



International Gas Outlook and Implications for Developing Tanzania's Gas Projects

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This brief reviews recent international gas developments, the outlook in this regard and implications for the development of proposed offshore gas projects in Tanzania. As the country aims to benefit from its gas discoveries by increasing its domestic gas use, it also outlines some of the trade-offs and considerations that need to be taken into account when negotiating the domestic gas allocation.



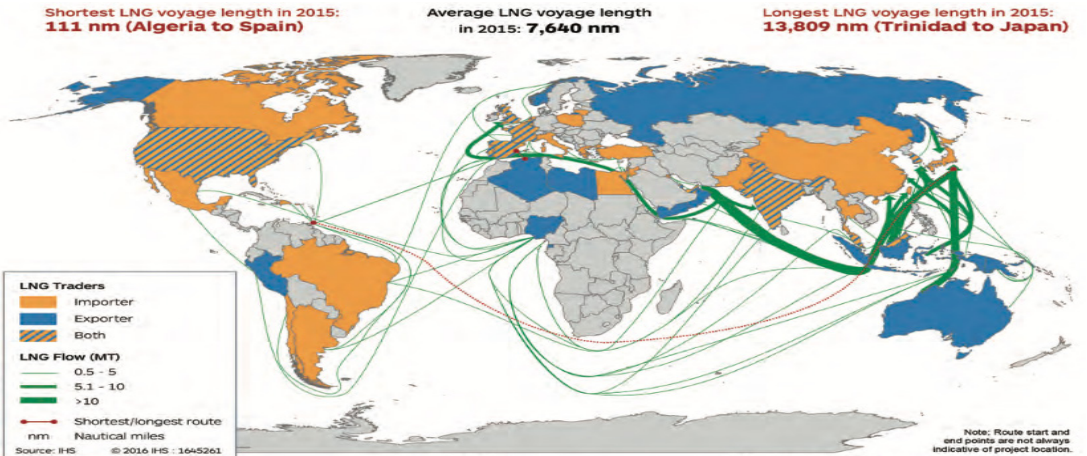
The International Gas Market

1. Recent Developments

Falling transport costs and large arbitrage opportunities arising as a result of price differentials between gas markets have made liquefied natural gas (LNG) projects attractive.¹ The LNG sector grew by 6% per annum between 2005 and 2014, and today makes up around 10% of natural gas consumption and 31% of natural gas trade (IEA, 2016). As of January 2017, global liquefaction capacity was estimated at 339.7mtpa. The major LNG producers in 2016 were Australia, Malaysia and Qatar, which together accounted for more than half of global exports. Angola, Egypt, Equatorial Guinea, Libya and Nigeria are the African LNG exporters. The biggest importing region was Asia Pacific, accounting for 54% of LNG imports, with Japan alone taking up 32%. Asia followed with 19% and Europe with 15% of global imports. Figure 1 below outlines the trade flows observed in 2015.

International gas prices have been highly volatile in recent years, as Figure 2 shows. Prices fell rapidly after the financial crisis in 2008, and this was followed by sharp increases in Asia and Europe. The gas supply glut in the US resulting from the shale boom kept prices down in North America. In contrast, the Fukushima disaster in 2011 in Japan, coupled with gas demand growth in China, India, South Korea and Taiwan, meant spreads between the US and Asia increased significantly, with the highest margins between these two markets ever seen in 2012 at around \$14/MMBtu. Prices in Europe, where pipeline import options mean there is less reliance on LNG, have been between those observed in the US and Asia since 2010.

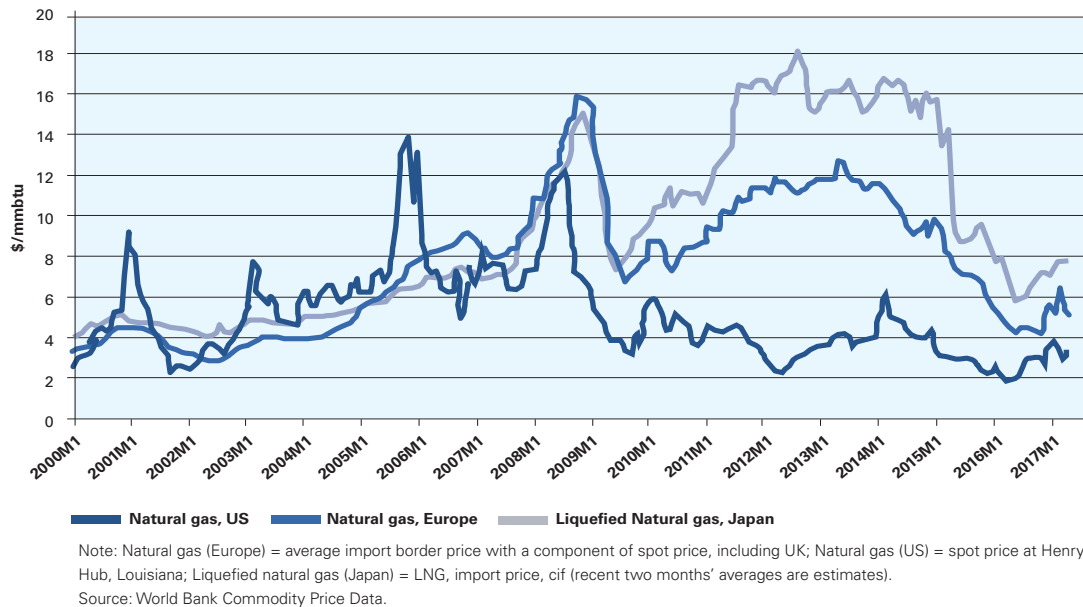
FIGURE 1: LNG IMPORTERS, EXPORTERS AND MAJOR SHIPPING ROUTES, 2015



Source: IGU (2016).

¹ Gas is not a commodity like oil or coal. Its physical nature creates a dependence on the presence of dedicated and specialised pressure, temperature control, processing and transportation infrastructure. This in turn explains why markets vary by location.

