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TANZANIA

OIL AND GAS REPORT

INCLUDES 10-YEAR FORECASTS TO 2025

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Tanzania Oil and Gas Report Q4 2016

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BMI Industry View

BMI View: *Tanzania continues to be an attractive prospect for investment, as a result of its gas-rich offshore resources. A 'lower-for-longer' oil price scenario and sustained downward pressure on LNG prices pose risks to FID on Tanzania's LNG export project. Continued fiscal and regulatory uncertainties are also a threat and could push first exports beyond our 10-year forecast period. Without the project, it is unlikely that a significant portion of the country's offshore assets will be developed in the near or medium term. Consumption growth looks strong for both refined fuels and gas, albeit from a comparatively low base. Gas consumption will be met domestically, but a lack of refining capacity will see an increased reliance on imported fuels.*

Table: Headline Forecasts (Tanzania 2014-2020)

	2014	2015e	2016f	2017f	2018f	2019f	2020f
Crude, NGPL & other liquids prod, 000b/d	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Refined products production, 000b/d	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Refined products consumption & ethanol, 000b/d	52.0	56.3	60.6	65.3	70.3	75.4	80.8
Dry natural gas production, bcm	1.0	1.5	1.8	2.0	2.2	2.3	2.5
Dry natural gas consumption, bcm	1.0	1.5	1.8	2.0	2.2	2.3	2.5
Brent, USD/bbl	99.50	53.60	46.50	57.00	62.00	65.00	71.00

e/f = BMI estimate/forecast. Source: National Sources/BMI

Latest Updates and Key Forecasts

- Ongoing uncertainty regarding the country's oil and gas regulations remains a key hurdle for investors, despite significant offshore gas resources. Based on the new model production sharing agreement, companies may expect higher taxation, an expanded role for the state and more stringent local content mandates.
- The **Tanzanian Petroleum Development Corporation** has extended **Aminexs'** Mtwara licence by one year. The company plans to drill the Ntorya-2 appraisal well over this time period, followed by an application for a 25-year development licence if drilling proves positive.
- After minor delays, **Aminex** announced that production began at the Kilwani North field in early April 2016. The company believes that optimal production rates will be around 30mmcf per day.
- As of September, Tanzania will adopt the bulk procurement system for the import of liquefied petroleum gas (LPG). Bulk procurement was brought in to make the importat of petroleum products easier, help regulate prices and promote efficiency in the sector.

- Major gas discoveries offer significant upside to the country's gas production outlook. However, delays to final investment decision (FID) on the LNG export terminal may push back first production outside our 10-year forecast period. Progress over the site for the LNG export facility in early 2016, however, is a modestly positive sign for project partners as they can now begin pre-FEED activities.

- Although domestic oil and gas consumption is relatively limited, consumption is set for strong growth across our forecast period, supported by an expanding population and economic development. Oil consumption continues to outstrip gas, although development of the country's substantial gas resources could tip the balance, as the power sector reorients its generating capacity.

- Development of the Tanzanian downstream will remain heavily constrained by a small domestic market, low level of infrastructure, poor regional connectivity and domestic fuel price caps.

SWOT

Oil & Gas SWOT

Tanzania Oil & Gas SWOT

Strengths	▪ Strong prospectivity offshore. ▪ Substantial underexplored acreage. ▪ Well positioned to tap lucrative Asian export markets.
Weaknesses	▪ Lack of physical infrastructure. ▪ Uncertain regulatory environment.
Opportunities	▪ Several major discoveries moving to the development stage. ▪ Ongoing exploration both onshore and off.
Threats	▪ Ongoing uncertainty regarding the country's oil and gas laws is dampening the appetite for investment and slowing project development. ▪ Fall in crude prices and increased saturation of global LNG markets is undercutting the value of prospective gas exports.

Industry Forecast

Upstream Exploration

***BMI View:** Steady investment into exploration and a string of major discoveries will likely lead to significant reserves growth in the coming years. An uncertain regulatory environment and global headwinds, however, may dampen interest in the country over the longer term.*

Latest Updates

- **Dodsal Group** announced in March 2016 that it made the country's largest onshore natural gas discovery in the Ruvu Basin coastal region. The company estimates that the deposit contains approximately 76.4 bcm, an upwards revision of its previous estimate of 61.44 bcm. Dodsal has committed to invest USD300mn in exploration over the next year.

- The **Tanzanian Petroleum Development Corporation** has extended **Aminexs'** Mtwara licence a one year extension. The company plans to drill the Ntorya-2 appraisal well over this time period, followed by an application for a 25-year development licence if drilling proves positive.

- **Motor Oil** has in principle reached an agreement for 25% participating interest with **Otto Energy** in the Kilosa-Kilombero License which lies onshore. Furthermore, **Swala Energy** has confirmed its plan to drill an exploration well targeting the Kito prospect on the Kilosa-Kilombero block. The announced spud date is September 2016.

- **ION Geophysical Corporation** has been awarded a seismic data acquisition study by the TPDC. The study covers 4,058km of 2D seismic, gravity and magnetic data in blocks 4/1B and 4/1C in the offshore Rovuma Delta area.

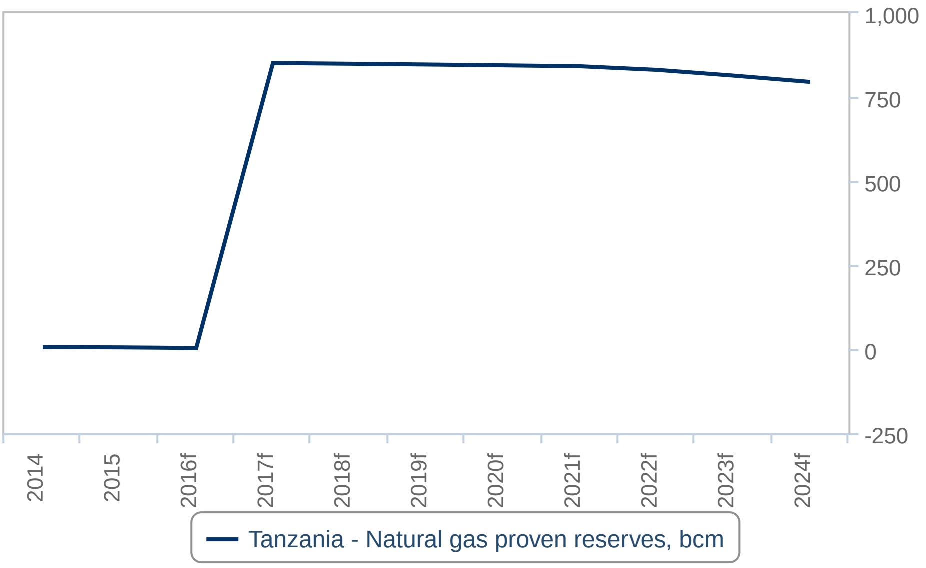
Structural Trends

Offshore Exploration

A strong exploration trend and string of major discoveries offshore will see significant reserves growth over the coming years. A number of industry majors are set to book reserves, including **BG Group** (**Shell**) and **Ophir Energy** in Blocks 1, 3 and 4. Estimates put combined recoverable resources at around 485bn cubic metres (bcm). In Block 2, **Statoil** has made a total of eight discoveries, with the most recent discovery bringing total gas-in-place to above 620bcm; recoverable resource estimates range from between 250-400bcm.

Exploration Yielding Major Results

Tanzania Proved Gas Reserves Forecast



f = BMI forecast. Source: EIA, BMI

Despite strong prospectivity below ground, an unsettled regulatory environment threatens to deter investment in exploration over the longer term, despite the passing of the Petroleum Act in 2015. Bids received from Tanzania's fourth deepwater round in 2013 bids remain under evaluation by the **Tanzanian Petroleum Development Corporation**. The round received only five bids for four of the eight blocks tendered. The blocks initially offered included seven deep-sea offshore blocks and one block in Lake Tanganyika.

An attractive fiscal and licensing regime will grow in importance as the industry moves into a period of sustained lower oil prices. We forecast the benchmark Brent crude to average below USD75 per barrel (/bbl) over the next five years, curbing revenues and imposing tighter fiscal discipline on major industry players. Therefore, layers of fiscal uncertainty and a large role for the Tanzanian state may weigh on the country's overall attractiveness.

Highly prospective acreage and the more proven nature of the basins will help draw continued investment into the Tanzanian offshore. However, the sustained fall in the Brent oil price and the emergence of a looser global gas market will continue to place downward pressure on the price of liquefied natural gas (LNG). This will result in a reduction in the potential returns on the development of Tanzania's substantial gas resource base. High exploration and development costs and long project lead times will also weigh heavily to the downside, and more attractive fiscal and licensing terms may be needed to buoy interest in expensive deepwater drilling campaigns.

Onshore Exploration

In March, Dubai-based **Dodsal Group** announced the country's largest onshore oil discovery in the Ruvu Basin coast region. The company estimates that the deposit holds 76.4bcm with an estimated value of approximately USD8 billion. An additional USD300 million will be invested into the discovery as a result.

Additional smaller players have also conducted initial exploration work on an onshore block bordering Tanzania's Lake Tanganyika. For example, a December 2013 independent assessment of Swala Energy and **Otto Energy**'s onshore Kito prospect found the area holds gross unrisked prospective resources of 151mn bbl of oil. Swala has plans to spud a well on the prospect in September 2016. **Solo Oil** has also been active in the onshore Rovuma PSC. In December 2014, the company updated its resource estimate for the concession from 59bcm to 91bcm of gas initially in place, based on the results of a 2D seismic acquisition programme. The company also points to the possibility of a liquids play in the area, with oil and condensate shows at the Likonde-1 and Ntorya-1 wells.

However, while inland Tanzania may offer lower entry costs, the lower potential rewards will dissuade larger players from shifting their offshore focus. As such, we see onshore activity remain dominated by the smaller independents.

Upstream Projects

Table: Tanzania Major Upstream Projects

Name	Field Name	Companies	Status	Est. Peak Liquids Output (b/d)	Est. Peak Gas Output (bcm)	Type of Project
Kito Prospect, Kilosa-Kilombero	Kito Prospect	Swala Energy (50%), Otto Energy (50%)	Exploration	-	-	Oil & Gas
Pangani	Pangani	Swala Energy (50%), Otto Energy (50%)	Exploration	-	-	Oil & Gas
Ntorya, Ruvuma Basin	Ntorya	Aminex (75%), Solo Oil Plc (25%)	Appraisal	-	-	Oil & Gas
Block 1	Taachui	BG Group (60%), Pavilion Energy Resources (20%), Ophir Energy (20%)	Discovery	-	-	Gas
Block 2	Block 2	Statoil (65%), ExxonMobil (35%)	Appraisal	-	-	Natural Gas
Block 4	Chewa	BG Group (60%), Pavilion Energy Resources (20%), Ophir Energy (20%)	Exploration	-	-	Oil & Gas
Block 3	Block 3	Pavilion Energy Resources (20%), Ophir Energy (80%)	Exploration	-	-	Gas
Block 1	Mzia	BG Group (60%), Pavilion Energy Resources (20%), Ophir Energy (20%)	Appraisal	-	-	Gas
Likonde	Likonde	Aminex	Exploration	-	-	Oil & Gas
Mnazi Bay Concession	Mnazi Bay	Tanzania Petroleum Development Corporation (TPDC) (20%), Maurel & Prom (48.06%), Wentworth (31.94%)	Development	-	1.3	Natural Gas
Block 4, Rovuma Basin	Kamba	BG Group (60%), Pavilion Energy Resources (20%), Ophir Energy (20%)	Discovery	-	-	Gas
Kiliwani North	Kiliwani North	Solo Oil Plc (6.5%), Aminex (58.5%), Bounty Oil & Gas NL (10%), RAK Petroleum (25%)	Production		0.0009	Gas
Block 7	Mkuki	Mubadala Petroleum (20%), Ophir Energy (80%)	Exploration	-	-	Oil & Gas
East Pande licence	Tende	Ras Al Khaimah Gas (RAKGAS) (30%), Ophir Energy (70%)	Exploration	-	-	Oil & Gas
Block 1	Chaza	BG Group (60%), Pavilion Energy	Discovery	-	-	Natural Gas

Tanzania Major Upstream Projects - Continued

Name	Field Name	Companies	Status	Est. Peak Liquids Output (b/d)	Est. Peak Gas Output (bcm)	Type of Project
		Resources (20%), Ophir Energy (20%)				
Block 1	Jodari	BG Group (60%), Pavilion Energy Resources (20%), Ophir Energy (20%)	Appraisal	-	-	Gas
Block 1	Mkizi	BG Group (60%), Pavilion Energy Resources (20%), Ophir Energy (20%)	Discovery	-	-	Gas
Block 4	Ngisi	BG Group (60%), Pavilion Energy Resources (20%), Ophir Energy (20%)	Discovery	-	-	Gas
Block 4	Pweza	BG Group (60%), Pavilion Energy Resources (20%), Ophir Energy (20%)	Appraisal	-	-	Gas
Songo Songo	Songo Songo	Orca Exploration (100%)	Expansion	-	1.9	Natural Gas
Lake Tanganyika South (LTS) block	Lake Tanganyika South (LTS) block	Beach Energy (30%), Woodside Petroleum (70%)	Exploration	-	-	Oil & Gas
Block Rukwa South, Rukwa Rift Basin	Block Rukwa South	Heritage Oil (100%)	Exploration	-	-	Oil & Gas
Block Kyela, Lake Nyasa Basin	Block Kyela	Heritage Oil (100%)	Exploration	-	-	Oil & Gas

Source: BMI Upstream Projects Database

Upstream Production - Gas

BMI View: *Tanzania currently produces small volumes of gas, and while we have seen some increased production from existing fields and progress in bringing others online, more substantial growth in output is unlikely to occur until closer to the end of our forecast period.*

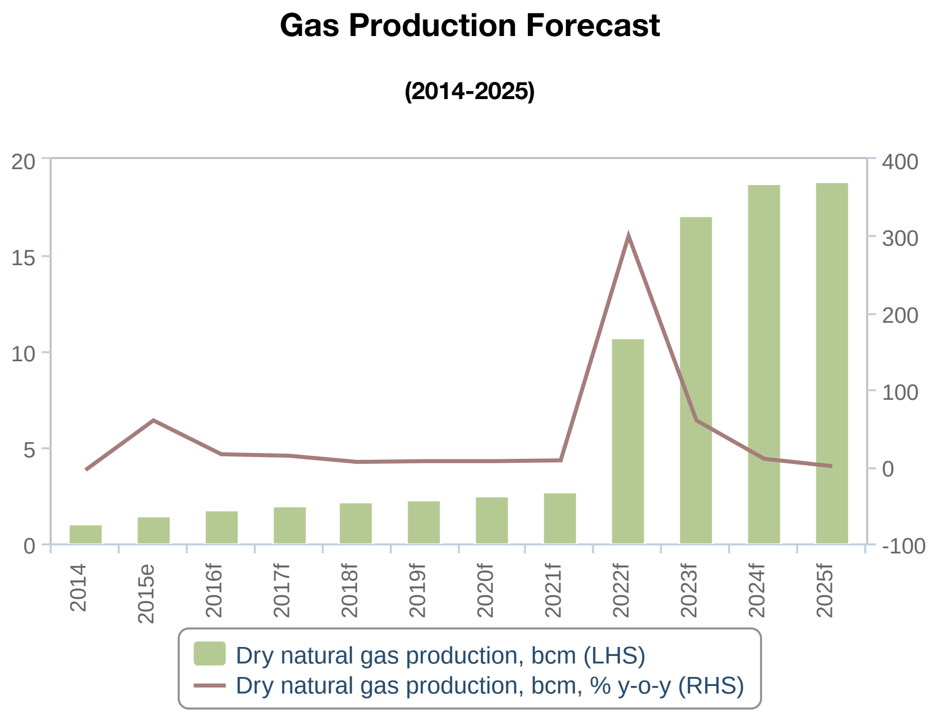
Latest Updates

- After minor delays, **Aminex** announced that production began at the Kilwani North field in early April 2016. The company believes that optimal production rates will be around 30mmcf per day.
- Aminex has secured a gas sales agreement (GSA) with the TPDC to offtake gas from the Kliiwani North development and will feed the nearby Songo Songo processing plant. Aminex will receive USD3.00 per mmbtu and is anticipating net cash revenues of USD10-15 mn annually.

