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Understanding the boom

Country study—Tanzania

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Abstract: There are large volumes of gas offshore Tanzania, which has raised hopes of a boom. But those hopes look set to be disappointed. A boom would depend on there being a sizeable flow of revenue to government from producing and exporting gas. This paper sets out the scale of the gas, and the array of risks which currently make investment in gas production, and any associated boom, unlikely. As well as geological, engineering, and market risks, the risks to investment from public policy have been elevated over the last few years.

Keywords: developing countries, economic development, institutions and economic growth, non-renewable natural resources, macroeconomics

JEL classification: O11, O13, O43, Q32, Q33, Q35

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1 Introduction

Large volumes of natural gas have been discovered offshore Tanzania. Current official estimates suggest proven reserves of 57 trillion cubic feet (tcf) of gas,¹ which is a lot of gas.² To put it into context, the price for liquefied natural gas (LNG) in Asia for most of 2018 was around US\$10 per million British Thermal Units (mmbtu), which values 57 tcf at \$55 billion: equivalent to about ten times the 2018 Tanzanian GDP, and about \$10,000 per person. The investment in the projects that would be needed to produce such gas is also large—it would be the biggest set of investments in Tanzania ever, with a total cost estimated at almost the same order of magnitude of GDP: potentially around \$44 billion (Baunsgaard 2016).

With such big numbers associated with the offshore natural gas, it is not hard to imagine the fantastic prospects of increased wealth and accelerated development that are tantalisingly almost within the government's grasp. The reality is that these numbers are indeed fantasy: the perceived scale of any revenue based on the numbers would be wildly overestimated. What matters is not the stock of reserves, but the value of any flow of production.

Any expectation that there will be a boom any time soon will be sorely disappointed. Not only does the commercial viability of the array of investments by private companies needed to produce, liquefy, and ship LNG need a minimum price higher than that achieved in the recent past, but project viability also needs reduced risk. Such investments face an array of risks, including technical, market, and policy risks. In the end, as well as prices, costs, and risks, a key determinant of the scale of any potential resource revenue is the time it will take to bring reserves to production: the longer it takes, the smaller any revenue will be relative to a growing GDP or population.

There have been a number of careful estimates of the likely scale and timing of the prospective boom which show a consistent picture of modestly material, but not transformative, revenue to government. They are reported here after a discussion of key assumptions in making such projections, and the risks that surround Tanzanian offshore gas.

I then look to embed the projections in a brief discussion of two topics relating to the role of natural resources in growth, structural change, and industrialization: first, the interactions between public policy and the risks faced by large-scale investment in natural resources; second, the way in which an array of public policies condition the impact of actual and prospective natural resource projects on wider matters of economic growth, structural change, and industrial development.

¹ Ministry of Energy and Minerals quarterly reports (MEM, various years), though estimates of the amounts of gas that could potentially be produced are lower.

² The units used to calibrate stocks and flows of gas and liquefied natural gas (LNG) are potentially confusing. As well as industry-specific units for pricing, a mix of imperial and metric units is used for both stocks of reserves and flows of production. There is a conversion table included in each annual publication of the BP Statistical Review of World Energy (www.bp.com/statisticalreview).

2 The magnitude and timing of a prospective resource boom

The official estimate of gas reserves in Tanzania is 57 tcf, but the estimates of actually ‘recoverable’ gas reported by the companies which have done the exploration are lower, perhaps below 30 tcf (Baunsgaard 2016; see also Scurfield and Mihalyi 2017). In any case, this is a significant quantity of gas, but it is deep under the sea far offshore. Any resource boom will be determined by flow of production and any associated revenue flows to government—which, in turn, are a function of the costs of capital investment and the cost of production; the recovery of those costs as part of earning a return on investment; and the structure of the fiscal terms which shape the shares of government and investor of the dollar net present value (NPV) of the project.

In this section, the factors which shape production volumes and costs, LNG prices, and the nature of the fiscal terms are set out. A key determinant of a boom—if in the end there is one—is time: the longer it takes to bring gas reserves to production, the smaller the boom relative to GDP or on a per-person basis.

Projections of gas production are in part determined by geological, engineering, and commercial risks and constraints. There is a minimum feasible flow of gas production needed to make the facilities for production, transport, and liquefaction of gas work efficiently. For offshore gas in Tanzania, that minimum ‘anchor volume’ of production is large, representing so much gas that it outstrips the capacity of Tanzania to absorb it, so almost all would be exported as LNG—hence the need to have a liquefaction plant.

To put the scale into context, it is useful to look first at the volumes of reserves and production onshore. As well as the large-scale offshore discoveries, Tanzania also has onshore or shallow water fields at Mnazi Bay and Songo Songo, shown in Figure 1. They are much smaller than the offshore discoveries: Mnazi Bay has technically recoverable gas estimated at just 0.3 tcf, while Songo Songo holds 0.7 tcf, compared with recoverable gas reserves estimated at a total of 29–37 tcf between the two main offshore consortia.³ However, the smaller quantities of shallow water or onshore gas can be brought into production more quickly and more easily, and so at a significantly lower cost. Songo Songo has produced since 1974. Production from Mnazi Bay by the companies Maurel et Prom and Wentworth Resources started in 2015, with the gas being delivered to Dar es Salaam via pipeline for power generation.

In April 2018, construction on the Kinyerezi II gas-fired power station was completed and the facility was opened by President Magafuli, with the project expected to be commissioned at full capacity of 240 megawatts (MW) in October 2018 (The East African 2018). The use of onshore and shallow water gas in power generation has supported a significant addition to Tanzania’s generating capacity, and gas production had increased from 78 million standard cubic feet per day (mscuf/d) in 2012 to 132 mscuf/d in 2016, with scope for further increases in line with the ambition for more investment in gas-fired power generation, to around 200 mscuf/d.⁴

To put this into context, the ambition of production of 200 mscuf/d of gas for power generation is equivalent to 2.1 billion cubic metres (bcm) or 1.5 million tonnes of LNG: below, we discuss the prospect of volumes of LNG from Tanzania of the order of 15–20 million tonnes. Taking just

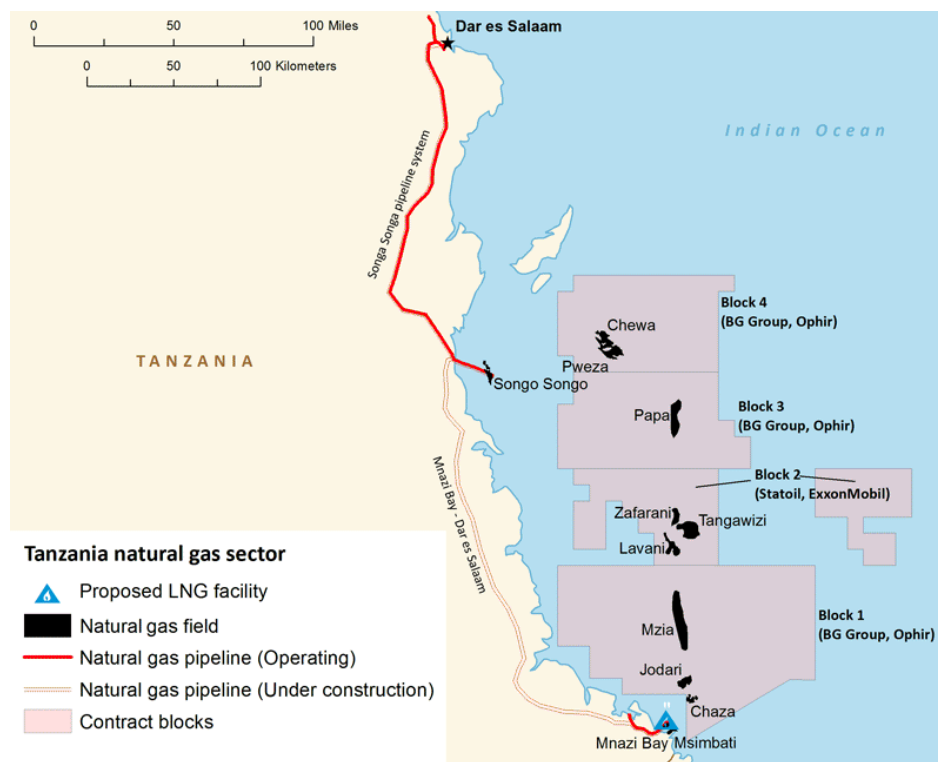
³ On Songo Songo reserves, see Orca Exploration Group (2017); on Mnazi Bay reserves, Wentworth Resources (2018); on the offshore blocks, Baunsgaard (2016) and Scurfield and Mihalyi (2017).