FIGURE 2: INTERNATIONAL GAS PRICES (IN NOMINAL TERMS), 2000–2017



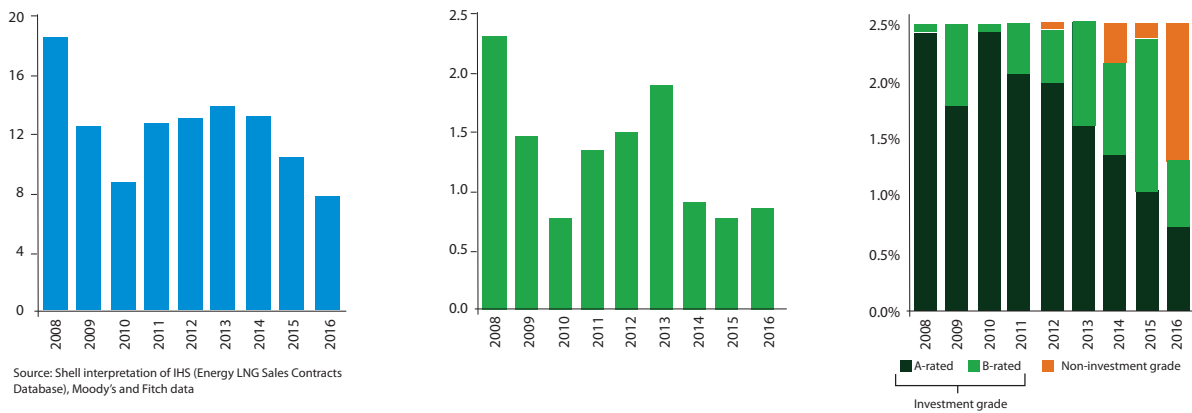
Since 2014, ‘A combination of robust LNG supply, slowing demand growth, low oil prices and ample availability of shale gas in North America has pulled down regional gas prices around the world’ (EIA, 2016). The fall in crude oil prices has had the largest impact on LNG prices, given that over two-thirds of gas sold in 2016 went at prices linked to crude oil. LNG and natural gas prices in the main markets finished 2016 below expectations: 17% lower in Japan, 20% lower in Europe and 30% lower in the US as compared with the end of 2015. Cold winter weather in Asia and Europe meant there was an increase in prices towards the end of 2016 and into 2017.

While the majority of LNG is still sold at prices linked to crude oil, there has been a rise in shorter-term spot market trades, an emergence of new trading hubs, in particular in Asia, and an increase in the flexibility of the destination clauses in US LNG export contracts.² The recent LNG supply glut has increased the influence of LNG buyers on contract terms, with a reduction in the average contract volumes and a rise in the number of new emerging market buyers with lower or no credit ratings (e.g. Egypt, India, Pakistan).³ These trends can be observed in Figure 3 and may fundamentally alter the LNG business by promoting the emergence of a global gas market. This, in turn, may have an important impact on the development of Tanzanian offshore gas projects, as outlined in Part C.

² Destination clauses limit the buyer’s right to resell the gas.

³ The increase in buyer credit risk also contributes to shorter contract lengths, since lower credit quality prevents these emerging buyers from contracting on a longer-term basis. Higher credit risk also contributes to an expansion of the role of intermediaries in the LNG market as commodity trading companies as effective managers of credit risk (Gas Strategies, 2017).

FIGURE 3: CHANGING DYNAMICS IN LNG CONTRACTING, 2008–2016



Source: Shell (2017), in Timera Energy (2017).

Short-term contracts on the rise in all markets

There is currently no globally integrated market for natural gas, and pricing mechanisms vary by regional market. In most cases, internationally traded natural gas has been indexed to crude oil prices in the frame of long-term contracts, given the liquidity and transparency of crude oil prices and the potential substitutability of natural gas for petroleum products (depending on the market). As a result of this indexing, gas prices do not necessarily reflect demand and supply.

However, the share of short-term and spot trade in total LNG trade increased from 13% to 29% between 2005 and 2014 (IEA, 2016). While Asia remains the stronghold for long-term contracts indexed to crude oil prices (generally the Japan Customs-cleared Crude – JCC), even there natural gas is increasingly traded on the spot market, or under short-term

contracts, reflecting international natural gas demand and supply more closely. The short-term and spot LNG trade in the Asia Pacific market almost tripled between 2010 and 2014 (ibid.).

Several Asian countries are developing regional trading hubs. Japan, for example, launched an LNG futures contract on the Japan over-the-counter exchange in 2014; Singapore's Stock Exchange launched the Singapore SGXLNG Index Group in 2015; and China launched the Shanghai Oil and Gas Exchange in 2015. However, lack of pipeline connectivity, low volumes of flexible LNG and/or high levels of government regulations mean trade on these exchanges remain limited (IEA, 2016). In Europe, where natural gas is imported both by pipeline and as LNG, most of the trade is still based on long-term contracts indexed to crude oil prices. Nevertheless, hub-

based spot trading that uses either the National Balancing Point in the UK or the Title Transfer Facility in the Netherlands as a benchmark has been on the rise over the past decade, in particular for LNG re-exports. Both benchmarks have a strong influence on hub prices in other European markets, and other trading hubs in continental Europe are growing in terms of traded volumes (IEA, 2016).

Lastly, in the US, nearly 80% of LNG export volumes for projects currently under construction have been contracted either on pricing terms directly linked to the US gas benchmark (Henry Hub) or under a hybrid pricing mechanism related to the Henry Hub (IEA, 2016). Given that the US will become one of the major LNG exporters in the coming years (see Section 2 below), this will rapidly decrease the indexing to oil prices.

2. Looking Ahead

2.1 Short Term (2017–2020)

2.1.1 Demand

The US Energy Information Administration (EIA) projects growing domestic natural gas demand in the US along with higher pipeline exports to Mexico and LNG exports to Europe and Asia. The resulting price increase is expected to exceed the break-even in many basins, which could reinvigorate drilling that has stalled as a result of low prices.

In Europe and Asia, gas demand will struggle to grow enough to absorb the supply because ‘Gas remains uncompetitive against other fuels or because gaps in markets and infrastructure prevent consumers from taking advantage [from gas supplies]’ (IEA, 2016). In Asia, for example, coal is still cheaper in many instances, and renewables benefit from policy support that improves their competitiveness. The International Energy Agency (IEA) estimates that ‘In key Asian power systems new gas plants would be a lower cost option than new coal plants for baseload generation by 2025 ..., only if coal prices were at US\$150/ton [under current gas price projections]’ (ibid.).

In addition, the three traditional LNG consumer markets in Asia (Japan, Korea and Taiwan) have started decreasing their LNG consumption since 2015 as their nuclear power units are being brought back into operation, a trend that will continue in the short to medium term. In China, the growth of LNG imports will depend on 1) the government setting policies that grant a more material role for gas in the power sector and building gas infrastructure; 2) conventional and unconventional domestic gas production; and 3) the scale of future pipeline imports from Turkmenistan, other parts of Central Asia and Russia (Gas Strategies, 2017). For 2016, the combination of these factors plus the cold winter weather led to an increase by 33% in China’s imports. This step-up could continue well into 2017 as China has made large contractual commitments to Australia’s LNG projects (Gas Strategies, 2017).

2.1.2 Supply

LNG supply is expected to grow rapidly in the short term, to reach 292mt in 2017 – an increase of 34mt as compared with 2016, representing the largest year-on-year increase in LNG history (Gas Strategies, 2017). Projects with a nameplate capacity of 114.6mtpa are currently under construction, with 47.6mtpa expected to come on stream in 2017 in the Australia, Cameroon, Malaysia, Indonesia, Russia and the US (IGU, 2017). The development of the US as one of the three largest LNG exporters will have a fundamental impact on pricing, as these projects are linked to the Henry Hub price rather than to oil prices.

