As with the markets in the Cape Town region, coal usage again dominated the energy consumption representing approximately 71 percent of the energy mix. LPG consumption represented about 16 percent of the energy mix with fuel oil, paraffin and diesel accounting for the remaining fuel usage.

The existing "switchable" industrial markets in Saldanha Bay amounted to an energy consumption of about 1.3 million Gigajoule per annum. LPG usage was found to be high and constituted approximately 65 percent of the energy mix mainly because of the large consumption for pre-heating and heating purposes by the local steel and steel processing plants. Coal and HFO consumption contributed to the remaining fuel usage in the region.

It should however be noted that the future potential markets in the Saldanha Bay region could be substantial and significantly contribute to rapid industrial growth with the accompanying commercial and social benefits. A number of potential expansion projects by established companies in the region and planned projects by new investors have shown a specific requirement for additional electricity and natural gas as an energy feedstock for their business processes. For instance, should the planned Midrex/DRI expansion phase at the ArcelorMittal steel plant proceed, a potential direct natural gas requirement of approximately 16 million Gigajoule per annum would be required for the process. A realistic electricity requirement of approximately 450 MWe has also been identified for existing and planned industry operations in the Saldanha Bay region which could have an upside potential nearing 750 MWe.

Potential Gas Supply Options

The Cape West Coast region presently does not have sufficient proven natural gas reserves[10] that could commercially be developed in the foreseeable future for industrial usage and/or power generation. For this reason the study investigated alternative potential gas supply options for the period under review[11] which included:

- indigenous gas supplies from known gas reserves and resources;
- pipeline gas from neighbouring or near-neighbouring countries with proven gas reserves; and
- Liquefied Natural Gas (LNG) from existing and planned LNG liquefaction facilities.

[10] US Energy Information Administration – RSA Energy Overview/Natural Gas –An Update on South Africa's Potential, 2012
[11] First commercial gas deliveries by January 2018

The review took into consideration 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. Longer-term option i.e. planned exploration programs have, for the time being, not been considered.

Indigenous Gas Supplies

The review of currently known indigenous gas reserves or resources presented two potential gas supply options:

- *Forest Oil's offshore Ibhubesi gas field discovery situated in Block 2A north of Saldanha Bay* - this option was not favoured mainly due to the current limited gas resources (450 Bcf at a P50 probability level[12]) and the stated intent by the operators[13] not to proceed with any further development of the gas field until such time that sufficient gas off take agreements have been concluded. This, together with Forest Oil's recent attempts to sell their exploration interests in South Africa, indicated that any potential future development of the Ibhubesi gas field would not fall within the time frame required for the development of a natural gas industry in the Cape West Coast region; and
- *PetroSA's gas fields in the central Bredasdorp Basin offshore the Mossel Bay region* - PetroSA announced that the current gas fields supplying its gas-to-liquids refinery in Mossel Bay were in decline and nearing the end of their productive capabilities[14]. The company recently embarked on a 2-year, 5 well drilling campaign in the F-O gas fields with its main objective[15] to maintain commercial operations of its gas-to-liquids refinery until 2019/2020[16]. In support of this objective, PetroSA also embarked on assessing the viability of importing LNG to the Mossel Bay region as an intermediary measure to allow additional time for sourcing further feedstock for their refinery. The company described both the projects of critical importance for the sustainability of their gas-to-liquids refinery[17]. The review concluded that PetroSA's primary objective, for the time being, was to secure gas feedstock for its own requirements and potentially other industries in the immediate vicinity of Mossel Bay.

[12]Forest Oil – 2011 Annual Report
[13]Source: Forest Oil
[14]Africa Upstream Conference - 2012
[15]PetroSA Web Page, January 2013 (www.petrosa.co.za)
[16]PetroSA Web Page, January 2013 (www.petrosa.co.za)
[17]PetroSA Web Page, January 2013 (www.petrosa.co.za)

Opportunities of supplying natural gas from existing indigenous gas fields within the time frame required for introducing natural gas to the Cape West Coast region were therefore found to be unlikely.

Piped Gas

Potential opportunities for natural gas to be piped to the Cape Town region from neighboring states were found to currently be limited to gas produced from Sasol's Pande and Temane gas fields in Mozambique and the Tullow Oil-operated Kudu gas fields in Namibia.

The review showed the current gas pipeline from the Pande and Temane gas fields to Sasol's chemical plants in Secunda and Sasolburg and industries in the Kwazulu-Natal and Gauteng regions to be nearing its current full capacity[18] of 149 million GJ per annum suggesting that, should this option be considered and additional gas could be made available by Sasol from those gas fields, a new pipeline would be required to the Cape Town region. With distances in excess of 2 900 kilometers and a relatively small gas off take requirement (less than 90 million Gigajoule per annum) in the Cape West Coast region, the commercial viability of piping gas from the northern parts of Mozambique was found to be uneconomical if compared to alternative options available i.e. the importation of LNG or CNG.

Transporting gas by pipeline from the Kudu gas fields in Namibia to the Cape Town region has also proven to be commercially challenging. More importantly, the government of Namibia indicated a preference[19] to use natural gas from the Kudu gas fields for the country's own industrial and power generating requirements rather than exporting it to South Africa.

Lead time requirements for establishing the necessary pipeline and associated infrastructure further placed both option beyond the time frame requirements for importing natural gas to the Cape West Coast region, making the potential piping of gas form Mozambique or Namibia unlikely.

[18] Republic of Mozambique Pipeline Investment Company – Tariff Application for the Natural Gas Volumes Transported on the Additional 27 MMGJ/a – 23 August 2011

[19] Source: Namcor 2012

Liquefied Natural Gas (LNG)

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 and Saldanha Bay.

Five LNG producing countries were assessed based on LNG availability from within their portfolio of supplies and their distances from Saldanha Bay. These included the West African countries of Angola and Nigeria, the Middle Eastern countries of Qatar and Oman and Australia. Although Mozambique and Tanzania are currently non-producing LNG countries, they have been included in the assessment as future potential LNG suppliers because of the large recent gas discoveries in both countries and the intent, specifically by the Mozambique government[20] and concession operators, to establish LNG liquefaction and export facilities by 2018.

Of the countries assessed, four have been favored for their location and potential available LNG supplies by 2018; Mozambique and Tanzania on the East African coast and Nigeria and Angola along West Africa. LNG supplies from these countries carried a significant cost advantage over the other countries reviewed due to the shorter shipping distances between loading and delivery points.
Establishing an estimated price for LNG deliveries to the Saldanha Bay region was found to be highly dependent on the Freight on Board (FOB)[21] price at the LNG supply terminal, the distance between that supply point and Saldanha Bay and the availability of LNG supplies from the supply point. Using a "netback pricing methodology[22]" from known FOB supply prices[23] to the Saldanha Bay region, an estimated range of landed costs between US$10.00 per MMBtu and US$15.00 per MMBtu were calculated.

Gas Infrastructure Requirements

This section of the study report mainly represented the investigation into the infrastructure requirements for the importation of LNG and comprised a review of LNG receiving terminal options for receiving, storing and re-gasifying LNG, the high-pressure

[20] Instituto Nacional de Petrolea (INP) Mozambique - Mozambique Gas Master Plan - 2012
[21] Onboard Price of LNG at the LNG Supply Terminal
[22] Report to the Office of Queensland Gas Market Advisor - Modeling and Analysis for The Gas Market Review 2012
[23] The Federal Energy Regulatory Commission (FERC) - Estimated Landed Prices of LNG for February 2013

transmission pipeline network necessary to transport the natural gas from the receiving terminal(s) to the downstream markets and a low-pressure distribution pipeline network to distribute the gas to the downstream markets.

LNG Receiving Terminals

The LNG receiving terminal is the gateway for supplying natural gas to downstream markets. LNG is delivered to these terminals by LNG carrier vessels from where it is offloaded, transferred to large storage tanks, regasified and injected into the pipeline network.

Two types of LNG receiving terminals were reviewed in order to compare and highlight any cost, operational and timing advantages of the one over the other:

- The importation of LNG to a traditional land-based LNG importation terminal situated in the Port of Saldanha Bay; and
- The importation of LNG to a semi-submerged LNG receiving terminal situated approximately 8 kilometers offshore between Duynefontein and Yzerfontein[24].

Traditional LNG receiving terminals are land-based and comprise a ship mooring and unloading area, LNG offloading arms and cryogenic piping to storage facilities, large storage tanks, pumps to move stored LNG, vaporizers to convert the LNG into gas, and pressure and metering facilities measuring the discharge of the gas into the pipeline network to the downstream markets. Establishing these facilities were found to be capital intensive (approximately US$380 million) and was assessed take about 5 years to construct[25][26], especially as part of a greenfield development.

The review of a land-based LNG terminal further highlighted some of the expected difficulties when constructed inside an existing operational port. Other than environmental and safety issues (certain of the port operations could be sterilized during offloading operations), the proximity of a hazardous installation to residential and work areas were found to potentially present a number of significant issues, including possible conflict with spatial plans, aesthetic and sense of place concerns, public perceptions of risk, and air quality/health concerns. None of these or other concerns listed under item 6.1.1 were however

[24]Pre-feasibility Study Framework and Assumptions/Gas Receiving Terminals
[25]Fundamentals of the Global LNG Industry/International Gas Union – World LNG Report, 2012
[26]Excelerate Energy Webpage – (excelerateenergy.com), February 2013

found to be insurmountable and mainly carried the risk of added time and costs to establishing a land-based LNG receiving terminal.

An alternative to the conventional onshore LNG receiving terminal was the Energy Bridge concept which combines LNG shipping, storage and re-gasification on ocean-going LNG vessels. In this study, the concept comprised a submerged demountable buoy, a flexible marine riser and a submerged mooring system to which a buoy would be attached and a Floating Storage and Regasification Unit (FSRU)[27] be moored. The basis of the offshore LNG terminal option was the supply of LNG via conventional, slightly modified, LNG shuttle tankers to the FSRU where it would be stored, re-gasified, compressed and delivered into a transmission pipeline network to the downstream gas markets. Importantly, the concept has been proven in the harsh waters of the North Sea and was found to be ideally suited for remote countries and markets which have no existing LNG receiving terminal infrastructure[28]. The system has proven to be less capital intensive (US$135 million) and importantly, could be operational in about 3 years[29].

Transmission Pipelines

The two LNG receiving terminal positions resulted in different transmission pipeline networks necessary to supply gas to the Saldanha Bay, Atlantis and Cape Town regions.

The transmission pipelines from a land-based terminal in the Port of Saldanha Bay included the transmission and related infrastructure necessary for transporting natural gas to industries in Saldanha Bay, the Ankerlig power station near Atlantis, the Atlantis industrial area and the industrial areas of Cape Town, Paarl and Wellington. The transmission pipeline comprised 116 kilometres of high-pressure pipelines and associated infrastructure from the LNG terminal to the City Gates[30] in Atlantis and Milnerton at an estimated cost of US$122 million.

The transmission pipeline network from the offshore LNG terminal situated between Duynefontein and Yzerfontein included the phased development of the transmission and related infrastructure necessary for transporting natural gas to the same markets described above where phase one comprised the pipeline

[27] An LNG vessel with onboard storage, regasification and compression facilities typically about 138 000m^3 to 180 000m^3 in size
[28] Excelerate Energy Webpage (excelerateenergy.com)
[29] Source: Golar LNG/Blue Water Energy Services/Shell Upstream International
[30] Transmission pipeline end terminal with pressure protection and supervisory control and data acquisition facilities

infrastructure required to the Ankerlig power station, the Atlantis industrial area and the industrial areas of Cape Town, Paarl and Wellington and phase two the extension of the infrastructure to include industries in Saldanha Bay. The position between Duynefontein and Yzerfontein was selected as a case for this study because of its location to the Ankerlig power station near Atlantis and the existing downstream market potential in the Cape Town region and its favourable med-ocean scoping[31] results.

The basis of assuming a phase development from the offshore LNG receiving terminal was to capture the larger existing markets in Atlantis (including the Ankerlig power station), Cape Town, Paarl and Wellington soonest and to extend the pipeline infrastructure to Saldanha Bay, which was found to *currently* have limited, albeit high in value, “switchable” markets”[32], at a later date to allow for market growth in the region.

The transmission pipeline for Phase 1 comprised an 8 kilometre section offshore pipeline and 61 kilometres onshore pipeline to the City Gates in Atlantis and Milnerton at an estimated cost of approximately US$62 million.

Phase 2 comprised an approximate 62 kilometres extension of the high-pressure pipeline infrastructure to Saldanha Bay at an estimated cost of US$71 million.

Distribution Pipeline

The pipeline distribution network comprised a low-pressured (< 15bar) pipeline network which is the final delivery link of natural gas to the downstream markets. Typically, the installation of distribution networks is expensive since they are often routed through urban and sub-urban areas along existing municipal infrastructure and servitudes which require subsequent reparation to restore roads, road verges and servitude surfaces that were damaged during the installation process.

Three separate distribution pipeline networks were assessed to service the main industrial areas of Saldanha Bay, Atlantis and Cape Town, Paarl and Wellington. Of these the industrial areas in Cape Town, Paarl and Wellington were by far the largest and comprised approximately 105 kilometers of low-pressured pipeline at an estimated cost of about US$75 million. The distribution network serving the Atlantis industrial area comprised approximately 8 kilometers of pipeline estimated

[31] CSIR – Preliminary Assessment of Marine Environmental Conditions on the Cape West Coast – Dec 2009
[32] Item 4.3 - Gas Market Potential, Saldanha Bay

at US$5.5 million whilst the network in Saldanha Bay required about 13 kilometers of distribution pipeline to supply the identified markets costing about US$8.5 million.

Typical Schedule of Implementation

A schedule of implementation was developed for both the LNG receiving terminal options and their respective transmission and distribution infrastructure developments. For this study it was divided into two main activity periods namely;

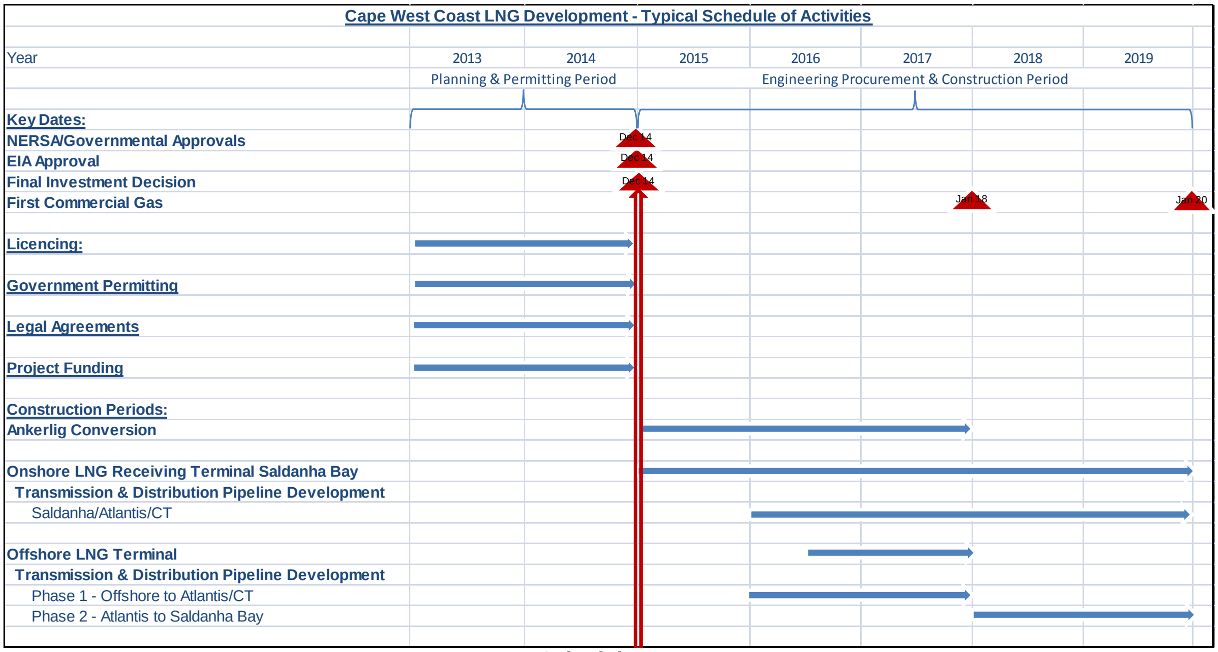
- *Planning and Permitting Period* – this period allowed for promoting and planning the importation of natural gas to the Cape West Coast region by the participating parties and included all the necessary pre-feasibility studies, required Environmental Impact Assessment (EIA) and necessary licensing and permitting requirements by the relative participants. These activities were scheduled for completion in a two-year period ending in December 2014; and
- *Engineering Procurement and Construction (EPC) period* – this period allowed for the construction of the LNG importation terminal, transmission and distribution gas pipelines and other associated infrastructure to a point ready for first commercial gas deliveries.

  The land-based terminal option in Saldanha Bay and its associated pipeline infrastructure was estimated to take five years for completion making first commercial gas deliveries available in January 2020. The construction period of the LNG receiving terminal determined the critical path for completion in this option. The conversion of the Ankerlig power station to a CCGT facility and the pipeline infrastructure were scheduled to align with the completion date of the terminal.

  The first phase of the offshore LNG terminal option provided the shortest timeframe of the options reviewed for first commercial gas deliveries to Atlantis, the Ankerlig power station and the industrial markets in Cape Town, Paarl and Wellington. The completion period for the offshore terminal and its associated pipeline infrastructure was estimated at three years making first commercial gas deliveries possible by January 2018. In this option the conversion of the Ankerlig power station to a gas-fired CCGT facility determined the critical path for the commencement of operations.

  The start of phase two was included to be concurrent with the completion of phase one with first commercial gas deliveries to Saldanha Bay scheduled two years thereafter in January 2020.

Schedule 1 below illustrates the key activities in the two periods described and highlights the different commencement dates between the two LNG terminal options.



Schedule 1

Economic Evaluation

The valuation of the different LNG importation and market scenarios described in Table 22 under item 8 resulted in the following key findings:

- The offshore LNG receiving terminal option required less capital investment and a shorter lead time for completion than the land-based receiving terminal option. However, with the exclusion of the Phase 2 of the development, this option showed a lower NPV (due to the exclusion of the high value industrial markets Saldanha Bay), but a higher IRR (due to the low up-front capital investment);
- With Phase 2 of the offshore receiving terminal option included, this option realized the highest NPV and IRR of the three Base Case scenarios evaluated. The inclusion of Phase 2 added value both in NPV and IRR terms;
- The substitution of the Ankerlig power station with a gas-fired power station at Milnerton destroyed significant value in all cases evaluated due to the significant decrease in gas sales volume and the increase in capital cost (larger diameter transmission pipeline from Atlantis to Milnerton). However, a gas-fired power station at Milnerton in addition to the Ankerlig power station, added significant value;

- An increase in the gas sales margin to all gas-fired power plants from 10 to 15 percent contributed substantially to the project IRR;
- The addition of a gas-fired power station at Saldanha Bay added value in all cases (except for the offshore receiving terminal option without Phase 2, where such addition was not possible). This value addition became more pronounced for the offshore terminal case, where the transportation tariff component in the sales price build-up was much higher than for the onshore terminal case; and
- The results of the evaluation included LNG to be supplied from Mozambique in all cases. Although the results did not show the impact of alternative supply sources of LNG, it can be deducted that:
  - Gas sales to the industrial markets would be negatively impacted by the higher landed cost; and
  - Gas sales to the power stations would be positively impacted due to the cost build-up pricing with a 10 percent margin on the landed cost.

Conclusion

This study highlighted the dependency of the Cape West Coast region on the importation of nearly all its energy requirements and the need for introducing an alternative affordable energy source to stimulate industrial growth and the accompanying commercial and social benefits it might bring. An analysis of the primary energy feedstock currently used by industry showed its complete reliance on coal, fuel oils, LPG and diesel for its operations, all of which are fully or partly imported to the region at great costs. The analysis further indicated that the Western Cape remained dependent on the importation of more than fifty percent of its daily peak electricity requirements. It demonstrated the region to basically be starved of alternative, affordable and reliable energy/electricity for existing industries and potential industrial growth.

This study therefore reviewed the various contributing factors for importing natural gas as an alternative energy source for industrial usage and power generation. These factors, individually and as a whole, contributed to assessing the technical and commercial viability of a natural gas importation scheme and were segmented into three main sections; the gas market potential in the Cape West Coast region, potential natural gas supply sources and the infrastructure requirements necessary to transport the natural gas to the downstream markets. The sections are briefly summarized in support of the conclusion at the end of each section:

- *Gas market potential in the Cape West Coast region* - a review of the gas market potential identified two potential market sectors which could be converted to natural gas as its primary energy feedstock; the industrial market sector and gas-fired power generation. The main existing industrial markets along the Saldanha Bay – Cape Town corridor were found to be situated in Saldanha Bay, Atlantis and the Cape Town, Paarl and Wellington regions. Although the total current energy consumption of these industrial hubs was found to be high in value, they were insufficient to support the high costs associated with the necessary gas infrastructure developments.

The inclusion of gas-fired power generation however, improved the commerciality of a natural gas importation scheme considerably. The conversion of the Ankerlig power station near Atlantis to a gas-fired CCGT facility not only contributed to a significant increase in gas consumption over a long period but also to a sufficient increase in the income necessary to underpin the large associated development costs. Similar results, except for gas-fired power generation in Milnerton as a stand-alone facility i.e. without Ankerlig (Case 1.1.1 under item 8), were obtained when the effect of new gas-fired power plants were assessed, in combination or separately, in Saldanha Bay and/or Milnerton.

The market evaluation of the Cape West Coast region concluded that gas-fired power generation would play an enabling role to the viability of any of the gas importation options evaluated.

- *Potential natural gas supply sources* - three potential options for the supply of natural gas to the Cape West Coast region were evaluated which included; indigenous gas supplies from known gas resources or reserves, piped gas from neighbouring or near-neighbouring countries and the supply of LNG.

  The evaluation concluded the importation of LNG to be the most viable gas importation option available. With new LNG liquefaction plants currently under construction in Nigeria and Angola and liquefaction plant(s) planned in Mozambique, the potential of sourcing LNG from these nearby countries carried potential price advantages due to the shorter shipping distances to the Saldanha Bay region. The timing of first planned LNG production from these plants by 2018 also coincided with the planned completion of one of the two LNG receiving terminal options reviewed.

  The review of gas supply options to the Cape West Coast region concluded the importation of LNG from Nigeria, Angola and potentially Mozambique to be the most viable of the gas supply options considered.

- *Gas Infrastructure Requirements* – the gas infrastructure comprised an LNG receiving terminal, high-pressure transmission pipelines and a low-pressure gas distribution pipeline network.

  This study evaluated two LNG receiving terminal options and their respective transmission and distribution gas pipeline networks to the downstream markets namely;

  - a permanent land-based LNG receiving terminal in the Port of Saldanha Bay; and
  - an offshore semi-submersible LNG receiving terminal between Duynefontein and Yzerfontein.

  The pipeline infrastructure for the land-based LNG receiving terminal was included to be constructed from the terminal to the downstream markets contemporaneously with the construction of the terminal.

  The construction of the pipeline infrastructure for the offshore LNG terminal on the other hand was considered in a phased manner where the first phase included the transmission and distribution pipelines necessary to supply the existing industrial areas in Atlantis, the Ankerlig power station and the industrial markets in Cape Town, Paarl and Wellington and the second phase the extension of the pipeline infrastructure to include industries in Saldanha Bay.

  The review of the different LNG receiving terminal options and their respective transmission and distribution networks highlighted two prominent advantages of the one over the other:

  - *Timing of Completion* – the total time required constructing a land-based LNG receiving terminal in the Port of Saldanha Bay and the associated gas pipeline infrastructure was estimated at approximately five years. Under this LNG receiving terminal option first commercial gas deliveries was scheduled to commence in *January 2020*.

    The estimated time required for constructing an offshore LNG receiving terminal and the associated pipeline infrastructure for phase one of this development option amounted to three years, making first commercial gas deliveries available in *January 2018*. Phase two of the development made first commercial gas deliveries available in Saldanha Bay two years later in *January 2020*.

- *Cost of Completion* – the capital costs for a land-based LNG receiving terminal situated in the Port of Saldanha Bay was estimated at approximately US$ 380 million with an additional approximately US$ 210 million for the associated gas transmission and distribution pipeline network system. The total estimated capital costs required for the onshore LNG receiving terminal option therefore amounted to *US$ 590 million*.

  The capital cost estimation for the semi-submersible LNG receiving terminal amounted to approximately US$135 million. In addition, the estimated costs for the transmission and distribution gas pipeline networks for phase one amounted to approximately US$142 million giving a total first phase development cost of *US$277 million.*

  The inclusion of phase two resulted in an additional capital expenditure of approximately US$80 million bringing the capital expenditure for the offshore LNG receiving terminal option (Phase 1 and Phase 2) to about *US$ 360 million*.
  Table 4 summarises the scheduling and costs of the terminal options.

LNG Terminal Options – Timing & Costs Summary				
	First Commercial Gas	**Terminal (US$ million)**	**Pipeline Infrastructure**	**Total Capital Costs (US$ million)**
Onshore LNG Terminal	**Jan 2020**	**380**	**210**	**590**
Offshore LNG Terminal				
Phase 1	**Jan 2018**	**135**	**142**	**277**
Phase 2	**Jan 2020**		**80**	**360**

Table 4

The review of the two LNG receiving terminal options and their respective transmission and distribution gas pipeline networks concluded that the importation of LNG through an offshore semi-submersible LNG terminal and the phased development of the gas pipeline transmission and distribution infrastructure would result in the shortest lead time for making first commercial gas available at lowest capital cost requirements.

- *Economic Evaluation* - the economic evaluation of the different LNG importation and market scenarios described in Table 22 under item 8 highlighted five key conclusions:

- The offshore LNG receiving terminal option required less capital investment and a shorter lead time for completion than the land-based receiving terminal option;
- The offshore receiving terminal option (including Phase 2) realized the highest NPV and IRR of the three Base Case scenarios evaluated;
- The substitution of the Ankerlig power station with a gas-fired power station at Milnerton destroyed significant value in all cases evaluated. However, a gas-fired power station at Milnerton in addition to the Ankerlig power station, added significant value;
- The increase in the margin of gas sales to all gas-fired power plant options contributed substantially to an improved project IRR in all cases evaluated; and
- The addition of a gas-fired power station at Saldanha Bay added value in all applicable cases.

The review of the economic analysis of the various LNG importation and market scenarios concluded the offshore LNG receiving terminal option (phase 2 included) to be commercially the most viable and that the inclusion of the Ankerlig power station contributed added value to all options evaluated.

The introduction of natural gas as an alternative energy feedstock to the Cape West Coast region will relieve its dependency on the importation of most of its energy requirements and serve as catalyst for industrial development in the region with all the accompanying commercial and social benefits. This study has clearly indicated the requirement for additional, affordable and reliable energy and/or electricity, especially in the Saldanha Bay region, to stimulate planned industrial expansion programs and the establishment of future new business opportunities. The economic evaluation has demonstrated natural gas to be price-competitive to the weighted average cost of current energy sources but has highlighted the enabling role that existing or potential future gas-fired power generation would play as an anchor gas off taker, without which a gas importation scheme is unlikely to succeed.

Of further importance is the current window of opportunity for the supply of LNG from liquefaction plants under construction in Nigeria and Angola and those planned in Mozambique, all of which could provide LNG at more competitive prices due the short transportation distances from Saldanha Bay by 2018.

2.0 Introduction

The Western Cape Government's Department of Economic Development and Tourism (DEDAT), through the Chief Directorate: Trade and Sector Development commissioned a pre-feasibility study for the importation of natural gas to the Western Cape with specific focus on the Saldanha Bay – Cape Town corridor. The study was to consider and build on previous studies for the importation of natural gas supply to the Western Cape.

The potential of importing natural gas to the Cape West Coast region has on several occasions been studied[33]. Since 2007/8, studies by PetroSA and Gigajoule Africa, both with participation by Eskom, have studied different permutation of importing LNG to the region as energy feedstock for gas-fired power generation and for industrial usage in the Saldanha Bay, Atlantis and Cape Town regions. These are the most recently known studies and have in part been used as reference documentation to this study.

The study by PetroSA was based on the importation of LNG to a land-based terminal in the Port of Saldanha Bay where gas would be received in liquid form, stored in two large concrete tanks, re-gasified and delivered to a newly constructed gas-fired power station situated near the Port of Saldanha Bay and transported onwards through a transmission and distribution pipeline network to the identified markets in the Saldanha Bay, Atlantis, Cape Town, Paarl and Wellington industrial regions. The study was based on a single phase development where all necessary infrastructures would be constructed and commissioned simultaneously.

The anchor and main gas consumer for the study was a newly constructed 1 600MW gas-fired power station situated in the port area of Saldanha Bay. Gas-fired power generation typically consumes large volumes of natural gas for its operations over a long period of time. At the time of the study Eskom indicated a time period for the supply of gas to the plant of 15 to 20 years. Pending on the plant configuration, a typical combined cycle gas-fired power plant of that size would consume about 200 MMScfd[34]. These two factors in combination make gas-fired power stations an ideal anchor for a natural gas importation scheme - large volumes requirements over a long time period.

The PetroSA study further investigated the industrial markets available in the region for conversion to natural gas. A market assessment was conducted[35] of the "switchable" industries in the industrial areas of Saldanha Bay, Atlantis, Cape Town and its

[33] Shell, Sasol, iGas, PetroSA, Forest Oil
[34] Platts- CCGT Dataset: May 2012
[35] Gapegas/PetroSA, date unknown

surrounding areas. The LNG terminal in the Port of Saldanha Bay was linked to the above-mentioned markets by a transmission and distribution pipeline network.

The Gigajoule Africa study on the other hand was conducted in 2010/11 and based on the conversion of the existing Ankerlig power station near Atlantis to a gas-fired power plant as its key gas consumer. Ankerlig is situated about midway between Saldanha Bay and Cape Town. As a result of the placement of the Ankerlig power station in relation to Saldanha Bay and Cape Town, and it being considered an anchor gas off taker in the study, Gigajoule Africa adopted a different method of landing LNG imports and developing the necessary infrastructure and markets. The basis of their study was the importation of LNG to an offshore LNG receiving terminal situated closest to the Ankerlig power station near Atlantis. The study indicated a position approximately 8 kilometres offshore between Duynefontein and Yzerfontein where LNG would be received by conventional, slightly modified, LNG supply vessel, transferred to and stored in a permanently moored LNG Floating Storage and Regasification Unit (FSRU), re-gasified and piped onwards through a transmission and distribution pipeline network to the downstream markets in Saldanha Bay, Atlantis, Cape Town, Wellington and Paarl. This study however adopted a phased development of the transmission and distribution pipeline and associated infrastructure with Phase 1 including transmission pipelines and associated infrastructure necessary to supply the Ankerlig power station and the identified markets in Atlantis, Cape Town, Wellington and Paarl. Phase 2 comprised the extension of the pipeline and associated infrastructure at a later date to supply gas to the existing markets in Saldanha Bay which could be converted to natural gas. The proposed phased development was influenced by the size of the existing markets in Saldanha Bay, which was considered by Gigajoule Africa as currently marginal[36] to support the large additional costs required for extending the infrastructure necessary to deliver gas to Saldanha Bay.

The Gigajoule Africa study included a similar and more recent market survey of existing industries in Saldanha Bay, Atlantis, Cape Town, Wellington and Paarl areas which could be converted to natural gas as its energy feedstock. The study further included transmission and distribution pipeline and associated infrastructure necessary to transport natural gas from the offshore terminal to the identified markets in Atlantis, Cape Town, Wellington and Paarl for Phase 1 and to the extension thereof from Atlantis to Saldanha Bay as Phase 2.

[36] Gigajoule Africa – NERSA License Application for the Distribution and Trading of Natural Gas in the Cape West Coast Region (2010)

3.0 Pre-feasibility Study Framework and Assumptions

The information and assumptions of this pre-feasibility study for the importation of natural gas to the Saldanha Bay – Cape Town corridor of the Western Cape has mainly been based on the available information from the two known and most recent studies conducted by PetroSA and Gigajoule Africa as well as currently available related information. Information from these studies, where applicable, has been revised in cases where more recent information became known and publically available.

3.1 Gas Market Potential

The gas market potential in the Saldanha Bay – Cape Town corridor considered two main potential off takers of natural gas as alternative energy feedstock to their current energy sources:

- *Power generation* - the conversion of the Ankerlig power station near Atlantis to a mid-merit[37][38] gas-fired power plant has been considered as a case study for evaluation; and
- *Industrial markets* - the industrial markets in the Saldanha Bay, Atlantis, Cape Town, Paarl and Wellington areas which could be converted to natural gas. The market assessment used was largely similar to that used by Gigajoule Africa in its application[39] to the National Energy Regulator of South Africa (NERSA) for the importation of LNG and the distribution and trading of natural gas in the Cape West Coast region. The study was conducted in 2010/11 and the market information has been considered recent enough to reference for evaluation purposes.