Structural Trends

We forecast incremental gas production growth across the next seven years, driven by a number of marginal field developments. We see output rising to 2.7bcm by 2021 from an estimated 1.5 bn cubic metres (bcm) in 2015.

Part of the forecast increase will stem from the Songo Songo gas field. Songo Songo began commercial production in 2004, and is producing at a rate of 2.0-2.5mn cubic metres per day (Mcm/d). Output from the field is mainly used to supply the Songas Ubungo power plant in Dar es Salaam. According to **Orca Exploration**, the field holds significant upside production potential, following discovery of an additional 28bcm of recoverable gas. However, production growth will be constrained by the limited midstream and processing infrastructure. A second field in the Songo Songo area, the Kiliwani North field, also began production in April 2016. Production is expected to reach a rate of 4,000-5,000boe in the coming months.



e/f = BMI estimate/forecast. Source: National Sources/BMI

Another key area is the Mnazi Bay Concession, in coastal, south-eastern Tanzania in the Rovuma Basin. The concession contains two gas fields: Mnazi Bay and Msimbati. Output from one of the wells in production is transported by pipeline to the Mtawara Power Plant for electricity generation. However, the key development for the concession was the Mnazi Bay to Dar Es Salaam Pipeline which connects gas fields in the south to population centres in the north. The pipeline came onstream in H215.

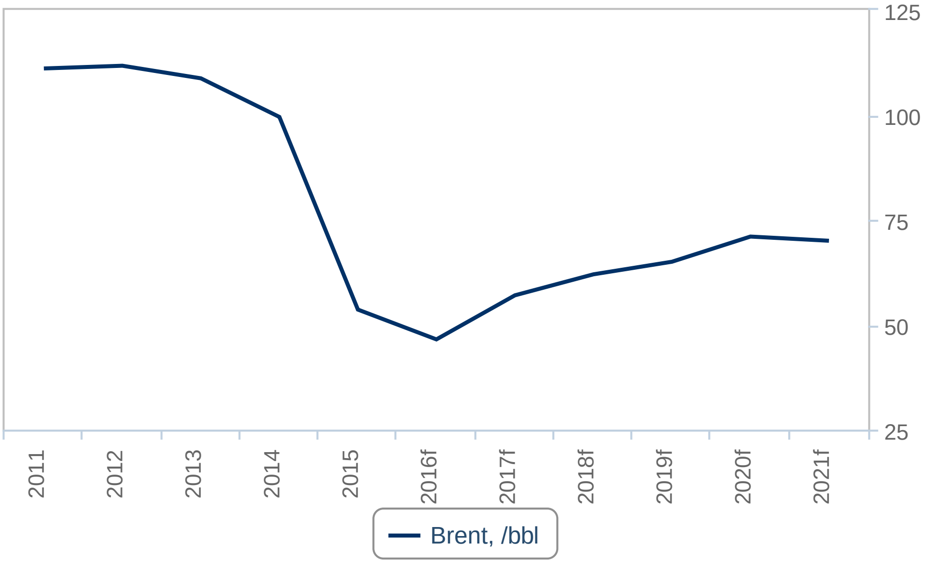
In September 2014, the government of Tanzania and **Wentworth Resources** signed a gas sales agreement (GSA). Under the terms of the GSA, Wentworth will supply a maximum of 2.3Mcm/d to the domestic market for the first eight months of production, with an option to increase supply to up to 3.7Mcm/d over a 17-year period. The contract is a take or pay contract, at a rate of USD3.0 per million British thermal units (/ mnBTU). The **Tanzania Petroleum Development Corporation** is financing the midstream infrastructure and Wentworth is exempt from any transit of processing fees.

We do not forecast major production growth until 2022, when we see output reaching 10.7bcm; for 2025, we put production at 18.9bcm. However, given limited domestic and regional gas demand, output will depend on construction of a liquefied natural gas (LNG) export terminal. The project partners - **BG Group** (**Shell**), **Ophir Energy**, **Statoil** and **ExxonMobil** - have yet to reach a final investment decision (FID), with a range of legal and regulatory uncertainties hampering progress. Most critical has been the delay in the passage of the country's Natural Gas Act. In July 2015, the act was abandoned and the country's natural gas policy has instead been subsumed with the Petroleum Act 2015. However, several key fiscal and regulatory uncertainties remain, including those relating to taxation, domestic supply obligations, and local content requirements. Further clarification will be needed before an FID can be taken, posing further risk of project delay.

As LNG contracts remain heavily indexed to oil, the fall in Brent also poses significant downside risk to the project. LNG export terminals are high cost and involve long project lead times, and a lower oil price environment adds strain to their commercial viability. Research by **Ernst & Young** estimates the commercial breakeven for the Tanzania LNG project at USD10.10/mnBTU (excluding shipping). Based on our forecast for Brent to average USD50.0-70.0/bbl over the next five years, and assuming a 14.5% slope to crude (typical of Asian LNG contracts), this would yield an LNG price in the range of USD7.2-10.2/mnBTU. This is broadly consistent with figures given by industry sources from within the region, which suggest an oil price of USD70.0-80.0/bbl would be needed for the project to breakeven. It is also worth noting that USD7.2-10.2/mnBTU is significantly above the current landed price for Asian LNG. Asia remains the project's main target market, but the sharp decline in crude in recent months has significantly eroded the Asian premium seen over the last two to three years. Through 2015, Asian landed prices were averaging around USD6.0-8.0/mnBTU.

Falling Oil To Drag On LNG

Front-Month Brent Price Forecast (USD/bbl)



f = BMI forecast. Source: BMI Calculation

Another and related factor is the forecast loosening in the global LNG market, which will increase competition for buyers and add further downward pressure on prices. A wave of new liquefaction capacity is due online in 2016-2018, largely in North America and Australia, significantly expanding supply. In contrast, demand in Asia has been weaker than expected and growth forecasts appear increasingly bearish. Given the level of price sensitivity amongst buyers, lower-cost LNG may stimulate consumption, but the market looks set to remain in surplus through the early 2020s.

In this context, buyers are reluctant to lock-in to long-term sales and purchase agreements, and the partners may struggle to find sufficient offtake to support FID in 2016. Given the size of the prospective reserves base, there is a low probability of it becoming a stranded resource. However, the partners may delay FID pending more favourable global supply and demand dynamics.

Another alternative would be to opt for a lower cost form of development. Currently, the partners are targeting a three-train export facility; this could be reduced to two trains. Their proposal is also for an onshore terminal, but a floating facility would be significantly less expensive. Either alternative would involve lower upfront costs and demand smaller contracted offtake volumes.

Table: Gas Production (Tanzania 2014-2019)

	2014	2015e	2016f	2017f	2018f	2019f
Dry natural gas production, bcm	1.0	1.5	1.8	2.0	2.2	2.3
Dry natural gas production, bcm, % y-o-y	-4.5	60.0	16.0	14.0	6.0	7.0
Dry natural gas production, % of domestic consumption	100.0	100.0	100.0	100.0	100.0	100.0

f = BMI forecast. Source: BMI Calculation

Table: Gas Production (Tanzania 2020-2025)

	2020f	2021f	2022f	2023f	2024f	2025f
Dry natural gas production, bcm	2.5	2.7	10.7	17.1	18.8	18.9
Dry natural gas production, bcm, % y-o-y	7.0	8.0	300.0	60.0	10.0	0.5
Dry natural gas production, % of domestic consumption	100.0	100.0	357.1	510.2	501.1	466.3

f= forecast. Sources: National Sources, BMI

Refining

BMI View: *Several factors will limit downstream expansion in Tanzania, including domestic price caps and poor connectivity between regional markets.*

Latest Updates

- There have been no developments in the domestic refining sector this quarter; Tanzania has no domestic refining capacity and no projects are under proposal or development.
- In June, the Energy and Water Utilities Regulatory Authority (EWURA) raised the retail price of petrol by 4.49%, diesel by 1.95% and kerosene by 1.84%. The increase reflected the improved crude price over Q216.

Structural Trends

Commissioned in 1969, the **Tanzanian and Italian Petroleum Refining Company Limited** (TIPER) refinery was located in Dar Es Salaam. The plant had an installed capacity of 17,500 barrels per day (b/d), although utilisation was low at around 60%. The facility was closed in the late 1990s - under pressure from the World Bank - and has now been converted to a tank farm.

Various plans have been put forward for greenfield refineries. In 2010, the government signed a USD6bn agreement with **Noor Oil & Industrial Technologies** (NOIT) for construction of a 200,000b/d refinery and 1,500km oil pipeline. Feedstock for the refinery was to be sourced from **Gazprom** and US-based **Flour** had been awarded a feasibility study. However, the project has stalled and there is relatively low probability of it being revived. No alternative projects have been proposed since.

Several factors have weighed on development of the Tanzanian downstream sector. The domestic market is small and connectivity to other markets in the region remains limited, restricting options for export. Excluding the Tazama pipeline to Zambia, Tanzania re-exports the bulk of its fuels via rail and road. The physical state of the infrastructure is relatively poor and in need of investment, and cross-border clearances can be slow. Re-exported volumes remain relatively small, although they continue to grow.

Domestic fuel prices in Tanzania, both retail and wholesale, are subject to the monthly Cap Prices, issued by the Energy and Water Utilities Regulatory Authority (EWURA). The caps are adjusted in line with changes in international oil prices and fluctuations in FX rates. The intention is to preserve fair prices for consumers and minimum fixed margins for oil marketing companies (OMCs). However, OMCs have opposed the caps, arguing they limit the profitability of the sector.

Given the small size of the domestic market, the retail sector is relatively competitive. The leading market shares are held by **Puma Energy** (11.67%) and **Oryx Energy** (10.29%); other major companies include **Camel Oil**, **Total**, **Oilcom**, **Gapco**, **Mogas**, **Lake Oil** and **Engen**.

Refined Fuels Consumption

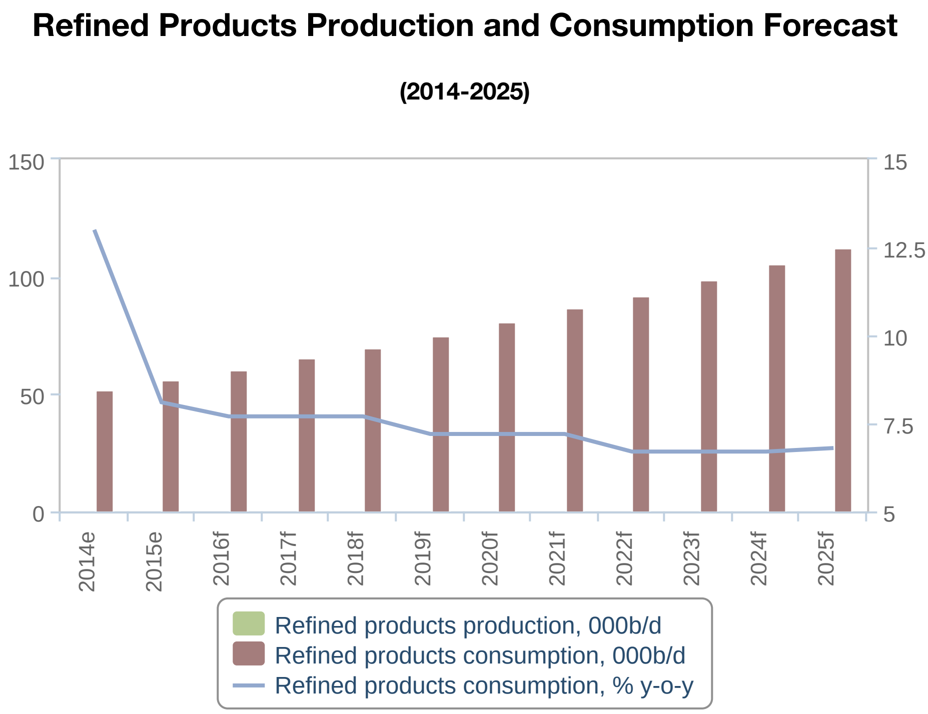
BMI View: *Tanzania is set to see strong refined product consumption growth across our 10-year forecast period, supported by strong economic growth and continued use of liquid fuels in the domestic power sector.*

Latest Updates

- The increased likelihood of La Nina occurring towards the end of Q416/Q117 presents downside risk to our refined fuels consumption, as it will provide a major boost to the hydropower sector, dampening domestic power sector demand for fuels.
- The government has launched an electricity roadmap. The roadmap poses downside risk to longer-term fuels consumption, targeting substantial increases in gas-fired and renewable generation capacity.

Structural Trends

In 2014, Tanzania consumed around 52,000 barrels per day (b/d) of refined fuels according to data from EWURA. We forecast this figure will rise sharply across our forecast period, to reach 112,400 barrels per day (b/d) by 2025.



e/f = BMI estimate/forecast. Source: EWURA, EIA, BMI

The power sector will remain a major driver of fuels consumption in Tanzania. The government is looking towards the increased use of natural gas and renewable technologies in domestic power generation in order to reduce reliance on hydropower as the country is fairly prone to droughts. The potential is significant, but a range of issues threaten to slow progress. Although Tanzania has opened the door to wider private sector participation, the broader business environment remains challenging and companies will face a number of bureaucratic and regulatory barriers to entry. The physical state of infrastructure is also poor, and substantial investment is needed in upgrading and expansion. For gas, there are concerns over the security of feedstock supply, and for renewables start-up costs are often prohibitively high.

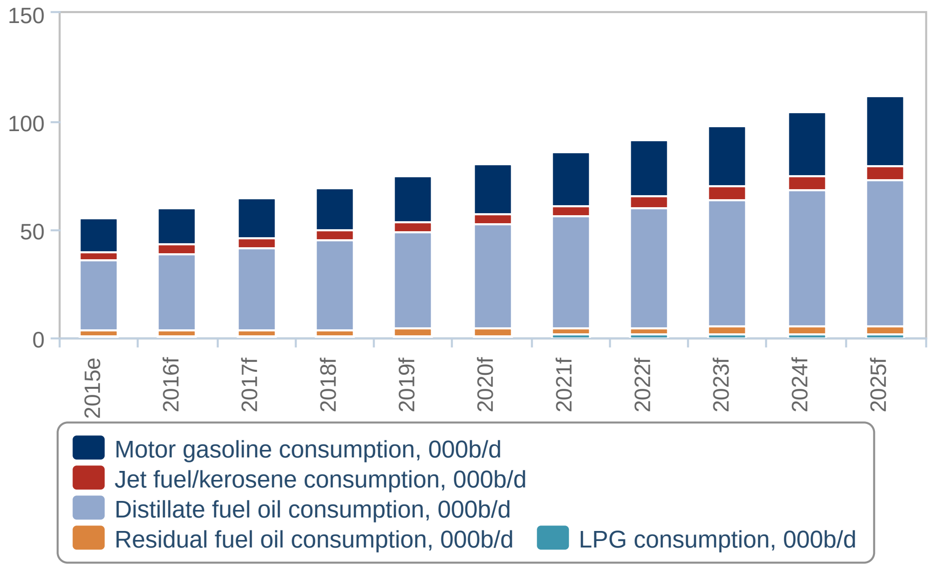
As such, a dependence on hydropower generation looks set to remain. However, hydropower is unreliable and the country relies on emergency diesel and residuals generators to offset frequent outages and periods of drought. According to EWURA, diesel-fired generators accounted for 17% of total electricity generation in 2014, with a number of emergency generators brought online to bridge generation gaps due to a shortage of rainfall in key catchment areas. This sustained dependence will therefore drive increased use of liquid fuels in the domestic power sector across our forecast period despite government efforts.

The demand for power in Tanzania is also set for strong growth in line with rapid economic expansion, averaging 10.9% a year across the next 10 years, and thus providing further support for our fuels demand forecast. Increased economic activity will buoy demand for electricity and increase consumption in energy-intensive domestic industries such as mining. The population is also set to increase to 72mn by 2025, representing an almost 18.5mn increase from 53mn in 2015. Therefore, we expect a strong uptrend in vehicle ownership, and correlative growth in demand for fuels from the domestic transport sector. Consumption is also heavily skewed towards diesel, which is prevalently used in both the transport and power sectors and accounted for around 59% of demand in 2014, followed by gasoline (28%), jet fuel (6%), fuel oil (5%), kerosene (1%) and LPG (1%). While diesel looks set to dominate across our forecast period, we see a slight shift in consumption patterns towards the end of the decade.