⁴ See World Bank (2017) for production data; expectations for onshore and shallow water production going into power generation are drawn from a 2013 private briefing by BG Group for Oxford Policy Management.

10 per cent of 15 million tonnes of LNG for domestic use would mean 1.5 million tonnes of LNG: the equivalent of around 200 mscuf/d, or a doubling of gas hoped to be going into power generation. This point illustrates the scale of potential LNG exports relative to expectations of gas consumption in Tanzania.

The offshore gas is 80–100 kilometres offshore Tanzania, in water depths of up to 2,000 m and a further 4,000 m below the seabed. The reserves have been discovered by two separate consortia of international oil and gas companies across several ‘blocks’. One consortium is led by Statoil as the operator, and includes ExxonMobil (Block 2). The other is led by Shell, following their takeover of BG Group, and also includes Ophir (Blocks 1, 3, and 4). The location of Blocks 1, 2, 3, and 4 is illustrated in Figure 1.

Figure 1: Natural gas offshore Tanzania



Note: Representation of international boundaries and names not authoritative.

Source: Reproduced from EIA (2013).

2.1 Risks

There is an interaction between solving the geological and engineering challenges and the commercial constraints and risks. The higher the capital costs required, and the longer the time it takes to build and install facilities, the more secure an investor will need to be in the expected return on investment, and the risks that surround it. There are, broadly, two sets of risks apart from the technical geological and engineering risks. These are the market or commercial risks, and the policy risks: the extent to which there is stability in the set of legal and regulatory measures, and the commercial agreements, which amount to a coherent ‘authorizing environment’ for a major natural resource project.

Geological and engineering challenges

There is a combination of geological and engineering challenges to producing and transporting gas from the bottom of the sea over a long distance. The gas from each of these different fields comes from different depths, and comes to the level of the seabed at different temperatures and pressures. Differential pressures mean that different gas fields cannot simply be plugged in to each other without careful management of relative reservoir and pipeline system pressures. The gas from different fields may also have a different mix of the butane and propane which makes up natural gas. These have to be blended, either at the wellhead on the seabed or onshore, and the longer hydrocarbons—natural gas liquids (NGLs)—have to be stripped out from the production flow of propane and butane. In addition, one feature of the seabed between several of the gas fields and the shore is a canyon, on the scale of the Grand Canyon, across which a pipeline will have to run to transport the gas from the sub-sea wellhead installations to the shore.

Such challenges can be overcome: but they need to be carefully evaluated, and engineering design work will need to be completed to meet them. The cost of engineering solutions will not be clear until such work is done—during a succession of engineering design projects starting with the preparatory ‘pre-Front End Engineering Design’ (pre-FEED) work—and it all takes time. The operator of a consortium of investors will typically incur the costs of pre-FEED work when the main parameters of a project are clear, even if they still face ongoing market and commercial risks.

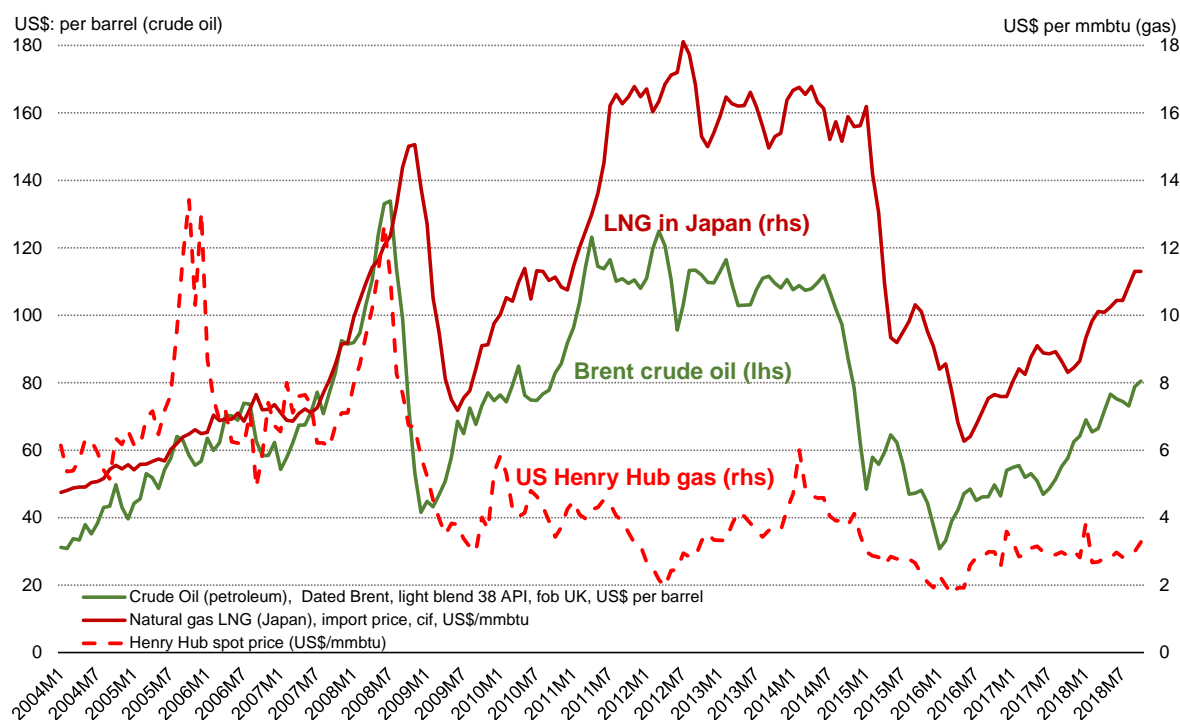
Market and commercial risks

A key market risk relates to the price that can be secured for exports of LNG. The current expectation is that East African gas will go to Asia. During 2017, prices for LNG imports to Japan were significantly lower than the average for the previous decade: an average of US\$8.61/mmbtu for the year, compared with an average of \$12.15/mmbtu for the ten years 2007–16. The extended period of higher prices reflected a mix of circumstances. LNG prices had been strong in Tokyo while Japan was importing gas to generate power after Japanese nuclear plants failed safety standards in 2002, were damaged by the tsunami of 2004, and suffered the Fukushima disaster of 2011. In addition, LNG had been priced using a formula that related gas prices to the oil price, and oil prices had been above \$50 per barrel for most of the period 2005–15. Figure 2 shows crude oil and natural gas prices from 2014 to late 2018.