The fall in prices in 2016 has not resulted in existing projects reducing production volumes or being shut down. The price has also had a limited impact on delays of projects already under construction. This is for several reasons:

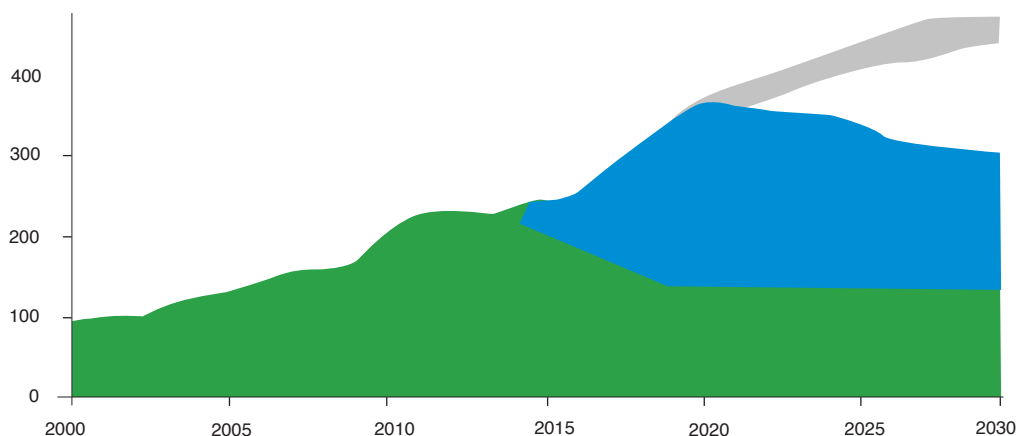
- The LNG sector is characterised by high capital expenditures and low operating costs. While lower prices may result in the operating projects not being able to repay the capital outlays and to earn as high a return as expected, the projects will continue to operate as long as they have a positive cash flow to repay investors. Similarly, many projects under construction have already incurred significant sunk costs and sponsors of those projects are interested in generating positive cash flows by starting operations.
- The LNG projects under construction view the market fundamentals over a 20- to 30-year project lifetime rather than under current conditions, and these are more favourable (see Section 2.2 below on the medium- to long-term outlook).
- Many projects under construction have made contractual commitments to construction contractors, upstream feedstock arrangements and sale contracts. Delays and cancellations would result in penalty payments to these parties.

2.1.3. Equilibrium

As a result of these projects coming on stream and sluggish demand growth, there will likely be excess LNG supplies in the short term. The additional LNG capacity is expected to be absorbed only by the 2020s, as Figure 4 outlines. Shell's projections anticipate an over-supply of LNG in the short term and inter-regional gas markets rebalancing only by the mid-2020s.

FIGURE 4: GLOBAL LNG DEMAND AND SUPPLY, 2000–2030

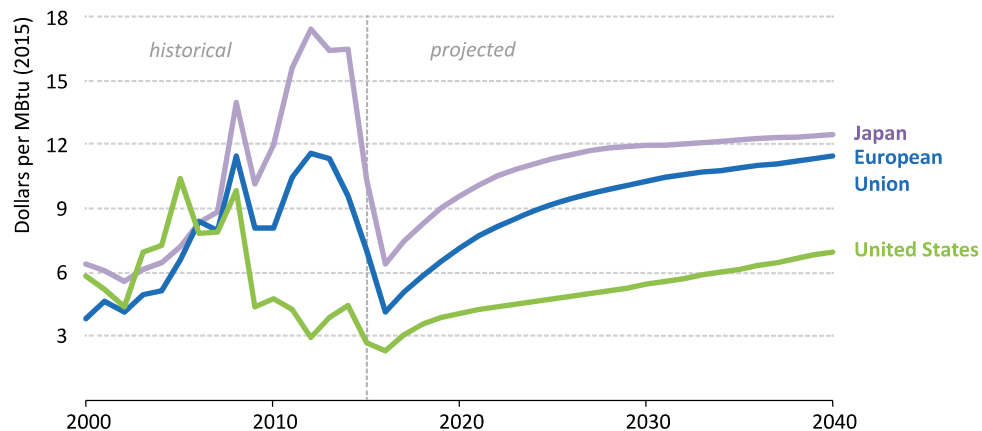
LNG supply/demand gap



Source: Shell (2017).

As a result of excess LNG supply in the short term, gas prices are expected to remain low in Europe and Asia. For the US, the EIA projects prices between \$3 and \$4/MMBtu well into the 2020s. This is expected primarily because of the rebounding oil price making tight oil (considering its associated gas is marketed) and wet gas developments profitable again, which in turn will continue to flood the US market with cheap gas.

FIGURE 5: GAS PRICE PROJECTIONS (IN REAL TERMS), 2000–2040



Note: US price is Henry Hub, EU and Asia are average import prices.

Source: International Energy Agency (IEA)

2.2 Medium to Long Term (2020–2040)

2.2.1 Demand

The major energy outlooks agree gas will be the fastest-growing fossil fuel in the international energy mix in the coming years, with its share increasing rapidly to reach about 25% of total demand.

FIGURE 6: SHARES OF PRIMARY ENERGY, 1965–2035

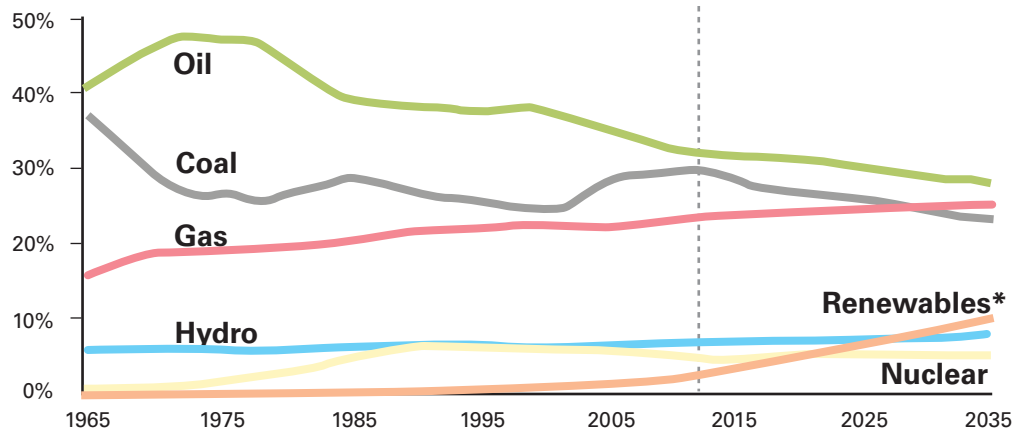
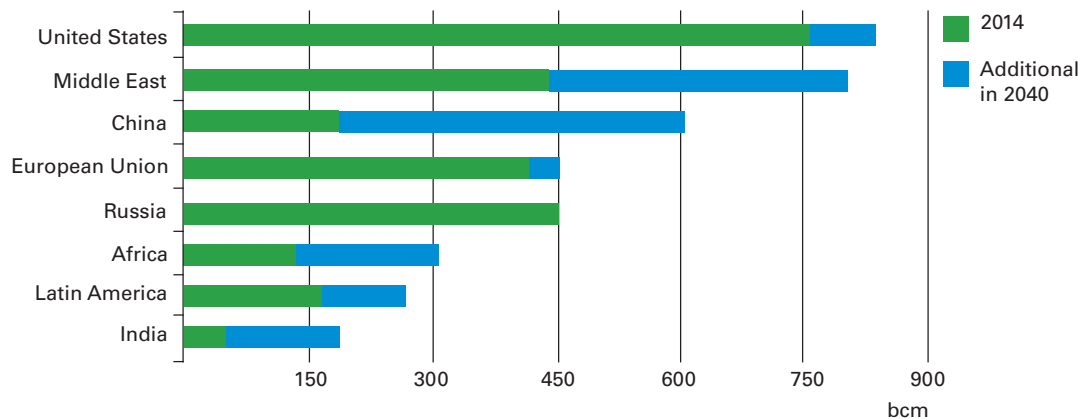