In particular, we forecast a robust increase in liquefied petroleum gas (LPG) consumption in the residential sector, driven by continued urbanisation and a shift away from traditional biomass and waste. Currently, biomass (largely charcoal and firewood) represents around 88.0% of primary energy consumption. In contrast, oil and gas represent just 12.0%. This leaves significant upside risk to fuels consumption from increased fuel switching.

Appetite For Diesel

Tanzania Refined Fuels Consumption (000b/d)



e/f = BMI estimate/forecast. Source: EWURA, EIA, BMI

Table: Refined Products Consumption* (Tanzania 2014-2019)						
	2014	**2015e**	**2016f**	**2017f**	**2018f**	**2019f**
Refined products consumption, 000b/d	52.0	56.2	60.6	65.3	70.3	75.3
Refined products consumption, % y-o-y	13.0	8.1	7.7	7.7	7.7	7.2

f = BMI forecast. Source: EWURA, EIA, BMI

Table: Refined Products Consumption* (Tanzania 2020-2025)						
	2020f	**2021f**	**2022f**	**2023f**	**2024f**	**2025f**
Refined products consumption, 000b/d	80.8	86.6	92.4	98.7	105.3	112.4
Refined products consumption, % y-o-y	7.2	7.2	6.7	6.7	6.7	6.8

f = BMI forecast. Source: EWURA, EIA, BMI

Gas Consumption

BMI View: *Planned gas-fired capacity expansion in the power sector will drive strong gas demand growth across our 10-year forecast. Consumption levels will remain significantly below unrestrained demand for much of our forecast period, depressed by limited domestic production and a lack of infrastructure.*

Latest Updates

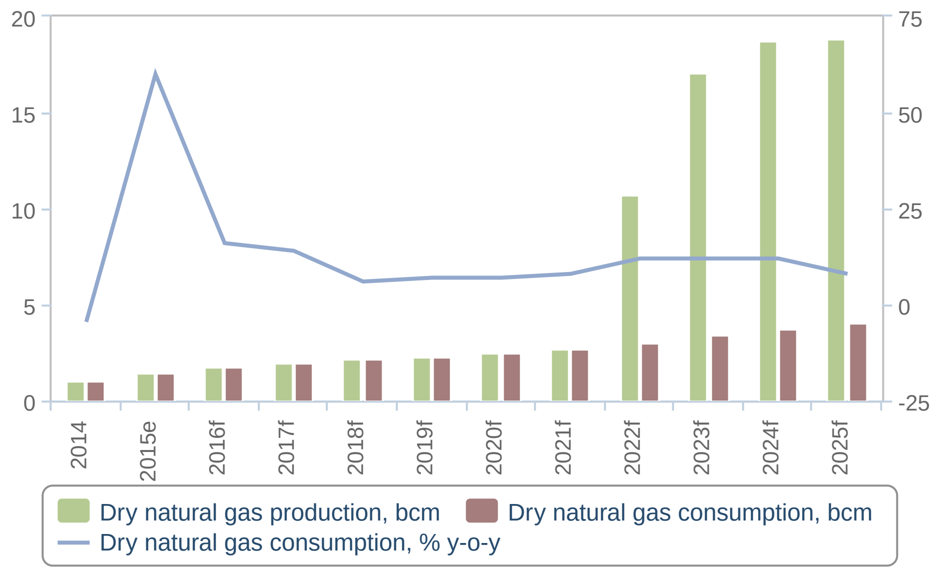
- The EWURA 2015 report concluded that there was considerable unmet natural gas demand in 2014/15 which the government hopes will be satisfied by the Mtwara-Dar es Salaam Gas Transportation Pipeline Project that was inaugurated in Q415.
- Gas consumption increased significantly in 2015, as gas from the Mnazi Bay Concession was brought on stream. According to a statement by the TPDC in December, gas-fired generation has increased by 280MW.
- Japan's **Sumitomo Corporation** announced in March 2016 that it had begun work on the 240MW Kinyerezi combined cycle natural gas plant, which would be the largest in the country and would supply 20% of the country's power generating capacity. It is expected to come online in 2018.

Structural Trends

In the absence of import infrastructure, gas consumption in Tanzania is capped by domestic production; this dynamic is unlikely to change before development of the country's major deepwater resources. As a result, from estimated 1.5bn cubic metres (bcm) in 2015, we forecast a gradual rise in consumption reaching 2.3bcm in 2019 and 4.1bcm by the end of our forecast period in 2025.

Gas Production and Consumption Forecast

(2014-2025)



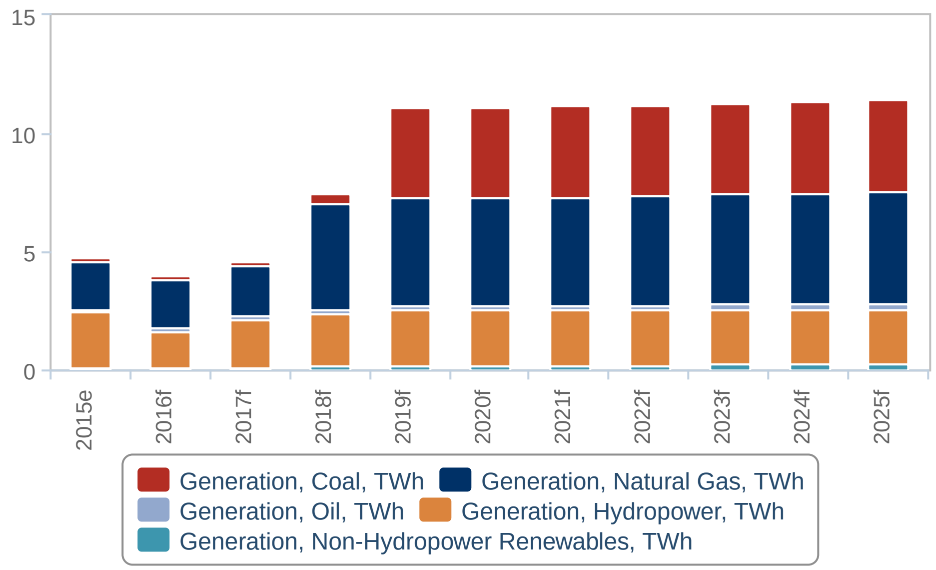
e/f = BMI estimate/forecast. Source: EWURA, EIA, BMI

Forecast consumption growth is strong, averaging around 10% a year across our forecast period; however, much of this is due to the low base effect. Consumption is set to remain comparatively limited, and significantly below unrestrained demand.

The bulk of demand will stem from the power sector, with plans to install an additional 1,500MW of new gas-fired generation capacity in the period up to 2020. The government also hopes to significantly boost electrification rates - which currently stand at 24% - and ease reliance on the country's cost-inefficient diesel generators. However, our forecast for gas-fired generation capacity is significantly more bearish.

Hitting The Gas Ceiling

Tanzania Power Generation By Source (TWh)



e/f = BMI estimate/forecast. Source: National sources, BMI

Two interrelated factors will cap consumption growth in the power sector: small domestic gas output, and a lack of midstream infrastructure. Small domestic output is a major constraint. Tanzania has no gas import capacity and the power sector will rely on increased production domestically for feedstock. However, until 2022, production growth will be limited, driven by the development of marginal offshore fields such as Mnazi Bay and Kiliwani North.

The lack of pipeline capacity to connect new gas production to the domestic power sector is a second issue. Slow infrastructural development has weighed heavily on marginal offshore field developments and is major threat to the security of feedstock supply for new gas-fired power plants. We see these plants remain relatively underutilised, over much of our forecast period.

Gas is used in the residential and commercial sectors as compressed natural gas (CNG); however, this accounts for only a small fraction of total consumption - less than 1% in 2014. Gas is also consumed by a number of industrial users, which make up around 15% of total demand.

The government has plans to develop a diverse downstream sector around the country's new gas production. However, with a major production increase not forecast until 2022, we do not see this materially impacting consumption within our forecast period.

We also flag downside risk to the government's downstream ambitions. Many of the projects proposed, such as the gas-to-liquids (GTL), methanol and fertiliser facilities, would have to be export-driven given limited demand domestically. Mozambique is targeting the development of similar industries and, critically, Tanzania is lagging Mozambique in its natural gas development by two to three years. Should Mozambique gain a foothold in the regional fuels, fertiliser, and liquids markets ahead of 2022, this would undermine the economic viability of many of Tanzania's major downstream projects.

Table: Gas Consumption (Tanzania 2014-2019)

	2014	2015e	2016f	2017f	2018f	2019f
Dry natural gas consumption, bcm	1.0	1.5	1.8	2.0	2.2	2.3
Dry natural gas consumption, % y-o-y	-4.5	60.0	16.0	14.0	6.0	7.0

f = BMI forecast. Source: EWURA, EIA, BMI

Table: Gas Consumption (Tanzania 2020-2025)

	2020f	2021f	2022f	2023f	2024f	2025f
Dry natural gas consumption, bcm	2.5	2.7	3.0	3.4	3.8	4.1
Dry natural gas consumption, % y-o-y	7.0	8.0	12.0	12.0	12.0	8.0

f = BMI forecast. Source: EWURA, EIA, BMI

Trade - Oil

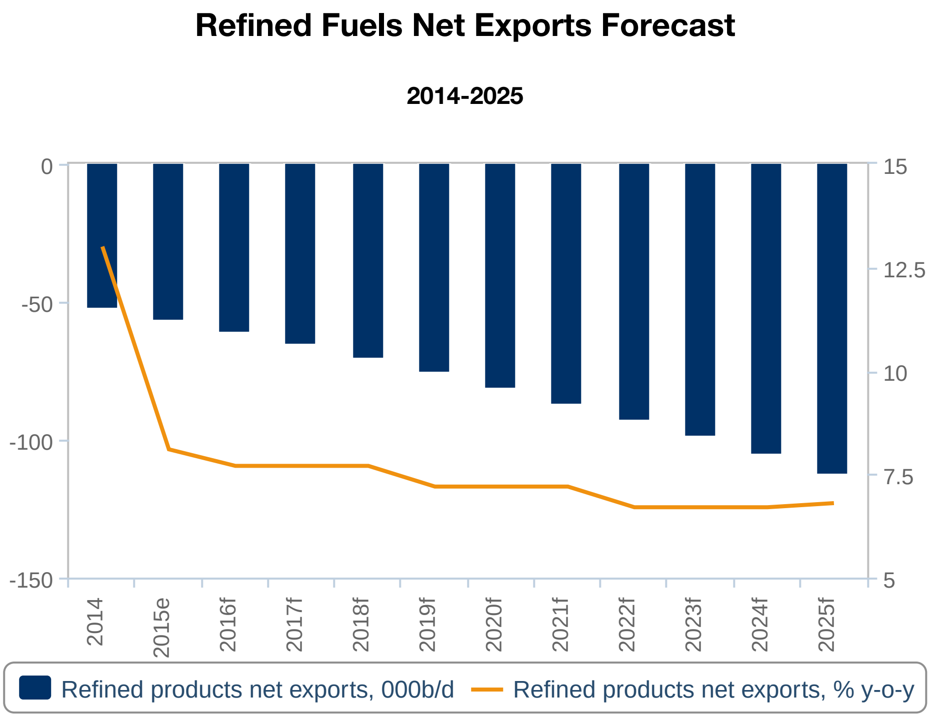
BMI View: *In the absence of domestic refining capacity, Tanzania is set to become increasingly import-dependent across our 10-year forecast period.*

Latest Updates

- The cost of refined fuels imports is set for a y-o-y decline in 2016, in line with falling international fuels prices.
- As of September 2016, Tanzania will adopt the bulk procurement system for the importation of Liquefied Petroleum Gas (LPG). Bulk procurement was brought in to make the importation of petroleum products easier, help regulate prices and promote efficiency in the sector.
- At the time of writing, the latest announced BPS tender was won by ADDAX Energy SA. The company was awarded the contract to supply the fuels for March 2016 at a weighted average premium of 32.349, the lowest premium recorded to date in Tanzania.

Structural Trends

In 2015, Tanzania's net refined fuels imports totalled 56,000 barrels per day (b/d). We forecast a strong rise in net fuels imports, reaching 112,000b/d by 2025. Tanzania also re-exports a significant portion of fuels - around 30,000b/d - largely to Malawi, Kenya, Rwanda, Burundi, the Democratic Republic of the Congo and Zambia.



e/f = BMI estimate/forecast. Source: EWURA, EIA, BMI

All refined fuels are imported via the bulk procurement system (BPS). Under the BPS, the Petroleum Importation Coordinator (PIC) collates orders from the various oil marketing companies (OMCs) and issues a monthly bulk tender, awarded by competitive bidding process. According to the PIC, cargoes are delivered on a cost, insurance and freight (CIF) or delivered at place (DAP) basis.

The intention of the BPS was to encourage greater transparency in the system and to tap the economies of scale. Coordinated delivery schedules have also reduced congestion at the Dar es Salaam port, lowering waiting times for vessels. According to a fiscal impact assessment carried out by the University of Dar es Salaam, as of 2014 the BPS had reduced the average number of days at port from 45 to 3, significantly reducing demurrage costs. The same study also found that the BPS had lowered the average premium paid on fuel tenders, equating to a saving of around USD26.4mn. However, critics of the BPS argue that the tendering process has lacked transparency and that the PIC has failed to secure the most competitive prices for its cargoes.

In the absence of domestic refining capacity, Tanzania is set to become increasingly dependent on imported fuels across our 10-year forecast period. Investment in expansion and upgrading of existing import and storage infrastructure will be needed to support this growth in demand.

The port at Dar es Salaam is the main entry point for fuels, accounting for around 99% of all imports in 2014, with the remainder transiting the Sirari border. In 2012, the Tanzania Port Authority replaced the aging oil terminal at the Dar es Salaam port with a Single Point Mooring (SPM) system. The SPM has capacity to accept larger vessels, of up to 150,000 deadweight tonnes (DWT), and has eased tanker congestion at the port. The government has also been extending domestic storage capacity, including an additional 100,000 cubic metres at the mothballed TIPER refinery in Dar es Salaam.

With forecast growth in imports of around 50,000b/d across our forecast, more investment in storage and midstream infrastructure will be needed.

Table: Refined Fuels Net Exports (Tanzania 2014-2019)

	2014	2015e	2016f	2017f	2018f	2019f
Refined products net exports, 000b/d	-52.0	-56.2	-60.6	-65.3	-70.3	-75.3
Refined products net exports, % y-o-y	13.0	8.1	7.7	7.7	7.7	7.2
Refined products net exports, USDbn	-2.1	-1.4	-1.1	-1.5	-1.7	-1.9

e/f = BMI estimate/forecast. Source: EWURA, EIA, BMI

Table: Refined Fuels Net Exports (Tanzania 2020-2025)

	2020f	2021f	2022f	2023f	2024f	2025f
Refined products net exports, 000b/d	-80.8	-86.6	-92.4	-98.7	-105.3	-112.4
Refined products net exports, % y-o-y	7.2	7.2	6.7	6.7	6.7	6.8
Refined products net exports, USDbn	-2.3	-2.4	-2.6	-2.8	-2.9	-3.1

f = BMI forecast. Source: EWURA, EIA, BMI

Trade - Gas (Pipeline And LNG)

BMI View: *The continued loosening of the global liquefied natural gas (LNG) market and falling LNG prices will threaten the commercial viability of the proposed Tanzania LNG project.*

Latest Updates

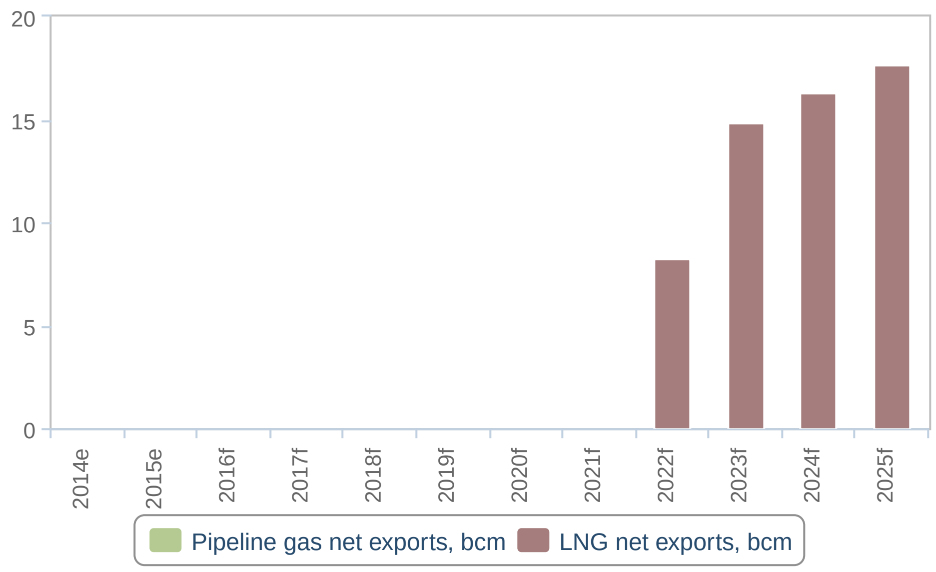
- The Tanzanian government finalised a land acquisition deal for the site of the planned Tanzania LNG plant at Lindi in January 2016, removing one of the obstacles to progress on the project.
- FID for the project is still planned for 2016.

