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POWER AFRICA NATURAL GAS ROADMAP FOR SOUTHERN AFRICA

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CONTEXT

This report provides the United States Agency for International Development's (USAID) Southern Africa Energy Program (USAID SAEP) with a regional gas roadmap it can use to prioritize its support for gas-to-power projects. The roadmap, known as the Southern Africa Gas Roadmap, initially focuses on four Southern African countries selected amongst the countries covered by USAID SAEP: Botswana, Mozambique, Namibia, and South Africa. These four countries have been selected initially, given their perceived potential for gas-to-power in the short run. This is largely driven by the potential availability of domestic gas supplies in these countries, in combination with emerging demand and their regional proximity. Although Angola is a sizeable gas producer and part of the USAID SAEP scope, it has been deprioritized for the initial phase of this work (along with other countries having more remote potential). Building on this initial analysis, additional countries can be added to create an encompassing Southern African Development Community (SADC) regional gas roadmap to guide regional gas advancement and economic growth. A similar methodology can be used to analyse Angola, Tanzania and global gas supply (e.g. virtual and real gas pipeline routes) to the region and demand analysis for all SADC members as applicable. SADC currently has plans to build out a SADC Gas Roadmap that will align to the SADC Industrial Plan and include the full region and additional economic impact analysis.

Given the large investments required to develop gas infrastructure, the development of gas-to-power projects may require additional gas adoption by other sectors (i.e., industrial, transport and commercial & residential). While the focus for USAID SAEP is on the region's potential for gas-to-power, this roadmap also assesses the potential for gas demand across these sectors. Matching the forecast demand with potential gas supplies from within the countries will create local gas balance surpluses and deficits. To unlock Southern Africa's gas potential in full, regional trade between countries could provide a solution to address these local imbalances. As a result, this report considers not only the supply and demand situation in each of the countries individually, but also assesses the potential for trade between them.

Furthermore, this report assesses the gas potential from a medium-term perspective, taking a snapshot in 2030. This timeframe is chosen as it provides a sufficient period for which demand, supply discoveries, and required trade infrastructure can be developed. However, no explicit assumptions are made for the short-term, allowing for various paths towards reaching this medium-term potential.

KEY FINDINGS AND IMPLICATIONS

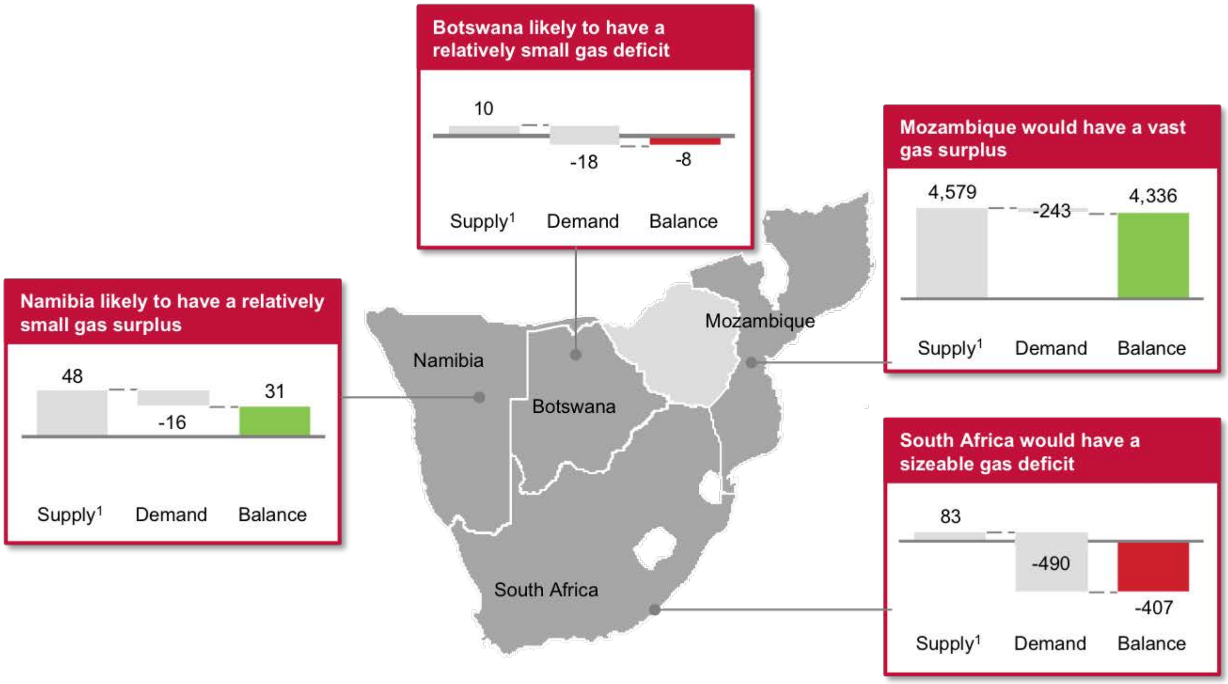
Based on the analysis of this report, four main insights emerged for gas trade in the region:

1. Mozambique and South Africa could address their local gas imbalances by trading as an integrated system, potentially through a gas pipeline.
2. Botswana could be a standalone gas system depending on successful development of its coalbed methane (CBM) resources.
3. Namibia could be a standalone system depending on successful development of the Kudu field or through small-scale LNG imports.
4. The regulatory environment in the four focus countries is uncertain and underdeveloped, and could be further advanced to enable the development and use of natural gas.

EXHIBIT 1

LOCAL GAS SUPPLY AND DEMAND BALANCES

PJ/year, 2030; (balances calculated using total recoverable reserves, assuming "medium" demand scenario)



1 Supply volumes estimated based on high level approach which assumes that remaining reserves are produced over 30 years (typical field life and most of fields are untapped yet), leading flat production profile, which is converted into PJ/year

SOURCE: Demand figure derived from bottom-up evaluation (IRP 2016, EIA energy balances, IPP gas-to-power programme, among others); supply volumes derived from WoodMackenzie, complemented with various public sources (e.g. Tlou Energy, South African journal of science)

1. MOZAMBIQUE AND SOUTH AFRICA AS AN INTEGRATED SYSTEM

Mozambique and South Africa are expected to have domestic gas surpluses and deficits. Evaluation of the individual gas supply and demand balances for a medium scenario (moderate demand development) suggests that Mozambique is likely to have large excess gas supplies (up to ~4,300 PetaJoules (PJ)/year, or ~10,700 million standard cubic feet per day (mmscfd)), while South Africa could have a significant deficit (up to ~400PJ/year (~1,000 mmscfd)), depicted in **Exhibit 1**.[1]

Mozambique has large gas reserves. It already produces gas from its Pande / Temane fields, has discovered large volumes of offshore gas (estimated reserves range from ~130 to 180 tcf, concentrated in the Rovuma basin), and has an unquantified onshore potential (e.g., CBM prospects in Tete). A final investment decision has already been taken for an FLNG vessel that will lean off the Area 4 complex of the Rovuma basin,[2] and a decision for the Area 1 complex is expected soon, suggesting the country's vast supply potential is starting to be tapped.

South Africa's current gas production is limited, though the Karoo basin has a potential of shale gas reserves, with initial estimates of 13 tcf.[3] However, these reserves have not reached commercial extraction, and their economic viability is still to be confirmed. Given the uncertainty around this, our analysis assumes that South Africa's Karoo shale reserves cannot be tapped by 2030.

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[1] Assuming that the Karoo's shale gas potential cannot be fully tapped by 2030; subsequently discussed

[2] Wood-Mackenzie upstream data tool, extract 13 October 2017

[3] South African Journal of Science (2017); retrieved from https://www.businesslive.co.za/bd/national/science-and-environment/2017-09-28-tests-reveal-less-karoo-shale-gas-than-expected/

While all four focus countries have potential gas demand, gas demand could be sizeable in South Africa and Mozambique. Because it is difficult to forecast future gas demand exactly, three scenarios were developed to estimate demand for each of the four countries in 2030. The scenarios are:

- Low: Regional gas does not take off
- Medium (base case): Gas as a solid part of the energy mix
- High: The region doubles down on gas

The scenarios are based on detailed evaluations of the likelihood that potential gas-to-power projects could come online, and supported by assumptions about the potential gas demand in other sectors (e.g., gas for industry and transport). **Exhibit 2** provides a breakdown of gas demand across the scenarios. Most of the conclusions in this report are based on the medium scenario. In the medium (or base case) scenario, gas is assumed to play both a strategic and economic role in diversifying the region's energy mix, with the support of petroleum-to-gas fuel switching within the industrial and transport sectors. Under this medium scenario, the incremental gas demand is concentrated in Mozambique (221 PJ/year, or 552 mmscfd) and South Africa (232 PJ/year, or 579 mmscfd). A number of gas-to-power projects in both countries combined with Mozambique's focus on creating new gas-based industries is to drive these increases.

In this scenario, over 6000 megawatts (MW) in newbuild combined-cycle gas turbines (CCGT) capacity is expected to materialize by 2030. South Africa is expected to deliver the majority of this capacity through its commitment from the 2016 Integrated Resource Plan (IRP); 3,000 MW in LNG-to-power, 726 MW in gas-to-power, and 1,500 MW of the non-specified IRP gas-to-power projects are expected to materialize under the medium scenario. Mozambique also makes a sizable contribution, with ~1000 MW of gas-to-power projects expected to materialize in this scenario. Its largest planned plants are Temane IPP (400 MW), and Rovuma gas-to-power (250 MW).

Beyond the power sector there will be gas demand in other sectors. Mozambique holds most of the region's new industrial demand potential. Shell plans to build a 38,000 barrel per day gas-to-liquids (GTL) plant and Norway's Yara aims to construct a 1.3 million tonne per annum (mtpa) fertilizer plant. Both will be located near Mozambique's Rovuma gas sources in Cabo Delgado. Potential demand from the transport sector, if fuel switching is to take place, would be mostly concentrated in South Africa because of the sheer size of its industrial economy and its relatively more advanced transport sector.

EXHIBIT 2

OVERVIEW OF GAS DEMAND POTENTIAL (EXISTING AND INCREMENTAL)

Country	Sector	"Regional gas does not take off"—Low scenario PJ (Mmscfd), 2030	"Gas as a solid part of the energy mix"—Medium scenario PJ (Mmscfd), 2030	"The region doubles down on gas"—High scenario PJ (Mmscfd), 2030
South Africa	Existing demand	258 (644)	258 (644)	258 (644)
	Power	93 (232)	168 (420)	274 (684)
	Industrial	-	27 (67)	182 (454)
	Transport	-	37 (92)	73 (182)
	Commercial/ Residential	-	-	20 (50)
	TOTAL	**351 (876)**	**490 (1,224)**	**808 (2,018)**

Country	**Sector**	**"Regional gas does not take off"—Low scenario** **PJ (Mmscfd), 2030**	**"Gas as a solid part of the energy mix"—Medium scenario** **PJ (Mmscfd), 2030**	**"The region doubles down on gas"—High scenario** **PJ (Mmscfd), 2030**
Mozambique	Existing demand	22 (55)	22 (55)	22 (55)
	Power	25 (62)	48 (120)	63 (157)
	Industrial	9 (22)	171 (427)	171 (427)
	Transport	-	1 (2)	2 (5)
	Commercial/ Residential	-	-	7 (17)
	TOTAL	**56 (140)**	**243 (607)**	**266 (664)**
Botswana	Existing demand	-	-	-
	Power	-	5 (12)	10 (25)
	Industrial	-	10 (25)	19 (47)
	Transport	-	3 (7)	4 (10)
	Commercial/ Residential	-	-	3 (7)
	TOTAL	**0**	**18 (45)**	**36 (90)**
Namibia	Existing demand	-	-	-
	Power	-	10 (25)	10 (25)
	Industrial	-	5 (12)	8 (20)
	Transport	-	1 (2)	2 (5)
	Commercial/ Residential	-	-	0 (0)
	TOTAL	**0**	**16 (45)**	**20 (50)**
Subtotal	**Existing gas demand**	**280 (699)**	**280 (699)**	**280 (699)**
Subtotal	**New gas demand**	**127 (317)**	**487 (1,216)**	**850 (2,122)**
TOTAL	**TOTAL DEMAND**	**407 (1,016)**	**767 (1,915)**	**1130 (2,822)**

Mozambique and South Africa could address their local imbalances by trading as an integrated system. A case for trade that could exist between the two countries is even more relevant in the context of the current developments in the global gas markets. The recent spate of new LNG liquefaction projects across the globe has led to a market oversupply, and as a result the premiums historically paid by buyers (particularly in Asia) no longer holds. Therefore, a mutually beneficial opportunity could exist for regional trade; Mozambique can secure a buyer for its gas, and South Africa can find a competitive source to cover its deficit. This is a material change compared to 5-10 years ago when Mozambique's best option may have been to sell gas on the global LNG market to Asia.

In this report we explored the opportunities for trade between Mozambique and South Africa. Three avenues of trade may prove fruitful. Pipeline gas and LNG are the two most likely; they would need to make trade-offs between which is the most economical, which addresses the most demand volume, and which has the greatest socioeconomic benefit. A third option would be for Mozambique to use an interconnector to trade its local gas-fired power generation with South Africa as electricity. Considering the global gas price pressures and the need to remain competitive, we focussed on a high-level economic assessment in this report. By applying broad assumptions around demand (taken from the medium case), the availability of supply, and the specifications of the infrastructure required, we performed a high-level comparison of the potential tariffs for trade via pipeline, via LNG, and via power transmission. This analysis produced several insights:

- **Gas trading is more cost-effective and versatile than power trading given the distances involved.** The high cost of constructing a 2,500km transmission line required to transmit power from Mozambique to South Africa is estimated at more than $3.2 billion, with $100 million annual operating expenses due to significant losses over such long distances. Initial analyses revealed that, in a case where 2,100 MW of generation capacity is linked via an interconnector, this option would likely come in well above South Africa's average electricity tariff and address only a small proportion of the system's gas potential because it does not directly consider potential demand from industry and transport. It is assessed that this issue would also apply at higher power capacities.
- **For South African gas demand volumes above ~135 Pj/Year (337 Mmscfd), gas trade with Mozambique could become cheaper through a pipeline than LNG.**[4] In the medium scenario, a Mozambique - South Africa pipeline could supply 149 PJ/year (372 mmscfd) of gas, of which 129 PJ/year (322 mmscfd) would meet South African demand and 20 PJ/year (50 mmscfd) would go towards Mozambican offtake along the route (based on an assessment of incremental gas demand use in the two countries that could potentially utilize a pipeline). For these volumes, a pipeline tariff could be expected around $4.69/million British thermal units (mmbtu) according to the initial high-level analysis. This is based on a 24-inch pipeline, running 2,500km from Cabo Delgado in Mozambique down to the Mpumalanga province in South Africa for onward domestic distribution. The associated pipeline would require a capital investment of $5-$6 billion, assuming a capital investment of ~$2.3 million per kilometre (km). This option could then be competitive with LNG trade from Mozambique to South Africa, which is estimated to have a tariff of $5.14/mmbtu. This takes into account the most economical LNG trade route options; partial offtake from a larger onshore liquefaction terminal in Cabo Delgado, shipping down to Richards Bay, and regasification on a floating storage and regasification (FSRU) unit. Both potential tariffs were estimated with a high-level cash flow analysis that calculated the tariff required to meet typical expected returns on equity (ROE) and cost of debt rates.
- **Because gas transport tariffs are sensitive to the volumes transported, anchoring the demand in South Africa is essential.** Using the high-level model, a variance of just -10 percent of the 149 PJ/year (372 mmscfd) volume would increase the pipeline tariff by $0.51/mmbtu, eroding any potential cost advantage a regional pipeline trade might have over LNG ($4.69/mmbtu vs. $5.14/mmbtu, respectively). Because of this sensitivity, it would be essential to anchor South African demand; it will be crucial to drive a successful business case.

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[4] This excludes potential South African gas demand, which is locked in as LNG through the SA IPP LNG-to-power PP initiatives (i.e., gas volumes required for Coega and Richard's Bay LNG-to-power plants)

This also intuitively makes sense as it will be challenging to attract investment in a major capital project without certainty around off-take. In the medium scenario (which estimates that ~50 percent of the IRP's non-LNG gas-to-power projects will materialize), South Africa would need to complement demand from gas-to-power with industry and transport demand to result in the volumes required for scale. This has large policy implications: beyond the need for overall volume commitments, the gas demand would need to come from multiple sectors including power, industry and transport.

The above analysis is based on a high-level economic model comparing three options of trade. While the statements above are directionally correct, additional and more detailed economic modeling is required prior to making any investment decisions. Furthermore, this analysis only considers a medium-run snapshot assessment. In the short-run, the varying timelines of demand, supply and trade infrastructure development may lead to other complementary outcomes to bridge the timeline gap.

Decision-makers also need to consider socioeconomic benefits and political risk considerations, as well as economics when assessing trade infrastructure options. For instance, Mozambique could maximize socioeconomic benefits by examining local Mozambican industrialization (e.g., through local spurs from a pipeline) and greater integration with the overall region (e.g., pipeline spurs/tee-offs to other countries such as Zimbabwe and Zambia). For any of these investments, economic returns are required. The exact trade-off, incorporating any relevant elements of risk, would need to be further studied as it was not part of this analysis.

2. BOTSWANA AS A POTENTIAL STANDALONE GAS SYSTEM

While Botswana holds some potential for gas-to-power, capturing this in the near term may be challenging. If Botswana's coalbed methane (CBM) resources were to materialize, the relatively small supply volumes involved and limited demand appetite would not justify cross-border gas pipelines (a small deficit is forecast for Botswana of ~8 PJ/year (20 mmscfd)). It would therefore be considered as a (potential) isolated gas system.

Botswana's potential to have an isolated gas system relies on the successful development of its CBM resources within the Lesedi field. Reserve estimates of this field range from 0.15 trillion cubic feet (tcf) of proven reserves to 3.2 tcf of contingent reserves.[5] The commercial viability of the reserves is however unproven.

In addition, Botswana has little known gas demand currently, and its future potential is also likely to be limited given the country's relatively small economic and demographic footprint (estimated at 18 PJ/year (45 mmscfd) in the medium scenario). Much of this demand stems from gas-to-power that is directly linked to the success of its uncertain CBM fields. High-level economic analysis further indicates that developing Botswana's gas fields for gas-to-power use would be economically challenging with the current electricity tariffs.

3. NAMIBIA AS A POTENTIAL STANDALONE GAS SYSTEM

While Namibia also has untapped gas potential, a variety of project-based factors make its development as a gas system unsure. Its gas supply sources depend on the development of the offshore Kudu field and Walvis Bay LNG imports. The Kudu field is estimated to have 1.3 tcf of proven reserves.[6] However, despite being discovered in the 1970's, it is yet to be commercially produced as the field's economics are still uncertain. Development of the Walvis Bay LNG project meanwhile has stalled due to a legal dispute with the project's tender process.

Similar to Botswana, Namibia has no significant gas demand at present. Its future potential is tied to the development of the Kudu field and Walvis bay LNG. Given it is contingent on uncertain supply, demand potential is also small, estimated at 16 PJ/year (40 mmscfd) in the medium scenario. Furthermore, high-level economic analysis indicates that the associated gas-to-power projects would be economically challenging with the current electricity tariffs.

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[5] Tlou energy, 2017; Wood-Mackenzie upstream data tool, extract 13 October 2017

[6] Wood-Mackenzie upstream data tool, extract 13 October 2017

Under the medium scenario, only the Walvis Bay LNG import terminal is assumed to materialize as an upstream source of gas, leading to a small surplus of up to ~30 PJ/year (75 mmscfd). Namibia would therefore be considered as a potential isolated gas system from a regional perspective, given the likely absence of substantial domestic supplies.

4. THE NEED FOR ADVANCEMENTS IN THE REGULATORY ENVIRONMENT TO ENABLE THE DEVELOPMENT AND USE OF NATURAL GAS

From our analysis we conclude that the region has some potential for gas-to-power development and even regional gas trade. Not only could this unlock further supply of (cleaner) energy, the development of natural gas resources can bring real benefits to the four countries' economies (Botswana, Mozambique, Namibia, and South Africa). It can generate employment, increase GDP, and raise foreign direct investments. The value chain associated with extracting natural gas can create substantial, permanent employment opportunities (direct and indirect). In addition, using natural gas locally supports industrialization (e.g., creating fertilizer and petrochemical industries), which also has positive effects on employment and GDP. Natural gas can also be an important contributor to a sustainable energy mix; gas-fired power generation, with relatively low emissions, can complement an intermittent supply of renewable energy generation and help diversify other energy sources. It is often more cost-competitive than other fuel sources (e.g., liquid fuels such as diesel, heavy fuel oil, or liquefied petroleum gas (LPG)).

Yet to unlock the region's gas potential, several regulatory hurdles must be overcome. Overall, in all four countries regulations on gas are relatively unclear (in the upstream or downstream segment of the gas value chain, or both). Botswana has a nascent energy regulatory system, with unclear upstream and downstream gas regulations. While Namibia has a relatively clear upstream gas regime, its downstream sector is currently unregulated. It has been working on a draft Gas Act since 2001, but the status of this regulation is unclear (i.e., when it will be finalized and implemented). In 2014, Mozambique drafted new Petroleum Laws and adopted them in 2015. While these provide more guidance on previously unclear issues (e.g., domestic gas market mechanisms), considerable uncertainties remain (e.g. on the volumes subject to royalties). However, Mozambique's Ministry of Minerals and Energy (MIREME) is setting up the High Authority for the Extractive Industry (AAIE), which could provide more clarity on the remaining uncertainties. And although South Africa has a relatively well established regulatory framework, it is currently revising its overall energy policies, including the outlook for natural gas. In combination with ongoing discussions around amendments to the Mineral and Petroleum Resources Development Act (28/2002), this brings considerable uncertainty to its gas sector.

A coordinated effort would be required to attract international investors. Although the reserves are sizeable, Southern Africa's gas opportunities would have to compete for capital on a global scale. For example, the size of Botswana's Lesedi CBM field falls somewhere between 0.15 tcf (proven reserves) and 3.2 tcf (contingent reserves), while the US' and Australia's CBM basins have reserves of ~15 tcf to ~47 tcf, respectively.[7] In the current oil price environment, capital investments are under pressure and competition from larger global basins is fierce. The region's lack of an established gas ecosystem and infrastructure will also complicate investment decisions. A coordinated perspective, effort, and supportive policies are therefore crucial to attract the investments and expertise required for the development of the gas resources.

RECOMMENDATIONS

To unlock the region's gas potential, USAID SAEP (and potentially other Power Africa initiatives as well) should focus on two areas: playing a coordinating role with the Southern African Development Community (SADC) in developing a gas roadmap and ensuring its implementation, and supporting the capture of 5.0 – 8.8 GW of gas-to-power projects in the four countries.

USAID SAEP could aim to start these interventions in the first six months of 2018. Although some of the timelines depend on external events (e.g., the availability of key stakeholders like the Regional Electricity Regulators' Association (RERA) or the SADC Gas Subcommittee, or the clarity on policies like a renewed South African IRP), the coordinating role and the unlocking of the projects could be started quickly.

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[7] Tlou energy, 2017

First, USAID SAEP could play a coordinating role in unlocking the region's gas potential by assisting in the development of a SADC gas roadmap, supported by regulatory guidance and training. As a first step, USAID SAEP could help SADC determine what components would be needed to form a SADC Gas Roadmap, potentially using the Southern Africa Gas Roadmap as a basis. USAID SAEP would discuss the roadmap and align on priorities with the SADC Gas Subcommittee leadership and, potentially, with RERA's leadership. As part of this effort, a number of meetings could be held with these leaders to ensure that the gas roadmap is successfully adapted and implemented. These meetings would help the groups align on the facts, adapt the roadmap to the SADC region, and develop implementation plans for the priority regulators (e.g., South Africa's National Energy Regulator (NERSA), Mozambique's Energy Regulatory Authority (ARENE), and Mozambique's Natural Petroleum Institute (INP)). USAID SAEP could also engage additional stakeholders to review the gas roadmap. It could then incorporate relevant stakeholder feedback into an updated roadmap.

In support of the roadmap's implementation, USAID SAEP could also provide guidance to the countries in developing the required regulatory environment. For instance, it could help build the capabilities of the relevant regulators. Furthermore, USAID SAEP could host training workshops on gas and LNG markets, targeted at government organizations to drive informed decision making, and at national oil companies to facilitate access to markets.

Second, USAID SAEP could directly support the capture of 5.0 - 8.8 Gw of gas-to-power projects in the four countries. This support would occur across two phases: an immediate, rapid diagnostic phase with 1.2 to 1.3 GW potential in Mozambique and Botswana, and a second phase of 3.8 – 7.5 GW potential in Namibia and South Africa once certain external events are resolved.

During the diagnostic phase, USAID SAEP could support currently planned gas-to-power projects in Mozambique and Botswana. The insights from the rapid diagnostic would help USAID SAEP align on what support to provide to priority projects and on which party is best positioned to drive them (e.g., USAID SAEP, USTDA). It could also develop the required Scope of Work for relevant priority projects. In Mozambique, USAID SAEP would work closely with the SPEED+ program to conduct a gap analysis of the gas-to-power projects; close coordination and cooperation would be an essential part of this effort. In Botswana, it would perform a gap analysis on Botswana's CBM gas-to-power projects. In parallel, it would consider whether it makes sense to offer technical support to the Government of Botswana to help interpret existing studies on the development of their CBM reserves, and consider whether a feasibility study of gas-to-power from other CBM reserves would be desirable. USAID SAEP could engage other agencies for this, like the US Department of Energy and/or U.S. Trade and Development Agency (USTDA).

In the second phase, USAID SAEP could support ~3.8 - 7.5 GW of gas-to-power projects in Namibia and South Africa. In Namibia, USAID SAEP could consider supporting the 200 MW Walvis Bay LNG-to-power project if the associated legal dispute is close to being resolved and the tender is reviewed. Financial transaction advisory services would be the most likely type of support, provided by either USAID SAEP and / or Power Africa Transactions and Reforms Program (PATRP). When South Africa releases an updated IRP, USAID SAEP could provide strategic support to the Department of Energy and / or NERSA as they create the gas-to-power agenda. It would potentially collaborate with the independent power producer (IPP) office as well. If feasibility studies are needed, the USTDA could support these (e.g., Western Cape for the IPP Office). **Subsequent support would be needs-based,** but could include helping to close power purchase agreements (PPAs), lock-in gas supply agreements, resolve land / community issues, and close financing (e.g., risk guarantees). USAID SAEP could provide these advisory services directly and / or through PATRP.

While the above two recommendations should guide USAID SAEP's priorities for gas-to-power development of the region, driving the gas trade opportunities between Mozambique and South Africa is a longer-term initiative that should be considered by the broader Power Africa group.

1. CONTEXT OF THIS WORK

1.1 INTRODUCTION TO POWER AFRICA AND USAID SAEP

Power Africa is a U.S. government-led initiative launched in 2013. Power Africa's goals are to increase electricity access in sub-Saharan Africa by adding more than 30,000 MW of electricity generation capacity and 60 million new home and business connections. Power Africa works with African governments and private sector partners to remove barriers that impede energy development in sub-Saharan Africa and to unlock the substantial natural gas, wind, solar, hydropower, biomass, and geothermal resources on the continent.

Power Africa has leveraged over $54 billion in commitments from the public and private sectors. To date, the initiative has helped 88 projects, comprising 7,402 MW, reach financial close.[8]

In 2017, Power Africa launched the USAID-funded Southern African Energy Program, a five-year project aimed at advancing its overall mandate, and with a focus on the Southern Africa region. USAID SAEP's aim is to advance energy policy and regulatory reform, and accelerate investment to increase power generation and access to electricity throughout the Southern African region. By strengthening the enabling environment and facilitating public and private transactions, USAID SAEP can leverage private investment and focus all possible resources so the reforms of national and regional energy ecosystems receive the best possible support.

The five-year program (March 2017-2022) focuses on eleven target countries in the Southern African region: Angola, Botswana, Lesotho, Madagascar, Malawi, Mozambique, Namibia, South Africa, Swaziland, Zambia, and Zimbabwe. USAID SAEP is collaborating closely with its regional partners (i.e., SADC, the Southern African Power Pool (SAPP), RERA, and the SADC Centre for Renewable Energy and Energy Efficiency (SACREE)). Governments, private sector counterparts, and the wider group of Power Africa partners) are also engaged in this effort.

The effort has three primary goals – to help develop generation capacity in Southern Africa of 3,000 MW, transmission capacity of 1,000 MW, and three million new connections. To achieve this, USAID SAEP would develop strategies to overcome the major issues that currently constrain investment in the energy sector. These would:

- Improve energy regulation, planning, and procurement
- Improve utilities' commercial viability
- Improve regional harmonization and cross-border trade
- Demonstrate and scale renewable energy and energy-efficient technologies and practices
- Increase human and institutional capacity

1.2 INTRODUCTION TO THE USAID SAEP REGIONAL GAS ROADMAP, AND THE POWER AFRICA GAS ROADMAP

While USAID SAEP has a wide range of mechanisms and resources at its disposal, it knew it needed to prioritize its efforts if it was to achieve its goals. Given natural gas' role as an emerging source of energy in Southern Africa, it made sense to evaluate the potential of gas-fired power generation for this effort. However, the investments required and the need for regional alignment of the various stakeholders along the value chain also made it clear that unlocking natural gas' potential would be challenging. To help address these issues, USAID SAEP decided to develop an integrated, regional natural gas roadmap rather than one or more plans that focused on individual countries (e.g., the Mozambique Gas Master Plan).[9] Known as the 'Southern Africa Gas Roadmap for Power Africa's Southern Africa Energy Program', this holistic perspective aims to help USAID SAEP unlock the region's overall potential.

In parallel, Power Africa has been developing its Power Africa Gas Roadmap, a distinct document that provides a comprehensive framework for defining and coordinating gas-to-power activities across the entire African continent, with the support of Power Africa and partners. Intended as a public facing document, the strategy aims to operationalize a plan to achieve ~12.5-16.0 GW of additional gas-fired power generation, across sub-Saharan

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[8] As of 15th March 2018; https://www.usaid.gov/powerafrica

[9] ICF International (2012); The Future of Natural Gas in Mozambique: Towards a Gas Master Plan

Africa, by 2030. The Power Africa Gas Roadmap identifies that natural gas has the potential to be the dominant power generating technology in Africa, climbing from under 10% of total generation capacity to nearly 50% by 2030. This is expected to be achieved primarily by targeting 12.5-16.0 GW of selected project interventions, and a broader enabling of the environment and market reforms critical for gas-to-power markets.

While having alignment with, and building on the insights of the Power Africa Gas Roadmap, this document has a distinct focus. The 'Southern Africa Gas Roadmap for Power Africa's Southern Africa Energy Program' (henceforth referred to as the USAID SAEP Regional Gas Roadmap), serves as a USAID SAEP internal document aimed at guiding and prioritizing its activities to unlock the gas-to-power potential in the Southern African region.

1.3 OBJECTIVES AND FOCUS OF THE ROADMAP

USAID SAEP's objective for the roadmap is to determine what it will take to completely unlock Southern Africa's gas-to-power potential. This gas roadmap reviews the potential gas supply and demand, infrastructure investments needed, and integration potential with neighboring countries for the four focus countries of Botswana, Namibia, Mozambique, and South Africa. In doing so, it tries to develop a regional view on the action plan required to unlock the gas-to-power potential of Southern Africa. Another important objective is to establish a baseline of facts that all stakeholders can agree on so they can begin to make policy decisions around the different scenarios.

The four countries were chosen because they are the most relevant ones for natural gas in Southern Africa that fall within USAID SAEP's focus. This selection was based on their combination of gas demand and domestic and/or neighboring supplies (see **Exhibit 19** in the Appendix for more detail on gas' relevance to each country):

- **Botswana** discovered potential CBM deposits in the Lesedi region and has stated an intention to build integrated CBM-to-power projects.
- **Namibia's** potential is from the offshore gas discovery, the Kudu field, and it recently began to develop a LNG-to-power project.
- **Mozambique** has significant potential from its vast reserves in the Rovuma region, existing production from the Pande/Temane fields, and a sizable gas-to-power project pipeline.
- **South Africa** discovered shale gas in the Karoo basin and recently renewed its offshore exploration. The government issued a directive to develop LNG-to-power along with a broader gas industrialization agenda.

Other countries that are within scope of USAID SAEP (e.g., Zambia, Zimbabwe) were initially excluded because they lack sizable domestic supplies or demand, are relatively isolated, and/or present a challenging business environment, or have stated no explicit interest in developing their resources.

Angola was also excluded, although this was because of potential barriers to gas-to-power and gas trade. The country has an active oil and gas sector with substantial gas reserves and an LNG export terminal, but the location of known gas reserves in the far north (on the border with the Democratic Republic of the Congo (DRC)) would probably limit trade options with USAID SAEP's eleven countries to LNG. In addition, Angola is not part of SAPP. The Power Africa Gas Roadmap is currently examining Angola's potential for gas-to-power and gas trade.

1.4 ADDITIONAL APPLICATION OF THIS WORK

This gas roadmap could form the basis for another gas roadmap which will be developed, as the SADC is working to develop a Regional Gas Roadmap for which it has requested USAID SAEP's support. At the 37th SADC Summit (20 August 2017), the Heads of State and governments directed that a regional Natural Gas Committee be constituted to promote the inclusion of gas in the regional energy mix. The Ministers would like to develop and adopt a Regional Gas Roadmap within the next two years.

1.5 HOW THIS ROADMAP BUILDS ON PREVIOUS WORK

Natural gas has already received significant attention in the region. Governments and other stakeholders in the focus countries have made it a top priority, keeping it high on their agenda (e.g., see the Appendix for excerpts of recent press coverage). Natural gas development has also been the subject of several prior studies.

This report builds on this earlier work and leverages insights from several studies and publications, some of which are listed below:

- **South Africa Department of Energy – Gas-based Industrialization in South Africa:** This 2017 study concludes that significant potential for gas demand exists in South Africa (over 700 PJ/year, or 1,748 mmscfd), with the industrial and transportation sectors contributing strongly in addition to gas-to-power. The report recognizes the potential from Mozambican gas supplies, and advocates for the development of regional gas pipelines to unlock domestic gas usage (after it evaluates various infrastructure scenarios). [10]
- **South Africa Department of Trade and Industrialization – Industrializing the KZN-Gauteng Corridor Through Natural Gas:** This study focused on the industrialization of the KwaZuluNatal-Gauteng corridor. It estimates that regional demand could be 47 PJ/year (117 mmscfd), with a significant contribution from transportation (28 PJ/year, or 70 mmscfd) which will have a relatively high willingness to pay as gas replaces more expensive liquid fuels. Throughout, the study discusses the importance of other sectors in developing regional gas. The report also assumes that, over time, regional and/or domestic gas supplies will replace the LNG imports at Richard's Bay. [11]
- **South Africa Department of Trade and Industrialization – The Potential for Gas-Based Industrialization in South Africa:** This study concludes that a vast industrial demand potential exists – over 1 tcf per/year – for gas prices below $6/mmbtu. Domestic supplies have even higher potential given that gas transport costs can vary between $0.5 - $4.0/mmbtu. It also highlights infrastructure's important role in gas industrialization, given price-sensitive demand and the wide spectrum of gas transportation costs. [12]
- **World Bank (ICF international) – Towards a Mozambique Gas Master Plan:** This publication states that Mozambique needs to undertake several immediate actions to unlock its gas sector. These include, among others: expediting LNG project development; developing a communication strategy; and initiating further studies (e.g., a regional integrated power study including South Africa). This report states that an LNG export terminal is the critical project required to unlock Mozambique's supply potential.[13]
- **Standard Bank – The Potential Impact of LNG on African Gas-to-Power:** This publication highlights the potential of kickstarting an African gas market through small-scale LNG projects, including the development of gas-to-power projects. It points out how several African countries leveraged LNG imports to offset maturing domestic gas production.[14]
- **Deloitte – The Socioeconomic Impact of Importing LNG into the West Coast of the Western Cape:** According to this publication, a strong case exists for the use of imported natural gas in power generation in the Western Cape. The study highlights the economic and social benefits of gas importation.[15]
- **Africa Energy – Bridging Africa's Energy Gap:** This article concludes that many countries across Africa have an opportunity to use current developments in the LNG market to bridge their energy gaps. LNG's increasing flexibility can potentially accelerate onshore value and drive innovation when countries are trying to raise large-scale capital for African projects.[16]

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[10] South Africa Department of Energy (2017); *Gas-based industrialization in South Africa*

[11] South Africa dti (2017); Industrializing the KZN-Gauteng corridor through natural gas

[12] South Africa dti (2015); The potential for Gas-Based industrialization in South Africa

[13] ICF International (2012); The Future of Natural Gas in Mozambique: Towards a Gas Master Plan

[14] Standard Bank (2016); The potential impact of LNG on African gas to power

[15] Deloitte (February 2015); Socio-economic impact of importing LNG into the West Coast of the Western Cape

[16] 2016 Africa Energy Yearbook (2016); *Bridging Africa's energy gap*

- **Transnet – Natural Gas Infrastructure Planning:** This report, which focuses on South Africa, examines three potential gas terminals and their associated pipeline networks. It sets out potential infrastructure and expansion plans for natural gas growth in South Africa.[17]

1.6 STRUCTURE OF THIS REPORT

This report is intended to inform policy decisions at various levels. It employs a regional perspective but conclusions are based upon in-depth analyses of data from each country and across the region. The methodology employs is a combination of high-level quantitative analysis, reviews of publicly available sources, and expert interviews whenever appropriate. Where possible, USAID SAEP adopted a conservative approach across all analyses and modelling techniques adopted, and therefore this report is more likely to understate than to overstate the region's gas potential.

Several quantitative models support the findings, including:

- **A Gas Demand Model:** This evaluates the gas demand potential in the four focus countries under various scenarios. It is based on granular gas-to-power project pipelines, which are combined with a top-down approach for gas demand from the industrial, transportation, and residential & commercial sectors (**Exhibit 20** in the Appendix provides a brief walkthrough).
- **A Gas Pipeline Model:** This model uses a simple cash-flow approach to assess the tariff ($/mmbtu) required to provide an expected return to debt and equity investors. It employs various technical and cost assumptions around the construction and operation of the gas pipeline (**Exhibit 21** in the Appendix provides a brief walkthrough).
- **An LNG Tariff Build-Up Model:** Based on a free cash-flow approach and an outside-in assessment, this model is comprised of three components that build up the tariff ($/mmbtu) of the LNG value chain (liquefaction, shipping and regasification).
- **A Simplified Transmission Line + Open- or Combined-Cycle Gas Turbine (OCGT)/CCGT Model:** Based on a free cash-flow approach, these models solve for two parameters: the built-up cost of the power generation required to provide an expected return to debt and equity investors, which is based on assumptions around fuel-input costs and transmission distances; and the funds ($/mmbtu) that would be available for the natural gas development to fuel a given OCGT/CCGT plant and still meet a competitive tariff ($/kWh). [18]

The rest of this report is structured along five main themes.

- *Chapter Two: Natural Gas Supply Potential* outlines the supply potential for each focus country, and explains why developing gas resources for the benefit of gas-to-power would benefit the countries' energy sectors.
- *Chapter Three: Natural Gas Demand Potential* evaluates the gas demand potential for each country and the three demand sectors of gas-to-power, transportation, and industry. It then defines three demand scenarios and forecasts potential demand for the focus countries.
- *Chapter Four: Supply and Demand Balances and the Emergency of Three Gas Systems* examines the countries' supply and demand profiles and uses these to design three potential gas systems that would provide optimal economic and social benefits. It also covers potential infrastructure options to for those countries that have the potential to trade gas balances.
- *Chapter Five: Regulatory Environment for Natural Gas in Southern Africa* discusses the regulatory environment in the four focus countries, and evaluates the type of enabling environment that may be required for natural gas development.
- *Chapter Six: Recommendations* discusses the various steps USAID SAEP could consider based on this report's findings and the gas roadmap work.
- The Appendix provides extensive detail and background around many of the topics discussed in the body of this document

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[17] Transnet Long Term Planning Framework (2015); *Natural gas infrastructure planning*

[18] Used in the case of Botswana and Namibia to assess the competitive potential for upstream gas development, for its application in gas-to-power projects

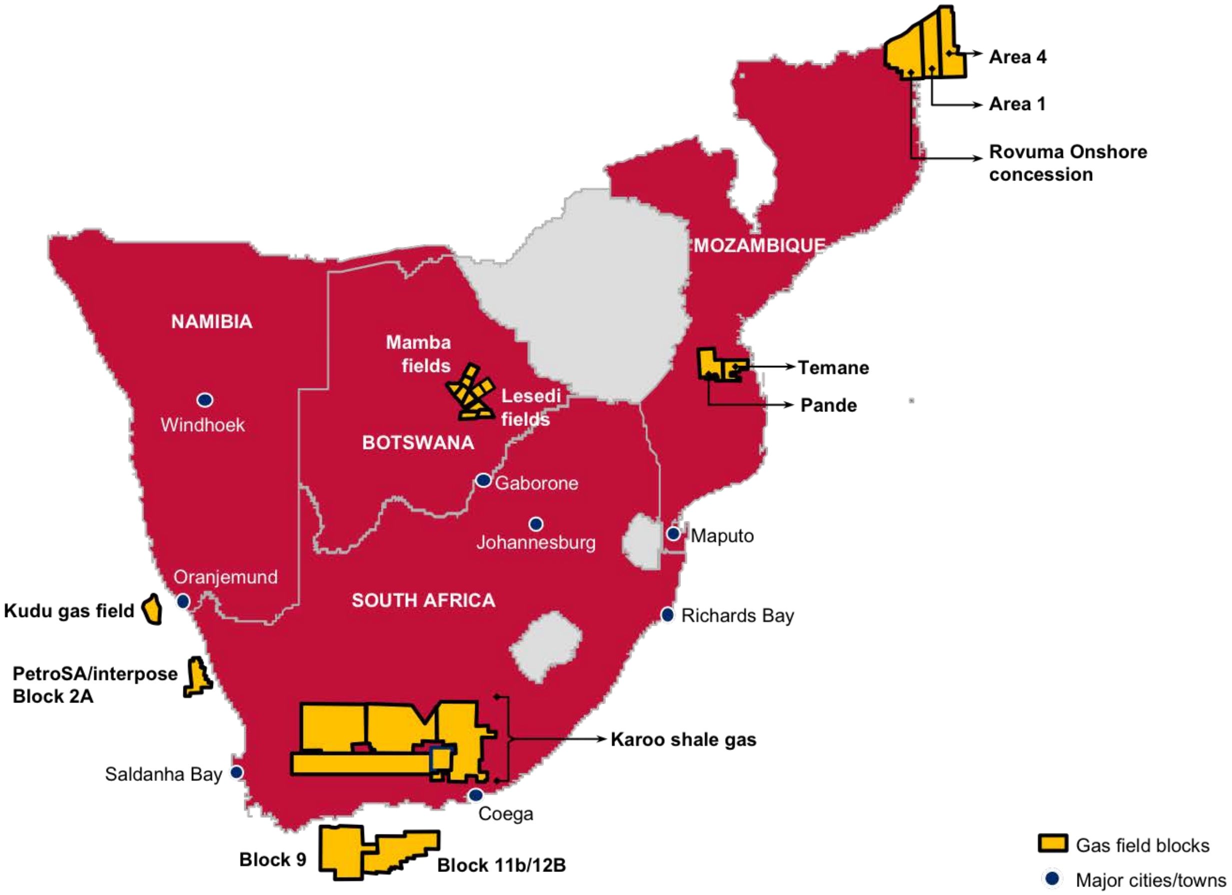
2. NATURAL GAS SUPPLY POTENTIAL

2.1 LOCAL SUPPLY POTENTIAL.

The discovered gas reserves of the four focus countries are mostly undeveloped, apart from some relatively minor production in South Africa and Mozambique. Exhibit 3 depicts the most important blocks and field discoveries in the four focus countries. We systematically discuss the supply potential of the focus countries in Sections 2.1.1 to 2.1.4. **Exhibit 23** to **Exhibit 25**, located in the Appendix, give a comprehensive overview of all known fields, along with their associated reserves and estimated annual production volumes.

EXHIBIT 3

SOUTHERN AFRICA'S GAS BLOCKS AND FIELD DISCOVERIES



SOURCE: Bowmans, Tlou Energy, Westbridge Energy

2.1.1 BOTSWANA

Botswana discovered CBM reserves in the Lesedi region. CBM is a type of unconventional gas, as opposed to conventional sources like Mozambique's. The estimates of its reserves vary widely, partially because there are different classes of reserves:

- Commercial reserves:
    - 1P reserves (proved reserves): these reserves are the most certain.
    - 2P reserves (probable reserves): These reserves include 1P reserves and "probable" reserves. In other words, 1P reserves are a subset of a field's 2P reserves.
    - 3P reserves (possible reserves): These reserves include 1P and 2P and "possible" reserves. In other words, 1P and 2P reserves are subsets of 3P reserves.
- Sub-commercial reserves (i.e., contingent resources) are classified similarly to commercial reserves as 1C, 2C, or 3C. Their scope expands as the uncertainty increases, and each category includes the ones before it.

Generally, recoverable reserves reflect 3P reserves. In Botswana's Lesedi field, the concessionaire Tlou Energy estimates 3C sources at 3.2 tcf,[19] and places the 1P and 3P reserves at 0.15 tcf and 0.261 tcf respectively.[20] We assume the 3P reserves to be ~0.3 tcf, with a forecast annual production of ~10 PJ/year (25 mmscfd). Although additional CBM resources may be discovered through other Botswana coal mining licenses, we did not have access to any additional credible sources which confirmed and / or quantified these volumes.

Given the overall conservative approach of this report, we estimate Botswana's overall gas supply potential to be 10 PJ/year (25 mmscfd).

METHODOLOGY

We relied on public sources for the gas supply potential assessment, primarily using Wood-Mackenzie, which tracks the world's oil and gas reserves. Its database differentiates between recoverable reserves (i.e., the fraction of the original oil and gas which is deemed technically recoverable), remaining reserves (i.e., the fraction of the recoverable reserves remaining, net of what has been produced), and the commercial remaining reserves (the reserves it deems commercially recoverable under current price projections). We used "remaining recoverable reserves" for our analyses. Other public sources were used to cover gas fields that Wood-Mackenzie did not (e.g., Botswana's CBM fields or South Africa's shale gas in the Karoo). In addition, spot cross-checks were performed with Rystad, another industry database mapping oil and gas reserves.

Gas reserves are typically measured in billion or trillion cubic feet (bcf or tcf). Other units of measure which are used are million barrels of oil equivalent (mmboe), or billion cubic meters (bcm). For comparison purposes across other energy sources, we converted tcf volumes to PetaJoules (PJ), which is 1015 Joules) – One tcf equals ~1,097 PJ. Exhibit 21 in the Appendix provides a quick conversion table. A 'cheat sheet' is located in Exhibit 22 within the Appendix, for quick conversions across benchmark volumes.

To evaluate supply and demand balances, we converted gas reserves to annually produced volumes. For fields Wood-Mackenzie deemed commercial, the models estimated the expected production profiles (i.e., the expected output in any given year). Wood-Mackenzie does not model production profiles for less certain fields. For any gas field that was not yet producing, we assumed that the remaining recoverable reserves would be produced over a period of 30 years. The industry generally considers this a reasonable expectation for the life of natural gas fields. We used no ramp-up periods, and held the production profile flat for the field's lifetime. This is justified because the analysis focuses on 2030, a distinct point in time that allows the field's production to plateau. We also applied this method to fields with production profiles from Wood-Mackenzie to test for significant inaccuracies; none were found.

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[19] Tlou Energy; http://tlouenergy.com/lesedi-cbm-project

[20] http://www.londonstockexchange.com/exchange/news/market-news/market-news-detail/TLOU/13127898.html

2.1.2 MOZAMBIQUE

Mozambique has the largest gas discoveries among the focus countries. Combining all known recoverable reserves (i.e., on and offshore natural gas, CBM) and converting them via the simplified approach (see methodology box on previous page) into an annual output, Mozambique's total annual output in 2030 could be as high as ~4,579 PJ/year (~11,434 mmscfd). Even if a substantial part of these volumes would be initially locked in for export through LNG, vast potential remains for local and/or regional supply.

Around 2010, Mozambique discovered significant offshore natural gas reserves in the Rovuma basin, which is offshore of Palma in the Cabo Delgado province in northern Mozambique. Wood-Mackenzie estimates the total recoverable Rovuma reserves at ~120 tcf; however, this can be considered relatively conservative as estimates from other sources range up to 180 – 200 tcf.[21] Relatively small offshore reserves were also found at the Njika and Buzi fields, totalling ~1.3 tcf of recoverable reserves.

Two offshore blocks are particularly relevant at Rovuma – Area One and Area Four:

- **Area One** is operated by Anadarko, which owns a 26.5 percent stake of the block. The other largest stakes belong to Mistui & Co (20 percent) and Egencia Nacional Hydrocarbones (ENH), the Mozambican national hydrocarbon company, at 15 percent. The remaining 38.5 percent is owned by Beas Rovuma Energy Mozambique (India, a joint venture of OVL and Oil India Limited), Bharat Petroleum (India), ONGC (India), and PTTEP (Thailand). The total recoverable reserves are estimated at 63 tcf across five fields (Golfinho Area 33.8 tcf, Prosperidade 25.5 tcf, Tubarao Tigre 2.6 tcf, Tubarao 1 tcf, and Ironclad 0.03 tcf). None of the fields are currently producing. The Golfhinho area appears likely to be developed with an estimated production start-up date of 2023.[22] Estimates indicate that 15.2 tcf of its reserves are currently commercially recoverable. Anadarko aims to develop the field as a feed to the Mozambique LNG project (MZLNG), which currently envisions two LNG trains with a total capacity of 12 mtpa.
- **Area Four** is operated by ENI East Africa, which owns 70 percent of the block (ENI has an indirect stake of 25 percent, ExxonMobil 25 percent, and China's National Petroleum Corporation (CNPC) 20 percent).[23] ENH owns 10 percent of the block, and the remaining 20 percent is split evenly between Galp Energia (Portugal) and KOGAS (South Korea). Area Four comprises total recoverable gas reserves of 58.2 tcf, split among three fields: the Mamba complex (44.8 tcf); the Coral field (11.6 tcf); and the Agulha field (1.7 tcf). Estimates indicate that currently 17.6 tcf of these reserves are commercially recoverable.[24] The Coral field is currently being developed, and ENI is building a floating LNG (FLNG) terminal with a capacity of 3.4 mtpa.[25]

In addition to these recent offshore discoveries, Mozambique is already producing gas from its onshore Pande/Temane fields, which are located ~500 kms from Maputo and operated by Sasol (with 70 percent ownership). Production started in 2004 at Temane and its remaining recoverable reserves are estimated at 2.3 tcf. Although potential additional discoveries of ~5 tcf were mentioned at a Mozambican gas conference held ,October 18-20,2017, no written confirmation is available. As a result, these were not included in the analysis. Production is also expected to come online from the adjacent Inhassoro PSA, which has recoverable reserves of 0.4 tcf (100 percent owned by Sasol). All three fields feed the 865 km Republic of Mozambique Pipeline Company (ROMPCO) pipeline to Secunda, South Africa.[26]

Lastly, Mozambique is expected to have unconventional gas potential from its CBM resources in the Tete region. However, these reserves are still unquantified and would probably be economically challenging to develop, especially when compared to the country's conventional gas reserves.