The average price of LNG imports to Japan during the first ten months of 2018 rose to \$10.40/mmbtu—a 21 per cent increase over the average for 2017. Figure 2 illustrates the extent to which Asian LNG prices continue to move in a similar way to crude oil prices, and the volatility of hydrocarbon prices. According to Scurfield and Mihalyi (2017) (of which more later), the level of prices in 2017 and 2018 is still below the long-run price of \$14/mmbtu that would make investment in Tanzanian LNG viable on the basis of the rate of return international companies usually require on capital investment, but not far off the \$11 that they argue could make investment possible.

Figure 2 also shows US gas prices at ‘Henry Hub’ in Louisiana, the part of the US gas pipeline network that serves as a reference point for market pricing of gas across the US. The average price at Henry Hub for the first ten months of 2018 was unchanged over the average for 2017, at a shade under \$3/mmbtu.

Figure 2: Crude oil and natural gas prices



Note: fob = 'free on board'.

Source: Author's construction based on IMF Primary Commodity Prices database, available at <https://www.imf.org/external/np/res/commod/index.aspx> (accessed 23 December 2018).

What matters for assessing the market risks for large investments in LNG is the prospects for the price in the future. The recent past, together with some expectations about the changes in global gas markets, provides some guidance for thinking about the future. There are at least three factors to bear in mind: (i) the sustainability of the LNG pricing link to crude oil and the scope for integration of global gas markets; (ii) expectations for demand for LNG in Asia; and (iii) expectations for supply of LNG.

The link between LNG prices and the oil price is eroding. This is related, in part, to an increasing integration in global gas markets through LNG. The volume of gas traded as LNG more than doubled between 2000 and 2010 to nearly 300 bcm, and increased further to 393 bcm in 2017.⁵ The growth in LNG now includes a link between the increase in supply of gas in the US, where new 'tight' and shale gas supplies have recently turned the US into an exporter of LNG. This supply shock helps explain why the US gas prices at Henry Hub, shown in Figure 2, are lower than LNG prices in Asia. In economics, the market price under competition is set by the intersection of supply and demand curves at the margin. As US exports grow, they add to the marginal supply of LNG across the Pacific and so put downward pressure on prices in Asia.

The link between oil prices and LNG prices is also eroding because there is dissonance between what LNG buyers want, which is short-term price flexibility, and what LNG suppliers need, which

⁵ Data from the BP Statistical Review of World Energy, available at <https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of-world-energy.html> (accessed 23 December 2018), and from BP (2018).

is long-term price stability. There has been a steady increase in the share of LNG traded on the basis of spot prices. Between 2010 and 2017, the number of cargoes of LNG traded on a spot basis more than doubled from 500 to over 1,000. The proportion of LNG trade accounted for by spot pricing increased from 12 per cent in 2010 to 25 per cent in 2017 (Shell 2018).

Although the price for LNG import to Japan did increase to over US\$10/mmbtu in 2018 to close in on the recent decade-long average price, it cannot be assumed that this is now a stable price level. The erosion of the link with oil prices and lower-cost marginal supplies of LNG from the US imply sustained downward pressure on prices.

However, there are forecasts of increased demand for gas, and hence LNG, in Asia, and there is some analysis of expected supply of LNG based on recent patterns of investment in liquefaction plants, which may shift the price outlook for the medium term.

The biggest changes in gas markets in Asia are in China. Gas demand in China has more than doubled from just over 100 bcm in 2010 to nearly 250 bcm in 2017. Over that period, China's imports of LNG have gone up from around 10 bcm in 2010 to around 40 bcm (Shell 2018). Both China's total gas demand and imports of LNG exceeded industry consensus forecasts in 2017.

Increased demand for LNG, in particular in Asia, is a key feature of the forward-looking outlook exercises conducted by both Shell and BP: Shell projects a 55 per cent increase in LNG trade, or an additional 200 bcm, by 2035; BP projections show a significantly higher increase—an 85 per cent increase in LNG, or an additional 335 bcm, over the same period.

Increases in supply of LNG can be expected over the two years to 2020 because there remains some major investment in LNG supply, much of it from Australia for the Asian market, coming on-stream in the next two years: an estimated additional 40 bcm in additional supply capacity is expected in both 2018 and 2019, but not much more after that. The Shell LNG outlook argues that there is a risk of a lack of supply investment around the middle of the next decade. This is possibly relevant to Tanzania given that the 'Final Investment Decision' (FID) for the offshore gas has been postponed a number of times, and is now not expected before 2022. A key party to investment in offshore gas in Tanzania will be Shell. At the same time, there are alternative new sources of supply, not least Mozambique, which has more than twice the recoverable reserves of Tanzania and is a few steps further along the path towards first production.⁶

Policy risks: The 'authorising environment'

Progress on the development of a project of scale and complexity requires work to solve geological and engineering challenges. But that work will not start until there is some degree of confidence in the policy environment for the project. For example, as touched on above, a consortium of investors will typically only incur the costs of pre-FEED work when the main policy and commercial parameters of a project are clear. Pre-FEED work is an essential input to an FID. And the more detailed and intense engineering work—FEED—usually starts when there is a clear HGA in place which defines the project, the associated fiscal terms, and their implications for the commercial case for an investor, given the market and commercial risks they face.

The policy risks come in two broad groups. One is the legal and regulatory requirements which cover fiscal terms and other formal obligations on a project. The other is the extent to which there

⁶ Reserves in Mozambique are estimated at 100–180 tcf, compared with the official reserves for Tanzania reported at 57 tcf. It was reported in August 2018 that Anadarko was targeting the first half of 2019 for FID in Mozambique (see *Offshore Energy Today* 2018), with plans to export 12.88 million tonnes a year, which is equivalent to 17.5 bcm a year.

is sufficient clarity in the roles and responsibilities across government for working with the consortia investing in a large and complex project. The administrative processes that confront the investor will be part of the assessment of the risks associated with any given set of policies—which combine in an assessment of how straightforward it is to do business. Section 3 below lays out these two broad categories of risk in more detail.

2.2 Projections: Production and prices

The geological, engineering, and market risks surrounding offshore gas in Tanzania suggest that there might be no production any time soon—especially when the policy risks set out below are also taken into account.

However, in looking at what *could* be feasible given the scale of reserves, a number of scenarios have been used as the basis for estimates of potential public revenue. In this section we look at the assumptions on production and prices, before reviewing the outcome of projections in terms of revenues to government.

There are at least three published exercises in projecting expected volumes of production, and their timing. Henstridge and Rweyemamu (2017) updated the model used in an earlier study that was published by the Africa Development Bank and the Bill & Melinda Gates Foundation.⁷ Scurfield and Mihalyi (2017) is part of a series of briefs on natural gas in Tanzania published by the Natural Resources Governance Institute (NRGI). Baunsgaard (2016) is an IMF ‘Selected Issues Paper’ which accompanied the 2016 IMF Article IV Consultation on Tanzania, and which updated earlier work reported more extensively in a 2014 Selected Issues Paper (Baunsgaard 2014).