Structural Trends

Our Tanzania gas export forecast is based on development of the joint venture project between **Ophir**, **BG Group (Shell)**, **Statoil** and **ExxonMobil**. **The plan is for a** three-train liquefaction facility, each with 5mn tonnes per annum (mtpa) - or 6.8bn cubic metres (bcm) - capacity. Around 420bcm would be needed to support the three-train facility over a 20-year period. Alongside 485bcm of 2C resources in Blocks 1, 3 and 4, resource estimates for Block 2 range from 250-400bcm. Assuming the project reaches final investment decision (FID) in 2016, we forecast first gas from 2022.

Gas Net Exports Forecast

(2014-2025)



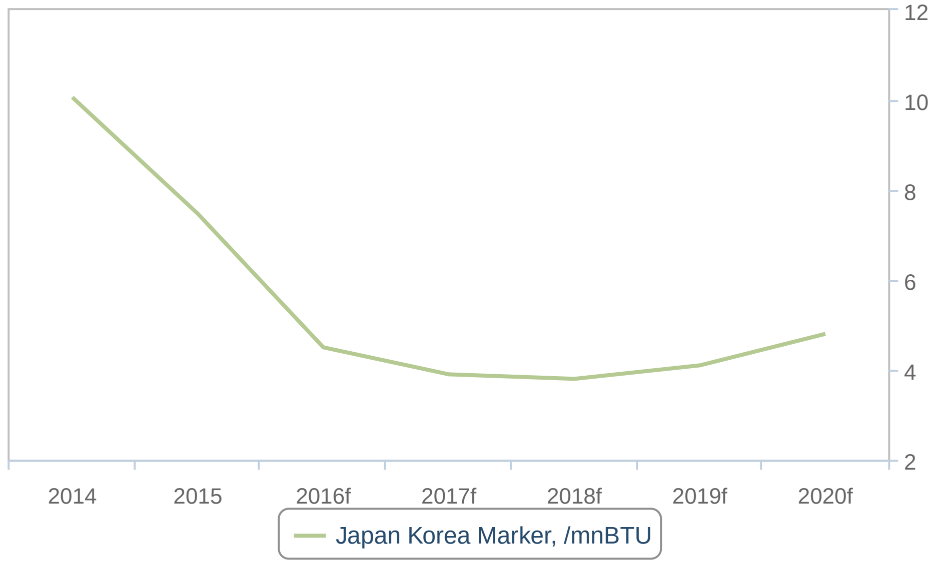
e/f = BMI estimate/forecast. Source: EWURA, BMI

However, as discussed previously, there remain strong downside risks to FID in 2016. Key risks include lower LNG prices, which undermine project economics, and difficulty securing buyers in an increasingly saturated global LNG market.

Delays are particularly concerning given mounting competition for share of the major Asian LNG import markets - markets which Tanzanian exports would look to tap. The bulk of new export capacity coming online in North America and Australia is also targeting the Asia Pacific market and over the coming 10 years we are forecasting demand growth in the region to be increasingly outstripped by the growth in supply. In addition to lower forecast crude prices (to which the price of LNG is linked) this could significantly reduce export revenues - a concern for a project estimated to cost up to USD30bn to develop.

Depressed Prices Threaten FID

Japan Korea Marker, USD/mnBTU



F=BMI forecast. Source: BMI, Bloomberg

One upside to the fall in oil prices is that it could make Tanzanian LNG more competitive against LNG from the US, which is primarily linked to the Henry Hub gas price. However, crude-linked LNG prices will have to remain sufficiently high to incentivise the major capital outlay demanded upfront.

Despite its relatively high development costs, Tanzania LNG may retain a cost advantage over many of the large Australian and Canadian greenfield projects. According to a report by Ernst & Young, the average cost of development for proposed greenfield LNG export facilities is around USD2.6bn/mtpa; for Australia, above USD3bn/mtpa. However, for the Mozambique LNG project, they estimate costs below USD2.4bn/mtpa; for Tanzania, less than USD2bn/mtpa. This report was made before the fall in crude prices; global industry cost deflation could further lower these estimates, depending on development timeframes.

Lower costs in Tanzania are supported by factors below ground. Well testing in Blocks 1-4 has returned positive results, indicating strong flow rates and good quality reservoirs of high porosity and high permeability. This implies lower lifting costs and stronger project economics.

In a context of falling prices and rising cost pressures globally, this offers some competitive advantage, particularly against projects in Australia. However, continued regulatory uncertainty, bringing further project delays, would threaten to erode this advantage over time.

Statoil has also flagged limited infrastructure and the restricted labour market as potential roadblocks to development. Stringent local content requirements would add further pressure here, but for the government the issue is a politically sensitive one. Violent protests broke out in 2013 over construction of the Mtwara pipeline, built to carry gas from Mnazi Bay to Dar es Salaam; the local population had lobbied to have the gas processed in the Mtwara region itself. Unless expectations are better managed, an LNG project could trigger similar unrest - LNG export facilities offer little in the way of job creation, either direct or indirect.

Any of the above factors could trigger a delay to the Tanzania LNG project. In the absence of alternative export routes, this could see first gas exports pushed back outside of our 10-year forecast period. Although this is not our core view, it is at this stage a realistic scenario.

Table: Gas Net Exports (Tanzania 2020-2025)

	2020f	2021f	2022f	2023f	2024f	2025f
Dry natural gas net exports, bcm	0.0	0.0	8.3	14.9	16.3	17.7
Dry natural gas net exports, % y-o-y	0.0	0.0	0.0	78.5	9.5	8.7
Dry natural gas net exports, USDbn	0.0	0.0	2.9	5.3	5.8	6.4
Pipeline gas net exports, bcm	0.0	0.0	0.0	0.0	0.0	0.0
Pipeline gas net exports, % y-o-y	0.0	0.0	0.0	0.0	0.0	0.0
Pipeline gas net exports, % of total	0.0	0.0	0.0	0.0	0.0	0.0
LNG net exports, bcm	0.0	0.0	8.3	14.9	16.3	17.7
LNG net exports, % y-o-y	0.0	0.0	0.0	78.5	9.5	8.7
LNG net exports, % of total gas exports	0.0	0.0	100.0	100.0	100.0	100.0

f = BMI forecast. Source: EWURA, EIA, BMI

Industry Risk Reward Index

Africa - Oil & Gas Risk/Reward Index

BMI View: *Africa has suffered renewed downgrades in the upstream indices this quarter, weighed down by large supply outages amongst major producers. The above-ground environment is challenging, with a mix of political, security and regulatory headwinds heightening risks and offsetting substantial rewards below ground. However, Egypt is emerging as a regional bright spot, reflected in its continued rise up the rankings. The downstream index continues to underperform, due to ageing and inefficient refining capacity. A softening fuels consumption growth outlook has further eroded the index this quarter.*

The main themes emerging from **BMI**'s Africa Oil & Gas Risk/Reward Index (RRI) are:

- Africa continues to underperform in the global Upstream Index this quarter, as a chronically weak risk profile undercuts strong prospective rewards.
- Africa has been heavily exposed to the collapse in global oil prices and consequent pullback in company spending. This has put downside pressure on the RRI scores, as project delays and cancellations undercut longer-term production growth.
- The worst performers in our Upstream Index are countries such as Sudan and Chad, which combine weak prospects for production with highly unattractive conditions above ground.
- Several countries - including Libya, Nigeria and South Sudan - have suffered downgrades this quarter. Weak security environments and repeated supply outages are a major drag on performance.
- Egypt is increasingly emerging as an outperformer in the region, with a strong projects pipeline and large prospects for growth.
- Africa's downstream sector remains challenging as stringent government regulations, segmented markets and poor intra-regional *c*onnectivity continue to deter investment.

Table: BMI Africa Oil & Gas Risk/Reward Index

	Upstream RRI	Downstream RRI	Oil & Gas RRI	Rank
South Africa	50.9	51.6	51.2	1
Egypt	51.2	46.6	48.9	2
Congo (Brazzaville)	55.9	41.2	48.5	3
Ghana	53.2	39.3	46.2	4
Mozambique	64.2	28.0	46.1	5
Libya	58.8	33.2	46.0	5
Nigeria	56.9	34.5	45.7	7
Algeria	52.8	37.6	45.2	8

BMI Africa Oil & Gas Risk/Reward Index - Continued				
	Upstream RRI	**Downstream RRI**	**Oil & Gas RRI**	**Rank**
Cameroon	53.0	33.2	43.1	9
Angola	55.8	30.1	43.0	10
Gabon	41.6	39.3	40.4	11
Tunisia	43.6	33.3	38.4	12
Tanzania	42.2	29.1	35.6	13
Equatorial Guinea	43.1	26.0	34.6	14
South Sudan	37.4	30.1	33.7	15
Sudan	30.8	35.8	33.3	16
Chad	33.8	28.0	30.9	17
Uganda	24.5	28.0	26.2	18
Average	*47.2*	*34.7*	*41.0*	-

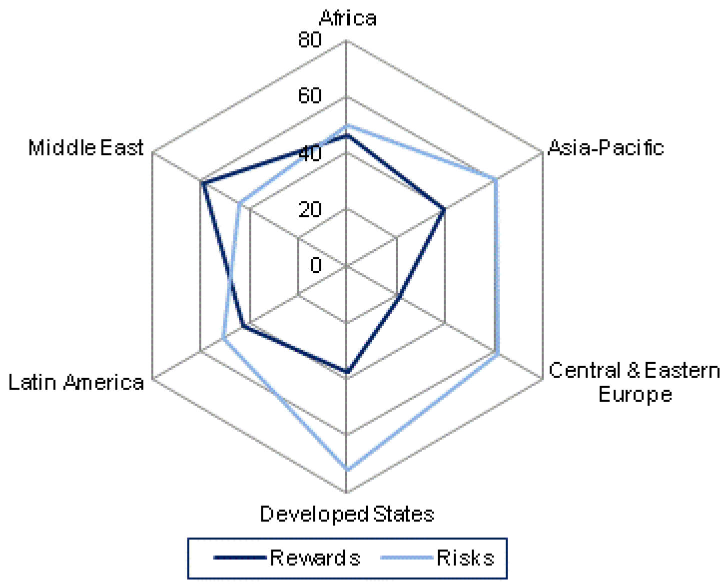
Note: Scores out of 100; higher score = lower risk. Source: BMI

Despite its substantial resource base, Africa has increasingly underperformed in the regional Upstream RRI. Political instability and an unsettled regulatory outlook in a number of countries have weakened the region's risk indices and - excluding the Middle East - Africa has the worst risk profile of any region globally.

Large reserves and a strong growth outlook are buoying Africa's reward indices, although persistent supply outages have put downward pressure on the region's Industry Rewards score. As the impacts of aggressive clawbacks in companies' exploration and production capex feed through to lower investments in African exploration and development, the Index will face increasing pressure.

Weak Showing Masks Significant Potential

Regional Upstream Risk/Reward Indices

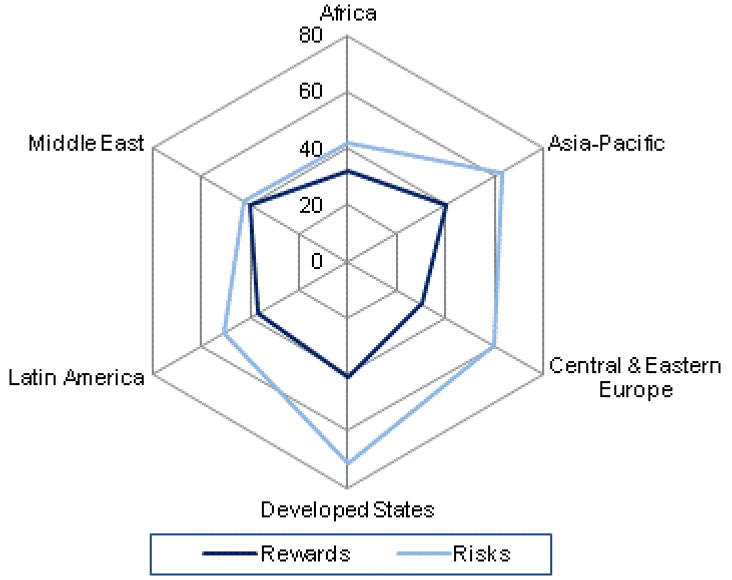


Note: Scores out of 100; higher score = lower risk. Source: BMI

Africa's Downstream RRI scores remain critically low, underperforming every other region in the index. A low level of physical infrastructure, lack of reliable crude feeds and continued use of fuel subsidies present key risks to the sector, overshadowing the rewards of a growing population and a strong rise in fuels consumption.

Downstream Blues Remain

Regional Downstream Risk/Reward Indices



Note: Scores out of 100; higher score = lower risk. Source: BMI

Above-Ground Risks Dulling Below-Ground Potential

Table: BMI Africa Upstream Risk/Reward Index

	Upstream Industry Rewards	Upstream Country Rewards	Upstream Rewards	Upstream Industry Risks	Upstream Country Risks	Up-stream Risks	Up-stream RRI	Rank
Mozambique	62.5	90.0	69.4	55.0	46.5	52.0	64.2	1
Libya	71.3	80.0	73.4	25.0	23.8	24.6	58.8	2
Nigeria	58.8	65.0	60.3	55.0	37.5	48.9	56.9	3
Congo (Brazzaville)	48.8	75.0	55.3	70.0	33.3	57.1	55.9	4
Angola	52.5	75.0	58.1	65.0	23.6	50.5	55.8	5
Ghana	43.8	45.0	44.1	80.0	63.9	74.4	53.2	6
Cameroon	51.3	40.0	48.4	80.0	33.5	63.7	53.0	7
Algeria	46.3	74.5	53.3	60.0	35.7	51.5	52.8	8
Egypt	37.5	85.0	49.4	62.5	42.4	55.5	51.2	9
South Africa	28.8	87.5	43.4	72.5	60.1	68.2	50.9	10

BMI Africa Upstream Risk/Reward Index - Continued

	Upstream Industry Rewards	Upstream Country Rewards	Upstream Rewards	Upstream Industry Risks	Upstream Country Risks	Up-stream Risks	Up-stream RRI	Rank
Tunisia	30.0	78.5	42.1	50.0	41.7	47.1	43.6	11
Equatorial Guinea	26.3	75.0	38.4	75.0	14.7	53.9	43.1	12
Tanzania	25.0	87.5	40.6	45.0	47.4	45.8	42.2	13
Gabon	30.0	77.5	41.9	40.0	42.8	41.0	41.6	14
South Sudan	31.3	50.0	35.9	52.5	18.8	40.7	37.4	15
Chad	20.0	63.8	30.9	55.0	13.9	40.6	33.8	16
Sudan	18.8	50.0	26.6	52.5	19.2	40.8	30.8	17
Uganda	5.0	55.0	17.5	40.0	42.6	40.9	24.5	18
Average	*38.2*	*69.7*	*46.1*	*57.5*	*35.6*	*49.8*	*47.2*	

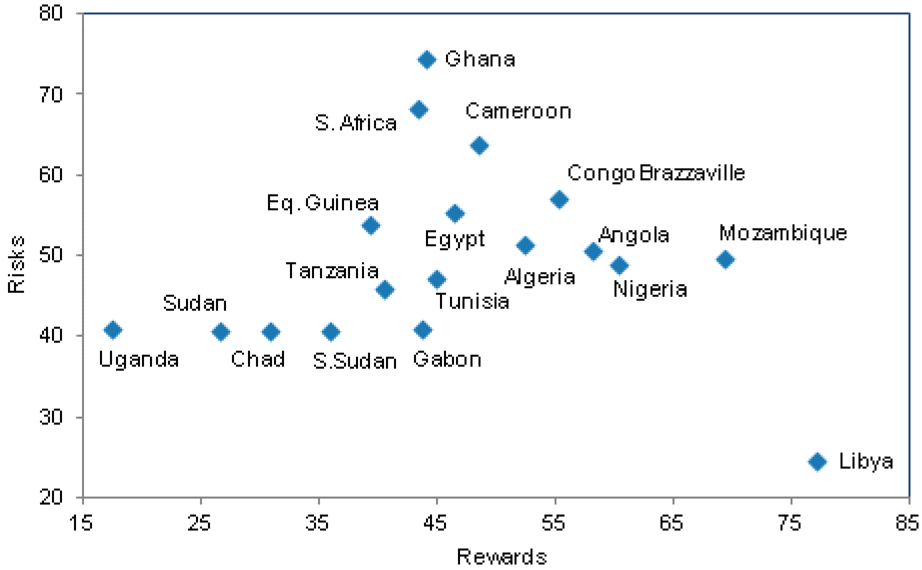
Note: Scores out of 100. Source: BMI

Oil & gas production in Africa is dominated by six countries, which together accounted for more than 80% of oil production in 2015: Algeria, Angola, Egypt, Libya, Nigeria and South Sudan. Given the size of their reserves bases and the volume of their output, these countries heavily underperform as a group. However, individual performances have increasingly diverged in recent quarters.