3.2 Gas Supply Options

Three natural gas supply options to the Cape West Coast region for the near future were considered and reviewed:

- Indigenous gas supplies from known gas resources;
- Pipeline gas from neighbouring countries with proven gas reserves; and
- The importation of Liquefied Natural Gas (LNG) from existing and planned LNG liquefaction facilities.

[37] Client assumption - DEDAT
[38] Mid-merit power operations – operational 5 days per week, 16 hours per day with an efficiency of 51.7 percent and utilization of 47 percent
[39] Gigajoule Africa – NERSA License Application for the Distribution and Trading of Natural Gas in the Cape West Coast Region (2010)

The current most viable method of importing natural gas to the Cape West Coast region in the shortest timeframe was assessed to be through the importation of LNG[40]. Other potential supply options are discussed in the main document under item 5.

3.3 Gas Infrastructure Requirements

3.3.1 Gas Receiving Terminals

The importation of LNG to the Cape West Coast region considered two LNG delivery methodologies;

- The delivery of LNG to a land-based LNG receiving terminal situated in the Port of Saldanha Bay: and
- The delivery of LNG to an offshore semi-submersible LNG terminal situated between Duynefontein and Yzerfontein. The selection of this area was one of the three areas evaluated by the CSIR[41] between Duynefontein and St Helena Bay as part of the med-ocean report for Gigajoule Africa for the importation of LNG to an offshore LNG terminal. The position was selected as a case for this study because of its location to the Ankerlig power station near Atlantis and large existing industrial markets in the Cape Town region and its favourable EIA and med-ocean scoping[42] results. The position of the offshore LNG terminal was approximately 8 kilometres[43] off the coastline between Duynefontein and Yzerfontein.

3.3.2 Transmission and Distribution Pipelines

This study considered two methods of developing the pipeline transmission infrastructure necessary to transport natural gas from the respective LNG receiving terminals to the industries in Saldanha Bay, the Ankerlig power station near Atlantis, the Atlantis industrial area and the industrial areas of Cape Town, Paarl and Wellington:

Method 1 The transmission and related infrastructure necessary for transporting natural gas from a land-based onshore LNG receiving terminal situated in the Port of Saldanha Bay to industries in Saldanha Bay, the Ankerlig power station near Atlantis, the Atlantis industrial area and the industrial areas of Cape Town, Paarl and Wellington; and

[40]Item 5, Potential Gas Supplies
[41]CSIR - Preliminary Assessment of Marine Environmental Conditions on the Cape West Coast – Dec 2009
[42]CSIR - Preliminary Assessment of Marine Environmental Conditions on the Cape West Coast – Dec 2009
[43]Position determined by water depth requirements for FSRU operations – CSIR/Golar LNG

Method 2 The phased development of the transmission and related infrastructure necessary for transporting natural gas from an offshore LNG receiving terminal between Duynefontein and Yzerfontein to industries in Saldanha Bay, the Ankerlig power station near Atlantis, the Atlantis industrial area and the industrial areas of Cape Town, Paarl and Wellington where Phase 1 comprised the pipeline infrastructure required to the Ankerlig power station, the Atlantis industrial area and the industrial areas of Cape Town, Paarl and Wellington and Phase 2 comprised the extension of the infrastructure to include industries in Saldanha Bay.

3.3.3 Typical Project Implementation Schedule

A commencement date for a gas importation scheme of January 2015 has been included for all options evaluated. The date was based on a two-year period prior to this date for promoting the importation of natural gas to the Cape West Coast region and to allow time for pre-feasibility studies, funding requirements, permitting and licensing, gas sales and purchase agreements and investment decisions by the interested and effected parties. The schedule of activities for the different operations and the timing requirements are discussed in the main document under item 7.

Completion dates for the infrastructure requirements for the different development options were estimated as follows:

Option 1 The delivery of LNG to a land-based LNG receiving terminal situated in the Port of Saldanha Bay and related transmission and distribution infrastructure to industries in Saldanha Bay, Atlantis and the industrial areas of Cape Town, Paarl and Wellington. The establishment of the land-based terminal formed the critical path and was estimated to be five years[44] - January 2020.

Option 2 The delivery of LNG to an offshore semi-submersible LNG terminal situated offshore between Duynefontein and Yzerfontein where the transmission and distribution infrastructure are constructed in phased manner where:

- Phase 1 comprise the pipeline infrastructure to the Ankerlig power station, the Atlantis industrial area and the industrial

[44] Pace Global Energy Services - South Africa Natural Gas Utilization - LNG Analysis (2008?) , PetroSA

areas of Cape Town, Paarl and Wellington – January 2018[45]; and

- Phase 2 comprise the extension of the infrastructure from the intersection of the on-land pipeline from the offshore receiving terminal and the pipeline to Atlantis to industries in Saldanha Bay. The start of phase 2 was included[46] to be concurrent with the completion of Phase 1 with first commercial gas deliveries to Saldanha Bay two years thereafter - January 2020[47].

The conversion of the Ankerlig power station formed the critical path in all the options described relating to the importation of LNG to a semi-submersible LNG terminal.

[45] Gigajoule Africa – NERSA License Application for the Distribution and Trading of Natural Gas in the Cape West Coast Region (2010)
[46] Case Study Assumption
[47] Gigajoule Africa – NERSA License Application for the Distribution and Trading of Natural Gas in the Cape West Coast Region (2010)

4.0 Gas Market Potential

4.1 Introduction

The Cape West Coast region currently has no developed natural gas business. There is no established gas market or any natural gas infrastructure for the offloading, storage, re-gasification, transportation and distribution of natural gas to any of the potential markets in the region which could be converted to natural gas. The establishment of such infrastructure in the Cape West Coast region will therefore classify as a greenfield development.

Various market surveys to establish the industrial and commercial market potential and value for natural gas in the Cape Town Metropolis, its surrounding areas, Atlantis and Saldanha Bay have been conducted by several companies since 2003. Information referenced in this current analysis is a culmination of the information contained in some of those studies and includes, but is not limited, to studies conducted or commissioned by CapeGas, Soekor, Sasol, Shell, Pioneer Natural Resources, Forest Oil, Eskom and Gigajoule Africa. A joint study by PetroSA and Gigajoule Africa, with various supporting studies by specialist companies such as the CSIR, CCA Environmental & Associates, Gaffney Cline & Associates, Pace Global Energy Services and others, have been identified as the most recent and updated information available. The market analysis is further based upon information held in the author’s non-proprietary database, public domain sources, and past interviews with key industry players.

In general the findings of the market studies are fairly consistent and in most cases based upon information obtained through interviews and telephonic contact with potential gas consumers in the greater Cape Metropolitan, the Paarl and Wellington industrial areas and industrial areas in Atlantis and Saldanha Bay. From the market analysis collected to date, a picture develops of industry in the region being largely dependent for its energy requirements on electricity, imported coal, fuel oils, diesel and LPG.

Of the identified market potential, power generation holds the key to a natural gas development in the region. Gas-fired power generation typically consumes large volumes of natural gas for its operations over a long period of time making it an ideal anchor gas off taker for a greenfield gas infrastructure development. The Western Cape has a peak daily electricity requirement of approximately 3 864 MWe[48]. With its local base load generating capacity by its Koeberg nuclear

[48]Source: Eskom, 2012

power plant and the Palmiet hydro-electric pump storage facility, and its electricity export commitments to Namibia, Eskom on average imports approximately 2 050 MWe[49] of power on any given day to the region from its coal-fired power plants based in the Mpumalanga province. This shortfall in generating capacity therefore provides an excellent opportunity for a gas-fired power station in the region. It will not only consume a large, constant demand of natural gas, it will also play an enabling role to any gas importation scheme in the region, which without, the initiative of importing natural gas is unlikely to succeed.

Ankerlig, Eskom's existing Open Cycle Gas Turbine (OCGT) power plant near Atlantis, presents a realistic opportunity to be converted to a mid-merit[50] or base load[51] Combined Cycle Gas Turbine (CCGT) power plant to provide the full electricity shortfall of 2 050 MWe for the region and to serve as anchor client for a gas importation scheme. The conversion of the Ankerlig Power Plant to a mid-merit gas-fired CCGT facility has, as a base case and for the purposes of assessing the commercial viability of importing natural gas to the region, been used as an anchor off taker for imported gas[52].

The markets for natural gas that could support the initial development of a natural gas business in the Cape West Coast region have been divided into "existing" and "future potential" market opportunities. Although cognisance was taken of future potential market opportunities in the small industrial, commercial and domestic sectors, it has been accepted that a greenfield natural gas development would initially require large off takers to underpin the intensive infrastructure capital investments requirements.

The grouping of markets has therefore been selected in support of existing markets and those markets with the best probability[53] of being established in time for first gas commercial deliveries.

[49] Source: Eskom, 2012
[50] Item 4.2.1 - Atlantis – Ankerlig Power Station
[51] Base load power operations – operational 7 days per week, 23 hours per day with an efficiency of 51.7 percent and utilization of 80 plus percent
[52] Client assumption - DEDAT
[53] Current coal, fuel oils, LPG and diesel consumers

4.2 Atlantis, Cape Town and Surrounding Areas

The market survey for a natural gas importation scheme included the main industrial areas of Atlantis which includes the Ankerlig Power plant. In Cape Town and its surrounding areas it covers the industrial areas of the Airport Industria, Beaconvale, Bellville South Industria, Blackheath Industria, Brackenfell, Bottelary, Contermanskloof/Philadelphia, Eerste Rivier Industria, Epping Industria, Killarney Gardens, Klapmuts, Kuilsrivier, Lansdowne, Maitland Industria, Montaque Gardens, Ndabeni Industria, Newlands, Paarl Industria, Parow Industria, Phesantekraal, Phillipi, Sacks Circle, Salt River Industria and the Wellington Industrial area. Although most of the companies contacted at the time were reluctant or unwilling to share their exact consumption and energy costs, they did provide indicative information sufficient for the purposes of the evaluation. The market survey was initially conducted in 2010 by a combined PetroSA and Gigajoule team and updated by Gigajoule in the first quarter of 2011. The energy consumption of new industrial developments or extensions to existing industry from that period onwards has not been included.

Figure 1 is a locality map highlighting the major industrial markets in the Saldanha Bay-Atlantis-Cape Town corridor

LOCALITY MAP OF MAJOR MARKETS

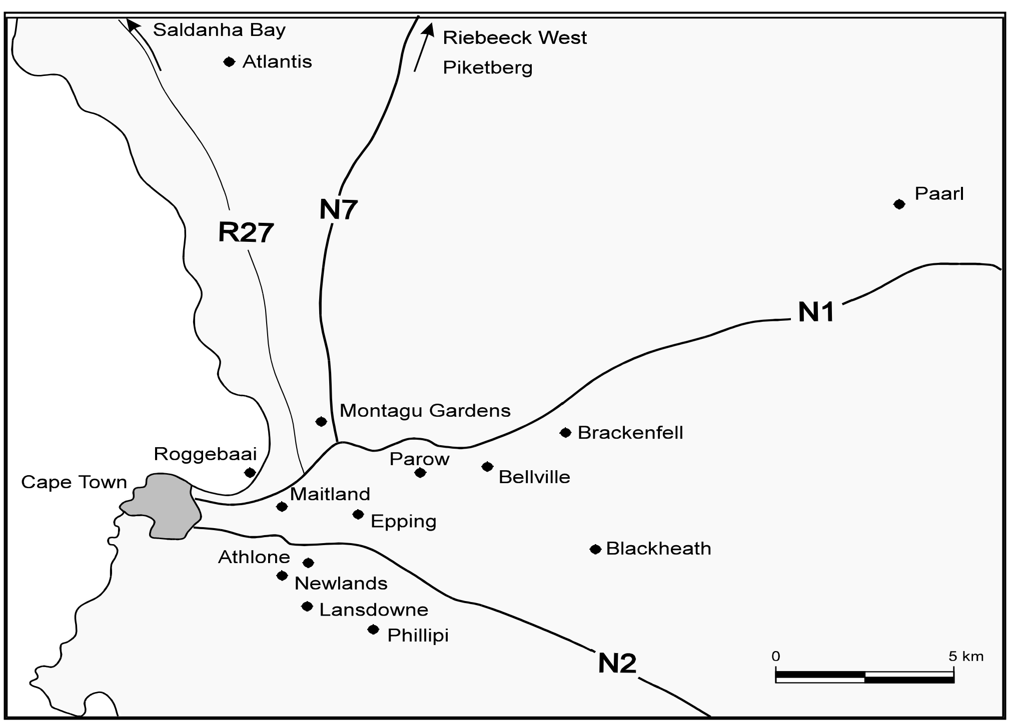


Figure 1

4.2.1 Atlantis – Ankerlig Power Station

The potential anchor gas market for Atlantis, and indeed for the importation of natural gas as an alternative energy feedstock to the Cape West Coast region, is Eskom's Ankerlig power station near Atlantis. Ankerlig is an existing Open Cycle Gas Turbine (OCGT) Power Station consisting of 9x150 MWe OCGT units, with a resulting total nominal generating capacity of 1,350 MWe. Although Ankerlig is classified as a gas/diesel dual-fired plant it currently runs on diesel only and is operated by Eskom as a peak[54] power station. Current operations have an efficiency of 32.7 percent and the plant has been designed within Eskom's generating portfolio to be utilized less than 6 percent per year. It has however over recent years frequently been used at a much higher percentage rate as an intermediate infill generating facility to allow for unscheduled maintenance on power stations related to electricity supply to the Western Cape.

The opportunity exists, should natural gas become available as an energy feedstock, for the conversion of the power plant to gas-fired Combined Cycle Gas Turbine (CCGT) plant operations. The process consists of recovering waste heat from each of the current gas turbines to drive newly installed steam turbines, which in turn will increase the plant's output to 2 070 MWe. This increase in generating capacity roughly equates to the electricity shortfall, as discussed in the introductory paragraph, in the Western Cape and the amount of electricity currently imported on any given day by Eskom to cover the shortfall. The conversion of Ankerlig to a CCGT unit will allow the plant to operate at a 51,2 percent efficiency which could be utilized at 47 percent or higher in either mid-merit or base load configuration.

Although various configurations for the conversion of the current nine generating units exist, the conversion of all 9x150 MWe units for mid-merit CCGT operations has been included for the analysis[55]. In this configuration it was included[56] that the Ankerlig power station will operate for 16 hours per day, 5 days per week with a generating capacity of 2 070 MWe.

The total energy requirement for the Ankerlig power station in the above-mentioned configuration will equate to approximately 66 500 000 GJ per annum[57] equating to 1.31 million tonnes of LNG per annum.

[54]Peaking power operations - efficiency of 32.7 percent with utilization less than 6 percent per year
[55]Client assumption - DEDAT
[56]Internal Assumption
[57]Conversion of Ankerlig - Internal Calculation

4.2.2 Cape Town, Paarl and Wellington -Industrial Markets

A large percentage of the potential gas markets in the Cape Town Metropolis and surrounding areas are made up of energy requirements for steam raising, baking, drying, heating and smelting purposes. Coal and fuel oil users continue to dominate the industrial and commercial markets in the area's industrial hubs. Of the identified markets (in these areas, coal remains the largest and constitutes approximately 60 percent of the existing energy fuel mix whereas fuel oil contributes approximately 20 percent to the total consumption. Waxy oil used in project specific applications constitutes 7 percent of the energy mix whilst LPG and diesel respectively represents 7 percent and 5 percent of the area's energy consumption. Paraffin is used in smaller commercial industries and constitutes about 2 percent of the remaining energy consumption (Figure 2).

Although the public transportation sector in the Cape Town and surrounding areas hold large potential to be converted to natural gas-fuelled vehicles, the determination of the potential conversion of buses, taxies and the government/city vehicle fleet is dependent on an eight to ten year replacement cycle of their fleets. It is understood that the conversion of existing diesel-fuelled vehicles is technically not feasible and that replacement vehicles require specially adapted engines for gas-fuelled operation.

With Golden Arrows operating more than 1 000 buses on a daily basis in the Cape Town Metropolis[58] and Cape Town's MyCiTi bus fleet currently consisting of more than 250[59] buses, the future opportunity for changing these public transportation vehicles to gas-fuelled operations are significant.

Minibus taxi services present a further significant opportunity for conversion to gas-fuelled operations. The industry has a reported 4 000 minibus vehicles[60] in the Cape Town Metropolis and surrounds of which later petrol models could be converted to gas-fuelled vehicles once natural gas becomes available.

For the purposes of this evaluation and in recognition of the potential contribution of the industry to natural gas consumption in the future, a provisional natural gas consumption of 900 000 GJ per annum has been allowed for.

[58] Source: Golden Arrows Web Report, Jan 2013 (www.gabs.co.za)
[59] Source: Cape Town City, February 2013 (www capetown.gov.za/myciti)
[60] Source: Department of Transport and Public Works, Western Cape, Jan 2013

If combined, the total energy mix requirement for the industrial and commercial markets in the Cape Town Metropolis and its surrounding industrial hubs amounts to approximately 20 000 000 GJ per annum or an equivalent LNG requirement of 0.4 million tonnes of LNG per annum.

Figure 2 illustrates the percent usage of the different fuels by industry in the region.

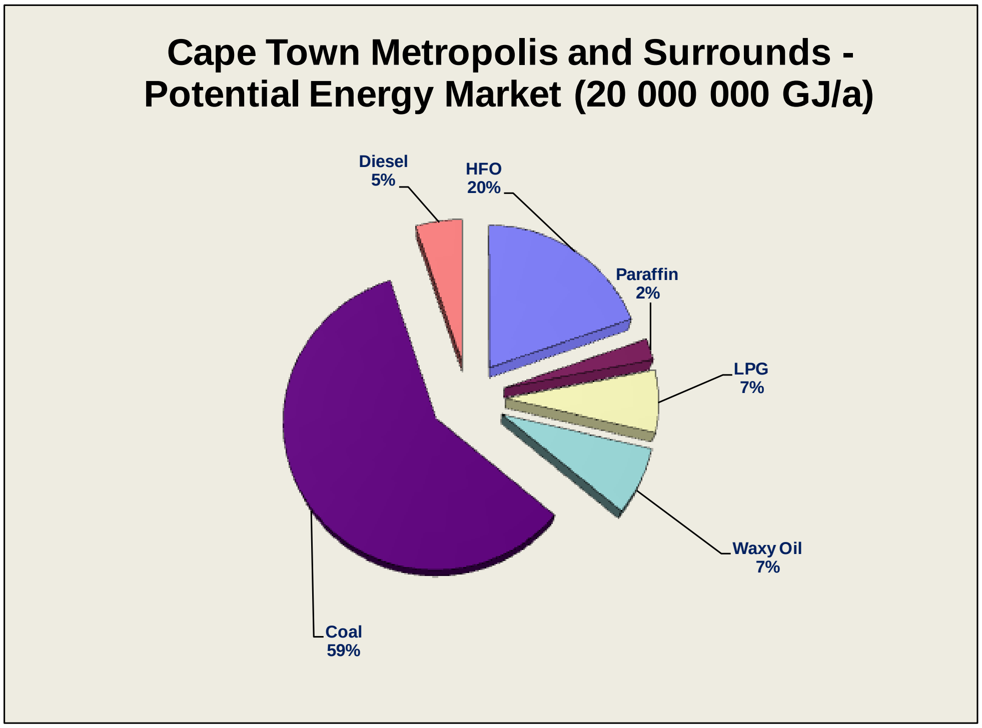


Figure 2[61]

The total identified market potential for the Atlantis and Cape Town and its surrounding areas amount to approximately 88 million GJ per annum or an equivalent 1.7 million tonnes of LNG per annum. This includes a nominal allowance of 900 000 GJ per annum for the replacement of public transport with natural gas vehicles in a later replacement cycle as previously discuss and a commercial and domestic contingency consumption of 600 000 GJ per annum.

Table 5 summarises the potential energy consumption in Atlantis (including Eskom's Ankerlig power station) and the Cape Town, Paarl and Wellington areas.

[61] Item 4.2 - Cape Town-Atlantis - Potential Energy Market

Potential Energy Market – Atlantis, Cape Town Metropolis & Surrounds	
Fuel Type	**Consumption (GJ/a)**
Atlantis Industrial	1 000 000
Atlantis – Ankerlig Power Station	66 500 000
Cape Town Metropolis and surrounds	20 000 000
Total	***87 500 000***

Table 5

Table 6 is a listing of the currently available markets within the Atlantis and Cape Town corridor susceptible for conversion to natural gas as an energy source.

Potential Customer	Customer Type	Assessed Energy Usage (GJ/a)	Total Energy Usage (GJ/a)
Airport Industria:			
SA Metal	Heating	20,500	**20,500**
Atlantis Industria:			
Ankerlig Power Station	Power generation	66,500,000	
Ahlesa Blankets	Boiler	11,250	
Brits Textiles	Boiler	43,333	
Comar Chemicals	Thermal oil heating	5,000	
Promeal	JT boiler	15,166	
MSA	JT boiler	18,000	
Appolo Bricks	Heat firing	550,000	
Nu Era Packaging	JT boiler	17,250	
Atlantis Foundries	End user	68,400	
Bokomo Foods - Paraffin	Baking & drying	85,625	
Bokomo Weetbix	Drying	34,250	
Braitex Tenslon	JT boiler	18,750	
Craft Box Corugated	JT boiler	76,500	
Kulu Roof Tiles	drying & baking	3,233	
Rotex Fabrics	JT boiler	39,375	
SA Fine Worsteds	JT boiler	28,416	
Elvinco Plastics	Printing	230	**67 514 778**
Beaconvale:			
Cape Galvanising	Heating	14,266	
Golden Girl Hosiery	Heating	5,860	
Metlite	Heating	36,600	
Svenmill	End user	2,220	**58,946**
Bellville South Industria:			
African Products	Boiler	353,095	
Good Hope Bakery	Boiler & baking	25,277	
Grace (Darex)	Boiler	2,195	
Falke Textiles	Boiler	18,750	

Winelands Pork	Heating	43,950	
Latex Threads	Boiler	203,496	
Marley Tiles	Drying & baking	26,410	
Nampak Tissue Cape	Boiler	58,300	
Nestle	Heating & boiler	30,000	
Spekenham (Supreme Foods)	Heating	111,091	
Trade Wipers	End user	3,350	**875,913**
Blackheath Industria:			
Cape Town Iron & Steel	Heating & smelting	27,519	
Continental China	Firing & baking	116,666	**144,185**
Brackenfell:			
HBH Textiles	Boiler & drying	11,016	
Everite	Firing & drying	40,693	**51,710**
Bottelary:			
Crammix Bricks	Drying & baking	286,562	
Cabrico - Coal	Drying & baking	525,000	
Joosten Brick Claytile	Tile firing & drying	685,000	**1,496,562**
Contermanskloof/Philadelphia:			
Brick & Clay	Drying & baking	225,000	
Much Asphalt	Drying & heating	117,390	**342,390**
Eersterivier:			
Much Asphalt	Drying & heating	45,800	**45,800**
Elsies Rivier Industria:			
Continental Knitting	Boiler	9,375	
Mattex	End user	4,000	
Messaris - LO 10	Boiler	19,555	
Romatex	Boiler	29,062	**61,992**
Epping Industria:			
Allnet	Boiler	18,256	
Anchor Yeast	Boiler	31,050	
Bevcan & Bevcap	Boiler	98,100	
Bowman Ingredients	Boiler	1,221	
Bokomo Ltd	Drying	5,100	
Cape Coaters	Boiler	6,250	
Coca-Cola Canners	Boiler	3,000	
Colas Southern Africa		32,840	
CTC		37,000	
Dairybelle		40,500	
Disaki Cores &Tubes		320	
Distell	Boiler	67,620	
Donaldson Filtration	Boiler	6,400	
DPM Transformers	Heating	5,175	

Duens Bakery	Boiler	87,390	
Fine Chemicals Corp	Boiler	26,600	
First Cut		230	
Gearings Foundry	Heating & smelting	4,000	
Glaxo Smith Kline	Boiler	12,200	
Greif		4,300	
Indigo Cosmetics		1,440	
Lafarge Roofing		12,810	
Maximore Knitg Mills	Boiler	25,920	
Migra Textiles	Boiler	54,700	
Mondipak	Boiler	9,000	
Monviso Knitwear	Boiler	10,000	
Nampak Corrugated	Boiler	63,450	
Nampak Divfood	Boiler	1,500	
Nampak Gravure	Boiler	2,900	
Nampak Sacks		320	
Premquip		12,700	
Richard Kane		4,400	
SA Metal & Machry	Heating	880	
SBH Cotton Mills		209,825	
Seyfert Corrugated	Boiler	14,700	
Tuna Marine Foods	Boiler	1,900	
Trentryre	Boiler	4,100	
Wella		1,800	
Xactics (Cape)		350	**920,247**
Killarney Gardens:			
Fruitique	Boiler	9,777	
Hosaf Fibres	Boiler	38,333	
Pex Foundry	Heating & smelting	1,666	
The Dairy Connection	End user	28,800	
Universal Cosmetic	Boiler	14	**78,590**
Klapmuts:			
Paarl brickfields	Firing & baking	38,250	
Satchwell		3,136	**41,386**
Kuilsrivier:			
Capetown Iron & Steel - HFO	Smelting	277,475	
Mondipak	Boiler & drying	7,600	
Polypak	Drying	4,666	**289,741**
Lansdowne:			
Lansdowne Textile Ind.	Boiler	314,257	
Steine Cleanings	Boler	202,406	**516,663**
Maitland Industria:			
SA Bias	Boiler	13,600	
SA Fine Worsteds - MFO	JT boiler	22,500	

Epic Oil	Boiler	222,210	
Tiger Oats	Drying & baking	30,812	
Premix	Heating	26,819	
Albany Bakery	Baking & drying	23,968	
Matal Closures (Paarden Eiland)	Heating	23,968	**363,877**
Montague Gardens:			
Chevron Refinery	Heating	1,500,000	
Linpak Industries	Boiler	333	
Paarl Gravure	End user	666	
Path Plastics	Heating	4,444	
Sappi Cape Kraft	Boiler	4,320,000	
Master Foods	Boiler	4,000	**5,829,443**
Ndabeni Industria:			
Albany Bakery	Baking & drying	20,000	
Cape Oil & Magrine	Boiler	390,000	
Nestle Purina	Boiler	100,000	**510,000**
Newlands:			
SA Breweries	JT Boilers	634,717	**634,717**
Paarl Industria:			
De Hoop Steenware	Firing & baking	72,500	
Kilotreads	Boiler	20,000	
KWV	Boiler	12,375	
Tiger Food Brands	Boiler	845,000	
Vlakte Bricks	Firing & baking	27,000	
Bakke Packaging	Boiler	122,089	
Berg River Textiles	Boiler	366,285	
Paarl Wine & Brandy	Boiler	2,221	
Courtheil Veleurs		40,686	
Food Can	Boiler	25,869	
Stellenbosch Farmers Winery	Boiler	42,924	
Langeberg Co-Op	Boiler	307,999	**1,884,948**
Parow Industria:			
Allcast Foundry	Heating & smelting	400	
BPB Gypsum	Heating	113,200	
Cape & Transvaal Printers	Heating	30,000	
Clover Dairy	Boiler	10,588	
Colcab Manufacturing		3,125	
Freudenberg Non-Woven	Boiler	29,600	
IQ foods	Baking & drying	42,000	
Isolite	Boiler	33,750	
Macbean Plastics	Boiler	7,000	
Parmalat Bonnita	Boler	38,500	
Peninsula Bevrages	Boiler	16,500	
Pep stores		14,062	

Simba Chips	Baking	161,333	
Snaxels Food	Boiler	3,499	
Sondor Industries	Heating	41,666	
Styromould	Boiler	24,000	
Tygerberg Hospital	Boiler	377,593	**946,816**
Phesantekraal:			
Corobrik	Firing & baking	325,000	
Apollo Bricks	Firing & baking	300,000	**625,000**
Phillipi:			
Puma Knitting		135,286	
Fine Wood Veneers	Boiler	92,406	**227,692**
Sacks Circle:			
Albany Bakery	Boiler	27,000	
Consul Glass	Heating & smelting	1,683,055	
Carnaud Metal Box Food		2,400	
Nettex	Boiler	60,000	
Sagex	Boiler	7,180	
SANS Fibres (Pty) Ltd	Boiler	116,666	**1,896,301**
Salt River Industira:			
Blue Ribbon Bakery	Baking & drying	20,000	
Groote Schuur Hospital	Boiler	140,000	
House of Monatic	Boiler	8,375	
Irvin & Johnson		9,260	
Irvin & Johnson #2		18,300	
Rex Trueform	Boiler	16,503	**212,438**
Wellington Industria:			
Boland Pulp	Boiler	80,000	
James Sedgwick Distillery	Boiler	62,500	
Mossop Western Leather	Boiler	44,100	
Pacmor (Pty) Ltd	Boiler	30,000	
Paarl Bottelering	Boiler	1,222	
Heinz Foods	Boiler	11,250	**229,072**
Natural Gas Vehicle Markets:			
Golden Arrow Bus	Transportation	500,000	
TPM Bus Services	Transportation	400,253	**900,253**
House hold & small industry:			
Domestic	Heating & cooking	300,000	
Light industry	Heating	300,000	**600,000**
Total			**87 319 960 GJ/a**

Table 6

4.2.3 Atlantis - Industrial Markets

Similar to the markets in the Cape Town Metropolis and its surrounding areas, coal users in Atlantis continue to dominate the energy mix of the current industrial and commercial markets. Energy requirements are mainly for steam raising, baking, drying and heating purposes. Of the identified markets, coal remains the largest and constitutes approximately 71 percent of the existing energy fuel mix. LPG on the other hand contributes a larger proportion to the energy mix and constitutes approximately 16 percent with fuel oil and paraffin each contributing approximately 6 percent and diesel the remaining 0.5 percent (see Figure 3).

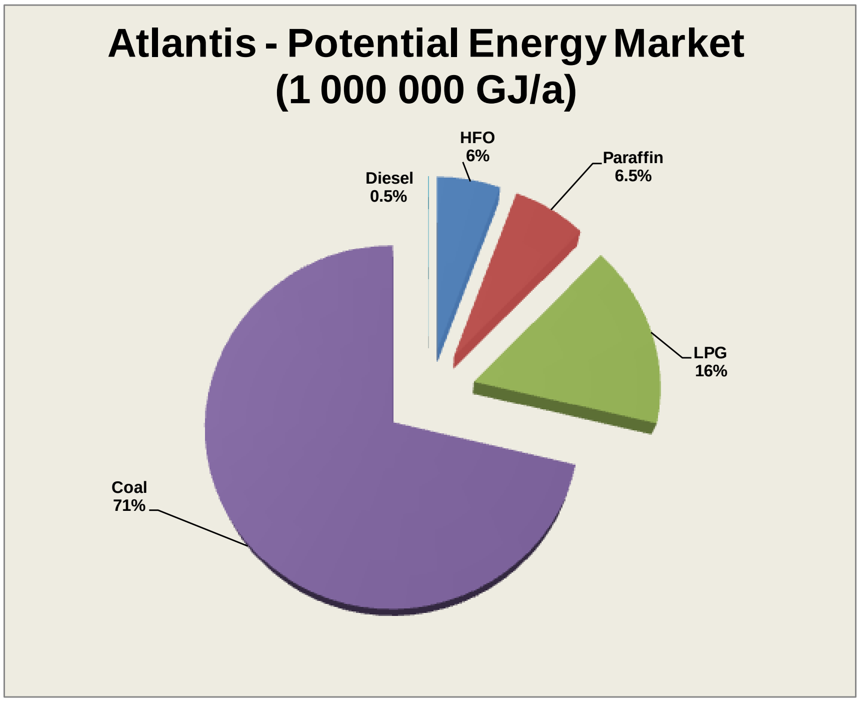


Figure 3[62]

4.2.4 Market Build-up

The industrial and commercial markets in the Cape Town, Paarl, Wellington and Atlantis regions could be converted to natural gas over a relatively short period due to the long lead times required for the necessary licensing, EIA approvals and infrastructure requirements. A period of 3 years has been provided for the transmission and distribution pipelines construction and commissioning[63] in which time the conversion of existing plant could be done to coincide with first commercial gas deliveries.

[62]Item 4.2 - Cape Town-Atlantis - Potential Energy Market
[63]Gigajoule Africa – NERSA License Application for the Distribution and Trading of Natural Gas in the Cape West Coast Region (2010)

Conversion of HFO users can proceed rapidly if dual HFO/gas burners are installed prior to the introduction of natural gas to the region. It could therefore be possible to have most of the HFO load converted to natural gas within six months[64] of first commercial gas deliveries becoming available. The conversion of coal and other smaller industrial and commercial users to natural gas on the other hand will be slower. A period of 24 months[65] after the availability of first commercial gas deliveries has been allowed for the majority of the identified markets to convert their facilities to gas-fired operations.