Because the scale of reserves and of production are such that the only feasible use for almost all the gas will be LNG exports, the assumptions on production become a function of the capacity of each ‘train’ for liquefying gas.⁸ The minimum production of gas will be the minimum needed to make one train work. Most modern trains process around 5 to 6 million tonnes of LNG a year—equivalent to between just under 7 and almost 9 bcm a year. Each study has broadly comparable assumptions on production, which include a steady state of 15–20 million tonnes of LNG each year, with the liquefaction plant building up to three or four trains.

There are a range of price assumptions in each study, reflecting the drop in prices in 2016. Baunsgaard (2016) and Scurfield and Mihalyi (2017) share the observation that prices need to be at least US\$11/mmbtu before investment becomes feasible, even if their estimates on rates of return to the investor are lower than most usually accept.

The assumptions on the capital investment costs are broadly similar as well: a total of around \$44 billion—comparable in order of magnitude to the US dollar value of Tanzanian GDP. The consistency across all the assumptions used in all three studies is not wholly unsurprising. The scale and complexity of producing LNG with offshore gas can be reasonably inferred, though the details of fiscal terms are not all in the public domain.

⁷ The AfDB/BMGF (2015) publication is ‘Background Paper 2’ on the timing and magnitude of new resource revenues, which was a background paper to a report, *Delivering on the Promise*, on the possibilities for increased investment in human development that could arise from new resource revenue opportunities in six countries in sub-Saharan Africa.

⁸ The term ‘train’ refers to the linked set of cooling plants that turn natural gas into a liquid at a temperature of -161°C .

2.3 Projections: Fiscal terms and cost recovery

To make projections of potential revenue, the fiscal terms have to be modelled, including the ‘cost recovery’ provisions for investors to have a relatively early recovery of the costs of capital investment, which shapes both the expected return on investment and the shares of the NPV of the project between the government and the investor. The larger the provision for early cost recovery, the higher the return on investment—which could mean that the government can take a larger share of the total NPV of the project over its lifetime—but the smaller the immediately available revenue to government.

The fiscal terms on a large hydrocarbon investment, sometimes referred to as a ‘petroleum operation’ to distinguish it from the taxation of a normal corporate entity, uses a mix of instruments:

- **Royalty:** Usually a fixed percentage of sales on all production.
- **Profit share:** The post-royalty receipts from sales can be shared between the government and the contractor. The contractor will need to be reimbursed for operating costs and for some share of the sunk capital costs—‘cost recovery’—together making up a ‘cost share’. The remaining balance is subject to a ‘profit share’. The split between government and contractor is often set by a formula, which varies the share as a function of the sales price or the returns earned by the contractor.
 - The provision for capital cost recovery in the calculation of a cost share means that once capital costs have been fully reimbursed, the amounts available for the profit share go up. At that point, there is an increase in the revenue to government. The relatively early reimbursement of capital costs reflects the fact that the contractor has shouldered the exploration, geological, engineering, and some market and commercial risks up-front.
- **Corporate income tax:** The investor consortium is also usually liable for conventional corporate income tax (CIT) such as is applied to a normal corporate entity—with a provision to carry forward losses incurred during the investment phase of a project.
- **Fees and charges:** There is almost always an acreage fee for the area of each block where there is exploration or production going on.
- **Equity:** In many countries, the nationally owned oil or gas company holds an equity share in the consortium running exploration or production operations, often with the commitment to finance a share of capital investment being carried forward by the other partners, which yields an equity share in due course.

To model revenue to government, the assumptions for capital investment costs, operating costs, volumes of production, and prices for a petroleum operation are combined to construct a sequence of cash flows. The applicable fiscal terms are then applied to give estimates of the profitability of the project for the investor, and the revenue going to government.

There are at least two broad trade-offs which any set of fiscal terms will resolve. One is between the share of the ‘rent’ from the project which goes to the government and the share which goes to the investor. This is usually calculated on an NPV basis, where future cash flows are discounted by how far into the future they are—meaning a dollar to be received in ten years’ time is discounted relative to a dollar received today. The share going to government on that basis might go down if the fiscal terms deliver more revenue earlier on: this could be through a tight ceiling on cost recovery which increases the ‘profit gas’ available for sharing, or through changes in the terms on the carry-forward of investment allowances. When the government gets earlier revenue, the

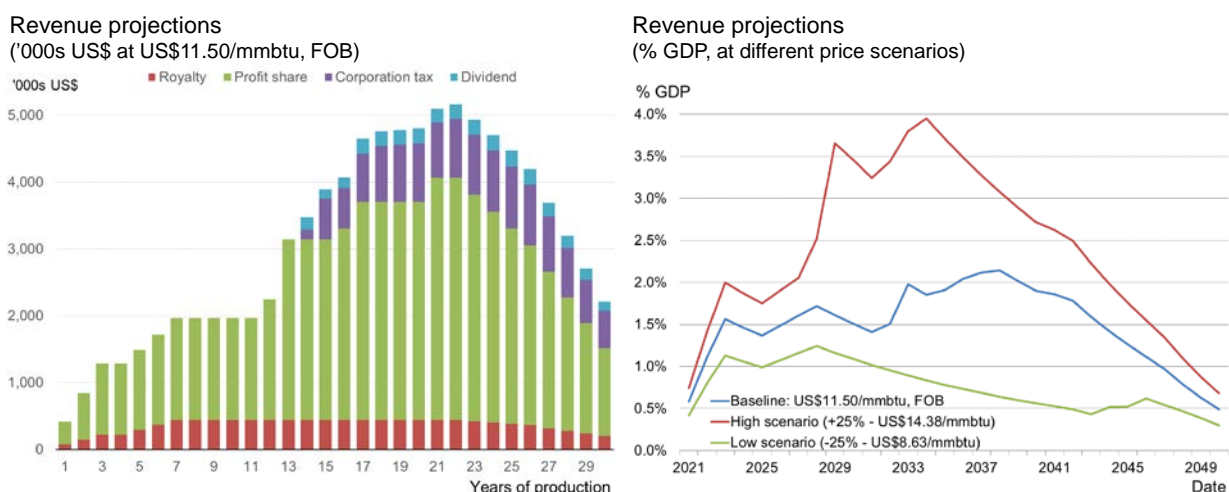
investor will need to have relatively more of the rest of the NPV to offset risks associated with the length of time it takes to go net cash flow positive.

The other trade-off for the government is that the more ‘progressive’ the implicit tax schedule, the higher the share of volatility in the public finances. What this means is that the more the government gets of any ‘up-side’ in rent when the price goes up, the more volatile will be the revenue stream as it amplifies any volatility in sales prices. When sales are made through long-term contracts, this effect is somewhat limited. But if there are sales on the growing spot market for LNG cargoes, there will be a bigger challenge of volatility in the management of the public finances.

The fiscal terms for Tanzania are assumed to be those reflected in the current Production Sharing Agreements (PSAs). These were agreed with BG Group and Statoil, the operators at the time, between 2005 and 2007, with an amendment to the Statoil PSA made in 2012, and were negotiated under the law on upstream gas production which applied at the time. They are not in the public domain, though the 2012 amendment was leaked. They are therefore approximate—and the assumptions for each of the modelling exercises which are summarized in Table 1 are set out in each publication. A new ‘model’ PSA was published in 2013, and raises the share of the state in each project—in effect, higher taxes. The implications for project viability are discussed in Section 3 below.