FIGURE 7: GAS DEMAND PROJECTIONS BY SELECTED REGIONS, 2014 AND ADDITIONAL IN 2040



Note: * Includes biofuels.

Source: BP (2017).

According to the reference case of the IEA, consumption of natural gas worldwide is forecast to increase from 120 Tcf in 2012 to 203 Tcf in 2040. This demand growth will be driven primarily by consumption growth in the industrial and electric power generation sectors, which will increase by an average of 1.7%/year and 2.2%/year, respectively. These two sectors are expected to account for about 74% of total natural gas consumption in 2040.

Consumption of natural gas is projected to grow in most jurisdictions, with demand in countries outside the Organisation for Economic Co-operation and Development (non-OECD) and in particular in non-OECD Asia increasing gas consumption more than twice as fast as those in the OECD. Non-OECD countries' share of world natural gas use is expected to grow from 52% in 2012 to 62% in 2040. As a result, non-OECD Asia is expected to move 'from its current position as the world's fourth-largest natural gas consuming region to the second-largest natural gas consuming region in 2030 and the largest consumer in 2040' (IEA, 2016). Non-OECD Asia is expected to become the world's largest importing region by 2040. In non-OECD Asia, 63% of growth is expected to come from China, where consumption is forecast to increase by an average of 6.2%/year between 2012 and 2040, with nearly one-third of it being met by imports. Imports are expected to come from various sources: LNG from Australia, Indonesia, Malaysia, Qatar, Papua New Guinea, Russia and the US or pipeline imports from Central Asia, Myanmar and Russia. The Middle East is expected to become the second-largest consumer (ibid.). As for Africa, its natural gas consumption is projected to increase by an average of 3.3%/year between 2012 and 2040, with the electric power sector accounting for 49% of the total increase in demand (ibid.).

It is noteworthy that, with the increase in exports from Australia and the US, the share of the natural gas demand in OECD nations met by net imports from non-OECD countries is expected to fall to 16% in 2040 from 23% in 2012.

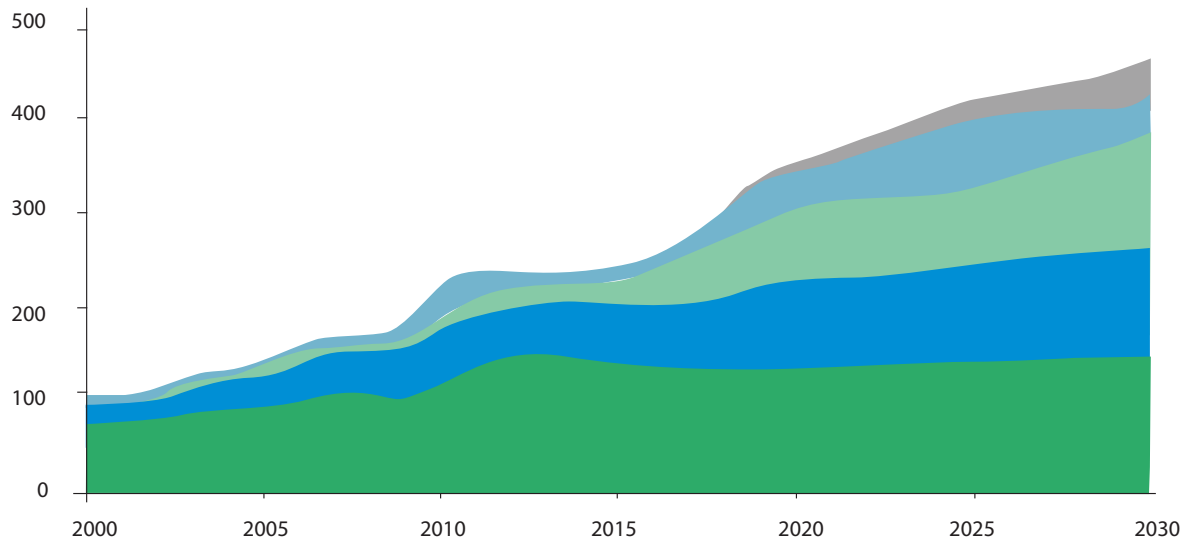
These trends are supported by the fact that, outside of North America, all regions have increased regasification capacity over the past few years, especially through the development of Floating Storage and Regasification Units (FSRUs) in Asia, the Middle East, Egypt and Latin America (IGU, 2016). FSRUs make LNG imports more flexible, limit capital expenditure as compared with land-based terminals and enable imports to be operational much faster than through land-based terminals.⁴ As such, FSRUs are expected to accelerate the entrance of new LNG-importing countries (IGU, 2016). In Sub-Saharan Africa, countries like Benin, Côte d'Ivoire, Ghana, Morocco, Namibia, Senegal and South Africa are planning on importing LNG through FSRU investments – primarily for domestic power generation with the objective of replacing expensive imports of diesel and heavy fuel.⁵

Figure 8 illustrates how LNG imports are progressively meeting domestic gas demand in various geographic regions and over time. The LNG demand drivers that experience the biggest growth by 2030 occur when LNG replaces declining domestic production and when it complements domestic and pipeline supplies.