A total time period of three years has been allowed for the conversion of the existing Ankerlig Power Plant to a gas-fired facility[66]. The period includes a one year planning and permitting period and two years for the engineering, procurement and construction. Since the conversion of Ankerlig to a gas-fired CCGT plant already carries EIA approval[67], many of the planning and permitting activities can proceed in parallel and prior to other infrastructure-related activities.

Figure 4 illustrates the market build-up for the conversion of Ankerlig to a gas-fired power plant and the respective markets in Cape Town, its surrounding areas and Atlantis.

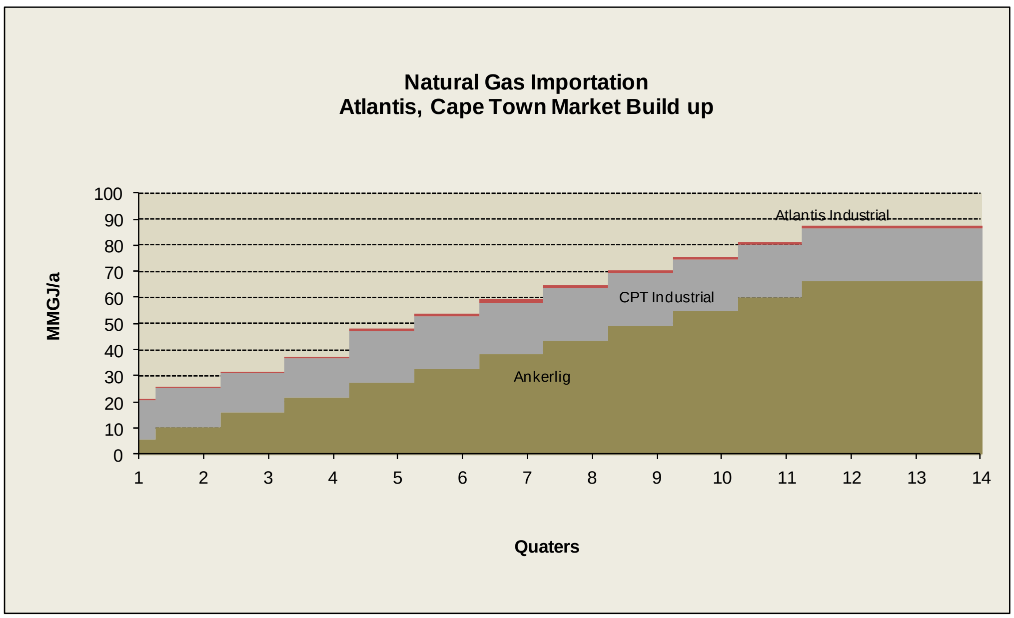


Figure 4

[64] Gigajoule Africa – NERSA License Application for the Distribution and Trading of Natural Gas in the Cape West Coast Region (2010)
[65] Gaffney, Cline & Ass – Gas Market Study for Selected Provinces in RSA/Gigajoule Africa NERSA License Application for the Distribution and Trading of Natural Gas in the Cape West Coast Region (2010)
[66] Eskom/Gigajoule Africa - 2010
[67] Department of Environmental Affairs & Tourism – Environmental Authorization Reg No 12/12/20/1014

4.2.5 Market Pricing

4.2.5.1 Industrial Market

The existing markets in the Atlantis, Cape Town, Paarl and Wellington industrial areas comprise coal, HFO, Paraffin, LPG, diesel and waxy oil users. Wholesale and regulated prices for these energy products have dramatically changed over recent years making the identified markets high in value. Under the current published coastal wholesale and retail prices obtained from the Department of Energy[68], the identified markets return a weighted average burner tip value for the various consumption sectors of US$ 15.82 per MMBtu[69].

4.2.5.2 Power Generation

An estimated cost[70] of electricity from the Ankerlig power station has been calculated in a manner to be comparable to the bid prices received by the Department of Energy during the second bidding window for the supply of renewable energy and the estimated cost of electricity from the Medupi coal-fired power station currently under construction near Lephalale. Table 7 lists the average bid prices for the supply of electricity from the second bid window.

Average Bid Prices for Renewable Electricity 2nd Bid Window	
Type	**Cost per kWh**
Concentrating Solar Power (CSP)	R2.51
Solar Photo-voltaic (PV)	R1.65
Wind	R0.90
Small Hydro	R1.03

Table 7 [71]

The levelized cost for the Medupi coal-fired power station was recently reported[72] as R0.97/kWh. With additional costs for high-voltage transmission lines to wheel the generated capacity from the Medupi power station to the mainline transmission network, substation(s), tie-in costs of the two networks, approximate ten percent transmission losses and cost of capital for the transmission lines, an estimated normalized price range for new coal-fired generating capacity from Medupi is estimated[73] at R1.15/kWh to R1.30/kWh.

[68] Central Energy Fund Wholesale Fuel Prices -2013
[69] Item 4.2 - Cape Town-Atlantis - Potential Energy Market
[70] Internal cost estimation
[71] moneyweb.co.za/moneyweb-economic-trends/renewables- reality-at-a-cost - 30 October 2012
[72] mg.co.za/article/2012-08-24-00-eskom – August 2012
[73] Internal cost estimate

To compare electricity prices from the Ankerlig power station after its conversion to a 2 070MWe CCGT gas-fired mid-merit plant with the above-mentioned prices, a levelized price of electricity has been calculated using the assumptions as reflected in Table 5. The capital cost requirements for the conversion of Ankerlig to a gas-fired CCGT power plant has been estimated at ZAR7.0 billion[74].

Two LNG landed prices, US$10/MMBtu and US$15/MMBtu, have been included[75] for calculating the levelized generation costs for Ankerlig in the configuration described above. An additional estimated[76] gas transmission cost of US$0.08/MMBtu from the offshore LNG terminal between Duynefontein and Yzerfontein and US$0.19/MMBtu from the land-based terminal in the Port of Saldanha Bay to the Ankerlig power station have been allow for calculating the gas transfer price at the Ankerlig power station. Table 8 summarizes the estimated levelized costs from the Ankerlig power station after its conversion to a gas-fired plant.

[74]Source: Eskom estimation – 2011
[75]Item 5.4.2.2 – LNG Pricing – Saldanha Bay
[76]Internal estimate

Estimated Levelized Costs[77] - Gas-fired Power Generation (Ankerlig CCGT Conversion)				
	Offshore LNG Terminal (Between Duynefontein & Yzerfontein)		Onshore LNG Terminal (Saldanha Bay)	
	LNG Landed Price (US$10/MMBtu)	**LNG Landed Price US$15/MMBtu**	**LNG Landed Price (US$10/MMBtu)**	**LNG Landed Price US$15/MMBtu**
Total Capex	ZAR 7.0 billion	ZAR 7.0 billion	ZAR 7.0 billion	ZAR 7.0 billion
Total MWe	2 070 MWe	2 070 MWe	2 070 MWe	2 070 MWe
Loan interest rate	10%	10%	10%	10%
Payback term	10 years	10 years	10 years	10 years
Cost of Capital	ZAR 1.14 billion	ZAR1.14 billion	ZAR 1.14 billion	ZAR 1.14 billion
Utilization	4 117 hrs/y	4 117 hrs/yr	4 117 hrs/y	4 117 hrs/y
Efficiency	51%	51%	51%	51%
Cost of fuel	**US$ 10/MMBtu**	**US$ 15/MMBtu**	**US$ 10/MMBtu**	**US$ 15/MMBtu**
Transmission cost-Ankerlig	US$ 0.08/MMBtu	US$ 0.08/MMBtu	US$ 1.19/MMBtu	US$ 1.19/MMBtu
Total cost of fuel	US$ 10.08/MMBtu	US$15.08/MMBtu	US$ 11.19/MMBtu	US$ 16.19/MMBtu
Cost of Fuel	ZAR 0.60/kWh	ZAR 0.90/kWh	ZAR 0.67/kWh	ZAR 0.97/kWh
Cost of Capital	ZAR 0.13/kWh	ZAR 0.13/kWh	ZAR 0.13/kWh	ZAR 0.13/kWh
Total generation costs	**ZAR 0.73/kWh**	**ZAR 1.03/KWh**	**ZAR 0.80/kWh**	**ZAR 1.10/kWh**

Table 8

Under these assumptions, the estimated levelized cost for the Ankerlig power station ranges between R0.73/kWh to R1.03/kWh if gas is supplied from an offshore LNG terminal between Duynefontein and Yzerfontein and R0.80/kWh to R1.10/kWh if supplied from a land-based LNG terminal in the Port Saldanha Bay. With the same principle applied of adding costs for the expansion of existing high-voltage transmission lines to wheel the generated capacity from the Ankerlig power station to the mainline transmission network, upgrading of the existing substation, tie-in costs to the main transmission network, approximately ten percent transmission losses and cost of capital for the upgrades, an estimated normalized electricity price range for new gas-fired generating capacity from Ankerlig is estimated[78] at R0.84-R0.95/kWh (US$10/MMBtu landed cost case) to R1.18-R1.34/kWh (US$15/MMBtu landed cost case) for gas supplied form the offshore LNG terminal and R0.92-R1.04/kWh (US$10/MMBtu landed cost case) and to R1.27-R1.43/kWh (US$15/MMBtu landed cost case) for gas supplied from the onshore LNG terminal.

[77]Levelized costs – reflect overnight capital cost, fuel cost, fixed and variable O&M costs of a power plant over its lifetime
[78]Internal cost estimate

Table 9 summarizes the estimated normalized electricity costs from the Ankerlig power station under the different pricing assumption and LNG terminal options.

Estimated Normalized Electricity Costs - Gas-fired Power Generation (Ankerlig CCGT Conversion)			
Offshore LNG Terminal (Between Duynefontein & Yzerfontein)		Onshore LNG Terminal (Saldanha Bay)	
LNG Landed Price (US$10/MMBtu)	LNG Landed Price (US$15/MMBtu)	LNG Landed Price (US$10/MMBtu)	LNG Landed Price (US$15/MMBtu)
ZAR 0.84-R0.95/kWh	ZAR 1.18-1.34/KWh	ZAR 0.92-1.04/kWh	ZAR 1.27-1.43/kWh

Table 9

Calculations for the estimated levelized and normalized costs for the 350 MWe and 450 MWe Saldanha Bay, and 800 MWe and 1 000 MWe Milnerton gas-fired power plants have been included as *Annexure A*. The costs for these examples were based on recently published[79] estimated overnight plant capital costs for electricity generation plants.

With estimated[80] additional costs for high-voltage transmission lines to wheel the generated capacity from the power stations to the mainline transmission network, substation(s), tie-in costs of the two networks, approximate ten percent transmission losses and cost of capital for the transmission lines, an estimated normalized electricity price range for new gas-fired generating capacity from Saldanha Bay and Milnerton are summarized in Tables 10 & 11 below.

Estimated Normalized Electricity Costs - Gas-fired Power Generation (Saldanha Bay)				
	Offshore LNG Terminal		Onshore LNG Terminal	
	LNG Landed Price (US$10/MMBtu)	LNG Landed Price (US$15/MMBtu)	LNG Landed Price (US$10/MMBtu)	LNG Landed Price (US$15/MMBtu)
350 MWe	ZAR 1.14-1.28/kWh	ZAR 1.48-1.67/KWh	ZAR 1.08-1.22/kWh	ZAR 1.42-1.61/kWh
450 MWe	ZAR 1.12-1.27/kWh	ZAR 1.46-1.65/kWh	ZAR 1.08-1.22/kWh	ZAR 1.42-1.61/kWh

Table 10

[79] US Energy Information Administration (Energy Analysis) – Report on Updated Capital Cost Estimates for Electricity Generation Plants – Nov 2010/May 2011
[80] Internal estimation

Estimated Normalized Electricity Costs - Gas-fired Power Generation (Milnerton)				
	Offshore LNG Terminal		Onshore LNG Terminal	
	LNG Landed Price (US$10/MMBtu)	LNG Landed Price (US$15/MMBtu)	LNG Landed Price (US$10/MMBtu)	LNG Landed Price (US$15/MMBtu)
800 MWe	ZAR 1.09-1.23/kWh	ZAR 1.43-1.62/KWh	ZAR 1.10-1.25/kWh	ZAR 1.44-1.63/kWh
1 000 MWe	ZAR 1.09-1.23/kWh	ZAR 1.43-1.62/kWh	ZAR 1.09-1.23/kWh	ZAR 1.44-1.62/kWh

Table 11

4.3 Saldanha Bay

4.3.1 Saldanha Bay Industrial

Saldanha Bay's existing commercial and industrial markets (excluding electricity requirements) available for conversion to natural gas as its energy feedstock are currently limited in size and value[81]. Except for mineral beneficiation, steel manufacturing and cold rolled steel products manufacturing, the existing commercial and industrial markets are represented by the fishing processing industry and general engineering companies supporting the marine and manufacturing industries[82].

The ArcelorMittal steel manufacturing plant, Duferco steel processing plant and Exxaro's mineral beneficiation plants are currently the main consumers of energy in Saldanha Bay. Processes within their operations which could be converted to natural gas mainly consist of the replacement of LPG. When in full production, ArcelorMittal and Duferco consume approximately 500 000 GJ per annum[83] and 320 000[84] GJ per annum respectively of LPG in their steel plants. Exxaro's Namakwa Sands mineral beneficiation processes consumes approximately 250 000 GJ per annum of LPG[85]. Combined fuel oil, coal and LPG consumption for the remaining small industrial and commercial industries were estimated at 230 000 GJ per annum[86]. Direct use of coal as a reductant for ArcelorMittal's Corex process in its steel manufacturing process as well as the direct use of anthracite and coal as reductant in the smelting furnaces of Exxaro's Namakwa Sands mineral beneficiation processes have been discounted as current fuels which could be replaced by natural gas. Coal usage for the two cement plants at Piketberg and Riebeeck West has also been excluded from the regional coal consumption analysis due to their respective distances from Saldanha Bay.

The total energy mix requirement for the existing industrial and commercial markets in the Saldanha Bay industrial hubs therefore amounts to approximately 1 300 000 GJ per annum and are distributed in usage as indicated in Figure 5.

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[81] Item 4.3 - Saldanha Bay – Potential Energy Market
[82] Gaffney, Cline & Ass – Gas Market Study for Selected Provinces in RSA
[83] Source: ArcelorMittal
[84] Source: Duferco
[85] Source: Exxaro Namakwa Sands
[86] Source: Gigajoule Africa

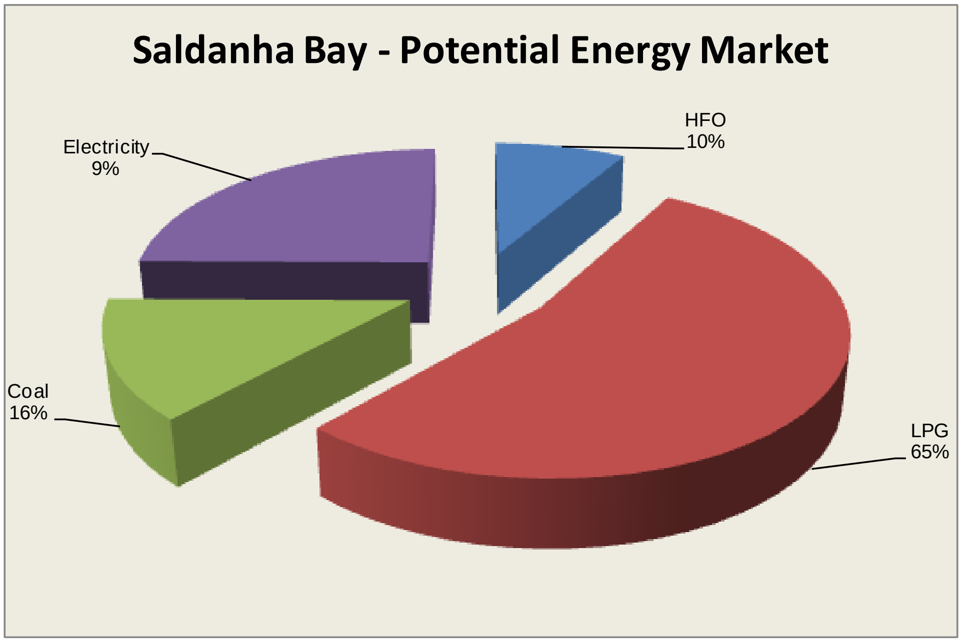


Figure 5

Liquefied Petroleum Gas (LPG) usage dominates the energy consumption in the industrial and commercial markets mainly because of the large consumption for pre-heating and heating purposes by the ArcelorMittal and Duferco steel and steel processing plants. LPG consumption constitutes approximately 65 percent of the existing energy fuel mix. Coal and HFO consumption, representing 16 and 10 percent respectively, are mainly used in the small industrial and commercial markets for steam raising, baking, drying and heating purposes.

It should however be noted that the future potential markets, should natural gas and electricity become available to the region, could be substantial and significantly contribute to rapid industrial growth with the accompanying commercial and social benefits.

It has long been suggested that Saldanha Bay should serve as an industrial hub with specific emphasis on supporting the oil and gas exploration and production activities along West Africa and elsewhere. Saldanha Bay has excellent harbour export facilities and has attracted a multitude of energy intensive local and international industries interested in establishing their businesses in the region with the objective of using the facilities as an integral part of their business and business expansion plans. Interest has over recent times been expressed[87] by companies such as ArcelorMittal, Rare Metal Industries (RMI), Steel Authority of

[87]The Saldanha Bay IDZ Licensing Company

India (SAIL), Exxaro, BHP Billiton, Frontier Rare Earth, Chlor Alkali Holdings and the Indian mining group Vedanta to either expand their current businesses, as in the case with ArcelorMittal and Exxaro, or to establish new businesses as planned by RMI, Frontier Rare Earth, Chlor Alkali Holdings, SAIL, Vedanta and BHP Billiton. Without exception, all of the mentioned companies have indicated a requirement for additional electricity for any businesses they might consider in the region and has placed emphasis on an additional need for natural gas as an energy feedstock for their activities.

However, lack of access to secure affordable electricity and/or an alternative energy source such as natural gas has largely contributed to slow progress in establishing Saldanha Bay as a regional industrial hub.

4.3.2 Potential Convertible Natural Gas Markets

Saldanha Bay currently has three potential large users of natural gas; Exxaro (Namakwa Sands), the ArcelorMittal steel plant and Duferco Steel Processing plant.

4.3.2.1 ArcelorMittal Steel Plant

ArcelorMittal, originally Saldanha Steel and formed as a partnership between Iscor and the Industrial Development Corporation (IDC), is situated on the Cape West coast roughly 10 kilometres away from Saldanha Bay. The steel plant has been designed to produce 1.2 million tonnes per annum (Mtpa) of hot-rolled carbon steel coil per year and was commissioned in 1998.

Current operations are based on a Corex process where coal is used as energy feedstock to reduce iron ore, made up of 80 percent iron ore and 20 percent pellets, to a hot pig iron liquid. This product is further heat-processed via an Electric Arc Furnace (EAF) to form liquid steel. The liquid steel gets processed through a Caster and Rolling Mill into hot-rolled carbon steel coils (Figure 6).

ArcelorMittal also uses the low calorific offgas from the Corex process for directly reduction of iron ore in the Midrex process. The feedstock is 60 percent iron ore and 40 percent pellets. This solid DRI is also fed to the Conarco EAF, as per the Corex output.

The combined processes have the capacity to produce approximately 1.2 Mtpa of hot-rolled carbon steel coils. ArcelorMittal consumes approximately 230 MWe of electricity for their current operations. Figure 6 illustrates the flow diagram of the current process used by the company. It should be noted that the plant presently operates below its design capacity due to insufficient offgas from the Corex process.

ArcelorMittal – Phase 1 Process

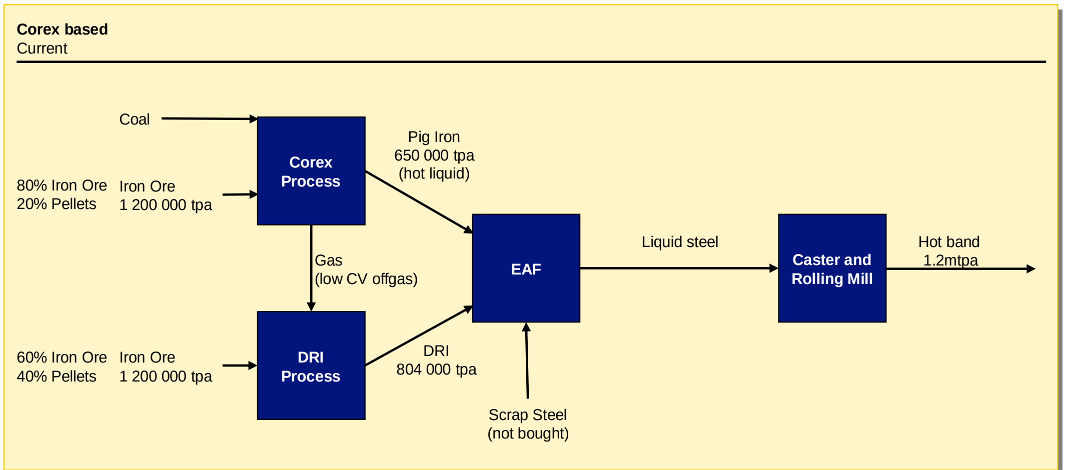


Figure 6[88]

Should natural gas become available, ArcelorMittal expressed interest in extending its current process to accommodate an additional DRI/Midrex process to increase its production capacity to 2.4 Mtpa. Extensions to the EAF and the Caster and Rolling Mill will however be required to de-bottleneck the system. Figure 7 illustrates the required changes for the enhanced process.

[88]Source: ArcelorMittal

ArcelorMittal – Enhanced Process

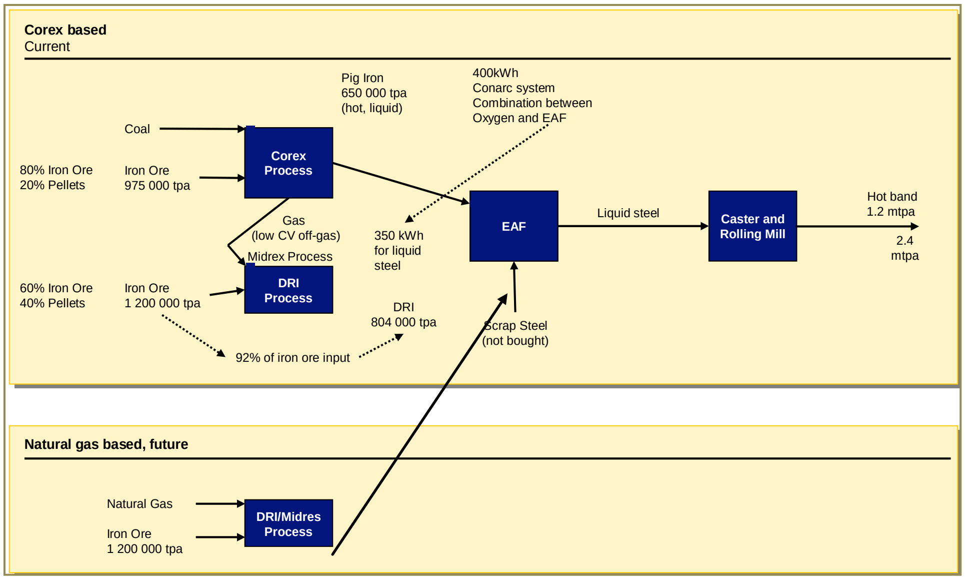


Figure 7[89]

The energy requirement for an additional 1.2 Mtpa Midrex/DRI plant will be approximately 12 GJ per ton of steel produced, which equates to an annual energy requirement of 14 400 000 GJ per annum[90]. The extension of the plant will consume approximately 0.3 million tonnes of LNG per annum. Extensions to the EAF and Caster and Rolling Mill for de-bottlenecking the system will also result in an additional thermal energy requirement of approximately 120 MWe for the increase capacity required by the EAF.

4.3.2.2 Duferco Steel Processing

Duferco was established in 1979 as a joint venture between Duferco SA of Switzerland and the Industrial Development Corporation with the primary objective to export its total production of hot rolled pickled and oiled, galvanised and cold rolled products. Duferco and ArcelorMittal, situated 3 kilometres away, have a joint agreement whereby ArcelorMittal provides hot-rolled carbon steel coils for further processing by Duferco.

Figure 8 below illustrates a flow diagram of the process used by Duferco. LPG (mainly propane) supplied by Afrox and PetroSA is currently used for heating purposes within the plant for the pickled, galvanizing and oiling processes. Although small, Duferco could contribute approximately 0.5 million GJ per annum

[89]Source: ArcelorMittal
[90]Source: ArcelorMittal

to the energy consumption in the area. Duferco consumes approximately 10 MWe of electricity for their current operations.

Duferco Steel Processing Plant

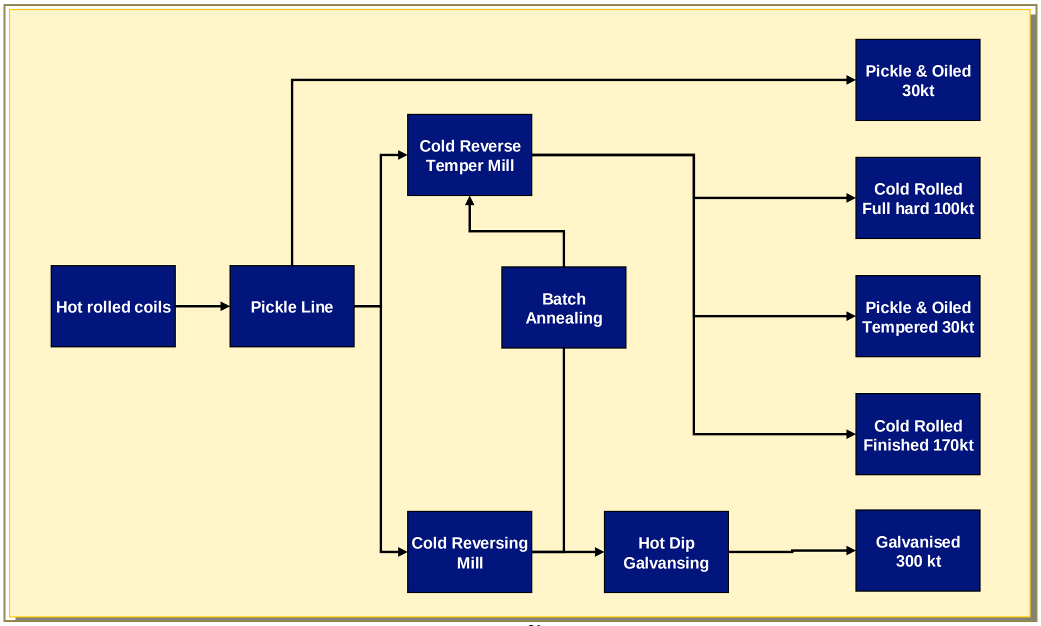


Figure 8[91]

4.3.2.3 Exxaro (Namakwa Sands)

Exxaro's (Namakwa Sands) main business is to mine and beneficiate heavy minerals. The operation is located on the west coast of South Africa and operates facilities at three separate sites. The mine and the concentration plants are located 385 kilometers north of Cape Town. Concentrate is transported from the mine to the mineral separation plant by truck. The mineral separation plant is located at Koekenaap, 60 kilometers from the mine. Imenite, zircon and rutile are recovered before the products are transported to a smelter situated in Saldanha Bay by rail.

Two furnaces are operated at the Saldanha Bay smelter where ilmenite is smelted to produce titanium slag and pig iron. Titanium is the primary product and is mined in the form of ilmenite and rutile. The pig iron is produced as a co-product of titanium slag and is used in the foundry and steel industry. Zircon is used in ceramics, chemicals and a range of other applications.

[91]Source: Duferco

Exxaro indicated[92] an initial electricity requirement, mainly for smelting operations in their arc furnaces, of 68MWe or an equivalent energy consumption of approximately 2 200 000 GJ per annum.

4.3.2.4 Future Potential Markets

Gas-fired power generation will play an enabling role and serve as anchor market for a natural gas development in the Saldanha Bay region.

The electricity requirements for potential expansion programs by existing business and potential future business opportunities in and around the Saldanha Bay region are briefly discussed below. Although the requirements are indicative only, they have been obtained during the market research[93] conducted for the Saldanha Bay IDZ development with the relevant companies. A summary of the potential future electricity requirements includes:

- ArcelorMittal - indicated an additional 120 MWe electricity requirement for the expansion of their Electric Arc Furnace and Caster and Rolling Mill operations should they embark on a planned expansion program of their current facilities;
- Rare Metals Industries (RMI) - indicated a future potential electricity requirement of 160 MWe from the 2018 period for the processing of titanium slag stockpiled at the Exxaro smelter;
- Saldanha Bay/IDZ port expansion program - back of port industrial development program requirement of 80 MWe of electricity;
- Exxaro Namakwa Sands and Duferco - existing electricity requirements of 80 MWe;
- ArcelorMittal – existing electricity requirements of 230 MWe;
- BHP Billiton – potential 580MWe electricity requirements for a manganese smelter. Note[94]: The project is seen to be unlikely to proceed and should be seen in the context of the national strategy of Transnet to allow for manganese export through the Port of Ngqura (Coega IDZ);
- Steel Authority of India (SAIL) - steel smelter requiring approximately 160 MWe of electricity. Note[95]: The project is unlikely to proceed in the medium to longer term as the planning horizon exceed 20 years;

[92]Source: Exxaro TSA Sands (Pty)/The Saldanha Bay IDZ Licensing Company
[93]Source: The Saldanha Bay IDZ Licensing Company
[94]Source: The Saldanha Bay IDZ Licensing Company
[95]Source: The Saldanha Bay IDZ Licensing Company

- Indian mining group Vedanta - tabled their interest in 70 MWe of power for a zinc beneficiation plant; and
- Frontier Rare Earths[96] – a 20 000 tonnes per year rare earth separation plant for the production of rare-earth oxides with a dedicated chlor-alkali plant for the production of hydrochloric acid requiring 50 MWe of electricity.

In summary, it appears that the Saldanha Bay region has a significant requirement for sustainable and affordable electricity. With existing electricity requirements between ArcelorMittal, Duferco and Exxaro Namakwa Sands of approximately 310 MWe and a forecast[97] of possible future requirements of an additional 410 MWe[98], a total electricity requirement for the Saldanha Bay region could amount to 720 MWe. An upside potential, should any or all of the remaining planned projects listed materialize, could add significantly to the electricity requirement of the region but these projects carry a high level of uncertainty[99].

As a result of the uncertainties in assessing the future electricity demand of potentially new businesses, option selection for a range of standard CCGT power plants will be provided for in the economic model to evaluate the commercial viability of various configurations of electricity demand. The selections include a 350 MWe CCGT plant to provide for the existing markets, a 450 MWe CCGT plant to provide for those industries identified as having a possibility of materializing and two additional plant sizes of 800 MWe and 1000 MWe respectively as sensitivities should any of the other projects materialize.

[96]Frontier Rare Earths-Update on Zandkopsdrift Project, Nov 2012
[97]Source: The Saldanha Bay IDZ Licensing Company
[98] ArcelorMittal (120MW); RMI (160MW); IDZ Port Expansion (80MW); Frontier Rare Metals (50 MW))
[99]Source: The Saldanha Bay Licensing Company

Figure 9 illustrates the typical gas requirements for a Combined Cycle Gas Turbines (CCGT) power generating facility. In this example the gas consumption is shown in billion cubic meters per annum (Bcm/a), million standard cubic feet per day (MMScfd) and million tonnes per annum of LNG (Mt/a) for an 800 MWe CCGT power plant operating at 68 percent load factor at a plant efficiency of 46 percent.