In the case of LNG, there is a question over whether the project, which includes at least three elements—the upstream production of gas, the pipelines to the shore, and the LNG liquefaction plant—is treated as one integrated taxable entity or whether each element is treated separately or in some combination. In the modelling reported here, with the results illustrated in Figure 3, the upstream is combined with the pipelines and treated separately from the LNG plant, to which normal corporation tax provisions were applied. A key variable is the transfer price between the two operations and the extent to which gas is bought and sold, or whether a tolling fee is paid to the LNG plant for liquefaction. There is a more detailed discussion of the implications of each option in Scurfield and Mihalyi (2017).

Figure 3: Tanzania revenue projections



Source: Author's construction based on Henstridge and Rweyemamu (2017).

The results for revenue to government from Henstridge and Rweyemamu (2017) are presented in Figure 3. The left-hand panel shows an estimate of the amounts that go to government from each

of the main instruments in the fiscal terms as at 2014, expressed in terms of constant-price 2012 US dollars. The take from a fixed-percentage royalty shows as flat during the plateau of constant production, with a constant-price assumption. The step increase in receipts from profit share shows after 11 years of production, which is the time when capital cost recovery is complete and profit gas increases, and at the same time receipts from CIT kick in and there would be some dividends from the share in the consortium held by the state through a national company.

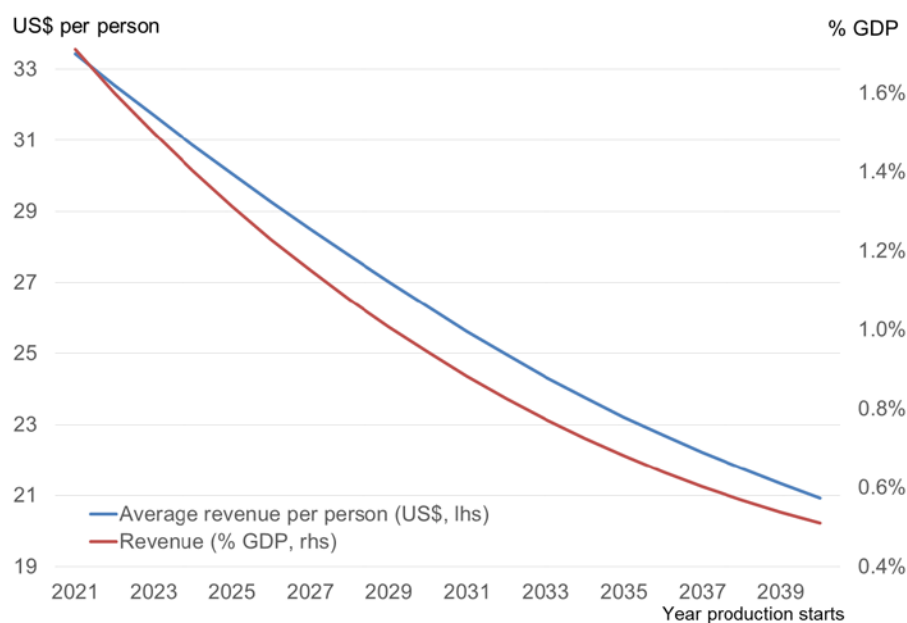
The right-hand panel of Figure 3 shows three variants of price assumption, the high scenario being 25 per cent above the central case, and the low price scenario being 25 per cent below it. The revenue projections are expressed as a share of GDP, which is assumed to be growing in line with UN population projections of workforce growth and with an assumption on trend growth in labour productivity that had led to an assumption of real GDP growth of the order of 7 per cent. Also arguably optimistic is the start date of 2021, which was not wholly realistic at the time of the modelling exercise on which the chart is based.

The right-hand panel provides an illustration of volatility: even with constant plateau production and a constant-price assumption, the profile of revenue is different at different price levels. This is partly a result of the pattern of receipts under the fiscal terms illustrated in the left-hand panel, and partly because a higher price means that cost recovery is completed sooner rather than later: that feature of the fiscal terms means that when prices do move around from year to year, revenue to government can be more volatile than spot prices for LNG.

The start date for production is dependent on the date of the FID, which is a critical moment for a major investment project. It is a decision based on analysis of considerable preparatory work, such as the Pre-FEED work referred to above, as well as appraisals of the full panoply of risks, opportunities, and alternatives. The FID for the upstream gas developments under both consortia, and the construction of the liquefaction plant that both would use, was once thought to be feasible in 2016. At the time of writing, at the end of 2018, it is not expected until 2022 at the earliest. The time between FID and the first production of gas is a minimum of five years—hence the modelling of a 2021 start date based on a risk-free assumption on construction and a 2016 FID date (as referred to above)—but delays are likely, and gas production might not start until 8–10 years after FID. Such a delay means that any projection of revenues based on constant US dollars leads to a shrinkage of revenues relative to GDP or when expressed as dollars per person.

The costs of delay for any given configuration of costs, production, prices, and fiscal terms are illustrated in Figure 4. Compared with production starting in 2021, a ten-year delay reduces the average revenue over the life of the project by about half when expressed as a percentage of non-resource GDP, from 1.7 per cent to 0.9 per cent—given the assumption that GDP continues to grow—and by a quarter when expressed as dollars per person, from US\$33 to \$25 per year. This is because both the economy and the population are growing, and any given scale for a project diminishes over time in relative terms. The point that Figure 4 underscores is that delays are costly to all concerned.

Figure 4: The costs of delay



Source: Author's construction based on Henstridge and Rweyemamu (2017).

Table 1 shows a select few summary indicators from published projections of production, profitability, and revenue from offshore gas. Each uses a slightly different set of assumptions, including start date. Nonetheless, they have broadly comparable sets of results, and share the conclusion that the potential for gas in Tanzania is material, in the sense of additional revenue to government of around 2 per cent of GDP, or US\$3–4 billion, a year. But it is in no sense transformative: there is nothing in this scale of a potential revenue boom that directly delivers economic structural change. Whether such revenue can finance some facilitation for growth, structural change, and industrialization critically hinges on the public policy environment into which it arrives.

Table 1: Projections of revenue from LNG

		Henstridge and Rweyemamu (2017)	Scurfield and Mihalyi (NRGI, 2017)	Baunsgaard (IMF, 2016)
Price cif Tokyo	(US\$/mmbtu)	16.0	14.0	9.0–10.0
Price fob Tanzania	(US\$/mmbtu)	11.5	12.0	7.0
Recoverable reserves	(tcf)	37	27	29
Production at plateau	(MMT LNG)	20	15	15–20
Date production starts		2021	2026	2024
Capital expenditure	(US\$bn)	40.0	37.5	44.0
Average government revenue (over project lifetime, or 30 years of production)	US\$bn:	3.1	3.8	c. 2.0–4.0
	% GDP:	1.7%	2.0%	-
	Per person:	US\$33	US\$22	-

Notes: cif = 'cost, insurance, and freight'; fob = 'free on board'; MMT = 'million metric tonnes'.

Source: Author's construction; sources as stated in columns 3, 4, and 5.

In the next two sections I set out two areas of public policy which matter for making the most of this sort of natural resource: (i) the policy which changes the risks and opportunities for the project

(Section 3); and (ii) some elements of public policy more broadly which shape whether there is scope for a contribution to growth, structural change, and industrialization (Section 4).

3 Public policy and risk

There are, broadly, two aspects of public policy which shape the risks faced by a complex large-scale natural resource project. One is the legal and regulatory requirements which cover fiscal terms and other formal obligations on a project; the other is the extent to which there is sufficient clarity in the roles and responsibilities across government for working with the consortia investing in a large and complex project.