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[21] https://macauhub.com.mo/2016/10/21/exxonmobil-will-explore-gas-in-area-4-of-the-rovuma-basin-in-mozambique/; http://text.ipim.gov.mo/en/portuguese-speaking-countries-news/government-of-mozambique-revises-natural-gas-reserves-of-the-rovuma-basin-upwards/

[22] Wood-Mackenzie

[23] http://news.exxonmobil.com/press-release/exxonmobil-acquire-25-percent-interest-mozambique-area-4-eni

[24] Wood-Mackenzie

[25] https://www.eni.com/en_IT/media/2017/06/eni-launches-coral-south-project-in-mozambique

[26] https://www.igu.org/sites/default/files/3-3 percent20IFC%20-%20Katia%20Daude%20Goncalves%20-%20Gas%20Competence%20Seminar%20-%20September%2022%202015.pdf

When it comes to estimated production costs, the onshore reserves in the Pande and Temane fields appear to have the lowest upstream-development cost in Mozambique, which is estimated to be between \$0.25 -\$0.38/mmbtu.[27]

The Rovuma basin's production costs appear to be higher, with a weighted average cost of \$2.09/mmbtu (**Exhibit 26** in the Appendix breaks down development costs for individual fields). After processing and localized piping costs of \$0.75/mmbtu are added on, the total cost of 'ready-to-use' gas from the Rovuma basin is estimated to be \$2.84/mmbtu, inclusive of all taxes and royalties (a detailed breakdown of the break-even cost components in provided in **Exhibit 27**) This figure is based on the ICF International Report's cost estimates from 2012 because no more recent objective, public cost estimates or sources were available. Because of this, the number may be slightly outdated.

2.1.3 NAMIBIA

Namibia's one substantial gas resource is the offshore Kudu field, which is ~130 km offshore near the city of Oranjemund. Its reserves are estimated at 1.3 tcf.[28] Although Kudu was discovered in 1974, it has not been developed. If Kudu comes online by 2030, Namibia's gas supply potential is estimated to be ~48 PJ/year (120 mmscfd). Section 4.3.3 discusses the background of this field in more detail.

2.1.4 SOUTH AFRICA

South Africa has the longest history of upstream gas production among the four focus countries. Using the same methodology, we estimate their supply potential at 83 PJ/year (207 mmscfd) by 2030. This stems largely from the potential development of the offshore blocks, excluding any volumes from the Karoo. We also assume that the currently known reserves at Mossel Bay are depleted by 2030. South Africa's supply situation includes:

- **Current production** in Block Nine from the Mossel Bay Gas and South Coast Gas project fields (both operated by PetroSA) provides approximately nineteen to twenty kilo barrels of oil equivalent per day (kboepd). Both fields feed into the Mossel Bay GTL plant, which has been operating since 1992.[29] The fields are now largely depleted, and a 2015 drilling campaign that tried to increase the reserve base was largely unsuccessful.[30] As a result, the remaining recoverable reserves base is a relatively modest 0.2 tcf. In September 2017, PetroSA announced that it and Russian State Geological Company (ROSGEO) would invest \$400 million in increased exploration in Block Nine and 11A.[31] If no new discoveries are made, it is very likely that the block's output will decline to zero by 2030.
- **Offshore discoveries in various offshore blocks** currently add up to a combined recoverable reserve base of ~2 tcf. Reserves from the fields in Block Two A (including the Ibhubesi field) equal 1.5 tcf. Interpose Holdings (former Sunbird Energy) owns 76 percent of this block and PetroSA owns 24 percent.[32] Although these discoveries occurred in 1987 and the early 2000s, production has not started and it is unclear whether solid plans exist to do so. PetroSA owns Block Eleven A, with ~0.5 tcf of reserves, but it is unlikely to be developed. Block Eleven was also included in the recent exploration deal between PetroSA and ROSGEO.

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[27] ICF International (2012); The Future of Natural Gas in Mozambique: Towards a Gas Master Plan

[28] Wood-Mackenzie

[29] http://www.petrosa.co.za/innovation_in_action/Pages/Operations-and-Refinery.aspx

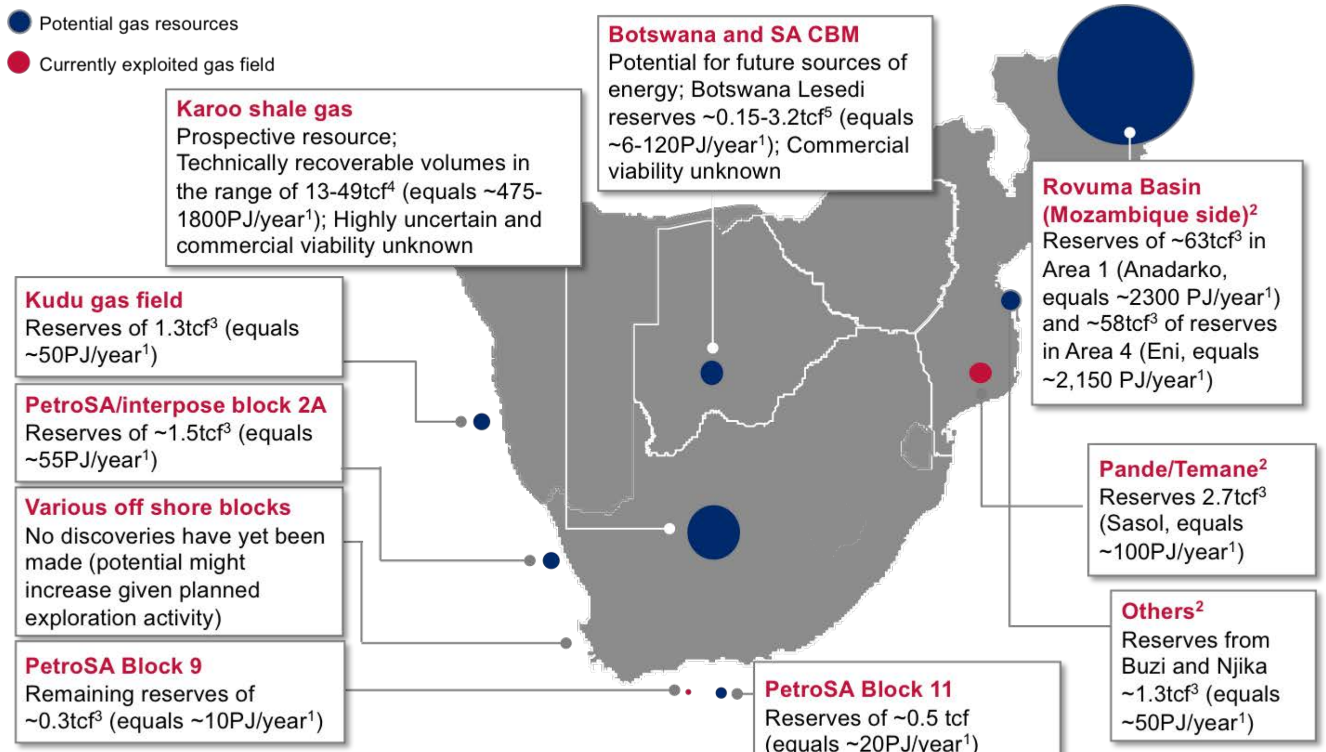
[30] https://af.reuters.com/article/commoditiesNewsidAFL8N12F3FA20151015

[31] http://www.petrosa.co.za/PressReleases/Pages/PetroSA-AND-ROSGEO-SIGN-MULTI-MILLION-DOLLAR-AGREEMENT-TO-DEVELOP-OIL-AND-GAS-BLOCKS-IN-SOUTH-AFRICA.aspx

[32] https://www.iol.co.za/business-report/companies/sunbird-still-plans-to-list-7136261; https://www.bloomberg.com/research/stocks/private/snapshot.asp?privcapId=143309727

EXHIBIT 4

SNAPSHOT OF THE GAS SUPPLY POTENTIAL IN THE 4 FOCUS COUNTRIES



Karoo shale gas
Prospective resource; Technically recoverable volumes in the range of 13-49tcf[4] (equals ~475-1800PJ/year[1]); Highly uncertain and commercial viability unknown

Botswana and SA CBM
Potential for future sources of energy; Botswana Lesedi reserves ~0.15-3.2tcf[5] (equals ~6-120PJ/year[1]); Commercial viability unknown

Rovuma Basin (Mozambique side)[2]
Reserves of ~63tcf[3] in Area 1 (Anadarko, equals ~2300 PJ/year[1]) and ~58tcf[3] of reserves in Area 4 (Eni, equals ~2,150 PJ/year[1])

Kudu gas field
Reserves of 1.3tcf[3] (equals ~50PJ/year[1])

PetroSA/interpose block 2A
Reserves of ~1.5tcf[3] (equals ~55PJ/year[1])

Various off shore blocks
No discoveries have yet been made (potential might increase given planned exploration activity)

Pande/Temane[2]
Reserves 2.7tcf[3] (Sasol, equals ~100PJ/year[1])

Others[2]
Reserves from Buzi and Njika ~1.3tcf[3] (equals ~50PJ/year[1])

PetroSA Block 9
Remaining reserves of ~0.3tcf[3] (equals ~10PJ/year[1])

PetroSA Block 11
Reserves of ~0.5 tcf (equals ~20PJ/year[1])

NOTE: Based on WoodMackenzie or publicly available sources
1 Assuming all reserves can be produced within 30 years, constant production profile over lifetime of fields
2 Potential gas reserves in Mozambique can be as high as 180-200 tcf, current numbers mentioned are reserves recognized and tracked in WoodMackenzie and Rystad databases; according to some sources (October-18-20 2017 Mozambique gas conference) most recent gas discoveries in Pande/Temane might add an additional 5tcf to the PSA
3 Total proven and probable (2P) reserves
4 13tcf estimate assumed contingent proved (1C) resources, and 49tcf estimate assumed contingent proved, probable and possible (3C) resources
5 0.15tcf estimate are proved (1P) resources, and 3.2tcf estimates are contingent proved, probable and possible (3C) resources

SOURCE: WoodMackenzie, South African Journal of Science

- **The Karoo Shale Gas Basin** appears to have sizeable potential, but these estimates are highly uncertain and controversial. Sources previously estimated reserves at a dazzling 485 tcf, but recent estimates (September 2017) showed much less potential. More realistic reserves ranged from 13 – 49 tcf, with the lower limit being the more likely one.[33] The development of the Karoo's shale gas reserves is also highly contentious, given the environmental concerns associated with them. These include the general opposition to fracking and concerns about production's use of much-needed water in the dry Karoo region. At a September 2017 conference, a Shell SA spokesman stated, "There is a strong likelihood that this process may not proceed beyond exploration."[34] Even if development did occur, it is unlikely that any sizable output would be produced by 2030 given the shale reserves' dispersed nature and the need to develop infrastructure and a value chain (which is likely to take more than a decade). We therefore excluded any output from the Karoo shale gas basin before 2030 from our analysis.

Exhibit 4 above summarizes the region's gas resources, and annual energy supply potential.

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[33] https://www.businesslive.co.za/bd/national/science-and-environment/2017-09-28-tests-reveal-less-karoo-shale-gas-than-expected/

[34] https://www.businesslive.co.za/bd/national/science-and-environment/2017-09-28-tests-reveal-less-karoo-shale-gas-than-expected/

2.2 BENEFITS OF GAS DEVELOPMENT

The economies of resource-holding countries can capture real benefits from developing natural gas resources. They can generate employment (directly and indirectly), increase GDP (directly and indirectly), increase foreign direct investments, and, with exports, increase the inflow of foreign currency. These stem from both the extraction and utilization of natural gas. Similar results could be demonstrated by the South African region.

The extraction and / or development of natural gas can provide substantial socioeconomic gains. This is particularly true of unconventional gas development and increased employment opportunities, given the increased complexity. One study by the South African Department of Trade and Industry estimates that ~22,800 permanent direct jobs are required for an unconventional gas basin with an output of 0.5 tcf/annum.[35] These jobs result directly from operating the technology involved, and from the first-level suppliers during operations. They include positions like drilling rig crews, truck drivers, jobs at manufacturers who supply well casings, etc. Another ~33,600 estimated permanent indirect jobs are also associated with an unconventional gas development. These jobs result from associated activities further down the value chain, e.g., jobs from 'suppliers to suppliers' (e.g. iron ore miners). One McKinsey Global Institute (MGI) report estimates that the shale-extraction industry could create 44,000 to 102,000 permanent jobs for South Africa.[36]

Natural gas utilization can provide significant benefits by driving industrialization or as a fuel source. In terms of industrialization, gas can serve as a feedstock for the fertilizer and petrochemical industries, or as a source of heat or power in energy-intensive industries (e.g., aluminium or cement).[37] When carefully developed, this utilization can increase employment and produce positive spin-off effects in the local economy (e.g., the availability of cheap fertilizers can support agricultural development). When available gas volumes are sufficiently large, it is even possible to convert gas to liquid fuels through GTL plants. These can enhance the balance of payments in countries that import liquid fuels. The aforementioned study by the South African Department of Trade and Industry estimated that such a GTL facility (with a capacity of 180,000 barrels per day) could create a further ~3,000 to ~8,000 sustainable jobs, highlighting the strong employment potential of the downstream gas sector as well.

When used as a fuel source, gas-fired power generation can make an important contribution to a sustainable energy mix can help balance supply and demand, diversify the energy mix, and improve costs.

- **It can complement an intermittent supply of renewable energy generation and maintain relatively low emissions.** In line with global trends and USAID SAEP's objectives and mandate, Southern Africa is increasingly focusing on renewable sources of power generation. Its primary aspiration is to reduce emissions, which are largely generated by fossil fuel-based energy sources (e.g., coal). However, the intermittent nature of most renewable energy sources (e.g., wind, solar, and hydro) increases the need for a flexible source of generation to balance power supply and demand. Gas-fired power generation is well-positioned to fill this role, given how flexibly it can scale its power output up and down, while resulting in relatively low emissions (compared to diesel / HFO or coal).

Key Takeaways

Substantial amounts of gas have been discovered in the four focus countries, with Mozambique having the largest available resources. Development of these resources can support the strengthening of the local energy sectors (as a relatively low-carbon component to a diversified sustainable energy mix), and fuel industrialization..

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[35] South Africa Department of Trade and Industry, *The Potential for Gas-Based Industrialisation in South Africa (*2015)

[36] McKinsey Global Institute, *South Africa's big five, bold priorities for inclusive growth* (September 2015)

[37] CIP, Serviço de Partilha de Informação – *Gas for development or just for money?* (2015)

- **Gas can help diversify the countries' energy sources.** Most countries in Southern Africa (except South Africa) have a supply system that is skewed towards one or two sources of generation. Hydro power is often the largest generation component, complemented with peak generation from diesel / HFO-fired power plants. This implies significant risks, both to the availability of generation (e.g. case of droughts) as well as the price of generation and the associated balances of payments (e.g. in case of rising liquid fuel prices as these are often imported). Diversifying the generation portfolio with gas has the potential to lower the countries' risk profiles.

- **It can be more cost-competitive compared to other sources of generation.** Gas can be relatively cheap (~8/ mmbtu), especially when compared to liquid fuels such as diesel, HFO, or LPG (~$15-$20/mmbtu).[38] Natural gas could displace these liquid fuels in both power generation in OCGTs and in wider applications like industrial use and transport when it is available. Several countries in the Southern African region are currently considering the conversion of diesel or HFO-fired power stations (e.g., Ankerlig in South Africa, Orapa in Botswana).[39]

These regional benefits are why SADC wants to seize the opportunity to develop the discovered resources. Real economic and social development could follow, far beyond the direct economic benefits of gas exports alone.

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[38] Gas Based Industrialization in South Africa, 2017

[39] http://www.miningweekly.com/article/eskom-moves-ahead-with-dual-fuel-conversion-of-ocgt-plants-despite-gas-uncertainty-2016-01-21; http://tlouenergy.com/wp-content/uploads/2016/11/AGM-Presentation.pdf

3. NATURAL GAS DEMAND POTENTIAL

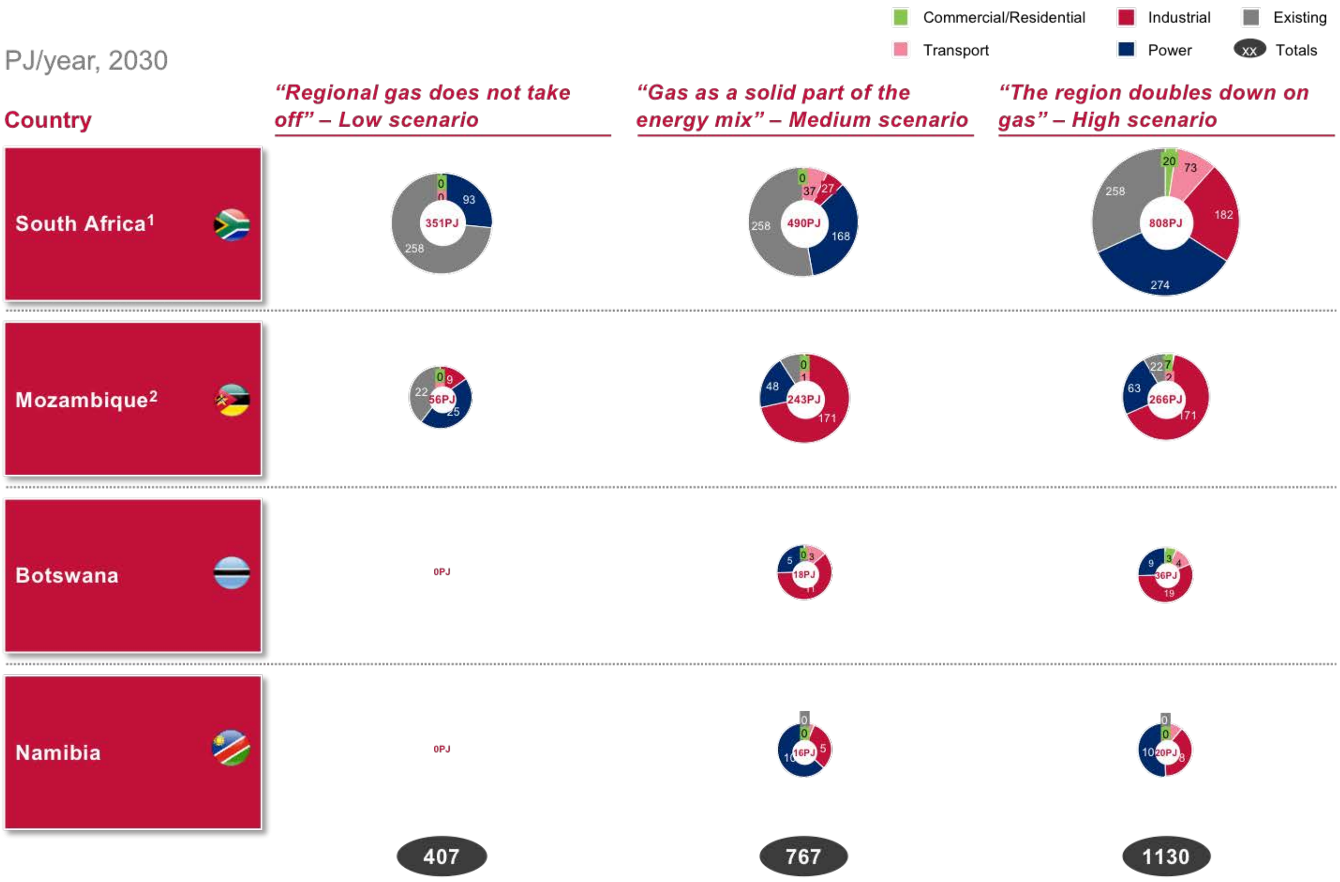
Our analysis shows that in the medium-term (by 2030), the demand for natural gas in Southern Africa could grow considerably. Demand has the potential to almost triple to 767 PJ/year (1,915 mmscfd) by 2030 from its current level of 280 PJ/year (699 mmscfd) in a medium or base case scenario. Most of this demand growth is expected to occur in Mozambique (253 PJ/year, or 632 mmscfd) and South Africa (490 PJ/year, or 1,224 mmscfd), with considerably smaller pockets in Botswana (18 PJ/year, or 45 mmscfd) and Namibia (16 PJ/year, or 40 mmscfd). In terms of the sectors, the power (250 PJ/year, or 624 mmscfd) and industrial (479 PJ/year, or 1,196 mmscfd) sectors are likely to drive most of this potential growth, while the transport sector's contribution (42 PJ/year, or 105 mmscfd) is only marginal. Commercial and residential demand will probably remain relatively negligible in the region (<1 PJ/year, or <1 mmscfd).

3.1 APPROACH TO GAS DEMAND FORECASTING

The demand forecasts examined Southern Africa's gas potential from a medium-term perspective, going out to 2030. They took a high-level overview of energy consumption in the region, focusing on the application of gas to the power sector. However, they also considered the wider landscape to determine gas' full utilization and development potential. In terms of methodology, the

EXHIBIT 5

OVERVIEW OF DEMAND ASSESSMENT



1 Includes 258PJ of existing demand

2 Includes 22PJ of existing demand

SOURCE: Derived from bottom-up evaluation (IRP 2016, EIA energy balances, IPP gas-to-power programme, among others) quantitative analysis was combined with empirical analysis whenever relevant and available. A broad range of sources were used, including publicly available data, institutional reports, databases, and expert interviews.

Gas demand was categorized into four sectors – power, industry, transport and, commercial / residential.[40] A sector-specific approach was used to assess demand:

- **Power:** The demand for gas-to-power was assessed from the perspective of new and existing CCGT power plants, and the potential to convert other fuel-driven power plants to gas.
- **Industry:** Industry demand for gas was assessed based on the expected growth trajectory of current industrial gas use, and on the ability for specific sectors to switch non-gas fueled energy consumption for heat, feedstock or off-grid electricity generation, into gas fueled energy.
- **Transport:** Advances in engine technology offer a largely untapped opportunity to convert transport vehicles to compressed natural gas (CNG) or LNG. Therefore, transport fleets of passenger cars, public transport, commercial fleets, long-haul trucks, rail, and shipping, were considered.
- **Commercial and Residential:** Small pockets of direct coal and petroleum-product consumption (e.g., LPG for cooking) were assessed as having switching potential into gas. However most of the energy used by the commercial and residential sector is electricity-based, and it is difficult to run most electric appliances off other fuel sources.

3.1.1 SCENARIO DEFINITION

While the analysis revealed the enormous potential in gas demand growth, it provided limited insight into how much of this demand could realistically materialize – or not – in each sector. The degree to which each sector could incorporate gas into its mix could vary greatly, from one extreme where no gas enters the fuel mix to a case where all energy that can switch to gas does so. The real potential for each sector would depend on the different assumptions and conditions associated with that sector.

- As a result, we employed scenario analysis to define the likely gas demand landscape both overall and for each sector, based on the specific assumptions and conditions that are believed to exist. We created three scenarios that varied the extent to which the energy policy and enabling environment drive gas use. Selecting energy policy as the key macro-level influencer and the overarching adjustable factor made sense because:
- The energy sector in developing nations tends to be nationalized, which can make it more susceptible to energy policy. Given the integrated value chain requirements for gas and large investments, it would be essential to have a clear national strategy and direction.
- USAID SAEP could support energy policy development directly by making the gas roadmap action-oriented.

The three resulting demand scenarios are described below; their practical applications for demand are provided in Section 3.2. **Exhibit 28** in the Appendix provides a more detailed breakdown.

- **Low** – *Regional gas does not take off.* Headwinds against gas development exist in the regulatory and commercial environment, governments tend to favor labor-intensive coal power generation, and the industry continues to operate in a business-as-usual environment.
- **Medium (Base Case)** – *Gas as a solid part of the energy mix.* Gas, along with other fuel sources, plays an important role in diversifying the energy mix. Industry and transport take part in the gas sector's development. This scenario (with its assumptions and outcomes) is used for the rest of the gas roadmap assessment in this report. It should further be noted that even for this base case, the assumptions are still cautious in order to provide a realistic yet conservative view.
- **High** – *The region doubles down on gas.* Strong government agendas exist and increase gas utilization across all sectors. These are supported by favorable policies and economics.

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[40] Commercial and residential are considered together as they are both small demand figures

3.1.2 REGIONAL AND COUNTRY SCENARIO FINDINGS

The results of the sector segmentation and scenario variability (Exhibit 5) produced a set of preliminary conclusions.

- **Southern Africa's Gas Landscape is Expected to Grow Significantly from the Current Base of ~280 PJ/year (699 mmscfd)**
  - Under the Medium / base case scenario, this figure could almost triple to 767 PJ/year (1,915 mmscfd) by 2030.
  - Even under the Low scenario, gas usage could grow to over 407 PJ/year (1,016 mmscfd) by 2030, indicating the region's strong gas trajectory.
  - In the High scenario, which has a strong, focused, and deliberate agenda to encourage gas usage, demand could increase fourfold to over 1,130 PJ/year (2,822 mmscfd).
- **While the Region Shows Strong Demand Potential Overall, Most of this is Concentrated Within Mozambique and South Africa**
  - South Africa is expected to generate the lion's share of new demand (232 PJ/year, or 579 mmscfd) by building on its strong industrial gas consumption profile and the large power sector development plans outlined in its IRP. The Medium scenario assumes that ~5,200 MW of the total planned 7,320 MW of new build CCGT capacity from the IRP will materialize.
  - Mozambique plans to use a significant portion of its vast gas reserves to develop its domestic power and industrial sectors (220 PJ/year, or 549 mmscfd). ~1,015 MW of new gas-fired power generation capacity is forecast to come online under the Medium scenario, along with sizable gas demand from the planned Shell 38,000 barrel/day GTL plant and Yara's 1.3 mtpa fertilizer plant.
  - Botswana (18 PJ/year, or 45 mmscfd), and Namibia (16 PJ/year, or 40 mmscfd) have limited scope for new demand because of their smaller footprint and the fact that their projects are linked directly to uncertain upstream supply potential.
- **The Power and Industrial Sectors Will Anchor Future Gas Demand, as They Do Now, While the Transport, Commercial and Residential Sectors Will be Secondary Beneficiaries**
  - Together, the power and industry sectors are forecast to make up 725 PJ/year (1,810 mmscfd) of the region's total 767 PJ/year (1,915 mmscfd) of gas demand in 2030. This is driven both by the fact that the two sectors are the only components of the current demand base (280 PJ/year, or 699 mmscfd), and that they make the largest contributions to the incremental demand that is over and above today's usage (445 PJ/year out of 487 PJ/year, or 1,111 mmscfd out of 1,216 mmscfd).
    - Under the Medium scenario, ~6,500 MW of Southern Africa's gas-based power generation projects are expected to be operational by 2030, and a further 760 MW of non-gas-powered plants could be converted into gas use. Combined with existing plants, gas-to-power use will contribute 248 PJ/year (619 mmscfd) of demand by 2030.
    - Industrial demand is expected to continue as the region's largest gas consumer. From a current use of 264 PJ/year (659 mmscfd), industrial gas use in the Medium scenario is expected to reach ~477 PJ/year (1,191 mmscfd) by 2030. The growth would largely come from new industry commitments in Mozambique.
  - Although transport demand could contribute a sizable volume (42 PJ/year, or 105 mmscfd) under the Medium scenario, it remains small relative to the total gas landscape and is unlikely to anchor regional gas development on its own.

- Commercial and residential are unlikely to contribute meaningfully to gas demand given the low price-incentives and dispersed nature of their demand. They are only likely to make a real difference in the High scenario, when regulatory incentives are very strong and the gas distribution infrastructure becomes more established. Even then, their contribution would probably remain marginal.

3.2 DEMAND ESTIMATION METHODOLOGY AND ITS APPLICATION IN THE SCENARIO ANALYSIS

This section describes the methodology used to estimate the likely gas demand potential for the various scenarios. Depending on the scenario, we estimated the extent to which the potential gas demand can materialize based on each sector's underlying drivers.

- Power
  - *Methodology:* The analysis for gas-to-power demand took a bottom-up view of the pipeline of future gas and non-gas power projects in each country. We used Platts' UDI World Electric Power Plants Database (WEPP) as an initial source; it is a global inventory for power-generating units across the world and is widely regarded as the best available public source. USAID SAEP expanded and adjusted this list based on stakeholder conversations, additional press searches, and company reports. The likelihood that each project would come online by 2030 was also evaluated. Once a final project list was developed for the scenario, USAID SAEP calculated the required gas demand to input by accounting for each plant's size, their thermal efficiencies, and their expected load factors.[41] For this report, the current assessment methodology excludes demand from off-grid and municipal-level generation projects.[42] The inclusion of such projects would be unlikely to materially change the conclusions of this report.
  - *Variations by scenario:* The variable that was adjusted across the scenarios for power was whether individual projects are expected to materialize by 2030, and therefore contribute to gas demand. In the Low scenario, only the gas-to-power projects that were assessed to be highly concrete are assumed to come online; in the Medium scenario, likely gas-to-power projects and expected diesel / HFO plant conversions were expected to materialize; and in the High scenario, this assumption was made about a more liberal gas-to-power project list and likely diesel / HFO and potential coal-plant to gas conversions. **Exhibit 29** to **Exhibit 36** in the Appendix give detailed breakdowns of power projects by country and their application to each scenario.
- Industry
  - *Methodology:* The top-down approach broke current demand down into sub-sector and fuel type based on the World Energy Balances.[43] These balances incorporate both public and private sector industrial energy use for electricity, heating, and feedstock. Demand is then extrapolated using expected growth trajectories to assess fuel demand out to 2030.[44] Where available, we complemented this approach with a bottom-up analysis that added further details or incorporated important new industries not reflected by the standard growth factors.
  - *Variations by Scenarios:* We filtered industrial demand across multiple dimensions including: industry sub-sector, dividing these into those that could easily switch their fuel use to gas (e.g., those that use diesel to generate electricity off-grid) and those that are unlikely to do so (e.g., aluminum smelters requiring coal to achieve high temperatures); and provincial region, to include only those regions that have a dense industry concentration or lie close to likely supply sources which would justify investment costs.[45]

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[41] Assumptions around thermal efficiencies and load factors for each country given in Exhibit 28, Exhibit 30, Exhibit 32, Exhibit 34.

[42] We are aware that in South Africa, Ekurhuleni Metro Municipality (EMM) has set an allocation for 195MW of gas-to-power projects, of which ~106MW is known to already be tendered for. This has been excluded from our demand build up given its relatively small contribution (~6 PJ/year), regulatory hurdles in getting approval from NERSA, and no known gas supply agreements.

[43] International Energy Agency (2015); World Energy Balances

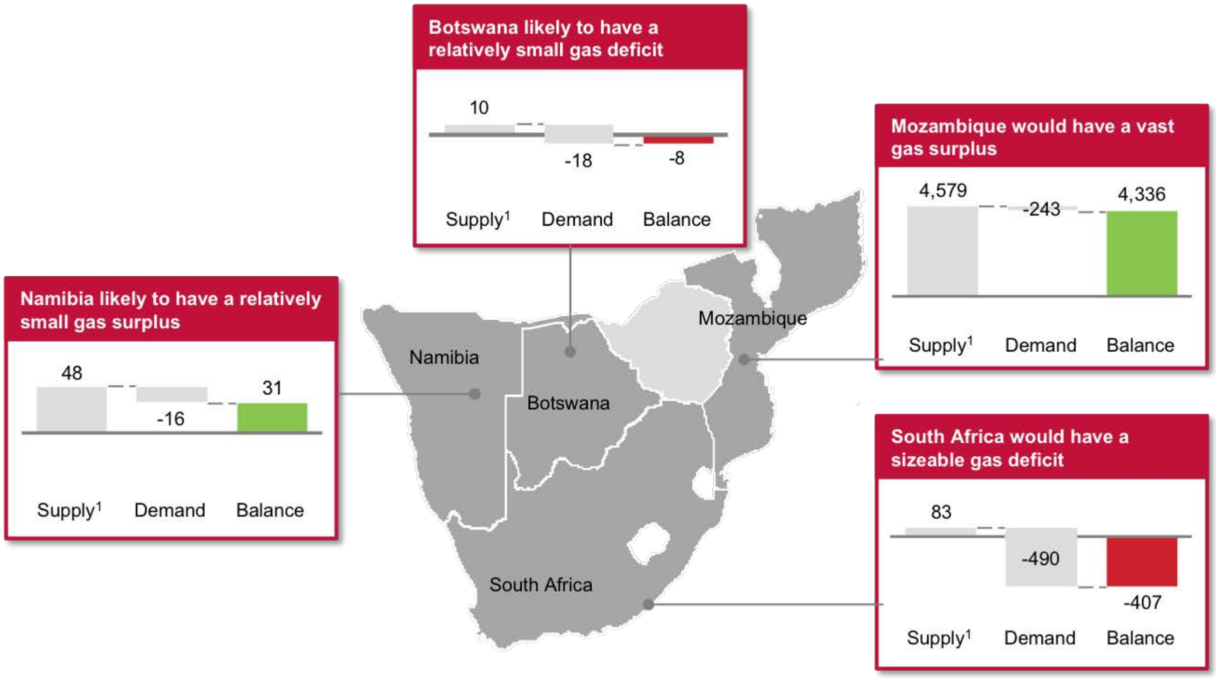
[44] Mozambique, Namibia and Botswana assume industry growth is in line with forecast GDP growth rates, given the nascent stage of industry within these countries. South Africa assumes an extrapolation of recent sector-specific growth rates.

[45] Note that for Botswana, Namibia and Mozambique, switching from other fuels was assumed to happen nationally under the assumption that geographical concentration of industry made this feasible. For the case of South Africa, industrial fuel switching was assumed to only occur in Gauteng, Kwa-Zulu Natal and Mpumalanga, given the need for proximity to potential supply sources.

EXHIBIT 6

LOCAL GAS SUPPLY AND DEMAND BALANCES

Demand in PJ/year, 2030; (balances calculated using total reserves, assuming “medium” demand scenario)



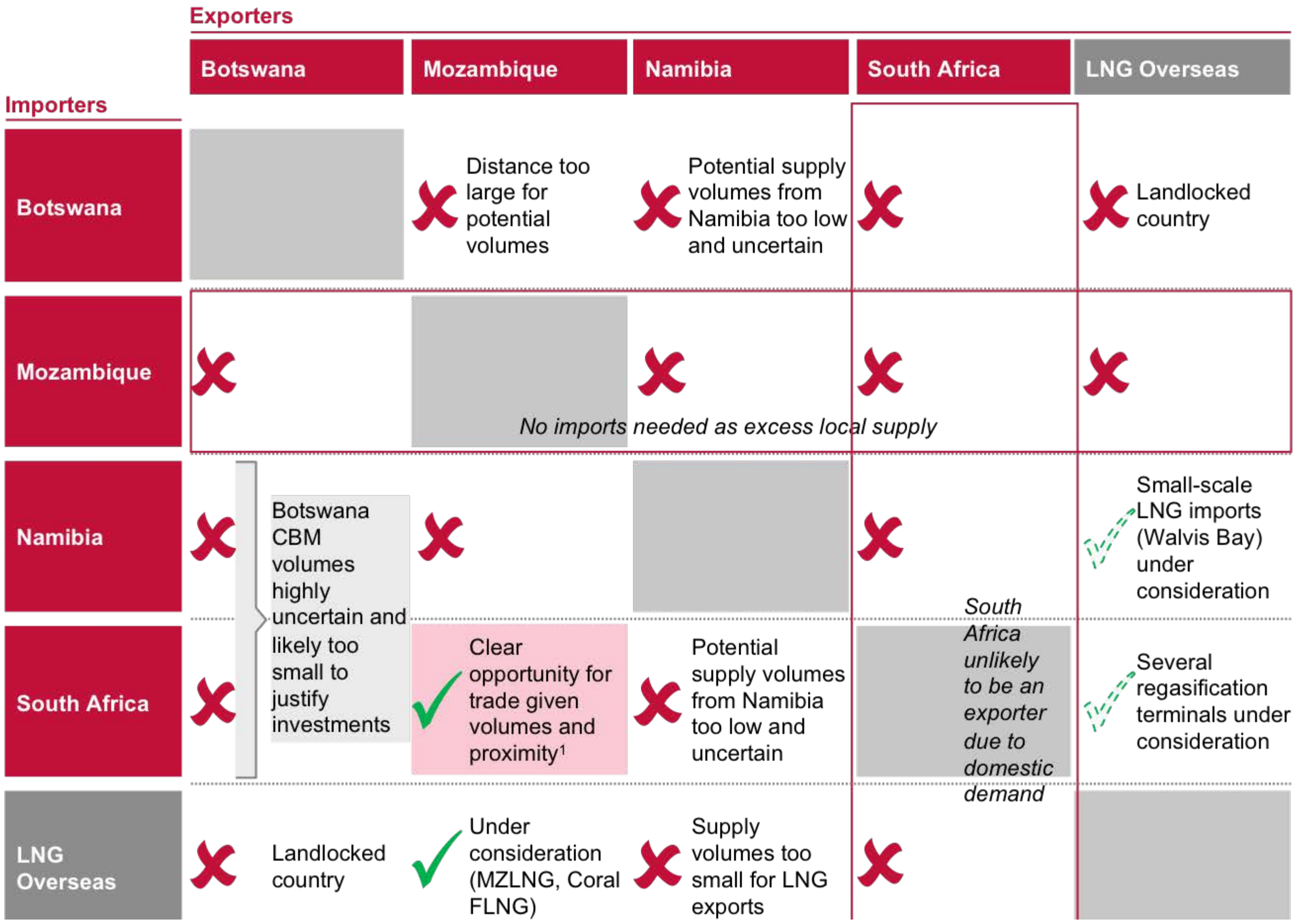
1 Supply volumes estimated based on high level approach which assumes that remaining reserves are produced over 30 years (typical field life and most of fields are untapped yet), leading to a flat production profile, which is converted into PJ/year

SOURCE: Demand figure derived from bottom-up evaluation (IRP 2016, EIA energy balances, IPP gas-to-power programme, among others); supply volumes derived from WoodMackenzie, complemented with various public sources (e.g. Tlou Energy, South African journal of science)

After applying these filters, we varied the degree to which fuels switched to gas across the scenarios. The Low scenario only considered incremental consumption from existing gas users; the Medium scenario also incorporated switching from high-value fuels (e.g., diesel, LPG) to gas; and the High scenario also assumed that industries that used low value coal would be incentivized to switch to gas. Policies and incentives (e.g., implementing a carbon tax which makes alternative fuel sources more expensive, or a ban on the most polluting types of coal) are the practical drivers for these assumptions. **Exhibit 37** in the Appendix provides more detail on the methodology for each of the focus countries. **Exhibit 38** to **Exhibit 41** have a detailed sub-sector and fuel-type breakdown of industrial demand.

EXHIBIT 7

OPPORTUNITIES FOR LARGE SCALE INTRA-REGIONAL GAS TRADE



Exporters

Importers	Botswana	Mozambique	Namibia	South Africa	LNG Overseas
Botswana		✗ Distance too large for potential volumes	✗ Potential supply volumes from Namibia too low and uncertain	✗	✗ Landlocked country
Mozambique	✗	*No imports needed as excess local supply*	✗	✗	✗
Namibia	✗ Botswana CBM volumes highly uncertain and likely too small to justify investments	✗		✗	✓ Small-scale LNG imports (Walvis Bay) under consideration
South Africa	✗	✓ Clear opportunity for trade given volumes and proximity[1]	✗ Potential supply volumes from Namibia too low and uncertain	*South Africa unlikely to be an exporter due to domestic demand*	✓ Several regasification terminals under consideration
LNG Overseas	✗ Landlocked country	✓ Under consideration (MZLNG, Coral FLNG)	✗ Supply volumes too small for LNG exports	✗	

- Transport
  - *Methodology:* USAID SAEP's assessment of transport fleet groups' ability to adopt CNG or LNG revealed that long-haul trucking and public transport are the most likely candidates given the scale of the individual players and centralized decision making (see **Exhibit 42** in the Appendix for the various transport fleets that were considered). For long-haul trucking, car registration data was used to determine the current fleet size for trucks, and a GDP-driven extrapolation indicated what the potential fleet size is expected to be in 2030.[46] Public transport followed a similar methodology, using car registration data to determine the number of buses in use today, and used forecast population growth rates to extrapolate this out to 2030.[47] Once fleet sizes were determined for both trucking and public transport, assumptions around fuel use per vehicle were built up to give the total fuel use potential for these transport sectors (**Exhibit 43** in the Appendix details these assumptions).
  - *Variations by scenario:* CNG is most likely to be implemented in new truck and bus orders (e.g., those required to grow and retire an existing fleet). Given this, adoption rate became the variable that changed across scenarios, i.e., how many new orders of trucks and buses would adopt CNG technology. In the Low scenario, with no government involvement, adoption would likely be negligible to zero; the Medium scenario assumes a 10 percent adoption rate based on some supporting policies; and the High scenario assumes that coordinated policies could push adoption up to 20 percent. These results were informed by a meta-analysis of CNG adoption rates carried out by the International Council of Clean Transport (ICCT). **Exhibit 44** in the Appendix provides more details.
- Commercial and Residential
  - *Methodology:* We used a high-level approach to assess the direct use of coal and petroleum products by commercial and residential users. It was based on the World Energy Balances.[48] Commercial use was assumed to grow in line with GDP, and residential use was assumed to grow in line with the population.
  - *Variations by Scenarios:* Whether direct fuel use by the commercial and residential sectors switched to gas was varied across scenarios. Given the segmented nature of demand within this sector, the Low and Medium scenarios assume that no commercial and residential demand materializes; the only change is in the High scenario where there could be enough of a regulatory push toward the sector's favoring of gas above direct petroleum and coal use. **Exhibit 45** and **Exhibit 46** in the Appendix give an overview of the applicable demand volumes of the commercial and residential sectors.

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[46] Sourced from the relevant Office of National Statistics where available, and the WHO Road Safety Report (2015)

[47] Population forecasts from World Bank website, 2017

[48] IEA, 2015

4. TRADE OPPORTUNITIES AND THE EMERGENCE OF THREE POTENTIAL GAS SYSTEMS

4.1 LOCAL SUPPLY BALANCES AND THE OPPORTUNITY FOR TRADE

To really unlock Southern Africa's gas potential, demand and supply need to be matched while accounting for local gas balance surpluses and deficits. Chapter Three made it clear that significant additional gas demand potential could exist across the region; Chapter Two identified the local supply potential, which is mostly concentrated in Mozambique. To evaluate each country's 2030 gas balance, we compared its Medium demand scenario volumes with the potential 2030 supplies (assuming the discovered reserves would be under development and onstream in 2030). Mozambique and South Africa have significant imbalances, with Mozambique experiencing a significant gas surplus and South Africa facing a substantial gas deficit. Botswana and Namibia have slight imbalances, with a small deficit and surplus respectively. See Exhibit 6 for more details.

Trading between countries could help overcome local surpluses and balances. However, the required gas infrastructure investments would need to be assessed against the potential trade volumes in order for trade to be economically viable. Aside from economics, there are other factors which imply whether trade would be feasible or not (e.g. environmental factors like the nature of the terrain, access to ports, political relationships, etc.). For the current high-level analysis of the trade potential, we focused on economics initially.

In terms of LNG trade, the distances to be bridged are historically less of a driving factor for transportation costs; its largest costs are associated with gas liquefaction. Because of this, LNG export infrastructure depends on sufficiently large supply volumes. This would not apply as strongly to LNG import infrastructure, although reliable demand volumes would still be a prerequisite for investments in regassification terminals.

An assessment of the combinations of distances and volumes for the four countries revealed limited options for large-scale gas trade (Exhibit 7). Only South Africa and Mozambique are likely to have substantial gas trade potential by 2030. This opportunity is based on their combined gas deficit and surplus, and the distances between supply and demand centres in their two countries. If Botswana discovers additional CBM reserves, trade could become possible between Botswana and South Africa (e.g., Gauteng Province) due to their relatively proximity. However, because Botswana's current gas supply projections result in a gas deficit, additional volumes would have to be brought online.

Three possible gas systems emerged across the four focus countries (**Exhibit 47** in the Appendix has more detail on the rationale behind these systems):

- **Botswana's Potential as a Stand-Alone Gas System:**[49] Botswana is expected to have a relatively small demand base of 18 PJ/year (45 mmscfd) in 2030. The majority of this would directly depend on the development of its currently small and uncertain CBM fields in the Lesedi region. Because it is likely to have modest volumes, large scale intraregional trade would be unlikely.
- **Namibia's Potential as a Stand-Alone Gas System:**[50] Similarly, Namibia is expected to have 16 PJ/year (40 mmscfd) of demand by 2030. Its domestic supply relies on the Kudu field's development, which is highly uncertain at present. Aside from the potential for small-scale LNG imports at Walvis Bay, the small volumes make intraregional trade unlikely.
- **Mozambique's and South Africa's Potential as an Interconnected Gas System:** South Africa has a large demand potential, while Mozambique has a vast excess supply potential. Given the size of the volumes involved, various infrastructure options could possibly make trade between the two countries feasible.

The subsequent sections will evaluate the three possible systems in detail.

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[49] Development of these systems are largely dependent on their respective supply sources materializing.

[50] Development of these systems are largely dependent on their respective supply sources materializing.

4.2 THE POTENTIAL FOR A BOTSWANA GAS SYSTEM

4.2.1 OVERVIEW OF BOTSWANA'S ELECTRICITY LANDSCAPE

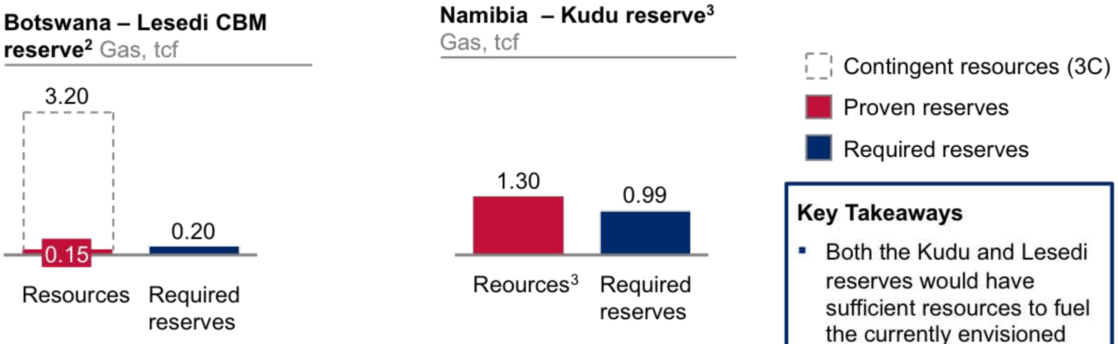
The Botswana Power Corporation (BPC) is the dominant player across generation, transmission, and distribution; only a few IPPs play a role in generation.

Botswana does not generate enough electricity to meet its domestic demand. In 2015, the BPC announced that internal generation capacity during peak hours was 260 MW from coal-fired Morupule A and Morupule B power plants, which have an installed capacity of 132 MW and 600 MW respectively. The electricity deficit was ~340 MW during peak hours. Botswana makes up this deficit by importing electricity from South Africa and, to a lesser extent, from Mozambique. By 2035, the BPC's demand scenarios anticipate that total demand could vary from 1,184 MW (conservative scenario) to 1,359 MW (medium scenario). This suggests that Botswana could have a deficit of 924 – 1,099 MW by 2035, unless it invests in developing local generation.[51]

Given Botswana's vast coal reserves (~40 million tons of proven recoverable coal), coal-fired power generation dominates its energy mix, comprising ~82 percent of installed generation capacity in 2015.[52] However, the Ministry of Energy intends to diversify the country's electricity energy mix by scaling up various CBM gas-to-power projects and developing concentrated solar thermal power plants, among other options.[53] **Exhibit 48** to **Exhibit 50** in the Appendix provide more detailed analyses of Botswana's power sector and energy mix.