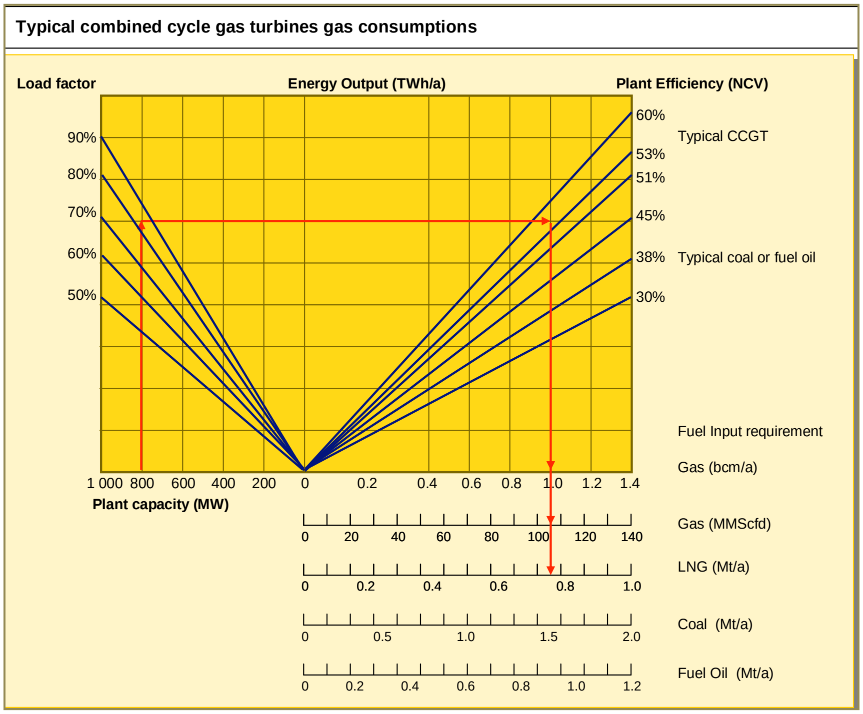


Figure 9[100]

4.3.3 Market Penetration

The conversion of the three main markets identified i.e. Exxaro Namakwa Sands, ArcelorMittal and Duferco Steel Processing could be conducted over a relatively short period due the long lead time required for the necessary licensing, EIA approvals and infrastructure requirements. Since most of these industries are clustered, and would receive gas from the mainline distribution facilities, the construction and commissioning of the main distribution lines to these industries could be completed within an estimated two years[101] to coincide with first commercial gas deliveries. The construction and commissioning of distribution pipeline to the smaller industries, which are mostly clustered close to the ArcelorMittal and Duferco plants, could be done contemporaneously[102].

[100]Source: Eskom Technical Department
[101]Pace Global Energy Services - South Africa Natural Gas Utilization - LNG Analysis (2008?) , PetroSA
[102]Gigajoule Africa – NERSA License Application for the Distribution and Trading of Natural Gas in the Cape West Coast Region (2010)

4.3.4 Market Pricing

The existing markets in the Saldanha Bay industrial areas mainly comprise LPG, HFO and coal users. Since LPG usage by the steel manufacturing and processing industries dominate the current energy mix in the region, the value of the market, albeit small, return a weighted average burner tip value for the various consumption sectors of US$ 31.82 per GJ[103]. Coastal wholesale and retail prices for the current fuel used in the different sectors were obtained from the Department of Energy[104].

[103]Item 4.2 - Cape Town-Atlantis - Potential Energy Market
[104]Central Energy Fund Wholesale Fuel Prices -2013

5.0 Potential Gas Supplies

5.1 Introduction

Natural gas supplies to the Cape West Coast region for the near future currently comprise three potential sources; indigenous gas supplies from known gas resources, pipeline gas from neighbouring countries with proven gas reserves and the importation of Liquefied Natural Gas (LNG) from existing and planned LNG liquefaction facilities. The overview takes into consideration 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. Longer-term option i.e. planned exploration programs have, for the time being, not been considered.

5.2 Indigenous Gas Supply

It appears that South Africa presently does not have sufficient proven natural gas reserves[105] on or offshore its boundaries that could be commercially developed in the foreseeable future for industrial usage or power generation. Since 2009, no additional exploration drilling activities have been undertaken by concessionaires although numerous operating companies have conducted seismic data acquisitions and processing, re-processing of existing data and a variety of technical studies within their licensed concession areas[106]. According to the Petroleum Agency of South Africa (PASA) these operators will only commit to future exploration and appraisal programs in line with the terms and conditions of their exploration licenses. Although sufficient gas resources may be proven during these campaigns, it will not fall within the time frame required for the development of a natural gas industry in the Cape West Coast region.

Of the companies holding petroleum exploration and production rights in South Africa, Forest Oil and PetroSA have been the most active over the past years. Although Forest Oil has registered the offshore Ibhubesi gas field discovery, situated about 350 kilometres north of Saldanha Bay, as a potential source for natural gas supplies to the Cape West Coast region, they have yet to commence with any gas development project. The field has estimated reserves of 450 Bscf[107] (billion standard cubic feet) at a 50 percent confidence level. Forest has stated[108], after their last drilling campaign in 2009 and the subsequent evaluation of its latest 3-dimensional seismic acquisition re-evaluation program, that no further upstream

[105] US Energy Information Administration – RSA Energy Overview/Natural Gas –An Update on South Africa's Potential, 2012
[106] Weekly Africa No 489/PASA
[107] Forest Oil - 2011 Annual Report
[108] Africa Upstream Conference - 2011

exploration activities would be conducted to improve the reserve estimate and confidence level of the Ibhubesi gas discovery until such time the company has concluded gas off take agreements commercially sufficient to justify a continuation of the gas field development program.

PetroSA on the other hand is concentrating on undeveloped discoveries of gas in the central Bredasdorp Basin, approximately 100 km off the southern coast of South Africa, to supplement current declining natural gas feedstock to their gas-to-liquids refinery near Mossel Bay. PetroSA plans to commence a 2-year, 5-well extensive drilling campaign in the F-O gas fields in the first quarter of 2013. The company stated[109] that production from the F-O field will maintain commercial operations of its gas-to-liquids refinery to 2019/2020.

PetroSA is also assessing the viability of importing LNG via marine technologies to a delivery point near Mossel Bay in order to secure additional long-term gas supplies for its gas-to-liquids plant. The company has recently contracted WorleyParsons to conduct the necessary feasibility and engineering studies for the LNG import facility and described the project of critical importance for the sustainability of their gas-to-liquids refinery[110]. In the same statement, PetroSA commented that the LNG project will allow additional time for sourcing further feedstock for their gas-to-liquids refinery through either further indigenous production, nearby sources of production or the importation of additional LNG for its operations. PetroSA's prime objective therefore appears to be securing gas for its own consumption and potentially other industries in the immediate vicinity of Mossel Bay.

Although the possibility exist for natural gas to become available from any of these resources in the future, the availability thereof might not fall within the time frame required for the development of a natural gas industry in the Cape West Coast region.

5.3 Piped Gas

Potential opportunities for existing natural gas reserves to be piped to South Africa from neighboring states are currently limited to gas produced from the Pande and Temane gas fields in Mozambique and the undeveloped Kudu gas fields in Namibia.

[109] Weekly Africa No 492
[110] PetroSA Web Page, January 2013 (www.petrosa.co.za)

Gas from the mentioned gas fields in Mozambique is currently delivered to Sasol's Secunda and Sasolburg chemical plants and the industrial areas around Gauteng and Kwazulu-Natal. The operations of this pipeline is nearing its current full capacity[111] of 149 million GJ per annum and any additional volumes for markets other than Sasol's would have to be transported through a newly constructed pipeline from the Pande and Temane gas fields to its end destination. With distances between the gas fields in Mozambique and the Cape West Coast region in excess of 2 900 kilometers and a relatively small volume of natural gas (< 2 million tonnes per annum) required to service the initial identified market requirements, gas supply via pipeline from the northern parts of Mozambique is deemed uneconomical[112]. Figure 10 illustrates the optimal methods of transporting different volumes of natural gas over increasing distances suggesting that the transportation of natural gas from the mentioned Mozambique gas fields could be achieved more economically via marine LNG or CNG methodologies than by pipeline to the Cape West Coast region. It should be noted that the transportation costs of natural gas via pipeline could become more competitive to the alternative methods as gas throughput increases, which in turn would be dependent on increased gas consumption in the Cape West Coast region and additional gas off take (additional markets) along the pipeline route. Additional factors such as the value of such potential markets, wellhead cost of natural gas, pipeline routing, potential pipeline compression requirements, etc. would also require further consideration. The technical and market analysis for such evaluations have been excluded from the scope of this study.

[111] Republic of Mozambique Pipeline Investment Company – Tariff Application for the Natural Gas Volumes Transported on the Additional 27 MMGJ/a – 23 August 2011
[112] Figure 10

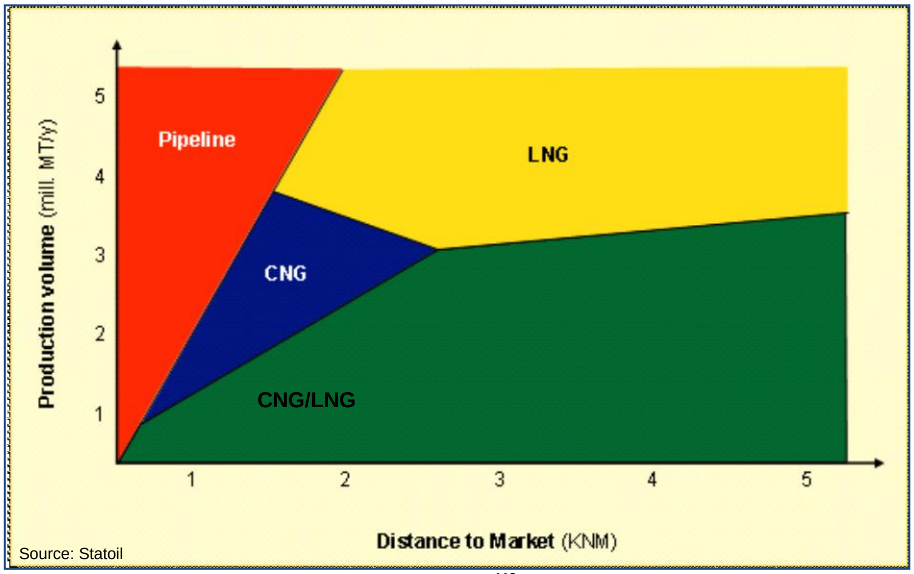


Figure 10[113]

Transporting gas by pipeline from the Kudu gas fields in Namibia to the Cape West Coast region has also proven to be commercially challenging. Various studies[114] on the technical and commercial viability of piping natural gas from the Kudu gas fields to the Cape Town region have returned marginal results with none of these companies currently pursuing the opportunity. More importantly the government of Namibia indicated a preference[115] to use natural gas for indigenous requirements rather than for exportation to South Africa. Current plans are to establish an 800 MWe gas-fired power plant at the planned infrastructure landfall from the Kudu gas fields in the southern parts of the country.

Based on the above, piped gas from Mozambique and Namibia as potential supply options for the Cape West Coast region for the immediate future and within the timeframe required for the importation of natural gas to the Western Cape seems to be unlikely.

5.4 Liquefied Natural Gas

Of the options available for importing natural gas to the Cape West Coast region, the importation of LNG appears to be the most viable. With recent large gas discoveries in neighboring and near-neighboring countries such as Mozambique and Tanzania, the potential future availability and delivery of LNG could become an attractively priced alternative energy source to the Cape West Coast region.

[113] Statoil Presentation – CNG Conference – St Johns, Canada - 2008
[114] PetroSA, Shell, Tullow Oil, Gigajoule Africa
[115] Source: Namcor – September 2012

The potential savings in shipping costs due to the short shipping distances to the Cape West Coast region could further favorably influence the delivery price of LNG from these countries.

5.4.1 Potential LNG Suppliers

Potential LNG suppliers to the Saldanha Bay region have been considered on two main contributing factors:

- The availability of LNG from either current supply or potential future supply opportunities; and
- The distance from supply sources to the Saldanha Bay region which will have a significant impact on the delivered price of LNG.

Based on the above, seven countries were reviewed as potential suppliers of LNG; Mozambique and Tanzania in the East Africa region, Angola and Nigeria in the West Africa region, Qatar and Oman in the Middle East region and Australia. Figure 10[116] illustrates the approximate shipping distances from these countries to the Saldanha Bay region.

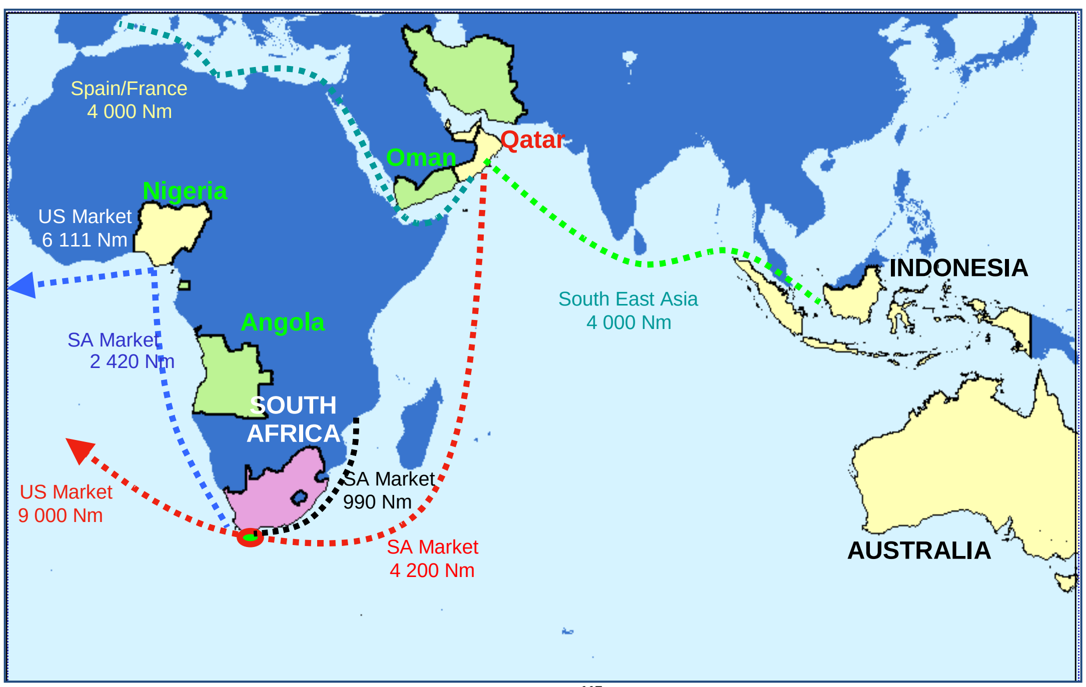


Figure 11[117]

[116] PortWorld - www.portworld.com
[117] PortWorld - www.portworld.com

5.4.1.1 Mozambique

The off and onshore hydrocarbon prospectivity of Mozambique is considered high, especially after the recent significant successes of Anadarko and Eni East Africa, the respective operators of the Rovuma Offshore Area 1 and Rovuma Offshore Area 4 concession areas. The Rovuma Basin represents one of the major basins located along the East African region and straddles the Mozambique-Tanzanian border (Figure 12).

Anadarko earlier in 2012 announced[118] the successful Barquentine-3 appraisal program which encountered an approximate 200 meter interval of natural gas pay. This, together with the previously Windjammer, Lagosta, Barquentine and Camarao discoveries, significantly expanded the estimated recoverable resource to 30 trillion cubic feet (Tcf) of natural gas. Anadarko further announced that the Atum prospect drilled towards the third quarter of 2012 encountered an additional 92 meters of net gas pay in two high-quality geological systems. Preliminary data[119] also indicated the latest discovery to be connected to recent Golfinho discovery located 16.5 kilometers away. The new geological complex is estimated to hold up to 30 Tcf[120] of incremental recoverable natural gas resources.

[118] Anadarko Petroleum Corporation/Weekly Africa No 460 to 508
[119] Weekly Africa No 489
[120] Anadarko Petroleum Corporation – Web page January 2013

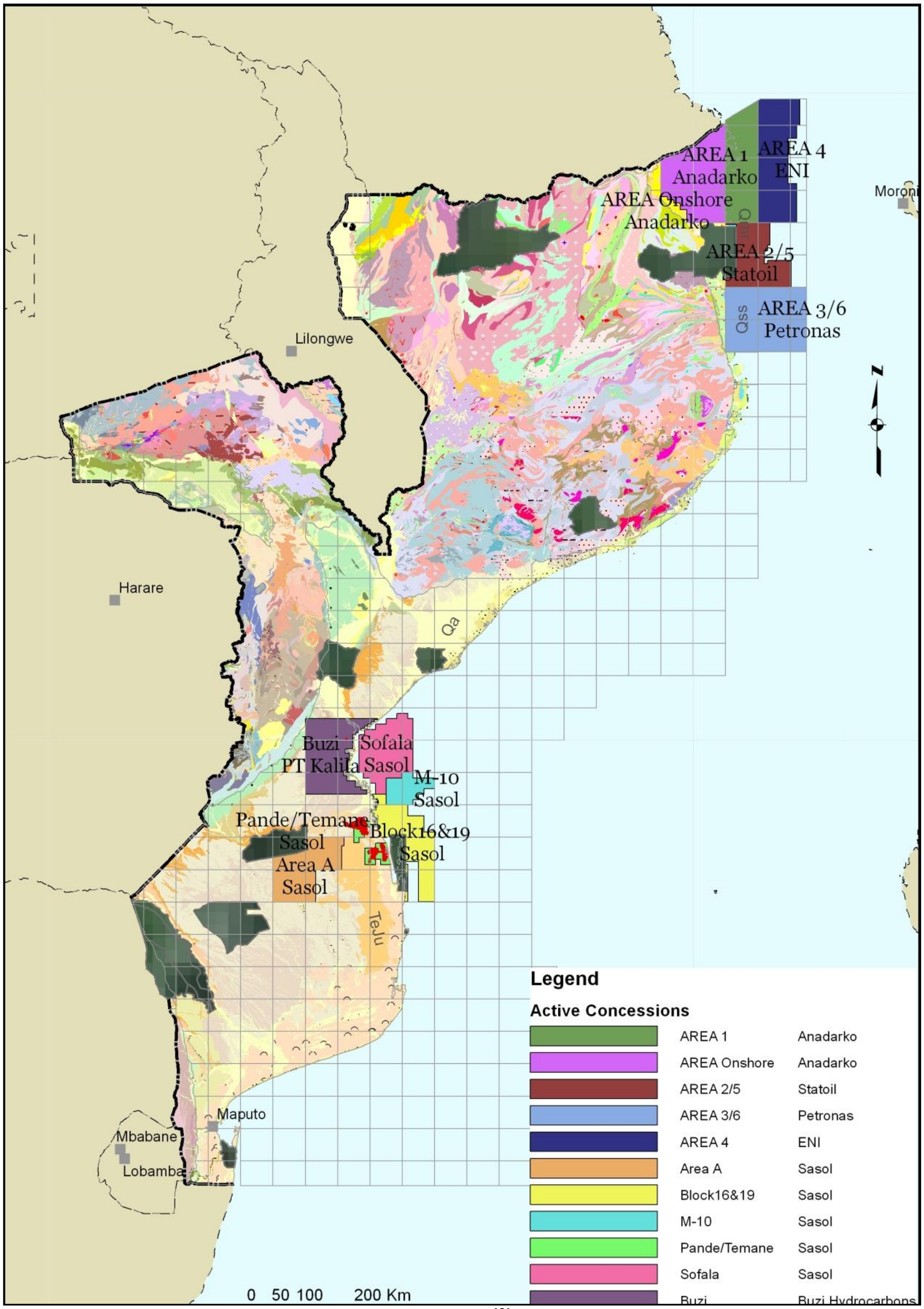


Figure 12[121]

[121] Instituto Nacional de Petrolea (INP) Mozambique - 2012

After updating and adjusting its acquired data sets, the company recently announced[122] that the Rovuma Area 1 discoveries alone now likely contains an estimated recoverable resources of 100 Tcf of gas and further indicated their intent of establishing a large-scale LNG development with first commercial LNG deliveries scheduled for 2018[123]. The plant would initially consist of at least two four million tonnes per annum LNG liquefaction trains with the flexibility of expansion to six trains. A decision is due early in 2013 on the project investment.

Eni East Africa's Rovuma Offshore Area 4 (Figure 12) is located immediately east of the Anadarko-operated Rovuma Offshore Area 1. Eni drilled its first geological prospects in the Mamba South Area which intersected large natural gas discoveries with an estimated recoverable resource of 15 Tcf of gas[124]. A subsequent exploration and appraisal program in the Mamba North Area intersected up to 200 meters[125] of net gas pay stacked in multiple high-quality sands. The combined discoveries in both North and South Areas are estimated at a recoverable resource of 62 Tcf of gas[126]. As with Anadarko, Eni indicated their intent of establishing a large-scale LNG development in the near future.

Anadarko Petroleum and Eni, with estimated combined recoverable natural gas resources of approximately 160 Tcf, have recently entered into discussions[127] to explore the possibility of a joint development of their offshore gas discoveries and the establishment of an initial four to six million tonnes per annum LNG liquefaction plant along the Mozambique coast[128]. Both companies have committed to commercialize their hydrocarbon discoveries in the shortest possible time.

LNG importation from Mozambique to the Cape West Coast region, should the development of the liquefaction terminal in Mozambique proceed, is considered an attractive option mainly because of its proximity to the Saldanha Bay region, uncommitted LNG volumes of their planned facilities and the large recent gas discoveries.

5.4.1.2 Tanzania

The off and onshore hydrocarbon prospectivity of Tanzania are also considered to be high. Ophir Energy, the operator in the offshore exploration Blocks 1, 3 and 4

[122]Anadarko Petroleum Corporation Webpage – September 2012 / Oil and Gas - Mergers & Acquisitions Data Sources –2012
[123]Anadarko Petroleum Corporation Webpage – September 2012
[124]Weekly Africa No 495
[125]Weekly Africa No 496
[126]Derrick Petroleum Data Source – 2012 (www.derrickpetroleum.com)/Weekly Africa No 495
[127]Derrick Petroleum Data Source – 2012 (www.derrickpetroleum.com)/Weekly Africa No 495
[128]Derrick Petroleum Data Source – 2012 (www.derrickpetroleum.com)

(Figure 13), made significant gas discoveries totaling 7 Tcf[129] of gas in their first drilling and appraisal campaign which started in 2010. The second campaign was also successful and out of the 5 wells drilled, all intersected gas pay in stacked multiple high-quality sands ranging from 90 to 180 meters in thickness[130]. Preliminary analysis of the discovery suggests a 0.5 - 2.0 Tcf Gas Initially in Place (GIIP).

Ophir Energy announced[131] that cumulative discovered, recoverable gas resources in Blocks 1, 3, 4 (Figure 13) have reached the minimum threshold volumes required for an 8 million tonnes per annum, two-train LNG development.

StatoilHydro is the operator in the Block 2 concession area (Figure 13) offshore Tanzania. The company started with an exploration campaign early in 2012 and intersected 120 meters of high-quality gas bearing reservoir sands in their first prospect drilled[132]. The second well drilled intersected 95 meters of similar high-quality gas bearing sands. StatoilHydro has confirmed an estimated recoverable resource of 9 Tcf[133] of gas by October 2012 and contracted engineering company KBR to conduct pre-front end engineering and design (pre-FEED) studies for a prospective LNG facility which is expected to be completed during 2013[134]. Although not as advanced as Anadarko with its pre-FEED and FEED studies, StatoilHydro anticipates that first commercial LNG production will be before 2020[135].

[129] Oil and Gas - Mergers & Acquisitions Data Sources –2012
[130] Weekly Africa No 448 - 500
[131] Orphir Energy Web Page – September 2012
[132] Weekly Africa 488 - 497
[133] StatoilHydro Web Page, October 2012
[134] Weekly Africa No 492 - 498
[135] Oil and Gas - Mergers & Acquisitions Data Sources –2012

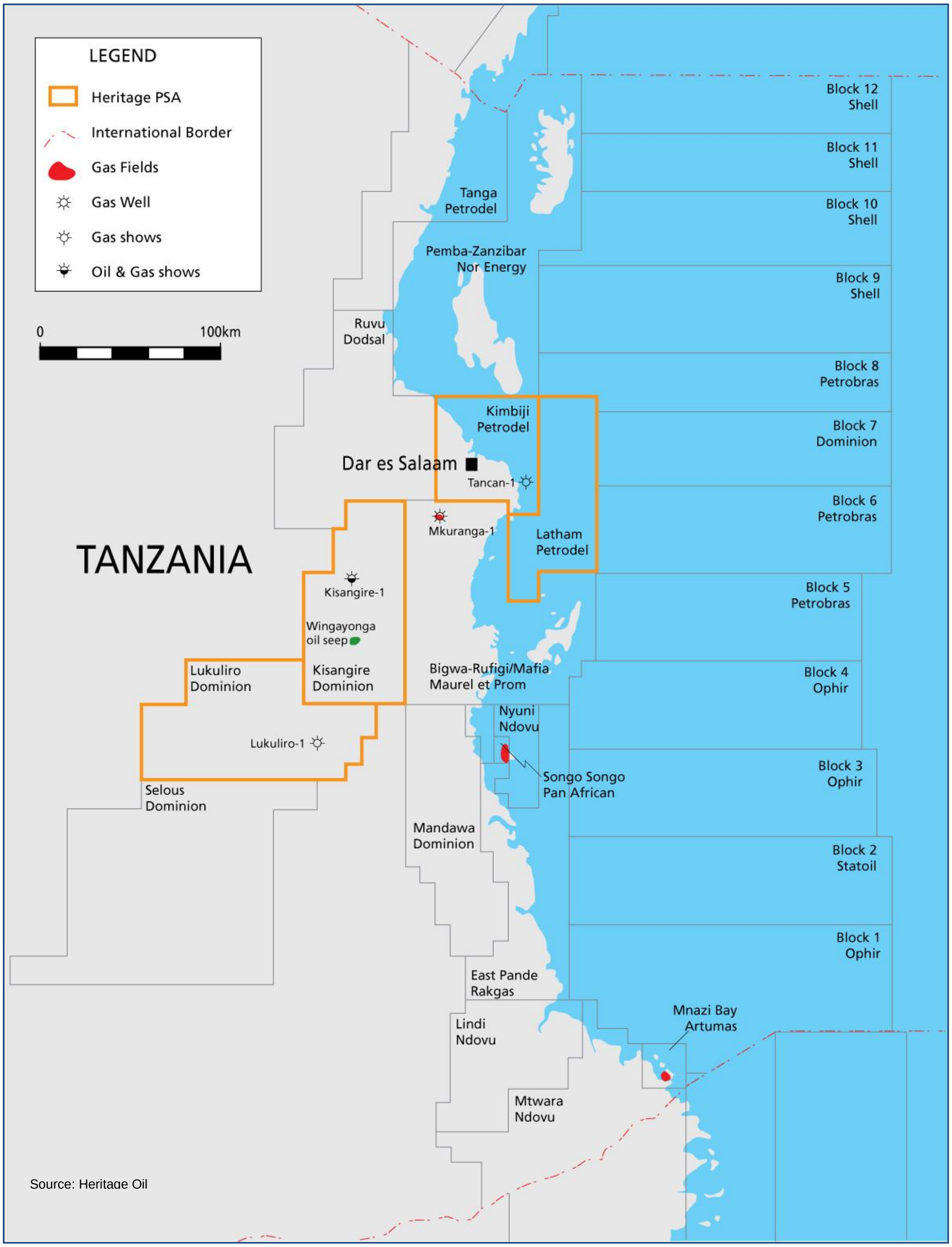

LEGEND
Heritage PSA
International Border
Gas Fields
Gas Well
Gas shows
Oil & Gas shows
0
100km
TANZANIA
Dar es Salaam
Block 12 Shell
Block 11 Shell
Block 10 Shell
Block 9 Shell
Block 8 Petrobras
Block 7 Dominion
Block 6 Petrobras
Block 5 Petrobras
Block 4 Ophir
Block 3 Ophir
Block 2 Statoil
Block 1 Ophir
Tanga Petrodel
Pemba-Zanzibar Nor Energy
Ruvu Dodsal
Kimbiji Petrodel
Tancan-1
Mkuranga-1
Latham Petrodel
Kisangire-1
Wingayonga oil seep
Lukuliro Dominion
Kisangire Dominion
Bigwa-Rufigi/Mafia Maurel et Prom
Nyuni Ndovu
Songo Songo Pan African
Lukuliro-1
Selous Dominion
Mandawa Dominion
East Pande Rakgas
Lindi Ndovu
Mnazi Bay Artumas
Mtwara Ndovu
Source: Heritage Oil

Figure 13

With cumulative discovered recoverable gas resources nearing a potential 20 Tcf and the stated intent by both Ophir Energy[136] and StatoilHydro[137] of planning to establish LNG liquefaction plants before 2020, the opportunity of importing LNG from Tanzania to the Cape West Coast region should be explored soonest. Short distances from the region as well as the potential availability of uncommitted LNG tonnage should make the Cape West Coast region an attractive option to both buyers and sellers of LNG quantities.

5.4.1.3 Nigeria

Nigeria is considered a serious contender for LNG exports to South Africa because of its proximity and its abundant gas reserves. Nigeria has become one of the top-ranked LNG suppliers in the world because of the rapid succession of LNG facility expansions coming into service and the possible addition of a Greenfield LNG export project at Brass Island in Bayelsa State.

Nigeria LNG indicated[138] that full production capacity from all seven LNG trains currently in operation at the Bonny Island liquefaction plant, with an overall capacity of over 30 million tonnes per annum of LNG, has been contracted to the European and Far East markets.

The addition of a planned greenfield plant at the mouth of the Brass River was however identified[139] as a potential alternative LNG supplier from Nigeria. The company has completed its early site works in 2009, which comprised the completion of preliminary engineering work on the Brass River LNG site, front-end engineering and design (FEED) studies, roads, housing and preparing the base for the LNG storage tanks. The Brass LNG project will comprise a 2-train LNG liquefaction facility each capable of producing of 5 million tonnes per annum. The company is expecting a final investment decision[140], which will activate the continuation of the project, in the first quarter of 2013.

[136] Weekly Africa – June 2012
[137] Weekly Africa – October 2012
[138] Nigeria LNG Webpage – Company Overview, 2012/3
[139] Nigeria LNG Webpage – Company Overview, 2012/3/ LNG News - Brass LNG, February 2012
[140] LNG News - Brass LNG, February 2012

Figure 14 indicates the positioning of the Nigeria LNG and Brass LNG facilities.

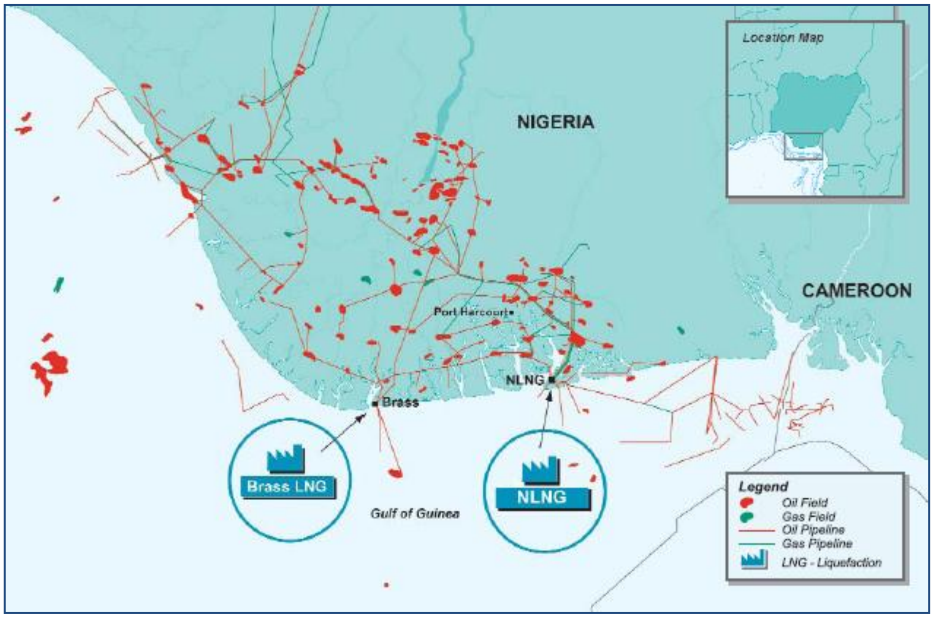


Figure 14

5.4.1.4 Angola

Angola has the second-largest oil and gas reserves in sub-Saharan Africa and is looking to LNG to monetise its natural gas resources[141]. Approximately 80 percent of natural gas produced in Angola is currently flared[142]. The remainder is re-injected to aid in crude oil production and processed into LPG.

To overcome the flaring of associated gas the Angolan government adopted a no-flare policy in December 2007 and subsequently played a facilitating role in encouraging international oil companies in Angola to monetise the gas. One of the projects proposed was a 4 to 5 million tonnes per annum LNG facility, which could use flared gas to produce LNG. A consortium made up of Sonangol, the national oil corporation of Angola, Total, Eni, BP and Chevron formed an international partnership with strong government support and investment and established the Angola LNG company for the execution of the project.

The Angola LNG liquefaction project, situated in Soyo about 315 kilometers north of Luanda in the Zaire district, is expected to become operational in early 2013[143]. The plant would utilise associated gas resources, primarily from shallow-water

[141]Angola LNG Webpage – An update on SOYO LNG Facilities, February 2013 – (www.angolalng.com)
[142]Angola LNG Webpage – An update on SOYO LNG Facilities, February 2013 - – (www.angolalng.com)
[143]Sonangol Webpage, February 2013 – (www.sonangol.co.ao)

fields, for its LNG production. This accumulated gas would provide a 5.2 million tonnes per annum LNG liquefaction plant with a relatively low inlet cost of gas since capital costs for upstream development and transport would be much lower than deeper offshore or onshore non-associated gas resource developments[144]. The facility would be supplied from gas reserves that are available from offshore Blocks 0, 1, 2, 14, 15, 17 and 18, which have been connected by pipeline to a central gathering hub located at Soyo (Figure 15). The facilities comprise 360,000m^3 of full containment LNG storage and a loading jetty sized to accommodate ships up to 210 000 m^3 capacity.