⁴ National Oil Companies, Skills Transfer Workshop 2016, "The Potential Impact of LNG on African Gas to Power

⁵ National Oil Companies, Skills Transfer Workshop 2016, "The Potential Impact of LNG on African Gas to Power

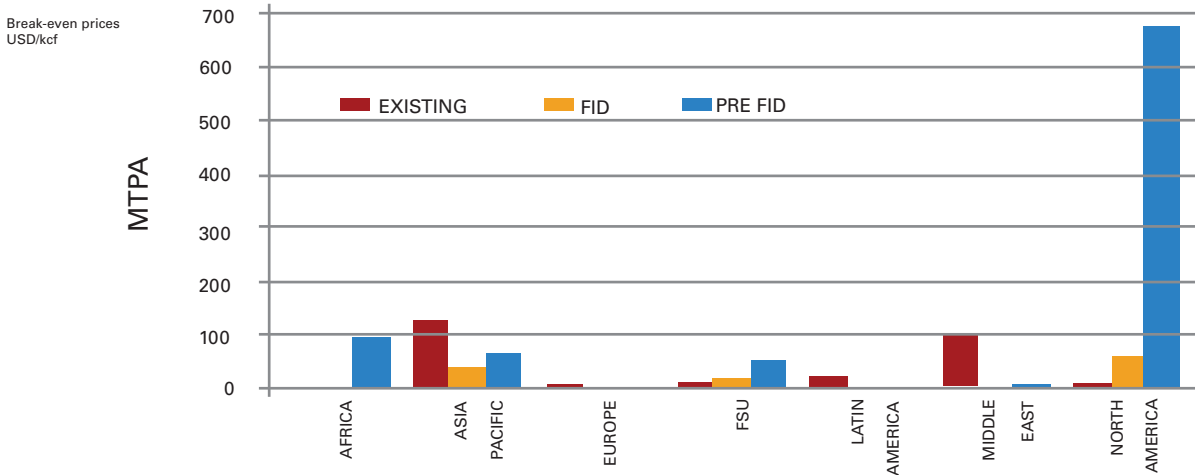
FIGURE 8: LNG DEMAND DRIVERS, 2000 – 2030



LNG demand driver	Countries/regions
Bunker fuel	<ul style="list-style-type: none"> <li style="width: 25%;">■ Atlantic <li style="width: 25%;">■ Middle East <li style="width: 25%;">■ Pacific
Balances LNG supply	<ul style="list-style-type: none"> <li style="width: 25%;">■ Northwest Europe <li style="width: 25%;">■ Middle East <li style="width: 25%;">■ Pacific
LNG replaces declining domestic production into existing demand	<ul style="list-style-type: none"> <li style="width: 25%;">■ Thailand <li style="width: 25%;">■ India <li style="width: 25%;">■ Indonesia <li style="width: 25%;">■ Malaysia <li style="width: 25%;">■ Pakistan* <li style="width: 25%;">■ Kuwait <li style="width: 25%;">■ Egypt* <li style="width: 25%;">■ UAE <li style="width: 25%;">■ Colombia* <li style="width: 25%;">■ Bahrain* <li style="width: 25%;">■ Bangladesh* <li style="width: 25%;">■ Philippines* <li style="width: 25%;">■ Vietnam*
LNG complements domestic and pipeline supply	<ul style="list-style-type: none"> <li style="width: 25%;">■ Southern Cape <li style="width: 25%;">■ Eastern Europe <li style="width: 25%;">■ Southern Europe <li style="width: 25%;">■ North America <li style="width: 25%;">■ China <li style="width: 25%;">■ Singapore <li style="width: 25%;">■ Morocco* <li style="width: 25%;">■ Jordan* <li style="width: 25%;">■ Israel
Gas supply solely dependent on LNG	<ul style="list-style-type: none"> <li style="width: 25%;">■ Japan <li style="width: 25%;">■ Korea <li style="width: 25%;">■ Taiwan <li style="width: 25%;">■ Puerto Rico <li style="width: 25%;">■ Dominican Republic <li style="width: 25%;">■ Jamaica* <li style="width: 25%;">■ Panama*

Source: Shell interpretation of Wood Mackenzie Q4 2016 data
 *Denotes new or emerging LNG importing countries

FIGURE 9: LIQUEFACTION CAPACITY BY STATUS AND REGION



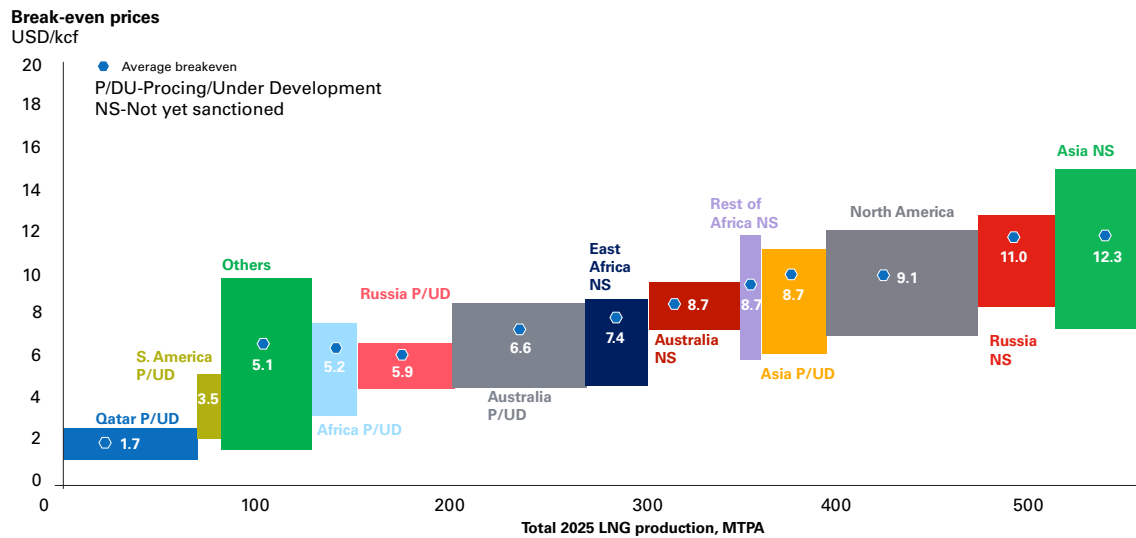
Source: IGU (2017).

This capacity is far greater than the most optimistic demand scenarios and hence only the most economic projects of this list are likely to go ahead. The price developments have resulted in buyers taking a wait-and-see approach to long-term contracts, which has forced project sponsors to push back final investment decisions (FIDs) for many of these projects. FIDs planned for 2016 were pushed to 2017 and project proposals significantly slowed in 2016.

2.2.3 Equilibrium

As can be seen from the demand and supply projections in Figure 5, there is additional demand for LNG expected post-2023/2025, even with the additional projects that most recently received the go-ahead. Figure 10 ranks LNG projects according to breakeven prices where the net present value (NPV) equals zero. The height of each box represents the 75% confidence interval (i.e. there is a probability of 75% that the breakeven price lies within the low and high margin) and the light blue dot the weighted average. The breakeven prices are highly related to whether these projects are already sanctioned or not, given that the projects that are operating or under construction have already incurred sunk costs. It is noteworthy that the East African gas projects are thought to have the lowest breakeven cost among the unsanctioned projects (shown as ‘NS’ in Figure 10), which suggests these projects have a good chance of getting the green light to satisfy demand post-2025. Actually, on 1 June 2017, three years after the drilling of the final exploration well in the Rovuma Basin in Mozambique, the Coral South LNG project implementation phase was launched (Offshore Energy Today, 2017).