3.1 Legal and regulatory requirements

As discussed above, for a contractor to commit to the initial pre-FEED phase of planning, and then to FID, there needs to be a reasonable degree of certainty over the laws, regulations, and commercial agreements that will govern the project. This is not yet the case in Tanzania.

In 2015 an incomplete legal and regulatory environment was strengthened when the Petroleum Bill received presidential assent: the Act is a major piece of legislation which: (i) expands the provisions regulating upstream petroleum operations that were previously governed by the Petroleum (Exploration and Production) Act, Cap. 328 (PEPA); (ii) includes mid- and downstream petroleum product supply operations (previously regulated by the Petroleum Act, Cap. 392); and (iii) provides regulation of the mid- and downstream natural gas activities.

Some of the salient features of the Act include:

- Establishing the Oil and Gas Advisory Bureau under the President's Office to advise the Cabinet on strategic matters of the petroleum industry;
- Establishing the Petroleum Upstream Regulatory Authority (PURA);
- Designating the Tanzania Petroleum Development Corporation (TPDC) as the National Oil Company (NOC);
- Providing exclusive rights to TPDC for exploration licences and collecting natural gas from producers and distributing to customers;
- Identifying revenue sources and obligations of licence holders and contractors to pay royalty, fees, income taxes, and other taxes including capital gains tax;
- Measures intended to strengthen Tanzanian participation in the petroleum value chain.

While the 2015 Act is the cornerstone for activities of the oil and gas sector in Tanzania, there were several areas where greater clarity in the broader legal framework was needed.

For example, the consortia partners investing in separate projects for upstream production of gas are also evaluating the joint LNG plant. There is a question of the extent to which the projects are treated as being integrated, both from a regulatory point of view and in terms of whether they constitute an integrated taxable entity. The operations of upstream gas production and an export LNG plant are distinct from traditional downstream activities, such as the transport, distribution, and sale of gas for the domestic market. It is preferable for large integrated gas projects which span upstream and midstream to have a single regulator to ensure consistent regulation and effective project execution and operation of the gas/LNG value chain. However, in the Act the construction and operation of export liquefaction facilities (and other related activities such as gas processing, storage, and jetties/marine facilities) are considered part of the midstream and

downstream regulated activities alongside domestic transportation and distribution and the sale of gas to the market in Tanzania.

In addition, the Act provides exclusive rights over the natural gas midstream and downstream value chain to the NOC, TPDC. This provision might not be beneficial for efficient development of gas resources, particularly in areas where the NOC has no experience, for example in large-scale gas liquefaction. In an integrated gas/LNG value chain, the upstream contractors are looking to establish their interest in the liquefaction plant in line with their upstream participation interests so as to secure common incentives between owners and users of the LNG plant. This is important to ensure cost-effective execution and operations. It also provides lower risk for the investors in upstream production.

As well as the broad legal framework provided by the Petroleum Act 2015, there are some specific laws, regulations, and contracts needed for even the preparatory work on a large-scale LNG project to start. These are all part of the broader authorizing environment that the government would need to have in place for the country to make the most of the opportunity offered to it by a new natural resource asset.

A key step is an HGA for the LNG plant. The discussions on the HGA were reported to have started in 2017 with the aim of completion by late 2018, although press reports suggest differences remained at October 2018 (see, for example, Ng'wanakilala 2017, 2018). The HGA will need to settle the question of how much the upstream gas production is integrated with the liquefaction of gas for export, which will affect the commercial viability of each investment and the associated risks. A key variable is the tolling fee if one is charged for liquefaction, or the price of upstream gas if the ownership of the gas is to pass to the operators of the LNG plant before export. This is because the tax liabilities of each part of the gas value chain could change, depending on whether integration creates one taxable entity, or whether the fiscal terms and other obligations in the PSAs that were negotiated between 2005 and 2007 would simply apply to upstream production.

However, at the same time, there are some commercial risks associated with the viability of those PSAs. Since they were agreed, a new model PSA was published in 2013. The analysis done by Scurfield and Mihalyi (2017) for NRGi suggests that a straight application of the terms of the model PSA to the gas projects in Tanzania would increase the minimum sales price needed to clear the threshold for investment from US\$14/mmbtu to \$21/mmbtu.

Under normal circumstances, there would be little risk of a fundamental renegotiation of PSA fiscal terms. However, Tanzania now has a mix of laws that raise precisely such a risk. They are: (i) the Written Laws (Miscellaneous Amendments) Act 2017 ('Amendments Act'); (ii) the Natural Wealth and Resources (Permanent Sovereignty) Act 2017 ('Sovereignty Act'); and (iii) the Natural Wealth and Resources (Review and Re-Negotiation of Unconscionable Terms) Act 2017 ('Contract Review Act'). These laws appear quite targeted at mining. But they significantly elevate risks in any evaluation of the commercial opportunities and risks that an international investor in gas would undertake. For example:⁹

- The Sovereignty Act appears to require approval of any mining or petroleum agreements by the National Assembly, which has the authority to require renegotiation of any existing or future arrangements. Review includes scrutiny for 'unconscionable' terms under the Contract Review Act; in addition, any clause that subjects the contract to the jurisdiction

⁹ Woodroffe et al. (2017) provide a thorough and considered guide to these laws, on which the observations of the next two paragraphs are based, which draws on the published versions as submitted to Parliament.

of an international arbitration body might be deemed unconscionable—the Sovereignty Act stipulates that disputes relating to resource extraction be adjudicated in Tanzania. This appears to rule out industry-standard arbitration clauses, and would need to be reconciled with the obligations of Tanzania’s bilateral investment treaties.

- There are a number of changes to income tax and other laws which appear to change the fiscal terms, for example: (i) the expiry of depreciation allowances for natural resource prospecting, exploration, and development after ten years of production—which may imply that companies would not be able to recover the full cost of a phased expansion in a project; (ii) the exclusion of cost oil/gas from gross income, which changes the calculations of taxable income for petroleum operations and deductions for depreciable assets whose costs are recouped through cost oil/gas; and (iii) royalties are no longer deducted from taxable income, which broadens the tax base.

The cost of elevated risks of this sort comes in the time it will take to work through the mitigations that any international investor would look to make when assessing the case for committing significant investment capital to a complex project in Tanzania. These considerations are not limited to extractives. The Dangote Group has invested US\$650m in a cement plant in Tanzania. Aliko Dangote is reported later in 2017 as saying that ‘They’ve scared quite a lot of investors and scaring investors is not a good thing to do’ (Financial Times 2017). In this environment, perhaps there is little surprise that the negotiations on the HGA appear to have taken longer than hoped (see, for example, Lewis 2018).

In addition to the HGA, or as part of it, there will need to be agreement on the site lease for the LNG plant, and an LNG Marine Rights Agreement; a Project Development Agreement on co-operation for FEED and beyond will need to be established between TPDC, as the national oil and gas company, and the international investors; and ‘Upstream Implementation Arrangements’ by block will also be needed—which will include the operationalization of ‘Domestic Market Obligations’ (DMO) terms and conditions, for which the price of gas delivered for domestic use in Tanzania will be key to further shaping the commercial case for the international investors: the more gas is required for delivery domestically at a price below parity with international prices, the less favourable the commercial case for investment.