Angola LNG is currently investigating the potential of supply LNG from the Soyo plant to the European and Far East markets[145].

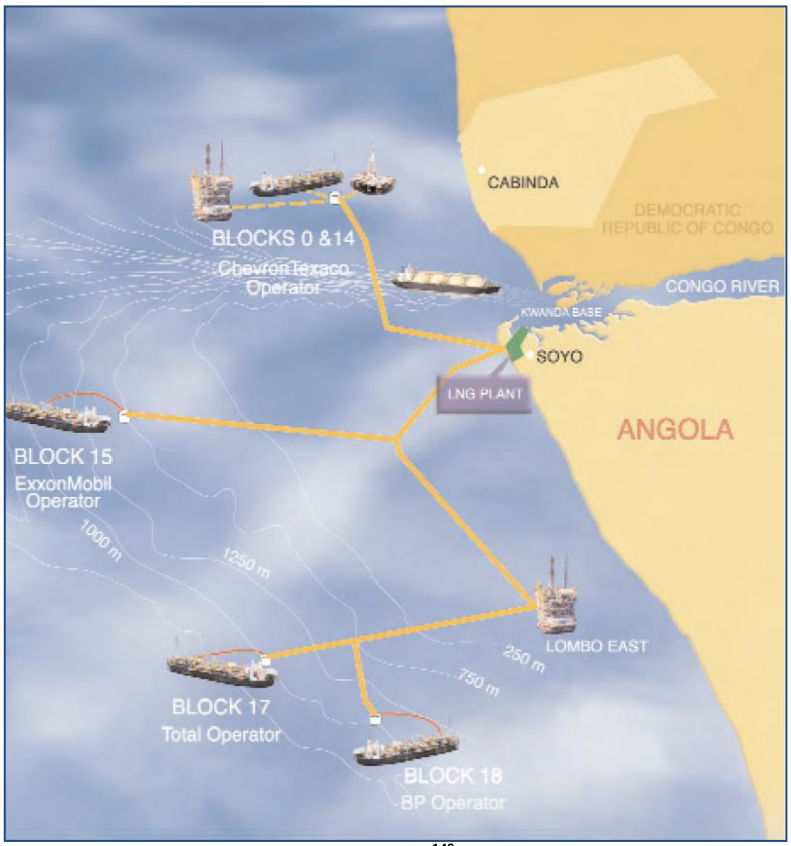


Figure 15[146]

[144] Angola LNG Webpage – An update on SOYO LNG Facilities, February 2013 - (www.angolalng.com)
[145] Angola LNG Webpage, February 2013 -(www.angolalng.com)
[146] Source: Sonangol/Chevron

5.4.1.5 Oman

Oman ranks 26th in the world for natural gas reserves and has been diversifying its previously oil-based economy to include natural gas exports in the form of LNG. The country is the seventh largest LNG exporter in the world, exporting significant supplies to Asian and Atlantic Basin markets, mostly to Spain and France, through spot, short-term and long-term agreements[147]. Oman began shipping LNG from its Al Qalhat LNG facility near Sur in early 2000.

The Al Qalhat LNG facility has three trains, two which has a design capacity of 3.3 million tonnes per annum LNG and the third with a capacity of 3.8 million tonnes per annum. The first two trains went into operation in early 2000 whilst the third train was commissioned in 2006. Capacity from the Qalhat LNG plant is mostly committed to long-term agreements with long standing off takers. Under its current operations and with the current medium-term agreements (5 to 10 years) in place, a smaller quantity of LNG could become available for longer-termed supplies agreements[148] (10 to 20 years).

5.4.1.6 Qatar

Qatar is currently the world's largest LNG producer with a combined annual LNG production capacity of 77 million tonnes per annum. Large reserves from the country's North Field could feed its LNG trains and expanding LNG facilities at the Ras Laffan Industrial Complex for several decades[149]. Qatar's QatarGas LNG Company ("QatarGas") and Ras Laffan LNG Company ("RasGas") are the leading exporters of long-term, as well as spot cargo LNG, and are able to expand their markets to meet short-term demand around the world[150].

QatarGas is the world's biggest producer of LNG with a total liquefaction capacity of 42 million tonnes of LNG per year. The plant consists of seven LNG liquefaction trains, four of which has a liquefaction capacity of 7.8 million tonnes per annum of LNG and two additional with a liquefaction capacity of 5.4 million tonnes of LNG per year each.

RasGas on the other hand is the second-biggest LNG producer in the world after QatarGas and operate seven LNG trains located in the Ras Laffan Industrial City. The company's seven LNG trains have a total capacity of 36.3 million tonnes of

[147] Pace Global Energy Services - South Africa Natural Gas Utilization - LNG Analysis (2008?) , PetroSA
[148] Pace Global Energy Services - South Africa Natural Gas Utilization - LNG Analysis (2008?) , PetroSA
[149] Qatar LNG Information, February 2013 – (www.qatargas.com)
[150] Pace Global Energy Services - South Africa Natural Gas Utilization - LNG Analysis (2008?) , PetroSA

LNG per year. Trains 6 and 7, each capable of producing 7.8 million tonnes per year, are amongst the largest LNG trains in the world

5.4.1.7 Australia

Chevron's new Wheatstone LNG Project in Western Australia is schedule for first LNG production by 2015[151]. This is Chevron's second LNG project in Australia and would include an onshore facility located 12 kilometers west of Onslow in Western Australia's Pilbara region. The initial project would include two LNG trains with a combined capacity of 8.9 million tonnes per annum and a domestic gas plant[152]. Long-term planning allows for an expansion program to an eventual production capacity of 15 million tonnes of LNG per annum, making it the world's second largest LNG liquefaction facility after Qatar. Eighty percent of the Wheatstone Project's initial capacity will be fed with natural gas from the Wheatstone and Lago gas field operations (Figure 16)[153].

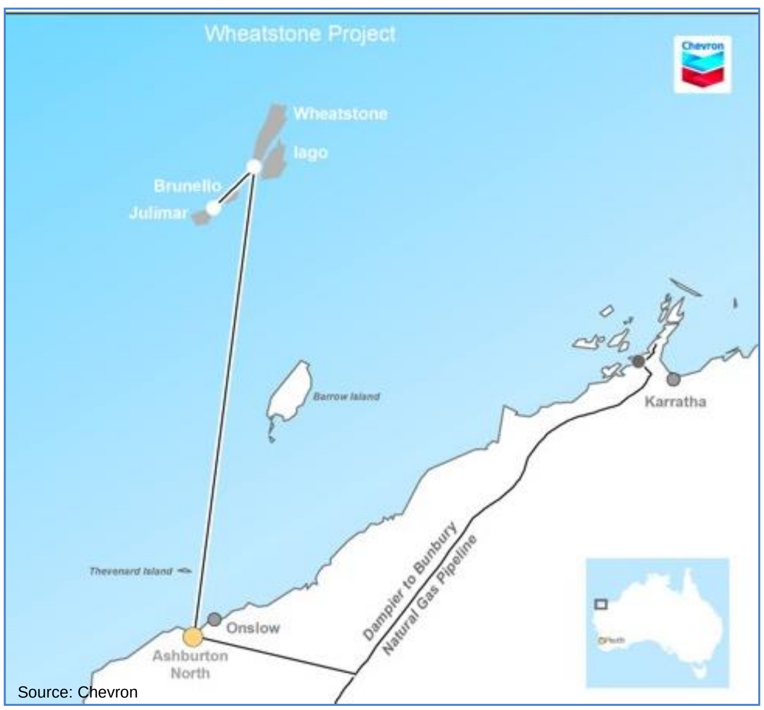


Figure16

Chevron has committed more that eighty percent of the Wheatstone LNG initial production capacity to markets in Japan[154].

151 Derrick Petroleum Data Source – 2012 (www.derrickpetroleum.com)
152 Chevron Australia Webpage - February 2013
153 Chevron Australia Webpage - February 2013
154 Weekly Africa No 490 - 500

5.4.1.8 International Portfolio Suppliers

Natural gas delivered by means of LNG could also be sourced from international portfolio suppliers. These companies hold a portfolio of supplies either as operator or owner throughout the world and typically include International Oil Companies (IOC's) such as Chevron, Shell, BG, BP, StatoilHydro, ExxonMobil, Total and others. In most cases such IOC's will internally decide from where it will supply volumes in order to optimize their LNG shipping fleet operations and production capabilities from their various LNG plants or option supplies. One of the advantages of such suppliers is the security of supplies; should LNG tonnage not be available from one of the supplier's plants it could secure supplies from another.

Figure 17 indicates current international trading of LNG[155].

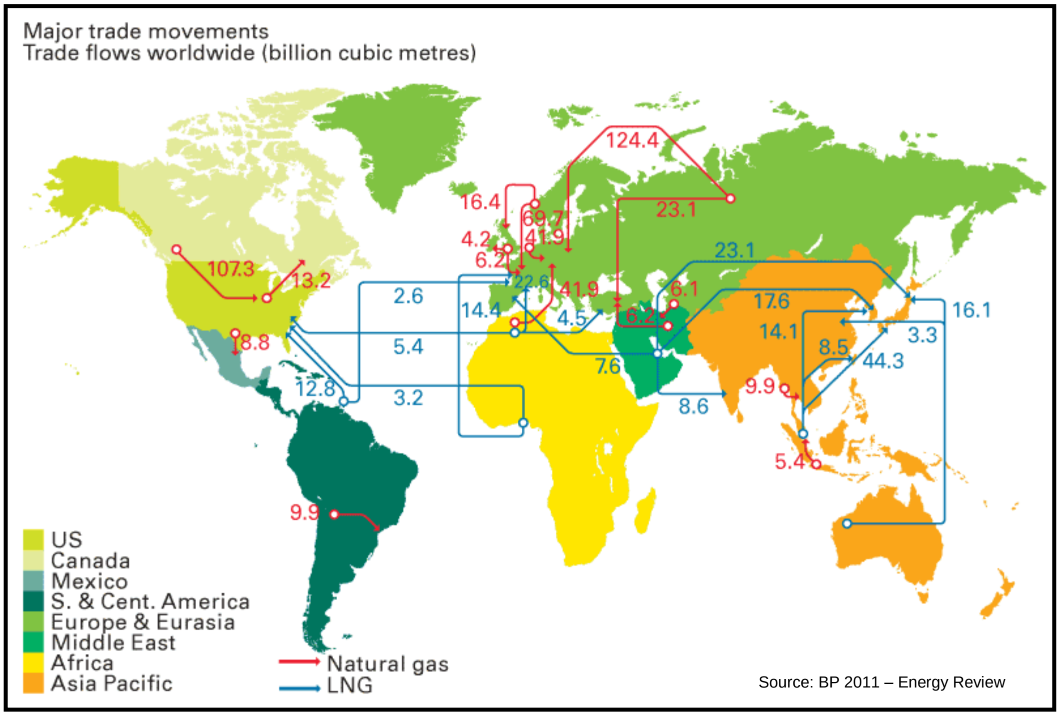


Figure 17

5.4.2 LNG Pricing

5.4.2.1 Overview

The Federal Energy Regulatory Commission (FERC) published the estimated landed prices of LNG for February 2013 (Figure 18) which indicated a high variance between LNG prices in North America, Europe, India and Asia. Where

[155] Source: BP 2011 – Energy Review

the North American LNG prices were influenced downwards to below US$4 per MMBtu, mainly as a result of the high shale gas production flooding the American market, the Asian market paid close to US$18 per MMBtu. These high prices were obtained because of higher demands for natural gas in Japan to compensate for the lost of nuclear power generation capabilities after the Fukushima disaster and the fast growing economies in Asia needing more gas to cater for its industrial and power generating needs. The landed prices for the European markets varied between US$10.22 per MMBtu to US$13.71 per MMBtu.

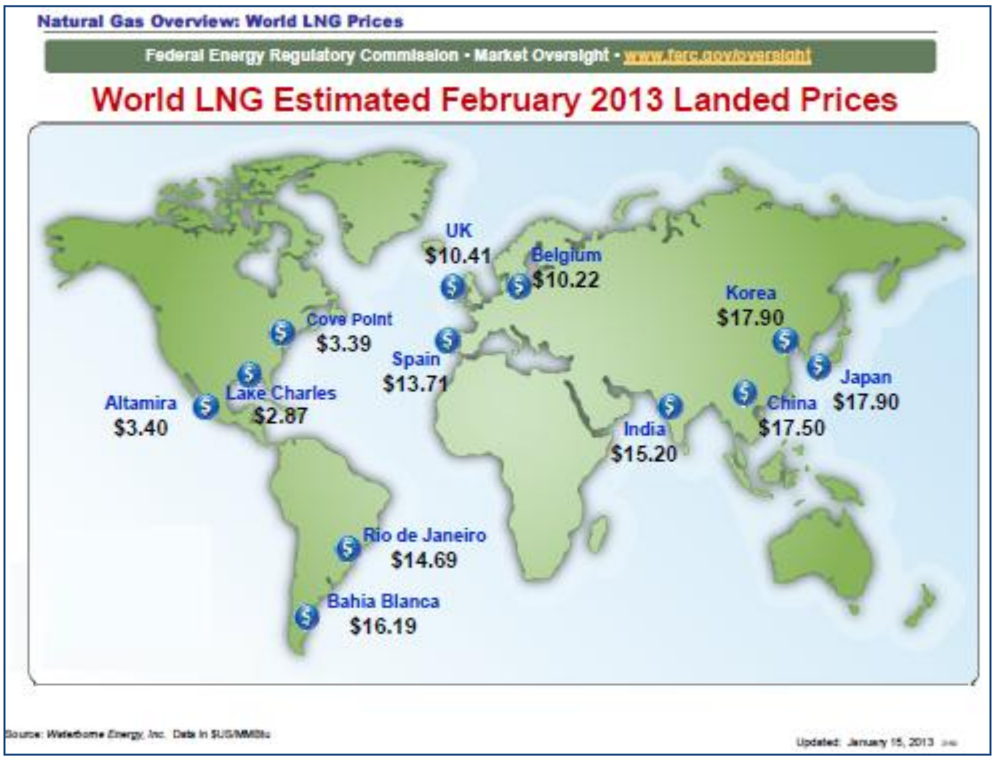


Figure 18

The LNG supply capabilities have increased only marginally during 2012 and are expected to follow a similar pattern during 2013[156]. With growing demands expected from Asia's leading economies and new LNG supply capacity only expected to become available from 2015[157] onwards from Australia, East and West Africa (except for Angola LNG which is scheduled for first production in 2013/14) and the United States, the potential exist that LNG for short-term and spot market trading might become in short supply over the next two years[158]. It is

[156]The Federal Energy Regulatory Commission, February 2013 - (Commission www.ferc.gov/market.../mkt.../overview/ngas-ovr-lng-wld-pr-est.pdf)
[157]Economist – LNG: A Liquid Market, July 2012 (economist.com/node/21558456)
[158]The Federal Energy Regulatory Commission, February 2013 - (Commission www.ferc.gov/market.../mkt.../overview/ngas-ovr-lng-wld-pr-est.pdf)

expected[159] that this trend will increase the short-term and spot trading LNG prices, which is currently around US$18 per MMBtu[160],

FERC however, predicted an LNG supply surge during 2015 to 2018 which would have a stabilizing or even downwards affect on short-term and spot-traded and new longer-termed LNG prices. The main sources listed for new supply capacity include:

- The conversion and commissioning of the Sabine Pass re-gasification facility in America to a liquefaction facility for the export of LNG. The plant will be supplied by shale gas;
- The Wheatstone LNG facilities in Western Australia planning first export deliveries by 2015;
- LNG production from East Africa after the recent large gas discoveries in Mozambique and Tanzania with expected first deliveries between 2018 and 2020;
- LNG production from the Brass LNG project currently under construction in Nigeria with first deliveries expected by 2016; and
- The Angola LNG plant in Soyo, Angola, which is expected to become operational in 2013/14.

5.4.2.2 LNG Pricing - Saldanha Bay

Establishing an estimated price for LNG deliveries to Saldanha Bay is highly dependent on the Freight on Board (FOB) price at the LNG supply terminal, the distance between that supply point and the Saldanha Bay region and the availability of LNG supplies from the supply point.

In the case of supplying LNG to the Saldanha Bay region, four countries have been favored for their location to Saldanha Bay and potential available LNG supplies by 2018; Mozambique and Tanzania on the East African coast and Nigeria and Angola along West Africa.

To establish a range of FOB prices from where LNG could be imported to South Africa, Nigeria was selected as a potential LNG supply source. Nigeria currently supplies LNG to the European markets of Belgium and Spain. The range of given landed prices (Figure 18) for these countries was “net-backed” to Nigeria by deducting an assumed shipping costs of US$1.90 per MMBtu for Belgium and US$1.60 per MMBtu for Spain, which resulted in an FOB price at the terminal in

[159] Reuters, January 2013 – (economist.com/node/21558456)
[160] Reuters, January 2013 – (economist.com/node/21558456)

Nigeria ranging between approximately US$8.30 per MMBtu (Belgium) and US$12.10 per MMBtu (Spain). If the calculated shipping costs[161] of US$1.97 from Nigeria to Saldanha Bay are then added to the FOB price in Nigeria, an approximate landed price in Saldanha Bay amounts to between US$10.30 per MMBtu and US$14.10 per MMBtu.

Although only expected to start producing LNG from its Soyo terminal in Angola later this year or early in 2014, the same principle could be applied to possible LNG supplies from Angola, once operational, assuming the range of FOB prices in Angola to be similar to that in Nigeria. With the shipping costs previously calculated at US1.53 per MMBtu[162] between Angola and Saldanha Bay, an approximate landed cost would then amount to US$9.80 per MMBtu and US$13.60 per MMBtu. If applied to an LNG terminal in Mozambique, although still under consideration, landed costs in Saldanha Bay could reduce to approximately US$9.60 – US$13.40 per MMBtu.

For pre-feasibility economic evaluation purposes a range of LNG landed prices between US$10.00 per MMBtu and US$15.00 per MMBtu will be assessed.

5.4.3 LNG Shipping

LNG carriers are a special class of vessels designed specifically for the transport of LNG. Of the approximately 180 LNG ships[163] currently transporting LNG, more than half are of the Moss Rosenberg spherical tank design, with a large percentage of the remaining fleet being of the membrane type design. Key features of these vessels include a double hull, cargo containment systems, cargo handling systems; and steam-turbine propulsion systems fueled with boil-off-gas from the cargo tanks.

The technology behind these ships are continuously refined and scaled up to achieve greater economies of scale. Modern LNG carriers are typically designed to transport 135 000m^3 to 220 000m^3 [164] for the large modern LNG export facilities such as those found in Qatar and Australia. Although the scale-up of LNG carrier capacity is considered technically feasible, the sizing of the larger ships is a function of the capability to upgrade ports at existing liquefaction and re-gasification plants.

[161] Item 5.4.3.1 – LNG Shipping Costs
[162] Item 5.4.3.1 – LNG Shipping Costs
[163] Pace Global Energy Services - South Africa Natural Gas Utilization - LNG Analysis (2008?) , PetroSA
[164] Danish Shipping Finance, January 2013 - (shipfinance.dk/en/SHIPPING-RESEARCH)

5.4.3.1 LNG Shipping Costs

The cost of transporting LNG by tanker is highly dependent upon the size of tankers employed, the distance to markets and the level of vessel utilisation achieved and show a wide variation depending on the type of LNG supply contract entered into with the LNG supplier. Proximity to markets can provide a significant advantage to one LNG liquefaction project over another.

Table 12 is a summary of the calculated shipping distances and costs[165] from Mozambique, Angola, Nigeria, Oman/Qatar and Australia to the Saldanha Bay region. The cost calculations were based on a standard 138 000m^3 size LNG vessel costing around US$200 million[166][167] with a calculated daily charter rate of approximately US$72 800[168]. *It should however be noted that these shipping costs were based on new-build vessels which could reduce proportionally pending on the daily charter rates for existing older LNG vessels*. *Negotiated prices with LNG suppliers which provide shipping as part of their LNG supply agreement could also result in much reduced prices.*

Shipping Distances and Costs – Saldanha Bay Region		
Country	**Distance (Nm)**	**US$/MMBtu**
Mozambique	990	1.34
Angola	1 250	1.53
Nigeria	2 400	1.97
Oman/Qatar	4 200	3.32
Australia	4 500	3.53

Table 12

Mozambique and Angola have a significant transport cost advantage over all listed LNG suppliers into the Saldanha Bay region. Shipping distances from these two proposed LNG liquefaction plants to the Saldanha Bay region range from approximately 1 000 and 1 250 nautical miles which would result in a round trip voyage for a LNG supply vessel from Mozambique of approximately 14 days whilst shipments from Angola will take one and a half days longer[169].

[165] Item 5.4.3 - LNG Shipping Costs – Mozambique, Angola, Nigeria Oman/Qatar/Australia to Saldanha Bay
[166] CBI LNG Value Chain: Typical Costs
[167] Bloomberg – LNG Tanker Costs, 2011 (bloomberg.com/news/2011-02-16/lng-tanker)
[168] Item 5.4.3.1 - LNG Shipping Costs – Mozambique, Angola, Nigeria Oman/Qatar/Australia to Saldanha Bay
[169] Table 7 - LNG Shipping Costs – Mozambique to Saldanha Bay (990 Nm)

LNG supplied from Nigeria will also be among the lowest cost transport options into the Saldanha Bay region and far less than gas transported from Oman or other Middle Eastern and Australian supply options.

Figure 19 illustrates the effect longer transportation distances of LNG between the various supply terminals and a delivery point in Saldanha Bay could have on shipping costs.

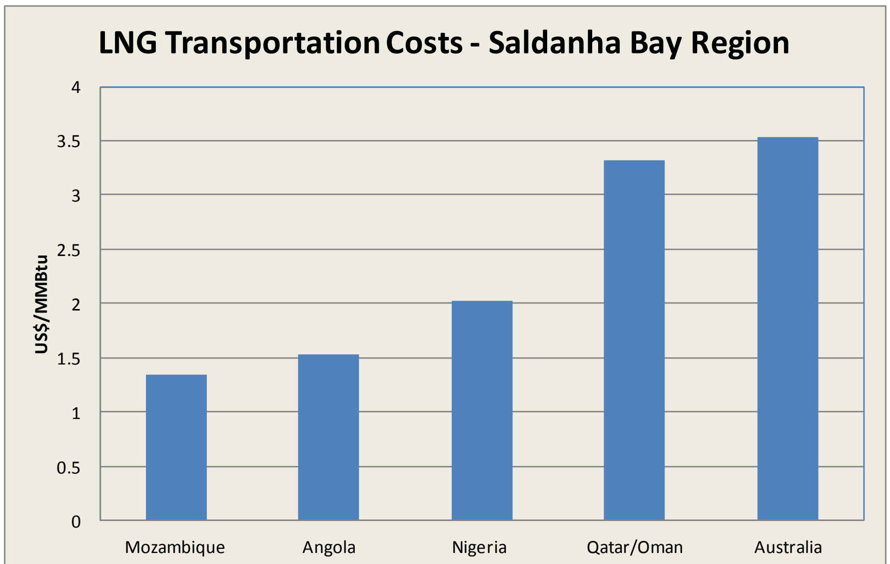


Figure 19[170]

For pre-feasibility economic evaluation purposes shipping costs from Mozambique, Angola, Nigeria, Qatar/Oman and Australia have been included as option selections in the economic analysis[171].

[170] Figure 19 - LNG Shipping Costs – Mozambique, Angola, Nigeria Oman/Qatar/Australia to Saldanha Bay

[171] Pre-Feasibility report for the importation of natural gas into the Western Cape with specific focus on the Saldanha Bay-Cape Town corridor – Economic Model

6.0 Gas Infrastructure Requirements

The infrastructure requirements for the importation of LNG to the Cape West Coast region would comprise an LNG receiving terminal for receiving, storing and re-gasifying LNG, a high-pressure transmission pipeline network to transport the natural gas to the main consumption areas and a low-pressure distribution pipeline network to distribute the gas to the identified markets.

6.1 LNG Receiving Terminals

Two types of LNG receiving terminals will be reviewed for this study; the conventional land-based terminal situated in the Port of Saldanha Bay and an offshore, permanently moored, submerged receiving terminal to which an FSRU is moored. The economic feasibility analysis[172] will consider both these methods of receiving LNG.

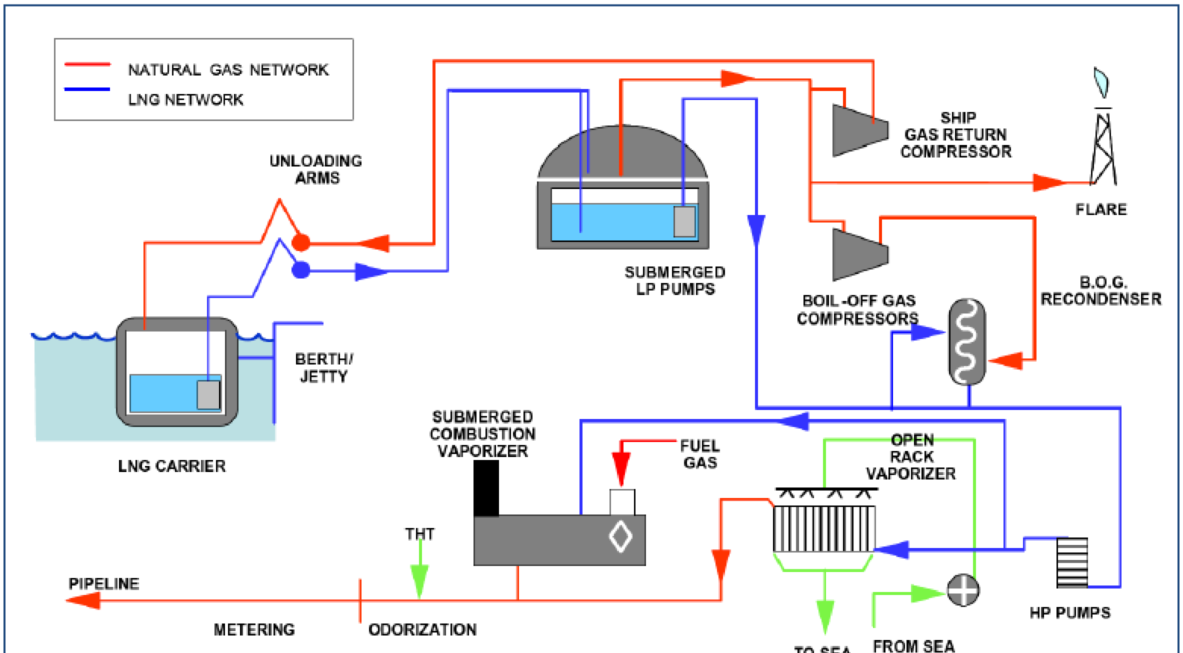
Onshore LNG Receiving Terminal

The gas receiving terminal is the gateway for LNG to downstream markets. Since the introduction of large-scale LNG receiving facilities in the 1960's, the conversion of LNG into gas for injection into the pipeline grid has taken place at dedicated onshore receiving terminals. These terminals generally comprised a jetty for offloading the LNG, storage tanks to store the LNG in liquefied form, a re-gasification plant which vaporise the LNG to a gaseous state and pressure and metering facilities measuring the discharge of the gas into the pipeline network. Establishing these facilities are capital intensive and takes about 5 years to construct[173][174], especially if part of a greenfield development. Figure 20 illustrates a simplified flow scheme for an onshore LNG re-gasification terminal.

[172] Pre-Feasibility report for the importation of natural gas into the Western Cape with specific focus on the Saldanha Bay-Cape Town corridor – Economic Model

[173] Fundamentals of the Global LNG Industry/International Gas Union – World LNG Report, 2011

[174] Excelerate Energy Webpage – (excelerateenergy.com)



Source: Groupe International Des Importateurs De Gas Naturel Liquèfiè

Figure 20

Offshore LNG Receiving Terminal

One of the alternatives to the conventional onshore LNG offloading terminals is the Energy Bridge concept which combines LNG shipping, storage and re-gasification on ocean-going LNG vessels. Along with a Floating Storage and Regasification Unit (FSRU), a buoy and mooring system, it is an innovative application of proven technologies[175] that allows gas to be delivered to coastal markets through a subsea pipeline.

With this new LNG receiving system, and various variants thereof, gas from remote regions can be delivered to markets worldwide. Typically, the Energy Bridge installation will use an offshore permanently moored submerged receiving terminal. The terminal comprises a submerged demountable buoy, a flexible marine riser and a submerged mooring system to which a buoy is attached and an FSRU is moored. LNG can also be delivered directly to similar type terminal systems on a rotational basis by LNG Storage and Regasification Vessels (SRV's) i.e. conventional LNG supply vessels adapted with re-gasification capabilities. Importantly, the concept has been proven in the harsh waters of the North Sea and is ideally suited for remote countries and markets which have no existing terminal infrastructure[176]. The system has been proven to be less capital intensive as

[175] Economist – LNG: A Liquid Market, July 2012 - (economist.com/node/21558456)
[176] Excelerate Energy Webpage, Febraury 2013 - (excelerateenergy.com)

demonstrated and discussed below and can be operational in about 3 years[177]. Figure 21 is an animated illustration of transferring LNG from an LNG supply vessel to an FSRU.

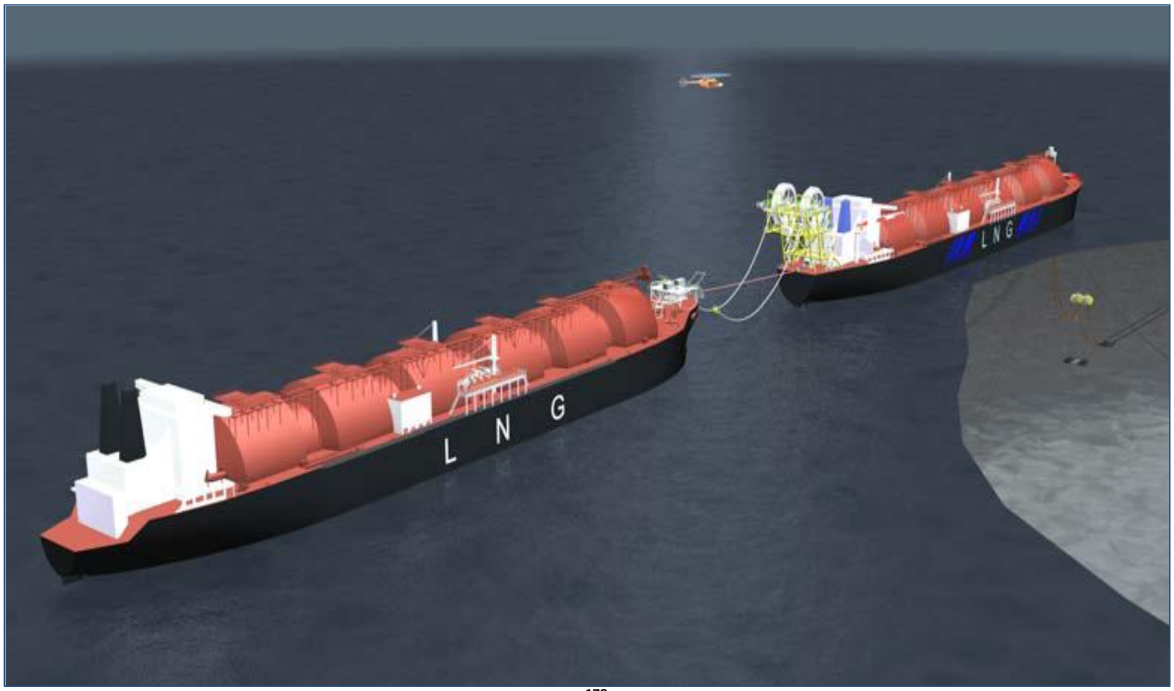


Figure 21[178]

Onshore LNG terminal infrastructure is of a permanent nature and is not suited for shorter term LNG importation schemes or intermediate solution to energy shortages[179]. The Energy Bridge concept is better suited for shorter term solutions and the offshore infrastructure could be re-deployed to an area where gas is required as an energy source at a later stage[180]. There is however no known reason why it could not become a permanent solution for the storage and re-gasification requirements of an LNG importation scheme.