EXHIBIT 8

RESERVES VS. GAS REQUIRED FOR GAS-TO-POWER PROJECTS



Key Takeaways

- Both the Kudu and Lesedi reserves would have sufficient resources to fuel the currently envisioned gas-to-power projects
- Botswana's Lesedi reserves however have potential to supply gas to additional gas-to-power plants if contingent reserves materialize

Assumptions

Plant size	100 MW²	800-885 MW³
Type	OCGT⁴	CCGT⁵
Utilization (%)	70%	70%
thermal efficiency (%)	31%	49%
Project lifespan	30 years	30 years

1 For a real feasibility study more accurate project-provided data would have to be considered
2 http://tlouenergy.com/overview
3 Offshore technology.com/projects; http://www.iii.co.uk/investment/detail?code=cotn:CHAR.L&display=discussion&id=10542444&action=detail indicates 1.3 tcf of proven reserves (as does WoodMackenzie); other sources provide conflicting information so only proven reserves are indicated (e.g. https://www.offshoreenergytoday.com/bw-offshore-to-take-over-kudu-field-off-namibia/ indicates the 1.3 tcf are 2C resources)
4 FT Markets Data; RNS Number: 7548B
5 Kudu high-level project update June 2015

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[51] Botswana Power Corporation (22 May 2017); https://www.bpc.bw/services-site/tenders/Pages/Expression-of-Interest-EOI.aspx

[52] United Nations Environment Programme (2017); Market-information: Botswana; https://www.africa-eu-renewables.org/market-information/botswana/

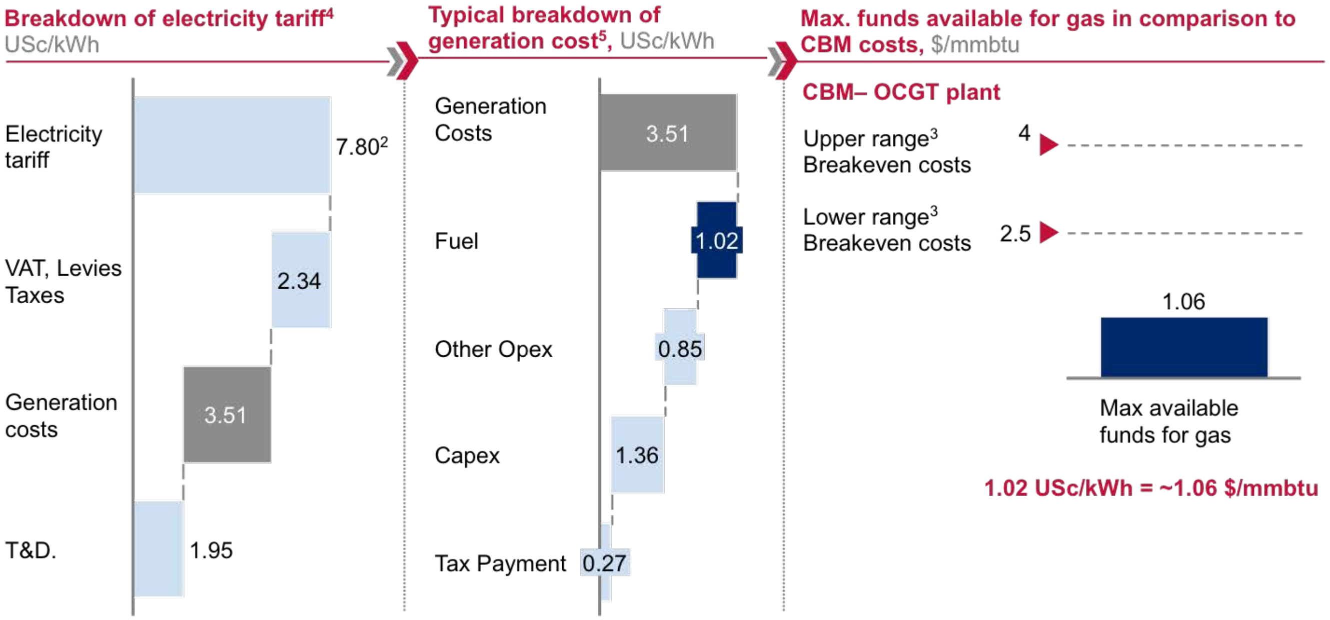
[53] Africa EU Renewable Energy Corporation Programme ((2017, November 24); Energy Profile: Botswana in Atlas of Africa Energy Resources

4.2.2 SUPPLY DEEP DIVE: CBM RESERVES IN BOTSWANA

Botswana's CBM reserves were explored and assessed in the early 2000's. The reserves form part of the Kalahari Karoo Basin and cover an area of 1.3 million acres; most exploration projects are in the east. The Gas Corporation of Botswana manages the mining and exploration leases.[54]

EXHIBIT 9

ESTIMATED FUNDS AVAILABLE FOR GAS PROCUREMENT FROM CURRENT TARIFFS – LESEDI



It is unlikely that current Botswana tariff levels can be achieved for Lesedi CBM-gas-to-power without incentives

1 Indicative – based on high level outside-in analysis
2 Average electricity selling price across all power stations & imports for 2016 FY- BPC annual report (2016)
3 Typical breakeven costs from other CBM fields, indicative ranges based on CBM expert interview
4 Assumed 45% of tariff is available for generation; breakdown based on case study examples from Kenya & Brazil; figures to be further refined for Botswana specific conditions
5 Based on 70% utilization factor - See appendix for details behind assumptions

SOURCE: As specified above

The government has demonstrated an interest in monetizing these reserves by driving gas-to-power generation, and several CBM power projects are in the pipeline. In the short-term, these include the development of two 100 MW CBM-fueled power plants in the Lesedi and Mmashoro regions.[55]

In August 2017, Botswana's Ministry of Mineral Resources, Green Technology, and Energy Security granted Tlou Energy a 25-year mining license to develop the CBM prospects in the Lesedi concessions in the Mamba basin.[56] Tlou Energy is a power producer listed with the Alternative Investment Market (AIM) and the Australian Securities Exchange (AUX). According to its website, Tlou's mission is to deliver power in Botswana and the broader Southern African region by developing CBM projects.[57] It has helped with the exploration of Botswana's CBM reserves since its establishment in 2009.

Because CBM is a form of unconventional gas where gas is extracted from coal deposits, its mining is more economically challenging than producing conventional gas.

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[54] SRK Consulting (2015); Independent Geologist Report - CBM Licenses in Botswana

[55] Tlou Energy website (Accessed 2017) http://tlouenergy.com/overview

[56] News Base (2017, September 27); AfrElec - Africa Power Monitor:: https://newsbase.com/topstories/tlou-energy-probe-botswana-cbm-prospects

[57] Tlou Energy website (Accessed 2017) http://tlouenergy.com/overview

This is due to:

- **The Need for an Extended Mining Process and Produced Water Treatment Solutions:** In CBM deposits, the gas is locked into the coal deposits. Freeing it requires the drilling of numerous wells - the largest expenditure - to decrease the underground pressure. Gas production from CBM also results in large amounts of associated water production (at least in the initial years of field development). Additional investments are necessary to treat these water volumes.

- **Lower Gas Densities:** Because CBM fields are typically less porous and concentrated than conventional gas fields, their technical and economic recovery rates are generally much lower.

These characteristics are exacerbated by CBM's current situation: CBM technology is relatively unexplored globally, and the industry is still going through a learning curve as it attempts to further optimize development and operations.

Botswana's CBM is considered even more challenging based on the country's current shortage of CBM-related skills. Botswana's Ministry of Energy is also attempting to bolster its technical expertise and ensure the effective management of Botswana's CBM resources. The Ministry informally approached the United States government embassy in Botswana to request technical assistance in how to manage CBM-related projects. The US government also supported Botswana's Development Corporation in the exploration of the CBM field between 2003 and 2008.[58]

4.2.3 DEMAND DEEP DIVE: BOTSWANA'S GAS-TO-POWER DEMAND

Botswana's gas demand depends heavily on the development of its upstream CBM reserves. In the Medium demand scenario, Botswana's gas demand could potentially reach ~18 PJ/year (45 mmscfd) by 2030. This figure reflects the planned gas-to-power project pipeline and the potential of the industry and transport sectors to switch to gas. This section provides more detail about Botswana's gas-to-power projects.

The Ministry of Energy has planned several gas-to-power projects based on the development of the Lesedi CBM reserve:

- **Lesedi 100 MW Plant:** In early 2017, the Ministry of Energy invited two companies – Tlou Energy and Sekaname (trading under Kalahari Energy) – to respond to a request for proposal (RfP) to develop the first 100 MW gas-to-power station in the country. Both companies are reported to have responded by the closing date (30 September 2017),[59] but the Ministry had not publicly announced the winner at the time this report was written (End of 2017). **Exhibit 51** in the Appendix provides an overview of the project's status and its development. Tlou Lesedi is said to have partnered with the Independent Power Corporation (IPC), a British power development company with power generation experience, to tender for the development of this 100 MW power plant.[60]

- **Mmashoro 100 MW Plant:** Kalahari Energy is also exploring CBM in the Mmashoro-Lephephe region. By 2013, it is supposed to have spent P211 million ($21 million) across the concession areas.[61] It also confirmed its interest in developing a gas-to-power plant in Mmashoro in late 2017, based on interactions with the US mission. The Mmashoro plant was initially scoped at 180 MW but was later reduced to 100 MW. In addition, the company stated that it had recently submitted a response to a RfP to develop another 100 MW CBM-fueled power plant in Botswana after the Lesedi plant.

Key Takeaways

Botswana's gas-to-power sector is completely dependent on the successful development of its CBM resources. To unlock gas demand and support gas-to-power in Botswana, USAID SAEP could focus on providing technical support to the government of Botswana on the interpretation of studies around its CBM reserves. In addition, USAID SAEP could leverage the broader Power Africa group to conduct a feasibility assessment of the gas-to-power projects based of Botswana's CBM reserves.

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[58] SRK Consulting (2015) Independent Geologist Report - CBM Licences in Botswana

[59] Tlou Energy (2017)

[60] ESI Africa, (2017, March 1); https://www.esi-africa.com/news/botswana-cbm-power-plant-making-headways/

[61] SRK Consulting (2015) Independent Geologist Report - CBM Licences in Botswana

- **Orapa Diesel Plant Conversion to Gas:** Orapa is a diesel-fueled OCGT plant with a generation capacity of ~90 MW that was commissioned in 2011. According to online news portals, four companies were in the running to win the BPC's 2015 tender to convert Orapa's power station into a gas-fired power plant. The BPC estimates that converting Orapa from diesel to gas could save up to 60 percent off its operational costs. These savings would offset the initial capital investment required for the infrastructure and conversion. This, however, would depend on the availability of CBM gas. If local CBM is not developed, the economics would be challenging.[62]
- **Francistown Diesel Plant Conversion to Gas:** Francistown's Matselagabedi is one of Botswana's diesel-fueled emergency plants. It has a capacity of 105 MW and was commissioned in 2009. In 2017, the BPC considered converting the plant to gas, but concluded that the conversion was not viable because of the age of the plant's machinery.[63]

4.2.4 ASSESSING THE LIKELIHOOD OF BOTSWANA'S GAS POTENTIAL

Botswana's gas demand depends heavily on the successful development of its upstream CBM reserves. The demand forecasts were largely based on the gas-to-power pipeline. To gain an initial understanding of the gas-to-power projects' economic robustness, we conducted a high-level, outside-in economic analysis of these projects. We first verified that sufficient resources exist to supply the planned projects for their projected lifetimes, and then conducted a high-level economic viability analysis to understand the maximum funds available for gas if the electricity tariffs remain the same.

The preliminary findings, based on the communicated reserves, showed that the Tlou Lesedi CBM field would have enough reserves to fuel the 100 MW gas-to-power project. If we also consider the contingent reserves, the field could supply more gas which could expand the Lesedi plant and serve other gas-to-power projects (assuming the Lesedi plant operates at 70 percent utilization (base load) and 31 percent thermal efficiency). We assumed that the project lifetime would be 30 years (Exhibit 8).

However, the high-level economic viability analysis indicated only limited funds would be available for upstream gas development if Botswana wants to keep gas-to-power project tariffs in line with the current retail tariffs (i.e., the average electricity selling price across all power stations and imports for 2016 FY).[64] Assuming fuel and generation costs account for 45 percent of the total electricity tariff, Botswana would need to produce gas at $1.06/mmbtu (Exhibit 9).[65]

The $1.06/mmbtu figure is significantly lower than gas prices in major global markets and the typical breakeven costs of other global CBM fields, which range from ~$2.5/mmbtu to ~$4/mmbtu (according to expert interviews). It may be hard to make these gas-to-power projects commercially viable if tariffs need to remain at current levels and / or the government offers no incentives that support the project's economics. We conducted a sensitivity analysis of the tariff to determine what tariff level might be needed to bring the Lesedi CBM field closer to a comparable breakeven cost. Generation would need to add $c1.87/KWh on top of the current $c3.51/KWh for the Lesedi field to potentially match comparable breakeven costs of around $3/mmbtu. **Exhibit 57** in the Appendix provides details on the sensitivity analysis. The increase in the generation tariff could be sourced in multiple ways (e.g., increasing electricity tariffs, optimizing transmission distribution costs through concentrated displacement, reducing levies and taxes for gas plants).[66]

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[62] MmegiOnline (2015, May 08), http://www.mmegi.bw/index.php?aid=51020&dir=2015/may/08

[63] Based on conversations with the US embassy in Botswana

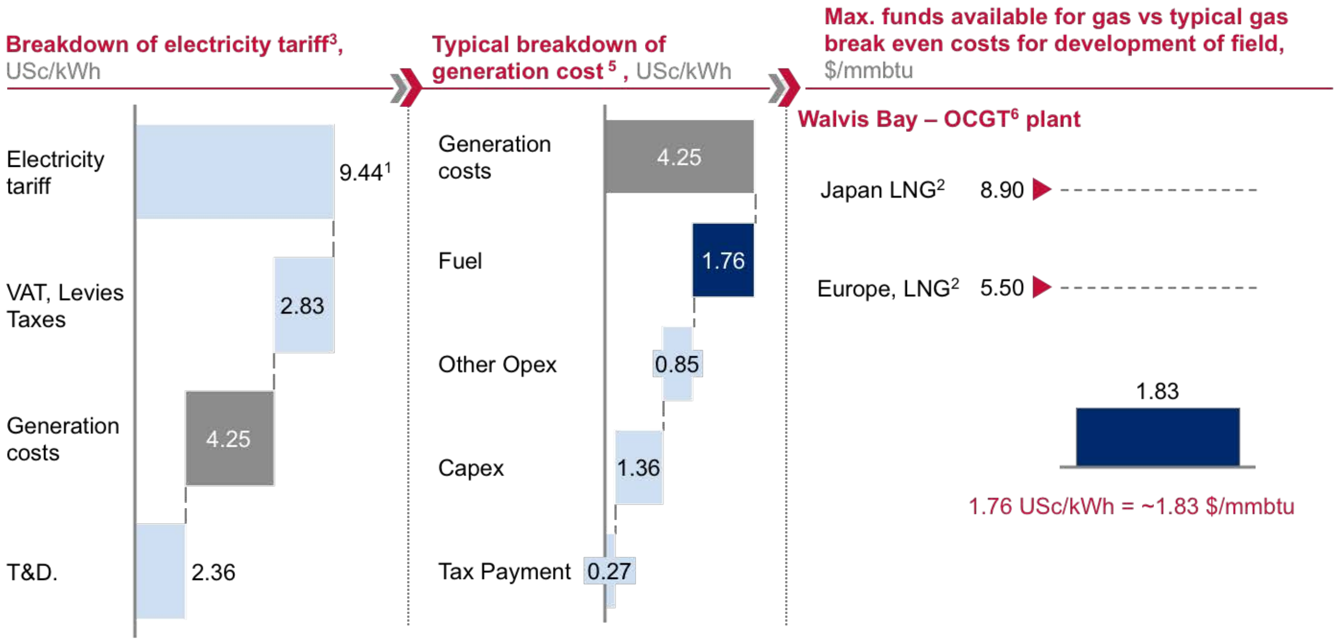
[64] BPC (2016); Annual report

[65] Range based on electricity breakdown examples from Kenya and Brazil; this should be further refined based on actual shares of tariff available for generation in Botswana

[66] Further analysis would be required to thoroughly assess the feasibility of this gas-to-power plant and its impact on tariffs for the end consumer

EXHIBIT 10

ESTIMATED FUNDS AVAILABLE FOR GAS PROCUREMENT FROM CURRENT TARIFFS – WALVIS BAY



It is unlikely that current Namibia tariff levels can be achieved for the Walvis Bay LNG-to-power project without incentives

1 Average electricity selling price across all power station & imports for period ended June 2016 - NamPower annual report (2016)
2 Word Bank – Commodities Price data (pink sheet); (2017)
3 Assumed 45% of tariff is available for generation; breakdown based on case study examples from Kenya & Brazil; figures to be further refined for Namibia specific conditions
4 Indicative – based on high-level outside in analysis
5 Based on 70% utilization factor - See Appendix for details behind assumptions
6 The Walvis Bay proposal presents itself as an OCGT plant

SOURCE: Various sources (see above)

Alternatively, Botswana's CBM development could also be assessed from a energy mix standpoint, rather than a purely economic one. As the BPC is committed to building a 100MW solar power plant,[67] a CBM-Solar hybrid solution could create significant synergies here. The ability for a natural gas plant to rapidly start up and shut down creates a natural complement to the intermittent nature of solar power generation. Such hybrid solutions could be assessed further when considering Botswana's CBM development.

4.2.5 CONCLUSIONS AND IMPLICATIONS FOR USAID SAEP AND POWER AFRICA

A clear opportunity appears to exist for USAID SAEP to help Botswana develop sustainable sources of power generation, given the country's expected power deficit and current fossil fuel-dependent generation mix.[68] However, the business case for significant gas-to-power contribution remains uncertain, partially because it depends on the successful development of the CBM reserves. Given this uncertainty, USAID SAEP could consider providing Botswana with support in two areas: technical support in interpreting studies around its CBM reserves, and assistance in conducting a feasibility assessment of the gas to-power projects that are based on Botswana's CBM reserves.

- **Providing Technical Support:** Although the government has appointed external investors to advance the development of the CBM fields, the Ministry of Energy has indicated a need for technical support. This support, or potential advisor, would help interpret the existing studies and ensure that the required enabling

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[67] Engineering News (2017, Aug 29) *Botswana reaffirms commitment to 100 MW solar project*

[68] Botswana Power Corporation website (2017, May 22); https://www.bpc.bw/services-site/tenders/Pages/Expression-of-Interest-EOI.aspx; Africa EU Renewable Energy Corporation Programme ((2017, November 24); Energy Profile: Botswana in *Atlas of Africa Energy Resources*

environment is created to develop the CBM reserves. USAID SAEP could leverage its close network with the US Department of Energy if it assists Botswana's government with this effort.

- **Conducting a Feasibility Assessment of the Gas-to-Power Projects Based on Botswana's CBM Reserves:** Preliminary analyses suggest that if Botswana's gas-to-power projects will have limited funds available for upstream CBM gas development if electricity tariffs remain in line with current retail tariffs. This would make the plants' commercial feasibility challenging unless additional incentives were provided. USAID SAEP could leverage its network (e.g., USTDA) and assist the Ministry of Energy by conducting a thorough feasibility analysis, of both CBM and CBM-Solar hybrid options. This could assess the downstream impact of the gas-to-power projects in terms of electricity tariffs, and taxes and levies. It could also include potential mitigation actions to enhance their feasibility.

Because of the closed nature of Botswana's potential gas system, the impact of USAID SAEP's efforts may only provide local benefits. Intraregional trade is unlikely to be feasible given the relatively small volumes of reserves and the large distances that would have to be bridged.

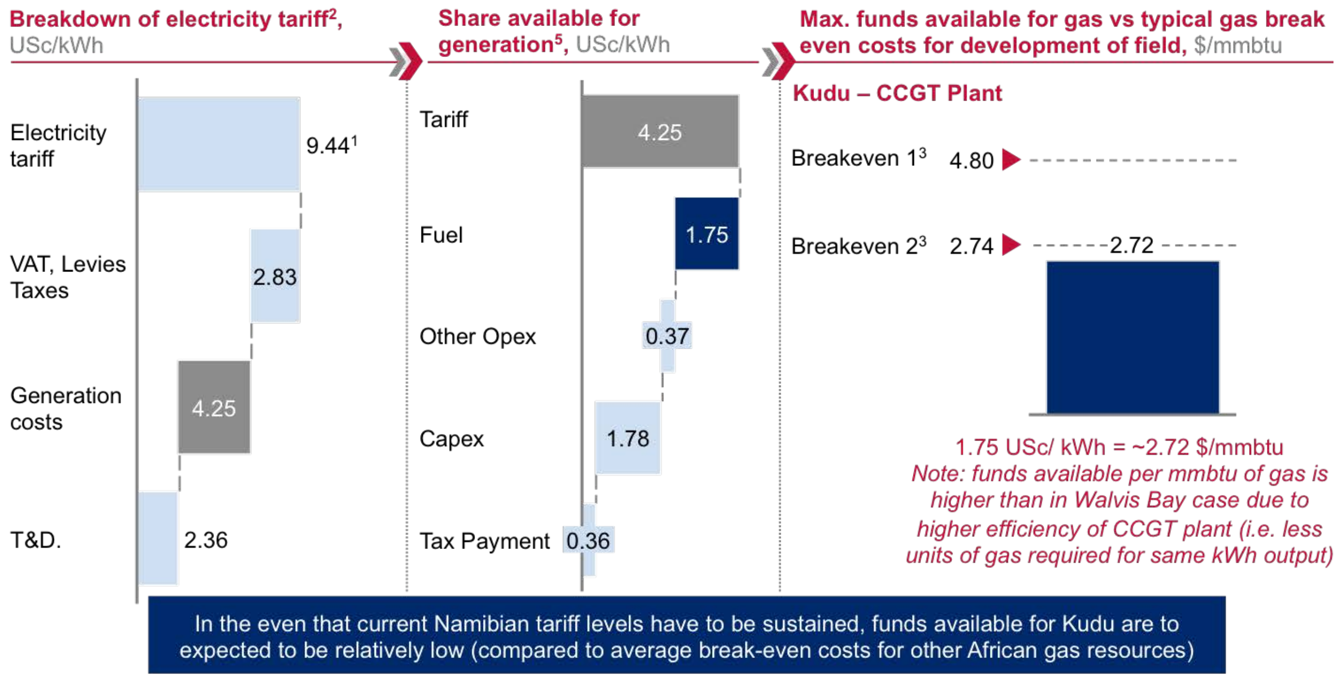
4.3 THE POTENTIAL FOR A NAMIBIA GAS SYSTEM

4.3.1 OVERVIEW OF NAMIBIA'S ELECTRICITY LANDSCAPE

Namibia has recently struggled to meet its peak electricity demand requirements. The Namibia Power Corporation (NamPower) dominates the country's generation and transmission sector, with a market share of more than 95 percent in each segment of the value chain. Distribution, however, is more unbundled because several companies operate on a regional level. In a media briefing in 2013, NamPower announced that Namibia was unable to meet its peak demand of ~524 MW because it only had

EXHIBIT 11

ESTIMATED FUNDS AVAILABLE FOR GAS PROCUREMENT FROM CURRENT TARIFFS – KUDU GAS-TO-POWER



1 Average electricity selling price across all power station & imports for period ended June 2016 - NamPower annual report (2016)
2 Assumed 45% of tariff is available for generation; breakdown based on case study examples from Kenya & Brazil; figures to be further refined for Namibia specific conditions
3 Based on average breakeven costs from similar shallow, offshore gas fields in Africa; scope is fields which (have) come online between 2015-2025;
Scope of breakeven 1: "discovered" fields only (i.e. not yet under development); scope of breakeven 2: Fields currently under development
4 Indicative – based on high-level outside in analysis
5 Based on 70% utilization factor - See Appendix for details behind assumptions

SOURCE: Various (see specified above)

300 MW of peak supply capacity. The country has been importing power from other power utilities in the region to cover this shortfall.[69] In addition, Namibia's National Planning Commission forecast that the total electricity demand would reach 1,100 MW by 2030 (assuming an average annual growth rate of four percent).[70]

To build the capacity needed to meet this increased demand, Namibia would need to invest in its electricity infrastructure and diversify its energy mix. Although hydro power accounts for ~38 percent of its electricity generation, Namibia is considered very dry; it only has two permanent rivers, the Kunene and the Orange. Both are shared systems that border Angola and South Africa respectively, making their use subject to protracted bilateral agreements.[71]

If the planned development of Walvis Bay and the Kudu gas-to-power station goes ahead, gas-to-power could be an important component of this strategy. Other projects in the pipeline include the NamPower wind project and the development of a concentrated solar power (CSP) plant.[72] **Exhibit 52** to **Exhibit 54** provide a detailed analysis of Namibia's power sector and energy mix.

4.3.2 DEEP DIVE ON THE WALVIS BAY LNG-TO-POWER PROJECT

As a coastal country, Namibia can use its harbors to leverage the global LNG market for gas supply. Market indicators suggest an oversupply in the global market which could result in LNG prices continuing to diverge from the Brent-based index, on which it has historically been based. The construction of an LNG terminal at the Walvis Bay harbor is linked to the development of the Walvis Bay gas-to-OCGT plant, which is planned to have ~200-250 MW of generation capacity.[73] Despite development delays due to legal and issues surrounding the tender process, we assume that the project will come onstream in the Medium and High gas demand scenarios, where gas is an important part of diversifying the energy mix.

In 2014, NamPower selected Xaris as the preferred bidder for the construction of the plant, but major legal disputes have beset the project. Arandis Power (which also tendered a bid) claimed that there were irregularities in the tender process.[74] In 2016, the High Court reinforced NamPower's decision to appoint Xaris, but in early 2018 the Supreme Court ruled that the tender award was indeed irregular, and asked NamPower to carry out a review. Prior to the ruling, NamPower also conceded that certain concessions were made during the process and cancelled the tender award to Xaris.[75] A replacement tender is yet to be issued.

Key Takeaways

USAID SAEP could focus on accelerating Namibia's gas-to-power project(s), specifically the Walvis Bay LNG-to-power plant (once the legal disputes are settled). An LNG terminal in Namibia could unlock other gas-to-power projects and expand their horizon for impact. The development of the Kudu gas field, however, is considered unlikely to occur within USAID SAEP's time frame.

Despite these obstacles, Walvis Bay was at a relatively advanced stage of preparation. Key environmental impact and feasibility assessments were complete and design concepts approved.[76] Xaris anticipated that construction would last twelve to fifteen months once it would have begun. **Exhibit 56** in the Appendix provides an overview of the project status and its development.

High-level economic viability analysis suggests that competitive tariffs for the Walvis Bay gas-to-power plant would result in gas procurement funds that are probably too low to access the LNG markets (see **Exhibit 10**). These figures assume that 45 percent of the blended national tariff is allocated to generation costs and a 70 percent baseload utilization of the plant.

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[69] NamPower (2013) *Update on the Current Power Supply Situation and Progress Made on NamPower Projects and Initiatives to Ensure Security of Supply in Namibia*

[70] Office of the President: National Planning Commission (2013) *Energy Demand and forecastin in Namibia*

[71] United Nations Environmental Programme, 2017

[72] Deputy Minister – Ministry of Mines and Energy at the Africa Energy Forum (2013)

[73] Xaris Report (2016), *Xaris Walvis Bay Power Plant - Project Overview & Status*

[74] Namibian Newspaper (2016-05-03); Legal battle over power tender postponed to June

[75] Namibian Sun (2018, Mar 19), *Xaris slain in court*: https://www.namibiansun.com/news/xaris-slain-in-court2018-03-19

[76] Xaris website and Excelerate Energy (2014) *Walvis Bay GasPort: FSRU Feasibility Report*

The available funds for gas procurement would be $1.83/mmbtu, which is considerably lower than other LNG prices in developed markets such as Europe and Japan. From the tariff sensitivity analysis in **Exhibit 57** in the Appendix, an additional $c4.99/KWh on top of the current $c4.25/KWh would be needed for generation if the Walvis Bay project were to be able to compete with global LNG prices.[77]

4.3.3 DEEP DIVE ON KUDU OFFSHORE GAS-TO-POWER

The Kudu gas field was discovered in 1974 and has 1.3 tcf of proven natural gas reserves. It is situated approximately 130 km offshore, near the city of Oranjemund in the Orange sub-basin. Although multiple development concepts are being considered, the gas would likely be transported to the shore via a sub-sea manifold and a 170 km 20-inch flowline.[78] Because Namibia has no established gas demand, the development of the Kudu field would be tied to a downstream gas-to-power plant that was originally designed to have ~800-885 MW capacity, although the current developers now considering lowering this to 442 MW.[79] Under the original plans, a portion of this electricity would help Namibia fill its electricity deficit, and approximately ~50 percent would be exported to other SAPP countries.[80]

Despite the Kudu field's potential, its development has been put on hold because of various economic challenges and other hurdles. We therefore treated the project as having been suspended in all three of the gas demand scenarios.

The field has had multiple corporate owners since its discovery, including Chevron (Texaco) Royal Dutch Shell, Tullow Oil, Gazprom, and, most recently, BW Offshore. Most stakeholders are said to have withdrawn their interest in the field because of insecure downstream off-take and other challenges (e.g., forex issues).[81] Because of these obstacles, the development of the field has now almost halted. BW Offshore had a 56 percent operating stake in the license as of February 2017, with NamCor holding the remaining 44 percent.[82] They were expected to make a final investment decision in the fourth quarter of 2017. This was delayed when BW Offshore moved the decision to the first half of 2018.

In addition, the Minister of Finance announced in 2015 that the government would no longer be able to fund the Kudu gas-to-power project because of Namibia's economic challenges. Although the Cabinet approved both the Kudu and Walvis Bay gas-to-power projects, funding tends to favor Walvis Bay and its much lower investment requirements.[83] By contrast, the development costs for Kudu's power plant and upstream development were initially estimated at $1 billion, but they had reportedly doubled to $2.3 billion by 2015.[84]

Finally, a high-level economic viability analysis suggested that the funds that would be available for upstream gas development would be relatively low if the Kudu gas-to-power plant had competitive tariffs. If the current blended tariff is set to 9.4USc/kWh and if 45 percent of the tariff is allocated to generation costs, only $2.72/mmbtu would be available for gas costs (**Exhibit 11**).[85] In the previous sentence, the current blended tariff is the average electricity selling price across all power station and imports for the period ending June 2016, and the generation cost is based on the Brazil and Kenya case example. The latter would be further refined based on conversations with NamPower.

Comparing the funds available for gas and the average breakeven range for other offshore conventional gas fields, it appears clear that Kudu would need to have a relatively low breakeven gas price for tariffs to remain in line with Namibia's current prevailing average tariffs. **Exhibit 57** in the Appendix shows the result of a sensitivity analysis around the tariff. For the Kudu project to match comparable breakeven costs of around $3.50/mmbtu, the generation tariff would need to add $c0.56/KWh on top of the current $c4.25/KWh.[86]

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[77] Further analysis would be required to thoroughly assess the feasibility of this gas-to-power plant and its impact on tariffs for the end consumer.

[78] Off shore Technology website (Retrieved 2017, November), http://www.offshore-technology.com/projects/kudugasfieldnamibia/

[79] African Energy, African Energy Newsletter Issue 361 (2018, January 18); BW Offshore postpones Kudu FID

[80] Reuters (2015, October 29); https://www.reuters.com/article/africa-oil-namibia/final-decision-on-namibias-kudu-gas-to-power-project-seen-mid

[81] Off shore Technology website (Retrieved 2017, November), http://www.offshore-technology.com/projects/kudugasfieldnamibia/

[82] African Energy, African Energy Newsletter Issue 361 (2018, January 18); BW Offshore postpones Kudu FID

[83] The Namibian Newspaper (2015, September 21); https://www.namibian.com.na/index.php?id=142101&page=archive-read

[84] Reuters (2011, November 3); https://www.reuters.com/article/ozabs-africa-oil-namibia-20111103-idAFJOE7A20L; Reuters (2015, October 29); https://www.reuters.com/article/africa-oil-namibia/final-decision-on-namibias-kudu-gas-to-power-project-seen-mid

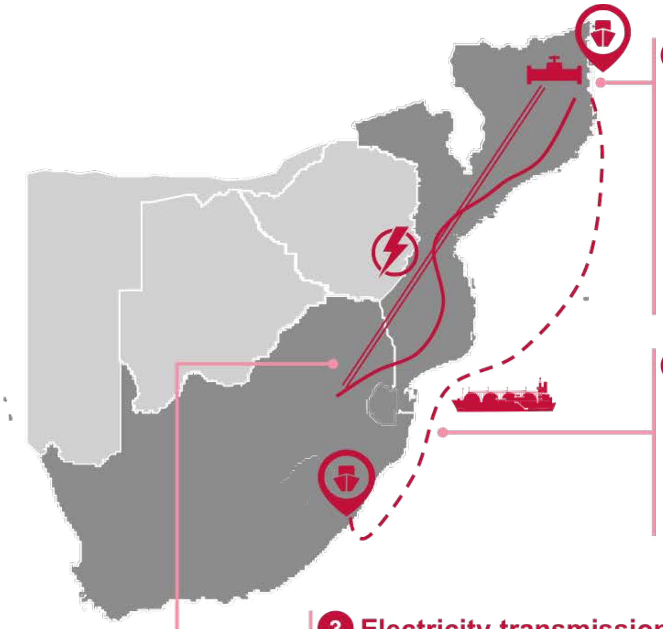
[85] The NamPower Annual Report, 2016

[86] Further analysis would be required to thoroughly assess the feasibility of this gas-to-power plant and its impact on tariffs for the end consumer

Although the field probably has sufficient reserves to fuel the planned gas-to-power project (see Exhibit 8 in Section 4.2.4), it is unclear whether Kudu will be developed given the current funding uncertainties, Namibia's technical capabilities, and doubts about power off-takers. We therefore treated the project as if it had been suspended in our projected gas demand scenarios. **Exhibit 55** within the Appendix provides an overview of the project status and its development.

EXHIBIT 12

INFRASTRUCTURE OPTIONS FOR SOUTH AFRICA AND MOZAMBIQUE TO ADDRESS THEIR LOCAL GAS BALANCES



① Pipeline

- Gas via pipe to South Africa, originating at Rovuma, with regional fee-offs in Mozambique to spur internal growth along the pipe
- Potential for export to other SADC countries from the pipe
- **Variables²:** On-shore vs. offshore piping; route and destination in South Africa; tariff models (e.g., postage stamp, zonal)

② LNG

- Gas originating and liquefied in Rovuma, subsequently shipped as LNG to a regasification terminal in South Africa
- **Variables²:** Floating versus onshore liquefaction and regasification options, site of regasification (Richards Bay, Coega, Saldanha Bay and/or additional regassification sites at Maputo, Nkala, etc.)

③ Electricity transmission

- Electricity generated via new build CCGTs using gas sourced in Rovuma, and exported via current and new build transmission lines to South Africa
- **Variables²:** Size of CCGT plant; location for CCGT plants; transmission route

1 Routes of infrastructure displayed are not exact routes but indicative; for Electricity option the gas is first converted into electricity in Mozambique, which is then exported through interconnector kV lines to South Africa

2 In current phase of this analysis a base case is assumed, variables are to be explored in analyses in subsequent phases

4.3.4 OTHER POTENTIAL GAS-TO-POWER PROJECTS IN NAMIBIA

Two other power plants have been considered for natural gas use: Sitentu and Paratus. Due to the uncertainty surrounding them (it seems highly unlikely that the projects will go through), they were excluded from this report (see **Exhibit 35** in the Appendix for further details).

4.3.5 CONCLUSIONS AND IMPLICATIONS FOR USAID SAEP

Three main insights emerged from our research and analyses:

- Development of the Walvis Bay LNG terminal could offer an alternative to additional gas-to-power projects in Namibia. The Paratus and Sitentu gas-to-power projects are both in the Walvis Bay area, although LNG gas has not been explicitly considered as a supply option in converting these plants.
- Development of the Kudu gas field by 2030 is unlikely, given the required capital investments, limited government support, and uncertainties around power off-take.

- If Namibia's gas-to-power project tariffs are kept in line with current retail tariffs, only limited funds would be available for the upstream production of gas or the purchase of LNG. Namibia could consider various options to increase the funds available for gas in these gas-to-power projects, including: increasing the proportion of funds available for generation costs; and reducing tax and levies for gas plants. Further analyses are required to determine which options would be most suitable.

4.4 THE POTENTIAL FOR A MOZAMBIQUE – SOUTH AFRICA INTERCONNECTED GAS SYSTEM

In Mozambique's Rovuma basin, natural gas was first discovered in 2011. Shortly after, Mozambique developed its Gas Master Plan that was centered around the development of an LNG export facility.[87] At the time, the price of delivered LNG in Asia, which has traditionally been the most lucrative LNG market, peaked at around $18/mmbtu.[88] However, a recent spate of new projects, mainly in Australia and the USA, has produced a global oversupply in the gas market; Asian LNG prices have since fallen from a peak of $18/mmbtu to ~$8/mmbtu.[89] Furthermore, it is becoming increasingly difficult for LNG offtake contracts to provide an anchor for upstream development, as short term LNG supply agreements are becoming more prevalent in place of traditional long term contracts (**Exhibit 58** in the Appendix charts these recent developments in global LNG markets). As a result, the favorable LNG market conditions that Mozambique's plan may have been based on no longer hold, and regional trade may therefore be a more attractive option for the country.

Based on Medium demand scenario projections, South Africa would have a significant gas deficit of ~400 PJ/year (~1,000 mmscfd) by 2030 given its large demand potential and uncertain domestic supplies. The existing gas infrastructure is adequate to fill South Africa's current needs, but given it operates close to capacity, any incremental trade volumes would require new infrastructure and further investment. In South Africa and Mozambique alone, a further 452 PJ/year (1,129 mmscfd) of demand is expected by 2030, over and above the existing 280 PJ/year (699 mmscfd). Meanwhile, Mozambique is likely to have a large gas surplus – one that exceeds 4,300 PJ/year (10,737 mmscfd). The volumes involved could provide a strong case for mutually beneficial trade between these two countries; Mozambique could secure a market for a portion of its gas, and South Africa could establish a gas source to cover its deficit. And given that South Africa's balance deficit is less than 10% of Mozambique's potential surplus, potential trade volumes between the two countries would be unlikely to cannibalize other uses of Mozambique's gas. **Exhibit 62** in the appendix provides a more systematic analysis of this.

4.4.1 EXISTING AND PLANNED TRADE INFRASTRUCTURE

Mozambique already supplies gas to South Africa via the ROMPCO pipeline. Set up as a joint venture between Sasol, the government of Mozambique, and the government of South Africa, gas from Mozambique's Pande and Temane gas fields is transported 865 km to Secunda, South Africa. It is assumed that the pipeline is utilized at close to its recently upgraded 212 PJ/year (529 mmscfd) capacity, mainly by industrial users.

Three different entities have investigated the possibility of building a second pipeline connecting South Africa to the Rovuma basin. [90]The first project, proposed by a consortium of Chinese, Mozambican, and South Africa investors, was the African Renaissance Pipeline (ARP). It would have been a $6 billion, 2,600 km pipeline and distribution facility.

The second one, the Gasnosu pipeline, was a joint venture between Gigajoule and ENH. It assessed the possibility of a 2,100-km pipeline from Cabo Delgado to Maputo, at a cost of $3 billion. The third was a tender launched by the government of Mozambique in 2014 for consulting services to assess opportunities for selling gas, whether through a pipeline or other CNG or LNG mechanisms. At this point, however, none of these initiatives seem to have reached any meaningful or tangible conclusions. Instead, the concept of a pipeline has often been dismissed as too risky and/or expensive, and no upstream volumes have been allocated to one.

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[87] ICF International (2012); The Future of Natural Gas in Mozambique: Towards a Gas Master Plan

[88] Japan Korea Marker (JKM), recorded by Platts; BP (2017); Statistical Review of World Energy 2017

[89] World Bank (Dec 2017); The Pink Sheet

[90] Interfax Energy (2015); http://interfaxenergy.com/gasdaily/article/16033/mozambique-not-the-answer-to-sas-power-woes

Although the two countries do not currently trade in LNG, each is considering investing in infrastructure that may facilitate such trade in the future. In Mozambique, the planning and development of the 12 mtpa MZLNG liquefaction and export terminal is well under way, with final commissioning expected to be around 2022 – 2023.[91] Meanwhile the investment of a 3.4 mtpa Coral FLNG terminal, operated by ENI, has already reached FID. In South Africa, the LNG-to-power IPP program has identified Richards Bay and Coega as priority sites for regasification terminals, and Saldanha Bay as the expected third site for Phase Two. The completion of the Mozambican and South African projects on both ends of the LNG lifecycle (i.e., liquefaction and regasification) would allow both countries to trade LNG regionally while maintaining access to the global LNG market.

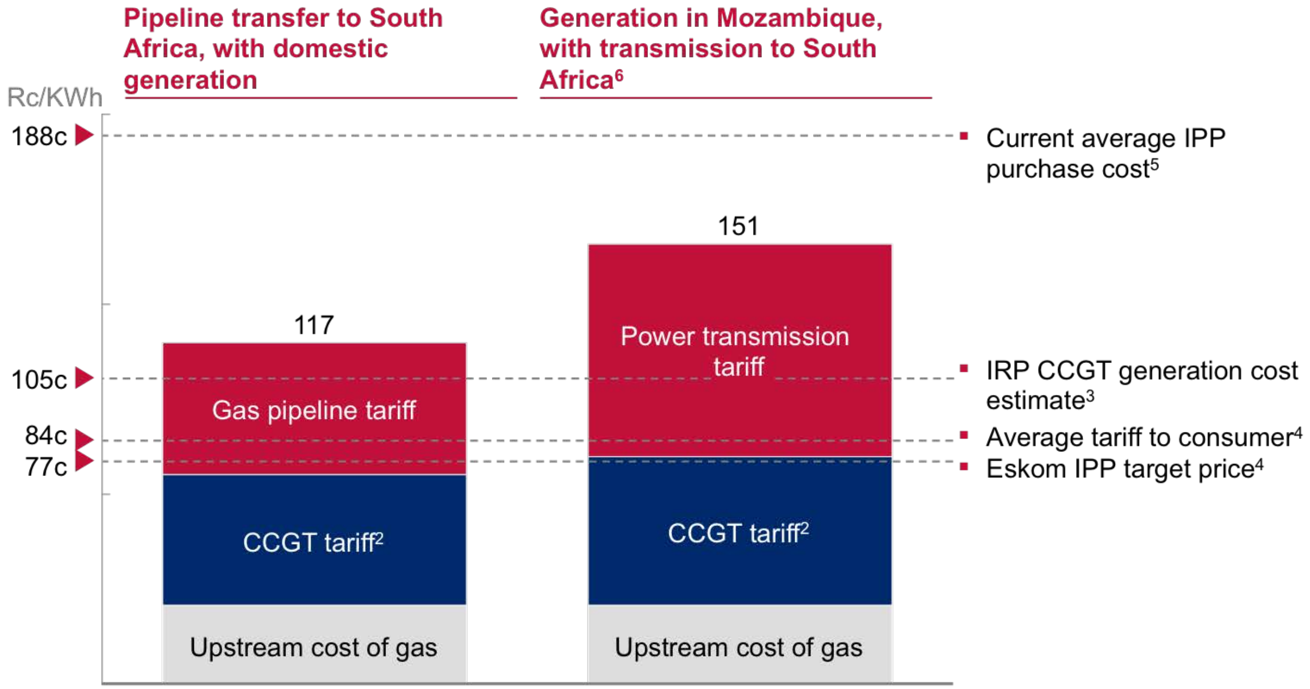
The two countries also trade power. Mozambique's 1,400 KM Cahora Bassa high-voltage direct current (HVDC) system can carry 1,920 MW of power transmission exclusively from the Cahora Bassa hydropower plant to the South African grid via the Songo and Apollo converter stations in Mozambique and South Africa respectively.[92]

4.4.2 ASSESSMENT OF TRADE INFRASTRUCTURE OPTIONS

First, we examined the options for transporting natural gas between Mozambique and South Africa. It can be transported by various means (see **Exhibit 12**): in its natural state via pipeline, liquefied and shipped as LNG, or trucked as CNG. Given the large volumes under consideration and the significant distance between the supply source in Mozambique and demand center in South Africa, the most likely infrastructure options are pipeline and LNG.

EXHIBIT 13

DOMESTIC (SOUTH AFRICAN) AND IMPORT (MOZAMBICAN) COST BREAKDOWN FOR CCGT POWER GENERATION



1 Assessed using medium demand case "Gas as a solid part of the energy mix" scenario, requiring ~2100MW of non-LNG CCGT capacity
2 CCGT tariff, net of fuel input cost. South Africa assumed to have marginally lower capital costs than Mozambique (~10%)
3 Assuming 48% load factor
4 As indicated in Eskom Integrated Report 31st March 2017 – likely requiring low fuel costs and high load factors
5 As indicated in Eskom Integrated Report 31st March 2017 – high purchase cost, ranging between R77.5c/KWh and R380c/KWh, likely due to low load factor of associated IPPs
6 While a HV AC/DC line may be more desirable to encourage offtake along the route, the costs are significantly higher; adopting a more conservative cost estimate, a 500KV HVDC transmission line is assumed for modelling purposes

SOURCE: Lazard, Black & Veatch Corporation, ICF International, team analysis

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[91] Club of Mozambique (2016); http://clubofmozambique.com/news/anadarko-may-take-fid-mozambique-lng-next-year-come-production-around-2022-2023/

[92] Contractual agreements prevent other power plants from tapping into the transmission line

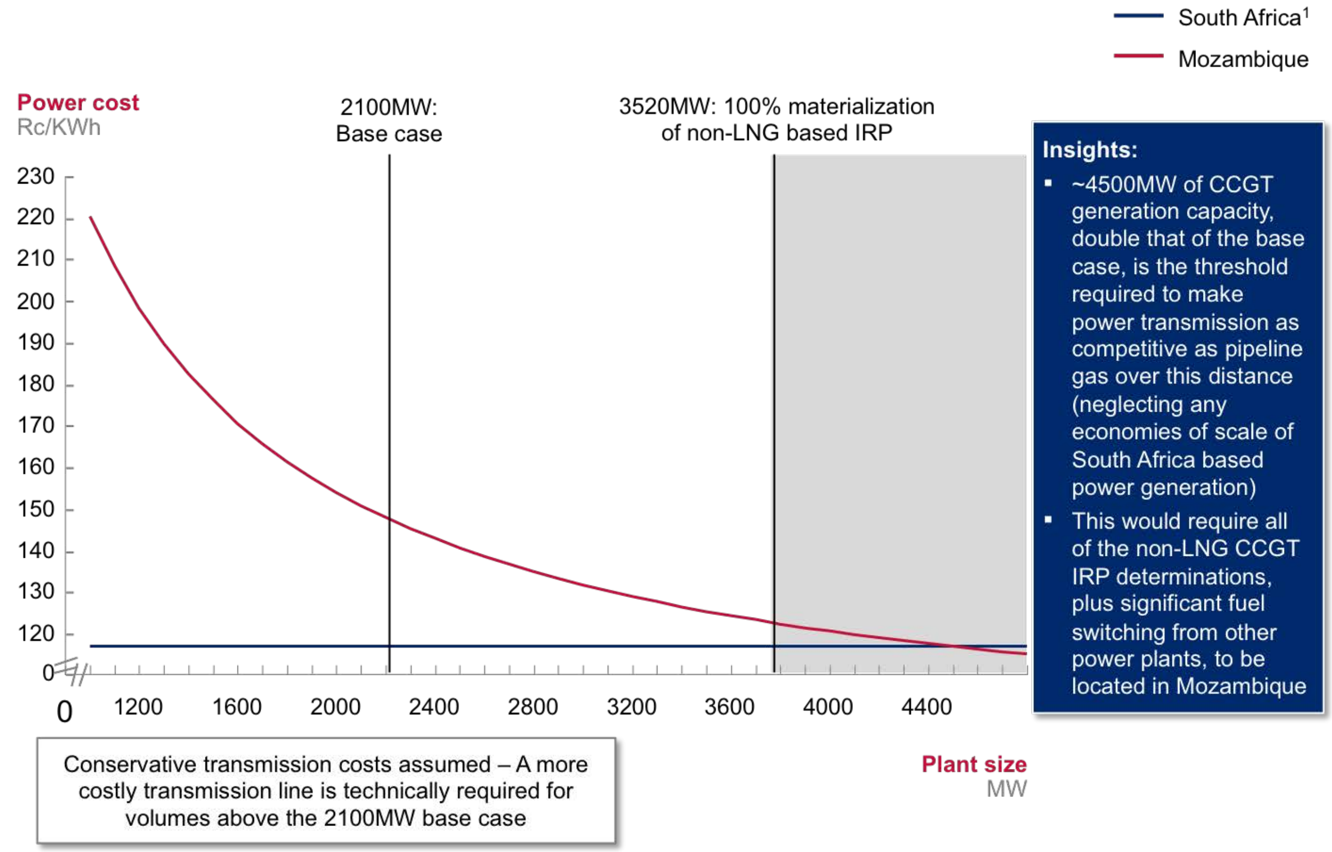
Since a large proportion of the incremental gas demand in South Africa derives from the demand for power, we also assessed the viability of trading electricity generated from gas-fired CCGT plants through a transmission interconnector.

When evaluating the case for these three options (i.e., the pipeline, LNG, and power transmission), we used the assumptions from the Medium scenario (**Exhibit 59** to **Exhibit 76** break down the assumptions used to evaluate each infrastructure method, the relevant volumes, and sensitivities around the assumptions used). Note that this analysis does not include the downstream infrastructure required for domestic gas/power distribution. The specific assumptions for each option include:

- Pipeline
  - *Infrastructure:* A 24" pipeline (based on the capacity required in the Medium scenario demand volumes) which runs 2,500 km onshore from Cabo Delgado to Mpumalanga (2,000 km in a straight line plus a 25 percent allowance for curves and turns).
  - *Capital Cost:* High-level assumptions lead to an estimated $5.8 billion.
  - *Volume Transported:* 149 PJ/year (372 mmscfd), a subset from the Medium scenario's 452 PJ/year (1,129 mmscfd) incremental demand across the two countries, which could be met via a pipeline. This

EXHIBIT 14

ILLUSTRATIVE COMPARISON OF GENERATION AND TRANSMISSION COSTS FOR INCREASING POWER DEMAND VOLUMES



Insights:

- ~4500MW of CCGT generation capacity, double that of the base case, is the threshold required to make power transmission as competitive as pipeline gas over this distance (neglecting any economies of scale of South Africa based power generation)
- This would require all of the non-LNG CCGT IRP determinations, plus significant fuel switching from other power plants, to be located in Mozambique

Conservative transmission costs assumed – A more costly transmission line is technically required for volumes above the 2100MW base case

[1] For simplicity, a constant delivered gas price and constant per unit power generation cost is assumed in the built up Rc/KWh tariff for South Africa. In reality, generation in South Africa would also benefit from economies of scale arising from 1) A lower pipeline tariff if more gas volumes are delivered to fuel CCGT units, and 2) A lower per unit generation costs for larger CCGT units

SOURCE: Lazard, Black & Veatch Corporation, ICF International, team analysis figure excludes South African power demand that are linked to LNG imports (and therefore assumes that the current LNG-to-power projects are not being compromised), Mozambican power projects that the Pande/Temane fields are expected to feed, and Mozambican power and industrial projects that are located close to the supply source in Cabo Delgado.

While some ~2,500 mmscfd of Mozambique's Rovuma basin gas production has already been allocated to LNG, domestic industry and gas-to-power projects, sufficient production capacity is assumed to remain to support a pipeline (see **Exhibit 62** in the Appendix for a breakdown of allocated and available volumes).

  - *Tariff:* A postage-stamp tariff approach (i.e., a flat fee charged for all users, regardless of the point of offtake) was used.

- LNG
  - *Infrastructure:* Many variations exist when assessing the required tariff for LNG trade between Mozambique and South Africa. These variations include the site of the LNG liquefaction terminal (MZLNG or Coral FLNG), the site of the regasification terminal (Richards Bay or Coega), and the type of regasification terminal (onshore or floating).

    Gas liquefied at MZLNG with shipping to a floating regasification terminal at Richards Bay was identified as the lowest cost option compared to the other liquefaction and regassification options publicly considered (e.g. vs. Coral FLNG and onshore regassification), and was therefore selected as the base case assumption for analysis.[93]

  - *Volume Transported:* 232 PJ/year (579 mmscfd) of South Africa's incremental gas demand could be met by LNG, largely driven by South Africa's LNG-to-power commitments. However, for a more direct comparison with a pipeline, the LNG tariff is assessed assuming 149 PJ/year is delivered at an import terminal at Richards Bay.

  - Tariff: A fixed-unit cost for liquefaction and shipping components as the associated economies of scale do not translate down to the end user. Regasification provides the only economies of scale. **Exhibit 65 - Exhibit 70** in the Appendix breaks down the LNG cost lifecycle from liquefaction to regasification, detailing these assumptions and their sensitivities.

- Power Transmission
  - *Infrastructure:* The 2,100 MW CCGT plant (calculated as on the non-LNG specific newbuild gas-to-power capacity assumed to materialize in the medium scenario) in Cabo Delgado is connected to the South African grid in Mpumalanga via a 2,500 km 500 kV HVDC line (this line is required for increased efficiency over large distances). At 2,500 km, this would be the world's longest transmission line. **Exhibit 75** in the Appendix lists out the longest transmission projects constructed to date for comparison.