- In both **Libya** and **South Sudan**, output remains highly uncertain. A poor security environment and deep political fragmentation point to a high probability of future production outages. The prospects for a negotiated settlement in Libya have improved, but progress remains sluggish and we have downgraded the production forecast this quarter, as reflected in the lower score for Industry Rewards.
- In **Algeria**, a restrictive fiscal and regulatory regime and the high level of state participation continue to deter foreign investors. Falling investment in a lower price environment risks further downgrades to the country's rewards indices.
- In **Nigeria**, repeated attacks on infrastructure by the Niger Delta Avengers have led production to collapse in 2016, undermining the country's upstream showing.
- In **Egypt**, the rapid return of investment in recent quarters has seen the country's upstream rewards scores begin to recover. The discovery at Zohr may help accelerate this trend.

Major Producers Underperforming

Africa Upstream RRI



Note: Scores out of 100; higher score = lower risk. Source: BMI

Among Africa's emergent producers, the rising scope for state intervention and mounting fiscal and regulatory uncertainties have heightened risks and undermined rewards in a number of countries.

- In **South Africa**, proposed overhauls of the legal and regulatory frameworks are broadly positive for the sector. However, the pace of reform is likely to be slow and has yet to feed through to the RRI. Depressed activity in the upstream is also weighing heavily on the rewards index.
- In **Uganda**, slow bureaucratic procedures, heavy state interference and weak institutional capacity have dragged on the country's rewards profile, as first production has been repeatedly delayed.
- In **Tanzania** and **Mozambique**, passage of key legislation has removed a layer of regulatory uncertainty. We note strong upside potential in the index, depending FID on LNG export projects.

Long-term production decline among smaller maturing producers - including **Equatorial Guinea** and **Gabon** - has seen them slip down the rankings. The lower oil price environment has tended to exacerbate this trend and both markets faced renewed downgrades this quarter in the Industry Rewards category. However, countries such as **Congo-Brazzaville** and **Cameroon**, with substantial pre-existing infrastructure and generally favourable above-ground conditions, have been resurgent in the Index in recent quarters, bolstered by improved reserves and production outlooks.

The worst performers in our Upstream Index are countries such as **Sudan** and **Chad**, which combine stagnant production and a falling reserves base with highly unfavourable conditions above ground. The weaknesses in these markets are largely structural and we see limited scope for near-term improvement.

Downstream Sector Holds Limited Opportunity

Table: BMI Africa Downstream Risk/Reward Index

	Downstream Industry Rewards	Downstream Country Rewards	Down-stream Rewards	Down-stream Industry Risks	Down-stream Country Risks	Down-stream Risks	Down-stream RRI	Rank
South Africa	32.2	66.0	40.7	95.0	50.3	77.1	51.6	1
Egypt	46.7	54.0	48.5	40.0	45.5	42.2	46.6	2
Congo (Brazzaville)	31.1	46.0	34.8	65.0	42.8	56.1	41.2	3
Ghana	35.6	34.0	35.2	50.0	47.8	49.1	39.3	4
Gabon	30.0	36.0	31.5	70.0	38.6	57.4	39.3	5
Algeria	38.9	37.8	38.6	25.0	50.4	35.2	37.6	5
Sudan	26.7	52.0	33.0	50.0	30.8	42.3	35.8	7
Nigeria	32.2	48.0	36.2	20.0	46.7	30.7	34.5	7
Tunisia	30.0	24.0	28.5	45.0	43.5	44.4	33.3	9
Libya	37.8	31.8	36.3	20.0	35.0	26.0	33.2	9
Cameroon	30.0	30.0	30.0	45.0	33.9	40.6	33.2	11
Angola	33.3	36.0	34.0	15.0	30.4	21.1	30.1	12
South Sudan	24.4	30.0	25.8	50.0	24.9	40.0	30.1	13
Tanzania	22.2	36.0	25.7	30.0	47.8	37.1	29.1	14
Mozambique	23.3	14.0	21.0	50.0	36.2	44.5	28.0	15
Chad	24.4	32.0	26.3	37.5	23.3	31.8	28.0	16
Uganda	25.6	30.0	26.7	20.0	47.4	31.0	28.0	17
Equatorial Guinea	15.6	24.0	17.7	60.0	23.9	45.6	26.0	18
Average	*30.0*	*36.8*	*31.7*	*43.8*	*38.8*	*41.8*	*34.7*	

Note: Higher score = lower risk, scores out of 100. Source: BMI

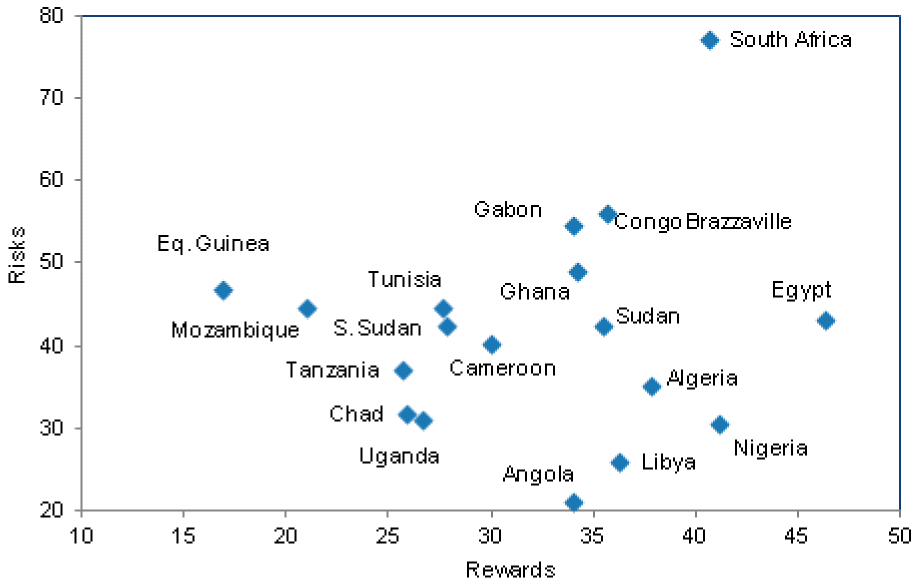
Africa on the whole performs poorly in our Downstream RRI. This is mainly due to the following factors:

- Small, segmented markets
- A lack of regional midstream infrastructure
- Fuel subsidies diminishing the potential returns on investment
- Unstable political environments

Together, these dynamics can render refinery projects - both greenfield and brownfield - uneconomic and uncertain. With the exception of South Africa, countries at the top of our table enjoy higher scores due to their large populations and implied growth potential, rather than the size of their downstream sectors.

High Risks And Low Rewards Undercutting Indices

Africa - Downstream RRI



Note: Scores out of 100; higher score = lower risk. Source: BMI

Angola has plans to construct the Soyo refinery slated to come online in 2017-2018, while **Nigeria** has plans to construct a new 650,000b/d refinery, targeting output from 2018. Several other countries, such as **Algeria**, **Equatorial Guinea** and **Ghana**, have plans for major upgrade and expansion work. However, due to a range of factors, including financing issues, limited availability of domestic crude feedstock and small local product markets, we do not see these projects progressing. **Uganda** also scores significantly below the regional average. However, the planned refinery at Hoima should buoy the country's scores over the coming years.

In general, the fuels consumption outlook in Africa is strong and the region is a global outperformer in growth terms. However, a deteriorating macroeconomic outlook among a number of the key consumers has softened our demand forecasts. This has been reflected in a slide in the regional average this quarter, with the Downstream Industry Rewards average falling from 30.5 to 30.0.

Tanzania - Risk/Reward Index

Tanzania continues to be ranked poorly in our Regional Upstream Risk/Reward Index, given ongoing regulatory uncertainty. Its prospectivity remains attractive but continues to be weighed down by these above-ground risks. The country also ranks among the lowest in our downstream index, due to a lack of refining capacity and small domestic market.

Upstream Index

Tanzania benefits from a growing gas reserves base, rising production profile and the low maturity of its assets. However, the lack of oil reserves and output weighs heavily on the overall Industry Rewards ranking. It receives a strong score for Country Rewards, due to its diverse competitive landscape and the low level of state ownership of assets.

Tanzania has suffered a substantial downgrade in the Industry Risk component over recent quarters. Downside pressure stems from ongoing regulatory uncertainty despite the passage of the Petroleum Act in 2015. The threat of resource nationalism is a key concern, alongside increasing tax burdens and more stringent local content mandates. Tanzania's Country Risk score also remains low, with widespread corruption and a critical lack of physical infrastructure dragging down its overall performance.

Downstream Index

Tanzania remains a poor performer in the downstream index. The country has no refining capacity and currently there is little opportunity for the refining sector to develop. As in the upstream, the lack of infrastructure is a key constraint. The regulatory environment is also convoluted and opaque, domestic demand remains comparatively limited, and there is poor connectivity to other regional markets.

Market Overview

Tanzania Energy Market Overview

Regulatory Structure

Previously, the Petroleum (Exploration and Production) Act 1980 was the key legislation governing the Tanzania Oil & Gas sector. Following major gas discoveries offshore, the government has worked to overhaul this legislation and incorporate new provisions to govern the exploration, development and production of natural gas. In July of the same year, the government passed the Petroleum Act 2015. Broadly, the act will create a more stable and transparent above-ground environment, improving the prospects for the upstream sector. However, several layers of fiscal and regulatory uncertainty remain and a significantly expanded role for the Tanzanian state may dull the appetite to invest.

Key terms include the following:

- The TPDC will be formed as the Tanzanian national oil company (NOC). It will manage the GoT's interests in all petroleum and natural gas agreements, performing a commercial but not regulatory role.
- Regulation in the upstream will be performed by the Petroleum Upstream Regulatory Authority (PURA) - established under the act - and in the midstream and downstream by the Energy and Water Utilities Regulatory Authority (EWURA).
- Among PURA's key functions it will act as advisor to the Minister of Energy and Minerals, implement local content policies and resolve disputes. The Minister of Energy will grant, renew and suspend licences, under advisement from PURA.
- PURA can decide to open new areas for exploration and development, pending a 60-day consultation period with interested parties and the approval of the cabinet. The TPDC will have exclusive rights over all petroleum and natural gas licences granted.
- There is some ambiguity surrounding the licensing procedures, but the act allows for both competitive bidding and direct negotiation.
- Any company (foreign or domestic) wishing to carry out petroleum operations in the country must do so via a joint venture (JV) vehicle with the TPDC.
- The JV must then enter into an agreement with the Minister of Energy, but the terms of the agreement (established in reference to the model PSA) must first be approved by the cabinet.
- PURA is empowered to resolve disputes arising from the industry; there is no framework for international arbitration, although this is a feature of the current model PSA.
- PURA has responsibility to develop a new model PSA, which will form the basis of future licence negotiations with oil and gas companies. The prospective terms of this PSA remain unknown.

The explicit requirement for cabinet approval through the various layers of the licensing process creates considerable risks of delay. In general, the act affords a more hands-on role for the central government in the country's petroleum affairs, a level of involvement which may be unwelcome to private sector investors.

Fiscal Regime

From the perspective of the oil and gas companies, fiscal terms have substantively worsened in the new model production sharing agreement (MPSA). However, contracts are negotiable. It is our view that the production sharing agreements (PSAs) currently under force may offer better fiscal terms than those of the MPSA.

Table: Tanzania MPSA Main Fiscal Terms

Corporate Income Tax	Royalties	Fees and Bonuses	Resource Tax	Export Duties	Import Duties	Other Key Fiscal Terms
30%	12.5% onshore; 7.5% offshore (including deepwater); royalties are allocated out of total production and not out of profit oil	Yes - signature bonus (USD2.5mn); production bonus (USD5mn); annual licence rental (USD50-200/sq km in exploration, USD500/sq km in development)	Yes - some contractors are subject to an additional petroleum tax, 25-35%	No	Yes - 0-25% although contractors may be granted special exemption during exploration	Cost recovery is capped at 50%

Source: TPDC, Ernst & Young, BMI

Licensing Regime

Table: Tanzania MPSA Main Contract Terms

Main Contract Type	Contract Duration	State Participation	Local Content Requirement	Domestic Supply Requirement	Stabilisation Clause	Other Key Licensing Terms
Production sharing agreement	Exploration up to 10 years; production 25 years, with one possible 15-year extension	Yes - 25% participating interest for TPDC; carried through exploration and appraisal	Yes - contractors must prefer domestic labour, goods and services and support capacity building and skills and technology transfers	Yes - contractors must allocate a proportion of their share in production to the domestic market; variable by contract	Yes	Relinquishment - contractors must relinquish 50% of their acreage after the initial exploration period and first extension period

Source: TPDC, Deloitte, BMI

Oil & Gas Infrastructure

BMI View: *Tanzania is critically lacking in oil and gas infrastructure, given the nascent state of its oil and gas sector.*

Oil & Gas Pipelines

Table: Tanzania - Main Oil & Gas Pipelines

Name	Company	Type	Capacity	Length	Route	Fields	Status	Completion
Songa Songa Pipeline	Songas Limited	Gas	3.0Mcm/d	207km	Songo Songo to Dar es Salaam	Songo Songo	Active	2004
Mtwara Pipeline	TPDC	Gas	22.0Mcm/d	532km	Mnazi Bay to Dar es Salaam	Mnazi Bay, Msimbati	Construction completed	2015
Tanzania-Zambia (Tazama) Pipeline	Tazama Pipeline Limited	Oil	22,000b/d	1,710km	Dar es Salaam to Ndola, Zambia	N/A - oil imported	Active	1969

Source: Company data, EIA, BMI

Oil Storage Facilities

Table: Tanzania Main Oil Storage Facilities

Location	Company	Type	Capacity ('000cm)	Access
Dar Es Salaam	Oryx Petroleum, Government of Tanzania	Tank Farm	150 (additional 100 under rehabilitation)	Open

Source: Company data, BMI

Oil Trade Facilities

Table: Tanzania Main Oil Terminals

Trading Operation	Facilities	Handling Capacity (b/d)	Ownership	Status	Completion
Dar es Salaam Port	Two berths	120,000	Tanzania Ports Authority	Active	-

Source: Tanzania Ports Authority, UNCTAD

LNG Terminals

Table: Tanzania Main LNG Terminals

Name	Location	Type	Capacity (bcm)	Company	Status	Completion
Tanzania LNG	Lindi*	Export	13.6 (two-train facility); 20.4 (three-train facility)**	Shell, ExxonMobil, Ophir Energy, Statoil	Proposed	2022

** Location unconfirmed. ** Proposal is for a two-train facility, with the option for a third additional train. Source: Company data, BMI*

Competitive Landscape

Vast gas resources are proving highly attractive to international oil companies (IOCs) and provide the government with an opportunity to improve dramatically its economic position and prospects. Norway's state-controlled **Statoil** is partnered with US oil major **ExxonMobil** in one gas-rich concession, while **Royal Dutch Shell** (formerly **BG Group**) has been highly successful in drilling its series of licences negotiated under production sharing agreement (PSA) terms with **Tanzania Petroleum Development Corporation** (TPDC). Several smaller, independent energy companies have moved into the Tanzanian upstream segment, but the drive towards long-term gas exports will be led by the leading IOC partners.