6.1.1 Onshore LNG Receiving Terminal

Regasification of LNG deliveries is the final component along the LNG value chain before on-selling of gas to consumers. Traditional LNG receiving terminals are land-based and comprise a ship mooring and unloading area, LNG offloading arms and piping to storage facilities, storage tanks, pumps to move stored LNG, vaporizers to convert the LNG into gas, and pressure and metering facilities

[177] Source: Golar LNG/Blue Water Energy Services
[178] Source: Golar LNG
[179] Source: CBI Energy Solutions
[180] Source: CBI Energy Solutions

measuring the discharge of the facility into the pipeline network for transportation to the markets. Although well proven and widely utilized throughout the world, this receiving method of LNG carries a multitude of difficulties[181] to overcome, especially in a greenfield development, where no natural gas infrastructure exists. These difficulties in many instances carry the risk of delaying first commercial gas deliveries as negotiations and agreements to overcome them could be protracted.

Some of the issues include:

- Availability of harbour infrastructure;
- Availability of land close to a harbour to minimise the length of cryogenic pipeline to storage and re-gasification facilities;
- Safe routing of high-pressure gas pipeline from the terminal;
- The proximity of a hazardous installation to residential areas presenting a number of potential significant issues, including possible conflict with spatial plans, aesthetic and sense of place concerns, public perceptions of risk, and air quality/health concerns;
- Marine and land environmental issues relating to the establishment of terminal infrastructure and port shipping activities;
- High capital cost requirements of dredging and establishing a suitable harbour for offloading LNG. Sediment movement could further necessitate constant dredging resulting in increased operational cost;
- Proximity of suitable markets to ensure competitive pricing; and
- High capital cost requirements for the offloading jetty, storage tanks and re-gasification plant.

In a study conducted in 2007/8 by Pace Global Energy Services[182] the Port of Saldanha Bay was used as one of the potential LNG receiving terminals for importing LNG to South Africa. The study indicated that some of the issues highlighted above could be applicable to an LNG terminal development in Saldanha Bay although none posed insurmountable or fatally flawed. It mainly carried the potential of added time and costs to establishing an LNG importation terminal.

[181] Pace Global Energy Services - South Africa Natural Gas Utilization - LNG Analysis (2008?) , PetroSA
[182] Pace Global Energy Services - South Africa Natural Gas Utilization - LNG Analysis (2008?) , PetroSA

6.1.1.1 Typical Cost Estimate

The costs of building re-gasification or LNG receiving terminals show a wide variation in cost and design and are very site-specific[183]. The size and materials used in the construction of the LNG storage tanks are a major cost determinant for re-gasification terminals and could either be double skinned steel or full containment reinforced concrete outer shells. Where storage tanks are close to population centers safety would be a prime concern and steel-reinforced concrete tanks would be used to address them[184].

During the study conducted by Pace Global Energy Services on the importation of LNG to Saldanha Bay, the type and sizing of the storage tanks, which accounts for approximately thirty percent of the total cost of a land-based LNG receiving terminal, have been selected as a sensitivity analysis for a near similar LNG importation requirement as this study. Two 150 000m^3 steel-reinforced concrete tanks have been provided for in the cost estimation which made provision for future market growth and an allowance for minimum LNG tank volume requirements between LNG tanker deliveries.

Other above-ground plant and equipment allowed for in their cost estimation included the LNG unloading system, vaporisation racking system, pressurisation plant and metering systems.

The cost requirements for the onshore receiving terminal in the Pace Global Energy Study amounted to US$380 million.

Annual operating costs for an onshore LNG receiving terminal are generally included to be 6 percent (approximately US$23 million per annum) of the capital expenditure on the plant[185].

6.1.2 Offshore LNG Receiving Terminals

An alternative to the more traditional onshore LNG receiving terminal comprise the importation of LNG via marine technology to an offshore submerged receiving terminal. The terminal is made up of a submerged demountable buoy, a flexible marine riser and a submerged mooring system to which the buoy is attached and a Floating Storage and Regasification Unit (FSRU) are moored (Figure 22). An FSRU is typically a modified LNG vessel with storage capability ranging between

[183] Pace Global Energy Services - South Africa Natural Gas Utilization - LNG Analysis (2008?) , PetroSA
[184] Pace Global Energy Services - South Africa Natural Gas Utilization - LNG Analysis (2008?) , PetroSA
[185] Pace Global Energy Services - South Africa Natural Gas Utilization - LNG Analysis (2008?) , PetroSA

125 000m^3 to 180 000m^3 [186] with re-gasification units retrofitted for re-gasifying LNG at a sufficient rate to meet demand requirements. The demand requirement of the identified markets in this study equates to approximately 227 MMScfd (1.7MMt/a LNG) of gas whilst the send-out capacity of a 138 000m^3 LNG vessel, which was selected as a case study, is approximately 350 MMScfd[187].

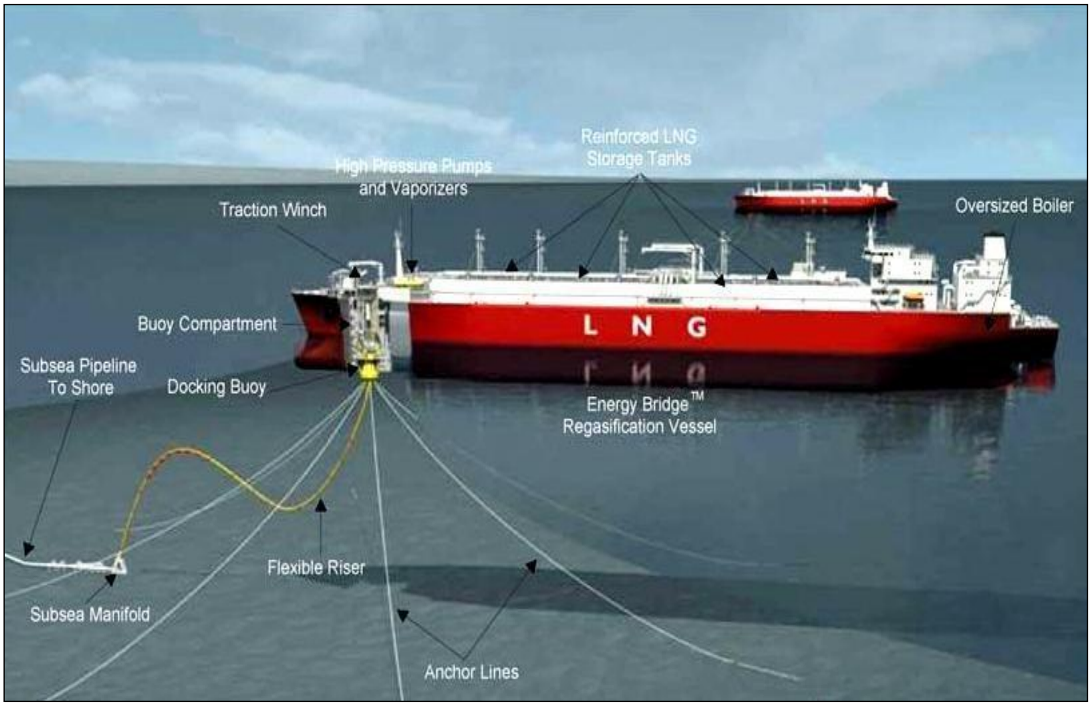


Exhibit 22[188]

This methodology is well suited to countries which lacks natural gas infrastructure and utilizes available technologies in a manner which has proved to be approximately half the capital cost[189] to conventional infrastructure for onshore LNG terminals.

An LNG importation scheme with similar delivery parameters to this report was studied[190] in 2010/11 for the importation of LNG to the Cape West Coast region where LNG would be delivered to a receiving terminal situated offshore between

[186]Golar LNG – Feasibility of an Offshore FSRU System for the Cape West Coast, 2011
[187]Eni Saipem/Mossmaritime – LNG FSRU Nominal Gas Send Out (Stalforbund.com/Norsk_Offshoredag/LNG)
[188]Golar LNG – Feasibility of an Offshore FSRU System for the Cape West Coast, 2011
[189]Source: CBI Engineering Solutions
[190]Gigajoule Africa – NERSA License Application for the Distribution and Trading of Natural Gas in the Cape West Coast Region (2010)

Duynefontein and Yzerfontein[191]. The basis of the study was the supply of LNG via conventional, slightly modified, LNG shuttle tankers to a permanently moored FSRU where it would be re-gasified and delivered into a transmission pipeline network to meet the volumes required by gas off takers. The configuration of the receiving terminal and the logistics surrounding the supply vessel turnarounds were such that sufficient volumes of LNG would be in storage in the FSRU at any one time to continuously deliver gas into the network.

6.1.2.1 Typical Costs Estimate

Approximate costs for a single buoy submerged receiving terminal which includes a submerged demountable buoy, a flexible marine riser and a submerged mooring system and the installation thereof was estimated at approximately US$135 million[192].

The estimated costs for an offshore LNG submerged terminal are summarized in Table 13.

Offshore LNG Receiving Terminal –Approximate Capital Costs	
	US$
Buoy System	106 000 000
Owners Costs[193]	29 000 000
Total	***135 000 000***

Table 13

Operational costs are made up of costs relating to the Ports Authorities, the FSRU daily charter rate, maintenance and insurance requirements. Current daily FSRU charter rates for a 138 000m^3 sized vessel are estimated between US$130 000 and US$140 000[194][195]. Estimated Port Authority charges for attending operational activities during LNG transfer operations and inspections amount to an additional

[191] Item 3.3.1 - Pre-feasibility Study Framework and Assumptions/Gas Receiving Terminals
[192] Internal Cost Estimation
[193] Owner's Costs – Class Certification, Third Party Services, Project Management, Construction Management, Commissioning & Start-up, Land-based Operation Facilities; Travel, Insurances, Foreign Exchange Hedging, Maintenance Spares & Special Tools and Project Financing
[194] ICIS – "Petrobras confirms Excelerate as FSRU Supplier", February 2013 - (icis.com/LNG)
[195] Hoegh – Lithuania FSRU, February 2013 - (hoeghlng/regas/Lithuania)

US$10 000 per day[196][197] bringing the estimated total daily operational costs for offshore terminal operations to between US$140 000 and US$150 000.

6.1.3 Transmission Pipeline Network

The two LNG receiving terminal positions resulted in different transmission pipeline networks necessary to supply gas to the Saldanha Bay, Atlantis and Cape Town regions. The first position comprise the gas transmission pipelines required from a conventional land-based LNG terminal situated in the Port of Saldanha Bay and the second position from an offshore LNG importation terminal situated between Duynefontein and Yzerfontein[198].

6.1.3.1 Onshore LNG Receiving Terminal

6.1.3.1.1 Gas Transmission Pipeline

The transmission pipeline from a land-based LNG receiving terminal in the Port of Saldanha Bay to the identified markets in Saldanha Bay, Atlantis, Cape Town, Paarl and Wellington would start at the boundary of the receiving terminal and connect to a City Gate[199] near the ArcelorMittal[200] steel plant in Saldanha Bay. The pipeline route would follow the road servitude along the N7 road and the existing Transnet pipeline and Eskom servitudes connecting Saldanha Bay to a City Gate near Atlantis and onwards along the same servitudes from Atlantis to a City Gate in Milnerton near Cape Town. Figure 23 illustrates the pipeline route from Saldanha Bay to Cape Town via Atlantis.

[196] Port Authority Costs –personnel costs, helicopter charges, boat charges, land-based support
[197] Internal estimation
[198] Item 3 - Pre-feasibility Study Framework and Assumptions/Gas Receiving Terminals
[199] Transmission pipeline end terminal with pressure protection and supervisory control and data acquisition facilities
[200] Gigajoule Africa – NERSA License Application for the Distribution and Trading of Natural Gas in the Cape West Coast Region (2010)

Figure 23

The transmission pipeline from Saldanha Bay to Atlantis would comprise 89 kilometres, 558mm high-pressure pipeline[201] from where gas would be delivered to the Ankerlig power station and the industrial areas in Atlantis. The pipeline would continue for approximate 27 kilometres from Atlantis via a 323mm[202] diameter high-pressure pipeline to the City Gate in Milnerton. Table 14 summarises the pipeline diameters and lengths from Saldanha Bay to Atlantis and Milnerton.

[201] Internal estimate
[202] Gigajoule Africa – NERSA License Application for the Distribution and Trading of Natural Gas in the Cape West Coast Region (2010)

Transmission Pipeline - Saldanha, Atlantis, Cape Town		
Pipeline Corridor	**Pipeline Diameter (mm)**	**Pipeline Length (Km)**
Receiving Terminal S/B to Atlantis	558	89
Atlantis to Milnerton	323	27

Table 14

The estimated costs for the main transmission line described above amount to approximately US$122 million[203]. Table 15 indicates the total cost requirements for the different sections from the on-land receiving terminal to the City Gates near Atlantis and Milnerton outside Cape Town.

The cost estimate includes pipeline material, pipeline construction, river and road crossings, servitudes, power protection stations, metering stations and engineering and environmental studies.

Transmission Pipeline – Saldanha Bay, Atlantis, Milnerton – Capital Costs	
	US$
Transmission (Saldanha Bay to Atlantis)	107 700 000
Transmission (Atlantis to Milnerton)	13 700 000
Total	***121 400 000***

Table 15

Typical annual operating costs for gas transmission pipelines are estimated to be 0.25 percent[204] of the capital expenditure on the pipeline.

6.1.3.1.2 Gas Distribution Pipelines

Saldanha Bay

The distribution network from the City Gate in Saldanha Bay to the ArcelorMittal, Exxaro and Duferco industries near Saldanha Bay and adjacent smaller industries comprised 13 kilometres[205] of mainline distribution pipelines along existing road and municipal servitudes.

[203] Internal estimate

[204] Internal estimate – includes annual aerial pipeline surveys, repair work to ground cover of pipelines, replacement of damaged SCADA equipment, replacement of cathodic protection, replacement of valves and equipment at the Power Protection Stations and intelligent pigging of the pipeline

[205] Gigajoule Africa – NERSA License Application for the Distribution and Trading of Natural Gas in the Cape West Coast Region (2010)

Cost estimates[206] for the distribution pipeline from the Saldanha Bay City Gate to the identified gas markets amounts to US$8.45 million which include pipeline material, pipeline construction, road crossings, servitudes, metering stations and engineering and environmental studies.

Typical annual operating costs for gas distribution pipelines are estimated at 0.25 percent[207] of the capital expenditure on the pipeline.

Atlantis

The distribution pipeline serving the industries in the Atlantis industrial hub comprises approximately 8 kilometers of low-pressure pipeline[208] along existing road verges and municipal servitudes

The cost estimate for the distribution pipelines serving the industrial hub in Atlantis amounts to approximately US$5.5 million. Costs include pipeline material, pipeline construction, road crossings, servitudes, metering stations and engineering and environmental studies.

Typical annual operating costs for gas distribution pipelines are estimated at 0.25 percent[209] of the capital expenditure on the pipeline.

Cape Town, Paarl and Wellington

The distribution pipelines necessary to supply gas to the identified markets within the Cape Town metropolis, Paarl and Wellington areas comprise approximately 105 kilometers of low-pressured pipeline[210]. The pipeline network was selected to mainly follow existing roads within the various industrial areas along the road verges to ensure minimum reparation to road, rail and other municipal infrastructure.

Cost estimates for the distribution pipeline network to industries identified in the Cape Town, Paarl and Wellington industrial areas amount to approximately US$75 million. The cost estimate includes pipeline material, pipeline construction

[206] Internal estimate

[207] Internal estimate – includes annual visual pipeline surveys, repair work to ground cover of pipelines, replacement of damaged SCADA equipment, replacement of cathodic protection, replacement of metering station equipment and intelligent pigging of the pipeline

[208] Gigajoule Africa – NERSA License Application for the Distribution and Trading of Natural Gas in the Cape West Coast Region (2010)

[209] Internal estimate – includes annual visual pipeline surveys, repair work to ground cover of pipelines, replacement of damaged SCADA equipment, replacement of cathodic protection, replacement of metering station equipment and intelligent pigging of the pipeline

[210] Gigajoule Africa – NERSA License Application for the Distribution and Trading of Natural Gas in the Cape West Coast Region (2010)

and crossings, distribution servitudes, metering stations and engineering and environmental studies.

Typical annual operating costs for gas distribution pipelines are estimated at 0.25 percent[211] of the capital expenditure on the pipeline.

Table 16 summarises the cost requirements for the distribution pipeline networks in the Saldanha Bay, Atlantis and Cape Town, Paarl and Wellington industrial areas.

Distribution Pipeline - Saldanha, Atlantis, Cape Town – Capital Costs	
	US$
Distribution (Saldanha Bay)	8 450 000
Distribution (Atlantis)	5 500 000
Distribution (Cape Town, Paarl & Wellington)	74 650 000
Total	***88 600 000***

Table 16

In summary, the estimated costs for the transmission and distribution infrastructure necessary to transport and distribute natural gas from an onshore LNG receiving terminal in Saldanha Bay to industries in Saldanha Bay, Atlantis, Cape Town, Paarl and Wellington amounts to approximately US$210 million (Table 17).

Onshore LNG Terminal	**Capex (US$ million)**	**Opex (US$ million)**
Transmission Network *(Saldanha Terminal, Atlantis, Milnerton)*	121.4	0.25 percent of Capex/a
Distribution Network *(Saldanha, Atlantis, Cape Town, Paarl, Wellington)*	88.6	0.25 percent of Capex/a
Total	***210.0***	

Table 17

[211] Internal estimate – includes annual visual pipeline surveys, repair work to ground cover of pipelines, replacement of damaged SCADA equipment, replacement of cathodic protection, replacement of metering station equipment and intelligent pigging of the pipeline

6.1.3.2 Offshore LNG Receiving Terminal

The pipeline infrastructure necessary from an offshore LNG receiving terminal position considers the phased development of the transmission pipeline and related infrastructure necessary for transporting natural gas from an offshore terminal between Duynefontein and Yzerfontein to industries in Saldanha Bay, the Ankerlig power station near Atlantis, the Atlantis industrial area and the industrial areas of Cape Town, Paarl and Wellington where:

- Phase 1 comprise the pipeline infrastructure to the Ankerlig power station, the Atlantis industrial area and the industrial areas of Cape Town, Paarl and Wellington; and
- Phase 2 comprise the extension of the infrastructure from the intersection of the on-land pipeline section from the offshore terminal and the pipeline to Atlantis to include industries in Saldanha Bay.

Figure 24 illustrates the pipeline network for Phase 1.

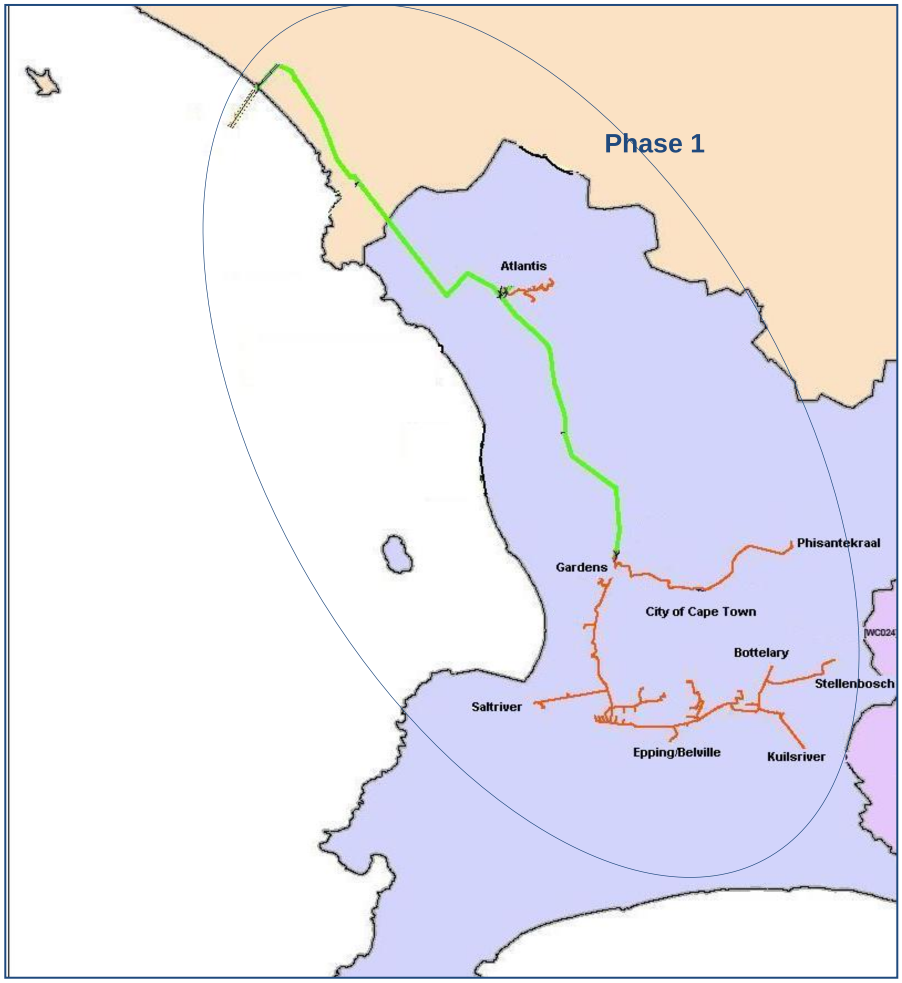


Figure 24

6.1.3.2.1 Gas Transmission Pipelines and Costs – Phase 1

For the first phase, the construction of the transmission pipeline would start at the offshore submerged receiving terminal and continue to a City Gate[212] near Atlantis and onwards to a similar facility near Milnerton. The gas pipeline would comprise an offshore pipeline section from the terminal to shore where it would tie into an onshore transmission pipeline network at a point situated close to the offshore pipeline landfall position between Duynefontein and Yzerfontein[213]. The transmission pipeline would run along existing Eskom, road and Transnet pipeline servitudes[214] to Atlantis and Milnerton from where gas would be distributed

[212]Transmission pipeline end terminal with pressure protection and supervisory control and data acquisition facilities
[213]Item 3 - Pre-feasibility Study Framework and Assumptions/Gas Receiving Terminals
[214]Gigajoule Africa – NERSA License Application for the Distribution and Trading of Natural Gas in the Cape West Coast Region (2010)

through the respective pipeline distribution networks to the identified industries in Atlantis, the Cape Metropolis, Paarl and Wellington.

In a recent study[215] for a gas importation scheme with similar LNG supply methodologies and gas markets to this study, the transmission pipeline from the offshore terminal comprised a 508mm diameter, 8 kilometers[216] long offshore export transmission pipeline delivering gas from the offshore terminal to a pipeline landfall position between Duynefontein and Yzerfontein. The gas was further transported through a similarly sized onshore pipeline over 34 kilometers to a City Gate near Atlantis. The transmission pipeline onwards from Atlantis to the Milnerton City Gate comprised a 323mm diameter pipeline approximately 27 kilometers in length.

Table 18 summarizes the pipeline sizes and approximate lengths to connect the offshore terminal and the City Gates in Atlantis and Milnerton.

Offshore & Onshore Transmission Pipeline (Phase 1)		
Pipeline Corridor	**Pipeline Diameter (mm)**	**Pipeline Length (Km)**
Receiving Terminal to shore	508	8
Shore to Atlantis City Gate	508	34
Atlantis to Milnerton City Gate	323	27

Table 18

The estimated costs[217] for the main transmission line described above amount to approximately US$62 million. Table 19 indicates the total cost requirements for the different sections from the receiving terminal to the proposed landfall position between Duynefontein and Yzerfontein and the respective City Gates near Atlantis and Milnerton. The cost estimate includes pipeline material, pipeline construction, river and road crossings, servitudes, power protection stations, metering stations and engineering and environmental studies.

[215] Gigajoule Africa – NERSA License Application for the Distribution and Trading of Natural Gas in the Cape West Coast Region (2010)
[216] Position determined by water depth requirements for FSRU operations – Golar LNG
[217] Internal cost estimation

Offshore & Onshore Transmission Pipeline (Phase1) – Capital Costs	
	US$
Subsea pipeline	9 700 000
Transmission (Coast to Atlantis)	38 300 000
Transmission (Atlantis to Cape Town)	13 700 000
Total	***61 700 000***

Table 19

Typical annual operating costs for gas transmission pipelines are estimated at 0.25 percent[218] of the capital expenditure on the pipeline.

6.1.3.2.2 Gas Distribution Pipelines and Costs - Phase 1

The distribution pipelines necessary to supply gas to the identified markets within the Cape Town metropolis, Paarl and Wellington areas comprise approximately 105 kilometers of low-pressured pipeline of varying diameters[219]. The pipeline network was selected to mainly follow existing roads within the various industrial areas along the road verges to ensure minimum reparation to road, rail and other municipal infrastructure.

In Atlantis the distribution pipeline into the region's industrial hub comprised approximately 8 kilometers of low-pressure pipeline[220] along existing road verges.

[218] Internal estimate – includes annual aerial pipeline surveys, repair work to ground cover of pipelines, replacement of damaged SCADA equipment, replacement of cathodic protection, replacement of valves and equipment at the Power Protection Stations and intelligent pigging of the pipeline

[219] Gigajoule Africa – NERSA License Application for the Distribution and Trading of Natural Gas in the Cape West Coast Region (2010)

[220] Gigajoule Africa – NERSA License Application for the Distribution and Trading of Natural Gas in the Cape West Coast Region (2010)

Figure 25 maps the proposed boundaries of the geographic areas in which gas would be distributed and includes the listed[221] industrial areas of Atlantis, Cape Town, Paarl and Wellington.

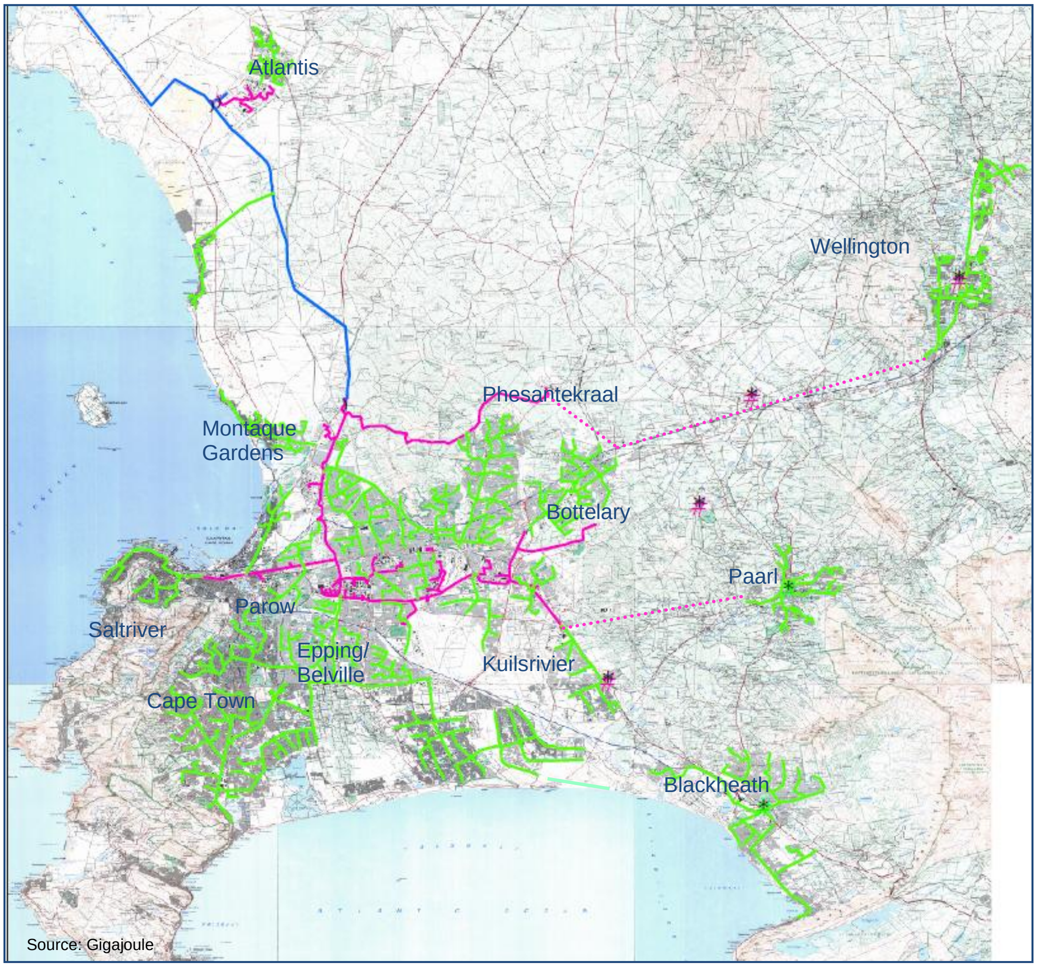


Figure 25

The capital cost requirements for the distribution system serving the Atlantis, Cape Town, Paarl and Wellington industrial hubs amount to approximately US$80 million. Table 20 summarizes the estimated costs[222] for Atlantis and Cape Town and the surrounding areas. The cost estimates include pipeline material, pipeline construction and crossings, distribution servitudes, metering stations and engineering and environmental studies.

[221] Item 4.2 - Gas Market Potential/Atlantis and Cape Town, Paarl and Wellington
[222] Internal cost estimation

Atlantis, Cape Town and Surrounds Distribution Pipeline (Phase 1) – Capital Costs	
	US$
Distribution network (Atlantis)	5 500 000
Distribution network (Cape Town)	74 650 000
Total	***80 150 000***

Table 20

Typical annual operating costs for gas distribution pipelines are estimated at 0.25 percent[223] of the capital expenditure on the pipeline.

6.1.3.2.3 Gas Transmission Pipeline and Costs – Phase 2

Phase 2 of the transmission pipeline comprise an extension of phase 1 described above from the intersection of the on-land pipeline section from the offshore terminal and the pipeline section to Atlantis to a City Gate near the ArcelorMittal[224] steel plant in Saldanha Bay. The pipeline route would follow the road servitude along the N7 road and existing Transnet pipeline and Eskom servitudes connecting Atlantis and Saldanha Bay.

[223] Internal estimate – includes annual visual pipeline surveys, repair work to ground cover of pipelines, replacement of damaged SCADA equipment, replacement of cathodic protection, replacement of metering station equipment and intelligent pigging of the pipeline

[224] Gigajoule Africa – NERSA License Application for the Distribution and Trading of Natural Gas in the Cape West Coast Region (2010)

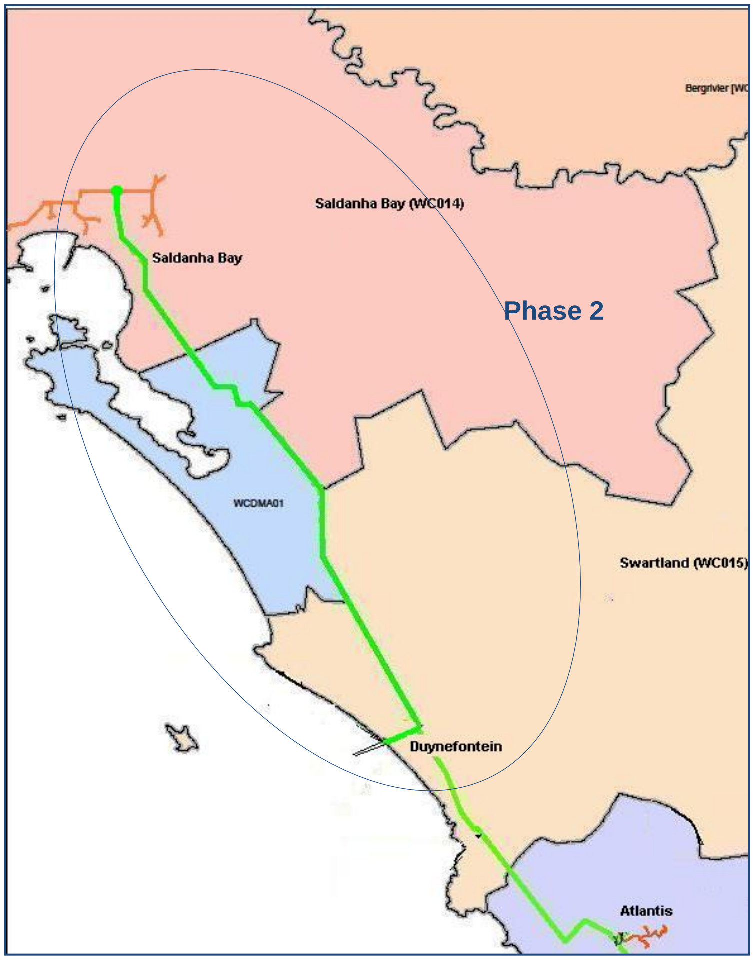


Figure 26

The transmission pipeline for Phase 2 (Figure 26) would comprise approximately 62 kilometres, 508mm high-pressure pipeline[225]. Gas would be fed into the pipeline and transported to Saldanha Bay where it would be reduced in pressure into main line distribution pipelines to the identified markets.

The estimated costs[226] for the main transmission line described above amount to approximately US$71 million. The cost estimate includes pipeline material, pipeline construction, river and road crossings, servitudes, power protection stations, metering stations and engineering and environmental studies.