  - *Capital Cost of the CCGT Generation:* $2.2 - $2.5 billion. South Africa is assumed to have a ~10 percent capital cost advantage ($1,050/KW based on lower cost estimate by Lazard) versus Mozambique ($1,175/KW based on a medium cost estimate by Lazard).[94]

  - *Capital Cost of the Transmission Line:* $3.2 billion. A cost estimate of ~$1.8 million/mile (including substation costs) was chosen from a wide range of estimates. **Exhibit 76** in the Appendix details the potential range of cost estimates that were considered in modelling these transmission costs.

  - *Volume Transported:* 66 PJ/year (165 mmscfd, or ~2,100 MW CCGT capacity at a 48 percent load factor) based on the non-LNG power projects that are expected to materialize in South Africa.

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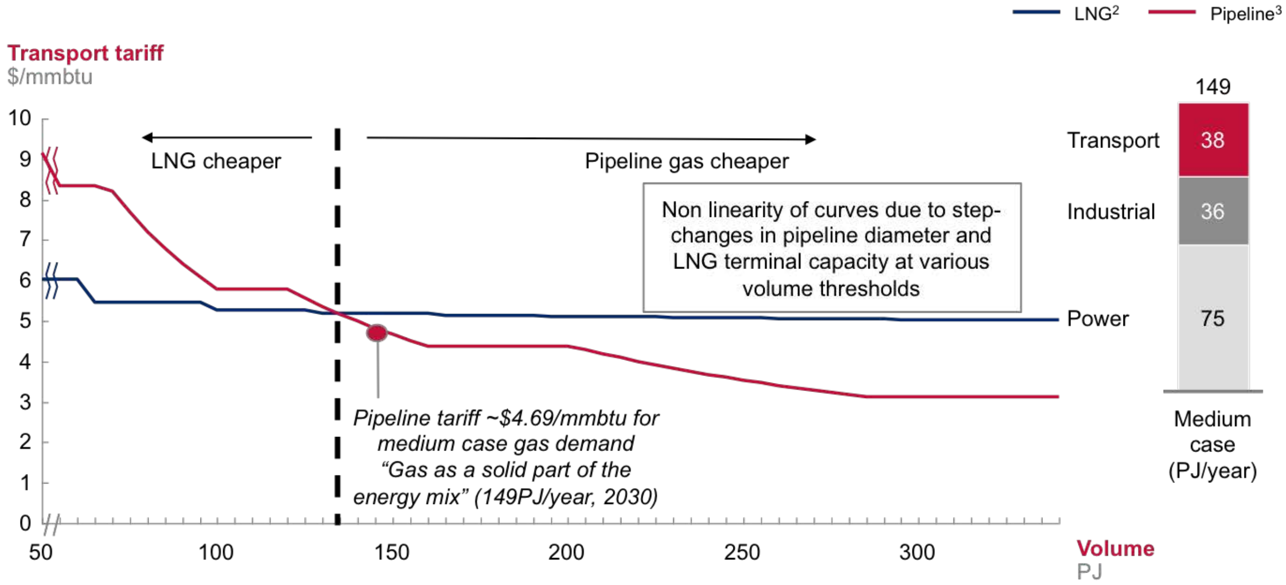
[93] Capex for MZLNG estimated at $1,300 per ton per annum (tpa), compared to Coral FLNG at $1,400/tpa (Wood Mackenzie, 2017)
Capex for an onshore 5 Mtpa terminal at Richards bay estimated at R11,870 million, compared to R7,570 million for a 5 Mtpa floating terminal (Transnet, 2017)

[94] Lazard (2012); Lazard's levelized cost of energy analysis – Version 10.0

EXHIBIT 15

PIPELINE VERSUS LNG TARIFF COMPARISON



- In a "medium" case gas demand scenario, traded volumes could be above the critical threshold required to make a pipeline more economical than LNG (for transportation of Mozambican gas to South Africa)
- Power demand would need to be supplemented by a co-ordinated approach with industrial and transport users[4]

[1] Analysis based purely from an economic standpoint; other factors should also to be taken into account (e.g. security of supply/demand, socio-economic implications, political preferences)
[2] For simplicity, comparison fixed at 149PJ volume for both pipeline and LNG. Given LNG volumes under base case are 228PJ, comparison could also be carried out at 228PJ for LNG with a resulting tariff of $5.10/mmbtu, or 114PJ for LNG (equally split between regasification terminals at Richards Bay and Coega) with a resulting tariff of $5.2/mmbtu.
[3] Smoothened curve to address the fact that increased compression would expand pipeline capacity at high utilization rates, to accommodate additional volumes
[4] Or alternatively it requires the 2030 gas-to-power targets of the IRP (2016) to fully materialize, as is the case in the high demand scenario

SOURCE: INGAA, NEMA, Cedigas, DoE Gas Based Industrialization in South Africa, team analysis from pipeline model

4.4.3 FINDINGS FROM INFRASTRUCTURE OPTION ANALYSIS

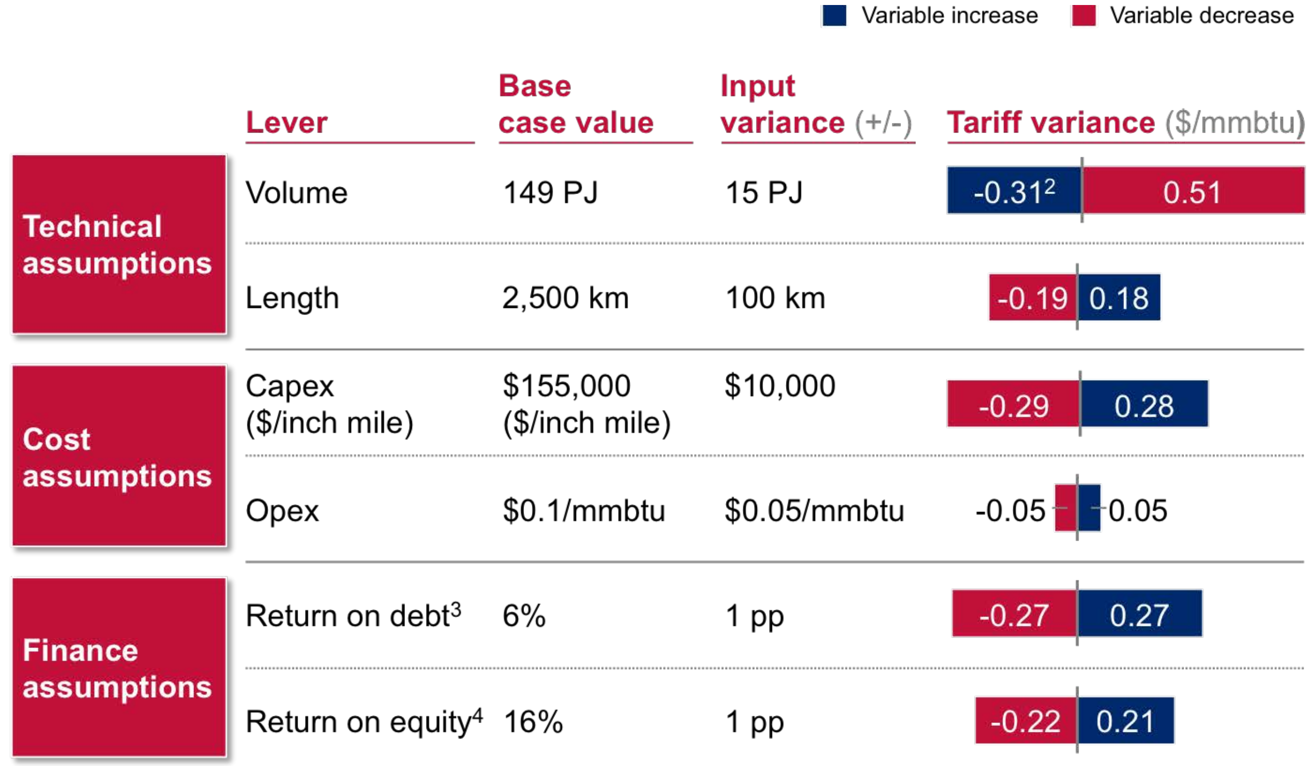
When evaluating the case for trade, one would need to make tradeoffs between the trade options that are most cost-effective, that have the lowest associated risks, and that could best address the region's economic and socioeconomic goals. Three clear insights emerged from the option assessment: gas trading (either via pipeline or LNG) is more cost-effective and versatile than power trading given the distances involved; LNG could potentially serve a larger share of South African demand due to LNG-to-power commitments; and trade through the pipeline could provide significant benefits from its economies of scale, and be cheaper than LNG at higher volumes.

- Gas Trading is More Cost-Effective and Versatile than Power Trading Given the Distances Involved

Initial results indicate that transporting gas molecules for conversion into electric power is more economical than transporting electricity over large distances, and it gives the end-user in a way more flexibility because its use is not limited to power generation. Power transmission also has two main cost disadvantages: it is difficult to scale up without incurring large line upgrade costs, and transmission line losses (i.e., Joule heating) drive up operating costs. Even the most cost-conservative case – connecting South Africa to 2 GW of power generation via a 500 kV HVDC line – would result in a tariff of R151c/KWh. Meanwhile, the tariff for transporting gas to South Africa and generating power domestically would be lower, at R117c/KWh (see **Exhibit 13**).
The Appendix describes other, more costly solutions, including an option where Mozambique offtakes some power domestically from the transmission line.

EXHIBIT 16

SENSITIVITY OF PIPELINE TARIFF TO MODEL ASSUMPTIONS



🟦 Variable increase 🟥 Variable decrease

	Lever	Base case value	Input variance (+/-)	Tariff variance ($/mmbtu)
Technical assumptions	Volume	149 PJ	15 PJ	🟦 -0.31[2] 🟥 0.51
	Length	2,500 km	100 km	🟥 -0.19 🟦 0.18
Cost assumptions	Capex ($/inch mile)	$155,000 ($/inch mile)	$10,000	🟥 -0.29 🟦 0.28
	Opex	$0.1/mmbtu	$0.05/mmbtu	🟥 -0.05 🟦 0.05
Finance assumptions	Return on debt[3]	6%	1 pp	🟥 -0.27 🟦 0.27
	Return on equity[4]	16%	1 pp	🟥 -0.22 🟦 0.21

1 All variables pivoted around base case values: 149PJ volume, 2500KM length, $155,000/inch mile capex, $0.1/mmbtu opex, 6% return on debt, 16% return on equity
2 Lies within smoothened range of tariff curve, where volumes between 160-200PJ assumed to be captured by increased compression of 24" pipeline
3 USD denominated interest rates
4 Defined as the post-tax leveraged return on equity

SOURCE: team analysis from pipeline model

Even at larger transmission volumes, domestic power generation would probably retain its economic advantage over long-range transmission (see **Exhibit 14**). The assumed 500 kV line would need to accommodate significantly increased CCGT capacity, 4,500 MW (a perhaps optimistic assumption), before the economics would start to favor long-range transmission over South Africa-based production. This amount is greater than what would occur if the entire non-LNG CCGT IRP determination materialized. In reality, the threshold could well exceed 4,500 MW, as generation costs in South Africa could become lower at this scale, and an upgraded HV transmission line would likely be required for greater volumes. Therefore, in the absence of a highly aggressive gas-to-power agenda, power transmission is unlikely to be economically competitive compared to gas transport through a pipeline followed by domestic South Africa power generation.

Finally, trading electricity would result in lower regional use and trade of gas, because it would only satisfy gas-to-power demand, ignoring industry and transport demand. In the Medium scenario, South Africa requires just 2,100 MW of gas-to-power capacity (outside of LNG-to-power commitments and domestic power generation obligations), which would lead to only 66 PJ/year (165 mmscfd) of gas trade (of a possible 232 PJ/year (579 mmscfd) forecast incremental gas demand).

- **LNG Could Potentially Capture a Larger Share of the South African Demand Through LNG-to-Power Commitments**

  LNG could address a greater demand potential in a joint Mozambique - South Africa system. Our analysis suggested that the net volume LNG could meet is estimated at 232 PJ/year (579 mmscfd), 83 PJ/year (207 mmscfd) more than pipeline transport (149 PJ/year, or 372 mmscfd).

In the Medium scenario, 3,000 MW of the gas-to-power IPP (93 PJ/year, or 232 mmscfd of gas demand) is linked directly to LNG across Richards Bay and Coega (High scenario demand provides a further 25 PJ/year, or 62 mmscfd based on 800 MW CCGT at Saldanha Bay). If we assume that these projects have made firm commitments to LNG and would not be served by pipeline gas, trading via LNG would provide a larger trade volume potential for Mozambique and South Africa in the current comparison. Even if projects were no longer constrained to sole links with LNG, it is still likely that LNG could meet more demand than a pipeline, which is more expensive over long distances (e.g., the demand center at Coega is much further than the Medium scenario assumption of 2,500 km from Cabo Delgado to Mpumalanga).[95] However, as a point-to-point transport solution LNG cannot address smaller pockets of demand that occur en-route, which a pipeline would under our current assumptions (20PJ/year, or 50 mmscfd of Mozambican demand met via pipeline tee-offs in the base case). Given the tradeoff, a pipeline between Mozambique and South Africa, and LNG infrastructure to connect the two countries, are not mutually exclusive (illustrated further in **Exhibit 77**). Multiple trade options could co-exist, and help address a larger portion of unmet demand.

In the current phase of this work, we assumed that LNG would adopt a simple approach with regasification in Richards Bay. In subsequent phases of this work, additional scenarios may be considered (e.g., multiple regasification sites along the Mozambican coast).[96]

EXHIBIT 17

OVERVIEW OF POTENTIAL CONSIDERATIONS FOR STAKEHOLDERS

Infrastructure option			
Stakeholder	Pipeline	LNG	Power transmission
South Africa	✓ Diversifies infrastructural options to supply gas (in addition to LNG)	✓ Provides flexibility to tap global LNG market (e.g. other prices)	✓ Minimal capex required by South Africa except for some transmission enhancements
	✓ Potential to replace supplies from Pande/Temane once depleted	✓ Limited additional capital investment on top of envisioned LNG-to power program	✗ Loss of control of power supply
	✓ For sufficiently large volumes, per unit cost could be more economical	✗ Above certain volume threshold Mozambican LNG would become less economically attractive compared to piped gas	✗ Reduces economies of scale for wider gas trade
	✗ Requires extra investment if LNG program is pursued in parallel		
	✗ Requires long term buyer contract to justify Mozambican investment		

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[95] Pipeline tariff sensitivity of +/- $0.19/mmbtu for a change in distance of +/- 100 km.

[96] Regasification terminals currently being considered off the coast of Mozambique, including at Maputo and Nacala. Informed by the US Embassy in Maputo

Infrastructure option			
Stakeholder	Pipeline	LNG	Power transmission
Mozambique	✓ Secures offtake volumes given global LNG price pressure on Mozambique	✓ MZLNG already undertaken large capital investments, so no incremental capex above this required	✓ Creates anchor demand for gas offtake
	✓ Allows for local development potential along the pipe via tee-offs	✓ Contracted volumes would support business case for MZLNG	✓ Domestic power development via sharing of infrastructure
	✓ Results in employment for construction of the pipe	✗ Exposes Mozambique to global LNG market prices (SA is not necessarily locked in to take Mozambican gas)	✗ Potentially lower return due to (regulated) power prices versus more volatile gas prices
	✗ Results initially in a single buyer for that portion of the gas (reduces selling power)	✗ Fewer Mozambican employment and local industrial development associated	✗ Reduces economies of scale for wider gas trade, less volume locked in
	✗ Requires substantial additional investment on top of MZLNG		
Investors	✓ More feasible business case given lower tariff	✓ Provides seller flexibility to tap global LNG market (e.g. other prices)	✗ Higher investment risk of Mozambique versus South Africa
	✗ Additional or more extensive risks (land risk, construction risk (larger project, security risk (sabotage))	✓ Potentially less complicated governance structures, lower capital investment required	✗ Potential of returns being ZAR denominated if dependent on domestic power tariffs
	✗ More complicated governance and stake-holder landscape with two host countries	✗ Increasing share of 'spot-trade' in the global LNG market reduces ability to lock in long term 'take-or-pay' contracts	

- **Trade Through the Pipeline Could Provide Significant Benefits from Economies of Scale and Could Be Cheaper Than LNG at Higher Volumes**

  At volumes above 135 PJ/year (337 mmscfd), trade via pipeline has the potential not only to be competitive, but to be the most cost-effective option for bridging the supply and demand imbalances across Mozambique and South Africa (**Exhibit 15**). It would therefore be the cost-based solution of choice for the Medium scenario where gas plays an important part of the energy mix, requiring 149 PJ/year (372 mmscfd) of gas to be traded. Under this scenario, pipeline gas could be transported at an estimated \$4.69/mmbtu, versus LNG transportation which would cost an estimated \$5.14/mmbtu.[97]

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[97] Processing and transportation costs only; cost of upstream gas is excluded; Processing and transportation costs only; cost of upstream gas is excluded. For simplicity, LNG tariff measured at 149PJ/year. Alternate comparison points for the LNG tariff would be at 232PJ/year (total volume transported by LNG in base case) and at 116PJ/year (base case LNG volumes split evenly between Richards Bay and Coega regasification sites).

Pipeline economies of scale arise from the fact that pipeline capital costs increase in an almost linear fashion to pipe diameter, while pipe volume capacity increases quadratically to pipeline diameter. LNG trade does not offer these scale benefits. From a buyer's perspective, the only likely cost component that benefits from scale in LNG is regasification, which comprises only a small proportion of the overall cost. Liquefaction costs are arguably fixed for the buyer, given they offtake just part of a terminal's production and therefore do not reap liquefaction economies of scale. Shipping costs also have limited scope for economies of scale, given that additional volume is simply met through more frequent deliveries of a standard vessel size.

Given that the pipeline and LNG tariffs lie within $0.50/mmbtu of one another under this scenario, we analyzed the sensitivity of the pipeline model to assess how changes in its underlying assumptions could widen, tighten, or potentially reverse the apparent cost advantage the pipeline holds over LNG.

The volume transported was found to be the most sensitive variable; a variance of negative 10 percent on the 149 PJ/year (372 mmscfd) base case could push the tariff up by $0.51/mmbtu, enough to erode all the cost advantage of pipeline transport over LNG. Given this, the anchoring of demand would be critical to the pipeline's success. A combination of demand from power, industry, and transport would probably be required to meet (much less exceed) the 135 PJ/year (337 mmscfd) threshold, which would likely entail a coordinated, Ministerial approach. Alternatively, a gas-to-power agenda, more ambitious than South Africa's current IRP and Mozambique's planned projects, would need to materialize if power alone is to anchor demand for a pipeline.

A pipeline's economic viability is also highly sensitive to its capex costs, and its return to its debt and equity investors. A variation of +/- $10,000 from the $155,000 per inch/mile (the typical way costs are scaled for gas pipelines) of capex assumed could change the tariff by +/- $0.29/mmbtu. Returns also have a strong effect; a 1 pp swing in the return on debt can change the tariff by +/- $0.27/mmbtu, and a 1 pp swing in the return on equity by +/- $0.22/mmbtu. The fact that ~80 percent of the total lifetime cost of the project is borne during initial construction costs drives these sensitivities. By contrast, the pipeline tariff does not react as strongly to any extensions of the pipeline length (or constructing additional tee-offs), and variations in its relatively small opex.

A similar analysis was performed to assess the sensitivity of the LNG model. The results of this analysis are included in **Exhibit 67** and **Exhibit 70** in the Appendix. The models are mostly sensitive to the choice of technology (onshore liquefaction vs, FLNG, onshore regassification vs. a FSRU) and the assumed costs of capital, but less so to the volumes involved.

4.4.4 STAKEHOLDER CONSIDERATIONS FOR INFRASTRUCTURE OPTIONS

The trade options assessed are not mutually exclusive. In principle, LNG trade, a pipeline, and a transmission line could co-exist if there are enough benefits in having multiple infrastructure options. For instance, while it seems likely that both countries will pursue their plans to construct LNG infrastructure, any non-LNG volumes could potentially be met more economically via a pipeline. Furthermore, a pipeline could complement LNG trade by offering Mozambique and South Africa the flexibility of an alternative avenue for marketing or sourcing gas. Both countries, however, would need to consider the tradeoff between the significant investment capital required for the project and its ability to meet their socioeconomic and political goals.

In light of considerations such as these, our analysis of the three trade options showed that no single method stands out as having clear merits above the others on all dimensions. Given the mutual tradeoffs which occur when comparing such options, we adopted a multi-lensed view which would help assess the potential benefits and drawbacks of each transmission option from the viewpoints of the various stakeholders involved, summarized in **Exhibit 17** above:

These stakeholder considerations can be consolidated and assessed across the following dimensions:

- **Economics:** While the assessed transport options indicate which are most economical, they do not compete in isolation. Gas, whether delivered by pipeline or LNG, must be able to compete in the global gas market, and CCGT-generated power (from Mozambique or domestic) must be able to compete with other fuel forms or the tariff charged to consumers.

  For gas, trade via pipeline appears to be cheaper than LNG for the volumes considered, but the difference is marginal and both options lie within a competitive range ($4.69/mmbtu for pipeline versus $5.14/mmbtu for LNG). From a global perspective, both tariffs could result in prices which lie within the $7-9/mmbtu range[98] at which delivered gas trades internationally after upstream development and regasification costs are added (see **Exhibit 78** in the Appendix for global gas price benchmarks). This could make Mozambican gas an economically viable option for South Africa. It could help the seller compete, help the buyer achieve the best possible price, and help the investor make this option commercially viable.

  For power, the high costs associated with power versus gas transmission firmly favor domestic power generation in South Africa based on gas transport through a pipeline. However, in the context of South Africa's average power tariff (R84c/KWh), even domestic CCGT generation (R117c/KWh) would place this above the average tariff, indicating a role for gas-to-power within mid-merit and peak load generation. But while gas-fired power generation may find it difficult to compete on price, other non-economic factors may validate its use (see the Socioeconomic and political environment below).

  Furthermore, all options would carry some element of investor concentration risk in a single project due to the sizable investment involved. This risk, and the associated challenge in raising capital, should be analyzed further when making investment decisions.

- **Timeframe:** While the above analysis considers a 2030 outlook, in practice stakeholders would assess multiple options across multiple timeframes. Various trade options could all be optimal, depending on the timeframe being considered. For example, a pipeline could in theory provide an economic trade solution for the medium-term, but it requires the associated demand and infrastructure to have materialized. In the short-run however, LNG could potentially be a more suitable option to fulfill pockets of demand before the needed scale is reached to support a pipeline.

  In addition, the flexibility of infrastructure options to accommodate seasonal variations in demand would need to be assessed. The volumes considered in the above analysis considers an average rate over the period of a year. In practice however, this could be lower or higher at any given time depending on the utilization profile of off-takers. This is particularly true for gas-to-power users, where capacity utilization could vary anywhere between 0% and 100%, from the average 48% - 64%[99] currently assumed. Under the medium case scenario where 149 PJ/year (372 mmscfd) of demand could be met by a pipeline, peak demand could be as high as 226 PJ/year (564 mmscfd) assuming 100% capacity utilization of CCGT demand, and negligible seasonality of industrial and transport demand (see **Exhibit 79** in the Appendix for breakdown).

Key Takeaways

Various options exist for Mozambican gas to supply South African demand. Pipeline trade can be an economically attractive way to do this, and could unlock substantial gas-to-power and broader economic development potential. However, a more detailed evaluation of the trade options would still be necessary, and could include an analysis of socioeconomic benefits associated with the various infrastructure options.

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[98] $2.84/mmbtu upstream and processing cost + $4.69 - $5.14/mmbtu cost of transport

[99] 48% assumed for South Africa based on IRP assumptions, while 64% assumed for Botswana, Mozambique, and Namibia as an average usage across all fuel types

An initial assessment suggests that the 24" pipeline (with increased gas compression, additional capex (e.g. for additional compressor stations), and/or storage solutions), and the 5 MTPA LNG terminal could both allow for such peak variations to be accommodated. In parallel, the ability for upstream production to ramp up and down, and the potential for downstream storage would need to be assessed to help accommodate seasonal variations in demand.

- **Security of Demand:** For Mozambique, the security of a willing and able end-buyer is vital to justify its upstream investment costs. As the development of Coral FLNG and MZLNG come closer to reality, any additional non-LNG offtake of Mozambique's gas reserves would help diversify its buyer base and secure additional offtake in a globally competitive LNG market. Trade via either pipeline or power transmission would secure an additional off-taker for Mozambique.

  In addition, Mozambique would need to consider the credibility and credit worthiness of its off-takers as part of its security of demand assessment. These could range from domestic/regional players (e.g. EDM, Eskom), traders (e.g. Trafigura, Vitol), and global end users (e.g., Kogas, Tepco). A credit assessment for each counterparty would need to be undertaken when Mozambique looks to market its gas.

  Furthermore, Mozambique would need to trade-off demand security against a potential overdependence on a single off-taker. Under the medium scenario, a total of ~300 PJ/year (~750 mmscfd) of Mozambican production could be consumed by South Africa alone (across a new pipeline and the existing ROMPCO pipeline). Nonetheless given Mozambique's large LNG export plans, these pipeline exports to South Africa would still only comprise of 27% of Mozambique's total exports. Mozambique would still be expected to have a moderate to high diversity of buyers (**Exhibit 80** in the Appendix provides more detail of Mozambique's buyer diversity assessment).

- **Security of Supply:** For South Africa, a similar logic would apply for security of supply. Much of South Africa's planned CCGT capacity would be locked into LNG through the IPP program (it is already considering developing LNG import terminals at Richards Bay and Coega (and Saldanha Bay in Phase 2)). An alternative source of supply (via pipeline or transmission) would help provide the country with supply security.

And similarly, South Africa would have to balance supply security against any potential overreliance on Mozambique for its gas requirements. Under the medium case scenario, South Africa has a domestic gas deficit of 397 PJ/year (991 mmscfd). Of this, 75% of this could potentially be supplied by Mozambique via the existing ROMPCO pipeline and a new pipeline from Rovuma, while the remaining 25% is supplied by LNG.[100] This would result in a moderate to low supplier diversity for South Africa under such a scenario. (**Exhibit 81** in the Appendix provides more detail on South Africa's supplier diversity assessment).

- **Socioeconomic and Political Environment:** Given the central role government plays in energy policy, a country's wider political targets would need to be considered. Decisions are often based on what most closely aligns with an overall agenda, and take socioeconomic and political considerations into account. Such considerations would encompass impacts on GDP, the creation of sustainable employment opportunities, and the diversification of the energy mix, among others. It would be especially important to achieve the buy-in and support from local government.

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[100] Assuming the LNG is not sourced from Mozambique

Investment, job creation, and a clean energy plan would all shape the final decision on the best way to trade energy between Mozambique and South Africa. While LNG trade could likely advance all agendas, it would probably offer Mozambique and South Africa fewer incremental socioeconomic benefits, especially if it is believed that Mozambique's LNG projects and South Africa's LNG-to-power IPP are independent and likely to develop regardless. Mozambique's LNG projects can always sell to other buyers, and South Africa can always buy from other sellers – mutual trade is not required for their development. Furthermore, the pipeline and power transmission projects arguably allow for additional economic development opportunities, given they could provide an option for tee-offs along the infrastructure route.

Although the current work focused more on the high-level economic analysis of the various trade options, a more detailed evaluation that more closely analyzes the socioeconomic benefits of the various options, and risk considerations, would need to be conducted. This could be done as part of a longer-term initiative to perform a detailed study of the gas trade between Mozambique and South Africa. Chapter Six will elaborate on the potential angles this could consider.

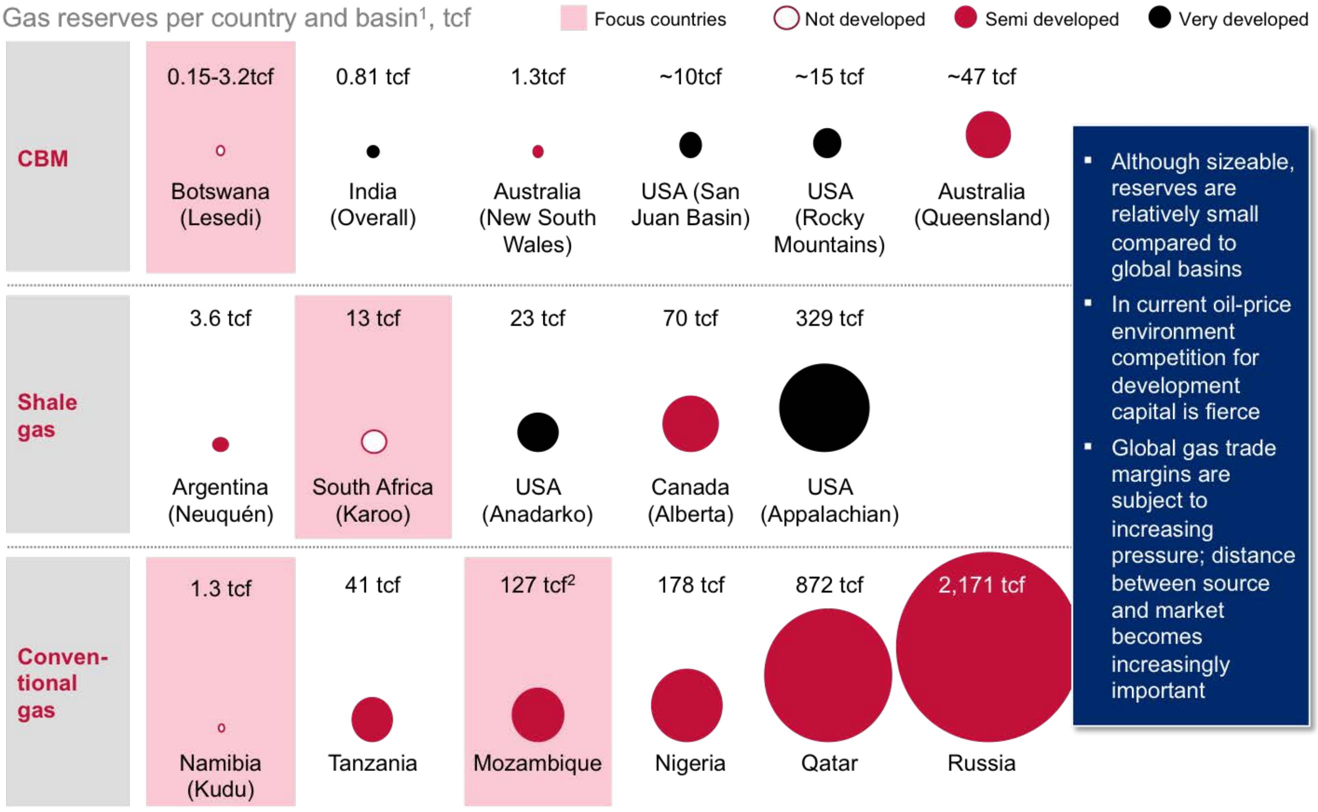
5. REGULATORY ENVIRONMENT FOR NATURAL GAS IN SOUTHERN AFRICA

In the previous chapters, we analyzed the extent to which gas demand and supply could materialize by 2030 and evaluated the infrastructure options that could bridge supply and demand. The latter analysis focused on economics. This chapter assesses the region's regulatory environment and examines what might be needed to unlock its gas potential.

Although sizable gas reserves have been discovered in Southern Africa, they would need to be assessed and developed in the context of increasingly competitive global gas markets. In the current oil price environment, capital investments are under significant pressure and face fierce competition from larger global basins. In just one example, Botswana's Lesedi CBM field, which is somewhere between 0.15 tcf (proven reserves) and 3.2 tcf (contingent reserves), would have to compete for development capital against various other gas and CBM basins (see **Exhibit 18**), including e.g. the US (~15 tcf) and Australia (~47 tcf). Global gas markets are also changing more rapidly as they become increasingly liquid – which puts even more pressure on gas margins. Finally, the current surplus of gas resources and the shift from long-term take or pay agreements to a spot market have dramatically increased the competition for the gas offtake. As a result, the physical distance between a gas source and its markets is becoming increasingly important.

EXHIBIT 18

COMPARISON OF SOUTHERN AFRICAN RESERVES WITH SELECTED GLOBAL BASINS[1]



- Although sizeable, reserves are relatively small compared to global basins
- In current oil-price environment competition for development capital is fierce
- Global gas trade margins are subject to increasing pressure; distance between source and market becomes increasingly important

1 Non-exhaustive list; covers total recoverable reserves (including those reserves which were in place but which are already produced, typically only a fraction of the total reserves)
2 As per WoodMackenzie estimates, some sources estimate larger reserves adding up to 180-200 tcf

SOURCE: Source: WoodMackenzie Upstream Data Tool, Reuters

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[1] Wood-Mackenzie upstream data tool, complemented with Tlou energy website and Reuters press clippings (for Karoo shale reserves)

In the light of the above, the Southern African region's lack of an established gas ecosystem and infrastructure is likely to complicate investment decisions. A well-coordinated effort and supportive regulatory frameworks are required to attract international investors to the region.

The region's gas regulatory framework is still in the early development stages, with current gas activities mostly governed by other petroleum and energy laws (i.e., few gas-specific laws exist). Most of the focus countries would need to provide additional clarity on certain regulatory elements that are key for investors in the gas market. Differences also exist in the extent to which these countries motivate companies to invest in the gas industry, whether through different tax allowances and/or other incentives. Often, these variations in policy are reflect the extent to which investors need to be incentivized to develop different types of resources (e.g., smaller vs. larger basins). However still, a countries' regulatory frameworks need to be globally competitive if they are to contend for investment on a global scale.

A high-level comparison of the four countries reveals that:

- Botswana, in relative terms, has the least developed regulatory environment of the focus countries. It only recently established an energy regulator (Botswana's Energy Regulatory Authority (BERA). The Act of Parliament Number Thirteen of 2016 established BERA as a corporate body that is primarily responsible for economic regulation of the country's energy supply sector. It is anticipated that BERA will assist Botswana in addressing the uncertainties in its energy and gas regulatory framework.
- Mozambique recently developed an updated regulatory framework that related to gas in 2014 – 2015. Its New Petroleum Law and Petroleum Tax Laws primarily focus on increasing Mozambique's share of gas development benefits. However, these laws were drafted at a time of high gas prices and often result in less favorable terms for investors. They have not been refined recently. In September 2017, Mozambique established its new Energy Regulator ARENE, which primarily focuses on downstream gas regulations. Details around its AAIE regulatory body and that body's responsibilities remain unclear.
- Namibia's upstream gas regulations were noted as "most attractive" in the Africa Global Petroleum Survey's Policy Perception Index and Africa Business Insight.[101] Namibia offers various incentives for oil and gas companies, including flat royalty rates of 5 percent across the board, VAT waivers, and other tax advantages.[102] However, the country lacks downstream regulatory policies.
- South Africa has the most developed regulatory framework for downstream gas in Southern Africa. It continues to refine its current policies through the envisioned amendment of the Mineral and Petroleum Resources Development Act (MPRDA) and the drafting of a National Gas Infrastructure Development Plan. South Africa is currently revising its upstream fiscal framework, and stakeholders have opposing views on whether the proposed revisions would be conducive for investments or not.[103]

The next four sections provide detailed descriptions of each country's regulatory framework.

5.1 BOTSWANA'S GAS REGULATORY LANDSCAPE

Botswana's gas regulations are relatively undeveloped. There is little clarity about upstream and downstream gas regulations, including domestic use policies. However, Botswana's Mines and Minerals Act appears to partially address the upstream regulations. Interfax Energy highlights a concern that because the regulatory framework was developed for hard minerals, it may not be entirely appropriate for gas or CBM.[104]

BERA focuses primarily on the economic regulation of the energy supply sector. Its functions will eventually be extended to include gas-related regulatory activities.[105]

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[101] Africa Business Insight (2016,March 29); How we made it in Africa; https://www.howwemadeitinafrica.com/africas-top-10-places-invest-2016/53885/.

[102] Africa Business Insight (2016,March 29); How we made it in Africa; https://www.howwemadeitinafrica.com/africas-top-10-places-invest-2016/53885/.

[103] Based on stakeholder interviews, we understand the proposed revisions may be considered too strict to enable shale gas development, while conventional gas developers would prefer to have the revisions finalized broadly in its current proposal to the benefit of clarity

[104] Interfax Global Energy (2016, August 18); http://interfaxenergy.com/gasdaily/article/21587/botswana-cbm-moves-forward-but-doubts-persist.

[105] ESI Africa, (2017, October 31); https://www.esi-africa.com/news/botswana-establishes-energy-regulator/.

The absence of a gas association also leaves a significant ecosystem gap; only two private companies, Tlou Lesedi and Kalahari Energy, lead Botswana's gas development. As of December 2017, the CBM field developers (e.g., Kalahari Energy) have been working with the Government of Botswana to characterize the resource. Discussions are ongoing around critical regulatory aspects that would help unlock further gas development in Botswana. However, no direct incentives are currently in place (based on available information).[106]

Key Takeaways

The gas regulatory framework in Southern Africa is still in its early stages of development. USAID SAEP, in collaboration with SADC and RERA, could support the priority regulators in refining and implementing the gas regulations required to unlock the gas potential.

Exhibit 85 in the Appendix provides further details on Botswana's Gas Regulatory landscape.

Mozambique's upstream gas regulatory framework is guided by other petroleum and energy regulations.[107] In 2014, new Petroleum and Petroleum Tax laws clarified various areas of uncertainty that previous laws had not addressed. However, the new laws were drafted when gas prices were high and focused on increasing Mozambique's share of the economic benefits, which resulted in less favorable terms for investors. Since then the industry has changed dramatically, with oil prices falling by more than 50 percent. Mozambique has not adjusted its legislation to account for the new market conditions and the lack of new investor interest.[108] However, these new laws only affect new concessions; for instance, they do not affect Rovuma Areas One and Four. Mozambique has also been able to boost investment by adapting laws for specific projects (e.g., the Decree Law Number 2/2014, which provides an adjusted royalty rate for Rovuma Areas One and Four, reducing it from 6 percent to 2 percent for the first ten years).

The New Petroleum law also clarifies the issue of the domestic gas obligation (25 percent+ per concession), although details remain unclear (e.g., whether it includes royalties). According to the law, these are to be agreed to on a case-by-case basis. The law also prescribes that the terms of the sales set by the government should be in accordance with "market terms;" the meaning of this is not entirely clear, but could indicate a favorable regime. All gas sales are to be carried out through the state-owned company ENH.

In addition, Mozambique recently established its new Energy Regulator, ARENE, which will primarily focus on downstream gas regulations. ARENE will regulate the distribution, transport, storage, and sale of natural gas at pressures equal to or less than 16 bars. It will approve any gas tariffs, and attribute and reinforce the concessions and licenses for the transportation, distribution, and sales of natural gas.

Mozambique's National Petroleum Institute (INP) is responsible for managing exploration, production, and transport concessions for petroleum products in accordance with Decree 25 of 2005. As a result, INP's and ARENE's responsibilities for the regulation of the transportation of natural gas appear to overlap.[109] At the time this report is being written, it was unclear how this overlap would be resolved. In September 2017, MIREME issued a tender requesting consultancy services to define the roles and responsibilities of the AAIE, an inactive regulatory authority appointed by the Petroleum Law to oversee the control of petroleum operations. Details of its role are not yet defined.[110] It is also unclear whether MIREME still intends to establish AAIE following the launch of ARENE.

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[106] Interviews with US_Missions_in_Botswana (2017)

[107] Law (2001) Regulations on Petroleum Operations (2004); Regulation on import, sale and distribution of petroleum products (2012); Tax Benefits for Mining and Petroleum (2007); Regulation of Employment of the Foreign Citizens in the Petroleum and Mining sector (2011), Energy Policy 1998, etc.

[108] Shearman & Sterling (2016, April 1); http://www.shearman.com/en/newsinsights/publications/2016/05/energy-update-articles/mozambiques-new-petroleum-legislation-completed

[109] Insights from discussions with the SPEED+ Project's Power portfolio team

[110] ZITAMR (2017, 20 September); ttps://zitamar.com/consultants-wanted-help-establish-mozambique-extractive-industry-regulator/.

In terms of bilateral trade agreements, Mozambique has been in discussions with South Africa to increase gas trade beyond the current ROMPCO pipeline. Details on the most recent status of these discussions are unavailable, and likely to be subject to new directions after South Africa's expected updates to its IRP and regulations.

Exhibit 83 in the Appendix provides further details on Mozambique's Gas Regulatory landscape.

5.3 NAMIBIA'S GAS REGULATORY LANDSCAPE

Namibia has a relatively clear upstream regulatory framework for natural gas, but the downstream regime is not clear. The Global Petroleum Survey's Policy Perception Index ranked Namibia as the number one investment destination in Africa in 2015. The country's oil and gas investors benefit from low royalties (e.g., 5 percent across the board) and other VAT waivers and tax advantages. Namibia's upstream legislation has been described as be inviting to investors.[111] These upstream regulations are guided by the Petroleum Exploration and Production, Act Two of 1991, and the Petroleum Products and Energy Act (Fourteen) of 1993.

However, despite the commendable appeal of its upstream regulations, Namibia has no downstream domestic gas regulation. No regulations have been put in place for the distribution or transportation of natural gas, LNG facilities, domestic gas prices, etc. As a result, the downstream gas industry is self-regulated. The Petroleum Act also makes no provision for cross-border trades of natural gas. In this vacuum, case-by-case agreements have been signed (e.g., South Africa and Namibia signed an agreement in August 2003 to facilitate gas trade between the countries). Namibia's draft Gas Bill, which has been under development since 2001, aims to address this gap in downstream regulations. However, it has not yet to be formally passed.

The Petroleum Commissioner and the Chief Inspector of Petroleum Affairs currently perform Namibia's gas regulatory functions under the guidance of the Minister of Mines and Energy.[112]

Exhibit 84 within the Appendix provides further details on Namibia's Gas Regulatory landscape.

5.4 SOUTH AFRICA'S GAS REGULATORY LANDSCAPE

South Africa's upstream gas regulatory framework and domestic gas policies are primarily guided by its broader petroleum regulations, which include the Mineral and Petroleum Resources Development Act (28/2002) and the Petroleum Pipelines Act (60/2003). The Gas Act (48/2001) provides the regulatory framework for the construction and operation of gas transmission, storage, distribution, liquefaction, and regasification facilities, and for gas trade.[113] NERSA oversees gas regulations and regulates the electricity, piped-gas, and petroleum pipeline industries. It is also the competent licensing authority under the Petroleum Pipelines Act and the Gas Act.

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[111] Africa Business Insight (2016,March 29); How we made it in Africa; https://www.howwemadeitinafrica.com/africas-top-10-places-invest-2016/53885/.

[112] International Comparative Legal guide (2017, 4 January); https://iclg.com/practice-areas/oil-and-gas-regulation/oil-and-gas-regulation-2017/namibia.

[113] International Comparative Legal Guides (2017); https://iclg.com/practice-areas/oil-and-gas-regulation/oil-and-gas-regulation-2017/south-africa#chaptercontent3.

South Africa recently refined several of its gas regulations:

- A Draft Amendment Bill to the MPRDA was released for public comment in early 2017. Several law firms and expert bodies warned that although the bill is crucial to establish regulatory certainty, the draft submitted for public review ending June 2017 faced constitutional challenges around the Codes of Good Practice.[114]
- South Africa is expected to issue an IRP at the end of 2017 that would clarify gas' role in the country. However, there are concerns that the IRP in its current form may have been politically influenced. The Council for Scientific and Industrial Research (CSIR) has also suggested that it understates the potential for renewables and gas.
- A draft of a National Gas Infrastructure Development Plan will serve as the blueprint to develop South Africa's gas infrastructure framework.[115]
- The Department of Energy has launched the LNG IPP program to kickstart gas development and encourage the use of imports to induce gas demand.[116] However, the exact path forward for this program would depend on the direction provided by the expected update to the IRP.

The role of gas in South Africa and its gas regulatory framework will remain uncertain until the country has finalized these amendments. In addition, alignment of South African and Mozambican (mid and downstream) gas regulations could be further investigated to further facilitate trade.

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[114] Chamber of Mines, Institute of Race Relations, Webber Wentzel & Legal Resource Centre; Cliffe Dekker Hofmeyr, (2016, November 11); Mining Review Africa ; https://www.miningreview.com/news/signing-mprda-mendment-act-bring-certainty/; MiningMx (2017,August 22); http://www.miningmx.com/special-reports/mining-yearbook/mining-yearbook-2017/30311-mprda-heading-legal-wrangling-mining-charter/.

[115] Department of Energy website: E-resources; http://www.energy.gov.za/files/esources/naturalgas/naturalgas_national.html.

[116] Norton Rose Fulbright (2016, October 6); http://www.nortonrosefulbright.com/knowledge/publications/149966/south-africa-pim-for-lng-to-power-ipp-procurement-programme.

6. NEXT STEPS

The analysis provided in this report is being used as a stepping stone in the development of a regional gas strategy. Given that USAID SAEP ends in March 2022 and taking into account the extended timelines needed for development of a gas pipeline, LNG imports and other gas infrastructure options analyzed above, USAID SAEP will focus on activities capable of realizing impact in the shorter term, while assisting the region in preparation for longer term industry development. Based on the report's findings and our ongoing discussions with stakeholders, USAID SAEP will focus on two main areas moving forward, including 1) playing a coordinating role with SADC and its members in adapting and implementing the Regional Gas Master Plan and 2) supporting the capture of gas-to-power projects in the region.

USAID SAEP will aim to execute these interventions in the coming four years of program delivery. Although some of the timelines depend on external events (e.g., the availability of key stakeholders like RERA or the SADC Gas Subcommittee, or the clarity / availability of a renewed South African IRP), the coordinating role and the unlocking of the projects can be started in the short-term.

6.1 COORDINATE GAS DEVELOPMENT IN THE REGION

To advance gas-to-power projects in the region, supply needs to be brought online, and demand anchored. For this to happen, an enabling environment and coordinated efforts to connect supply and demand are necessary.

USAID SAEP will seek to play a coordinating role to support other entities (e.g., SADC Secretariat, SADC member nations) to develop a regional gas master plan, provide regulatory support, and deliver practical training. With respect to driving adoption of a regional master plan, USAID SAEP will work with SADC, who has already requested USAID SAEP's support as it designs its approach to completing a regional master plan, and RERA to coordinate regional regulation for gas as part of the SADC Regional Gas Sub-Committee's work.

In building out the Regional Gas Master Plan, USAID SAEP may assist in:

- Determining what is required to develop a SADC Gas Master Plan. USAID SAEP could help SADC to identify the further analysis required to develop a SADC Gas Master Plan, using the USAID SAEP Regional Gas Master Plan as a basis. For example, expansion to all SADC member countries, socioeconomic cost/benefit analysis, and risk assessments could all form components of a SADC Gas Master Plan. As part of this process, USAID SAEP could evaluate pragmatic ways to carry out some of the additional analysis required, and where needed, formulate simple business cases that can facilitate these decisions.
- Convening meetings with RERA and the SADC Gas Subcommittee to ensure the adaptation and implementation of the roadmap. These meetings could occur over a period of six months, and would focus on: aligning on the facts related to natural gas in the region; adapting the roadmap for the SADC region; extensive stakeholder engagement to socialize the roadmap; and developing implementation plans for priority regulators (e.g., NERSA and Mozambique's regulator ARENE).
- Providing support to guide the development of required gas regulations. SAEP could work with local gas regulators, including NERSA and ARENE, when adapting the SADC roadmap. This could take the form of a gap analysis to assess what supporting regulatory environment is required for implementation of the roadmap. Based on the findings, the relevant strategic and legal support could be provided, including capability building, gap assessment for national gas-to-power programs, and capability building for cross-border gas collaboration.

Supporting the practical application of the gas roadmap by delivering training workshops on gas and LNG markets (e.g. on contracts, trading, and production). This could be targeted at ministries and regulators to drive more informed policy and decision making, and at national oil and gas companies to facilitate access to gas markets. These workshops could primarily provide knowledge, training, and strategic advice.

6.2 HELP UNLOCK 5.0 TO 8.8 GW OF GAS-TO-POWER PROJECTS

By playing a coordinating role that helps to unlock the wider gas landscape, USAID SAEP could subsequently support the unlocking of specific gas-to-power projects. As discussed in the analysis above, gas-to-power is an important anchor demand for the development of the gas industry in Southern Africa. Tying generation projects directly with supply and helping them to develop upstream as a result of the projects will be critical. Separately, there are projects that are closer to financial close and already have secured supply, but are facing other technical and financial hurdles where transaction advisory services could be beneficial. As the broader Regional Gas Master Plan develops it will still be important to move generation projects forward.

From a deep-dive of planned gas-to-power projects (see **Exhibit 29** to **Exhibit 36**), 5.0 to 8.8 GW have been identified for potential development across the four focus countries. USAID SAEP, with the broader Power Africa group, could provide strategic advice, technical expertise, financial analysis, transaction support, and regulatory guidance. The intervention would depend on what is needed to unlock the specific gas-to-power project.

To create the greatest impact, we would suggest that USAID SAEP and Power Africa offer this support in three phases:

- **During an immediate rapid diagnostic phase, USAID SAEP could support ~1.2 - 1.3 GW of currently planned gas-to-power projects in Mozambique and Botswana.** Based on the insights from this diagnostic, USAID SAEP and its partners would agree on the support priority projects would receive (e.g., technical, legal, and financial) and which party (e.g., USAID SAEP, USTDA) would be in the best positioned to provide it. USAID SAEP would aim to develop the required Scope of Work for the assistance on priority projects.

  In Botswana, USAID SAEP could perform a gap analysis on Botswana's CBM gas-to-power, and CBM-Solar hybrid projects. It could then understand what needs to be done to realize these. In parallel, it might consider offering the Government of Botswana technical support in interpreting the existing studies on the development of their CBM reserves, and whether it would be desirable to conduct a feasibility study about obtaining gas-to-power from Botswana's CBM reserves. USAID SAEP might engage another agency to provide such a study (e.g., the US Department of Energy and/or USTDA).

  In Mozambique, USAID SAEP could collaborate closely with the SPEED+ program to perform a gap analysis of the gas-to-power projects in Mozambique. It would:

  - Investigate whether capital productivity and / or lean construction support would be required for projects close to construction (e.g., the Gigawatt park (60 MW+, 2018) and Maputo (72 MW, 2018-2019)).
  - Assess projects earlier in their lifecycle to understand what kind of support would be required to bring them to materialization (e.g., Temane IPP (2020, 400 MW), Temane Sumitomo (100 MW, 2021), and Chokwe (78 MW, 2021)).
  - Reach out to upstream gas developers to understand if and where they might need assistance with their gas-to-power projects (e.g., Rovuma gas (Anadarko, 250 MW), Afungi GTL (Shell, 80 MW), Palma Cabo Delgado (ENI, 75 MW) and Yara gas-to-power (Yara, 50 MW)).