- Statoil has been in Tanzania since 2007, when it signed a PSA for Block 2 with TPDC. **Statoil Tanzania** is the operator with 65% working interest, with ExxonMobil as a partner with 35% interest. The companies have made several significant discoveries in recent years, with gas resources in place estimated to be approximately 623bcm.

- **BG Group** (now **Royal Dutch Shell**) entered Tanzania in 2010 and is the operator of offshore Blocks 1, 3 and 4 in which it holds a 60% interest (BG Group withdrew from Block 3 in October 2014 after not finding sufficient resources to continue investing in exploration activities). Around 425bcm of total gross resource has been discovered and work is progressing to develop a joint liquefied natural gas (LNG) plant in collaboration with the Block 2 partners. Since entering Tanzania, the joint venture (JV) has acquired more than 13,000sq km of 3D seismic data and has had 15 consecutive drilling successes, including 10 gas discoveries and five appraisal wells. A memorandum of understanding (MoU) between the government of Tanzania, the partners in Blocks 1, 3 and 4 and the partners in Block 2 was signed in April 2014. The MoU covers the site selected for the LNG plant, the process for acquiring the site, the lease to be negotiated, and how any resettlement will be managed.

- **Ophir Energy** is now the operator of Block 3, after BG Group withdrew. It holds an 80% stake. **Pavilion Energy**, owned by Singapore investment company **Temasek Holdings**, holds the other 20%.

- Independent operator **Aminex** and partner **Solo Oil** began production at the Kiliwani North onshore gas field in April 2016. The field will supply the nearby Songo Songo processing plant and is estimated to achieve a flow rate of 4,000-5,000 boe in its first months of operation. Aminex, through its wholly owned subsidiary **Ndovu Resources** operates 3 licenses in the country: Kiliwani North Development licence (65% WI), Ruvuma Exploration Licence (75% WI), and Nyuni Exploration Licence (70% WI).

- Australian energy company **Woodside Petroleum** pulled out of an exploration joint venture with **Beach Energy** for the Lake Tanganyika South (LTS) block in Tanzania in 2014. The onshore block is close to the border with the Democratic Republic of Congo. Following Woodside's decision to relinquish its 70% stake in the permits, Beach retains 100% ownership of the LTS block and remains operator. There have not beebn significant developments at this block since Woodwide's departure.

- Australia-based explorer **Swala Energy** has a license to explore the onshore Kilosa-Kilombero license in Tanzania. The Kito-1 well is schedule for a Q316 spud. An estimated 60.4mn barrels of P50 Best Estimate Prospective Resources is net to Swala. It also holds an exploration license for the Pangani area.

- **Wentworth Resources** saw first gas at its Mnazi Bay discovery in August 2015. The gas is being sold to TPDC and is being transmitted through the country's government-owned transnational pipeline.

- French company **Maurel et Prom** announced in January 2016 that it was suspending operations in Tanzania (as well as Myanmar and Colombia) due to the fall in global oil prices and a resulting need to cut its 2016 investment plan by 70%. The company operates in the Mnazi Bay, looking to deliver gas to the Madimba processing centre, the entry point of the gas pipeline linking Mtwara to Dar es Salaam, Tanzania.

Company Profile

Statoil

Latest Updates

- Statoil continues to view its Tanzanian acreage as a key strategic asset and has made several 'high impact' discoveries there in recent years; however no significant updates within Statoil's upstream occurred in this quarter.

- A recent land deal signed with the Tanzanian government in January 2016 will give LNG export project developers, including Statoil, access to the proposed LNG export site for the first time.

Strengths	▪ Up to 595bcm of gross gas resource discovered in Block 2.
	▪ Partnership with ExxonMobil in Block 2.
Weaknesses	▪ Need to secure gas export options before reserves can be exploited.
	▪ Over-supply in global gas markets challenges commerciality of exports.
Opportunities	▪ Further exploration upside potential.
	▪ Scope for large-scale LNG exports and well positioned to serve Asian markets.
Threats	▪ Changes in national energy policy that increase costs or state interests.
	▪ Controversy over license terms.
	▪ Inability to secure gas sales contracts.

Company Overview	Norway's Statoil has been in Tanzania since 2007, when it signed a production sharing agreement (PSA) for Block 2 with Tanzania Petroleum Development Corporation (TPDC). Statoil Tanzania is the operator with 65% working interest with ExxonMobil as a partner with 35% interest. Statoil and ExxonMobil have made significant gas discoveries in Block 2 in recent years, including Zafarani, Lavani, Tangawizi and Mronge. The discoveries proved 482bn cubic metres (bcm) and 592bcm of in-place volumes. Statoil also holds a 12% interest in the Petrobras-operated Block 6, which covers 5,549sq km in the Mafia basin.

Strategy

Statoil has made rapid progress in developing its Tanzanian position in recent years, including several high impact discoveries in its Block 2 holding. It's drilling campaign there was completed in 2015, after having drilled the Mdalasini prospect and theTangawizi-2 appraisal well. The company continues to assess its options for developing its discoveries, most importantly through its participation in the Tanzania LNG export project. That project is slated to receive FID in 2016, although above-ground uncertainties in Tanzania as well as global oil price dynamics and growing competition from existing and new LNG export capacity may delay or hinder a green light on the project. If an FID is made, the LNG export project is scheduled to come online in 2022 or 2023.

Table: Discoveries In Block 2 And Gas-In-Place

Block	Well	Announcement	Water depth (m)	Size (bcm, Lower Limit)	Size (bcm, Upper Limit)	Total (bcm)
2	Zafarani-1	Feb-12	2,582	0.14	0.14	0.616
2	Lavani-1	Jun-12	2,400	0.084	0.084	
2	Lavani-2	Dec-12	2,580	N/A	N/A	
2	Tangawizi-1	Mar-13	2,300	0.112	0.168	
2	Mronge-1	Dec-13	2,500	0.056	0.084	
2	Piri-1	Jun-14	2,360	0.056	0.084	
2	Gilligiliani-1	Oct-14	2,500	0.0336	0.0336	
2	Mdalasini-1	Apr-15	2,296	0.028	0.0504	

**Interest in Block 2 is held by the following: Statoil (65%), ExxonMobil & TPDC (35%). Source: Statoil*

Financial Data

Revenue:

- USD56.3bn (2015)
- USD73.4bn (2014)
- USD74.6bn (2013)

Capital Expenditure And Investments:

- USD15.1bn (2015)
- USD14.8bn (2014)
- USD13.9bn (2013)

ExxonMobil

Latest Updates

- A January 2016 land deal made by the Tanzanian government is a positive step in the development of the Tanzania LNG project, of which ExxonMobil is a stakeholder. This may enable pre-FEED activities to begin at Lindi, as project partners are now able to gain access to the site.

Strengths	▪ A significant stake the highly prospective Block 2 area offshore Tanzania
	▪ Demonstrated commitment to East African regional offshore gas development
Weaknesses	▪ Offshore natural gas acreage development contingent upon LNG project
	▪ Global gas price weakness and downward pressure on long-term LNG contract prices
Opportunities	▪ A steady pace of discoveries both offshore and onshore
	▪ Recent progress on a land deal for LNG site suggest some positive project momentum
Threats	▪ Ongoing fiscal and regulatory uncertainty for E&P and LNG project development
	▪ Rapid development of Mozambique LNG project and others globally outcompete Tanzania LNG

Company Overview

ExxonMobil established an official presence in Tanzania in 2013 through its acquisition of a 35% stake in the offshore Block 2, which is 65% held and operated by Norway's **Statoil**. The two companies have made a substantial number of discoveries in recent years, including the Zafarani, Lavani, Tangawizi and Mronge finds, bringing the estimated resources up to 595bcm of gas-in-place. The two companies remain active in their exploration activities while continuing to press toward the development of the Tanzania LNG project, an FID on which could be made in 2016. ExxonMobil maintains a stake in that LNG project, along with **Tanzania Petroleum Development Corporation** (TPDC), **Statoil**, **BG Group** (**Royal Dutch Shell**), **Ophir Energy** and **Pavilion Energy**

(Natural Gas Asia). Development of Block 2 is dependent upon a successful FID on the LNG export project.

Strategy

ExxonMobil is heavily invested in natural gas exploration activities in East Africa as demonstrated by its stake in offshore production and export projects in both Tanzania and Mozambique. Its commitment to the region appears to remain strong despite a 58% fall in profit for the company in Q42015 and sustained global headwinds for greenfield LNG projects. Indeed, it was reported in March 2016 that ExxonMobil is looking to acquire a 15% stake in Eni's Area 4 natural gas field in the Rovuma Basin offshore Mozambique. If completed, it would represent the company's first major acquisition since oil prices collapsed. There are also rumours of the company's interest in a slice of Anadarko's Area 1 acreage.

However, Mozambique's LNG project is progressing more rapidly than the project in Tanzania (with an FID expected in June 2016) and could therefore pose as a threat to the latter's near-term attractiveness, particularly if Tanzania's LNG project developers, including ExxonMobil, expect continued softness in Asian LNG demand and downward pressure on contracts.

Finally, it has been speculated that ExxonMobil's reported interest in additional acreage in Mozambique may be as a result of the BG Group merger with Royal Dutch Shell which gives the new company -- the largest LNG player in the world - control of a significant amount of Tanzania's offshore assets and an opportunity to integrate Tanzanian gas into its global LNG trading network. While ExxonMobil stands to benefit from progress in Tanzania, it could be interested in expanding its holdings in Mozambique which is both farther along and in which Shell does not have a stake.

Financial Data

Upstream Earnings:

- 2015: USD7.1bn
- 2014: USD27.55bn
- 2013: USD26.84bn
- 2012: USD29.89bn
- 2011: USD34.44bn

Capital And Exploration Expenditures

- 2015: USD25.41bn
- 2014: USD32.73bn
- 2013: USD38.23bn
- 2012: USD36.08bn
- 2011: USD33.09bn

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**Interest in Block 2 is held by the following: Statoil (65%), ExxonMobil & TPDC (35%). Source: Statoil*

Shell

Latest Updates

- Royal Dutch Shell won shareholder approval to formally acquire BG Group in January 2016, making the company the largest LNG trader in the world, with control of approximately 53mn tonnes per annum (mtpa) by 2020.
- Shell announced in March 2016 that it had appointed the investment bank Lazard to advice on USD30 billion in asset sales in the wake of the merger. It is not yet known whether or not that will include any of the company's holdings in Tanzania.

Strengths	▪ At least 425bcm of gross gas resources in Tanzania. ▪ Large acreage position. ▪ Shell's takeover of BG makes it the world's largest LNG seller.
Weaknesses	▪ Ongoing fiscal and regulatory uncertainty challenge LNG export development. ▪ Falling global LNG prices amid rising competition.
Opportunities	▪ Additional natural gas discoveries. ▪ LNG export volumes well positioned to serve Asian markets.
Threats	▪ Falling global LNG prices amid rising competition. ▪ Shell merger results in sale of Tanzanian assets. ▪ Changes in government energy policies.

Company Overview	Shell entered Tanzania through the purchase of BG Group, which entered the market in 2010 as the operator of offshore Blocks 1, 3 and 4 in which it has a 60% interest. Its acreage currently holds approximately 425bcm of total gross gas resources although the area still remains highly prospective, giving its estimate additional upside potential. Shell is also a primary project partner in Tanzania's LNG export project, along with ExxonMobil, Statoil, Ophir Energy, and Tanzania Petroleum Development Corporation (TPDC). The project partners are expected to make an FID in 2016 on the project,

although rising competition in the global gas market and regulatory delays in Tanzania may delay that. A decision to not move forward with the LNG export project will likely threaten the development of a significant amount of Tanzania's offshore gas resources.

Strategy

Royal Dutch Shell's takeover of BG Group has given the company the title of 'ultramajor', which it shares only with ExxonMobil. The merger also created the largest LNG business in the world, which is expected to have control over 53mn tonnes per annum (mtpa) by 2020. The company's involvement in Tanzania's LNG export project is therefore positive for the project's outlook, as gas volumes could be traded through Shell's worldwide LNG trading business.

The company's role in Tanzanian gas development is significant, as it is one of the major investors in its offshore acreage and its LNG export project. The merger of BG Group's portfolio of assets with that of Shell's began in Q116, however, and it is not yet known how Shell leadership will view its Tanzanian investments. Growing competition within the global LNG market is depressing prices, adding additional challenges to high-cost greenfield projects as in Tanzania. Additionally, the more rapid progress being made in Mozambique on its LNG export project is its most direct competition. An FID for Mozambique's project, which is being led by Anadarko, is expected in H216. These factors will all weigh into Shell's asset review process, as will the company's long-term global LNG strategy in the post-2020 period. Indeed, the company's view on whether the global gas glut will have passed by 2022-2023 will be essential to its investment strategy vis-a-vis Tanzania.

Financial Data

Gross exploration expenditure in Tanzania:

- 2015: USD57mn
- 2014: USD256mn

Group Revenue and other operating income:

- 2015: USD16.419bn
- 2014: USD19.546bn
- 2013: USD19.101bn

EBITDA:

- 2015: USD5.633bn
- 2014: 9.176bn
- 2013: USD10.41bn

Table: Shell (BG Group) Assets in Tanzania

License/ Concession/ Block	Area, sq km	Year of entry/ acquisition	License/ Concession Period	Discoveries	Fiscal Regime	Equity Holders (%) and Operator
Block 1	8,254	2010		Chaza Jodari Jodari North Mkizi Mzia Taachui	PSA	**BG Group (60%)** Ophir Energy (20%) Pavillion Energy (20%)
Block 4	3,806	2010		Chewa Ngisi Pweza	PSA	**BG Group (60%)** Ophir Energy (20%) Pavillion Energy (20%)

Source: BG Group

Regional Overview

Africa - Bullish Gas, Bearish Oil

BMI View: *Africa's gas production is set for strong growth, led by major additions in Tanzania and Mozambique. However, delays to FID on LNG export projects in these countries pose risk to the downside. The long-term outlook on oil is heavily bearish, as a thinning projects pipeline and a lack of new investment push production into secular decline post-2019. The short-term outlook has become increasingly clouded this quarter and large-scale outages in Nigeria, Libya and South Sudan threaten to drive 2016 output growth into negative territory. Consumption is a bright spot for both oil and gas, with strong growth rates forecast for the period. However, given the region's small and poorly efficient refining sector, this implies a growing dependence on imported fuels.*

To highlight key themes in **BMI**'s Africa oil and gas outlook and forecasts, we have compared countries on the basis of the following key indicators:

- Oil Production
- Oil Consumption
- Refining Capacity
- Gas Production
- Gas Consumption

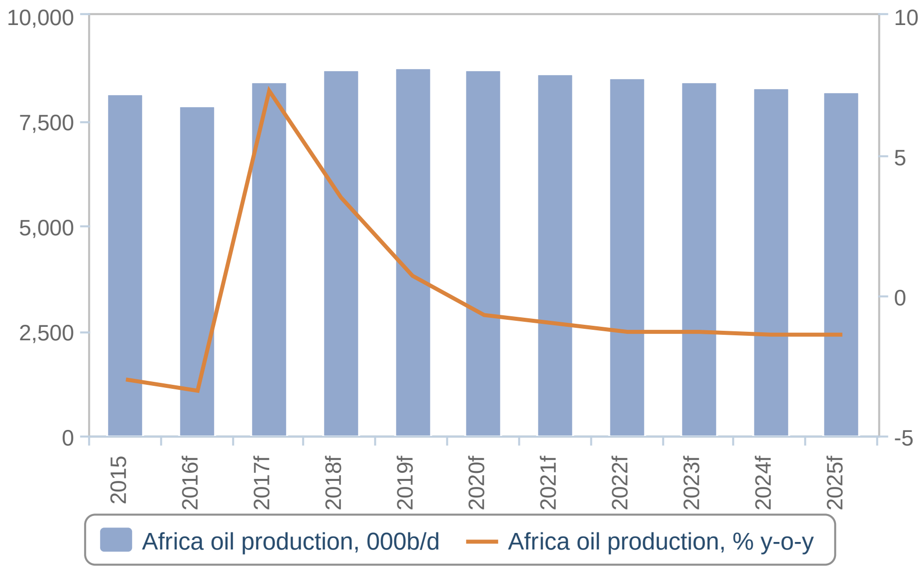
Oil Production

Despite the region's substantial reserves and vast prospective resource base, Africa's long-term oil production outlook is bearish. A mix of lower oil prices, continued insecurity and ongoing fiscal and regulatory uncertainties has undercut upstream investments and will ultimately drag on overall production.