FIGURE 10: GLOBAL LNG COST SUPPLY CURVE FOR DIFFERENT SOURCES



Source: Rystad Energy (2015).

In the medium to long term, the IEA forecasts US gas prices will increase more rapidly than in the short term, to around \$7/MMBtu by 2040 (see Figure 6). This is because the more profitable reserves will have been exhausted, leading producers to develop higher-cost projects in order to meet demand. In the longer term it is also thought that the international gas market will become more flexible, which will narrow the price spread between the European and the Asian market. The IEA projects that European and Asian market prices will settle above the US price by around \$4–5/MMBtu and \$5–6/MMBtu, respectively. These spreads result from the US continuing to be the lowest-cost exporting producer in the long run, with Asian prices slightly above European prices owing to the transport cost differential.

2.3 The Role of Competing Energies

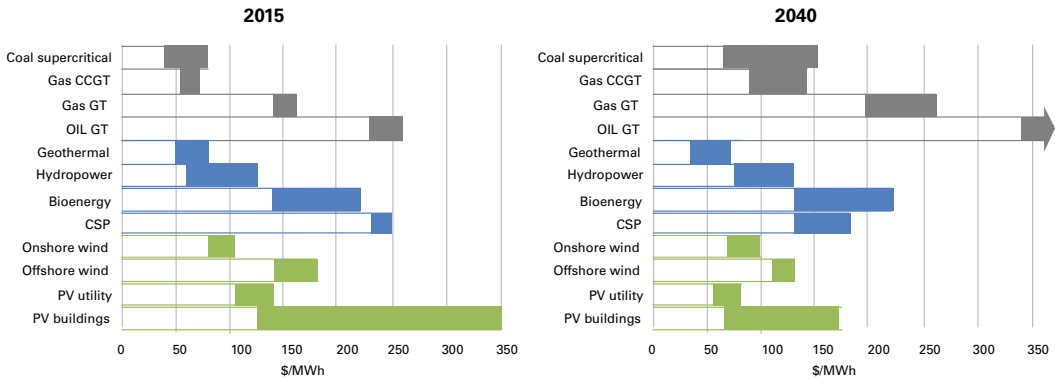
The biggest uncertainty surrounding gas demand and price projections is related to 1) the costs of alternative energy solutions and 2) countries' policies in diversifying their energy sources and implementing the Intended National Determined Contributions of the Paris Agreement.

2.3.1 Costs of alternative energy solutions

Figure 11 shows levelised cost of electricity (LCOE) estimates for various technologies to produce electricity for 2015 and 2040. The LCOE represents the average cost per MWh for which a project would break even. It includes capital and operating expenditures. These costs vary by region, and the IEA generated projections for them for China, India, the EU and the US in its latest outlook. The below LCOEs show the cost ranges for these four regions.

Fossil-fuel power plants are represented in grey, dispatchable renewables (technologies where output can be easily controlled) in blue and variable renewables (technologies where output cannot be controlled without storage) in green. In 2015, the LCOE for hydropower, for example, was estimated to be around \$60/MWh in India, \$80/MWh in China, \$110/MWh in the EU and \$125/MWh in the US. Hence the blue bar in the graph to the left in Figure 11 (representing 2015 levelised energy costs) ranges from \$60 to \$125/MWh. In 2015, only the most competitive renewable power plant solutions could compete with coal- and gas-powered power plants. This is partly because of the low operating costs resulting from depressed prices of the coal and gas feedstock. In the coming years, it is expected that the impressive cost reductions observed in some renewable technologies (particularly wind and solar) will continue to drive down costs (photovoltaic solar capital costs have fallen by 60% in the past five years), making them increasingly competitive with fossil-fuel based power plants, which are expected to become more expensive as a result of higher feedstock price projections increasing operating expenditures. Technologies that have already matured and where there are no expected price changes in the feedstock, such as hydropower, are not expected to see significant cost changes.

FIGURE 11: LEVELISED ENERGY COSTS FOR 2015 AND 2040



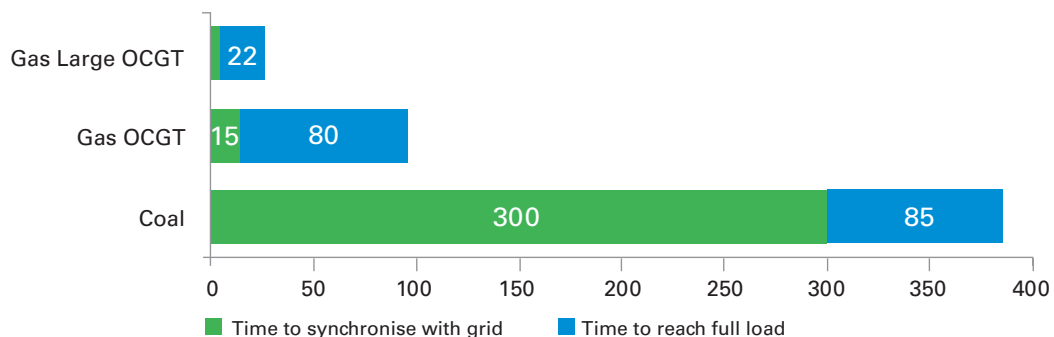
Note: CCGT = combined cycle gas turbine, GT = gas turbine, PV = photovoltaic, CSP = concentrating solar power.

Source: IEA (2016).

2.3.2. Countries' policies

As more governments begin implementing national and regional plans to reduce CO2 emissions in accordance with their commitments under the Paris Agreement, they may encourage the use of natural gas to displace more carbon-intensive coal and liquid fuels. The Paris Agreement may also provide renewed impetus to levy carbon taxes, which in turn would put gas at an advantage over coal and oil. Gas is also advantageous in the energy transition as it can be dispatched quicker than coal (see Figure 12), thereby serving as a complementary fuel to intermittent renewable energy sources.

FIGURE 12: AVERAGE TIME REQUIRE TO COME ONLINE (MINUTES)



Note: OCGT = open cycle gas turbine, CCGT = combined cycle gas turbine.

Source: Shell (2017).

However, gas is still a fossil fuel, and as such emits CO2 and other greenhouse gases (methane leakages have been known to be particularly problematic). As such, gas should not play a prominent role in the long term when the world economy needs to decarbonise, unless carbon capture technologies become viable on a large scale (in which case other fossil fuels such as coal may also continue to be used). Thus, the question remains whether (and how quickly) countries will put in place policies to move from coal to gas or jump directly to renewables in order to reduce carbon emissions.⁶

Energy security concerns will continue to play an important role in the uptake of gas and particularly LNG. Countries seek to diversify their energy systems by source – Brazil, for example, is seeking to increase LNG in its energy mix to reduce its reliance on hydropower to avoid power outages during dry spells – and by country of origin – one of the principle reasons for LNG demand in Europe is the need to reduce its dependence on Russian gas. An increasingly flexible and abundant LNG market with various suppliers will make this energy source more appealing to policy-makers seeking to diversify their energy systems.