- **USAID SAEP could support ~3.8 - 7.5 GW of gas-to-power projects in Namibia and South Africa once certain external events have occurred.** In Namibia, USAID SAEP could support the developers of the 200 MW Walvis Bay LNG-to-power project – once the associated legal dispute is close to being resolved. USAID SAEP or other Power Africa projects could provide this assistance, which would most likely be financial transaction advisory services.

In South Africa, USAID SAEP could support the Department of Energy / NERSA after the country releases an updated IRP. It could help scope and implement the gas-to-power agenda, possibly in cooperation with the IPP office. USAID SAEP could also provide strategic support and, if feasibility studies are required, bring in USTDA (e.g., the Western Cape study for the IPP office). If the IRP retains a clear mandate for gas-to-power (e.g., current IRP projections stand at 7.3 GW for 2030), USAID SAEP could investigate whether large industrial gas consumers can be brought on board to increase their gas use such as Sasol and Glencore.

- **Subsequent support would be needs-based,** but could include transaction advisory services to help close PPAs, lock-in gas supply agreements, resolution of land / community issues, and close financing (e.g., risk guarantees). This transaction assistance could be provided by USAID SAEP directly or other Power Africa projects.

6.3 FURTHER IMPLICATIONS

From the analysis in the report, trade between Mozambique and South Africa has also been identified as having a clear potential to develop the region's gas-to-power landscape. However, this is likely to be a longer-term initiative and given the timelines involved, supporting this initiative would likely extend past USAID SAEP's intended lifetime. Assessing the region's gas trade potential is therefore something that will be considered at a later stage by the broader Power Africa network.

As a suggestion, the broader Power Africa group could evaluate specific infrastructure projects (e.g. a pipeline connecting Rovuma with South Africa), and as part of this assessment may look to consider the socioeconomic costs and benefits, market and political risks, and detailed capital requirements relevant to the project.

APPENDIX

APPENDIX A: ACRONYMS

Acronym	Definition
AC	Alternating current
AIM	Alternate Investment Market
ARENE	Energy Regulatory Agency (Mozambique)
ARP	African Renaissance Pipeline
ASX	Australian Securities Exchange
bcf	Billion cubic feet
bcm	Billion cubic meters
bcma	Billion cubic metres per annum
BERA	Botswana Energy Regulatory Authority
BPC	Botswana Power Corporation
Capex	Capital expenditure
CBM	Coal-bed methane
CCGT	Combined cycle gas turbine
CNG	Compressed natural gas
CNPC	China National Petroleum Corporation
CSIR	Council for Scientific and Industrial Research
DBSA	Development Bank of South Africa
DC	Direct current
DoE	Department of Energy
DRC	Democratic Republic of Congo
dti	Department of Trade and Industry
ENH	Empresa Nacional de Hidrocarbonetos
FLNG	Floating liquefied natural gas
FSRU	Floating storage and regassification unit
GDP	Gross domestic product
GTL	Gas-to-liquids
GW	Gigawatt
GWh	Gigawatt hours
HFO	Heavy fuel oil

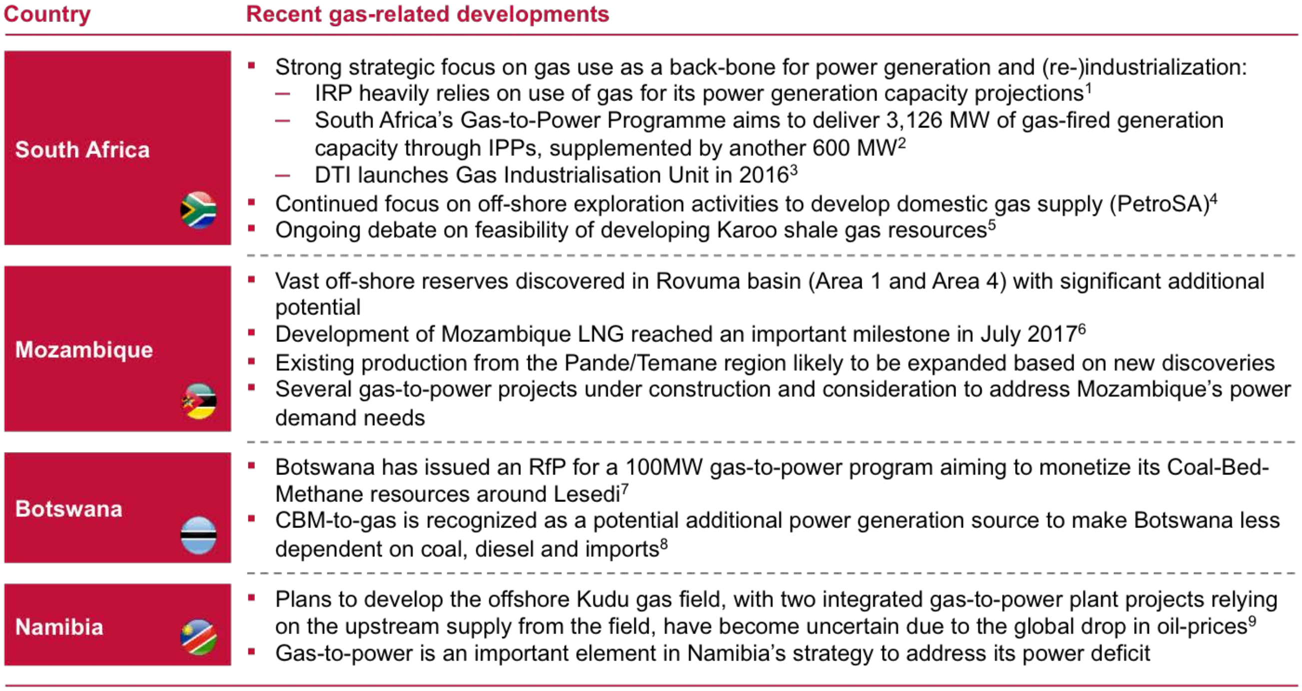
Acronym	**Definition**
HV	High voltage
HVDC	High voltage direct current
IEA	International Energy Agency
INP	Instituto Nacional de Petroleo
IPPs	Independent power producers
IRP	Integrated Resource Plan
JV	Joint venture
kboe	Thousand barrels of oil equivalent
kboepd	Thousand barrels of oil equivalent per day
km	Kilometre
KOGAS	Korea Gas Corporation
kV	Kilovolt
KW	Kilowatt
KWh	Kilowatt-hour
KZN	KwaZuluNatal
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
MIREME	Ministério dos Recursos Minerais e Energia
mmboe	Million barrels of oil equivalent
mmbtu	Million British thermal units
mmscfd	Million standard cubic feet per day
MPRDA	Mineral and Petroleum Resources Development Act
mtpa	Million tonnes per annum
MW	Megawatt
MWh	Megawatt hour
MZLNG	Mozambique LNG
NAMCOR	National Petroleum Corporation of Namibia
NamPower	Namibia Power
NERSA	National Energy Regulator of South Africa
OCGT	Open cycle gas turbine
ONGC	Oil and Natural Gas Corp (India)
Opex	Operating expenditure

Acronym	Definition
OVL	ONGC Videsh Ltd (India)
PATRP	Power Africa Transactions and Reforms Program
PJ	Petajoule
PPA	Power purchase agreement
PPP	Public-private partnership
PSA	Production sharing agreement
PTTEP	PTT Exploration and Production Plc
Rc	South African Rand cents
RERA	Regional Electricity Regulators' Association
RfP	Request for proposal
ROMPCO	Republic of Mozambique Pipeline Company
SACREE	SADC Centre for Renewable Energy and Energy Efficiency
SADC	Southern African Development Community
SAEP	Southern Africa Energy Program
SAPP	Southern African Power Pool
tcf	Trillion cubic feet
USAID	United States Agency for International Development
$	United States dollar
1P	Proven reserves
2P	Proven and probable reserves
3P	Proven, probable and possible reserves
1C, 2C, 3C	Contingent resource equivalents of 1P, 2P and 3P reserves

APPENDIX B: ADDITIONAL CHARTS

EXHIBIT 19

RELEVANCE OF GAS FOR THE FOUR FOCUS COUNTRIES



Country	Recent gas-related developments
South Africa	▪ Strong strategic focus on gas use as a back-bone for power generation and (re-)industrialization: – IRP heavily relies on use of gas for its power generation capacity projections[1] – South Africa's Gas-to-Power Programme aims to deliver 3,126 MW of gas-fired generation capacity through IPPs, supplemented by another 600 MW[2] – DTI launches Gas Industrialisation Unit in 2016[3] ▪ Continued focus on off-shore exploration activities to develop domestic gas supply (PetroSA)[4] ▪ Ongoing debate on feasibility of developing Karoo shale gas resources[5]
Mozambique	▪ Vast off-shore reserves discovered in Rovuma basin (Area 1 and Area 4) with significant additional potential ▪ Development of Mozambique LNG reached an important milestone in July 2017[6] ▪ Existing production from the Pande/Temane region likely to be expanded based on new discoveries ▪ Several gas-to-power projects under construction and consideration to address Mozambique's power demand needs
Botswana	▪ Botswana has issued an RfP for a 100MW gas-to-power program aiming to monetize its Coal-Bed-Methane resources around Lesedi[7] ▪ CBM-to-gas is recognized as a potential additional power generation source to make Botswana less dependent on coal, diesel and imports[8]
Namibia	▪ Plans to develop the offshore Kudu gas field, with two integrated gas-to-power plant projects relying on the upstream supply from the field, have become uncertain due to the global drop in oil-prices[9] ▪ Gas-to-power is an important element in Namibia's strategy to address its power deficit

1 Integrated Resource Plan 2016 (http://www.energy.gov.za/files/irp_frame.html)
2 https://www.ipp-gas.co.za/; https://gas600.ipp-gas.co.za/;
3 http://www.engineeringnews.co.za/article/dti-launches-gas-industrialisation-unit-2016-05-16
4 http://www.petrosa.co.za/PressReleases/Pages/PetroSA-AND-ROSGEO-SIGN-MULTI-MILLION-DOLLAR-AGREEMENT-TO-DEVELOP-OIL-AND-GAS-BLOCKS-IN-SOUTH-AFRICA.aspx
5 https://www.businesslive.co.za/bd/national/science-and-environment/2017-09-28-tests-reveal-less-karoo-shale-gas-than-expected/
6 http://investors.anadarko.com/2017-07-31-Anadarko-Reaches-Significant-Mozambique-LNG-Milestone
7 http://www.ogj.com/articles/2017/09/botswana-government-awards-cbm-gas-to-power-tender.html
8 https://www.reuters.com/article/us-botswana-power/botswana-to-sell-struggling-chinese-built-power-plant-idUSKBN1300EQ
9 http://www.powerandrenewablesinsight.com/industry-trend-analysis-kudu-removed-our-power-forecasts-oct-2015

SOURCE: Press clippings (as indicated)

EXHIBIT 20

PRACTICAL GUIDE TO THE DEMAND MODEL

Objective

To solve for the total demand potential, for various scenarios and sectors

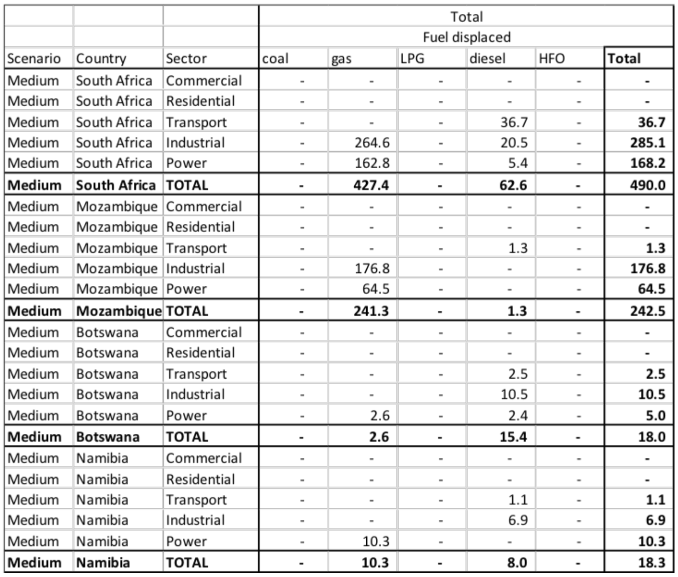
How it works

① ▪ Assess the total demand potential that exists for gas

  – Various methodologies adopted for each sector

② ▪ Assign what portion of this is relevant for each given scenario

③ ▪ Sum each of the relevant parts to reach the total demand potential, for a given country, under a given scenario



			Total					
			Fuel displaced					
Scenario	Country	Sector	coal	gas	LPG	diesel	HFO	**Total**
Medium	South Africa	Commercial	-	-	-	-	-	**-**
Medium	South Africa	Residential	-	-	-	-	-	**-**
Medium	South Africa	Transport	-	-	-	36.7	-	**36.7**
Medium	South Africa	Industrial	-	264.6	-	20.5	-	**285.1**
Medium	South Africa	Power	-	162.8	-	5.4	-	**168.2**
Medium	**South Africa**	**TOTAL**	**-**	**427.4**	**-**	**62.6**	**-**	**490.0**
Medium	Mozambique	Commercial	-	-	-	-	-	**-**
Medium	Mozambique	Residential	-	-	-	-	-	**-**
Medium	Mozambique	Transport	-	-	-	1.3	-	**1.3**
Medium	Mozambique	Industrial	-	176.8	-	-	-	**176.8**
Medium	Mozambique	Power	-	64.5	-	-	-	**64.5**
Medium	**Mozambique**	**TOTAL**	**-**	**241.3**	**-**	**1.3**	**-**	**242.5**
Medium	Botswana	Commercial	-	-	-	-	-	**-**
Medium	Botswana	Residential	-	-	-	-	-	**-**
Medium	Botswana	Transport	-	-	-	2.5	-	**2.5**
Medium	Botswana	Industrial	-	-	-	10.5	-	**10.5**
Medium	Botswana	Power	-	2.6	-	2.4	-	**5.0**
Medium	**Botswana**	**TOTAL**	**-**	**2.6**	**-**	**15.4**	**-**	**18.0**
Medium	Namibia	Commercial	-	-	-	-	-	**-**
Medium	Namibia	Residential	-	-	-	-	-	**-**
Medium	Namibia	Transport	-	-	-	1.1	-	**1.1**
Medium	Namibia	Industrial	-	-	-	6.9	-	**6.9**
Medium	Namibia	Power	-	10.3	-	-	-	**10.3**
Medium	**Namibia**	**TOTAL**	**-**	**10.3**	**-**	**8.0**	**-**	**18.3**

EXHIBIT 21

PRACTICAL GUIDE TO THE PIPELINE MODEL

Objective

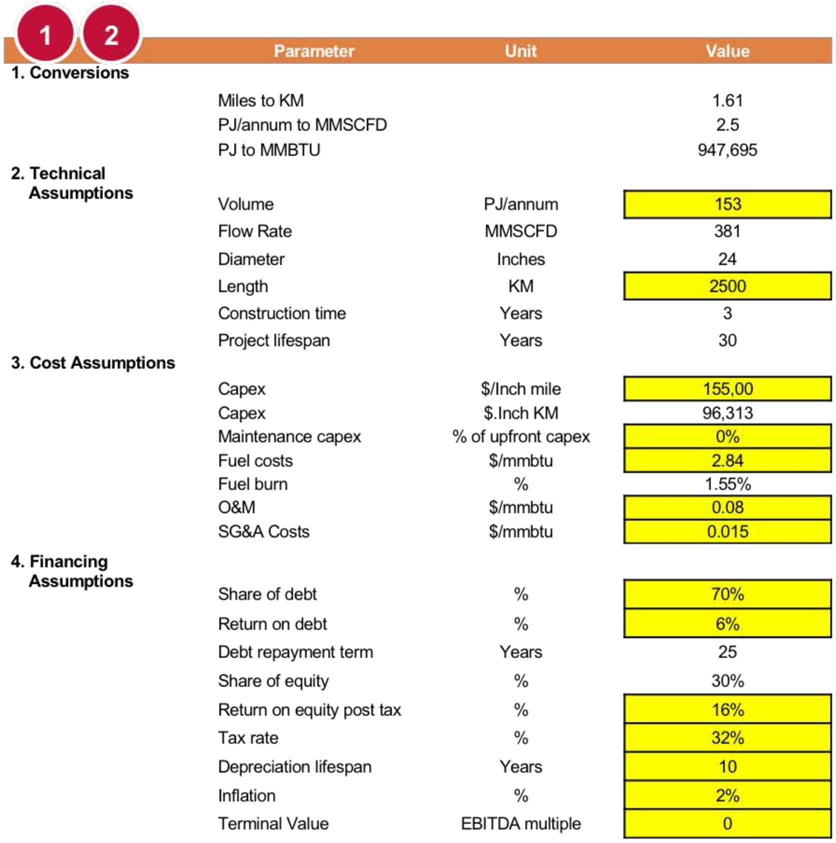
To solve for the tariff required to meet a required return to debt and equity investors

How it works

①
- Input volumes
  - Defines pipeline size required and utilization

②
- Align on various inputs
  - Includes technical, costing, and financial assumptions

③
- Goal seek the required tariff



①②

	Parameter	Unit	Value
1. Conversions			
	Miles to KM		1.61
	PJ/annum to MMSCFD		2.5
	PJ to MMBTU		947,695
2. Technical Assumptions			
	Volume	PJ/annum	153
	Flow Rate	MMSCFD	381
	Diameter	Inches	24
	Length	KM	2500
	Construction time	Years	3
	Project lifespan	Years	30
3. Cost Assumptions			
	Capex	$/Inch mile	155,00
	Capex	$.Inch KM	96,313
	Maintenance capex	% of upfront capex	0%
	Fuel costs	$/mmbtu	2.84
	Fuel burn	%	1.55%
	O&M	$/mmbtu	0.08
	SG&A Costs	$/mmbtu	0.015
4. Financing Assumptions			
	Share of debt	%	70%
	Return on debt	%	6%
	Debt repayment term	Years	25
	Share of equity	%	30%
	Return on equity post tax	%	16%
	Tax rate	%	32%
	Depreciation lifespan	Years	10
	Inflation	%	2%
	Terminal Value	EBITDA multiple	0

③

Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
FY Year	0	1	2	3	4	5
Total Revenue	**-**	**-**	**-**	**662,053,345**	**675,294,412**	**688,800,300**
Tariff	-	-	-	4.57	4.67	4.76
Quantity (mmbtu)	-	-	-	144,713,064	144,713,064	144,713,064

EXHIBIT 22

CHEAT SHEET FOR GAS CONVERSIONS

		LNG	Gas			Energy	Electricity	Oil equivalent	Gas field size (30 yrs lifetime)
General	Per annum	1 mtpa	50 bcf	1.4 bcma	51.5 million mmbtu	54.4 PJ	15,110 GWh	9.35 mmboe	1.49 tcf total field size
	Per day	2.7 ktpd	136 mmscf/d	3.8 mcm/day	141,149 mmbtu/day	0.1 PJ/day	41 GWh/day	25.6 kboepd	N/A
Potential MZLNG ph1, 2 trains of 6 mpta each	Per annum	**12 mtpa**	595 bcf	16.8 bcma	618.7 million mmbtu	652.8 PJ	181,325 GWh	112.22 mmboe	17.85 tcf total field size
	Per day	32.9 ktpd	1,629 mmscf/d	46.1 mcm/day	1,693,786 mmbtu/day	1.8 PJ/day	496 GWh/day	307.2 kboepd	N/A
3 tcf field produced over 30 years, 100bcf per year	Per annum	2.017278mtpa	100 bcf	2.8 bcma	104.0 million mmbtu	109.7 PJ	30,482 GWh	18.86 mmboe	**3.00 tcf** total field size
	Per day	5.5 ktpd	274 mmscf/d	7.8 mcm/day	284,736 mmbtu/day	0.3 PJ/day	83 GWh/day	51.6 kboepd	N/A
10 bcm pipeline	Per annum	7.1 mtpa	353 bcf	**10.0 bcma**	367.2 million mmbtu	387.5 PJ	107,631 GWh	66.61 mmboe	10.59 tcf total field size
	Per day	19.5 ktpd	967 mmscf/d	27.4 mcm/day	1,005,405 mmbtu/day	1.1 PJ/day	295 GWh/day	182.4 kboepd	N/A
400 PJ demand per annum	Per annum	7.4 mtpa	364 bcf	10.3 bcma	379.0 million mmbtu	**400 PJ**	111,106 GWh	68.76 mmboe	10.93 tcf total field size
	Per day	20.1 ktpd	998 mmscf/d	28.3 mcm/day	1,037,859 mmbtu/day	1.1 PJ/day	304 GWh/day	188.3 kboepd	N/A
30 tcf field (~25% of Rovuma basin, high level conservative estimate)	Per annum	20.2 mtpa	1,000 bcf	28.3 bcma	1,040.0 million mmbtu	1097 PJ	304,819 GWh	188.65 mmboe	**30.00 tcf** total field size
	Per day	55.2 ktpd	2738 mmscf/d	77.5 mcm/day	2,847,365 mmbtu/day	3.0 PJ/day	835 GWh/day	516.5 kboepd	N/A

EXHIBIT 23

BOTSWANA AND NAMIBIA SUPPLY POTENTIAL

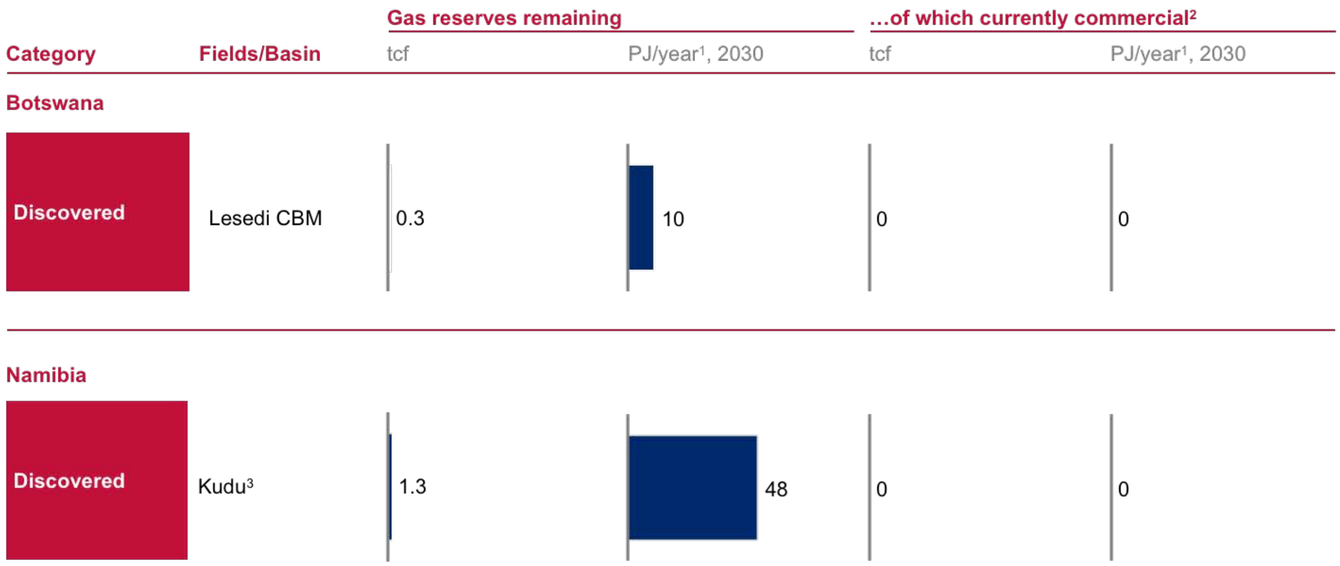


EXHIBIT 24

MOZAMBIQUE SUPPLY POTENTIAL

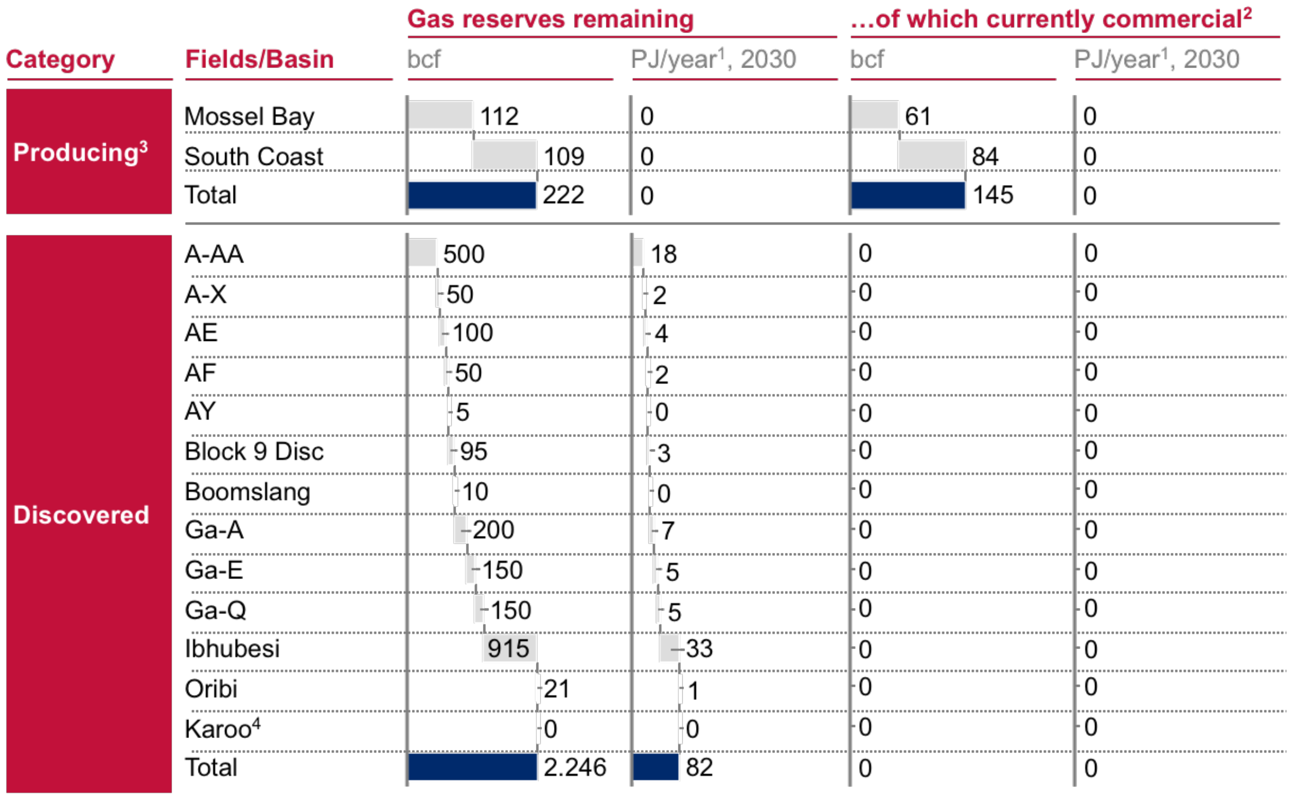
		Gas reserves remaining		…of which currently commercial[2]	
Category	**Fields/Basin**	tcf	PJ/year[1], 2030	tcf	PJ/year[1], 2030
Producing[3]	Pande/Temane[3]	2.3	85	2.2	80
	Total	2.3	85	2.2	80
Discovered	Mamba Complex	45	1.641	13	480
	Golfinho Area	34	1.235	15	557
	Prosperidade	26	934	0	0
	Coral	12	425	5	165
	Tubarao Tigre	3	96	0	0
	Agulha	2	63	0	0
	Njika	1	37	0	0
	Tubarao	1	37	0	0
	Inhassoro PSA	0	14	1	21
	Buzi	0	10	0	0
	Ironclad	0	1	0	0
	Tembo	0	1	0	0
	Total	123	4.494	33	1.223

1 Assuming reserves in scope are produced over 30 years, with a flat production profile (output per year = reserves / 30 years)
2 "Commercial" is defined by WoodMackenzie as reserves which in current price scenarios are considered to be certainly economically viable and/or under development
3 Remaining reserves according to WoodMackenzie are lower compared to reserves of 2.7tcf

SOURCE: WoodMackenzie exctract Oct 2017

EXHIBIT 25

SOUTH AFRICA SUPPLY POTENTIAL



Category	Fields/Basin	Gas reserves remaining		…of which currently commercial[2]	
		bcf	PJ/year[1], 2030	bcf	PJ/year[1], 2030
Producing[3]	Mossel Bay	112	0	61	0
	South Coast	109	0	84	0
	Total	222	0	145	0
Discovered	A-AA	500	18	0	0
	A-X	50	2	0	0
	AE	100	4	0	0
	AF	50	2	0	0
	AY	5	0	0	0
	Block 9 Disc	95	3	0	0
	Boomslang	10	0	0	0
	Ga-A	200	7	0	0
	Ga-E	150	5	0	0
	Ga-Q	150	5	0	0
	Ibhubesi	915	33	0	0
	Oribi	21	1	0	0
	Karoo[4]	0	0	0	0
	Total	2.246	82	0	0

[1] Assuming reserves in scope are produced over 30 years, with a flat production profile (output per year = reserves / 30 years)

[2] "Commercial" is defined by WoodMackenzie as reserves which in current price scenarios are considered to be certainly economically viable and/or under development

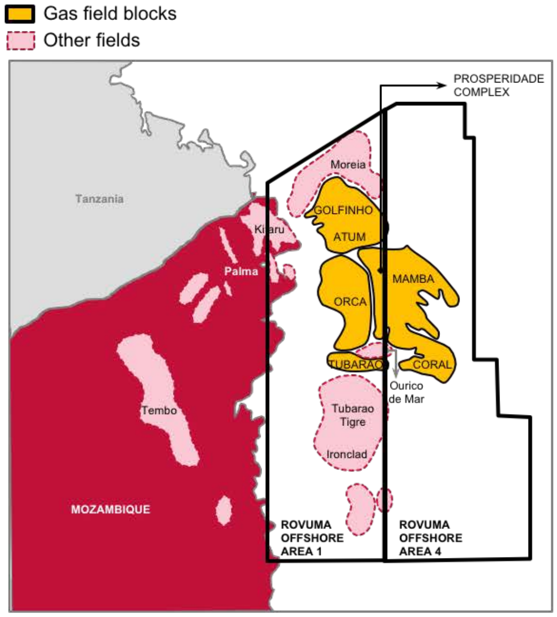
[3] PetroSA's currently producing gas fields (Mossel Bay gas fields & South Coast gas project) are likely to be depleted by 2030; 2017 production from these fields add up to ~37PJ/year of gas production

[4] Assumed most likely range of Karoo reserves as per South African Journal of Science (De Kock, South African Journal of Science 2017)

SOURCE: WoodMackenzie exctract Oct 2017; South African Journal of Science

EXHIBIT 26

INDIVIDUAL VOLUMES AND COSTS FOR FIELDS IN THE ROVUMA BASIN



Field	**Recoverable gas (ICF),** (bcf)	**Recoverable gas (Wodmac),** (bcf)	**EPCC Resource cost**[1] ($/mmbtu)	**Weighted Contribution**[1] ($/mmbtu)
Prosperidade / Mamba	48,000	70,400	1.74	1.12
Golfinho/Atum	20,000	33,700	2.14	0.57
Tubarao	1,500	1,000	6.56	0.13
Coral	5,100	11,600	3.84	0.26
	74,600	**116,700**		**2.09**
+ Cost of processing and domestic piping				0.75
				2.84

1 ICF estimates, used as base assumption for upstream costs

SOURCE: The Future of Natural Gas in Mozambique: Towards a Gas Master Plan (ICF), Woodmac, Wildcat International

EXHIBIT 27

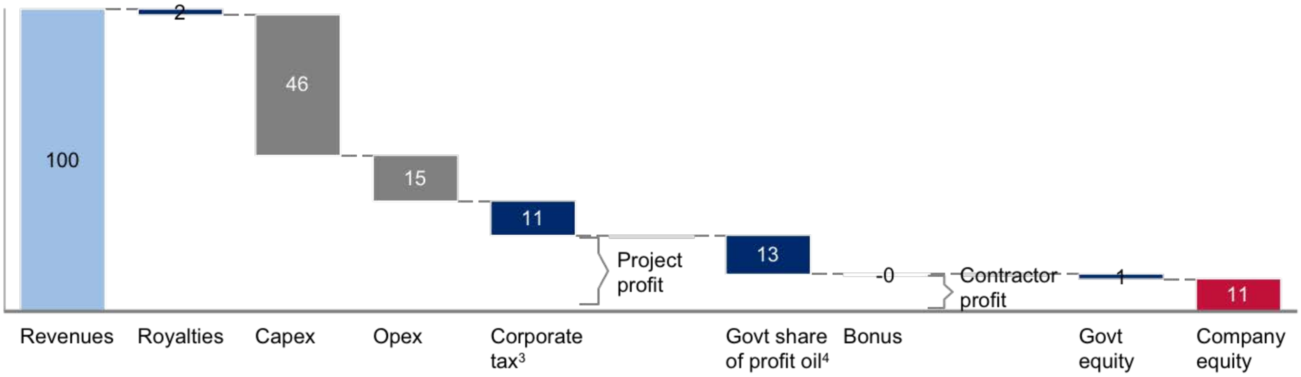
ROVUMA BASIN UPSTREAM COST BREAKDOWN

🟦 Government cash flows 🟥 Private equity holder cash flows

The Rovuma basin's upstream breakeven costs are estimated at $2.84/mmbtu[1]

- As per the industry standard definition of breakeven costs, the ICF's independent assessment of Area 1 and Area 4 upstream costs are considered to include all government taxes, royalties, and non-equity share of profit gas
- Assuming a similar breakdown of cash flows exist for upstream as for the integrated upstream + midstream project, the project's cost breakdown is estimated as follows:

Integrated upstream and midstream breakdown of project cash flows[2] (%)



Various adjustments are considered, however they would not affect the price significantly

Royalties and taxes	▪ If taxes, royalties and the non-equity government offtake of profit gas were assumed to be excluded from breakeven costs, scaling up to include these could still lead to a competitive gas price of ~$4/mmbtu
Upstream cost compression	▪ Upstream capital cost costs have fallen by ~20% since 2012 (i.e. when the $2.84/mmbtu estimate was assessed). However we intentionally take this nominal value for a more conservative approach

1 Calculated from a weighted average assessment of individual field level estimates (ICF, 2012)
2 Rovuma Area 1 and Area 4 aggregated cash flows based on Wood Mackenzie's Upstream Data Tool
3 Tax assumed to be based off revenues – (royalties + opex + depreciation)
4 Non-equity government share of profit based on R-factor scheme. Profit oil assumed to be based off revenues – (royalties + opex + depreciation + taxes)

SOURCE: Wood Mackenzie Upstream Data Tool, ICF, team analysis

EXHIBIT 28

DEMAND SCENARIO DESCRIPTIONS

		Gas demand scenario definitions (general principles underlying scenario[1])		
Sectors	**Basis**	***"Regional gas does not take off"* – Low scenario**	***"Gas as a solid part of the energy mix"* – Medium scenario**	***"The region doubles down on gas"* – High scenario**
Scenario description		▪ Headwinds for gas adoption in the regulatory and commercial environment ▪ Governments favor labor intensive coal power gen ▪ Industry operates in BAU with no investment in new infrastructure	▪ Gas is seen as an important part of the energy mix, alongside other fuel sources	▪ Strong government agenda towards gas, alongside favorable policy ▪ Gas viewed as a stable and competitive source of energy
A Power	a) Existing gas plants b) New-build gas plants c) Existing diesel/ HFO/ coal plants d) New-build diesel/ HFO/ coal plants	a) Included b) Firm projects included c) Excluded d) Excluded	a) Included b) Firm agendas included c) Planned conversions included d) Included where likely conversion plans exists	a) Included b) Likely agendas included c) Planned conversions included d) Included where likely conversion plans exists
B Industrial	▪ "Unconstrained" demand potential for industry	▪ Existing and incremental industry gas demand included if infrastructure allows for	▪ Existing and incremental industrial gas demand is included ▪ High value fuel use included for relevant sectors / geographies	▪ Existing and incremental industrial gas demand is included ▪ High and low value fuel use included for relevant sectors / geographies
C Transportation	▪ Long haul trucking demand and public transport	▪ Adoption rate (share of new vehicles which are gas-based) at 0%	▪ Adoption rate (share of new vehicles which are gas-based) at 10%	▪ Adoption rate (share of new vehicles which are gas-based) at 20%
D Commercial	▪ Commercial based coal and oil usage	▪ Excluded	▪ Excluded	▪ All commercial oil and coal use included for switching
E Residential	▪ Residential based coal and oil usage	▪ Excluded	▪ Excluded	▪ All residential oil and coal use included for switching

1 Serve as overall guidelines, specific exceptions applicable (included in detailed back-up slides)

EXHIBIT 29

SOUTH AFRICA GAS-TO-POWER PROJECTS

Planned plants	Capacity (MW)	Commissioned	Comment
LNG-to-Power IPP PP Richard's Bay	2,000	Date unclear (issuing of RfQ postponed)	Ensuring alignment between the IRP[2] and IPP PP[3] , the DoE proposes LNG-to-power as first phase for procuring the initial 3,000MW of the 3,726MW gas fired power plant Determinations 2,000MW of this is expected to be developed from Richards Bay, and 1000MW from Coega (as per Preliminary Information Memorandum – subsequently released Information Memorandum does not specify specific targets but indicates 1-3GW for both locations)
LNG-to-Power IPP PP Coega	1,000	Date unclear (issuing of RfQ postponed)	
Saldanha Bay	800	Date unclear	N/A
Gas-fired power generation	600	Date unclear	From an initial 3,126MW, the DoE confirmed plans to procure a further 600 MW for a new gas-fired power generation project, to be developed alongside a 'strategic partner'
Domestic gas programme	126	Date unclear	126MW allocated to the gas-to-power programme, to be supplied using domestic gas resources
Other projects from IRP	2,794[4]	Date unclear	3,594MW of the 7,320MW IRP target by 2030 for gas-to-power capacity by 2030 is yet to be determined by the IPP Purchase Programme; out of this 800MW would be in Saldanha bay, leaving 2,794MW to come from other projects
Total planned	7,320		

[1] Initial qualitative assessment, requires further refinement

[2] Integrated Resource Plan, which specifies the preferred energy mix that is needed to meet the projected electricity demands over a 20-year planning horizon

[3] Independent Power Producer Procurement Programme, a DoE initiative to secure electrical energy from the private sector through new generation capacity

[4] 7320MW of gas power capacity projected to required up to 2030, out of a total 21960MW projected out to 2050

SOURCE: South Africa Integrated Resource Plan 2016 (revision 1), IPPPP LNG-to-Power Preliminary Information Memorandum and Information Memorandum

EXHIBIT 30

SOUTH AFRICA GAS DEMAND FOR POWER SCENARIOS

XX PJ/year equivalent demand[2]

✓ Assumed to materialize by 2030 as gas-fueled

● xx Scenario totals: PJ/year equivalent demand[2]

✗ Will not materialize by 2030 as gas-fueled

	Name	Size (MW)	*"Regional gas doesn't take off"*	*"Gas as a part of the energy mix"*	*"The region doubles down on gas"*	Rationale
Existing gas-fired plants	N/A[1]					
New build gas-fired plants	LNG to power Richards Bay	2000	✓ 62	✓ 62	✓ 62	Strong mandate exists
	LNG to power Coega	1000	✓ 31	✓ 31	✓ 31	Strong mandate exists
	Saldanha Bay	800	✗ -	✗ -	✓ 25	Considered to be phase 2 of IPP
	Gas fired power generation	600	✗ -	✓ 19	✓ 19	Likely, but no firm details as yet
	Domestic gas programme	126	✗ -	✓ 4	✓ 4	Likely, but no firm details as yet
	Other gas-projects from IRP[5]	2794	✗ -	✓ 47	✓ 47	Potential overestimation
Existing diesel/HFO-fired plants	Ankerlig[3]	1350	✗ -	✗ -	✓ 11	Dependent on Saldanha Bay LNG
	Avon[4]	670	✗ -	✓ 5	✓ 5	Dependent on Richards Bay LNG
	Dedisa	335	✗ -	✗ -	✓ 3	Proximity to Coega imports
	Acacia	171	✗ -	✗ -	✗ -	Highly uncertain (remote from potential gas sources)
	Port Rex	171	✗ -	✗ -	✗ -	
New build diesel/ HFO-fired plants	OCGT planned capacity (from IRP)[5]	5412	✗ -	✗ -	✓ 24	Potential overestimation
Existing Coal fired plants	Kelvin Power Plant	600	✗ -	✗ -	✓ 44	Coal mining employment displacement might be challenging
			93	168	274	

1 Existing CCGT plants mostly decentralized, amounting to 0PJ of grid-connected gas demand

2 Assumptions: CCGT utilization rate 48%, efficiency 49%. OCGT utilization rate 8%, efficiency 31%, Coal utilization rate 85%, efficiency 37% - based on assumptions from IRP

3 Easily convertible to gas fueled, but dependent on LNG import terminal at Saldanha Bay

4 Easily convertible to gas fueled, but dependent on LNG import terminal at Richards Bay

5 Assumes 56% materialization rate in medium and high scenarios, based on recent cancelation and and indefinite deferral rate of power projects in South Africa

SOURCE: Platts WEPP UDI database, South Africa Integrated Resource Plan 2016 (revision 1), IPPPP LNG-to-Power Preliminary Information Memorandum and Information Memorandum, team analysis

EXHIBIT 31

MOZAMBIQUE GAS-TO-POWER PROJECTS

x Subtotals
▨ Concessions

		Capacity (MW)	Commissioned	Comment	Source
Existing plants	CTRG (Gigawatt Park)	175	2014	Partnership between Sasol and EDM Relevant organization(s): EDM (51%), Sasol (49%)	UDI http://www.sasol.com/media-centre/media-releases/sasol-edm-inaugurate-new-gas-power-plant-mozambique/
	Gigawatt park	120	2012	In operation, expansion planned (see planned projects) Relevant organization(s): Gigawatt Mozambique	https://constructionreviewonline.com/2016/02/mozambique-unveils-120-mw-gas-fired-power-station/
	Kuvaninga	40	2017	Construction complete, production online Relevant organization(s): ADC Projects	https://zitamar.com/mozambiques-kuvaninga-gas-power-plant-finally-starts-operations/
	Beiram	12	1989	In operation Relevant organization(s): EDM	UDI
	Temane EDM	8	Unknown	In operation Relevant organization(s): EDM	http://www.edm.co.mz/index.php?option=com_content&view=article&id=71&Itemid=12&lang=pt
355 MW					
Planned plants	Temane IPP	400	2020	Joint venture between Sasol and EDM expected to come on stream Relevant organization(s): EDM (51%), Sasol (49%)	UDI http://clubofmozambique.com/news/sasols-400-mw-thermal-plant-temane-maputo-power-line-close-becoming-reality/
	Rovuma Gas	250	Date unclear	GLA Energy selected in 2017 to investigate opportunity to convert Anadarko domestic gas obligation into power Relevant organization(s): GLA Energy, Anadarko	UDI https://www.glaenergy.com/news/gas-powered-plant-Mozambique.html
	Gigawatt Park	60 170 230	2018 onwards	A further 60MW expansion recently confirmed (gas allocated) and potential of a final total capacity of 350MW for the concession, dependent on availability of gas	http://allafrica.com/stories/201708211100.html http://www.engineeringnews.co.za/article/mozambique-president-inaugurates-120-mw-gas-fired-power-station-2016-02-19/rep_id:4136
	Temane (Sumitomo)	100	2021	100MW CCGT plant to be built by Sumitomo and IHI in Temane Relevant organizations: Sumitomo, IHI, EDM	http://www.sumitomocorp.co.jp/english/news/detail/id=29812
	Shell Afungi GTL	80	Date unclear	Supplied by the Rovuma gas development, Shell has tendered to build a 38,000 bpd GTL plant, along with 50-80MW of power generation Relevant organizations: Shell	http://www. oilreviewafrica.com/gas/gas/mozambique-and-shell-sign-mou-for-domestic-use-of-the-rovuma-basin-gas
	Chokwe	78	2021	Feasibility 2018Q1, 2021 commissioning expected Gas supplies from Pande/Temane PSA (approved by EDM and ministry in Feb 2016) Relevant organisations: Kuikila investments	https://zitamar.com/planned-78-mw-mozambique-gas-fired-power-project-enters-consultation/ https://www.ustda.gov/news/press-releases/2017/ustda-connects-us-industry-energy-opportunities-mozambique
	Palma Cabo Delgado	75	Date unclear	ENI commitment related to Rovuma gas development; MoU with Mozambican government not yet concluded Likely to be 75MW gas-to-power project	UDI https://www.gastopowerjournal.com/markets/item/3764-mozambique-plans-two-new-power-plants-to-reach-800-mw-gas-fired-capacity
	Maputo	72	2018/2019	100MW plant, of which 72MW fueled by gas, and the remainder using waste to heat, construction started in Nov-17 Relevant organization(s): EDM, Sumitomo	http://www.edm.co.mz/index.php?option=com_content&view=article&id=699%3Amaputo-tera-uma-central-termoelectrica-de-ciclo-combinado-a-gas-natural&catid=53%3Anoticias&Itemid=78&lang=en
	Yara Fertilizer	50	Date unclear	Supplied by the Rovuma gas development, Yara Fertilizer has tendered to produce 1.3MT of fertilizer, along with 30-50MW of power Relevant organization(s): Yara Fertilizer	https://www.reuters.com/article/ozabs-uk-yara-intl-mozambique-idAFKBN1D20O3-OZABS
1,335 MW					

1 Initial qualitative assessment, requires further refinement

NOTE: Does not include off-grid/decentralized industrial generators

SOURCE: Platts WEPP UDI database, press clippings (as indicated)

EXHIBIT 32

MOZAMBIQUE GAS DEMAND FOR POWER SCENARIOS

XX PJ/year equivalent demand[2]
● xx Scenario totals: PJ/year equivalent demand[2]
✓ Assumed to materialize by 2030 as gas-fueled
✗ Will not materialize by 2030 as gas-fueled

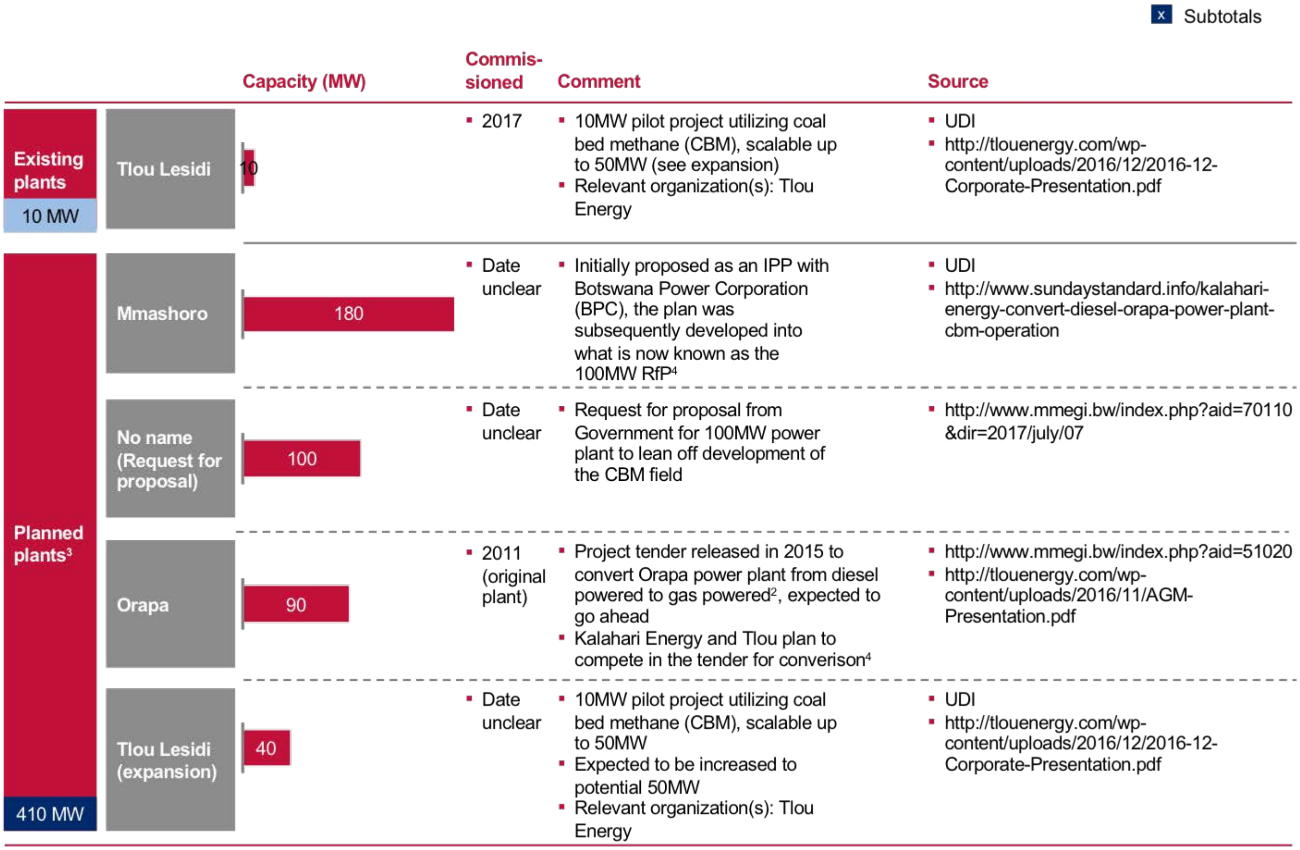
	Name	**Size** (MW)	***"Regional gas doesn't take off"***	***"Gas as a part of the energy mix"***	***"The region doubles down on gas"***	**Rationale**
Existing gas-fired plants[4]	CTRG	175	✓ 8	✓ 8	✓ 8	All operational
	Gigawatt park	120	✓ 6	✓ 6	✓ 6	
	Kuvaninga	40[5]	✓ 2	✓ 2	✓ 2	
	Beira	12	✓ 1	✓ 1	✓ 1	
	Temane EDM	8	✓ 1	✓ 1	✓ 1	
New build gas-fired plants	Temane IPP	400	✓ 19	✓ 19	✓ 19	Certain
	Rovuma gas	250	✗ 0	✓ 12	✓ 12	Dependent on Anadarko gas Area 1
	Gigawatt park (expansion)[1]	230	✓ 3	✓ 3	✓ 11	Gas for 60MW expansion allocated, remaining potential dependent on gas availability
	Temane (Sumitomo)	100	✗ -	✗ 0	✓ 5	Potential delay if Sasol comes online
	Shell GTL (Afungi) Gas-to-power[6]	80	✗ -	✓ 2	✓ 4	Dependent on Rovuma upstream gas supply, output ranges varied for different scenarios
	Chokwe	78	✗ -	✓ 4	✓ 4	Feasibility study underway
	Palma Cabo Delgado	75	✗ -	✓ 4	✓ 4	Dependent on ENI gas Area 4
	Maputo	72[7]	✓ 3	✓ 3	✓ 3	Construction started in Nov'17
	Yara fertilizer Gas-to-power[8]	50	✗ -	✓ 1	✓ 2	Dependent on Rovuma upstream gas supply, output ranges varied for different scenarios
Existing diesel/ HFO-fired plants	Maputo	61	✗ -	✗ -	✗ -	Status of existing units to be clarified; Gas powered expansion already under way (see above)
New build diesel/ HFO-fired plants	N/A					
			42	64	80[9]	