Output growth will be strong in the period 2017-2018, due to a large pipeline of projects which are post-FID and under construction. However, from 2019 growth rates will slump before production lapses into decline in 2020.

Production Growth Unsustainable

Africa Oil Production Forecast (000b/d & % chg y-o-y)



f = BMI forecast. Source: National sources, EIA, BMI

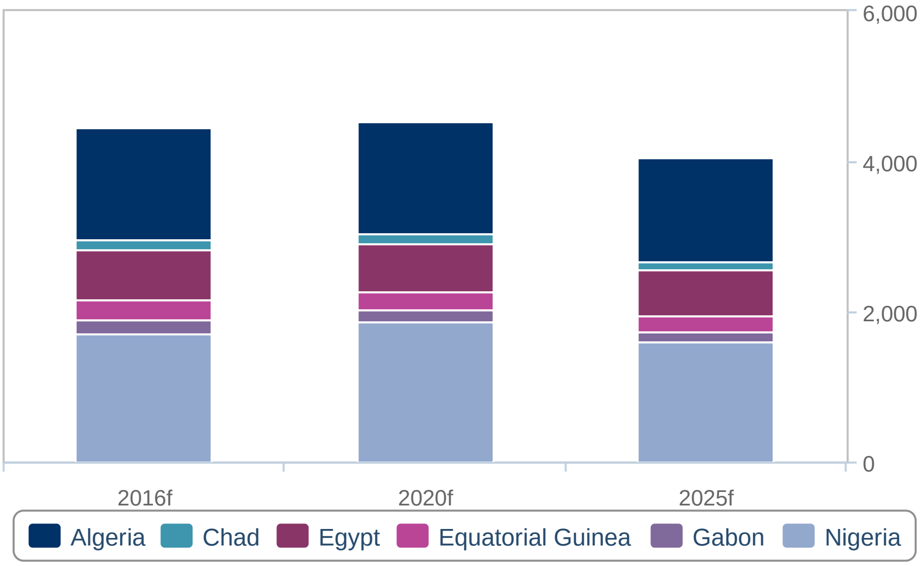
Sustained lower oil prices will be a major driver of structural decline in the region's production. Cutbacks in spending in higher cost and higher risk areas are putting a number of African markets and several key projects at a disadvantage; for instance, those offshore Tanzania and Mozambique or in deepwater West Africa are facing a high risk of cancellation or delay.

Among the region's major maturing producers, several are battling falls in output. The heaviest losses are seen in Algeria and Nigeria. In the latter, underlying insecurity, widespread oil theft and continued uncertainty over the passage of the Petroleum Industry Bill have all inhibited investment. A recent resurgence of violence in the Niger Delta - led by the Niger Delta Avengers - has crippled output, with little scope for a recovery in 2016. We have downgraded our Nigeria oil production forecast from 2.3mn b/d to 1.7mn b/d for 2016, dragging the region as a whole into a 3.4% y-o-y decline.

The security environment in Algeria is also fragile, but the impact on output has been relatively muted. The country boasts relative fiscal and regulatory stability, but contract terms are poor and the dominance of national oil company **Sonatrach** is a major deterrent to investors. These dynamics are unlikely to change, posing little upside risk to our 10-year forecast.

Mature Producers Driving Decline

Select Countries - Oil Production Forecasts (000b/d)



f = BMI forecast. Source: National sources, BMI

Libya and South Sudan are also both producing significantly below production capacity. Pervasive security threats have triggered repeated outages, contributing to high volatility in output in recent years. Given the degree of social and political fragmentation in these countries and the deeply entrenched nature of the conflicts, prospects for a full recovery in production are relatively poor.

West Africa is a regional bright spot and we forecast net output additions of 455,000b/d in Angola, Congo-Brazzaville and Ghana combined over 2016 and 2017. However, there remain risks to these countries at the tail end of our forecast period, due to the slow pace of exploration and a continued pullback in spending across the industry.

Oil Consumption

Africa is set for the most rapid growth in refined fuels consumption of any region globally, averaging 2.8% a year over the next 10 years. However, there are mounting risks to the forecast, due to the deteriorating macroeconomic environment in several key consumer countries and ongoing subsidy reforms.

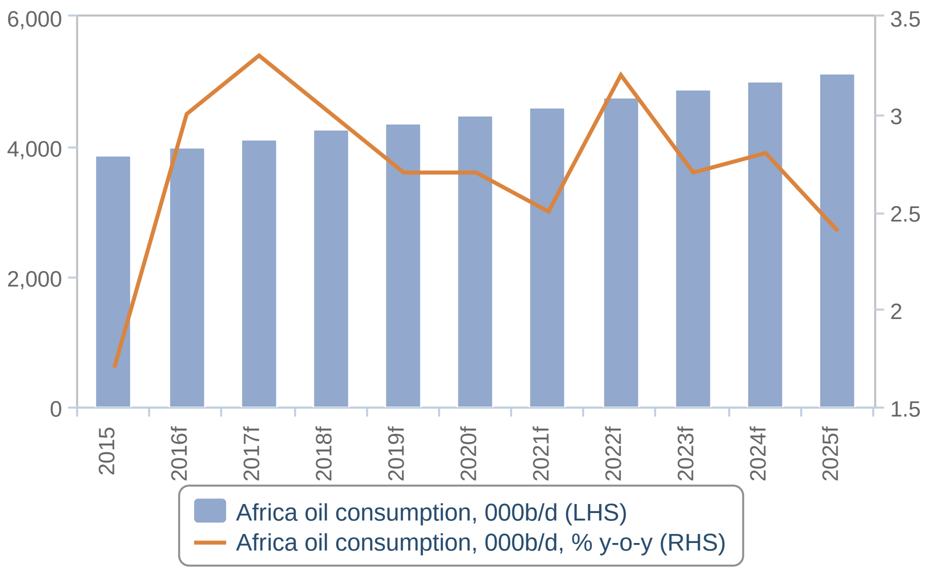
Consumption is heavily concentrated in Algeria, Egypt, Nigeria and South Africa, which will together account for 54.9% of the regional total in 2016. We forecast these four majors to consume 52.6% of Africa's refined fuels in 2025. Strong growth in a number of peripheral markets in both East Africa (Mozambique, Tanzania and Uganda) and West Africa (Cameroon, Congo-Brazzaville, Ghana and Gabon) will only partly dilute their share of consumption.

Subsidy reforms in Egypt are driving a slower pace of consumption growth, averaging 2.2% over the 10-year period. However, continued signs of policy slippage led us to upgrade consumption this quarter. Algeria and Nigeria have both reduced domestic fuel subsidies in 2016, although prices in Algeria remain substantially below market rates. South Africa has also proposed subsidy reform, but we believe continued inflationary pressures will likely restrain progress here.

Of greater concern, the commodity price slump has exacerbated existing structural weaknesses in the economies of Algeria, Nigeria and South Africa, worsening their growth outlooks. A sustained slowdown of growth in these countries could have significant feed through effects on regional consumption levels.

Outpacing Global Peers

Africa Oil Consumption Forecast (000b/d & % chg y-o-y)



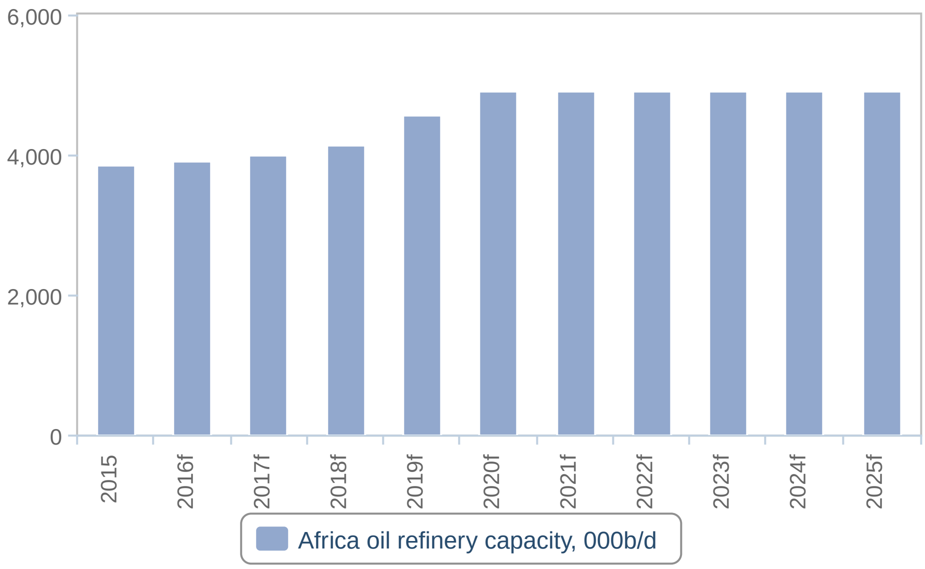
f = BMI forecast. Source: National sources, EIA, BMI

Refining

The African downstream sector is weak and faces major barriers to growth. Nominally, regional refining capacity will be broadly sufficient to keep pace with demand across our forecast period; however, output will continue to lag below capacity, driving a continued dependence on imported fuels in the region.

Set For Small But Significant Capacity Growth

Africa Refining Capacity Forecast (000b/d)



f = BMI forecast. Source: National sources, EIA, BMI

Typically, African refineries are low complexity and have poor operational efficiency. Refiners face various headwinds including fuel subsidies, financing constraints and the unreliability of crude feeds, which undercut overall profitability. We forecast capacity additions in Angola, Cameroon, Egypt, Nigeria and Uganda but see limited appetite for further investment in the African downstream in the coming years.

In total, Africa refining capacity will see a net addition of 1.1mn b/d over our 10-year forecast period, in line with the 1.1mn b/d increase in refined fuels consumption. Incremental efficiency gains will also support marginally higher utilisation rates at existing facilities. However, a substantial deficit will remain, with net fuels imports standing at 1.3mn b/d in 2025, compared to 1.2mn b/d in 2015.

Gas Production

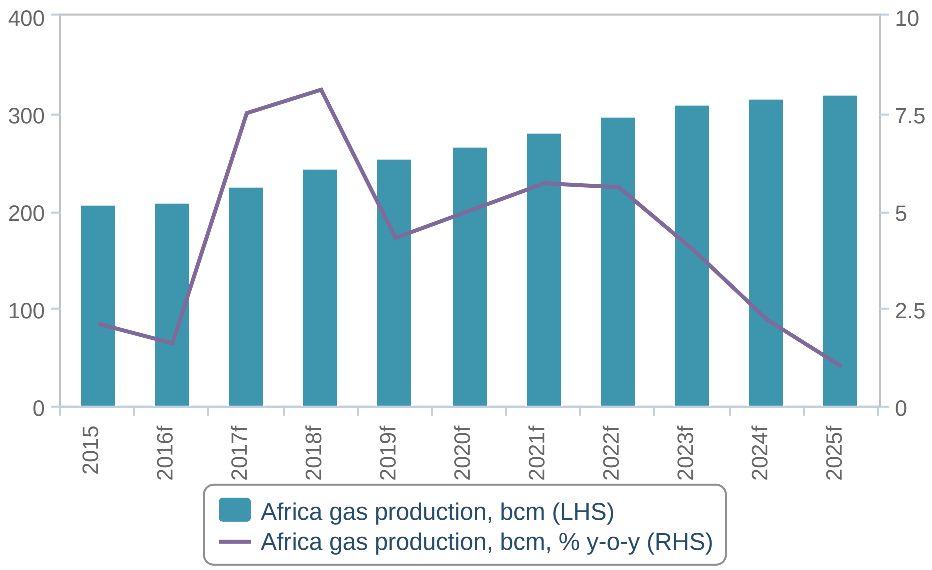
In contrast to oil, the outlook on gas production is broadly bullish. We forecast a net increase of 112.8bcm over the next 10 years, with 5.5% CAGR.

Increased political stability and rising investment will support higher production in Egypt, while the discovery at Zohr poses large risk to the upside. Nigeria is also growing its output, with progress made on a reduction in flaring. However, the country will underperform its vast potential, with infrastructural bottlenecking and pervasive insecurity dragging on growth.

Algeria is the only country in the region facing decline in gas production over the period, as the depletion of the major Hassi R'Mel field offsets a number of smaller field developments. A slowdown in investment and falling foreign participation in the sector pose further downside risks.

Emergent Producers Drive Surge In Output

Africa Gas Production Forecast (bcm & % chg y-o-y)

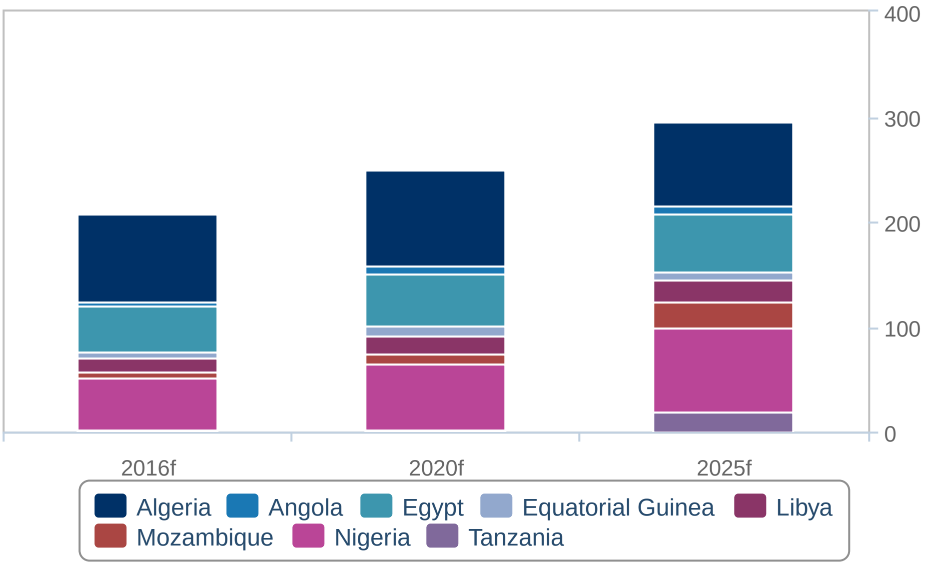


f = BMI forecast. Source: National sources, EIA, BMI

Mozambique and Tanzania will see the fastest pace of growth, with major offshore discoveries forecast to add a combined 36.7bcm by 2025, representing CAGR 52.2%. However, the risks to this forecast lie to the downside. Given the small size of the domestic markets, production depends on the development of large LNG export facilities. With softening LNG prices and a mounting glut in the global supply, there are downside risks to 2016-2017 FID on the major onshore projects, which could push the ramp-up in production outside our forecast period.