[225] Gigajoule Africa – NERSA License Application for the Distribution and Trading of Natural Gas in the Cape West Coast Region (2010)
[226] Internal estimation

Typical annual operating costs for gas transmission pipelines are estimated to be 0.25 percent[227] of the capital expenditure on the pipeline.

6.1.3.2.4 Gas Distribution Pipeline – Phase 2

The distribution network to the ArcelorMittal, Exxaro and Duferco industries near Saldanha Bay and adjacent smaller industries comprised 13 kilometres[228] of mainline distribution pipelines along existing road and municipal servitudes.

Cost estimates[229] for the distribution pipeline from the Saldanha Bay City Gate to the identified gas markets amounts to US$8.45 million which include pipeline material, pipeline construction, road crossings, servitudes, metering stations and engineering and environmental studies.

Typical annual operating costs for gas distribution pipelines are estimated at 0.25 percent[230] of the capital expenditure on the pipeline.

In summary (Table 21), the estimated costs for the transmission and distribution infrastructure necessary for the transportation and distribution of natural gas from an offshore LNG receiving terminal to industries in Saldanha Bay, Atlantis, Cape Town, Paarl and Wellington amount to approximately US$222 million.

Offshore LNG Terminal	Capex (US$ million)	Opex (US$ million)
Transmission Network		
Phase 1 (Terminal, Atlantis, Milnerton)	61.7	0.25 percent of Capex/a
Phase 2 (Atlantis, Saldanha Bay)	71.0	0.25 percent of Capex/a
Distribution Network		
Phase 1(Atlantis, Cape Town, Paarl, Wellington)	80.2	0.25 percent of Capex/a
Phase 2 (Saldanha Bay)	8.5	0.25 percent of Capex/a
Total	***221.4***	

Table 21

[227] Internal estimate – includes annual aerial pipeline surveys, repair work to ground cover of pipelines, replacement of damaged SCADA equipment, replacement of cathodic protection, replacement of valves and equipment at the Power Protection Stations and intelligent pigging of the pipeline

[228] Gigajoule Africa – NERSA License Application for the Distribution and Trading of Natural Gas in the Cape West Coast Region (2010)

[229] Internal estimate

[230] Internal estimate – includes annual visual pipeline surveys, repair work to ground cover of pipelines, replacement of damaged SCADA equipment, replacement of cathodic protection, replacement of metering station equipment and intelligent pigging of the pipeline

7.0 LNG Importation – Typical Schedule of Implementation

A typical schedule of implementation for a greenfield LNG importation scheme comprise two main activity periods; the planning and permitting period where the importation of natural gas to the Cape West Coast region is promoted and planned by the participating parties up to a Final Investment Decision (FID) and the necessary licences and permits are obtained, and the Engineering Procurement and Construction (EPC) period where the construction of the LNG importation terminal, transmission and distribution pipelines and associated infrastructure are completed to a point ready for first commercial gas deliveries.

During the planning and permitting period the participating parties will conduct all the necessary pre-feasibility studies, the required Environmental Impact Assessment (EIA), NERSA licensing requirements, governmental permitting, funding requirements and legal negotiations. These activities have been scheduled to be completed in a two-year period ending in December 2014.

Some of the key milestone achievements during the planning and permitting period, which could ultimately influence the start date of first commercial gas deliveries, include:

- Obtaining agreement with Eskom regarding the conversion of the Ankerlig power station outside Atlantis to a gas-fired facility;
- The necessary permitting and licences required by South African governmental authorities, especially the issuing of the necessary licences by the National Energy Regulator of South Africa (NERSA); and
- The approval of the Environmental Impact Assessment (EIA) for the project without which governmental approvals[231] to proceed will be withheld;

Completion dates for the construction and commissioning of the required infrastructure for the two different LNG terminal options have been estimated as follows:

Option 1 The first option comprise the construction of an onshore LNG receiving terminal situated in the Port of Saldanha Bay, 116 kilometres of transmission pipeline from the terminal to the City Gates in Atlantis and Milnerton and 126 kilometres of distribution network supplying the natural gas to the identified industrial markets in Saldanha Bay, Atlantis and Cape Town, Paarl and Wellington. The construction period for the onshore terminal was estimated

[231]NERSA, Department of Environment, Department of Energy & others

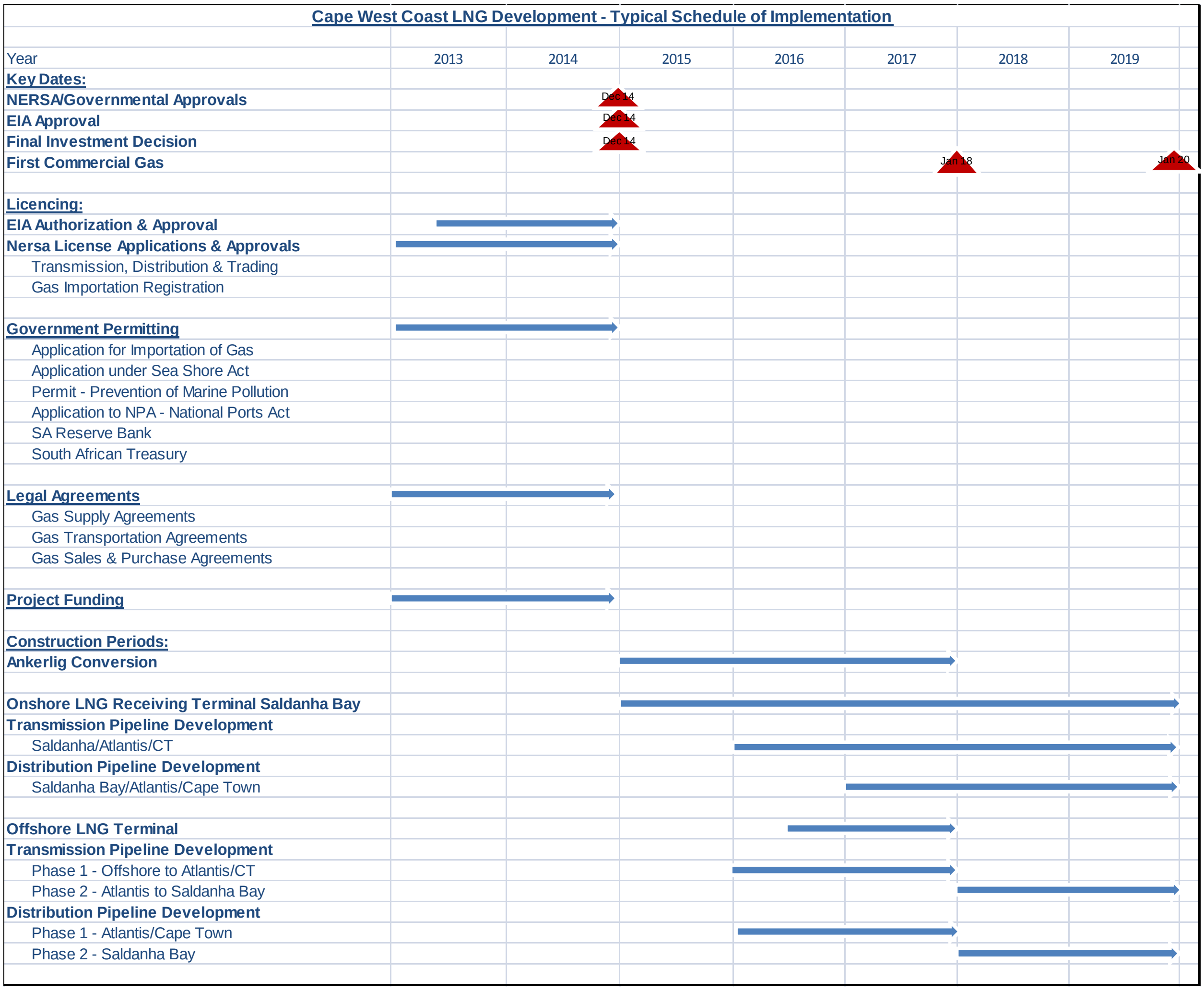
at five years[232] to complete making first commercial gas available in January 2020.

Option 2 The second option reviewed comprised the delivery of LNG to an offshore semi-submersible LNG terminal situated offshore between Duynefontein and Yzerfontein where the transmission and distribution infrastructure would be constructed in a phased manner and where:

- Phase 1 would comprise the planning and construction of an offshore LNG receiving terminal, an 8 kilometre section of offshore pipeline, 62 kilometres of onshore pipeline from the offshore pipeline landfall position between Duynefontein and Yzerfontein to the City Gates in Atlantis and Milnerton and a 113 kilometres distribution pipeline network to the identified industrial hubs in Atlantis, Cape Town, Paarl and Wellington. A lead time for the EPC period for phase 1 has been estimated at three years[233] making first commercial gas deliveries available to the identified markets in these regions by January 2018; and
- Phase 2 would comprise the extension of the pipeline infrastructure from the intersection of the on-land pipeline section from the offshore terminal and the pipeline section to Atlantis to Saldanha Bay which would include the construction of a 69 kilometre long transmission pipeline and 13 kilometres of distribution pipeline network in Saldanha Bay. The start of phase 2 was included to be concurrent with the completion of phase 1 with first commercial gas deliveries to Saldanha Bay scheduled two years thereafter in January 2020.

[232] Source: CBI Engineering Solutions
[233] Gigajoule Africa – NERSA License Application for the Distribution and Trading of Natural Gas in the Cape West Coast Region (2010)

Schedule 2 is a typical timing framework of pre- and post FID activities necessary for the importation of LNG to the Cape West Coast region.



Schedule 2

8.0 Economic Evaluation

A detailed description of the assumptions and parameters for each of the cases evaluated are described in Annexure B. The summary description below highlights the key assumptions and conclusions of the economic evaluation for the cases evaluated.

The potential commerciality of the various gas (LNG) importation options was evaluated with reference to a number of different scenarios and permutations thereof. The scenarios were compiled of a number of input assumptions which included:

- *LNG Supply Source*
  - LNG importation from Mozambique was included in all cases.
- *LNG Receiving Terminals*
  - *Land-based Receiving Terminal* - The Port of Saldanha Bay; and
  - *Offshore Receiving Terminal* – A location approximately 8 kilometres offshore between Duynefontein and Yzerfontein.
- *Industrial Markets*
  - The industrial markets in Atlantis and Cape Town, Paarl and Wellington were included in all cases; and
  - The Saldanha Bay industrial markets were included for all the onshore terminal cases and as an option (Phase 2) for the offshore terminal cases.
- *Power Generation*
  - The conversion of Eskom's existing Ankerlig power station was included for the Base Cases;
  - Additional gas-fired power generation at Milnerton was included for 800 MWe and 1 000 MWe generating capacity options. The capital and operating costs associated with the power station were not included in the valuation, the assumption being that gas was directly sold as feedstock to the power station; and
  - Additional gas-fired power generation at Saldanha Bay was included as 350 MW and 450 MW generating capacity options. Similarly to Milnerton, the capital and operating costs for the power stations were excluded.

Economic Assumptions

The valuation was done in constant 2013 terms. Both Net Present Value (NPV) and Internal Rate of Return (IRR) were calculated for each case.

Macro assumptions included:

- Project term — 20 years (after first commercial gas sales)
- Discount rate — 8%

USD inflation rate	2.5%
RSA inflation rate	6.0%
ZAR/US$ exchange rate	R8.50
Crude oil price	Brent
Natural Gas Price	NYMEX - Futures, Nominal
Europe Gas Price	EGEX - Futures, Nominal

Fiscal terms included:

Tax rate	28%
Depreciation	5 years straight line

Gas Sales Assumptions

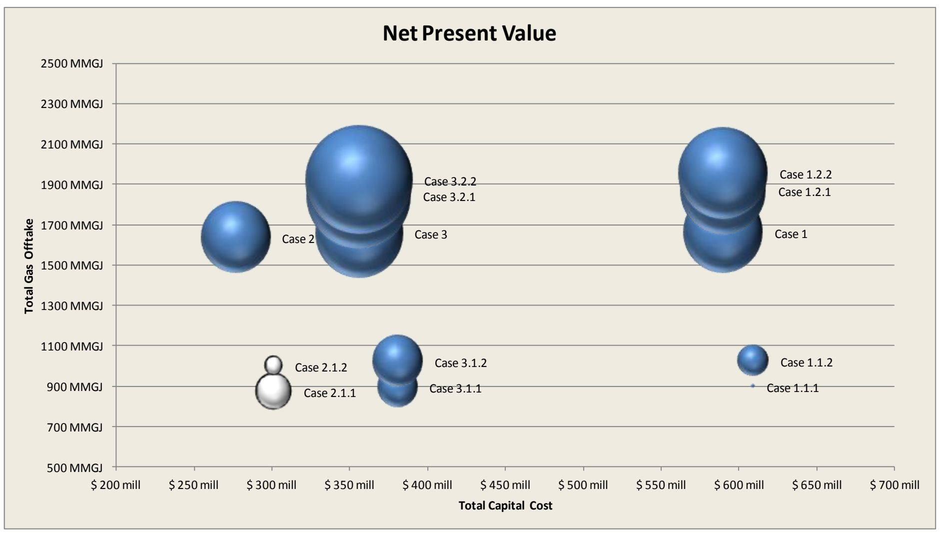
- *Industrial Markets*
  - It was included that gas sales to the industrial markets in Saldanha Bay, Atlantis and Cape Town, Paarl and Wellington would be prices at a discount of 10 percent to their respective current weighted average fuel costs in order to allow comparative results of the various scenarios, and to encourage potential consumers to “switch” their operations to natural gas.
- *Power Generation*
  - Sales to the different gas-fired power plants were priced using a cost build-up approach, assuming a 10 year amortisation of capital cost at a 10 percent interest rate and applying a margin of 10 percent.

The different cases and their results are summarised in Table 22 and Figure 27 below:

Scenarios	Base Case Scenarios			Case 1 Alternatives				Case 2 Alternatives		Case 3 Alternatives			
	Case 1	Case 2	Case 3	Case 1.1.1	Case 1.1.2	Case 1.2.1	Case 1.2.2	Case 2.1.1	Case 2.1.2	Case 3.1.1	Case 3.1.2	Case 3.2.1	Case 3.2.2
LNG Receiving Terminal	Onshore	Offshore	Offshore	Onshore	Onshore	Onshore	Onshore	Offshore	Offshore	Offshore	Offshore	Offshore	Offshore
Phase 1 Construction Start	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015	2015
Phase 2 Construction Start	NA	2018	2018	NA	NA	NA	NA	2018	2018	2018	2018	2018	2018
Phase 2 Included	NA	No	Yes	NA	NA	NA	NA	No	No	Yes	Yes	Yes	Yes
Ankerlig Power Generation	Yes	Yes	Yes	No	No	Yes	Yes	No	No	No	No	Yes	Yes
Milnerton Power Generation	None	None	None	800MW	1,000Mw	None	None	800MW	1,000Mw	800MW	1,000Mw	None	None
Saldanha Power Generation	None	None	None	None	None	350MW	450MW	None	None	None	None	350MW	450MW
LNG Importation Case	Mozambique	Mozambique	Mozambique	Mozambique	Mozambique	Mozambique	Mozambique	Mozambique	Mozambique	Mozambique	Mozambique	Mozambique	Mozambique
Gas Sales Price Case	Constant 2013	Constant 2013	Constant 2013	Constant 2013	Constant 2013	Constant 2013	Constant 2013	Constant 2013	Constant 2013	Constant 2013	Constant 2013	Constant 2013	Constant 2013
Production Life (years post first sales)	20	20	20	20	20	20	20	20	20	20	20	20	20
Model Terms	Constant 2013	Constant 2013	Constant 2013	Constant 2013	Constant 2013	Constant 2013	Constant 2013	Constant 2013	Constant 2013	Constant 2013	Constant 2013	Constant 2013	Constant 2013
Discount Rate	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%

Results	Base Case Scenarios			Case 1 Alternatives				Case 2 Alternatives		Case 3 Alternatives			
	Case 1	Case 2	Case 3	Case 1.1.1	Case 1.1.2	Case 1.2.1	Case 1.2.2	Case 2.1.1	Case 2.1.2	Case 3.1.1	Case 3.1.2	Case 3.2.1	Case 3.2.2
Gross Sales Volume	1660 MMGJ	1635 MMGJ	1657 MMGJ	899 MMGJ	1025 MMGJ	1869 MMGJ	1956 MMGJ	874 MMGJ	1000 MMGJ	897 MMGJ	1023 MMGJ	1844 MMGJ	1921 MMGJ
Gross Sales Revenue	$ 18 747 mill	$ 17 933 mill	$ 18 541 mill	$ 10 987 mill	$ 12 272 mill	$ 20 854 mill	$ 21 731 mill	$ 10 266 mill	$ 11 542 mill	$ 10 875 mill	$ 12 150 mill	$ 20 584 mill	$ 21 369 mill
Effective Sales Price	$ 11.29 /MMBtul	$ 10.97 /MMBtul	$ 11.19 /MMBtul	$ 12.22 /MMBtul	$ 11.97 /MMBtul	$ 11.16 /MMBtul	$ 11.11 /MMBtul	$ 11.74 /MMBtul	$ 11.54 /MMBtul	$ 12.13 /MMBtul	$ 11.88 /MMBtul	$ 11.16 /MMBtul	$ 11.12 /MMBtul
Total Opex	$ 16 467 mill	$ 16 824 mill	$ 17 045 mill	$ 9 138 mill	$ 10 351 mill	$ 18 482 mill	$ 19 321 mill	$ 9 496 mill	$ 10 709 mill	$ 9 716 mill	$ 10 929 mill	$ 18 842 mill	$ 19 590 mill
Total Capex	$ 590 mill	$ 277 mill	$ 356 mill	$ 609 mill	$ 609 mill	$ 590 mill	$ 590 mill	$ 301 mill	$ 301 mill	$ 381 mill	$ 381 mill	$ 356 mill	$ 356 mill
Maximum Exposure	$ 590 mill	$ 281 mill	$ 337 mill	$ 609 mill	$ 609 mill	$ 590 mill	$ 590 mill	$ 311 mill	$ 310 mill	$ 375 mill	$ 373 mill	$ 337 mill	$ 337 mill
Payout (undiscounted, post 1st investment)	11 Years	9 Years	9 Years	12 Years	12 Years	10 Years	10 Years	12 Years	11 Years	11 Years	10 Years	8 Years	8 Years
Undiscounted Net Cash Flows	$ 1 217 mill	$ 599 mill	$ 821 mill	$ 893 mill	$ 945 mill	$ 1 283 mill	$ 1 311 mill	$ 337 mill	$ 383 mill	$ 560 mill	$ 605 mill	$ 998 mill	$ 1 025 mill
Net Present Value @ 8.00%	$ 102 mill	$ 78 mill	$ 124 mill	$ 0 mill	$ 15 mill	$ 121 mill	$ 128 mill	-$ 21 mill	-$ 5 mill	$ 25 mill	$ 41 mill	$ 177 mill	$ 185 mill
Internal Rate of Return	10.2%	11.6%	12.6%	8.0%	8.3%	10.5%	10.7%	7.0%	7.8%	9.0%	9.5%	14.2%	14.4%

Table 22



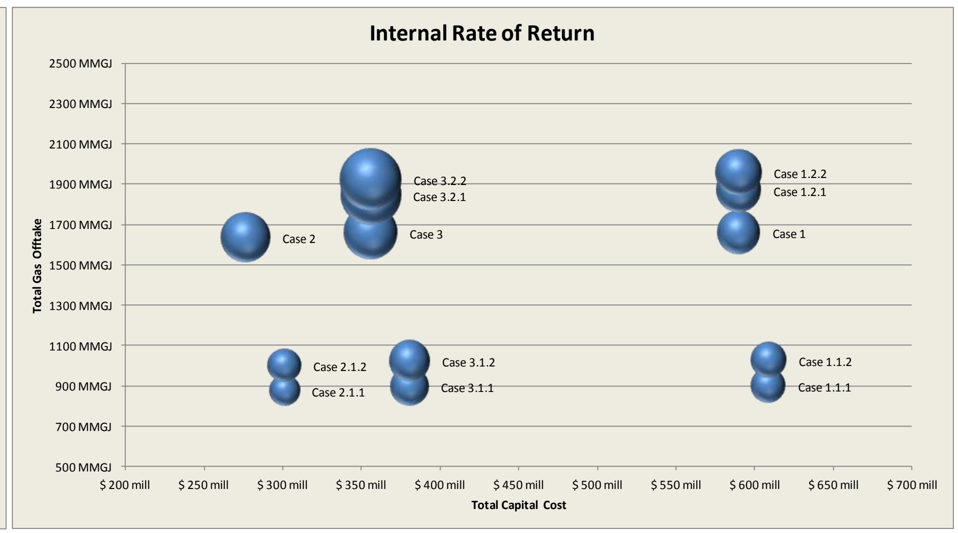


Figure 27

The following key observations were made from a review of the evaluation results:

LNG Receiving Terminal Options

- The offshore LNG receiving terminal option required less capital investment and a shorter lead time for completion than the land-based receiving terminal option. However, with the exclusion of the Phase 2 of the development, this option showed a lower NPV (due to the exclusion of the high value industrial markets Saldanha Bay), but a higher IRR (due to the low up-front capital investment).
- With Phase 2 of the offshore receiving terminal option included, this option realized the highest NPV and IRR of the 3 Base Case scenarios evaluated. The inclusion of Phase 2 added value both in NPV and IRR terms. This was mainly due to the high value (albeit small volume) added by the inclusion of the Saldanha Bay industrial markets.

Power Generation

- The conversion of the Ankerlig power station played an enabling role in the viability of importing natural gas to the West Coast region and added value in all cases evaluated (mainly due to the high gas consumption).
- As a case in point of its importance, Ankerlig was substituted with the gas-fired power station at Milnerton. This substitution destroyed significant value in all cases evaluated due to the significant decrease in gas sales volume and the increase in capital costs (larger diameter transmission pipeline from Atlantis to Milnerton). However, a gas-fired power station at Milnerton in addition to the Ankerlig power station added significant value, as shown in Figure 28 below for the 3 Base Cases[234]:

[234]Annexure B, Page 120 – Economic Model – Assumptions and Parameters, Case Descriptions

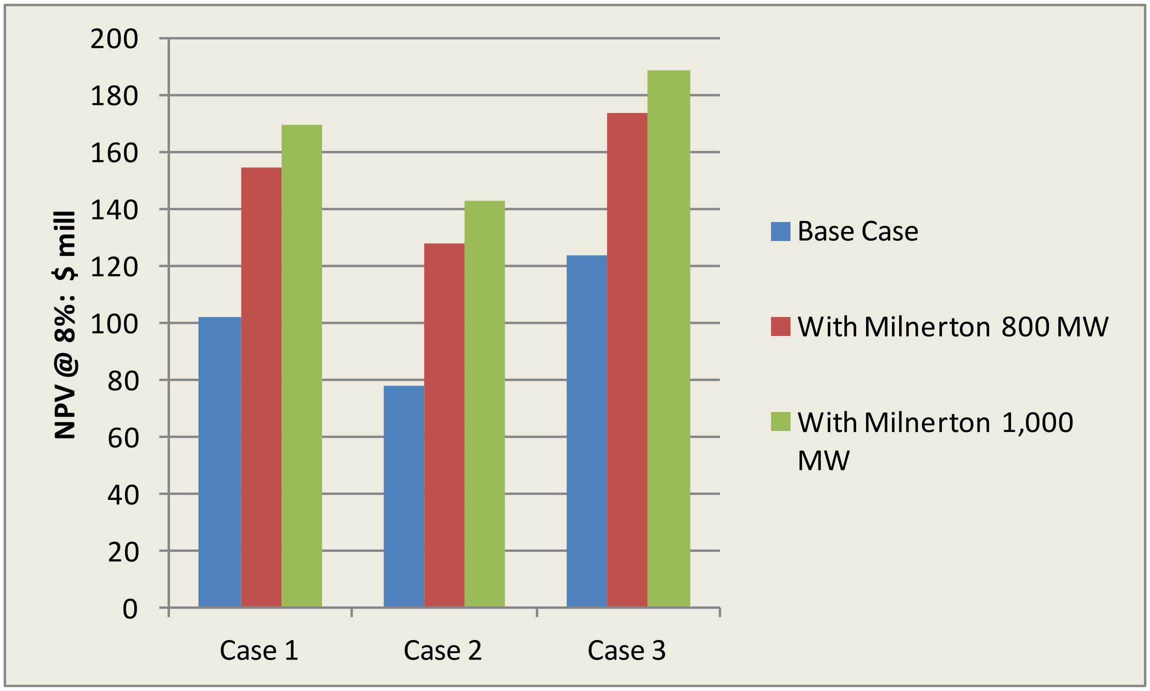

NPV @ 8%: $ mill
200
180
160
140
120
100
80
60
40
20
0
Case 1
Case 2
Case 3
Base Case
With Milnerton 800 MW
With Milnerton 1,000 MW

Figure 28

- The addition of a gas-fired power station at Saldanha Bay added value in all cases (except for the offshore receiving terminal option without Phase 2, where such addition was not possible). This value addition became more pronounced for the offshore terminal case, where the transportation tariff component in the sales price build-up was much higher than for the onshore terminal case.
- Similarly, the addition of gas-fired power generation at Milnerton also added value in all cases.
- The results of all the cases evaluated were based on a 10 percent margin on gas sales to the power plant options. The impact on the IRR when increasing this margin to 15 percent for all cases is illustrated in Figure 29 below.

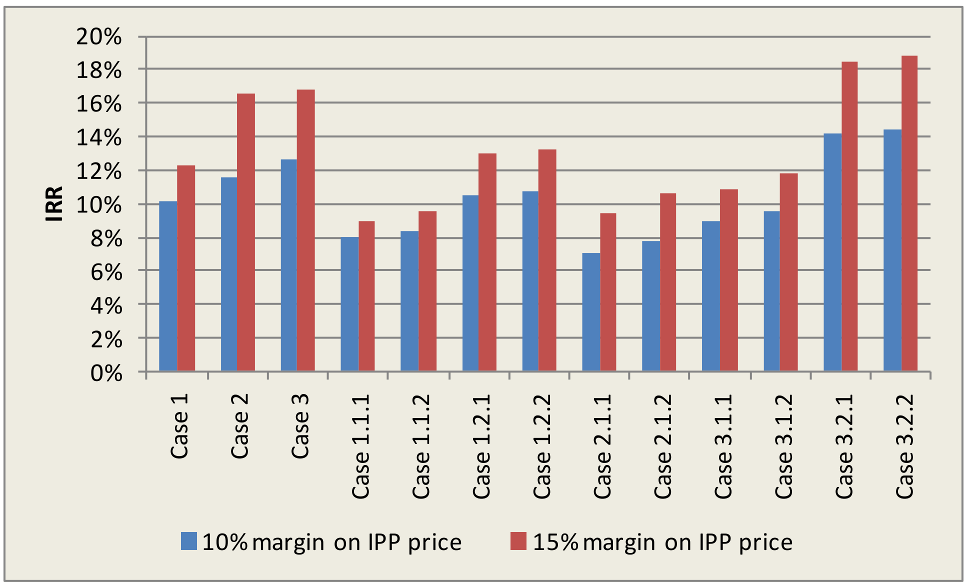


Figure 29

LNG Supplies

These results all included LNG supplied from Mozambique, which is the closest of the alternative locations and therefore resulted in the cheapest landed cost in the Saldanha Bay region. Although the results above do not show the impact of alternative supply sources of LNG, it can be expected that:

- Sales to the industrial markets would be negatively impacted by the higher landed cost; and
- Sales to the power stations would be positively impacted due to the cost build-up pricing with a 10 percent margin on the landed cost.

The net effect, as shown graphically in Figure 30 below for Case 3, was shown to be negative:

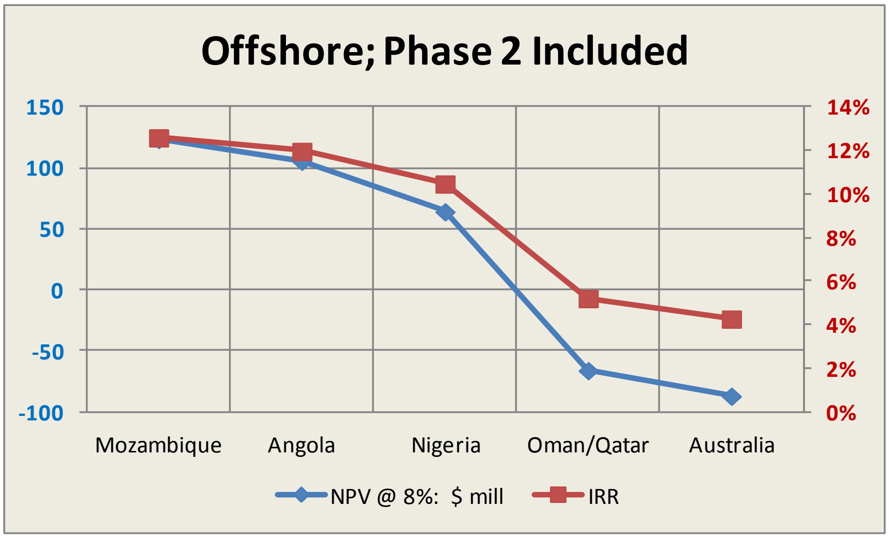


Figure 30

Economic Sensitivity Analysis

An economic sensitivity analysis was conducted on all Cases considered to determine the impact of the major input criteria, which included the gas sales volumes, gas sales prices, the capital and operational expenses and the gas purchase prices, on the economic valuation. A production life sensitivity was further done to demonstrate the effect of changes in the IRR and NPV over the proposed project period.

Although input criteria and production life sensitivities were conducted for all Cases, the three Base Cases (Cases 1, 2 & 3) were used to demonstrate the results of the analysis. The Sensitivity Diagrams (Figures 31, 33 & 35) and Production Life Sensitivities (Figures 32, 34 & 36) are shown below for Cases 1, 2 & 3 respectively.

Base Case 1

Base Case 1 - the importation of LNG through a land-based LNG receiving terminal in the Port of Saldanha Bay with the associate pipeline infrastructure to industries in Saldanha Bay, Atlantis, Cape Town, Paarl and Wellington. The conversion of the Ankerlig power station in Atlantis has been included in the case evaluation.

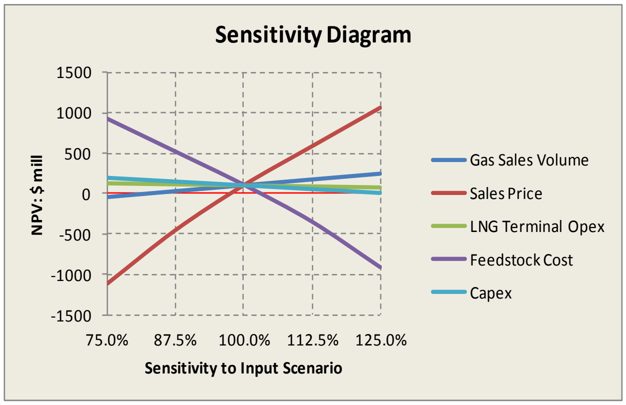


Figure 31

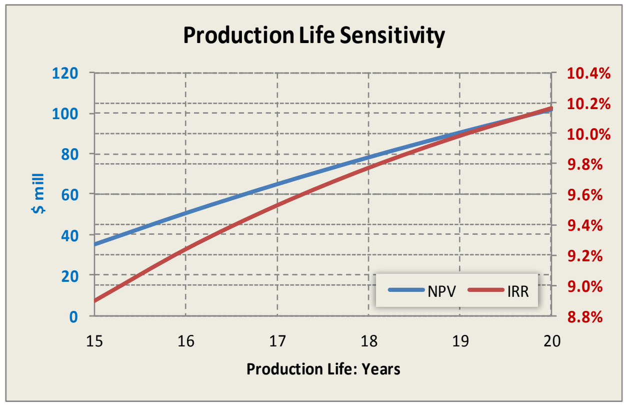


Figure 32

Base Case 2

Base Case 2 - the importation of LNG through an offshore receiving terminal and the associated pipeline infrastructure for Phase 1 to industries in Atlantis, Cape Town, Paarl and Wellington. The conversion of the Ankerlig power station has been included in the case evaluation.