160 MW considered firm for low scenario, with full 230 MW expansion for high scenarios
2 Assumptions: CCGT utilization rate 64% (in line with EDM average as CCGT assumed to be used in base, mid-merit and peak), efficiency 43%. OCGT utilization rate 27%, efficiency 32%
4 Existing grid gas demand amounting to 17PJ
5 Project sponsor indicates plant becomes operational Nov 2017. Initially at 36 MWs, by May 2018 operating at 40MWs (when last engine is repaired)
6 Output ranging from 50-80MW as indicated in various sources
7 Project is 100MW, but sources indicate 72MW powered by gas, with the remainder being fulfilled via waste-to-heat initiatives
8 Output ranging from 30-50MW as indicated by sources
9 Totals and individual figures do not line up due to rounding errors

SOURCE: Platts WEPP UDI database, team analysis

EXHIBIT 33

BOTSWANA GAS-TO-POWER PROJECTS



		Capacity (MW)	Commis-sioned	Comment	Source
Existing plants 10 MW	**Tlou Lesidi**	10	2017	10MW pilot project utilizing coal bed methane (CBM), scalable up to 50MW (see expansion) Relevant organization(s): Tlou Energy	UDI http://tlouenergy.com/wp-content/uploads/2016/12/2016-12-Corporate-Presentation.pdf
Planned plants[3] 410 MW	**Mmashoro**	180	Date unclear	Initially proposed as an IPP with Botswana Power Corporation (BPC), the plan was subsequently developed into what is now known as the 100MW RfP[4]	UDI http://www.sundaystandard.info/kalahari-energy-convert-diesel-orapa-power-plant-cbm-operation
	No name (Request for proposal)	100	Date unclear	Request for proposal from Government for 100MW power plant to lean off development of the CBM field	http://www.mmegi.bw/index.php?aid=70110&dir=2017/july/07
	Orapa	90	2011 (original plant)	Project tender released in 2015 to convert Orapa power plant from diesel powered to gas powered[2], expected to go ahead Kalahari Energy and Tlou plan to compete in the tender for converison[4]	http://www.mmegi.bw/index.php?aid=51020 http://tlouenergy.com/wp-content/uploads/2016/11/AGM-Presentation.pdf
	Tlou Lesidi (expansion)	40	Date unclear	10MW pilot project utilizing coal bed methane (CBM), scalable up to 50MW Expected to be increased to potential 50MW Relevant organization(s): Tlou Energy	UDI http://tlouenergy.com/wp-content/uploads/2016/12/2016-12-Corporate-Presentation.pdf

1 Initial qualitative assessment, requires further refinement; 2 Gas to be sourced from CBM fields; 3 Conversion of Francis Town plant is considered unfeasible due to age of the equipment
4 Informed by US Mission in Gaborone
NOTE: Does not include off-grid/decentralized industrial generators

SOURCE: Platts WEPP UDI database, press clippings (as indicated)

EXHIBIT 34

BOTSWANA GAS DEMAND FOR POWER SCENARIOS

XX PJ/year equivalent demand[1]

xx Scenario totals: PJ/year equivalent demand[1]

✓ Assumed to materialize by 2030 as gas-fueled

✗ Will not materialize by 2030 as gas-fueled

	Name	**Size** (MW)	***"Regional gas doesn't take off"***	***"Gas as a part of the energy mix"***	***"The region doubles down on gas"***	**Rationale**
Existing gas-fired plants[3]	Tlou Lesidi	10	✗ -	✓ 0	✓ 0	Although the pilot is being constructed, it is uncertain if it is successful
New build gas-fired plants	Mmashoro	180	✗ -	✗ -	✗ -	Initial plan, which subsequently developed into the 100MW RfP[5]
	No name (RFP)	100	✗ -	✗ -	✓ 5	Tender recently concluded, but exact feasibility still unclear
	Tlou Lesidi (expansion)[2]	40	✗ -	✓ 2	✓ 2	Dependent on success of 10MW pilot
Existing diesel/HFO-fired plants	Francis town	105	✗ -	✗ -	✗ -	Deemed unfeasible for conversion due to plant age[5]
	Orapa	90	✗ -	✓ 2	✓ 2	Kalahari Energy and Tlou plan to compete in tender for converison[5]
New build diesel/HFO-fired plants	N/A					
			0	5[4]	10[4]	

1 Assumptions: CCGT utilization rate 70% (Assumed to be used in base, mid-merit and peak), efficiency 43%. OCGT utilization rate 27%, efficiency 32%.
2 Provision already exists to increase current 10MW scale to 50MW, with plans to do so
3 Existing grid gas demand amounting to 0.5PJ
4 Does not match sum of individual components due to rounding
5 Informed by US Mission in Gaborone

SOURCE: Platts WEPP UDI database, US Mission Gaborone, team analysis

EXHIBIT 35

NAMIBIA GAS-TO-POWER PROJECTS

x Subtotals

Planned plants	Capacity (MW)	Commis-sioned	Comment	Source
Kudu gas-to-power project	800	▪ Date unclear	▪ CCGT planned to be directly supplied from the Kudu gas field ▪ Unlikely to proceed given uncertain-ties around production of Kudu field ▪ Different capacities mentioned (ranging from 800-1050MW)[2] ▪ Relevant organization(s): NAMPOWER, BW offshore	▪ UDI ▪ http://www.powerandrenewablesinsight.com/industry-trend-analysis-kudu-removed-our-power-forecasts-oct-2015 ▪ http://www.nampower.com.na/Page.aspx?p=215 ▪ https://www.namcor.com.na/kudu-gas
Walvis Bay	200[3]	▪ Date unclear	▪ LNG-to-power project still under discussion with the government ▪ Relevant organization(s): NAMPOWER, Xaris ▪ Some sources mention 250MW capacity	▪ Power Africa ▪ http://interfaxenergy.com/gasdaily/article/24486/more-delays-still-no-ppas-for-namibian-gas-to-power
Total planned	1,000			

1 Initial qualitative assessment, requires further refinement; 2 NAMCOR mentions on their website that ~400MW will be for domestic use, while remainder to be exported to Zambia + South Africa
3 200MW based on transaction listings from Power Africa Tracker
NOTE: Does not include off-grid/decentralized industrial generators

SOURCE: Platts WEPP UDI database, Power Africa Tracker, press clippings (as indicated)

EXHIBIT 36

NAMIBIA GAS DEMAND FOR POWER SCENARIOS

XX	PJ/year equivalent demand[1]
● XX	Scenario totals: PJ/year equivalent demand[1]
✓	Assumed to materialize by 2030 as gas-fueled
✗	Will not materialize by 2030 as gas-fueled

	Name	**Size** (MW)	***"Regional gas doesn't take off"***	***"Gas as a part of the energy mix"***	***"The region doubles down on gas"***	**Rationale**
Existing gas-fired plants	N/A					
New build gas-fired plants	Kudu gas to power project	800	✗ -	✗ -	✗ -	Highly uncertain given no public sector financial backing
	Walvis bay	200	✗ -	✓ 10	✓ 10	Advanced planning stage with public sector focus, despite legal complications
Existing diesel/HFO-fired plants	Paratus (Walvis)[2]	26	✗ -	✗ -	✗ -	No specific mandate to be replaced by gas, especially given the uncertainty around domestic upstream landscape
	Paratus Anixas	22	✗ -	✗ -	✗ -	
New build diesel/HFO-fired plants	Arandis power	120	✗ -	✗ -	✗ -	
	Paratus Walvis (expansion)	100	✗ -	✗ -	✗ -	
			0	10	10	

[1] Assumptions: CCGT utilization rate 64% (Assumed to be used in base, mid-merit and peak), efficiency 43%. OCGT utilization rate 27%, efficiency 32%.
[2] Recently decommissioned, with plans to re-build still as an OCGT plant: http://namibtimes.net/paratus-power-station-to-be-upgraded-to-40mw/

SOURCE: Platts WEPP UDI database, team analysis

EXHIBIT 37

INDUSTRIAL DEMAND METHODOLOGY FOR SCENARIOS

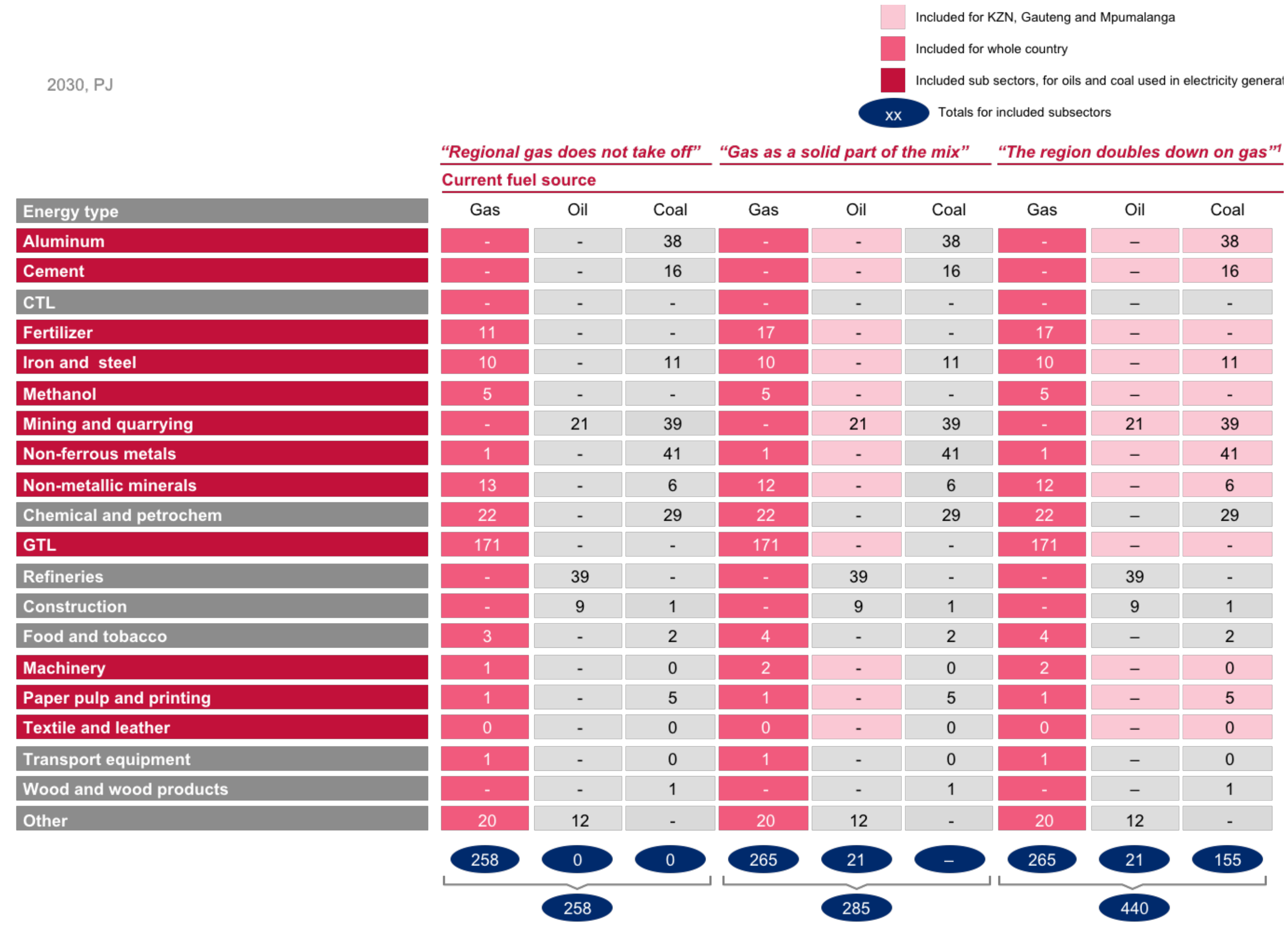
		Low scenario	Medium scenario	High scenario
South Africa	**Parameters included**	- Existing gas demand	- Existing and incremental gas demand, from all sectors, nationally - High value fuel[1] switches, in selected sectors[2] and selected regions[3]	- Existing and incremental gas demand, from all sectors, nationally - High value fuel switches, in selected sectors, and selected regions - Low value fuel for electricity generation switches, in selected sectors, in selected regions
	Description/ rationale	- While incremental gas consumption is in scope, existing infrastructure (ROMPCO) already operates close to capacity, implying only existing gas demand can be met in this scenario.	- Incremental gas demand satisfied through new infrastructure, and industries already have capacity to consume gas. High value fuel switches value to economics, but only in certain sectors where feasible, and in close proximity to the new supply infrastructure	- As per medium scenario, with coal in electricity use in certain regions and sectors also switching. Coal for heating considered uneconomical to switch.
Mozambique, Botswana and Namibia	**Parameters included**	- Existing and incremental gas demand, from all sectors, nationally	- Existing and incremental gas demand, from all sectors, nationally - High value fuel switches, in selected sectors, nationally	- Existing and incremental gas demand, from all sectors, nationally - High value fuel switches, in selected sectors, and selected regions - Low value fuel for electricity generation switches, in selected sectors, nationally
	Description/ rationale	- Infrastructure and capacity exists to continue supplying domestic industry gas demand	- Incremental gas demand satisfied through new infrastructure, and industries already have capacity to consume gas. High value fuel switches due to economics, but only in certain sub sectors where feasible, and nationally given industry in these countries tend to be geographically concentrated	- As per medium scenario, with coal in selected industrial electricity use also incentivized to switch

1 Includes LPG, diesel and HFO

2 Industries that normally operate at scale and are likely able to switch fuel source. Includes aluminium, cement, iron and steel, methanol, mining and quarrying, non-ferrous metals, non-metallic minerals, GTL, refineries, machiney, paper pulp and printing, textile and leather

3 Provinces that have high industrial demand and/or that are geographically close to supply route of new gas. Includes Gauteng, KwaZulu-Natal and Mpumalanga

SOUTH AFRICA INDUSTRIAL GAS DEMAND BY SCENARIO



Included for KZN, Gauteng and Mpumalanga

Included for whole country

Included sub sectors, for oils and coal used in electricity generat

xx Totals for included subsectors

2030, PJ

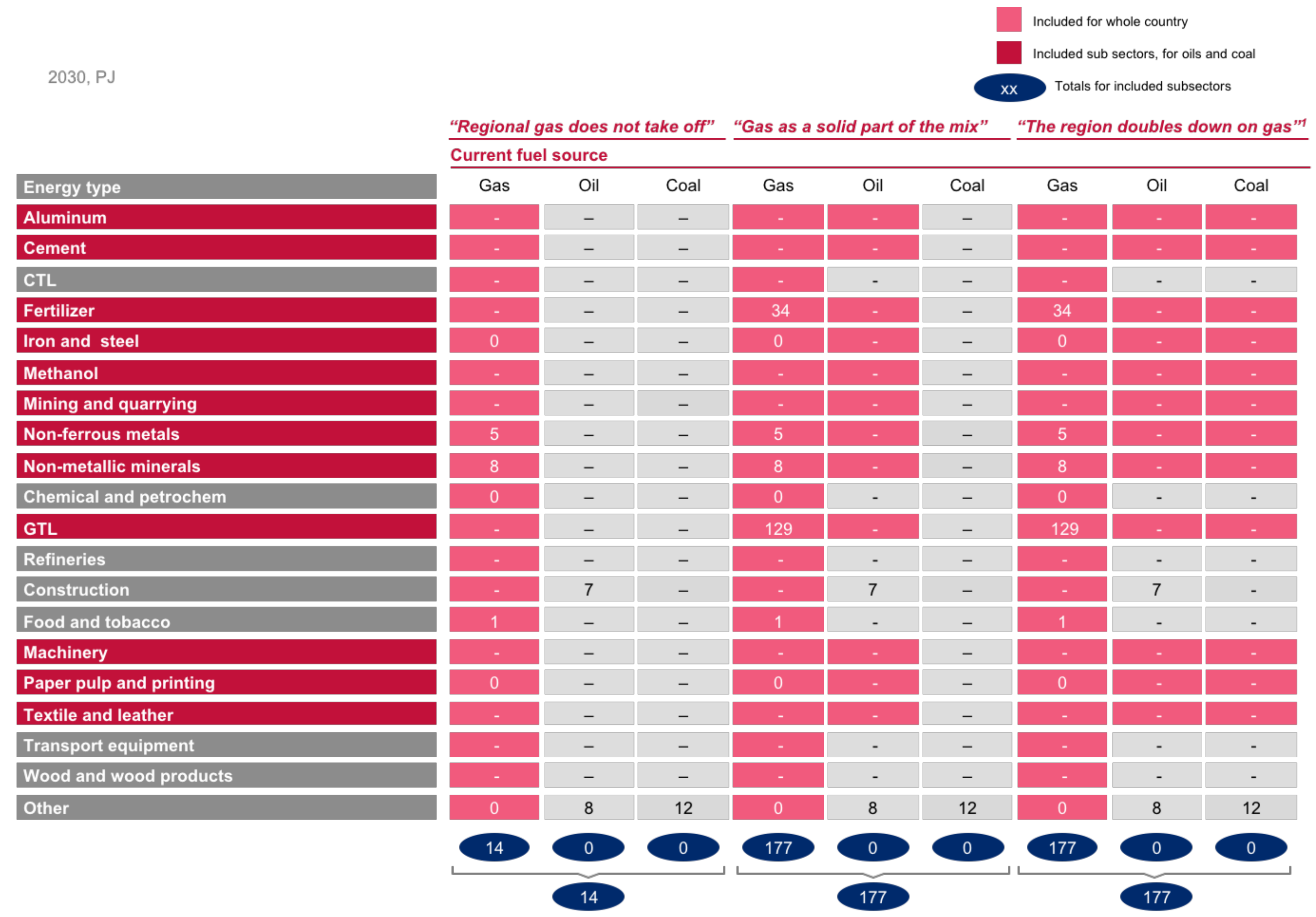
	“Regional gas does not take off”			“Gas as a solid part of the mix”			“The region doubles down on gas”[1]		
	Current fuel source								
Energy type	Gas	Oil	Coal	Gas	Oil	Coal	Gas	Oil	Coal
Aluminum	-	-	38	-	-	38	-	–	38
Cement	-	-	16	-	-	16	-	–	16
CTL	-	-	-	-	-	-	-	–	-
Fertilizer	11	-	-	17	-	-	17	–	-
Iron and steel	10	-	11	10	-	11	10	–	11
Methanol	5	-	-	5	-	-	5	–	-
Mining and quarrying	-	21	39	-	21	39	-	21	39
Non-ferrous metals	1	-	41	1	-	41	1	–	41
Non-metallic minerals	13	-	6	12	-	6	12	–	6
Chemical and petrochem	22	-	29	22	-	29	22	–	29
GTL	171	-	-	171	-	-	171	–	-
Refineries	-	39	-	-	39	-	-	39	-
Construction	-	9	1	-	9	1	-	9	1
Food and tobacco	3	-	2	4	-	2	4	–	2
Machinery	1	-	0	2	-	0	2	–	0
Paper pulp and printing	1	-	5	1	-	5	1	–	5
Textile and leather	0	-	0	0	-	0	0	–	0
Transport equipment	1	-	0	1	-	0	1	–	0
Wood and wood products	-	-	1	-	-	1	-	–	1
Other	20	12	-	20	12	-	20	12	-
	258	0	0	265	21	–	265	21	155
	258			285			440		

[1] Includes258PJ of existing demand

SOURCE: DoE Gas-based Industrialization in South Africa, IEA World Energy Balances 2015, team analysis

EXHIBIT 39

MOZAMBIQUE INDUSTRIAL GAS DEMAND BY SCENARIO



2030, PJ

🟥 Included for whole country

🟥 Included sub sectors, for oils and coal

xx Totals for included subsectors

	"Regional gas does not take off"			"Gas as a solid part of the mix"			"The region doubles down on gas"[1]		
	Current fuel source								
Energy type	Gas	Oil	Coal	Gas	Oil	Coal	Gas	Oil	Coal
Aluminum	-	–	–	-	-	–	-	-	-
Cement	-	–	–	-	-	–	-	-	-
CTL	-	–	–	-	-	–	-	-	-
Fertilizer	-	–	–	34	-	–	34	-	-
Iron and steel	0	–	–	0	-	–	0	-	-
Methanol	-	–	–	-	-	–	-	-	-
Mining and quarrying	-	–	–	-	-	–	-	-	-
Non-ferrous metals	5	–	–	5	-	–	5	-	-
Non-metallic minerals	8	–	–	8	-	–	8	-	-
Chemical and petrochem	0	–	–	0	-	–	0	-	-
GTL	-	–	–	129	-	–	129	-	-
Refineries	-	–	–	-	-	–	-	-	-
Construction	-	7	–	-	7	–	-	7	-
Food and tobacco	1	–	–	1	-	–	1	-	-
Machinery	-	–	–	-	-	–	-	-	-
Paper pulp and printing	0	–	–	0	-	–	0	-	-
Textile and leather	-	–	–	-	-	–	-	-	-
Transport equipment	-	–	–	-	-	–	-	-	-
Wood and wood products	-	–	–	-	-	–	-	-	-
Other	0	8	12	0	8	12	0	8	12
	14	0	0	177	0	0	177	0	0
		14			177			177	

---

1 Includes 6PJ of existing demand

SOURCE: IEA World Energy Balances 2015, team analysis

EXHIBIT 40

NAMIBIA INDUSTRIAL GAS DEMAND BY SCENARIO

🟥 Included for whole country

🟥 Included sub sectors, for oils and coal

● Totals for included subsectors

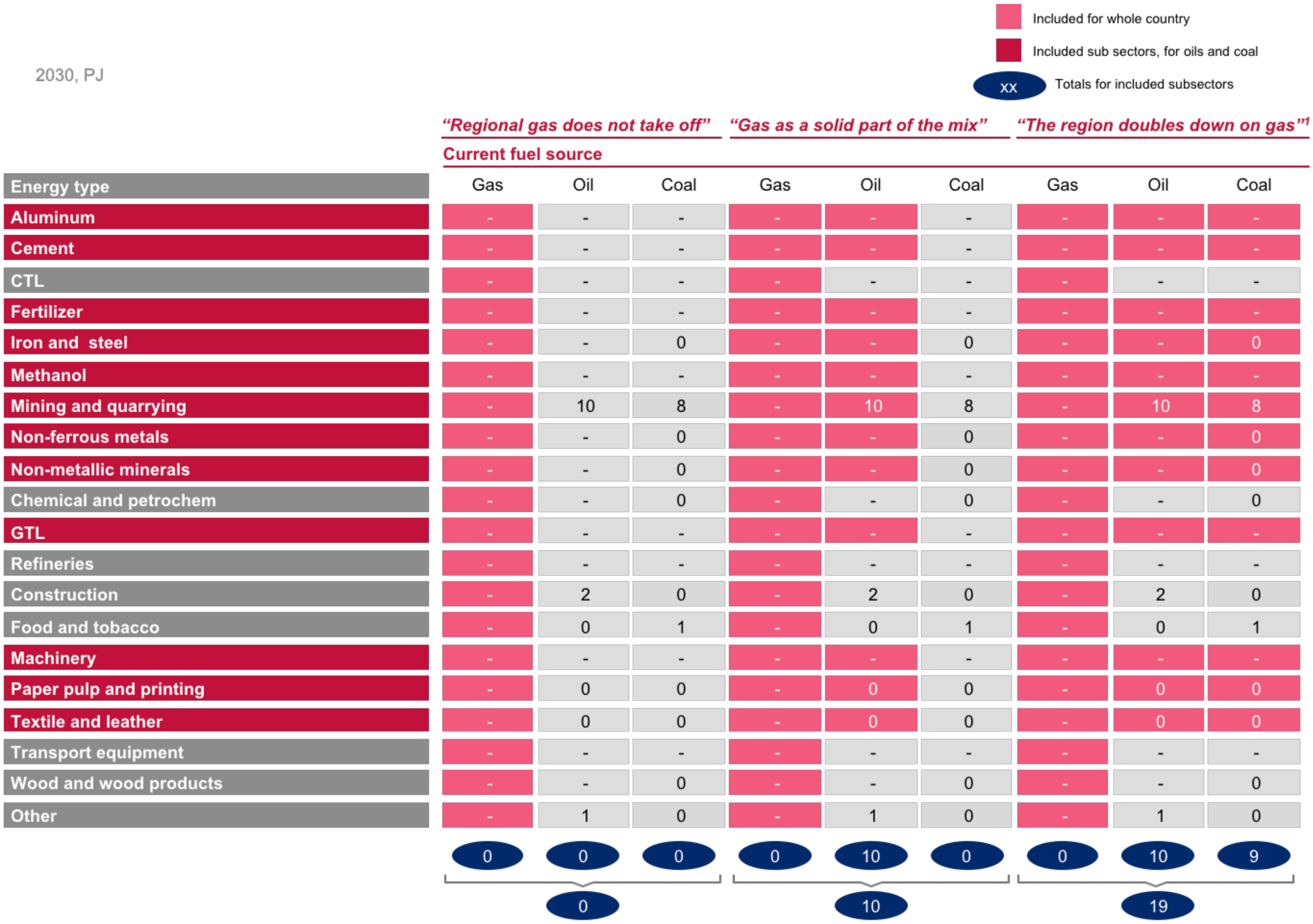
2030, PJ

	"Regional gas does not take off"			*"Gas as a solid part of the mix"*			*"The region doubles down on gas"*[1]		
	Current fuel source								
Energy type	Gas	Oil	Coal	Gas	Oil	Coal	Gas	Oil	Coal
Aluminum	-	-	-	-	-	-	-	-	-
Cement	-	-	-	-	-	-	-	-	-
CTL	-	-	-	-	-	-	-	-	-
Fertilizer	-	-	-	-	-	-	-	-	-
Iron and steel	-	-	-	-	-	-	-	-	-
Methanol	-	-	-	-	-	-	-	-	-
Mining and quarrying	-	5	3	-	5	3	-	5	3
Non-ferrous metals	-	-	-	-	-	-	-	-	-
Non-metallic minerals	-	-	-	-	-	-	-	-	-
Chemical and petrochem	-	-	-	-	-	-	-	-	-
GTL	-	-	-	-	-	-	-	-	-
Refineries	-	-	-	-	-	-	-	-	-
Construction	-	2	-	-	2	-	-	2	-
Food and tobacco	-	-	-	-	-	-	-	-	-
Machinery	-	-	-	-	-	-	-	-	-
Paper pulp and printing	-	-	-	-	-	-	-	-	-
Textile and leather	-	-	-	-	-	-	-	-	-
Transport equipment	-	-	-	-	-	-	-	-	-
Wood and wood products	-	-	-	-	-	-	-	-	-
Other	-	1	1	-	1	1	-	1	1
	0	0	0	0	5	0	0	5	3
		0			5			8	

SOURCE: IEA World Energy Balances 2015, team analysis

EXHIBIT 41

BOTSWANA INDUSTRIAL GAS DEMAND BY SCENARIO



2030, PJ

▨ Included for whole country
■ Included sub sectors, for oils and coal
● xx Totals for included subsectors

	"Regional gas does not take off"			*"Gas as a solid part of the mix"*			*"The region doubles down on gas"*[1]		
	Current fuel source								
Energy type	Gas	Oil	Coal	Gas	Oil	Coal	Gas	Oil	Coal
Aluminum	-	-	-	-	-	-	-	-	-
Cement	-	-	-	-	-	-	-	-	-
CTL	-	-	-	-	-	-	-	-	-
Fertilizer	-	-	-	-	-	-	-	-	-
Iron and steel	-	-	0	-	-	0	-	-	0
Methanol	-	-	-	-	-	-	-	-	-
Mining and quarrying	-	10	8	-	10	8	-	10	8
Non-ferrous metals	-	-	0	-	-	0	-	-	0
Non-metallic minerals	-	-	0	-	-	0	-	-	0
Chemical and petrochem	-	-	0	-	-	0	-	-	0
GTL	-	-	-	-	-	-	-	-	-
Refineries	-	-	-	-	-	-	-	-	-
Construction	-	2	0	-	2	0	-	2	0
Food and tobacco	-	0	1	-	0	1	-	0	1
Machinery	-	-	-	-	-	-	-	-	-
Paper pulp and printing	-	0	0	-	0	0	-	0	0
Textile and leather	-	0	0	-	0	0	-	0	0
Transport equipment	-	-	-	-	-	-	-	-	-
Wood and wood products	-	-	0	-	-	0	-	-	0
Other	-	1	0	-	1	0	-	1	0
	0	0	0	0	10	0	0	10	9
		0			10			19	

SOURCE: IEA World Energy Balances 2015, team analysis

EXHIBIT 42

FLEET ASSESSMENT FOR INCLUSION IN TRANSPORT DEMAND

▨ Focus of this sizing exercise

🔵 High potential ⚪ Low potential 🟢 Pros ⚫ Cons

	Current typical fuel	Alternative fuel	Potential to switch to gas	Comments / rationale
Passenger cars/LDV fleets	Gasoline Diesel	Electricity LPG **CNG**	◔	⚫ Huge infrastructure investment ⚫ Competitive alternative technologies (hybrids, electric)
Public transport	Diesel	Electricity Hydrogen **CNG/LNG**	◕	🟢 Centralized decision-making 🟢 Limited infrastructure requirements ⚫ Competitive alternative technologies
Commercial fleets/intra-city trucks/buses	Diesel	Electricity LPG **CNG/LNG**	◔	🟢 Centralized decision-making ⚫ High infrastructure investments ⚫ Competitive technologies
Long-haul trucking	Diesel	**CNG/LNG**	◑	⚫ High infrastructure investments 🟢 Meets environmental requirements 🟢 Big players ready to invest in infrastructure
Rail	Diesel Electricity	**CNG/LNG**	◔	⚫ High electrification of rail tracks ⚫ High infrastructure investments ⚫ Limited equipment manufacturers
Shipping	Fuel oil Gasoil	Fuel oil + scrubber **LNG**	◔	⚫ Requires regulation on sulfur limits to incentivize ⚫ High investments[1] (vessels, infrastructure) ⚫ Needs existing base customers supporting infra ⚫ Uncertainty about capturing transiting fleet

[1] capex for vessel switch to LNG ~ $1.5/mmbtu, adapting existing LNG terminal to bunkering ~ $1.5/mmbtu

SOURCE: DoE Gas-based industrialization in South Africa

EXHIBIT 43

TRANSPORT DEMAND METHODOLOGY AND ASSUMPTIONS

	Methodology	Assumptions
Long haul	▪ Long haul trucking demand is calculated based on specific point-to-point tonnage data, with assumptions on driving time, speed and number of journeys ▪ Where tonnage data does not exist, a proportional fraction of total registered trucks is assumed to be long haul (based on neighbor countries that have granularity), with assumptions made on driving time, speed, and distance	▪ **Initial fleet:** Vehicle registration data ▪ **Growth rate in trucking**: In line with GDP growth ▪ **Scrap rate**: 2.5% ▪ **Other conversions rate**: 1.6% ▪ **Avg driving distance/day**: 320km ▪ **Proportion of driving days/year**: 75%
Public transport	▪ Based on total number of registered buses, fuel demand for public transport is calculated making assumptions around driving time, speed and distances ▪ Where the number of registered buses does not exist, a proportional fraction of total vehicles are assumed to be buses (based on countries neighbor countries that have granularity)	▪ **Initial fleet:** Vehicle registration data ▪ **Growth rate in public transport**: In line with population growth ▪ **Scrap rate**: 4% ▪ **Other conversions rate**: 0.1% ▪ **Avg driving distance/day**: 160km ▪ **Operating days/week:** 6 days

SOURCE: eNaTIS, WHO Global status report on road safety (2013, 2015), INTT , DoE Gas-based industrialization in South Africa, World Bank, IMF, team analysis

EXHIBIT 44

TRANSPORT DEMAND VARIATION BY SCENARIO

<table>
<tr><th></th><th></th><th>“Regional gas does not take off”</th><th>“Gas as a solid part of the energy mix”</th><th>“The region doubles down on gas”</th></tr>
<tr><td rowspan="2">Long haul</td><td>Adoption rate[2]</td><td>0%</td><td>10%</td><td>20%</td></tr>
<tr><td>Rationale</td><td colspan="3">▪ Following off of a comprehensive meta-analysis carried out by the International Council on Clean Transport (ICCT)[1], where a market penetration rate upper bound of 20% is considered in a high scenario, and 10% as a mid range</td></tr>
<tr><td rowspan="2">Public transport</td><td>Adoption rate</td><td>0%</td><td>10%</td><td>20%</td></tr>
<tr><td>Rationale</td><td colspan="3">▪ Following off of a comprehensive meta-analysis carried out by the International Council on Clean Transport (ICCT), where a market penetration rate upper bound of 20% is considered in a high scenario, and 10% as a mid range</td></tr>
</table>

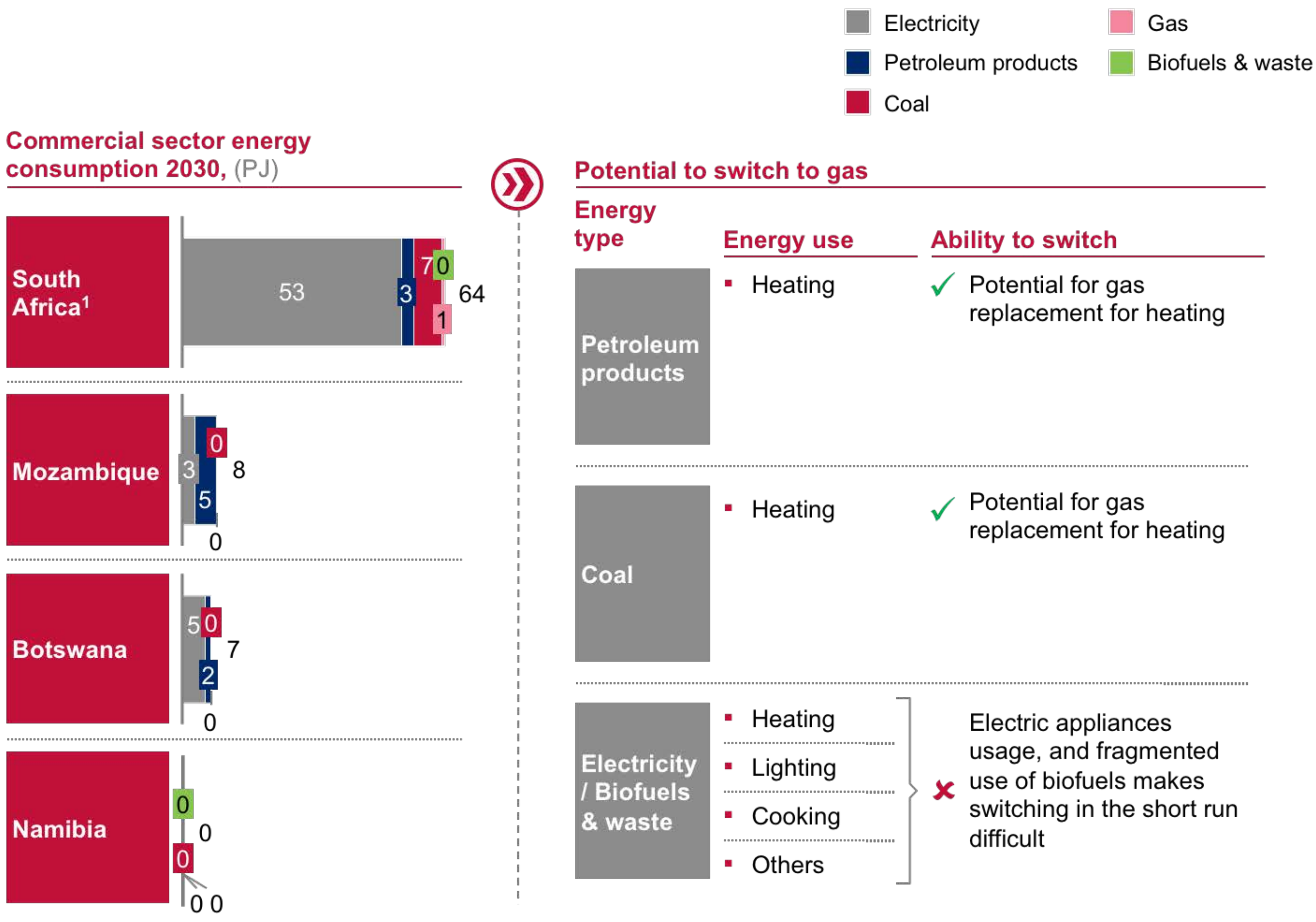
[1] Link: http://www.theicct.org/sites/default/files/publications/ICCT_NG-HDV-emissions-assessmnt_20150730.pdf

[2] Adoption rate is the share of newly purchased vehicles which is considered to be fueled by natural gas

SOURCE: ICCT, team analysis

EXHIBIT 45

COMMERCIAL DEMAND ASSESSMENT



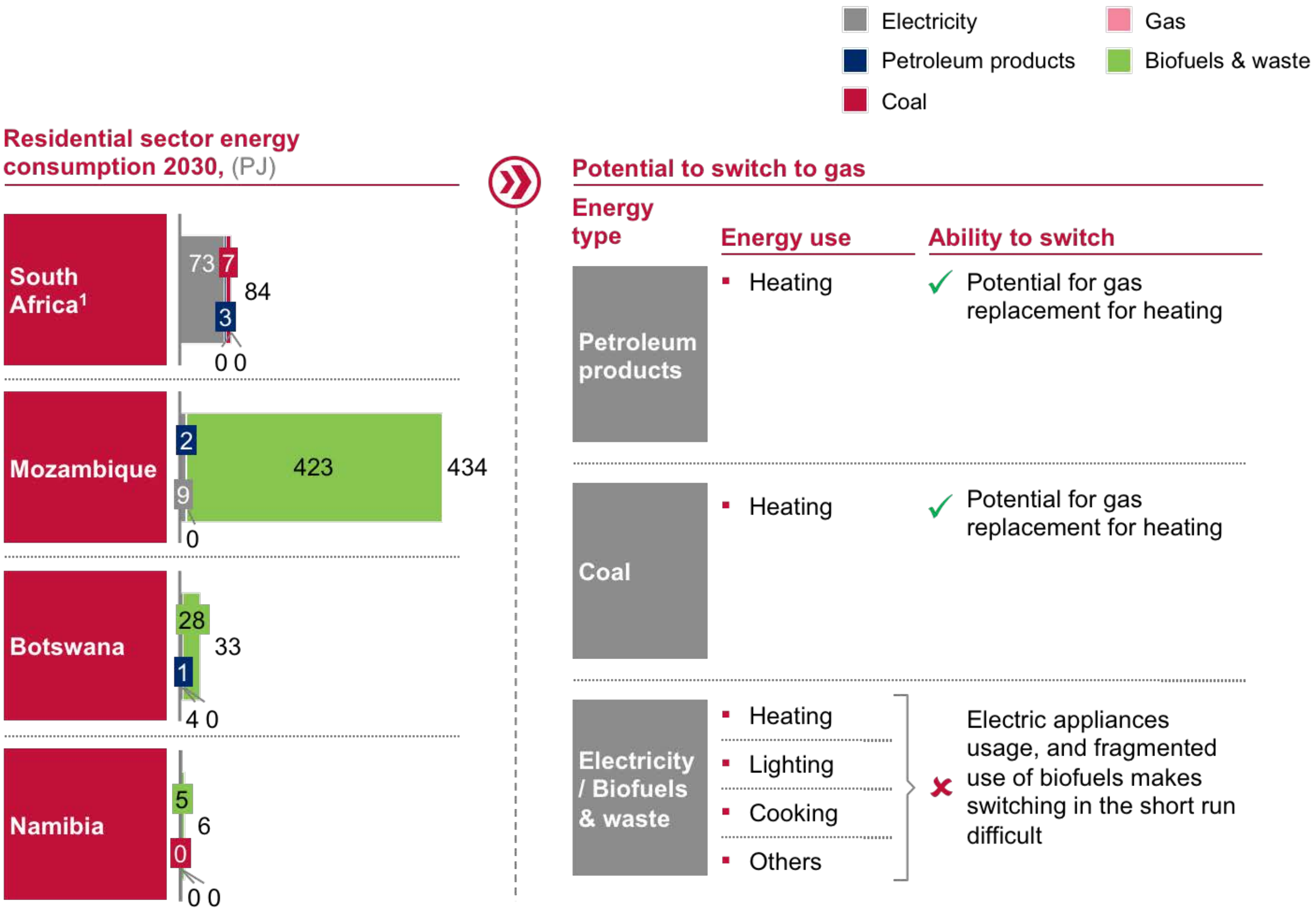
Potential to switch to gas

Energy type	Energy use	Ability to switch
Petroleum products	▪ Heating	✓ Potential for gas replacement for heating
Coal	▪ Heating	✓ Potential for gas replacement for heating
Electricity / Biofuels & waste	▪ Heating ▪ Lighting ▪ Cooking ▪ Others	✗ Electric appliances usage, and fragmented use of biofuels makes switching in the short run difficult

1 Only includes Gauteng, KwaZuluNatal, and Mpumalanga given their proximity to likely supply sources

EXHIBIT 46

RESIDENTIAL DEMAND ASSESSMENT



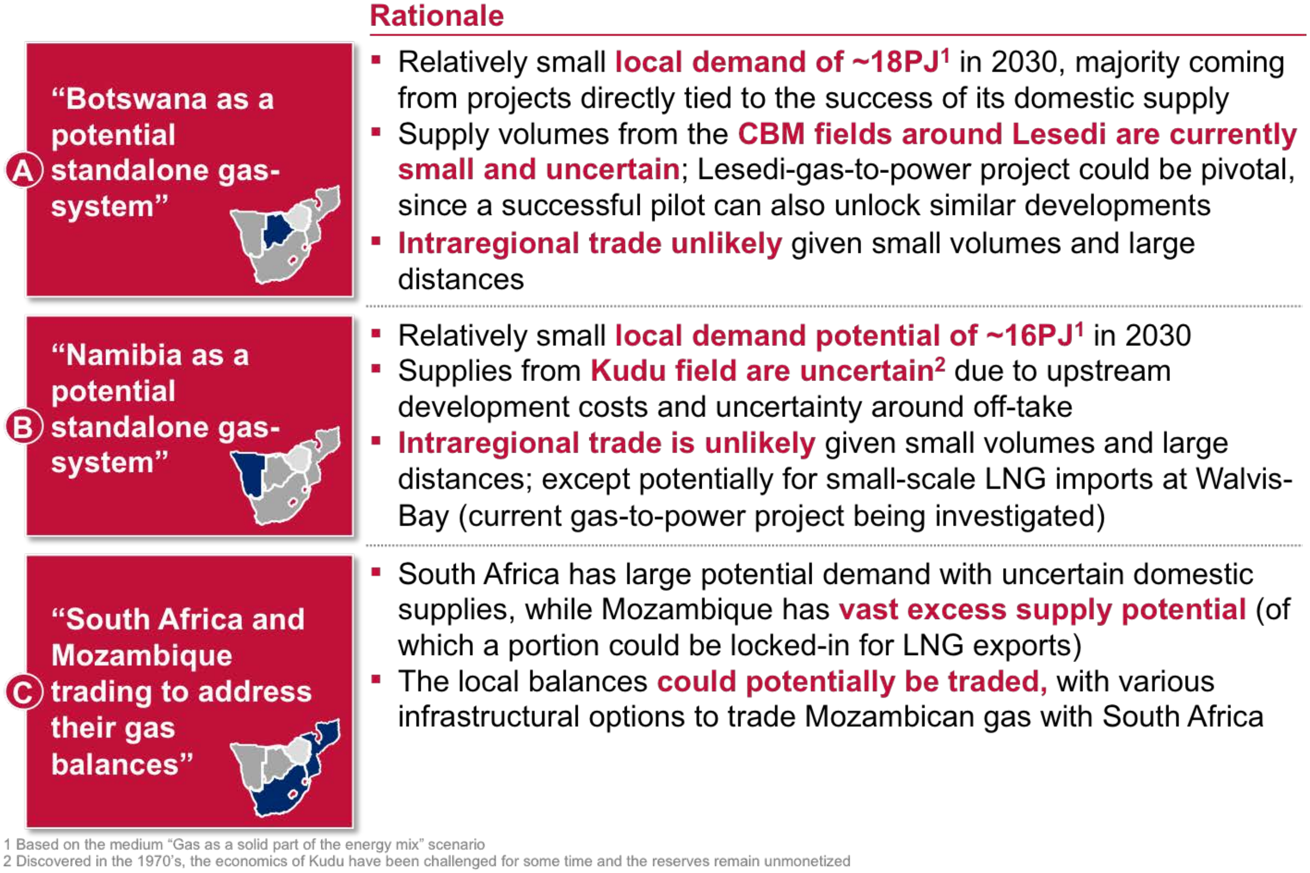
Potential to switch to gas

Energy type	Energy use	Ability to switch
Petroleum products	▪ Heating	✓ Potential for gas replacement for heating
Coal	▪ Heating	✓ Potential for gas replacement for heating
Electricity / Biofuels & waste	▪ Heating ▪ Lighting ▪ Cooking ▪ Others	✗ Electric appliances usage, and fragmented use of biofuels makes switching in the short run difficult

1 Only includes Gauteng, KwaZuluNatal, and Mpumalanga given their proximity to likely supply sources

EXHIBIT 47

DESCRIPTION AND RATIONALE OF THE THREE POTENTIAL SYSTEMS



Rationale

A “Botswana as a potential standalone gas-system”

- Relatively small **local demand of ~18PJ[1]** in 2030, majority coming from projects directly tied to the success of its domestic supply
- Supply volumes from the **CBM fields around Lesedi are currently small and uncertain**; Lesedi-gas-to-power project could be pivotal, since a successful pilot can also unlock similar developments
- **Intraregional trade unlikely** given small volumes and large distances

B “Namibia as a potential standalone gas-system”

- Relatively small **local demand potential of ~16PJ[1]** in 2030
- Supplies from **Kudu field are uncertain[2]** due to upstream development costs and uncertainty around off-take
- **Intraregional trade is unlikely** given small volumes and large distances; except potentially for small-scale LNG imports at Walvis-Bay (current gas-to-power project being investigated)

C “South Africa and Mozambique trading to address their gas balances”

- South Africa has large potential demand with uncertain domestic supplies, while Mozambique has **vast excess supply potential** (of which a portion could be locked-in for LNG exports)
- The local balances **could potentially be traded,** with various infrastructural options to trade Mozambican gas with South Africa

[1] Based on the medium “Gas as a solid part of the energy mix” scenario

[2] Discovered in the 1970’s, the economics of Kudu have been challenged for some time and the reserves remain unmonetized

EXHIBIT 48

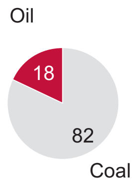
BOTSWANA POWER SECTOR SNAPSHOT (1/2)

Overview as of March 2016

Generation

- **Installed capacity of ~892 MW** mainly consists of coal and oil
- Electricity generation capacity[4] by fuel type, 2015

100% = 892MW



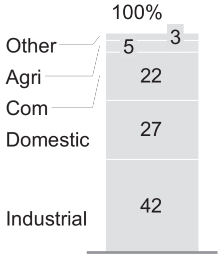
- **Govt. keen on developing additional capacity in view of the power deficit and shortfall in imported power** – Morupule B expansion[6] (300 MW) planned, new rental power plant by APR (35 MW) has come up, etc.