⁶ On the supply side, tighter government regulations to protect the environment may also have an impact on international gas prices. In the US, for example, there has been extensive debate about the negative externalities of gas fracking. More stringent environmental regulations may increase gas prices and make US gas less competitive, which in turn would have global consequences, given the country's major role as an exporter in the years to come.

B

Domestic Gas Allocation

The international gas outlook indicates that the overseas natural gas markets are large and lucrative enough in the medium to long term to make development of Tanzanian offshore gas deposits economically viable. It is therefore understandable why proposals from international oil companies (IOCs) in Tanzania have focused on liquefaction of the gas for export.

As recognised by the Government of Tanzania, however, natural gas can be a powerful tool to facilitate the country's broader economic development and diversification, as it provides a readily available and relatively clean source of energy for power generation, industrial use and residential consumption as compared with coal, liquid fuels and biomass. Thus, the complex and important questions related to the use of the gas domestically must be answered in all countries that develop their gas primarily for export.

The Government of Tanzania, through Article 8 of its production-sharing agreements, has the right to require IOCs to make available up to an extra 10% of the exported gas to be sold within Tanzania. Prior to its final approval of the offshore development and LNG proposals, the Government must agree with upstream companies on the arrangements as to how much gas will be reserved for domestic use, how it will be delivered, how costs will be shared and the price for the gas that will be paid to the developers. Each of these upstream arrangements must be considered in conjunction with decisions on how onward usage, transmission and pricing of that gas to final consumers will work. This section outlines some of the key considerations that will need to be taken into account in domestic gas allocation.

1. LNG Export and Domestic Gas Projections

Natural gas reserves in place offshore Tanzania are currently estimated to be somewhere in the range of 45–50 Tcf, with around 38 Tcf deemed recoverable. Current preliminary plans are for a 2-Train LNG plant, which could be expected to utilise in the range of 11–15 Tcf for export over a 30-year period. In addition to these export volumes, the Tanzania Natural Gas Utilization Master Plan envisions up to an additional 19 Tcf that could be used domestically in Tanzania over the next 30 years, which represents roughly a 10-fold growth in domestic demand over that period. While power generation and industrial use account for two-thirds of that projected usage, another one-third includes aspirational projects such as Methanol, steel plants and Gas To Liquids (GTL), plus a regional export pipeline project. These projections by necessity must make numerous assumptions about economic growth and diversification, the price of gas to consumers and the price of alternative imported or local fuels such as diesel, charcoal, fuel oil and LPG. If any of these projections do not materialise,

growth in domestic gas usage could be considerably less. Furthermore, this volume of gas is well in excess of the 10% domestic requirement imposed on upstream producers. Exceeding the 10% allocation may either trigger renegotiation of the deal with the IOCs asking for tax incentives or end up with the Government buying some gas at world market prices.

2. Capacity Design and Domestic Gas Decisions

When developing natural gas fields, all offshore production facilities must have a planned daily productive capacity, which is predicated on the size and configuration of reservoirs, which then dictates the number of wells drilled, the number and size of platforms required, the size of the pipelines, etc. But for natural gas, unlike crude oil, these offshore facility plans additionally must take into account the volumes that its customers have committed to, and these commitments in turn translate into the planned productive capacity of the LNG plant that will liquefy the Tanzanian gas in order to supply those customers' contracted commitments. In addition to overseas export customers, the offshore facilities' plans must take into account the volumes required by local customers in Tanzania.

If the volumetric commitments local customers make are set higher than what they can take, then the offshore investors end up constructing and paying the capital costs of an offshore facility that is greater than what was needed (it should be noted that the Tanzania Petroleum Development Corporation - TPDC - is also one of these offshore investors). Of course, this problem is compounded by the fact that usually there are no take-or-pay clauses in the sales contract with government agency buyers. Even if there were such clauses, these would not be easily enforceable. In this situation, international financiers will also be hesitant to finance a project with unallocated gas supply, given that they require sale guarantees that warrant back-payment of the loans.

If the amount of volumetric commitment ends up being lower than what could actually be used for domestic needs, the offshore facilities' capacity cannot be easily expanded at a later date to meet this higher need. If the domestic gas is to be increased over time on a sliding scale basis to accommodate the progressive increase in demand, transporting infrastructure will have to be developed for a larger capacity than is initially needed, which will affect the economics of field development. In exchange for such flexibility or unexpected expansion, investors are likely to request subsidies and incentives and possibly renegotiation of the deal.

This is to say that setting either an unrealistically high or unrealistically low demand has financial consequences for the IOCs, TPDC and tax revenues collected by the Government.

3. Domestic Gas Prices

The price negotiated to be paid to upstream investors for the domestic gas is another critical factor. If the gas is to become an enabler of economic development, the price paid by the Government to obtain it must be low enough to avoid, or minimise the amount of, the ‘subsidy’ it may need to incur – the difference between what is paid for the upstream gas and the price at which it is sold to the final consumer.

It is readily apparent that the role of the Tanzania Electric Supply Company, the Energy and Water Utilities Regulatory Authority, the Ministry of Energy and Minerals and other government agencies becomes critical in establishing this volumetric commitment at an amount as close as possible to what will be the reality, and that prices do not result in unexpected subsidies. The problem is that the country legitimately and realistically expects significant growth in the domestic use of natural gas but there is a significant risk that a combination of factors will prevent this growth from occurring as forecast. In order to mitigate these risks, the Government can consider a series of strategies.

C. Implications and Strategic Considerations for Tanzania

1. International Gas Market

The fall in gas prices has delayed FIDs for projects across the board. This development may further push out the FID for Tanzania towards the end of this decade, which would result in a production start in the mid-2020s. It should be noted that such long timelines are not unusual in the LNG business, and provide time for all stakeholders to prepare. Particularly for a frontier country that is new to such large-scale petroleum investments such as Tanzania, it is crucial to build up capacity within the various institutions in order to maximise the benefits these gas developments may provide. Furthermore, capital cost overruns of LNG projects have been common in recent years, particularly when such projects have been fast-tracked. Time and care should be taken by the involved IOCs, TPDC and the Government to ensure all options to minimise costs are exhausted.

Global cost curves and other reports reviewed for the purpose of this brief suggest Tanzanian gas deposits are slightly more expensive to develop than Mozambique’s deposits but are still very competitively placed to serve LNG markets post-2025. Reported Free on Board (FOB) breakeven costs are around \$7–9/MMBtu lower than many of the other projects in the pipeline around the world, and they are thought to be competitive with US LNG, with Henry Hub prices of around \$3–4/MMBtu (see Corbeau and Ledesma, 2016).

Risks remain, though, and the below ‘strengths, weaknesses, opportunities and threats’ (SWOT) analysis outlines these in greater detail.⁷

⁷ The SWOT analysis is a useful tool to evaluate factors that may influence whether LNG projects will go ahead. The strengths and weaknesses are related to the project characteristics and the opportunities and threats are related to external factors.