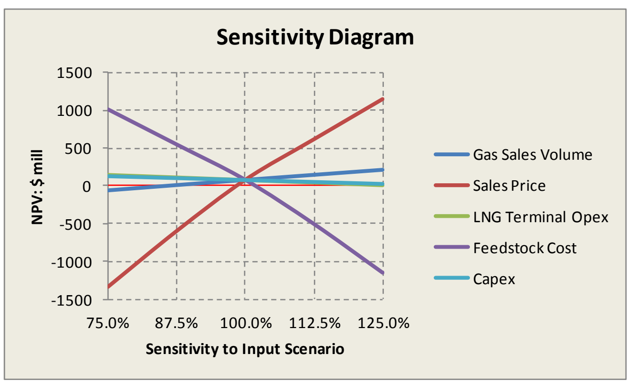


Figure 33

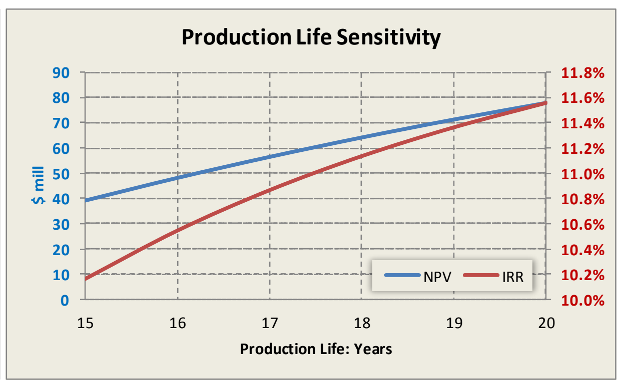


Figure 34

Base Case 3

Base Case 3 - the importation of LNG through an offshore receiving terminal and the associated pipeline infrastructure for Phases 1 and 2 to industries in Saldanha Bay, Atlantis, Cape Town, Paarl and Wellington. The conversion of the Ankerlig power station has been included in the case evaluation.

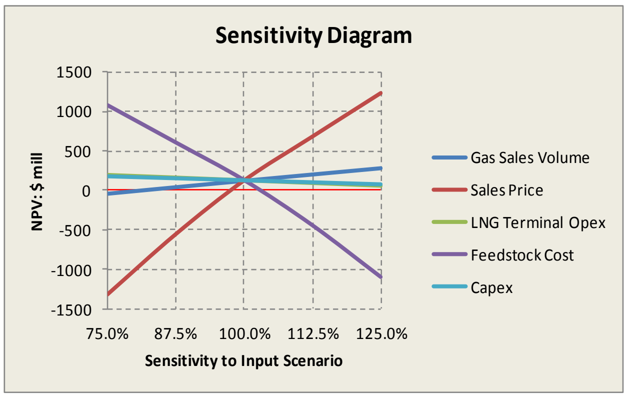


Figure 35

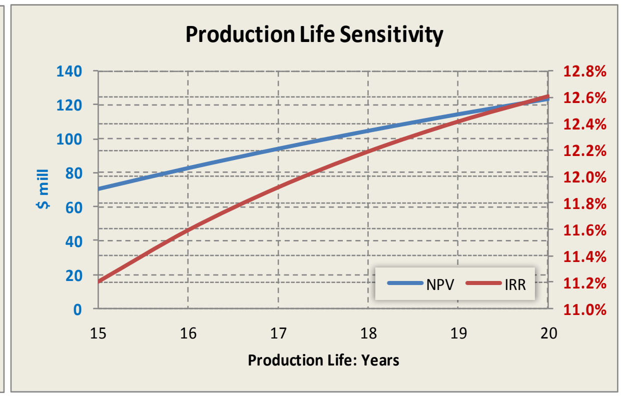


Figure 36

The following main observations were made from a review of the Sensitivity Diagrams and Production Life Sensitivity graphs:

- The landed gas price from LNG suppliers and gas sales prices to industry, especially for gas-fired power generation, are the two most sensitive input criteria to the NPV valuation;
- Changes to the capital and operational costs are less sensitive to NPV changes mainly due to the long (20 years) amortization period of equipment;
- A ±25% change in gas sales volumes has a minimal effect on the project NPV; and
- An increased NPV and IRR would be obtained towards the latter part of the project and would increase should the operational period be extended beyond 20 years.

9.0 Study Conclusion

This study highlighted the dependency of the Cape West Coast region on the importation of nearly all its energy requirements and the need for introducing an alternative affordable energy source to stimulate industrial growth and the accompanying commercial and social benefits it might bring. An analysis of the primary energy feedstock currently used by industry showed its complete reliance on coal, fuel oils, LPG and diesel for its operations, all of which are fully or partly imported to the region at great costs. The analysis further indicated that the Western Cape remained dependent on the importation of more than fifty percent of its daily peak electricity requirements. It demonstrated the region to basically be starved of alternative, affordable and reliable energy/electricity for existing industries and potential industrial growth.

This study therefore reviewed the various contributing factors for importing natural gas as an alternative energy source for industrial usage and power generation. These factors, individually and as a whole, contributed to assessing the technical and commercial viability of a natural gas importation scheme and were segmented into three main sections; the gas market potential in the Cape West Coast region, potential natural gas supply sources and the infrastructure requirements necessary to transport the natural gas to the downstream markets. The sections are briefly summarized in support of the conclusion at the end of each section:

- *Gas Market Potential* – a thorough understanding of the potential gas markets was required to ensure that its size and value would be sufficient to underpin the large capital and operational cost requirements necessary to establish and maintain the infrastructure required to import, transport and distribute natural gas into the region. In this regards a market review was conducted of the "switchable" industries in the Cape Town, Paarl and Wellington areas, the Atlantis industrial area and the industries in the Saldanha Bay region. Although the total energy consumption of these industrial hubs was found to be high in value, they were insufficient to support the high costs associated with the necessary infrastructure developments.

  The inclusion of gas-fired power generation however, improved the commerciality of a natural gas importation scheme considerably. The conversion of the Ankerlig power station near Atlantis to a gas-fired CCGT facility not only contributed to a significant increase in gas consumption over a long period but also to a sufficient increase in the income necessary to underpin the large associated development costs. Similar results, except for gas-fired power generation in Milnerton as a stand-alone facility i.e. without Ankerlig (Case 1.1.1 under item 8), were obtained when the effect of new gas-fired power plants were assessed, in combination or separately, in Saldanha Bay and/or Milnerton.

The market evaluation of the Cape West Coast region concluded that gas-fired power generation would play an enabling role to the viability of any of the gas importation options evaluated.

- *Potential Gas Supplies* – three potential options for the supply of natural gas to the Cape West Coast region were evaluated which included; indigenous gas supplies from known gas resources or reserves, piped gas from neighbouring or near-neighbouring countries and the supply of LNG.

  The evaluation concluded the importation of LNG to be the most viable gas importation option available. With new LNG liquefaction plants currently under construction in Nigeria and Angola and liquefaction plant(s) planned in Mozambique, the potential of sourcing LNG from these nearby countries carried potential price advantages due to the shorter shipping distances to the Saldanha Bay region. The timing of first planned LNG production from these plants by 2018 also coincided with the planned completion of one of the LNG receiving terminal options reviewed.

  The review of gas supply options to the Cape West Coast region concluded the importation of LNG from Nigeria, Angola and potentially Mozambique to be the most viable of the gas supply options considered.

- *Gas Infrastructure Requirements* – the gas infrastructure comprised an LNG receiving terminal, high-pressure transmission pipelines and a low-pressure gas distribution pipeline network.

  This study evaluated two LNG receiving terminal options and their respective transmission and distribution gas pipeline infrastructure namely;
  - a permanent land-based LNG receiving terminal in the Port of Saldanha Bay; and
  - an offshore semi-submersible LNG receiving terminal between Duynefontein and Yzerfontein.

  The pipeline infrastructure for the land-based LNG receiving terminal was included to be constructed from the terminal to the downstream markets contemporaneously with the construction of the terminal.

The construction of the pipeline infrastructure for the offshore LNG terminal on the other hand was considered in a phased manner where the first phase comprised the pipeline infrastructure necessary to supply the existing industrial areas in Atlantis, the Ankerlig power station and the industrial markets in Cape Town, Paarl and Wellington and the second phase the extension of the gas pipeline infrastructure to include industries in Saldanha Bay.

The most significant conclusions of the different LNG receiving terminal options and their respective transmission and distribution pipeline networks included:

- *Timing of Completion* – the total time required constructing a land-based LNG receiving terminal and its associated gas pipeline infrastructure was estimated at approximately five years. Under this LNG receiving terminal option first commercial gas deliveries was scheduled to commence in *January 2020*.

  The estimated time required for constructing an offshore LNG terminal and its associated gas pipeline infrastructure for Phase 1 of this development option amounted to three years, making first commercial gas deliveries available in *January 2018*. Phase two of the development made first commercial gas deliveries available in Saldanha Bay two years later in *January 2020*.
- *Cost of Completion* – the capital costs for the land-based LNG receiving terminal was estimated at approximately US$ 380 million with an additional estimated US$ 210 million for the associated gas transmission and distribution pipeline network. The total estimated capital costs required for the onshore LNG terminal option therefore amounted to *US$ 590 million*.

  The capital cost estimation for the offshore LNG receiving terminal amounted to approximately US$135 million. In addition, the estimated costs for the transmission and distribution pipeline networks for phase one amounted to approximately US$142 million giving a total first phase development cost of *US$277 million.*

  The inclusion of phase two resulted in an additional capital expenditure of approximately US$80 million bringing the capital expenditure for Phase 1 and Phase 2 for the offshore LNG receiving terminal option to about *US$ 360 million*.

Table 23 summarises the scheduling and costs of the terminal options.

LNG Terminal Options – Timing & Costs Summary				
	First Commercial Gas	**Terminal (US$ million)**	**Pipeline Infrastructure**	**Total Capital Costs (US$ million)**
Onshore LNG Terminal	**Jan 2020**	**380**	**210**	**590**
Offshore LNG Terminal				
Phase 1	**Jan 2018**	**135**	**142**	**277**
Phase 2	**Jan 2020**		**80**	**360**

Table 23

The review of the two LNG receiving terminal options and their respective transmission and distribution gas pipeline networks concluded that the importation of LNG through an offshore semi-submersible LNG terminal and the phased development of the gas pipeline transmission and distribution infrastructure would result in the shortest lead time for making first commercial gas available to the major existing downstream markets at lowest capital cost requirements.

- *Economic Evaluation* - the valuation of the different LNG importation and market scenarios described in Table 17 under item 8 highlighted five key conclusions:

  - The offshore LNG receiving terminal option required less capital investment and a shorter lead time for completion than the land-based receiving terminal option;
  - The offshore receiving terminal option (including Phase 2) realized the highest NPV and IRR of the three Base Case scenarios evaluated;
  - The substitution of the Ankerlig power station with a gas-fired power station at Milnerton destroyed significant value in all cases evaluated. However, a gas-fired power station at Milnerton in addition to the Ankerlig power station, added significant value;
  - The increase in the margin of gas sales to all gas-fired power plant options contributed substantially to an improved project IRR in all cases evaluated; and
  - The addition of a gas-fired power station at Saldanha Bay added value in all applicable cases.

The review of the economic analysis of the various LNG importation and market scenarios concluded the offshore LNG receiving terminal option (Phase 2 included) to be commercially the most viable and that the inclusion of the Ankerlig power station contributed added value to all options evaluated.

The introduction of natural gas as an alternative energy feedstock to the Cape West Coast region will relieve its dependency on the importation of most of its energy requirements and serve as catalyst for industrial development in the region with all the accompanying commercial and social benefits. This study has clearly indicated the requirement for additional, affordable and reliable energy and/or electricity, especially in the Saldanha Bay region, to stimulate planned industrial expansion programs and the establishment of future new business opportunities. The economic evaluation has demonstrated natural gas to be price-competitive to the weighted average cost of current energy sources but has highlighted the enabling role that existing or potential future gas-fired power generation would play as an anchor gas off taker, without which a gas importation scheme is unlikely to succeed.

Of further importance is the current window of opportunity for the supply of LNG from liquefaction plants under construction in Nigeria and Angola and those planned in Mozambique, all of which could provide LNG at more competitive prices due the short transportation distances from Saldanha Bay by 2018.

Annexure A
Estimated Levelized and Normalized Electricity Costs – Saldanha Bay & Milnerton

Case: Saldanha Bay – 350 MWe

Estimated Levelized Costs[235] - Gas-fired Power Generation (Saldanha Bay 350 MWe)

	Offshore LNG Terminal (Between Duynefontein & Yzerfontein)		**Onshore LNG Terminal (Saldanha Bay)**	
	LNG Landed Price (US$10/MMBtu)	**LNG Landed Price US$15/MMBtu**	**LNG Landed Price (US$10/MMBtu)**	**LNG Landed Price US$15/MMBtu**
Total Capex[236]	ZAR 2.75 billion	ZAR 2.75 billion	ZAR2.75 billion	ZAR 2.75 billion
Total MWe	350 MWe	350 MWe	350 MWe	350 MWe
Loan interest rate	10%	10%	10%	10%
Payback term	10 years	10 years	10 years	10 years
Cost of Capital	ZAR 484 million	ZAR 484 million	ZAR 484 million	ZAR 484 million
Utilization	4 117 hrs/y	4 117 hrs/yr	4 117 hrs/y	4 117 hrs/y
Efficiency	51%	51%	51%	51%
Cost of fuel	**US$ 10/MMBtu**	**US$ 15/MMBtu**	**US$ 10/MMBtu**	**US$ 15/MMBtu**
Transmission cost	US$ 0.87/MMBtu	US$ 0.87/MMBtu	US$ 0.03/MMBtu	US$ 0.03/MMBtu
Total cost of fuel	US$ 10.87/MMBtu	US$15.87/MMBtu	US$ 10.03/MMBtu	US$ 15.03/MMBtu
Cost of Fuel	ZAR 0.65/kWh	ZAR 0.95/kWh	ZAR 0.60/kWh	ZAR 0.90/kWh
Cost of Capital	ZAR 0.34/kWh	ZAR 0.34/kWh	ZAR 0.34/kWh	ZAR 0.34/kWh
Total generation costs	**ZAR 0.99/kWh**	**ZAR 1.29/KWh**	**ZAR0.94/kWh**	**ZAR 1.24/kWh**

Table 24

Estimated Normalized Electricity Costs - Gas-fired Power Generation (Saldanha Bay 350 MWe)

Offshore LNG Terminal		**Onshore LNG Terminal**	
LNG Landed Price (US$10/MMBtu)	**LNG Landed Price (US$15/MMBtu)**	**LNG Landed Price (US$10/MMBtu)**	**LNG Landed Price (US$15/MMBtu)**
ZAR 1.14-1.28/kWh	**ZAR 1.48-1.67/KWh**	**ZAR1.08-1.22/kWh**	**ZAR 1.42-1.61/kWh**

Table 25

[235] Levelized costs – reflect overnight capital cost, fuel cost, fixed and variable O&M costs of a power plant over its lifetime
[236] US Energy Information Administration (Energy Analysis) – Report on Updated Capital Cost Estimates for Electricity Generation Plants – Nov 2010/May 2011

Annexure A
Estimated Levelized and Normalized Electricity Costs – Saldanha Bay & Milnerton

Case: Saldanha Bay 450 MWe

Estimated Levelized Costs[237] - Gas-fired Power Generation (Saldanha Bay 450 MWe)

	Offshore LNG Terminal		Onshore LNG Terminal	
	LNG Landed Price (US$10/MMBtu)	**LNG Landed Price US$15/MMBtu**	**LNG Landed Price (US$10/MMBtu)**	**LNG Landed Price US$15/MMBtu**
Total Capex[238]	ZAR 3.83 billion	ZAR 3.83 billion	ZAR 3.83 billion	ZAR 3.83 billion
Total MWe	450 MWe	450 MWe	450 MWe	450 MWe
Loan interest rate	10%	10%	10%	10%
Payback term	10 years	10 years	10 years	10 years
Cost of Capital	ZAR 623 million	ZAR 623 million	ZAR 623 million	ZAR 623 million
Utilization	4 117 hrs/y	4 117 hrs/yr	4 117 hrs/y	4 117 hrs/y
Efficiency	51%	51%	51%	51%
Cost of fuel	**US$ 10/MMBtu**	**US$ 15/MMBtu**	**US$ 10/MMBtu**	**US$ 15/MMBtu**
Transmission cost	US$ 0.63/MMBtu	US$ 0.63/MMBtu	US$ 0.03/MMBtu	US$ 0.03/MMBtu
Total cost of fuel	US$ 10.63/MMBtu	US$15.63/MMBtu	US$ 10.03/MMBtu	US$ 15.03/MMBtu
Cost of Fuel	ZAR 0.64/kWh	ZAR 0.94/kWh	ZAR 0.60/kWh	ZAR 0.90/kWh
Cost of Capital	ZAR 0.34/kWh	ZAR 0.34/kWh	ZAR 0.34/kWh	ZAR 0.34/kWh
Total generation costs	**ZAR 0.98/kWh**	**ZAR 1.28/KWh**	**ZAR0.94/kWh**	**ZAR 1.24/kWh**

Table 26

Estimated Normalized Electricity Costs - Gas-fired Power Generation (Saldanha Bay 450 MWe)

Offshore LNG Terminal		Onshore LNG Terminal	
LNG Landed Price (US$10/MMBtu)	**LNG Landed Price (US$15/MMBtu)**	**LNG Landed Price (US$10/MMBtu)**	**LNG Landed Price (US$15/MMBtu)**
ZAR 1.12-1.27/kWh	**ZAR 1.46-1.65/KWh**	**ZAR 1.08-1.22/kWh**	**ZAR 1.42-1.61/kWh**

Table 27

[237] Levelized costs – reflect overnight capital cost, fuel cost, fixed and variable O&M costs of a power plant over its lifetime

[238] US Energy Information Administration (Energy Analysis) – Report on Updated Capital Cost Estimates for Electricity Generation Plants – Nov 2010/May 2011

Annexure A
Estimated Levelized and Normalized Electricity Costs – Saldanha Bay & Milnerton

Case: Milnerton 800 MWe

Estimated Levelized Costs[239] - Gas-fired Power Generation (Milnerton 800 MWe)

	Offshore LNG Terminal		**Onshore LNG Terminal**	
	LNG Landed Price (US$10/MMBtu)	**LNG Landed Price US$15/MMBtu**	**LNG Landed Price (US$10/MMBtu)**	**LNG Landed Price US$15/MMBtu**
Total Capex[240]	ZAR 6.8 billion	ZAR 6.8 billion	ZAR 6.8 billion	ZAR 6.8 billion
Total MWe	800 MWe	800 MWe	800 MWe	800 MWe
Loan interest rate	10%	10%	10%	10%
Payback term	10 years	10 years	10 years	10 years
Cost of Capital	ZAR 1.11 billion	ZAR 1.11 billion	ZAR 1.11 billion	ZAR 1.11 billion
Utilization	4 117 hrs/y	4 117 hrs/yr	4 117 hrs/y	4 117 hrs/y
Efficiency	51%	51%	51%	51%
Cost of fuel	**US$ 10/MMBtu**	**US$ 15/MMBtu**	**US$ 10/MMBtu**	**US$ 15/MMBtu**
Transmission cost	US$ 0.17/MMBtu	US$ 0.17/MMBtu	US$ 0.26/MMBtu	US$ 0.26/MMBtu
Total cost of fuel	US$ 10.17/MMBtu	US$15.17/MMBtu	US$ 10.26/MMBtu	US$ 15.26/MMBtu
Cost of Fuel	ZAR 0.61/kWh	ZAR 0.91/kWh	ZAR 0.62/kWh	ZAR 0.91/kWh
Cost of Capital	ZAR 0.34/kWh	ZAR 0.34/kWh	ZAR 0.34/kWh	ZAR 0.34/kWh
Total generation costs	**ZAR 0.95/kWh**	**ZAR 1.25/KWh**	**ZAR 0.96/kWh**	**ZAR 1.25/kWh**

Table 28

Estimated Normalized Electricity Costs - Gas-fired Power Generation (Milnerton 800 MWe)

Offshore LNG Terminal		**Onshore LNG Terminal**	
LNG Landed Price (US$10/MMBtu)	**LNG Landed Price (US$15/MMBtu)**	**LNG Landed Price (US$10/MMBtu)**	**LNG Landed Price (US$15/MMBtu)**
ZAR 1.09-1.23/kWh	**ZAR 1.43-1.62/KWh**	**ZAR 1.10-1.25/kWh**	**ZAR 1.44-1.63/kWh**

Table 29

[239] Levelized costs – reflect overnight capital cost, fuel cost, fixed and variable O&M costs of a power plant over its lifetime
[240] US Energy Information Administration (Energy Analysis) – Report on Updated Capital Cost Estimates for Electricity Generation Plants – Nov 2010/May 2011

Annexure A
Estimated Levelized and Normalized Electricity Costs – Saldanha Bay & Milnerton

Case: Milnerton 1000 MWe

Estimated Levelized Costs[241] - Gas-fired Power Generation (Milnerton 1 000 MWe)				
	Offshore LNG Terminal		Onshore LNG Terminal	
	LNG Landed Price (US$10/MMBtu)	**LNG Landed Price US$15/MMBtu**	**LNG Landed Price (US$10/MMBtu)**	**LNG Landed Price US$15/MMBtu**
Total Capex[242]	ZAR 8.5 billion	ZAR 8.5 billion	ZAR 8.5 billion	ZAR 8.5 billion
Total MWe	1 000 MWe	1 000 MWe	1 000 MWe	1 000 MWe
Loan interest rate	10%	10%	10%	10%
Payback term	10 years	10 years	10 years	10 years
Cost of Capital	ZAR 1.38 billion	ZAR 1.38 billion	ZAR 1.38 billion	ZAR 1.38 billion
Utilization	4 117 hrs/y	4 117 hrs/yr	4 117 hrs/y	4 117 hrs/y
Efficiency	51%	51%	51%	51%
Cost of fuel	**US$ 10/MMBtu**	**US$ 15/MMBtu**	**US$ 10/MMBtu**	**US$ 15/MMBtu**
Transmission cost	US$ 0.15/MMBtu	US$ 0.15/MMBtu	US$ 0.24/MMBtu	US$ 0.24/MMBtu
Total cost of fuel	US$ 10.15/MMBtu	US$15.15/MMBtu	US$ 10.24/MMBtu	US$ 15.24/MMBtu
Cost of Fuel	ZAR 0.61/kWh	ZAR 0.91/kWh	ZAR 0.61/kWh	ZAR 0.91/kWh
Cost of Capital	ZAR 0.34/kWh	ZAR 0.34/kWh	ZAR 0.34/kWh	ZAR 0.34/kWh
Total generation costs	**ZAR 0.95/kWh**	**ZAR 1.25/KWh**	**ZAR 0.95/kWh**	**ZAR 1.25/kWh**

Table 30

Estimated Normalized Electricity Costs - Gas-fired Power Generation (Milnerton 1 000 MWe)			
Offshore LNG Terminal		**Onshore LNG Terminal**	
LNG Landed Price (US$10/MMBtu)	**LNG Landed Price (US$15/MMBtu)**	**LNG Landed Price (US$10/MMBtu)**	**LNG Landed Price (US$15/MMBtu)**
ZAR 1.09-1.23/kWh	**ZAR 1.43-1.62/KWh**	**ZAR 1.09-1.23/kWh**	**ZAR 1.44-1.62/kWh**

Table 31

[241] Levelized costs – reflect overnight capital cost, fuel cost, fixed and variable O&M costs of a power plant over its lifetime

[242] US Energy Information Administration (Energy Analysis) – Report on Updated Capital Cost Estimates for Electricity Generation Plants – Nov 2010/May 2011

Annexure B
Economic Model – Assumptions and Parameters

Economic Assumptions

The valuation was done in constant 2013 terms. Both Net Present Value (NPV) and Internal Rate of Return (IRR) were calculated for each case.

Macro assumptions:

o	Project term	20 years (after first commercial gas sales)
o	Discount rate	8%
o	USD inflation rate	2.5%
o	RSA inflation rate	6.0%
o	ZAR/US$ exchange rate	R8.50
o	Crude oil price	Brent
o	Natural Gas Price	NYMEX - Futures, Nominal
o	Europe Gas Price	EGEX - Futures, Nominal

Fiscal terms:

o	Tax rate	28%
o	Depreciation	5 years straight line

Market Assumptions

Industrial Markets:

- the industrial markets in Atlantis and Cape Town, Paarl and Wellington were included in all cases; and
- the industrial markets in Saldanha Bay were included for all the onshore terminal cases and as an option (Phase 2) for the offshore terminal cases.

Power Generation:

- The conversion of Eskom's existing Ankerlig power station was included for the Base Cases;
- Additional gas-fired power generation at Milnerton was included for 800 MWe and 1 000 MWe generating capacity options. The capital and operating costs associated with the power station were not included in the valuation, the assumption being that gas was directly sold as feedstock to the power station; and
- Additional gas-fired power generation at Saldanha Bay was included as 350 MW and 450 MW generating capacity options. The capital and operating

costs associated with the power station were not included in the valuation, the assumption being that gas was directly sold as feedstock to the power station.

Gas Sale Assumptions

Industrial Markets

- 10 percent discount to respective current weighted average fuel costs of the industrial markets in Saldanha Bay, Atlantis and Cape Town, Paarl and Wellington in order to allow comparative results of the various scenarios, and to encourage potential consumers to “switch” their operations to natural gas.

Power Generation

- Sales to the different gas-fired power plants were priced using a cost build-up approach, assuming a 10 year amortisation of capital cost at a 10 percent interest rate and applying a margin of 10 percent.

LNG Supply Source:

- LNG importation from Mozambique was included in all cases.

LNG Receiving Terminals

- *Land-based Receiving Terminal* - The Port of Saldanha Bay; and
- *Offshore Receiving Terminal* – A location approximately 8 kilometres offshore between Duynefontein and Yzerfontein.

Annexure B
Economic Model – Assumptions and Parameters

Case Evaluations

Table 32 illustrates the three Base Cases and ten permutations of the Base Cases. The economic parameters for each Case are summarized in Table 19, Page 103.

Economic Evaluation - Case Selection Options													
Scenario	**Base Case**			**Case 1 Alternatives**				**Case 2 Alternatives**		**Case 3 Alternatives**			
	1	**2**	**3**	**1.1**	**1.1.2**	**1.2.1**	**1.2.2**	**2.1.1**	**2.1.2**	**3.1.1**	**3.1.2**	**3.2.1**	**3.2.2**
LNG Receiving Terminal													
Onshore													
Offshore													
Phase 2 included													
Saldanha Industrial													
Atlantis Industrial													
Cape Town Industrial													
Paarl Industrial													
Wellington Industrial													
Ankerlig Power Station													
Milnerton Power Station													
800 MWe													
1000 Mwe													
Saldanha Power Station													
350 Mwe													
450 Mwe													

Table 32

Base Case 1:
Base Case 1 represents the importation of LNG through a land-based LNG receiving terminal in the Port of Saldanha Bay with the associate pipeline infrastructure to industries in Saldanha Bay, Atlantis, Cape Town, Paarl and Wellington. The conversion of the Ankerlig power station in Atlantis has been included in the case evaluation.

Base Case 2:
Base Case 2 represents the importation of LNG through an offshore receiving terminal and the associated pipeline infrastructure for Phase 1 to industries in Atlantis, Cape Town, Paarl and Wellington. The conversion of the Ankerlig power station has been included in the case evaluation.

Base Case 3:
Base Case 3 represents the importation of LNG through an offshore receiving terminal and the associated pipeline infrastructure for Phases 1 and 2 to industries in Saldanha Bay, Atlantis, Cape Town, Paarl and Wellington. The conversion of the Ankerlig power station has been included in the case evaluation.

Case 1.1.1
Case 1.1.1 represents the importation of LNG through the land-based LNG receiving terminal with the associated pipeline infrastructure to industries in Saldanha Bay,

Annexure B
Economic Model – Assumptions and Parameters

Atlantis, Cape Town, Paarl and Wellington. This case evaluation includes an 800 MWe gas-fired power station at Milnerton but excludes the Ankerlig power station.

Case 1.1.2
Case 1.1.2 represents the importation of LNG through the land-based LNG receiving terminal with the associated pipeline infrastructure to industries in Saldanha Bay, Atlantis, Cape Town, Paarl and Wellington. This case evaluation includes a 1 000 MWe gas-fired power station at Milnerton but excludes the Ankerlig power station.

Case 1.2.1
Case 1.2.1 represents the importation of LNG through the land-based LNG receiving terminal with the associated pipeline infrastructure to industries in Saldanha Bay, Atlantis, Cape Town, Paarl and Wellington. This case evaluation includes a 350 MWe gas-fired power station at Saldanha Bay and the conversion of the Ankerlig power station.

Case 1.2.2
Case 1.2.2 represents the importation of LNG through the land-based LNG receiving terminal with the associated pipeline infrastructure to industries in Saldanha Bay, Atlantis, Cape Town, Paarl and Wellington. This case evaluation includes a 450 MWe gas-fired power station at Saldanha Bay and the conversion of the Ankerlig power station.

Case 2.1.1
Case 2.1.1 represents the importation of LNG through an offshore LNG receiving terminal with the associated pipeline infrastructure to industries in Atlantis, Cape Town, Paarl and Wellington. This case evaluation includes an 800 MWe gas-fired power station at Milnerton but excludes the Ankerlig power station.

Case 2.1.2
Case 2.1.2 represents the importation of LNG through an offshore LNG receiving terminal with the associated pipeline infrastructure to industries in Atlantis, Cape Town, Paarl and Wellington. This case evaluation includes a 1 000 MWe gas-fired power station at Milnerton but excludes the Ankerlig power station.

Case 3.1.1
Case 3.1.1 represents the importation of LNG through an offshore LNG receiving terminal with the associated pipeline infrastructure for Phase 1 and 2 to industries in Saldanha Bay, Atlantis, Cape Town, Paarl and Wellington. This case evaluation includes an 800 MWe gas-fired power station at Milnerton but excludes the Ankerlig power station.

Annexure B
Economic Model – Assumptions and Parameters

Case 3.1.2
Case 3.1.2 represents the importation of LNG through an offshore LNG receiving terminal with the associated pipeline infrastructure for Phase 1 and 2 to industries in Saldanha Bay, Atlantis, Cape Town, Paarl and Wellington. This case evaluation includes a 1 000 MWe gas-fired power station at Milnerton but excludes the Ankerlig power station.

Case 3.2.1
Case 3.2.1 represents the importation of LNG through an offshore LNG receiving terminal with the associated pipeline infrastructure for Phase 1 and 2 to industries in Saldanha Bay, Atlantis, Cape Town, Paarl and Wellington. This case evaluation includes a 350 MWe gas-fired power station at Saldanha Bay and the conversion of the Ankerlig power station.

Case 3.2.2
Case 3.2.1 represents the importation of LNG through an offshore LNG receiving terminal with the associated pipeline infrastructure for Phases 1 and 2 to industries in Saldanha Bay, Atlantis, Cape Town, Paarl and Wellington. This case evaluation includes a 450 MWe gas-fired power station at Saldanha Bay and the conversion of the Ankerlig power station.

Table 33 summarizes the key economic results for the case evaluations.

Economic Results													
Scenario	**Base Case**			**Case 1 Alternatives**				**Case 2 Alternatives**		**Case 3 Alternatives**			
	1	**2**	**3**	**1.1.1**	**1.1.2**	**1.2.1**	**1.2.2**	**2.1.1**	**2.1.2**	**3.1.1**	**3.1.2**	**3.2.1**	**3.2.2**
Net Present Value - (US$ million)	102	78	124	0	15	121	128	-21	-5	25	41	177	185
Internal Rate of Return - (Percent)	10.2	11.6	12.6	8	8.3	10.5	10.7	7	7.8	9	9.5	14.2	14.4
Maximum Exposure - (US$ million)	590	281	337	609	590	590	311	310	375	373	337	337	337
Payout Period post 1st investment - (Years)	11	9	9	12	12	10	12	12	11	11	10	8	8

Table 33

Reference Documentation

Author	Description
CSIR	Preliminary Assessment of the Marine Environmental Conditions on the Cape West Coast, Gigajoule Africa – December 2009
Gaffney, Cline and Associates	Gas Market Study for Selected Provinces in the RSA – 2000
Gigajoule Africa	NERSA License Application for the Distribution and trading of Natural Gas in the Cape West Coast Region – 2010
Golar LNG	Feasibility of an Offshore FSRU System for the Cape West Coast – 2010
Instituto Nacional de Petrolea (INP)	Natural Gas Master Plan for Mozambique – 2012 (www.inp-mz.com/ & www.enh.mz.com)
Intelligent Energy Systems	Report to the Office of Queensland Gas Market Advisor – Modeling and Analysis for the Gas Market Review - 2012
International Gas Union	Fundamentals of the Global LNG Industry – June 2012 (www.igu.org/igu-publications)
Pace Global Energy Services	Pace Global Energy Services - South Africa Natural Gas Utilization - LNG Analysis (2008?) , PetroSA
Republic of Mozambique Pipeline Investment Company	Tariff Application for the Natural Gas Volumes Transported on the Additional 27 MMGJ/a – 23 August 2011 (www.nersa.org.za)
South African Department of Energy	National Gas Infrastructure Development Plan
The Federal Energy Regulatory Commission (FERC)	Estimated Landed Prices of LNG for February 2013 (www.ferc.gov)
US Energy Information Administration	Energy Overview, South Africa (www.eia.gov/countries/analysisbriefs/South_africa/south_africa.pdf)
US Energy Information Administration (Energy Analysis)	Report on the Updated Capital Cost Estimates for Electricity Generation Plants – November 2010/May 2011