The cost of elevated risks and additional complexity comes in the additional time it takes to finalize the basis for moving forward with the project: recall that the HGA is a necessary step before embarking on the engineering work in the FEED necessary to find solutions to the engineering challenges that have not yet gone away, and that delay progressively reduces the value of the natural asset relative to GDP or to the population of Tanzania.

3.2 Policy co-ordination and the authorizing environment

Too often the transformation of resource wealth into prosperity fails not because of a lack of the correct policies, but because of a weak underlying system of governance. Implementation of policies and strategies in the oil and gas sector will require co-ordination and an authorizing environment across a range of different government institutions.

The Ministry of Energy and Minerals (MEM) is the lead policy and administrative institution and plays a co-ordinating role with other institutions in the sector, many of which are its affiliates. Working alongside MEM, the nationally owned petroleum company TPDC is the national partner in all petroleum ventures. The potential conflict of interest given that TPDC still holds policy and regulatory roles in addition to its commercial role is being addressed through the restructuring of the company to take on a purely commercial role, and the portioning off of its upstream regulator

role to a new independent regulatory body, the PURA. The Energy and Water Utility Regulatory Authority (EWURA) role is confined to midstream and downstream regulation.

Looking towards taxation and revenue collection, the Ministry of Finance (MOF) is the lead policy institution, but MEM and TPDC also play an important role in setting royalty and profit-sharing terms at the project level. The Attorney General is also involved in negotiation and devising contracts. In terms of revenue collection, several institutions have roles to play in relation to different components. Among the institutions involved, the Tanzania Revenue Authority (TRA) collects income taxes from gas companies, while MEM collects the large share of non-tax revenues from petroleum activities via TPDC, including royalties, licence fees, application fees, annual rent, and profits from oil and gas. The MOF collects revenues from equity holdings, and local authorities collect a local service levy from mining companies. Tax audits are carried out by the TRA. These institutions play similar roles in relation to all other economic agents in the economy.

Co-ordination on environmental and community issues is also complex. The Vice President's Office (VPO) is the lead policy institution in this domain, and has to co-ordinate with MEM and the national agencies on policy issues. Compliance and enforcement of law is implemented by the National Environment Management Council (NEMC), in co-ordination with local authorities. Meanwhile the Ministry of Labour and Employment leads on the formulation of labour, labour market, social security, and employment policies, while the Ministry of Lands, Housing and Human Settlements Development has to approve land allocations for extractives use.

Two key challenges pervade when it comes to co-ordination on the full range of issues required to harness natural gas for development. First, the fact that many of these institutions lack the authority to convene high-level decision-makers from partner institutions on a regular basis means that they tend to operate in an environment of inadequate information. Second, without high-level oversight to direct activities, there has been no one to oversee organizational roles and responsibilities, opening possibilities of 'mission creep' where institutions work beyond their mandate, sometimes leading to potential conflicts of interest, while lack of engagement or inaction has meant that other institutions are not doing the work that they should be. Co-ordination challenges and complexity are most acute when one considers the relationship between oil and gas and wider economic issues. The key institutions in this realm include the President's Office Planning Commission (POPC), the body which develops Tanzania's national planning framework centred on the Five-year Development Plan (FYDP), and the MOF, which manages the national budget and the financing framework for the Medium-Term Expenditure Framework (MTEF). Strengthening the co-ordinating agencies and institutions is critical if natural gas resources are to be effectively integrated within the wider economy.

4 Public policy and the contribution of natural resources to growth, structural change, and industrialization

Public policy will influence the impact of natural resources on economic development in, broadly, four phases, aligned with the phases through which a natural resource project goes as it is developed and as it operates. Policy will condition: (i) construction jobs and skills training; (ii) the environment for private business investment—which can increase ahead of the development of the natural resource, and which includes 'local content' that seeks to support firms who can be part of an international supply chain and other externalities, such as the effect on the standards of operations and management if managers can provide a transition of international business and management practices from multinational companies involved in the oil and gas investments and value chain into other business activities; (iii) appropriate fiscal policy management in the face of

possibly large and volatile macroeconomic flows as the revenue arrives; and (iv) the efficiency and focus of public investment, including in infrastructure and other forms of public capital. In this section I focus on the first two, and only briefly touch on the last two.

4.1 Jobs and construction

The construction phase of an LNG investment entails building or assembling a facility for the ‘trains’ which condense natural gas to a liquid by cooling it to -161°C (-260°F), and associated infrastructure such as jetties, so that the gas can be exported by ship. There is likely to be a material impact on the labour market for a range of semi-skilled and skilled workers, such as construction workers, bricklayers, metal workers, carpenters, plumbers, and electricians. It has been estimated that some 4,000–5,000 jobs would be created directly during construction of LNG facilities in Tanzania. This compares with a number of jobs on other LNG construction projects ranging from around 2,000 in Australia to 8,000 in Angola (OPM 2013).

Training will be essential for secure project delivery, and it may well need a specific initiative: there are not the skilled people to meet this demand, even if the requirements number just a few thousand in a labour force numbering in the millions. An assessment of vocational and educational training needs concluded, among other findings, that: (i) those graduating from ‘vocational education and training’ are not directly employable; (ii) the trades which will be needed are not being taught; (iii) in any case, the training is low-quality (VSO 2013, 2014). However, most of the areas in which training would be needed to fill the jobs created as part of the investment in hydrocarbons were not sector-specific: the VSO assessment showed that a significant number of the skills needed are transferable. These include the skills needed in metal work, building works, civil engineering and infrastructure, mechanical work, and electrical work.

As argued in the framing paper (Henstridge 2019), more and better construction skills are important for strengthening the contribution of a boom when ‘Dutch disease’ leads to an appreciation of the real exchange rate. That appreciation raises the returns to non-tradeables, including non-traded capital, which is mainly buildings. If the construction sector is weak, the supply of structures is inelastic and the real estate boom is more in prices than buildings. If, however, there are growing numbers of people with transferable construction skills, the supply of structures is more elastic and the boom is then more in the supply of buildings, and relatively less a real estate price boom. Therefore a widespread programme of vocational training to a standard good enough to permit trainees to work on the construction phase of a natural resource project means a stronger and more elastic supply of people with the skills which will be in demand as the boom kicks in.

4.2 Externalities and private investment

One of the ways to show that an apparently large investment in oil or gas production is at the same time very small is to point out that when it is in operation, it creates very few jobs directly. Although it takes several thousand people to build an LNG plant, only a few hundred are needed to operate it. This then points to the scope for linkages with the domestic economy, in particular in a local supply chain, as a key source of impact on growth, structural change, and industrialization.

Perhaps the best summary of this opportunity was given by John Sutton at the launch of the ‘Enterprise Map of Tanzania’, his review of industrial capabilities: ‘If oil industry supply chains can be fully integrated with Tanzania’s domestic industrial sector, then the payoff to medium-term growth will be huge ... No single issue in Enterprise policy is more important right now’ (Sutton and Olomi 2013). The emphasis in Sutton’s analysis of the opportunity is on the development of firm capabilities—meaning, essentially, the organizational ability to get things done, including

through absorbing and innovating by using new ideas or ways of doing things. Sutton gauges capabilities in terms of quality and productivity. As he put it in his Gilman Rutihinda Memorial Lecture: ‘Crude measures such as an “x per cent local content rule” are ineffective: rules of this kind are too easily circumvented, and may generate an unfortunate bias in the supplier base towards those activities that contribute little to the development of the host country’s industrial capabilities’ (Sutton 2014).