Emergent Producers Spurring Growth

Selected Countries Gas Production Forecast (bcm)



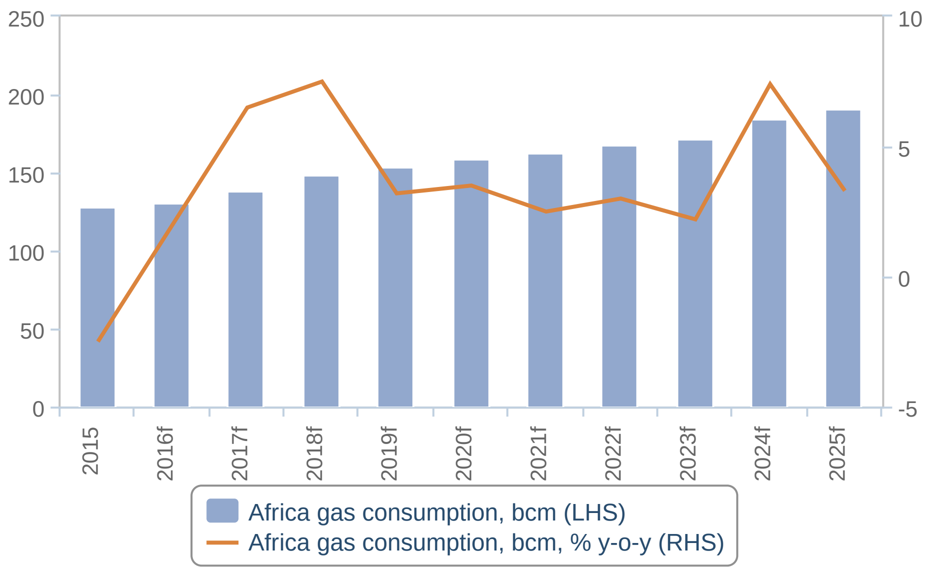
f = BMI forecast. Source: National sources, BMI

Gas Consumption

We forecast strong gas consumption growth for the region at 63.1bcm, with an annual average growth rate of 4.9%. However, consumption will remain heavily dominated by Algeria, Egypt and Nigeria, which accounted for 76.5% of the region's consumption in 2015, and will account for 69.8% in 2025.

Regional Demand Growth On Solid Uptrend

Africa Gas Consumption Forecast (bcm & % chg y-o-y)



f = BMI forecast. Source: National sources, EIA, BMI

Due to the lack of regional pipeline infrastructure, the small size of the domestic markets and the high cost of LNG import terminals, consumption growth in most countries - excluding South Africa and Ghana - is closely tied to the growth in domestic production. We flag Angola, Cameroon, Ghana and Gabon in West Africa, and Mozambique and Tanzania in East Africa as the key emergent growth markets. However, midstream and offtake infrastructure remains limited in all these countries, and could serve to bottleneck consumption. Mozambique and Tanzania are both exploring options for pan-regional gas networks, but the high cost of these developments coupled with the lack of anchor offtake projects pose barriers.

Table: Africa Oil & Gas Production, Consumption, Refining Capacity And Trade

	2014	2015	2016f	2017f	2018f	2019f	2020f
Africa oil production, 000b/d	8,369.1	8,121.7	7,844.4	8,417.4	8,715.1	8,778.3	8,717.1
Africa oil production, % y-o-y	-3.4	-3.0	-3.4	7.3	3.5	0.7	-0.7
Africa oil consumption, 000b/d	3,822.3	3,887.0	4,005.2	4,137.1	4,262.4	4,379.1	4,496.9
Africa oil consumption, 000b/d, % y-o-y	1.0	1.7	3.0	3.3	3.0	2.7	2.7
Africa oil net exports, 000b/d	4,546.8	4,234.8	3,839.3	4,280.4	4,452.8	4,399.2	4,220.2
Africa oil net exports, 000b/d, % y-o-y	-6.9	-6.9	-9.3	11.5	4.0	-1.2	-4.1
Africa oil refinery capacity, 000b/d	3,837.7	3,863.7	3,916.7	4,001.7	4,147.7	4,559.7	4,919.7
Africa oil refinery capacity, 000b/d, % y-o-y	0.7	0.7	1.4	2.2	3.7	9.9	7.9
Africa gas production, bcm	202.1	206.2	209.6	225.3	243.4	253.8	266.5
Africa gas production, bcm, % y-o-y	-0.9	2.1	1.6	7.5	8.1	4.3	5.0
Africa gas consumption, bcm	131.0	127.7	130.3	138.8	149.2	154.0	159.4
Africa gas consumption, bcm, % y-o-y	-2.5	-2.5	2.0	6.5	7.5	3.2	3.5
Africa gas net exports, bcm	71.1	78.5	79.3	86.5	94.3	99.8	107.1
Africa gas net exports, bcm, % y-o-y	2.2	10.4	1.0	9.1	9.0	5.9	7.3

f = BMI forecast. Source: BMI, EIA

Glossary

Table: Glossary Of Terms

AOR	additional oil recovery	**KCTS**	Kazakh Caspian Transport System
APA	awards for predefined areas	**km**	kilometres
API	American Petroleum Institute	**LAB**	linear alkyl benzene
bbl	barrel	**LDPE**	low density polypropylene
bcm	billion cubic metres	**LNG**	liquefied natural gas
b/d	barrels per day	**LPG**	liquefied petroleum gas
bn	billion	**m**	metres
boe	barrels of oil equivalent	**mcm**	thousand cubic metres
BTC	Baku-Tbilisi-Ceyhan Pipeline	**Mcm**	mn cubic metres
BTU	British thermal unit	**MEA**	Middle East and Africa
Capex	capital expenditure	**mn**	million
CBM	coal bed methane	**MoU**	memorandum of understanding
CEE	Central and Eastern Europe	**mt**	metric tonne
CPC	Caspian Pipeline Consortium	**MW**	megawatts
CSG	coal seam gas	**na**	not available/ applicable
DoE	US Department of Energy	**NGL**	natural gas liquids
EBRD	European Bank for Reconstruction & Development	**NOC**	national oil company
EEZ	exclusive economic zone	**OECD**	Organisation for Economic Cooperation & Development
e/f	estimate/forecast	**OPEC**	Organization of the Petroleum Exporting Countries
EIA	US Energy Information Administration	**PE**	polyethylene
EM	emerging markets	**PP**	polypropylene
EOR	enhanced oil recovery	**PSA**	production sharing agreement
E&P	exploration and production	**PSC**	production sharing contract
EPSA	exploration and production sharing agreement	**q-o-q**	quarter-on-quarter
FID	final investment decision	**R&D**	research and development
FDI	foreign direct investment	**R/P**	reserves/production
FEED	front end engineering and design	**RPR**	reserves to production ratio
FPSO	floating production, storage and offloading	**SGI**	strategic gas initiative
FTA	free trade agreement	**SoI**	statement of intent
FTZ	free trade zone	**SPA**	sale and purchase agreement
GDP	gross domestic product	**SPR**	strategic petroleum reserve

Glossary Of Terms - Continued			
G&G	geological and geophysical	**t/d**	tonnes per day
GoM	Gulf of Mexico	**tcm**	trillion cubic metres
GS	geological survey	**toe**	tonnes of oil equivalent
GTL	gas-to-liquids conversion	**tpa**	tonnes per annum
GW	gigawatts	**TRIPS**	Trade-Related Aspects of Intellectual Property Rights
GWh	gigawatt hours	**trn**	trillion
HDPE	high density polyethylene	**T&T**	Trinidad & Tobago
HoA	heads of agreement	**TTPC**	Trans-Tunisian Pipeline Company
IEA	International Energy Agency	**TWh**	terawatt hours
IGCC	integrated gasification combined cycle	**UAE**	United Arab Emirates
IOC	international oil company	**USGS**	US Geological Survey
IPI	Iran-Pakistan-India Pipeline	**WAGP**	West African Gas Pipeline
IPO	initial public offering	**WIPO**	World Intellectual Property Organization
JOC	joint operating company	**WTI**	West Texas Intermediate
JPDA	joint petroleum development area	**WTO**	World Trade Organization

Source: BMI

Methodology

Industry Forecast Methodology

BMI's industry forecasts are generated using the best-practice techniques of time-series modelling and causal/econometric modelling. The precise form of model we use varies from industry to industry, in each case being determined, as per standard practice, by the prevailing features of the industry data being examined.

Common to our analysis of every industry is the use of vector autoregressions. Vector autoregressions allow us to forecast a variable using more than the variable's own history as explanatory information. For example, when forecasting oil prices, we can include information about oil consumption, supply and capacity.

When forecasting for some of our industry sub-component variables, however, using a variable's own history is often the most desirable method of analysis. Such single-variable analysis is called univariate modelling. We use the most common and versatile form of univariate models: the autoregressive moving average model (ARMA).

In some cases, ARMA techniques are inappropriate because there is insufficient historic data or data quality is poor. In such cases, we use either traditional decomposition methods or smoothing methods as a basis for analysis and forecasting.

BMI mainly uses OLS estimators and in order to avoid relying on subjective views and encourage the use of objective views, **BMI** uses a 'general-to-specific' method. **BMI** mainly uses a linear model, but simple non-linear models, such as the log-linear model, are used when necessary. During periods of 'industry shock', for example poor weather conditions impeding agricultural output, dummy variables are used to determine the level of impact.

Effective forecasting depends on appropriately selected regression models. **BMI** selects the best model according to various different criteria and tests, including but not exclusive to:

- R^2 tests explanatory power; adjusted R^2 takes degree of freedom into account;
- Testing the directional movement and magnitude of coefficients;
- Hypothesis testing to ensure coefficients are significant (normally t-test and/or P-value);
- All results are assessed to alleviate issues related to auto-correlation and multi-collinearity.

BMI uses the selected best model to perform forecasting.

Human intervention plays a necessary and desirable role in all of **BMI**'s industry forecasting. Experience, expertise and knowledge of industry data and trends ensure that analysts spot structural breaks, anomalous data, turning points and seasonal features where a purely mechanical forecasting process would not.

Sector-Specific Methodology

There are a number of principal criteria that drive our forecasts for each energy indicator.

Energy Supply

This covers the supply of crude oil, natural gas, refined oil products and electrical power, which is determined largely by investment levels, available capacity, plant utilisation rates and national policy. We therefore examine:

- National energy policy, stated output goals and investment levels;
- Company-specific capacity data, output targets and capital expenditures, using national, regional and multinational company sources;
- International quotas, guidelines and projections from organisations such as OPEC, the International Energy Agency (IEA), and the US Energy Information Administration (EIA).

Energy Consumption

A mixture of methods is used to generate demand forecasts, applied as appropriate to each individual country:

- Underlying economic (GDP) growth for individual countries/regions, sourced from **BMI** published estimates;
- Historic relationships between GDP growth and energy demand growth in an individual country are analysed and used as the basis for predicting levels of consumption;
- Government projections for oil, gas and electricity demand;
- Third-party agency projections for regional demand, from organisations such as the IEA, EIA and OPEC;

Extrapolation of capacity expansion forecasts based on company- or state-specific investment levels.

Cross Checks

Whenever possible, we compare government and/or third-party agency projections with the declared spending and capacity expansion plans of the companies operating in each individual country. Where there are discrepancies, we use company-specific data as physical spending patterns to determine capacity and supply capability. Similarly, we compare capacity expansion plans and demand projections to check the energy balance of each country. Where the data suggest imports or exports, we check that necessary capacity exists or that the required investment in infrastructure is taking place.

Source

Sources include those international bodies mentioned above, such as OPEC, IEA, and EIA, as well as local energy ministries, official company information, and international and national news, plus international and national news agencies.

Risk/Reward Index Methodology

BMI's Risk/Reward Index (RRI) provides a comparative regional ranking system evaluating the ease of doing business and the industry-specific opportunities and limitations for potential investors in a given market. The RRI system is divided into two distinct areas:

Rewards**:** Evaluation of sector's size and growth potential in each state, and also broader industry/state characteristics that may inhibit its development. This is further broken down into two sub-categories:

- Industry Rewards (this is an industry-specific category taking into account current industry size and growth forecasts, the openness of market to new entrants and foreign investors, to provide an overall score for potential returns for investors);
- Country Rewards (this is a country-specific category, and the score factors in favourable political and economic conditions for the industry).

Risks**:** Evaluation of industry-specific dangers and those emanating from the state's political/economic profile which call into question the likelihood of anticipated returns being realised over the assessed time period. This is further broken down into two sub-categories:

- Industry Risks (this is an industry-specific category whose score covers potential operational risks to investors, regulatory issues inhibiting the industry, and the relative maturity of a market);
- Country Risks (this is a country-specific category in which political and economic instability, unfavourable legislation and a poor overall business environment are evaluated to provide an overall score).

We take a weighted average, combining Market and Country Risks, or Industry and Country Rewards. These two results in turn provide an overall Risk/Reward Index score, which is used to create our regional ranking system for the risks and rewards of involvement in a specific industry in a particular country.

For each category and sub-category, each state is scored out of 100 (with 100 the best), with the overall Risk/Reward Index score a weighted average of the total score. Importantly, as most of the countries and territories evaluated are considered by **BMI** to be 'emerging markets', our index is revised on a quarterly basis. This ensures that the index draws on the latest information and data across our broad range of sources, and the expertise of our analysts.

Sector-Specific Methodology

BMI's approach in assessing the Risk/Reward balance for oil and gas industry investors is three-fold:

- First, we have disaggregated the upstream (oil and gas exploration and production) and downstream (oil refining and marketing, gas processing and distribution), enabling us to take a more nuanced approach to analysing the potential in each segment, and identifying the different risks along the value chain.
- Second, we have identified objective indicators that may serve as proxies for issues and trends that were previously evaluated on a subjective basis.
- Finally, we have used **BMI**'s proprietary Country Risk Index in a more refined manner in order to ensure that only those risks most relevant to the industry have been included.

Conceptually, the index is organised in a manner that enables us clearly to present the comparative strengths and weaknesses of each state. The headline oil and gas index score is the principal score. However, the differentiation of upstream and downstream and the articulation of the elements that comprise each segment enable more sophisticated conclusions to be drawn, and also facilitate the use of the index by clients who have varying levels of exposure and risk appetite.

Our sector-specific industry indices include:

- Oil & Gas Risk/Reward Index: this is the overall index score, which comprises 50% upstream and 50% downstream;
- Upstream Oil & Gas Risk/Reward Index: this is the overall upstream index score, which is composed of rewards/risks (see below);
- Downstream Oil & Gas Risk/Reward Index: this is the overall downstream index score, which comprises rewards/risks (see below).

The following indicators have been used. Overall, the index uses three subjectively measured indicators and 41 separate indicators/datasets.

Table: Bmi's Oil & Gas Upstream Risk/Reward Index	
	Rationale
Upstream RRR: Rewards	
Industry Rewards	
Resource Base	
- Proven oil reserves, mn bbl	Indicators used to denote total market potential. High values given better scores.
- Proven gas reserves, bcm	
Growth Outlook	
- Oil production growth, 2009-2014	Indicators used as proxies for BMI's market assumptions, with strong growth accorded higher scores.
- Gas production growth, 2009-2014	
Market Maturity	
- Oil reserves/production	Indicator used to denote whether industries are frontier/emerging/ developed or mature markets. Low existing exploitation in relation to potential is accorded a higher score.
- Gas reserves and production	
- Current oil production versus peak	
- Current gas production versus peak	
Country Rewards	
State ownership of assets, %	Indicator used to denote opportunity for foreign NOCs/IOCs/ independents. Low state ownership scores higher.
Number of non-state companies	Indicator used to denote market competitiveness. Presence (and large number) of non-state companies scores higher.
Upstream RRR: Risks	
Industry Risks	
Licensing terms	Subjective evaluation of government policy towards sector against BMI-defined criteria. Protectionist states are marked down.
Privatisation trend	Subjective evaluation of government industry orientation. Protectionist states are marked down.
Country Risks	
Physical infrastructure	Score from BMI's Country Risk Index (CRI). It evaluates the constraints imposed by power, transport and communications infrastructure.
Long-term policy continuity risk	From CRI. It evaluates the risk of a sharp change in the broad direction of government policy.
Rule of law	From CRI. It evaluates government's ability to enforce its will within the state.

Bmi's Oil & Gas Upstream Risk/Reward Index - Continued

	Rationale
Corruption	From CRI, to denote risk of additional legal costs and possibility of opacity in tendering or business operations affecting companies' ability to compete.

NOC = national oil company; IOC = international oil company. Source: BMI

Weighting

Given the number of indicators/datasets used, it would be inappropriate to give all sub-components equal weight. Consequently, the following weighting has been adopted:

Table: Weighting

Component	Weighting, %
Upstream RRI	50, of which
Rewards	70 of Upstream RRI, of which
- Industry Rewards	75
- Country Rewards	25
Risks	30 of Upstream RRI, of which
- Industry Risks	65
- Country Risks	35
Downstream RRI	50 of Oil & Gas RRI, of which
Rewards	70 ,of which
- Industry Rewards	75
- Country Rewards	25
Risks	30, of which
- Industry Risks	60
- Country Risks	40

Source: BMI