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Negotiating Tanzania's Gas Future: What Matters for Investment and Government Revenues?

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SUMMARY

Tanzania stands at a critical juncture in the development of its offshore gas. The government (led by the Ministry of Energy and Minerals) and a consortium of companies (headed by Shell and Statoil) are negotiating a host government agreement (HGA) that will govern a liquefied natural gas (LNG) plant and be a significant part of the regulatory framework governing the entire offshore gas sector.

In this brief, we take a closer look at the regulatory framework for this sector and examine the impact of some of the framework's key components on: (1) the companies' decision on whether or not to invest in the LNG project, and (2) expected government revenues from the project.

ABOUT THE SERIES

This brief is part of a series analyzing the government's approach to managing the offshore natural gas sector. Other briefs in the series include "Localizing Tanzania's Gas Sector" and "Uncertain Potential: Managing Tanzania's Gas Revenues."

OUR RESULTS

Unless expectations around the project's economics change, it is unlikely that companies will invest in the LNG project. For investors to earn a return comparable to that seen in other LNG projects, we estimate that a long-term LNG price of USD 14 per one million British Thermal Units (mmBtu) would be required over the life of the project. With long-term forecasts for LNG prices in east Asia at $8, it appears unlikely that companies will decide to invest in the current environment. Companies and investors will have their own views of long-term prices and other market variables and may reach a different conclusion, and economic conditions may also change prior to the investment decision. Thus, it is of course still possible that investment will go ahead. Nevertheless, it would be advisable for the government to start considering ways to increase its chances of securing this investment while ensuring that the country still fully benefits from the project if it does proceed.

The modeled financial benefits point to the government benefiting more from an integrated value chain, but the practicalities of other projects linking to the LNG project—and the Tanzania Petroleum Development Corporation's (TPDC) role in the project and sector—point to a partially segmented structure. We estimate that the after-tax internal rate of return will be slightly lower and the average effective tax rate slightly higher if the LNG project has an integrated structure. This runs counter to the impact of segmentation typically observed in large LNG projects, and results from the project's expected low profitability. However, despite the potentially higher tax take, the government may still see disadvantages in an integrated structure.

CONTENTS

Imposing the stricter fiscal terms contained in the 2013 Model Production Sharing Agreement (2013 MPSA) and more recent changes to the generally applicable regime would significantly reduce the likelihood of investment, but changes to the composition of the current regime could still be beneficial. While the government would likely get a much larger share of the project's returns by imposing the 2013 MPSA regime, we estimate that it would mean a long-term LNG price of at least $21 would be needed for the project to proceed.

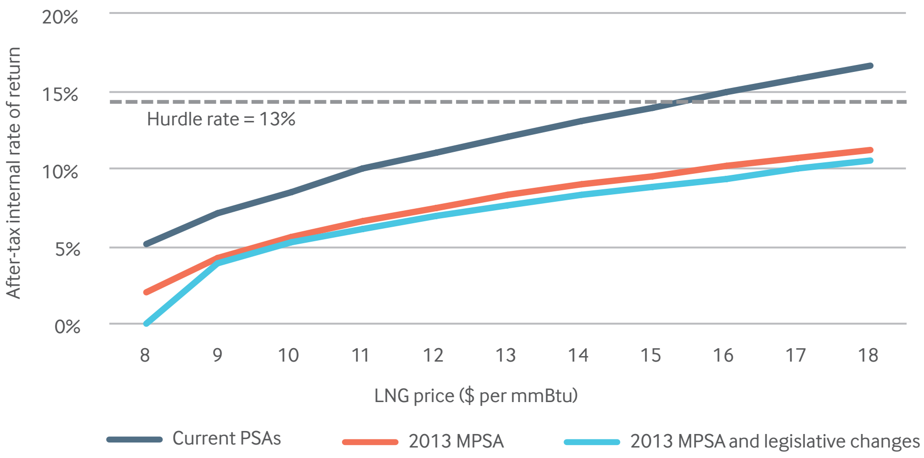


Figure 1. Estimated internal rate of return with different upstream fiscal regimes

On the other hand, moving in the opposite direction and succumbing to company pressure to reduce taxes is also fraught with risk, as the history of Tanzania's taxation of the mining sector illustrates. One possible solution is to apply a resource rent tax or another highly progressive fiscal instrument that, when combined with changes in the rest of the regime, produces a relatively low tax burden in years of paucity and a high burden in years of plenty.