Transmission

- **Member of Southern Africa Power Pool (SAPP)**
- **Mainly depends on imported power from Eskom**
- **Electricity T&D losses[5]~11%**
- **Electrification rate[6] 66%**

Distribution

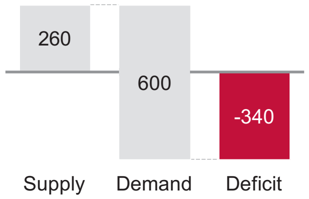
- End user tariffs[3] 2017 (USD cents/kWh) low than SSA avg: Residential: 6-9, industrial 5)
- Grid consumption[3] by end user, 2014



- **Operational data – quality of supply, etc**
  - Average duration of an outage~3-4 hours in a day
  - ~35% firms own a generator
  - 40 days to obtain an electrical connection

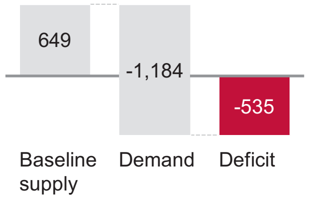
Electricity supply/demand

Baseline[2] 2015, MW



Electricity tariff: 5-9USc/kWh

Forecast[2] 2035, MW



More salient facts :

- **Govt. also keen on diversifying fuel mix - 30% of generation to come from renewables by 2030**
- A coal to liquid project to develop oil based derivatives and 304 MW of electricity has been planned

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1 Actual supply minus losses and internal consumption

2 Botswana Corporation, Tender information, May 2017

3 RECP - Botswana

4 Based on installed generation capacity , not actual generated electricity; source: RECP

5 World bank, 2014

6. Power Africa 2013

6 https://www.sourcewatch.org/index.php/Morupule_B_power_station

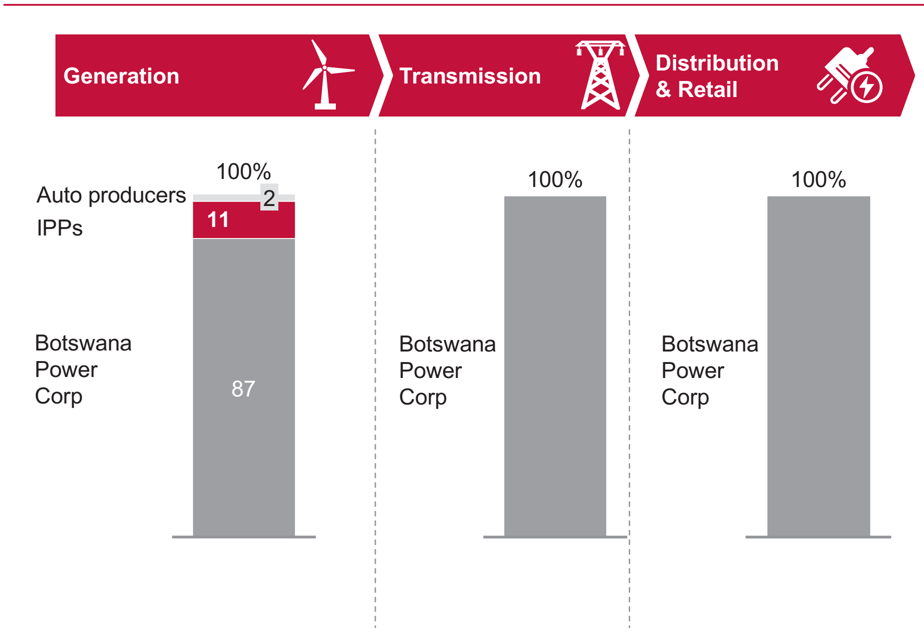
Other Source: UDI, World Bank, World Bank Enterprise surveys, CIE, Enerdata, Botswana Power Corporation, Mckinsey Analysis

EXHIBIT 49

BOTSWANA POWER SECTOR SNAPSHOT (2/2)

PERCENTAGE, 2016

▨ State-owned entities



- Generation, Transmission and Distribution of electricity carried out by state owned entity Botswana Power Corporation
- For IPPs, **a single buyer model is followed where a power purchase agreement** is signed with the national power utility
- Govt. has passed the legislation for private sector generation investment i.e. Independent power producer (IPP) framework; **around 1 IPP present** i.e. APR Energy LLC (105 MW)

SOURCE: Platts UDI 2016 (March version); Botswana Power Corporation website; Press

EXHIBIT 50

BOTSWANA ENERGY MIX

	Current % of energy mix[1]	Potential for power generation
Coal[1,2]	82%	▪ Currently 731MW installed capacity on coal fired plants ▪ The proven coal recoverable reserves of 40 million[2] tonnes while production in 2011 was 0.9 million tonnes as only Morupule Colliery is currently being mined ▪ Botswana Dept. of energy considering development of other plants
Solar[2]	<0.1%	▪ >3,200 hours of sunshine per year ▪ avg. global irradiation of 21 MJ per m2/day throughout the country, one of the highest levels of solar irradiation in the world ▪ Botswana government has shown interest in establishing a 100MW PV solar plant and /or 100MW Concentrated Solar Thermal Plant (CSTP)
Fuel[4]	18%	▪ Currently 195MW installed capacity on emergency diesel plants, i.e. Orapa & Matshelagabedi ▪ Very expensive source of energy, Botswana government exploring options of converting Orapa to gas
Gas[5,6]	0%	▪ Botswana’s Lesedi CBM field has gas reserves ~3.2tcf ▪ A 100MW gas to power plant is planned, possible future expansions ▪ Botswana government is supportive of the development
Other[1]	0%	▪ Low avg. wind speeds range from 2.0 to 3.5 m/s are not considered attractive for large-scale wind power development ▪ Low and uneven rainfall that has caused severe water restrictions and supply interruptions, making hydro power not viable option

1 RECP - Africa renewable energy cooperation programme 2 World Energy council 2013
3 Based on RSA estimates Source: Daily Maverick Article/2016-10-18
4. Platts WEPP UDI database 5 Tlou Energy website; 6 Oil & Gas Journal 09-2017

Other Source: UDI, World Bank, World Bank Enterprise surveys, CIE, Enerdata, Mckinsey Analysis

EXHIBIT 51

DEEP DIVE OF THE LESEDI CBM-TO-POWER PROJECT

Focus areas	Overall	Details
Project overview[1,2]	🟡	▪ **Location**[1]**:** Within proximity to Lesedi CBM field ▪ **Magnitude**[1]: Lesedi CBM field has gas reserves of 0.15-3.2tcf discovered in the early 2000's ▪ Planned Tlou Lesedi plant has electricity generation plan of 100MW (to be developed in stages) ▪ **Project status**[2,3]: Tlou Energy has been awarded mining rights on Lesedi CBM field and have drilled numerous exploration wells. The ministry has issued an RFP for construction of the gas plant, RFP closed Sept 2017 ▪ **Ownership**[1]**:** Tlou Energy has 100% ownership and mining rights for the Lesedi CBM field
Key stakeholders, financing & feasibility[3]	🟡	▪ Tlou Energy holds 100% ownership of the field. ▪ Ministry of Mineral Resources, Green Technology, and Energy Security granted Tlou Energy a 25-year mining license to terminate in August 2042 ▪ It is unclear whether Tlou will be accommodating in the event that Sekaname Pvt Ltd, wins the RFP for development of downstream power plant
Legal & political landscape[3,4,5]	🟡	▪ The ministry requires Tlou Energy to pay an annual $9,000 license[2] fee with an additional royalty of 3% of gross market value ▪ No public ownership may limit the ministry's ability to influence decision around this field
Secured demand / Off take[6]	🟡	▪ Botswana is currently not meeting its demand of 600MW, as it is only generates 350MW[4]. ▪ Tlou Lesedi plant to assist in meeting this demand ▪ RFP for construction has not been awarded thus no PPA in place
Socio economic and environmental implications[7]	🟡	▪ Environmental: Botswana's Dept. of Environmental Affairs has approved the EIS submitted by Tlou Energy in 2015 ▪ Socio – economic: No clear socio economic reports exists on the project
Other[8]	🟡	▪ There are concerns on skills and technical ability to develop CBM in this region; However Tlou Energy has partnered with IPC, a British power development company to tender for and develop the plant ▪ IPC meant to bring its power generation experience to increase visibility, feasibility and attract funding

1 http://tlouenergy.com/overview
2 Oil & Gas Journal 09-2017 ; Independent geologist's report – CBM licenses in Botswana
3 Stock market wire article 5672565

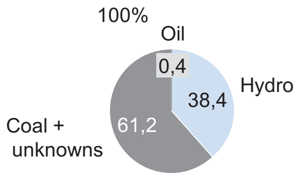
EXHIBIT 52

NAMIBIA POWER SECTOR SNAPSHOT (1/2)

Electricity overview as at 2016

Generation

- **Installed capacity of ~545 MW** mainly consists of hydro, oil and coal
- Electricity production mix, 2012.[4]



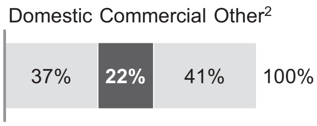
- **Govt. keen to diversify fuel mix** - plans to install 70MW of biomass, wind and solar photovoltaic power under the ReFit[1] Another 30 MW to be tendered soon
- To meet growing demand Govt. will get into a PPA with **Xaris Energy for a 200MW temporary open-cycle gas power plant**

Transmission

- **Member of the Southern Africa Power Pool**
- **Is a net importer of electricity**
- **Electricity T&D losses[7]~38%**
- **Electrification rate[8] 32%**, most of this is urban ~50% Urban and rural electrification of ~ 17%

Distribution

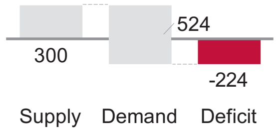
- End user tariffs[5] (USD cents/kWh) quite low: Residential 9, industrial 10-12)
- Grid consumption[6] by end user, 2011



- **Operational data – quality of supply, etc**
  - Average duration of an outage ~6 hrs. a day
  - ~25-30% of firms own a generator

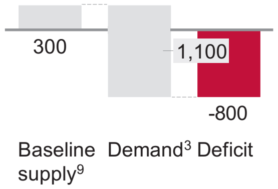
Electricity supply/demand

Baseline[3] 2013, MW



Electricity tariff: 9-12USc/kWh

Forecast 2030, MW



More salient facts :

- **This peak deficit is mostly met by imports from South Africa and other neighboring countries**

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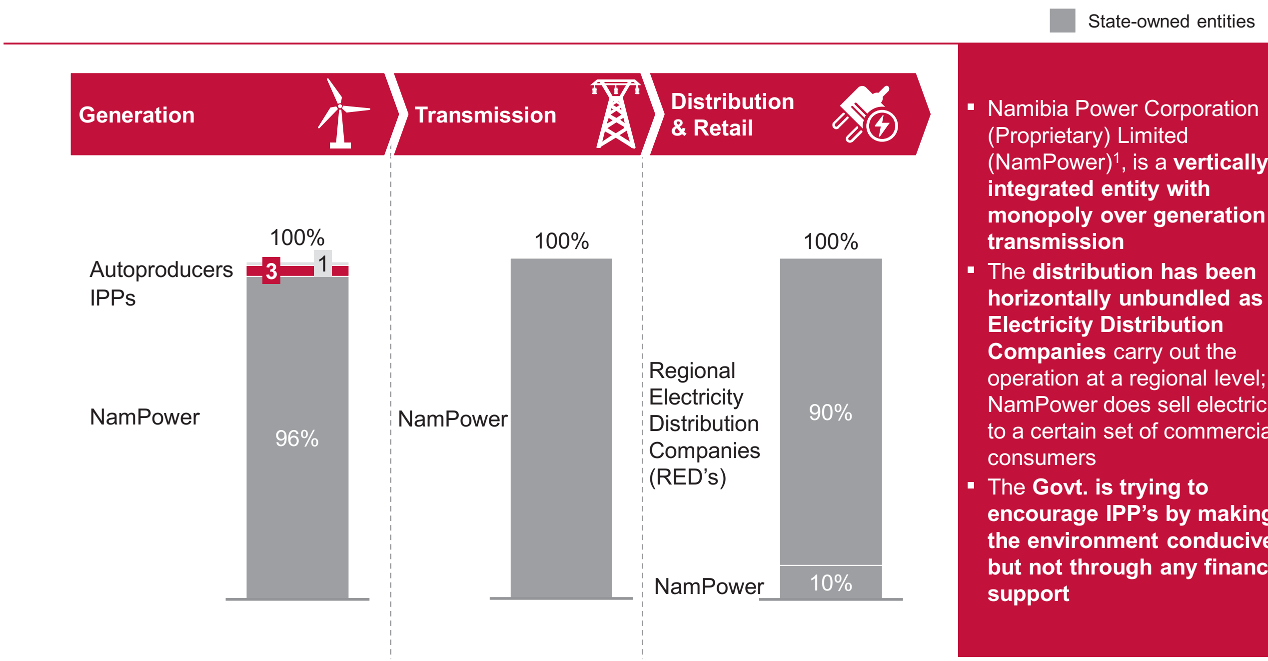
1 Renewable Energy Feed-In tariff Programme 2 Includes bulk consumption e.g. from mines
3 NamPower media briefing; Ministry of mines and energy –Africa energy forum 2013
4 Journal of Power and Energy engineering 2016,4-19-30 figure 3 -- Includes Eskom imported electricity generated from coal
5 City of Windhoek; Electricity tariffs 2016 July ; 6 A case for Renewables – Konrad Stiftun 7 Word Bank - Electric power transmission and distribution losses (% of output)
8 Power Africa – NAMIBIA POWER AFRICA FACT SHEET 9 Based on a scenario that no new power plants come on line before 2030, thus supply = 2015 baseline supply
Other Source: UDI, World Bank, World Bank Enterprise surveys, CIE, Enerdata, Mckinsey Analysis

EXHIBIT 53

NAMIBIA POWER SECTOR SNAPSHOT (2/2)

PERCENTAGE, 2016



- Namibia Power Corporation (Proprietary) Limited (NamPower)[1], is a **vertically integrated entity with monopoly over generation & transmission**
- The **distribution has been horizontally unbundled as 5 Electricity Distribution Companies** carry out the operation at a regional level; NamPower does sell electricity to a certain set of commercial consumers
- The **Govt. is trying to encourage IPP's by making the environment conducive but not through any financial support**

1 NamPower is wholly owned by the government of Namibia; however its origins are as a private company established by South Africa to operate the Ruacana hydropower project in 1964.

SOURCE: Global Data; Platts UDI 2016 (March version); Nampower website

EXHIBIT 54

NAMIBIA ENERGY MIX

	Current % of energy mix[3]	Potential for power generation
Coal[1,4]	61.2%	▪ Namibia has little proven reserves and Zambia some 0.1bt[4], compared to Botswana with 40bt reserves ▪ Currently only one coal power station of 120MW[1], Van Eck plant
Hydro[1]	38.4%	▪ Although it is currently dominant source of energy, Namibia is very dry and has only two permanent rivers (the Kunene and Orange rivers), both are shared systems which require bilateral negotiations ▪ Namibia's hydro potential is unknown according to the World Bank ▪ Stated pipeline projects include Epupa dam, the Baynes hydro project
Fuel[6]	0.4%	▪ Currently 48MW installed capacity for two emergency diesel plants, i.e. Paratus (Walvis and Anixas) ▪ Although this is an expensive method of electricity generation, additional capacity of 220MW diesel plants are planned
Solar[5]	<0.1%	▪ Namibia has an excellent solar potential since the average high direct insolation is 2,200[5] kWh/m2 /yr ▪ Only installed Solar water Heaters, which reduced peak demand by ~18MW[2]
Gas[6]	0%	▪ Kudu offshore gas field has been discovered in 1974, however development of the reserves has been a struggle without secure off-takers combined with high development costs of the reserves ▪ Walvis Bay LNG gas power plant (200 MW) is likely to come online by 2030 despite current legal disruptions
Other[1]	<0.1%	▪ Namibia has ~26mil hectares of invasive plant spices that can be controlled by harvesting to produce electricity . ▪ No current plans in place to explore this

1 Namibia Energy profile, World Bank, REEEP, 2014
2 Energy situation in Namibia, Africa energy forum 2013
3 REEEP, 2014
4 World Coal, Tuesday, 07 January 2014 11:30
5 Journal of Power and Energy engineering 2016,4-19-30 figure 3 -- Includes Eskom implored coal fired electricity
6 Recently decommissioned, with plans to re-build still as an OCGT plant: http://namibtimes.net/paratus-power-station-to-be-upgraded-to-40mw/
7 Based on RSA estimates Source: Daily Maverick Article/2016-10-18

EXHIBIT 55

DEEP DIVE OF KUDU GAS-TO-POWER AND KUDU FIELD DEVELOPMENT

Focus areas	Overall	Details
Project overview[1,2]	🔴⚪⚪	▪ **Location:** Offshore location makes it more expensive to develop and less accessible ▪ **Magnitude[1]:** Kudu field has gas reserves of 1.3tcf . Planned Kudu plant has electricity generation plan of 800MW ▪ **Project status[1]**: Kudu gas field was discovered in 1974, however development of this field never progressed with key developers withdrawing due to high development costs and uncertain take-off (Namibia's gas demand too limited). Kudu power plant is directly linked to the development of Kudu gas field ▪ **Ownership[2]:** Currently ownership is split between BW Offshore (56%) and NAMCOR (44%)
Key stakeholders, financing & feasibility[1,3]	🔴⚪⚪	▪ Kudu has had multiple stakeholders since its discovery in 1974, including Chevron Texaco, Shell and Tullow Oil ▪ Currently BW Offore[1] owns 56% operated stake with NAMCOR owing the remaining 44% ▪ Upstream development costs[3] estimated at $1.1 billion ▪ Offshore location and geology is complex causing high upstream costs
Legal & political landscape[4, 5]	🟠⚪⚪	▪ Namibia's finance minister publicly declared that Kudu was not economically feasible ▪ Government decided to pull funding[4] from the project in Jan 2016, despite the current minister of Energy's passion for the development of Kudu ▪ Government focus is also on more towards Walvis bay rather than Kudu at this stage ▪ The project is unlikely to be developed without government[5] funding due to feasibility
Secured demand / Off take[6]	🟠⚪⚪	▪ Ìn 2014 it was estimated that Namibia would consume 400MW of the 800MW plant capacity while 100-300MW would be exported to South Africa via Eskom. ▪ Current potential for export with South Africa uncertain as Eskom's new plants come online and with Namibia currently still importing most of it's power from South Africa
Socio economic and environmental implications[7]	⚪⚪🟢	▪ Socio-economic benefits include employment during construction and operation, infrastructure expansion, increased utilization of harbor ▪ Environmental impact assessments conducted conclude that the development is environmentally viable. Some of the areas that are within the projects' "ecological footprint" have already been highly disturbed. ▪ The component- specific EIAs and this IIMR have identified the safeguards that must be put in place to avoid unnecessary negative impacts while enhancing project benefits

1 Offshore technology.com/projects ; 2 Powerandrenewablesinsights.com 3 iol business repor19 JULY 2005 4 Africa Independent 5 JANUARY 2016, 1:39PM
5 Interview with Botswana USG 6 Offshore mag -OCTOBER 29, 2015 / 2:21 PM Kudu INTEGRATED IMPACT AND MITIGATION REPORT May 2006

EXHIBIT 56

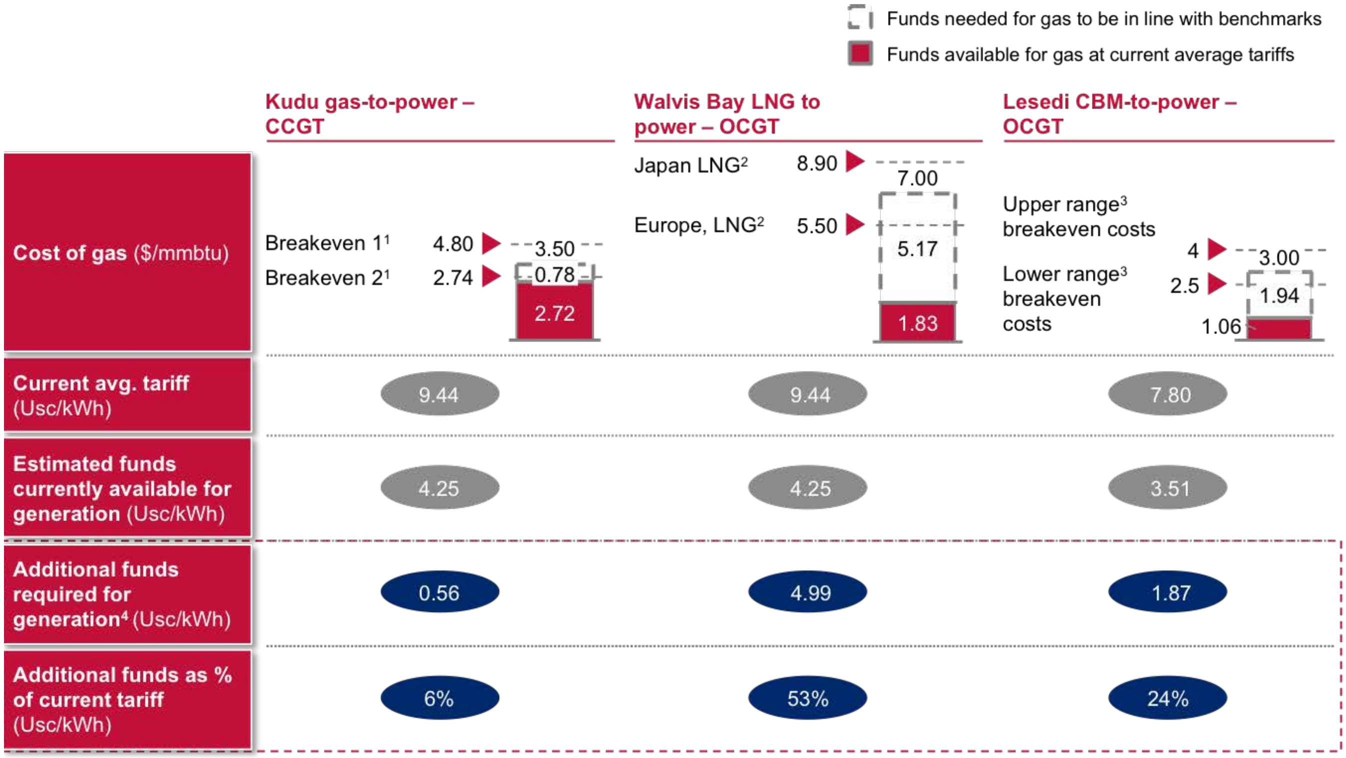
DEEP DIVE OF THE WALVIS BAY GAS-TO-POWER PROJECT

Focus areas	Key indicator	Details
Project overview[1,2]	🟡	▪ **Location:** Walvis Bay ▪ **Magnitude:** 200-250MW of electricity ▪ **Ownership & Funding:** Xaris the current bid winner and key financer, NamPower holds 30% ownership ▪ **Gas supply:** LNG import via Walvis bay harbor, regasification will be done through FSRU. International markets point to the over supply of LNG and prices are forecasted to continue to be favourable ▪ **Gas supplier:** Excelerate Gas marketing (EGM) had been selected as fuel provider. EGM is well established with over 75 master sales & purchase agreements in place. ▪ **Project status**[2]: Project currently experiencing delays due to legal issues. However the project is in advanced stages of development with EIAs[9], feasibility studies, construction and distribution designs completed
Key stakeholders, financing & feasibility[3]	🟡	▪ Xaris the current bid winner (as at Oct 2017) estimates establishment costs at N$5.5Billion (~US$390mil). ▪ State has committed to assisting with funding but no amount disclosed, despite the Minister of Finance's warning that the project will be unfeasible ▪ NamPower also owns 30% stake in this transaction ▪ Xaris estimates that the electricity tarrif will be ~13USc/KWh[5], this is 30% more expensive than current tariffs of 9USc/KWh
Legal & political landscape[3,4,5]	🔴	▪ Arandis Power suggests that there were irregularities in the tender process ▪ High court has affirmed NamPower's decision to award Xaris as bid winner, in 2016 ▪ However both Arandis Power and Xaris are still going through court processes with last appearance in Oct 2017 ▪ Xaris also claims to have already invested N$400Mil (~US$28mil) to the project to date which they'll demand refund if bid is withdrawn
Secured demand / Off take[6]	🔴	▪ Walvis bay agreement with NamPower is to 200-250MW as per plan ▪ However no PPA has been signed with NamPower as at March 2017 ▪ Root cause of NamPower's hesitation in signing PPA is unclear
Socio economic and environmental implications[7]	🟢	▪ Environmental: No fresh water to be used in the plant, plant will enhance Walvis Bay Water Treatment Plant and use grey water from the plant. Overall benefits of use of gas as opposed to coal and other fuels apply, these include lower carbon, sulfur oxides and lower nitrogen ▪ Socio economic: Local job creation during construction & operation, Spin off job creation, local skills development ▪ Xaris's bid included issuing of scholarships, bursaries and building new education facilities
Other[8]	🟡	▪ Potential further delay: Walvis bay harbor needed to be developed to allow for LNG terminal ▪ Potential for further development: Chinese investor (Huimin Natural Gas Investment (HNGI)) interested in developing gas plant at Walvis bay harbour

1 FSRU Feasibility Report XARIS, 2 Jan 2014; 2 Xaris project overview and status Jan 2016; PDF 3 The Namibian 2017-06-08 4 The Namibia - 2016-05-13 & 2016-07-11
5 https://walvisbaypowerplant.com/qa/ 6 Interfaxenergy.com 7 Xaris project overview and status- Jan 2016 –PDF 8 New Era June 8, 2017 9 Environmental Impact Assessment

EXHIBIT 57

SENSITIVITY ANALYSIS: ADDITIONAL TARIFF FOR GENERATION REQUIRED TO MATCH COMPARABLE BREAKEVEN MARGINS OF GAS INPUT



	Kudu gas-to-power – CCGT	Walvis Bay LNG to power – OCGT	Lesedi CBM-to-power – OCGT
Cost of gas ($/mmbtu)	Breakeven 1[1] 4.80; Breakeven 2[1] 2.74; 3.50; 0.78; 2.72	Japan LNG[2] 8.90; Europe, LNG[2] 5.50; 7.00; 5.17; 1.83	Upper range[3] breakeven costs 4; Lower range[3] breakeven costs 2.5; 3.00; 1.94; 1.06
Current avg. tariff (Usc/kWh)	9.44	9.44	7.80
Estimated funds currently available for generation (Usc/kWh)	4.25	4.25	3.51
Additional funds required for generation[4] (Usc/kWh)	0.56	4.99	1.87
Additional funds as % of current tariff (Usc/kWh)	6%	53%	24%

[1] Based on average breakeven costs from similar shallow, offshore gas fields in Africa; scope is fields which (have) come online between 2015-2025; Scope of breakeven 1: "discovered" fields only (i.e. not yet under development); scope of breakeven 2: Fields currently under development

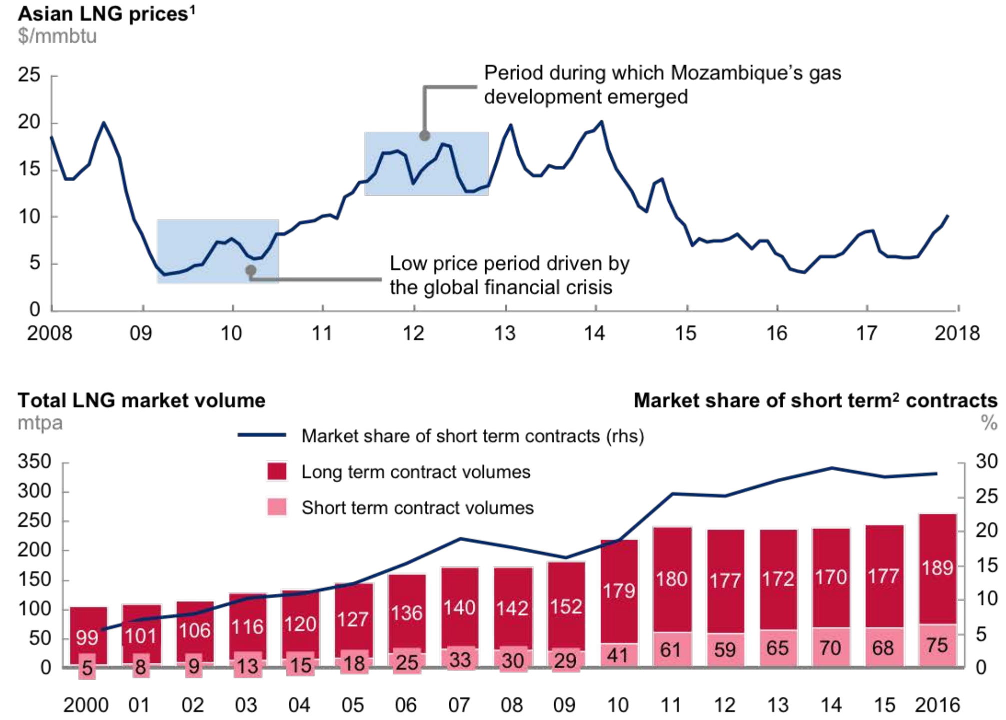
[2] Word Bank – Commodities Price data (pink sheet) (2017)

[3] Typical breakeven costs from other CBM fields, range based CBM expert interview

[4] Various options are available for consideration in raising extra funds required for generation, e.g. reducing tax pressure on tariffs, generation and/or upstream gas production, increasing tariff for

EXHIBIT 58

RECENT DEVELOPMENTS IN GLOBAL LNG MARKETS



- Locking down long-term supply agreements (e.g. via a pipeline) would help to anchor demand for upstream producers, particularly at a time in which LNG price premiums have been eroded, and when the LNG market has been moving away from long-term supply contracts

1 Japan Korean Marker (JKM) is the industry standard benchmark for Asian LNG prices
2 Short term contracts defined as being <4years in duration

SOURCE: CME Group, Platts, GIIGNL

EXHIBIT 59

RELEVANT VOLUMES FOR INFRASTRUCTURE ANALYSIS (MOZAMBIQUE)

✓ Delivered by infrastructure
✗ Not delivered by infrastructure
xx Totals for included components

			Infrastructure option			
Sector	**Name**	**Size** (PJ)	**Pipeline**	**LNG**	**Power transmission**	**Comments**
Power	Temane IPP	19	✗	✗ Domestic Mozambique demand would not be supplied by LNG (regasification terminal required)	✗ Under cost conservative base case assumption, DC transmission line would only have single off take in South Africa	Fueled by Temane field
	Rovuma Gas	12	✗			Located at Cabo Delgado
	Gigawatt Park (expansion)	3	✓			
	Shell Afungi GTL	2	✗			Located at Cabo Delgado
	Chokwe	4	✓			
	Palma Cabo Delgado	4	✗			Located at Cabo Delgado
	Maputo (expansion)	3	✓			
	Yara Fertilizer	1	✗			Located at Cabo Delgado
Industry	Shell Afungi GTL	129	✗			Located at Cabo Delgado
	Yara Fertilizer	34	✗			Located at Cabo Delgado
	Gas demand growth	8	✓			
	Fuel switching	0	✓			
Transport	Long Haul	1	✓			
	Public transport	0	✓			
		220	20	0	0	

1 Only considers incremental demand volume, assuming existing demand is met via existing infrastructure

EXHIBIT 60

RELEVANT VOLUMES FOR INFRASTRUCTURE ANALYSIS (SOUTH AFRICA)

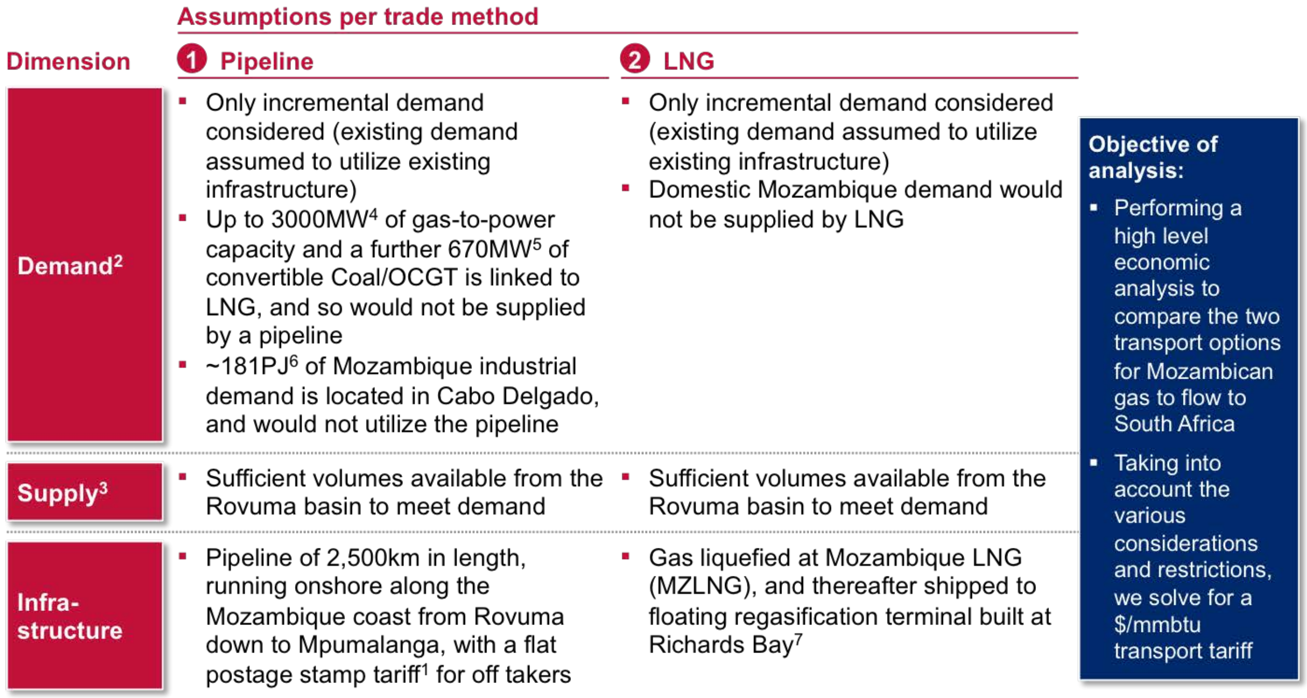
✓ Delivered by infrastructure
✗ Not delivered by infrastructure
● xx Totals for included components

		Infrastructure option				
Sector	**Name**	**Size** (PJ)	**Pipeline**	**LNG**	**Power transmission**	**Comments**
Power	LNG-to-power Richards Bay	62	✗	✓	✗	▪ Committed to LNG
	LNG-to-power Coega	31	✗	✓	✗	
	Gas to power generation	19	✓	✓	✓	
	Domestic gas programme	4	✗	✗	✗	▪ Domestic production sourced
	Other projects from IRP	47	✓	✓	✓	▪ ~56% of remaining IRP determination assumed to materialize
	Avon (conversion)	5	✗	✓	✗	▪ Linked to Richards by LNG
Industry	Gas demand growth	7	✓	✓	✗	
	Fuel switching	21	✓	✓	✗	
Transport	Long Haul	14	✓	✓	✗	
	Public transport	22	✓	✓	✗	
		232	129	228	66	

1 Only considers incremental demand volume, assuming existing demand is met via existing infrastructure

EXHIBIT 61

BASE CASE SET UP FOR PIPELINE AND LNG ASSESSMENT



	Assumptions per trade method	
Dimension	**① Pipeline**	**② LNG**
Demand[2]	▪ Only incremental demand considered (existing demand assumed to utilize existing infrastructure) ▪ Up to 3000MW[4] of gas-to-power capacity and a further 670MW[5] of convertible Coal/OCGT is linked to LNG, and so would not be supplied by a pipeline ▪ ~181PJ[6] of Mozambique industrial demand is located in Cabo Delgado, and would not utilize the pipeline	▪ Only incremental demand considered (existing demand assumed to utilize existing infrastructure) ▪ Domestic Mozambique demand would not be supplied by LNG
Supply[3]	▪ Sufficient volumes available from the Rovuma basin to meet demand	▪ Sufficient volumes available from the Rovuma basin to meet demand
Infra-structure	▪ Pipeline of 2,500km in length, running onshore along the Mozambique coast from Rovuma down to Mpumalanga, with a flat postage stamp tariff[1] for off takers	▪ Gas liquefied at Mozambique LNG (MZLNG), and thereafter shipped to floating regasification terminal built at Richards Bay[7]

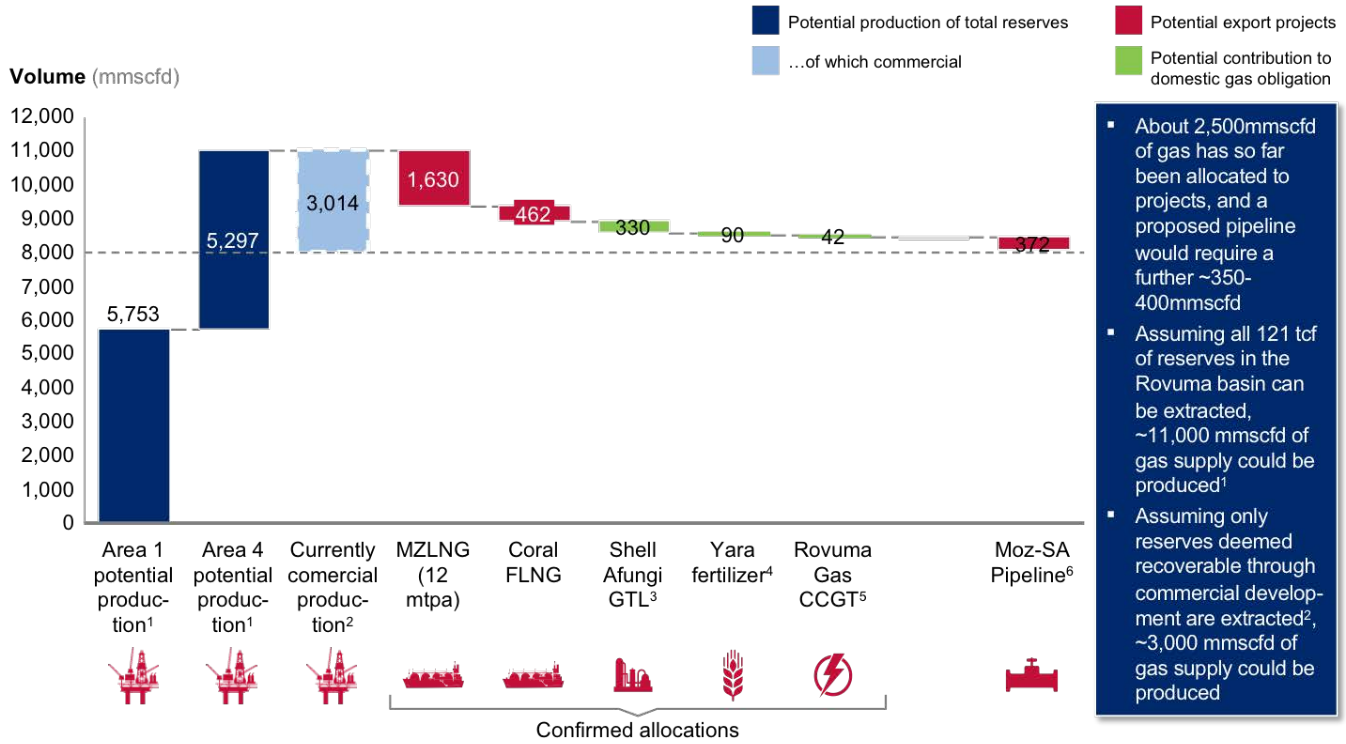
Objective of analysis:

- Performing a high level economic analysis to compare the two transport options for Mozambican gas to flow to South Africa
- Taking into account the various considerations and restrictions, we solve for a $/mmbtu transport tariff

1 Flat fee per unit of volume, regardless of distance
2 Volumes in consideration for each infrastructure option detailed in appendix
3 Although initial volumes for development might be locked-in into existing contracts, it is assumed other fields would have sufficient reserves to potentially supply South Africa if demand exists
4 2000MW LNG-to-power at Richards Bay, 1000MW LNG-to-power at Coega in the medium demand case
5 670MW Avon plant linked to Richards Bay LNG in the medium demand case
6 18PJ of gas-to-power from Rovuma Gas, Shell GTL and Yara Fertilizer, and 163PJ of industrial demand from Shell GTL and Yara Fertilizer all located in Cabo Delgado
7 This base case was selected over other options (e.g. Floating liquefaction units, onshore regasification terminals, and Coega/Saldanha Bay destinations) given their most favorable economics
SOURCE: Team analysis

EXHIBIT 62

ALLOCATED AND AVAILABLE ROVUMA BASIN PRODUCTION VOLUMES



- About 2,500mmscfd of gas has so far been allocated to projects, and a proposed pipeline would require a further ~350-400mmscfd
- Assuming all 121 tcf of reserves in the Rovuma basin can be extracted, ~11,000 mmscfd of gas supply could be produced[1]
- Assuming only reserves deemed recoverable through commercial development are extracted[2], ~3,000 mmscfd of gas supply could be produced

1 Area 1 reserves are estimated at 63tcf and Area 4 reserves at 58tcf. Annual production is calculated using a high level approach which assumes that remaining reserves are produced over 30 years (typical field life and most of fields are untapped yet), leading to a flat production profile

2 As per Wood MacKenzie definition of commercial reserves

3 Shell would need 310-330 mmscfd for its 38,000bpf GTL plant, and to produce 50 MW – 80 MW of power

4 Yara would need 80-90 mmscfd for its 1.3mtpa fertilizer plant, and to produce 30 MW – 50 MW of power

5 GTL Energy would need 42 mmscfd for 250 MW CCGT plant

6 Based on the medium case scenario where 149PJ/year of Mozambique and South African demand could be met via a pipeline

SOURCE: team analysis, http://clubofmozambique.com/news/shell-and-heineken-investing-in-mozambique/

EXHIBIT 63

SIMPLIFICATIONS IMPOSED WITHIN THE PIPELINE MODEL

Parameter	Current assumptions	Potential next step refinements
Tariff structure	▪ Flat tariff fee across the lifetime of the project (only adjusted for inflation, no pre-determined hikes)	▪ Apply refined tariff structure, e.g. a lower tariff in early stage to encourage usage with potential to increase tariff in later stage
Terminal value	▪ No terminal value (similar to "Buy, operate, transfer" (BOT) structure); ▪ Assumes O&M costs but no large sustain capex included	▪ Include terminal value, together with annual maintenance capex (e.g. 2% of upfront CAPEX annually) incurred to extend project lifetime
Depreci-ation	▪ Accelerated straight line depreciation, over 10 years (assuming this is the shortest allowed depreciation duration)	▪ Adjust depreciation plan structure to be more favorable (and based on actual tax regulations, e.g. front-loading)
Tax	▪ Flat tax fee, at Mozambican corporate tax rate, for project duration	▪ Include potential tax breaks and benefits granted by government

EXHIBIT 64

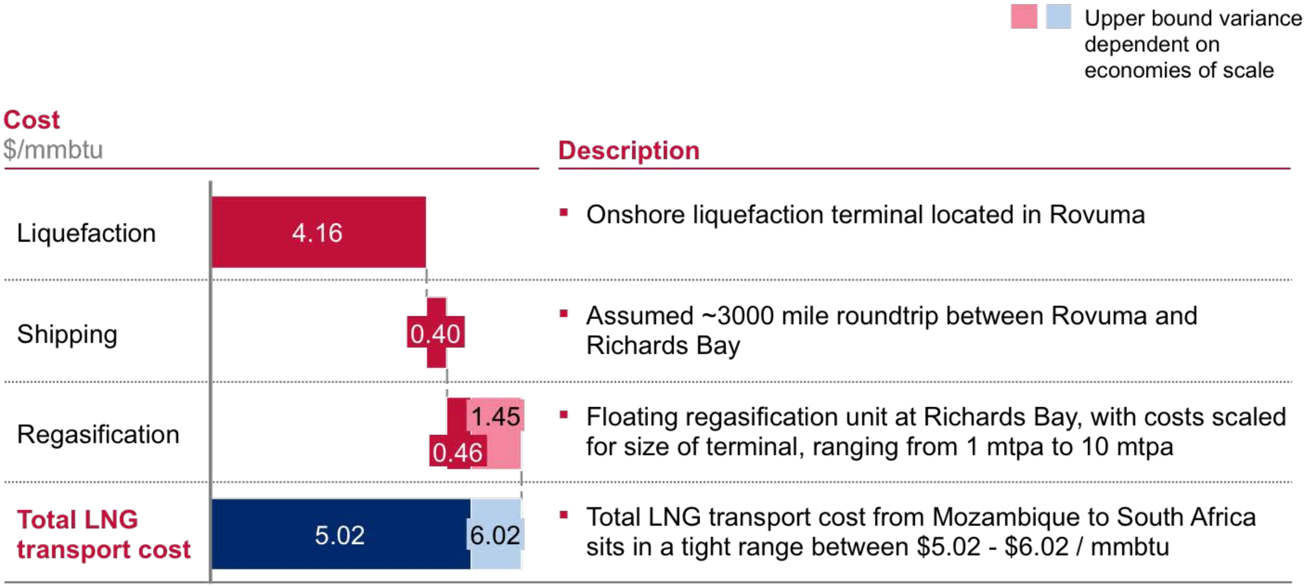
PIPELINE MODEL ASSUMPTIONS

Variable	Unit	Value	Rationale/Source
① Technical assumptions			
Volume	PJ/annum	Dependent on scenario	Sourced from demand model, accounting for incremental demand with potential to be supplied by pipeline
Pipeline diameter	Inches	Derived from volume	Pipeline rules of thumb
Pipeline length	Km	2500	~2000km with +25% allowance for curves and bends
Construction time	Years	3	McKinsey meta-analysis of comparable projects
Project lifespan	Years	30	Rule of thumb
② Cost assumptions			
Capex	$/inch mile	155,000	The Interstate Natural Gas Association of America Foundation (2016)
Fuel cost	$/mmbtu	2.84	ICF (2012)
Fuel burn	%	0.5% per 500miles	McKinsey meta-analysis of US pipeline tariffs
O&M	$/mmbtu	0.04	FERC Form 2 via ABB Energy Velocity
SG&A	$/mmbtu	0.015	FERC Form 2 via ABB Energy Velocity
③ Financial assumptions			
Share of debt	%	70	Assumed strong government backing, with preferential borrowing rates
Return of debt	%	6	
Share of equity	%	30	1- share off debt
Return on equity post tax	%	16	Assumed Mozambique investment premium
Tax rate	%	32	Mozambique corporate tax rate
Depreciation lifespan	Years	10	10% - 16.7% accelerated depreciation allowance in Mozambique

SOURCE: As indicated, with detailed calculations in model spreadsheet

EXHIBIT 65

LNG MODEL ASSUMPTIONS



Description

- Onshore liquefaction terminal located in Rovuma
- Assumed ~3000 mile roundtrip between Rovuma and Richards Bay
- Floating regasification unit at Richards Bay, with costs scaled for size of terminal, ranging from 1 mtpa to 10 mtpa
- Total LNG transport cost from Mozambique to South Africa sits in a tight range between $5.02 - $6.02 / mmbtu

Assumptions:

- Liquefaction costs are arguably fixed at any given level of South Africa offtake, given they are apportioned as part of a broader Mozambique LNG terminal cost base
- Shipping costs also have limited scope for scale economies, as increased volumes would simply require more frequent shipments of a standard vessel size (~170,000 cbm)

SOURCE: NERA Economic consulting – Macroeconomic impacts of LNG exports from the United States, Cedigaz, DoE Gas Based Industrialization in South Africa

EXHIBIT 66

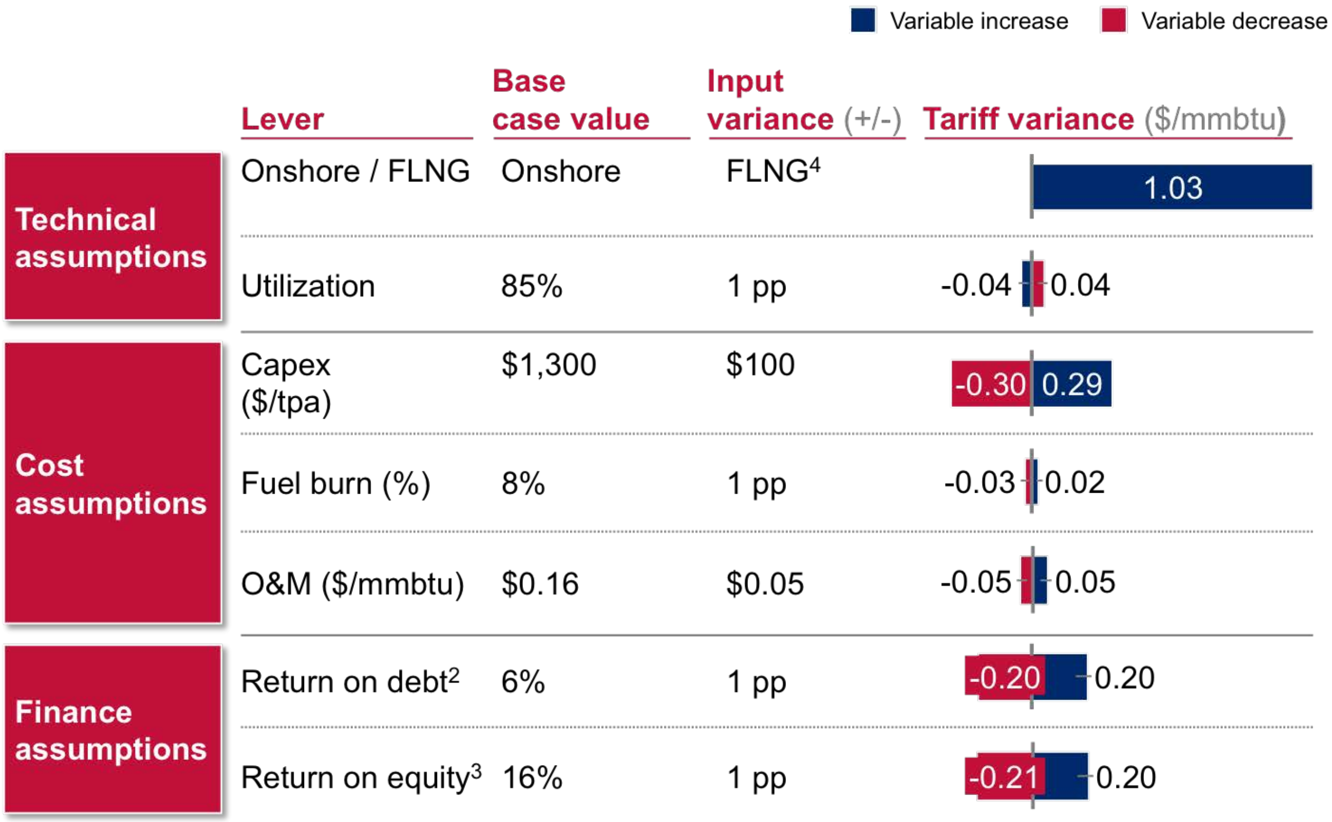
LNG LIQUEFACTION MODEL ASSUMPTIONS

Variable	Unit	Value	Rationale/Source
① Technical assumptions			
Plant type	Onshore / Floating	Variable	Base case assumption takes most economic case for trade, which is assessed to be an onshore terminal
Number of trains	Number	2	Modelled off MZLNG initial 2 x 6MTPA train economics
Capacity per train	MTPA	6	
Utilization	%	85	Globally ranges between 80-100%. 85% taken as the 5-year average (IEA, 2016)
Construction time	Years	5	Oxford Energy, PwC: 4-5 years post FID
Project lifespan	Years	25	Rule of thumb
② Cost assumptions			
Capex	$/tpa	1,300	Middle of the range estimate between $1,100-$1,500 (Oxford Energy)
Fuel cost	$/mmbtu	2.84	ICF (2012)
Fuel burn	%	8	Sources indicate between 6-10% depending on technology
O&M	$/mmbtu	0.16 for onshore 0.70 for FLNG	Nera (2012) Oxford Energy (2016)
③ Financial assumptions			
Share of debt	%	70	Assumed strong government backing, with preferential borrowing rates
Return of debt	%	6	
Share of equity	%	30	1- share off debt
Return on equity post tax	%	16	Assumed Mozambique investment premium
Tax rate	%	32	Mozambique corporate tax rate
Depreciation lifespan	Years	10	10% - 16.7% accelerated depreciation allowance in Mozambique

SOURCE: As indicated, with detailed calculations in model spreadsheet

EXHIBIT 67

LNG LIQUEFACTION MODEL SENSITIVITIES



🟦 Variable increase 🟥 Variable decrease

	Lever	Base case value	Input variance (+/-)	Tariff variance ($/mmbtu)
Technical assumptions	Onshore / FLNG	Onshore	FLNG[4]	1.03
	Utilization	85%	1 pp	-0.04 0.04
Cost assumptions	Capex ($/tpa)	$1,300	$100	-0.30 0.29
	Fuel burn (%)	8%	1 pp	-0.03 0.02
	O&M ($/mmbtu)	$0.16	$0.05	-0.05 0.05
Finance assumptions	Return on debt[2]	6%	1 pp	-0.20 0.20
	Return on equity[3]	16%	1 pp	-0.21 0.20