The context for these opportunities for gains from being in the supply chain is one of recently sustained growth in GDP, but little improvement in productivity. The economic structural change in Tanzania since 2000 has been driven by a shift of workers out of agriculture. Only agriculture and mining achieved within-sector labour productivity gains from 2000 to 2010: it was the between-sector shifts of workers out of agriculture which led to all gains in average productivity in the economy.¹⁰

At the same time, of all jobs created outside agriculture, 83 per cent were in the informal sector, mainly in micro-enterprises or self-employment. Tanzania’s enterprise survey data suggest that even in the formal sector, firm-level labour productivity fell in almost all non-agricultural industries. Overall, there are very few individual industries in which innovation and technology absorption seem to be working to raise productivity.

In other words, there should be great scope to use the opportunities of a prospective international supply chain for gas to strengthen firm capabilities—and scope for improvements in productivity that could come from foreign direct investment (FDI) into Tanzania associated with strengthening firm capabilities—of both nationally owned and foreign-owned firms.

The scope for such FDI has been illustrated by the experience of Mozambique under broadly similar circumstances. Between 2003 and 2012, there was a 58 per cent increase in non-resource-extraction FDI in the two years following the discovery of gas offshore Mozambique (Toews and Vezina 2017). Toews and Vezina estimate that each FDI job resulted in 6.2 additional local jobs. The detail in their data suggests that 45 per cent of jobs were created in the formal sector, and that only workers with at least secondary education benefited from the wave of job creation. This suggests that openness to the non-resource FDI would be useful for unlocking the gains to job creation and for strengthening firm capabilities associated with FDI. It also highlights the importance of a well-functioning education system with strong learning outcomes.

In looking to be practical, Sutton argued for a small and effective local content unit rather than such rules. A local content department was established in 2015 in the National Economic Empowerment Council (NEEC) in the Prime Minister’s Office, with responsibility for local content strategy. However, MEM has taken the lead in the development of the gas sector’s local content policy and legislation.

The policy framework for local content in Tanzania has emerged in the last few years.¹¹ In November 2017, the local content regulations for the 2015 Petroleum Act, published by MEM, came into effect. They reflect the 2015 Energy Policy. The policy and legal framework prioritizes local participation in the gas value chain, rather than developing linkages. ‘Participation’ seems to

¹⁰ The analysis underpinning these conclusions is reported in a detailed background paper on Tanzania for the ‘Pathways Commission’ (Salam et al. 2018) looking at the opportunities and challenges of new technology for economic development.

¹¹ The policy and legal context is thoroughly analysed in Scurfield et al. (2017).

mean ‘a progressive and comprehensive integration of Tanzanian citizens into all aspects of the petroleum industry to ensure maximization of benefits’ in the National Energy Policy.

The regulations set out minimum local content levels for both employment of nationals and the use of goods and services across the value chain, with significant penalties for non-compliance. However, the policy is somewhat inconsistent: the definition of ‘local’ varies, but allows an 85 per cent foreign-controlled joint venture to qualify as a ‘local’ company. The implicit definition of local goods or services includes those which are ‘locally available’, which could include goods imported into Tanzania by a foreign-owned company. However, at the same time, the Non-Citizens Act 2014 limits foreign participation in economic activities in Tanzania.

The policy approach in Tanzania therefore takes a literal sense of ‘local’ content, combined with uncertainty on what it means in practice. It is not a policy approach which is mindful of the development of firm capabilities for improved productivity in Tanzanian firms more broadly.

4.3 Fiscal policy management and public investment

The third and fourth channels for impact on growth and structural change are through the public finances. The offshore gas finds have yielded revenue through receipts from sales taxes and personal income taxes that have been bolstered by the activity surrounding exploration. But there has of course been no direct revenue, and none can reasonably be expected until the late 2020s. Accordingly I only touch on these two issues here—they have been widely discussed in a range of writings elsewhere—in light of the establishment of a fiscal framework for oil and gas in 2015.¹²

Parliament approved a fiscal framework for the management of oil and gas revenue in 2015, which is integrated into the overall fiscal and budget framework, reinforcing rather than fragmenting it. It codifies a fiscal rule with a threshold at 3 per cent of GDP. If revenues are below that threshold—as expected in the projections discussed above—then they can go to finance a non-gas budget deficit. Above 3 per cent of GDP, they are saved. The stock of savings can be drawn down at a limit of 3 per cent of GDP. At the same time, there is a ceiling on recurrent expenditure—which is that it is limited to increase by nominal GDP—and a ceiling of total expenditure of 40 per cent of GDP. A summary and brief analysis by Baunsgaard (2016) highlights some threshold effects around 3 per cent of GDP, and contrasts the application of these rules with those that would follow constructs such as the permanent income hypothesis (PIH).

However, neither this fiscal rule nor PIH use a broader economic consideration, which is that in transforming gas from a sub-soil asset into a flow of expenditure it should, in principle, be treated as a capital financing item: as an asset transformation this is a rearrangement of the public sector balance sheet. The further transformation from the dollar receipts as the government share of the rent, through public investment into public infrastructure or other public assets, should in principle be evaluated against the relative costs and benefits of the alternative investments. The accumulation of human capital through better health status, or through improvements in literacy, numeracy, and the other learning outcomes which contribute to a productive labour force, are to be included in such an evaluation of the costs and benefits of alternatives.

In reality, however, there are considerable limitations on the public sector’s ability to manage such flows of investment efficiently. And in practice, there will be some investments (such as roads)

¹² See, for example, work by the Collaborative Africa Budget Reform Initiative on revenue management in the extractive sector (CABRI 2016).

that are relatively more straightforward to administer than others (such as materially improved learning outcomes) even as Tanzania falls woefully short on both.

5 Conclusion

This review of the prospects for a boom from natural resources in Tanzania points to the conclusion that there probably won't be one.

First, the costs of extracting large quantities of gas from deep under the sea far offshore are high compared with immediate market price prospects; second, the array of risks facing the billions of dollars of investment needed to produce offshore gas are high. Those risks are partly technical—there are engineering problems to solve—and partly related to the markets for LNG, and there are also significant policy risks.

The government has reinforced the policy risks: the trio of laws passed in 2017—the Amendments Act, the Sovereignty Act, and the Contract Review Act—has postponed the prospects of the preparation for an FID, as evidenced by ongoing negotiations on the HGA for the LNG plant. Had there been an FID in 2016, as was once thought possible, and production starting in 2021, the average revenue during the project would have been 1.7 per cent of GDP. If the FID does not take place until after 2022, as currently expected, and there are further delays as technical, market, and policy risks are navigated, and production starts ten years later in 2031, then the average lifetime revenue will nearly halve. Some of that forgone revenue is a result of market risks materializing; much is simply the cost of delay. The progress of broadly similar investments in Mozambique provides a hint of what might have been for Tanzania.

In addition, the prospect of large-scale offshore gas supporting economic transformation is dimmed by the approach to local content being focused on 'participation' rather than meeting the broader challenge of raising productivity through strengthened firm capabilities. This approach looks unlikely to support growth, structural change, or industrialization.

After early hopes of a boost to growth and industrialization that pulled in advice from many sources on how to manage revenues, and the exploration of the lessons to be learned from other countries which took place back when gas prices were still high in Asia, it is disappointing that the prospects of production and the potential contribution to growth have faded.

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