SWOT Analysis of Tanzanian Offshore Gas Projects

Strengths

- * Deposit size
- * Location
- * Cost competitive

Opportunities

- * FSRUs
- * Climate change concerns
- * Energy security

Weaknesses

- * Deep & complex
- * Frontier country
- * Lack of infrastructure
- * Dry gas

Threats

- * Pricing structure
- * Renewables
- * Other gas projects coming on-stream

Strengths:

- **Deposit size:** The deposit size is large enough to warrant LNG investments, and recoverable reserves keep increasing. LNG projects elsewhere have gone ahead with much smaller reserves. However, finds up to now are not as large as in Mozambique, and therefore the domestic gas allocation negotiation may present a double-edged sword whereby the Government needs to balance the preference of the investors to serve export markets versus how much will be used domestically in order to boost the economy.
- **Location:** Tanzania is well positioned to reach major LNG markets, increasing destination flexibility without significantly increasing transport costs.
- **Cost competitive:** Tanzania is competitively placed on the global LNG cost curve to serve markets after the mid-2020s.

Weaknesses:

- **Deep and complex:** The deposits are in deep waters off the coast of Tanzania, which makes them more difficult to develop and increases capital cost uncertainties as compared with in a shallow water field. However, deep water fields may be preferred to onshore fields by investors, given that the latter imply the development of pipeline infrastructures and on-land risks to reach the point of liquefaction and exportation.
- **Frontier country:** Tanzania is new to such large-scale petroleum investments and as such the regulatory regime is still evolving and the Government has to continue to build its capacity. Furthermore, expectations of the population since the discoveries have been high. These need to be managed carefully to avoid disappointment – particularly regarding job creation and benefits surrounding local content.
- **Lack of infrastructure:** Infrastructure around the proposed LNG facility needs to be developed, as do gas and power transportation systems for the domestically allocated gas.
- **Dry gas:** Tanzanian deposits are thought to be dry – meaning there are no significant amounts of liquids associated with the gas. While these attributes simplify gas processing, no revenues from oil and condensates can be made, which could have significantly improved the economics of gas projects.

Opportunities:

- **FSRUs:** Technology advances and falling costs of floating regasification units may lead to more countries considering gas as a power source, thereby unlocking new markets. The transferability of these terminals also reduces the risk for investors, as they can be used for different markets.
- **Climate change concerns:** Gas is the fossil fuel with the lowest carbon emissions. As such, countries may increasingly move away from coal and liquids, and rely on gas to meet their commitments under the Paris Agreement.
- **Energy security:** An increasingly flexible and abundant LNG market with various suppliers will make LNG more appealing to policy-makers seeking to diversify their energy systems.

Threats:

- Pricing structure: Customers increasingly favour short-term contracts, which may result in difficulties for developers in Tanzania in terms of securing off-take agreements. This lack of security in turn could discourage the IOCs and financiers from investing large sums into upstream and LNG developments.
- Renewables: The costs of renewables are falling rapidly and are expected to continue to decrease. While gas is a relatively clean fuel as compared with oil and coal, the world will need to adopt renewable technologies in the long run to achieve the targets set out in the Paris climate accord.
- Other gas projects coming on stream: While Tanzania is competitively placed to serve the global LNG market after the mid-2020s, delays may result in other LNG projects going ahead and flooding the market. Furthermore, a fracking boom in LNG importing countries such as China could significantly reduce demand (or, as in the case of the US, result in an additional exporter) and result in lower prices.

In order to reduce the ‘weakness’ of being a frontier country, the obvious and most direct way the Government of Tanzania can influence these projects is to continue to develop its petroleum regulatory regime and build its institutional capacity to support and regulate the gas sector. While the external ‘opportunities’ and ‘threats’ cannot be influenced directly, the Government should closely follow international developments that may have an impact on the supply and demand fundamentals and thereby affect the scope and timeline of these projects going ahead. As such, the Government should keep a close eye on the number of competing LNG projects reaching FID and coming on stream; the technological and price developments of gas infrastructures and alternative energy sources; government policies – particularly of large LNG importing countries – related to climate change, energy security and fracking; and the development of international pricing structures for large-scale LNG projects.

2. Domestic Gas Allocation

Tanzania is fortunate to already have experience with domestic utilisation of natural gas with the Songo Songo project and pipeline. The scope of the LNG developments will be significantly greater and have more ability to influence economic development. Dedicating resources and fully utilising the time leading up to the FIDs to consider experiences in other countries and develop strategies for managing some of the risks would assist in achieving the country’s stated development objectives. Some strategic considerations should include:

Demand and supply scenario planning: The demand for gas and the development of offshore fields and LNG plants are not unrelated. Factors such as world energy prices affect both. Higher world market prices result in higher returns to the projects, which translates into more of the offshore reserves being developed. By the same token, higher world prices may mean higher costs to energy consumers in Tanzania, not only for domestic gas but also for other alternative imported fuels. It would make sense for the Government to expand the Gas Master Plan to consider two or three different world energy price scenarios and the related impacts on Tanzania's offshore developments and demand for energy in the country. One possible result of this scenario planning could be to not fully burden the first LNG plant with all of the domestic obligation and to anticipate that future developments will also be able to contribute to the growth in demand. While waiting for developments, the Government would shape its understanding of the future of the local demand and could also choose to build up domestic gas infrastructure from revenues received from export LNG. Another possible result may be development of a pricing strategy that looks at the overall combined average energy costs of feeding into power plants or industrial development, including alternative fuels.

Development of an integrated pricing strategy: There may not be a natural link between the price paid to the upstream producer for gas and the price charged to the Tanzanian consumer of gas if these are approached as separate strategies. For example, if consumer prices are fixed artificially low as an economic development strategy by the Government, the result could be significant 'subsidy' costs as mentioned above. This phenomenon is similar to what has happened in countries like Nigeria and Venezuela that have kept petrol prices artificially low with no links to the costs of acquiring that petrol, and which has on occasion resulted in unintended negative impacts on their economies. Some linkage between the two prices could minimise that exposure to the government treasury and could help incentivise appropriate reactions, for example more energy-saving plant designs for when prices are high or substitution of alternate fuels.

Developing strategic regional alliances with neighbouring countries: A clear example of this is the current plan for the oil pipeline from Uganda through Tanzania (BBC, 2016) and participation by several countries in the planned refinery (Abdallah, 2016). Growth in regional natural gas demand could be satisfied by either Tanzania or Mozambique, given the proximity of the offshore gas developments. Finding a way to collaborate rather than compete on natural gas pipelines, GTL, fertiliser and methanol plants could provide a greater likelihood of capturing at least a share of those growth and diversification opportunities. This could even take the form of being linked into existing collaborations in crude oil refining and export projects to include some of the potential gas consumer countries in the region.

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