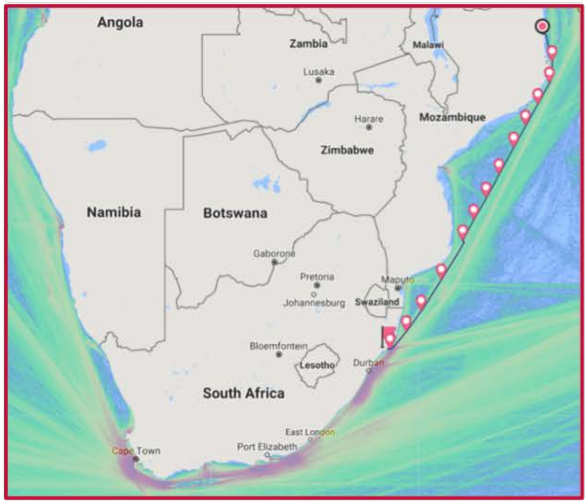
1 All variables pivoted around base case values: Onshore 2 x 6 mtpa terminal, 85% utilization, $1,375/tpa capex, 8% fuel burn, $0.17/mmbtu O&M, 6% return on debt, 16% return on equity
2 USD denominated interest rates
3 Defined as the post-tax leveraged return on equity
4 Assumes a single train 3.4MTPA FLNG terminal, with $1,400/tpa capex and $0.92/mmbtu opex costs

SOURCE: team analysis from LNG liquefaction model

EXHIBIT 68

LNG SHIPPING ASSUMPTIONS

Assumed shipping route (marinetraffic.com)



Variable	Value	Rationale/Source
① Technical assumptions		
Origin	Rovuma	Location of upstream gas and associated LNG terminals
Destination	Richards Bay	Shortest distance and demand concentration
Distance	~3000 miles	Based on ~2200NM roundtrip
Vessel size	170,000 cbm	Standard LNG vessel size
② Cost assumptions		
Capital cost	$0.13 / mmbtu	Drewry, 2017
Operating cost	$0.06 / mmbtu	
Voyage fees	$0.22 / mmbtu	
TOTAL	**$0.40 / mmbtu**	

SOURCE: As indicated, with detailed calculations in model spreadsheet

EXHIBIT 69

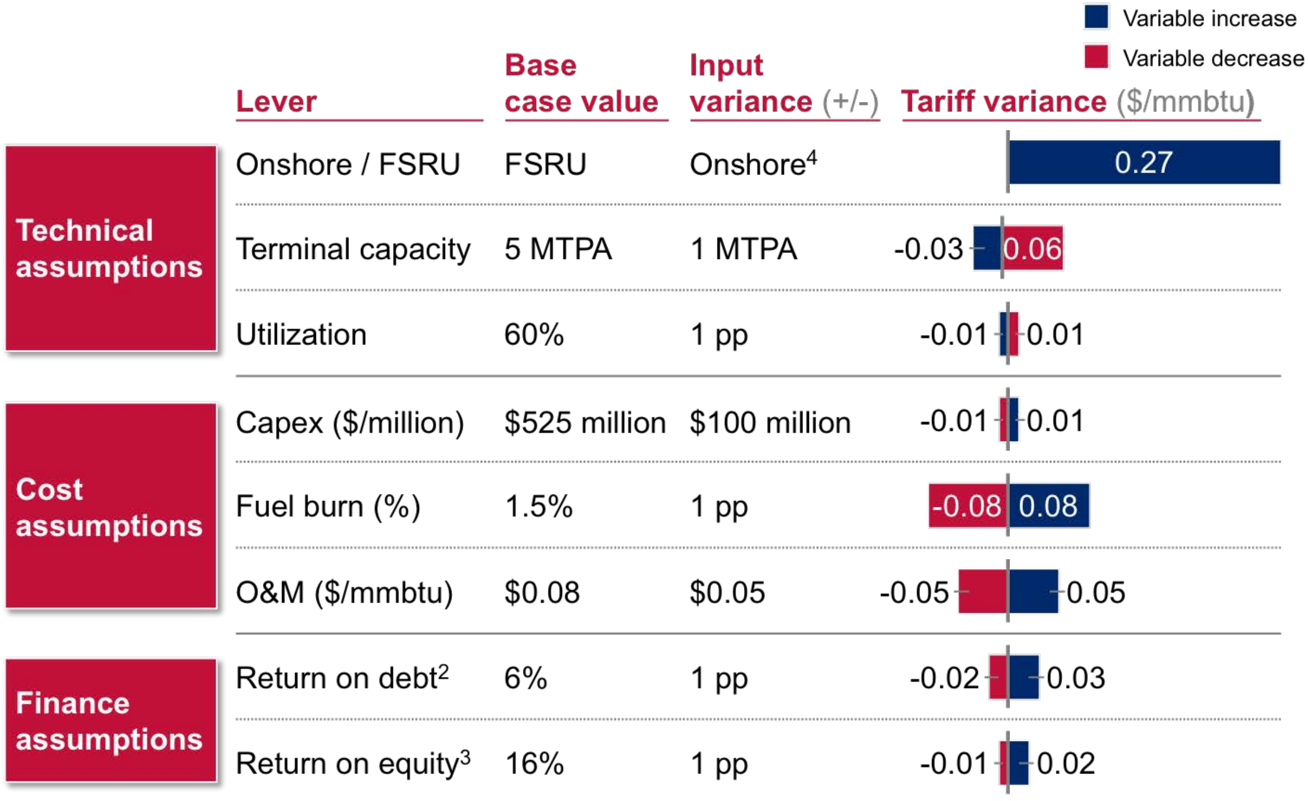
LNG REGASIFICATION MODEL ASSUMPTIONS

Variable	Unit	Value	Rationale/Source
① **Technical assumptions**			
Location	Various	Richards Bay	Base case assumption takes most economic case for trade and location of demand, which is assessed to be Richards Bay
Plant type	Onshore, FSRU	FSRU	Base case assumption takes most economic case for trade, which is assessed to be an FSRU terminal
Capacity	MTPA	Variable between 1-10	Dependent on demand scenario. Base case assumes 5MTPA for comparison with pipeline
Utilization	%	60	Globally ranges between 40-70%. 60% estimate taken given 48% LNG-to-power utilization, along with industrial and transport use
FX rate	USD/ZAR	14.43	Spot rate assumed at time of analysis (15/11/2017)
Construction time	Years	30	Simplified to ~36months: 36-42 months for onshore, 27-36 months for FSRU (Oxford Energy, 2017)
Project lifespan	Years	25	Rule of thumb
② **Cost assumptions**			
Capex	$/million	823 for onshore 525 for FSRU	Transnet LTPF 2017, with linear scaling for tank storage, regasification and compression units
Fuel cost	$/mmbtu	7.41	Upstream cost ($2.84) + liquefaction tariff ($4.17) + shipping ($0.40)
Fuel burn	%	1.5%	Use in vaporizers (Nera, 2012)
O&M	$/mmbtu	0.13 for onshore 0.08 for FSRU	Assumed 2.5% of capex cost (also quoted to be between $20,000 - $45,000 per day
③ **Financial assumptions**			
Share of debt	%	70	Assumed strong government backing, with preferential borrowing rates
Return of debt	%	6	
Share of equity	%	30	1- share off debt
Return on equity post tax	%	16	Assumed South Africa investment premium
Tax rate	%	28	South Africa corporate tax rate
Depreciation lifespan	Years	10	10% - 16.7% accelerated depreciation allowance in Mozambique

SOURCE: As indicated, with detailed calculations in model spreadsheet

EXHIBIT 70

LNG REGASIFICATION MODEL SENSITIVITIES



🟦 Variable increase

🟥 Variable decrease

	Lever	Base case value	Input variance (+/-)	Tariff variance ($/mmbtu)
Technical assumptions	Onshore / FSRU	FSRU	Onshore[4]	0.27
	Terminal capacity	5 MTPA	1 MTPA	-0.03 / 0.06
	Utilization	60%	1 pp	-0.01 / 0.01
Cost assumptions	Capex ($/million)	$525 million	$100 million	-0.01 / 0.01
	Fuel burn (%)	1.5%	1 pp	-0.08 / 0.08
	O&M ($/mmbtu)	$0.08	$0.05	-0.05 / 0.05
Finance assumptions	Return on debt[2]	6%	1 pp	-0.02 / 0.03
	Return on equity[3]	16%	1 pp	-0.01 / 0.02

[1] All variables pivoted around base case values: 5 MTPA FSRU facility, 60% utilization, $525million capex, 1.5% fuel burn, $0.08/mmbtu O&M, 6% return on debt, 16% return on equity

[2] USD denominated interest rates

[3] Defined as the post-tax leveraged return on equity

[4] Assumes a 5 MTPA, $823million onshore regasification terminal, with $0.13/mmbtu O&M costs

SOURCE: team analysis from LNG regasification model

EXHIBIT 71

BASE CASE SET UP FOR POWER TRANSMISSION ASSESSMENT

▨ Not evaluated in current analysis

Assumptions

Value chain stage	Pipeline transfer to South Africa, with domestic generation	Generation in Mozambique, with transmission to South Africa	Partial generation in both Mozambique and South Africa
1 Upstream gas	▪ Processed gas price of \$2.84/mmbtu[1]	▪ Processed gas price of \$2.84/mmbtu	▪ Processed gas price of \$2.84/mmbtu
2 Gas transfer to CCGT Plant	▪ Gas transferred via pipeline from Rovuma to Mpumalanga at a cost of \$4.69/mmbtu as per “Gas as a solid part of the energy mix” scenario	▪ N/A – CCGT plant assumed to be located near source in Cabo Delgado province	▪ Partial gas transfer to Mpumalanga via pipeline, with remaining gas kept locally for generation near source
3 CCGT power generation	▪ 2100MW CCGT plant, as defined by “Gas as a solid part of the energy mix” scenario requirement for South African (non-LNG) CCGT capacity ▪ Marginal Capex cost advantage assumed in South Africa	▪ 2100MW CCGT plant, as defined by “Gas as a solid part of the energy mix” scenario requirement for South African (non-LNG) CCGT capacity	▪ 2 x 1050MW CCGT plants, split between Mozambique and South Africa to meet “Gas as a solid part of the energy mix” scenario requirement
4 Power transmission to grid	▪ N/A – CCGT plant assumed to be located near existing grid connection in South Africa	▪ 2500km 500KV HVDC line, running from Cabo Delgado to Mpumalanga	▪ 2500km HV AC/DC line[2], allowing for offtake along route

1 \$2.09 gas upstream cost + \$0.75 costs for processing and local transportation *(ICF International, Towards a Mozambique Gas Master Plan, 2012)*
2 At 2,500km, this would be the world’s longest transmission line

SOURCE: Various sources (see appendix), amongst others ICF International, Lazard, Black and Veatch international)

EXHIBIT 72

TRANSMISSION MODEL ASSUMPTIONS

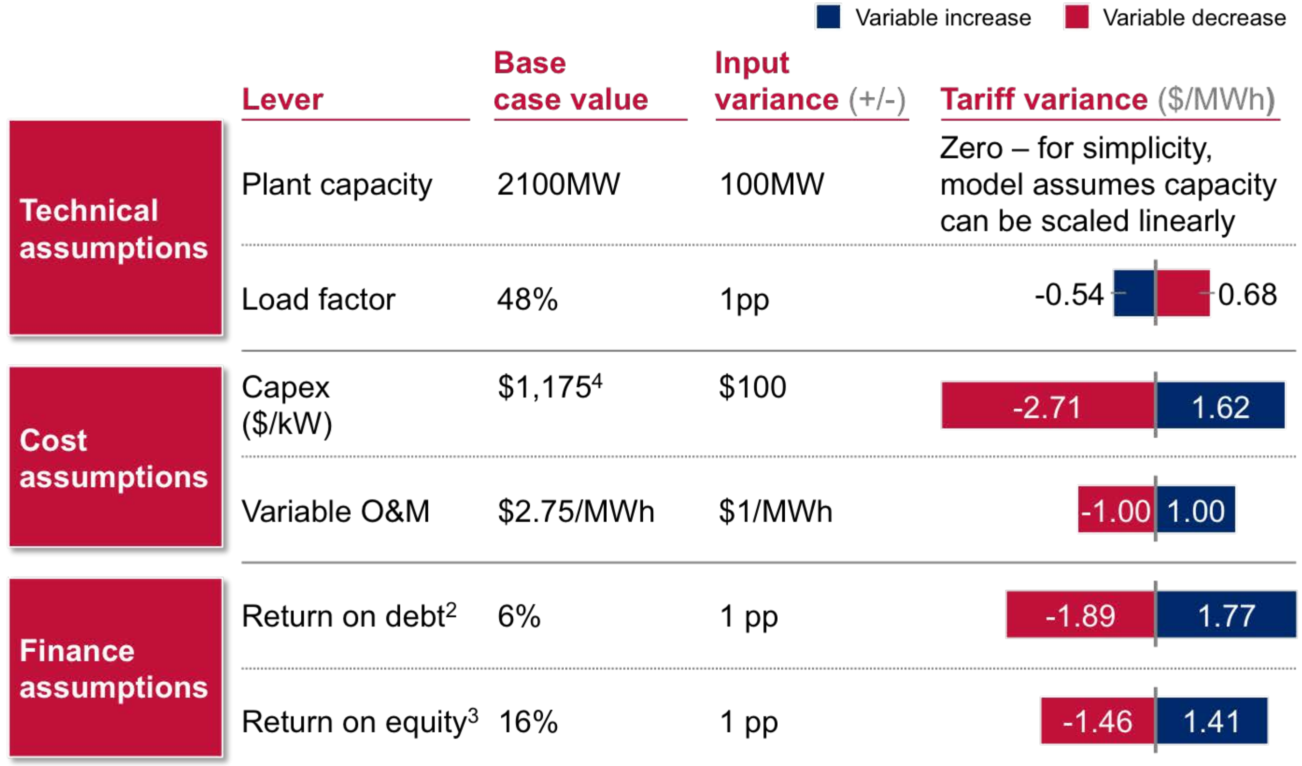
Variable	Unit	Value range	Rationale/Source
① **CCGT Power generation assumptions[1]**			
Plant capacity	MW	2100	Derived from base case scenario CCGT requriements
Capital costs	$/kW	1000 -1300	Middle of range estimate assumed for Mozambique, while lower range cost advantage assumed for South Africa
Fixed O&M	$/kW-yr	5.85	Lazard
Variable O&M	$/MWh	2.75	Lazard
Heat rate	Btu/kWh	6600	Lazard – implies efficiency of plant
Load factor	%	48	Based of IRP (revision 1) assumptions
Construction time	Years	3	Lazard
Lifespan	Years	30	Based of IRP (revision 1) assumptions
② **Power transmission line assumptions**			
Transmission Line	KV	500KV HVDC	Efficient lines required for long distances
Length	KM	2,500	~2000KM distance +25% for curves, and offshoots
Capex	$/mile	1,484,000	Black & Veatch
Substation cost (x2)	$	450,000,000	Black & Veatch
Power loss	%	12	Siemens HVDC Factsheet (2012)
O&M	$/km	15,000	McKinsey analysis of best-in-practice European examples
Construction time	Years	3	McKinsey analysis of similar projects
Project lifespan	Years	40	Rule of thumb
Depreciation lifespan	Years	10	10% - 16.7% accelerated depreciation allowance in Mozambique

[1] Based off Lazard's levelised cost of energy analysis - version 10.0 (2012)

Source: As indicated, Capital costs for transmission and substations - Recommendations for WECC (Black & Veatch Corporation), Lazard's levelised cost of energy analysis – version 10.0

EXHIBIT 73

CCGT MODEL SENSITIVITIES



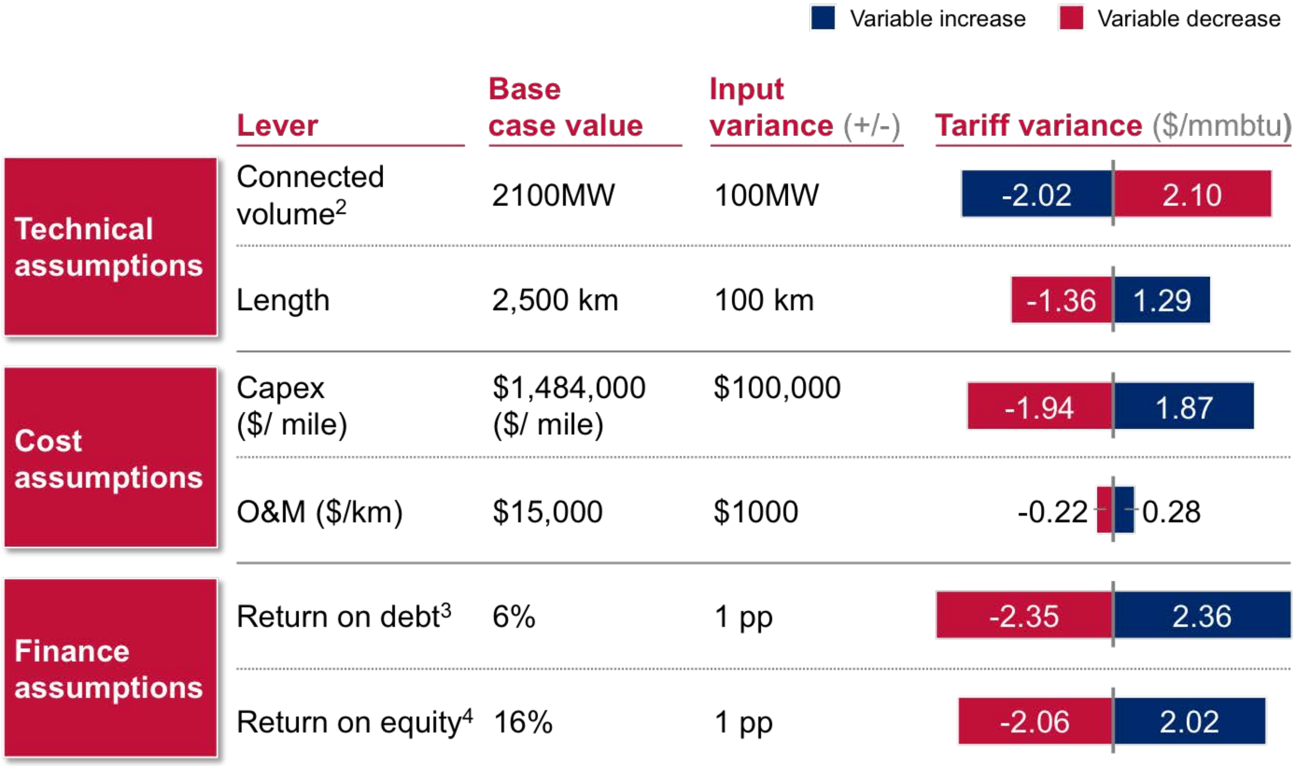
	Lever	Base case value	Input variance (+/-)	Tariff variance ($/MWh)
Technical assumptions	Plant capacity	2100MW	100MW	Zero – for simplicity, model assumes capacity can be scaled linearly
	Load factor	48%	1pp	-0.54 / 0.68
Cost assumptions	Capex ($/kW)	$1,175[4]	$100	-2.71 / 1.62
	Variable O&M	$2.75/MWh	$1/MWh	-1.00 / 1.00
Finance assumptions	Return on debt[2]	6%	1 pp	-1.89 / 1.77
	Return on equity[3]	16%	1 pp	-1.46 / 1.41

1 All variables pivoted around base case values: 2100MW capacity, 48% load factor, $1,175/KW capex, $2.75/MWh variable O&M, 6% return on debt, 16% return on equity
2 USD denominated interest rates
3 Defined as the post-tax leveraged return on equity
4 Assumed case for the Mozambique CCGT model. Small variances expected for the South African CCGT model

SOURCE: team analysis from CCGT model

EXHIBIT 74

TRANSMISSION LINE MODEL SENSITIVITIES



🟦 Variable increase 🟥 Variable decrease

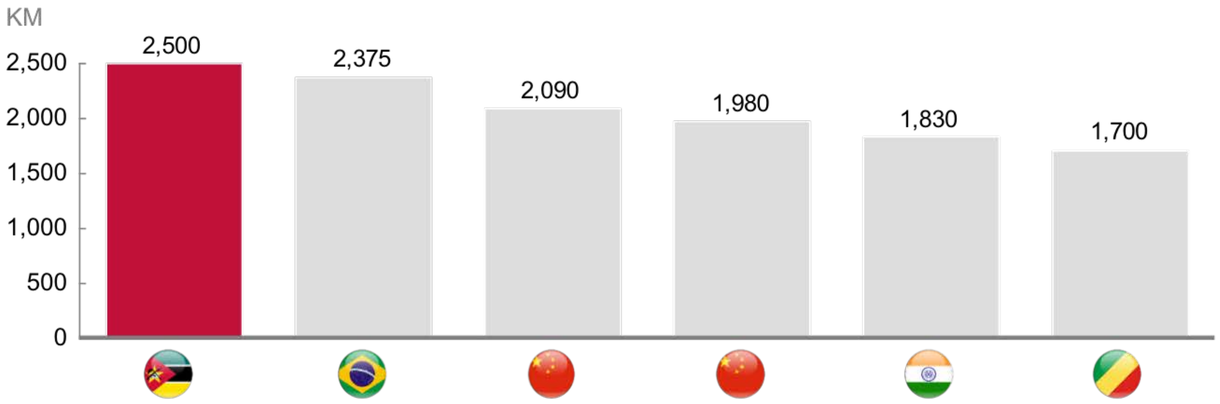
	Lever	Base case value	Input variance (+/-)	Tariff variance ($/mmbtu)
Technical assumptions	Connected volume[2]	2100MW	100MW	🟦 -2.02 🟥 2.10
	Length	2,500 km	100 km	🟥 -1.36 🟦 1.29
Cost assumptions	Capex ($/ mile)	$1,484,000 ($/ mile)	$100,000	🟥 -1.94 🟦 1.87
	O&M ($/km)	$15,000	$1000	-0.22 🟥 🟦 0.28
Finance assumptions	Return on debt[3]	6%	1 pp	🟥 -2.35 🟦 2.36
	Return on equity[4]	16%	1 pp	🟥 -2.06 🟦 2.02

1 All variables pivoted around base case values: 2100MW throughput, 2500KM length, $1,484,000//mile capex, $15,000/km opex, 6% return on debt, 16% return on equity
2 Based on a 48% load factor rate
3 USD denominated interest rates
4 Defined as the post-tax leveraged return on equity

SOURCE: team analysis from pipeline model

EXHIBIT 75

WORLD'S LONGEST TRANSMISSION LINES



Line name :	Cabo Delgado - Mpumalanga	Rio Madeira	Jinping-Sunan	Xiangjiaba-Shanghai	Raigarh-Pugalur (Planned)	Inga-Kolwezi
Country :	Mozambique/ SA	Brazil	China	China	India	Congo
Technical specification :	500kv	600kv HVDC	800kv UHVDC	800kv UHVDC	800kv UHVDC	500kv HVDC
Total cost :	-	-	3,500	-	-	1,254[1]
Cost/km :	-	-	1.675	-	-	0.73
Source :	-	Power technology	Power technology	Power technology	T&D World	US AID

[1] Cost is for line upgrade only

SOURCE: ABB, Power Technology, T&D World, US AID, team analysis

EXHIBIT 76

COST VARIATIONS FOR TRANSMISSION LINE MODELING

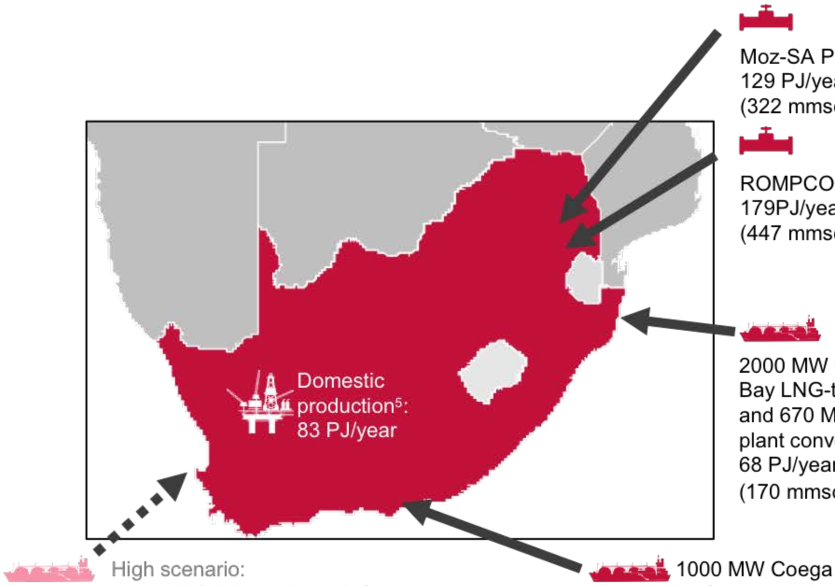
Line type	Capacity (mw)	Terrain	Source	Cost/mile ($m)	Total cost ($bn)
500kv double circuit[2]	~4,000	Forested land[1]	Black & Veatch	7,0	17.60
500kv HVDC	~2,000	Forested land[1]	Black & Veatch	3,7	9.25
500kv double circuit[2]	~4,000	Flat land	Black & Veatch	3,3	8.32
800kv HVDC	11,200	Generic	Amprion	2,4	5.90
500kv HVDC	4,000	Generic	Amprion	1,9	4.72
500kv HVDC	~2,000	Flat land	Black & Veatch	1,8[1]	4.61
800kv HVDC	4,000	Flat land	Technofi	1,4	3.55
500kv HVDC	3,000	Flat land	Technofi	0,7	1.87

1 2.25x multiplier applied to forested land
2 2x multiplier applied to double circuit
$1.5m/mile, plus 2 x $450m substation cost apportioned over 2500KM

SOURCE: As indicated

EXHIBIT 77

SUPPLY OPTIONS FOR SOUTH AFRICA IN THE MEDIUM SCENARIO



Moz-SA Pipeline[2]:
129 PJ/year
(322 mmscfd)

ROMPCO[3]:
179PJ/year
(447 mmscfd)

Domestic production[5]:
83 PJ/year

2000 MW Richards Bay LNG-to-power and 670 MW Avon plant conversion[4]:
68 PJ/year
(170 mmscfd)

High scenario:
800 MW Saldanha Bay LNG-to-power and 1350 MW Ankerlig plant conversion[6]:
36 PJ/year
(90 mmscfd)

1000 MW Coega LNG-to-power[4]:
31 PJ/year
(77 mmscfd)

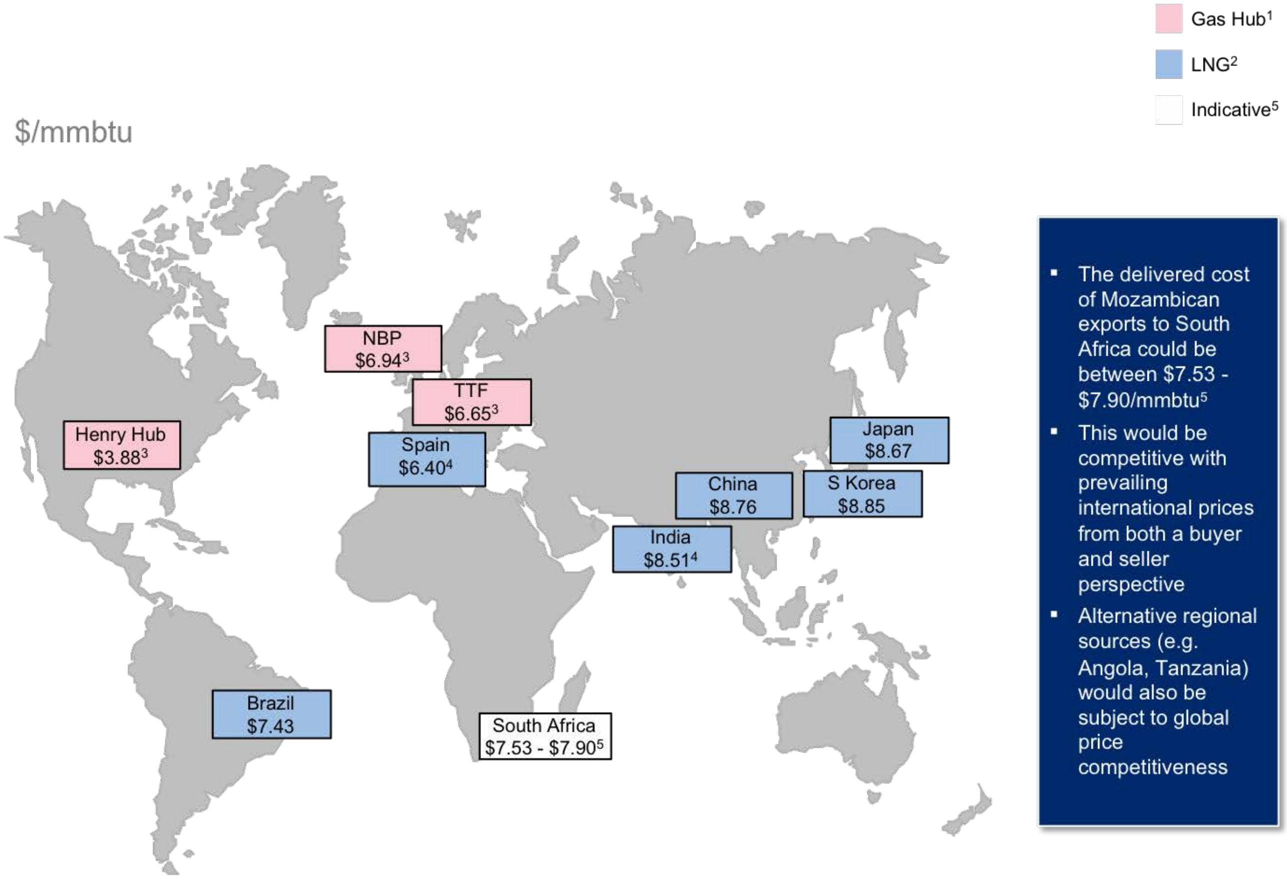
- Out of a planned 7.3 GW of CCGT capacity by 2030 set out in the IRP, 5.2 GW is assumed to materialize in the medium scenario
- Of this, 2.1 GW can be met by pipeline, while 3.0 GW is specifically dependent on LNG as a fuel source (equivalent to ~2mtpa of LNG)
- A proposed pipeline from Mozambique would not be able to serve coastal power demand

1 Based on the assumption that South Africa's medium demand scenario materializes
2 Adopted from the medium case scenario, where a pipeline could meet 129PJ/year of South African demand
3 ROMPCO pipeline deliveries to South Africa could deliver South Africa's remaining balance requirements, a volume that is similar to current throughput
4 Adopted from the medium case scenario, where global LNG imports could meet 99PJ of LNG-to-power commitments
5 Domestic production estimated based on high level approach which assumes that remaining reserves are produced over 30 years (typical field life and most of fields are untapped yet), leading to a flat production profile, which is converted into PJ/year

SOURCE: IEA Model of short-term energy security, European Commission Member States' Energy Dependence: An Indicator-Based Assessment

EXHIBIT 78

GLOBAL GAS AND LNG BENCHMARK PRICES



- The delivered cost of Mozambican exports to South Africa could be between $7.53 - $7.90/mmbtu[5]
- This would be competitive with prevailing international prices from both a buyer and seller perspective
- Alternative regional sources (e.g. Angola, Tanzania) would also be subject to global price competitiveness

1 Month average spot prices (Jan-18)
2 Month average landed LNG prices (i.e. price of LNG received at import terminal), plus an estimated $0.57/mmbtu for regasification based on model assumptions to give a delivered gas price
3 Prices as at Jan-18
4 Prices as at Nov-17
5 Gas delivered price from Mozambique, based on an upstream cost of $2.84/mmbtu plus $4.69 - $5.06/mmbtu for pipeline and LNG tariffs from the medium case demand scenario

SOURCE: The Future of Natural Gas in Mozambique: Towards a Gas Master Plan (ICF); Platts; Cedigaz

EXHIBIT 79

CONSIDERATIONS FOR SEASONAL DEMAND VARIATIONS

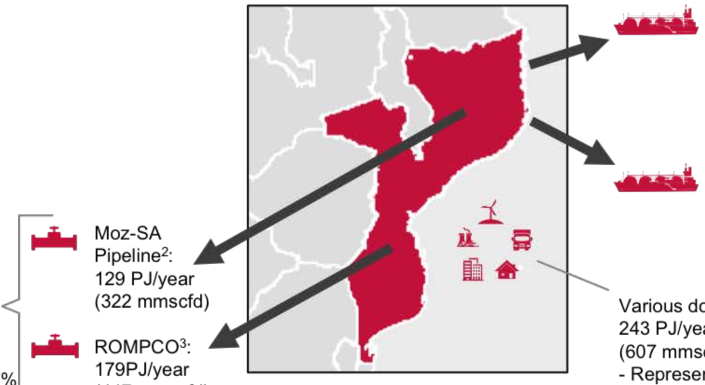
	Component	Base case capacity	Base case throughput	Peak demand throughput	Ability to accommodate seasonal variations
Upstream	**Upstream production**	Sufficient reserves exist for supply	149 PJ/year produced to supply pipeline	226 PJ/year to supply pipeline (see below)	✓ Not assessed, but ability to ramp-up and down to accommodate seasonality could be considered
Midstream	**24" pipeline**	160 PJ/year, assuming 100% utilization at standard compression rates	149 PJ/year, of which ▪ Power: 75 PJ/year[1] ▪ Transport: 38 PJ/year ▪ Industrial: 36 PJ/year	226 PJ/year, of which: ▪ Power: 152 PJ/year[2] ▪ Transport: 38 PJ/year[3] ▪ Industrial: 36 PJ/year[3]	✓ Peak demand volumes could be accommodated, but further analysis on additional capex (e.g. for additional compressor stations) is required
	5 MTPA LNG regasification terminal	272 PJ/year assuming 100% utilization	For comparison, same as pipeline assumptions above	For comparison, same as pipeline assumptions above	✓ Sufficient LNG regasification capacity to meet peak demand periods, with option for LNG storage
Downstream	**Storage facilities**	N/A	N/A	N/A	✓ Not assessed but storage options in depleted gas fields and/or mines could be considered

1 Made up of ~2100MW of South African CCGT capacity at 48% load factor, and 210MW of Mozambican CCGT capacity at 64% load factor
2 Peak gas-to-power demand calculated assuming CCGT units running at 100% load factor
3 Transport and industrial demand assumed to have negligible seasonality

EXHIBIT 80

ASSESSMENT OF MOZAMBIQUE'S GAS DEMAND DIVERSITY

Sources of Mozambique gas demand



MZLNG[4]:
653 PJ/year
(1,631 mmscfd)
- Represents 47% of total demand, or 57% of exports)

Coral FLNG[5]:
185 PJ/year
(462 mmscfd)
- Represents 13% of total demand, or 16% of exports)

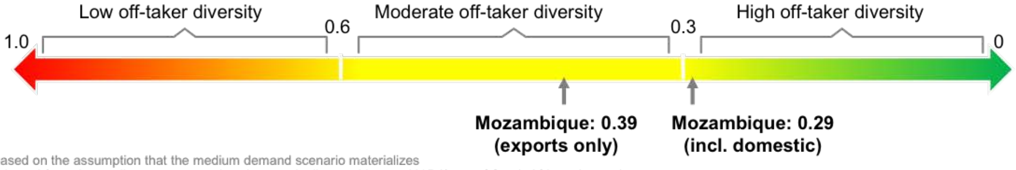
South Africa combined purchases:
308 PJ/year
(769 mmscfd)
- Represents 22% of total demand, or 27% of exports

Moz-SA Pipeline[2]:
129 PJ/year
(322 mmscfd)

ROMPCO[3]:
179PJ/year
(447 mmscfd)

Various domestic buyers[6]:
243 PJ/year
(607 mmscfd)
- Represents 17% of total demand

Diversity of natural gas off-take, HHI index[7]



- While a pipeline would further commit long-term gas supply to South Africa (in addition to ROMPCO gas supply), Mozambique could still have a moderate/high gas off-taker diversity according to the industry standard measure of off-taker concentration (HHI Index)

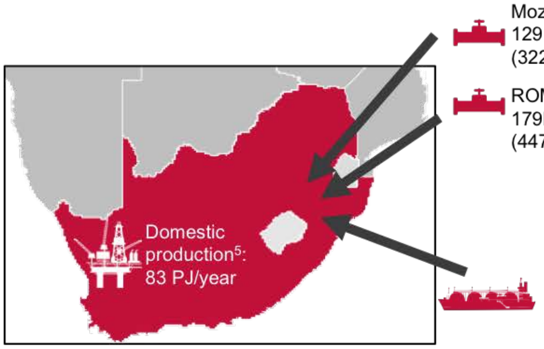
1 Based on the assumption that the medium demand scenario materializes
2 Adopted from the medium case scenario, where a pipeline could meet 129PJ/year of South African demand
3 ROMPCO pipeline deliveries to South Africa could deliver South Africa's remaining balance requirements, a volume that is similar to current throughput
4 12mtpa export terminal - taking a conservative approach to calculate buyer concentration, all volumes assumed to be bought by a single buyer
5 3.4mtpa export terminal – all volumes contracted to BP
6 As assessed in the medium scenario. Domestic buyers are further broken down into Shell Alfungi (132 PJ/year), Yara Fertilizer (36 PJ/year), Rovuma CCGT (17 PJ/year), existing demand (22 PJ/year) and other new incremental demand (36 PJ/year)
7 Herfindahl-Hirschman index, used as an industry standard measure of supply concentration.

SOURCE: IEA Model of short-term energy security, team analysis

EXHIBIT 81

ASSESSMENT OF SOUTH AFRICA'S GAS SUPPLY DIVERSITY

Sources of South Africa gas supply



Moz-SA Pipeline[2]:
129 PJ/year
(322 mmscfd)

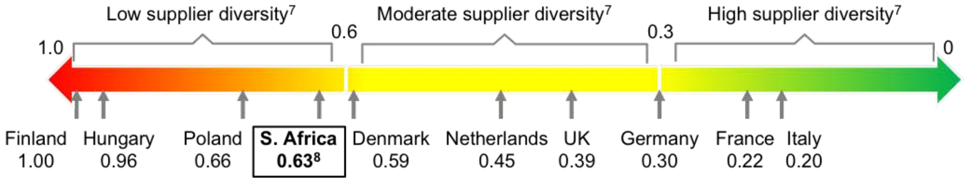
ROMPCO[3]:
179PJ/year
(447 mmscfd)

Mozambique sourced supply: 308 PJ/year (769 mmscfd)
- Represents 63% of total supply, or 75% of imports

LNG[4]:
99 PJ/year
(247 mmscfd)

Domestic production & LNG: 182 PJ/year (454 mmscfd)
- Represents 17% and 20% of total supplies respectively, and LNG @ 25% of imports

Diversity of natural gas supply, HHI index (2012)[6]



- An additional pipeline would require a commitment via long-term supply agreements, and lead to a moderate-to-low supplier diversity for South Africa
- Mozambique would have a moderate-to-high gas off-taker diversity under these assumptions (see back-up for details)

[1] Based on the assumption that South Africa's medium demand scenario materializes [2] Adopted from the medium case scenario, where a pipeline could meet 129PJ/year of South African demand
[3] ROMPCO pipeline deliveries to South Africa could deliver South Africa's remaining balance requirements, a volume that is similar to current throughput
[4] Adopted from the medium case scenario, where global LNG imports could meet 99PJ/year of LNG-to-power commitments through various import terminals
[5] Domestic production estimated based on high level approach which assumes that remaining reserves are produced over 30 years (typical field life and most of fields are untapped yet), leading to a flat production profile, which is converted into PJ/year [6] Herfindahl-Hirschman index, used as an industry standard measure of supply concentration. [7] Ranges defined by the IEA's model of short-term energy security [8] Assumes domestic supply is not included in the HHI calculation (as done for benchmarks, which only evaluate HHI for imports); if domestic supply is included, SA's gas supply HHI would be 0.46

SOURCE: IEA Model of short-term energy security; European Commission Member States' Energy Dependence: An Indicator-Based Assessment

EXHIBIT 82

SOUTH AFRICA REGULATORY OVERVIEW

Dimension	Details
Upstream regulatory framework established	▪ The Gas Act (48/2001) provides regulatory framework for the construction and operation of gas transmission, storage, distribution, liquefaction and re-gasification facilities, as well as gas trade ▪ Additionally other[1] petroleum and international trade regulations act as frameworks for gas regulation in South Africa ▪ The South African government is taking various efforts to refine gas regulations in the country and the roles of gas in South Africa's energy mix, which include: – **MPRDA[1] amendments**: Some issues on revision include "free[2] carried interest" and transfer of responsibilities from the Petroleum agency regional members of Dep. of Mineral Resource. Proposed amendments were not well received by all stakeholders, with some contesting with Parliament that proposed amendments would result in negative implications on the gas industry – **LNG IPP Programme** is ran by the DoE (first announced in 2016), with the aim of improving gas development in South Africa – A **revision of the Integrated Resource Plan** (IRP) is expected to clarify the role of gas in South Africa's energy mix. It is expected the revised IRP will be released at of 2017. CSIR suggests that contrary to the draft IRP findings, gas and renewables provide the most economical option for South Africa to generate power[3] – **A National Gas Infrastructure Development Plan** is being drafted to provide a blueprint for the development of an infrastructure framework for gas – Exploration of shale gas in South Africa is also on hold, pending finalisation of regulations governing shale gas development
Gas regulator assigned	▪ Gas regulatory functions are performed by the National Energy Regulator of South Africa (NERSA). NERSA is responsible to regulate the electricity, piped-gas and petroleum pipelines industries ▪ NERSA is also the competent licensing authority under the Petroleum Pipelines Act and the Gas Act
Domestic gas policies defined	▪ The South Africa Department of Energy is mandated to regulate tariffs applicable to the manufacturing, wholesaling and retailing of natural gas through the implementation of the Petroleum Products Act, 1977 ▪ The regulator (NERSA) may set the maximum prices for LNG and natural gas distributors, and all classes of consumers, where there is inadequate competition in the gas industry ▪ Prescriptive domestic gas prices were introduced in 2010 but only applicable to LPG
Enablers in place (Subsidies, Carbon tax laws, etc.)	▪ Income tax act of 1962 has favourable tax provisions for gas companies, e.g. companies may claim 100% uplift in respect of capital expenditure for exploration and 50% for post- exploration capital expenditure ▪ Another enabler, the Draft Carbon Tax Bill has faced delays. The Bill was released for public comment on the 2nd of November 2015. National Treasury had announced that the bill would be passed In early 2017, however had not been realised as at Dec 2017 ▪ Based on current available information, it is unclear if other enabling regulations/ decrees exist
Bilateral agreements in place	▪ South African government signed bilateral investment agreement including cross- boarder gas trade agreements Mozambique, in April 2001. A binational gas commission was also established to the oversee movement of gas between Mozambique and South Africa ▪ To facilitate trade of natural gas between Namibia and South Africa, a bilateral trade agreement between was signed on 1 August 2003

[1] The Mineral and Petroleum Resources Development Act (28/2002); The National Environmental Management Act (107/1999); The International Trade and Administration Act (71/2002); The Petroleum Products Act (120/1977); The Petroleum Pipelines Act (60/2003)

[2] The government will have "free carried interest" in all new exploration and production rights with option to acquire further interest or ownership

[3] http://www.energy.gov.za/files/esources/naturalgas/naturalgas_national.html

Source: Cliffe Dekker Hofmeyr, 2016 MiningMx, 2017; Department of Energy Web site; Norton Rose Fulbright, 2016; Interviews with US missions in South Africa

EXHIBIT 83

MOZAMBIQUE REGULATORY OVERVIEW

Dimension	Details
Upstream regulatory framework established	▪ Mozambique's gas regulatory framework is predominantly covered by other petroleum and energy regulations[1]. These provide guidelines mainly on upstream development of gas fields. Other mining concession responsibilities are handled by MIREME/INAMI under the terms of the Mining Law 20 of 2014 ▪ In 2014 New Petroleum Law and Petroleum Tax Laws were passed, details of which were only published in 2015. However, the new laws were drafted when gas prices were high and they focused on increasing Mozambique's share of benefits – resulting in less favourable terms for investors. These are yet to be reviewed to take into consideration new dynamics of gas market, e.g. lower gas prices & growing LNG market (Shearman, 2016) ▪ The updated act gives clarity to areas of previous concern including concessions, listing requirements on Mozambican stock exchange, infrastructure concession and training/hiring of local workforce ▪ These new laws however only affect new concessions and do not affect Rovuma area 1 and 4 which remain subject to the Decree Law no 2/2014 under a grandfathering clause
Gas regulator assigned	▪ A new energy regulator (ARENE[2]) was established in May 2017. It is primarily focused on the downstream gas regulatory framework and is responsible for the regulation of the distribution, transport, storage and sale of natural gas at pressures equal to or less than 16 bar, including the issuing & managing of concessions and licences this this regard ▪ Mozambique's National Petroleum Institute (INP) is responsible for managing exploration, production and transport concessions for petroleum products in accordance with Decree 25 of 2005. Thus this might be overlapping slightly with ARENE's responsibilities ▪ Another regulatory body to be considered is the High Authority for the Extractive Industry (AAIE) first envisioned in the Petroleum Law. AAIE has not yet been established, while details of its roles and responsibilities are still being defined. In September 2017, MIREME released an RfP for consultants to assist with detailing AAIE's responsibilities[3]
Domestic gas policies defined (share of volume, pricing principles, etc.)	▪ The New Petroleum law give clarity on certain domestic issues, such as domestic gas obligation clauses (25%+ to be agreed exactly per concession), however overall domestic policies have not been defined, e.g. terms of sales set by government in accordance to "market terms", which is not entirely clear ▪ All natural gas sales are to be done through state owned oil company Empresa Nacional de Hidrocarbonetos (ENH) ▪ A national content law is being drafted to clarify uncertainties around local content requirements for the gas industry, e.g. local company registration, local supplier contracts, etc. This has lead to several questions from the industry which are still to be addressed
Enablers in place (Subsidies, Carbon tax laws, etc.)	▪ Gas projects in Mozambique are normally subjected to 6% royalty rate, however on an agreement basis this can be reduced for the first 10 years to up to 2%. This is e.g. part of the Decree law under the Unitization and Unit Operating Agreement (UUOA) for Anadarko Petroleum Corporation (APC) and Eni SpA development in 2014 ▪ Based on current available information, it is unclear if other enabling regulations/ Decrees exist
Bilateral agreements in place	▪ Mozambique has previously signed bilateral investment agreement for cross-border gas trade with South African government in April 2001 The agreement included the extraction of natural gas from Mozambique and construction of cross-border transmission pipelines ▪ Mozambique currently supplies gas to Secunda, South Africa through the ROMPCO pipeline from Mozambique's Pande/Temane gas fields

[1] Law (2001) and regulations on Petroleum Operations (2004); Regulation on import, sale and distribution of petroleum products (2012); Tax Benefits for Mining and Petroleum (2007); Regulation of Employment of the Foreign Citizens in the Petroleum and Mining sector (2011), Energy Policy 1998 etc.

[2] Energy Regulatory Authority

[3] https://zitamar.com/consultants-wanted-help-establish-mozambique-extractive-industry-regulator/ ; https://gettingthedealthrough.com/area/24/jurisdiction/137/oil-regulation-mozambique/

Source : Getting The Deal through: Mozambique Petroleum; Sherman & Sterling (1/04/2016); infomercatiesteri (29/12/2014) Mozambique Publishes Law Enabling; ZITAMR, 2017; Interviews with US missions in Mozambique; selected interviews

EXHIBIT 84

NAMIBIA REGULATORY OVERVIEW

Dimension	Details
Upstream regulatory framework established	▪ Gas regulatory framework in Namibia is predominantly guided by the Petroleum Exploration and Production (Act 2 of 1991) and the Petroleum Products and Energy Act (14 of 1993) ▪ Other legislation to be considered include amongst other the Water Act 54 of 1956, Environmental Management Act 7 of 2007 and Prevention and combating of pollution of the Sea by Oil Act 6 of 1981 ▪ According to Africa Business Insights, upstream gas regulations in Namibia are amongst the most favourable In Africa
Gas regulator assigned	▪ Gas regulatory functions are performed by the Petroleum Commissioner and the Chief Inspector of Petroleum Affairs under the governance of the Minister of Mines and Energy ▪ No dedicated gas regulator has been established to date
Domestic gas policies defined (share of volume, pricing principles, etc.)	▪ Downstream gas industry is self regulated (downstream gas regulations related to distribution or transportation of natural gas, LNG facilities or domestic gas prices are still to be established) ▪ The Gas Bill has been under development since 2001. It is anticipated that the bill will bring a lot of clarity to downstream gas regulation, however the bill has not yet been adopted
Enablers in place (Subsidies, Carbon tax laws, etc.)	▪ In 2015 Namibia was ranked first in Africa for gas investment, by Lobal Petroleum Survey's Policy Perception Index. This was highly driven by incentives Namibia offers gas investors which include VAT waiver incentives and other tax advantages oil and gas companies (in combination with relatively low royalties of 5% across board)
Bilateral agreements in place	▪ The Petroleum Act makes no provision for cross-boarder trade of natural gas ▪ However case by case agreements have been signed, e.g. a gas trade agreement between South Africa and Namibia was signed by in August 2003, to facilitate gas trade between the countries

Source: Africa Business Insight, 2016 International Comparative Legal guide, 2017;Interviews with US missions in Namibia

EXHIBIT 85

BOTSWANA REGULATORY OVERVIEW

Dimension	Details
Upstream regulatory framework established	▪ Botswana's upstream gas regulations are mainly addressed by the Mines and Minerals Act ▪ Interfax Energy highlighted that sentiments were raised the Mines and Minerals Act had been developed for hard minerals and found it may be less capable of dealing with gas or CBM (Interfax Global Energy, 2016)
Gas regulator assigned	▪ The Botswana Energy Regulatory Authority (BERA), was established by an Act of Parliament No 13 of 2016 as a corporate body, to be responsible primarily for economic regulation of the country's energy supply sector; BERA is also responsible for gas regulations
Domestic gas policies defined (share of volume, pricing principles, etc.)	▪ No explicit policies defined, given that establishment of BERA is fairly new and has been primarily focus on downstream energy sector ▪ Absence of gas association has not been helpful in advancing the gas regulatory sphere
Enablers in place (Subsidies, Carbon tax laws, etc.)	▪ Based on currently available information, Botswana does not have direct incentives for gas development in the country
Bilateral agreements in place	▪ Unclear based on current information available

Source: Interfax Global Energy, 2016; ESI Africa 2017; Interviews with US missions in Botswana

DISCLAIMER

Power Africa is a U.S. Government-led initiative comprised of 12 U.S. Government Departments and Agencies, over 130 private sector companies, and 16 bilateral and multilateral development partners. Launched in 2013, Power Africa's goals are to increase electricity access in sub-Saharan Africa by adding more than 30,000 megawatts of electricity generation capacity and 60 million new home and business connections. The Power Africa Coordinator's Office uses a USAID-led model to integrate the 12 U.S. Government Departments and Agencies into a one-stop-shop to remove barriers that impede energy development in sub-Saharan Africa and to unlock the substantial natural gas, wind, solar, hydropower, biomass, and geothermal resources on the continent. To date, Power Africa has leveraged over $50 billion in commitments from the public and private sectors, including more than $40 billion in commitments from the private sector.

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