Given the difference between the upstream and midstream fiscal regime, the tolling fee established in the HGA is likely to have a significant impact. A high tolling fee paid by the upstream entities to the LNG plant would shift income from the higher taxed upstream to the lower taxed midstream and therefore may reduce overall government revenues, while a low tolling fee could negatively impact the economic viability of the LNG plant and the overall project.

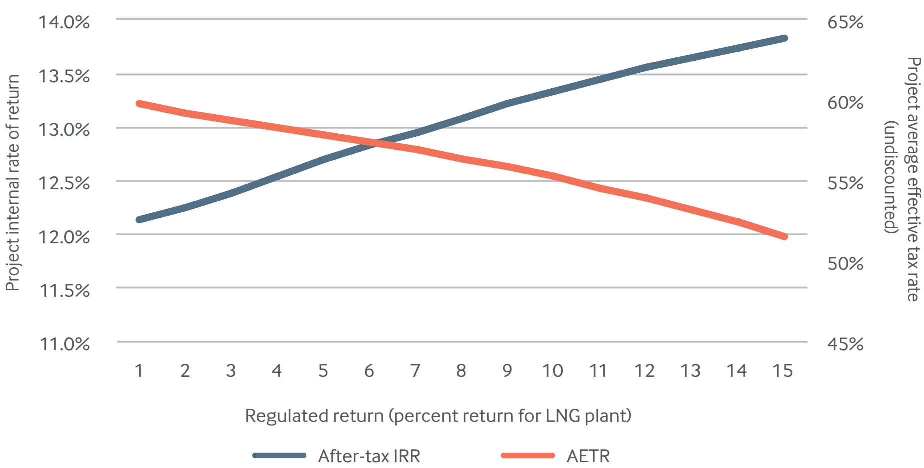


Figure 2. Estimated impact of LNG plant return at a LNG price of $14

The price at which companies sell gas to the domestic market will be an important factor in determining how the domestic market obligation impacts investment and government revenues. We believe that a domestic market obligation (DMO) larger than the one currently agreed in the production sharing agreements (PSAs) would make investment even less likely and would reduce government revenues if the project did proceed. A low price for domestic gas would amplify this effect. However, further analysis is required to support this conclusion.

INTRODUCTION

Tanzanians—12 million of whom live in extreme poverty[1]—are hoping that the natural gas lying 100 kilometers off their coast will transform their lives. And these large gas deposits could indeed accelerate industrialization, supply power and drive human development through the government revenue generated by the export of LNG. But to get this gas out of the ground and realize these benefits (particularly at current low gas prices) the companies and Tanzania have much work to do.

Since the discovery of offshore gas in 2010, the government has developed a number of policies for the sector. The effective design and implementation of these policies will play a critical role in determining whether extracting the gas will fully benefit Tanzanians. This is not a straightforward task, and many countries have ultimately failed to manage their extractive resources in a way that benefits the whole country.[2] Evidence from other countries and from Tanzania's mining sector suggests that there are many potential challenges to be navigated. One such challenge is the uncertainty that generally characterizes the extractives sector, and is particularly pervasive in the natural gas sector currently. This uncertainty makes it even more difficult for the government to develop policies that both ensure Tanzania gets a "good deal" from its resources and make the country sufficiently attractive to investors.

When companies discovered gas off the coast, the price of LNG in Asia—Tanzania's likely export market—was historically high. The LNG price has since fallen, and with it forecasts of future prices. In early 2015, the International Monetary Fund (IMF) forecast that gas prices would be $16 per mmBtu in 2020. By October of the following year, the forecast was only $7 in 2020.[3] The price outlook for many other commodities is also more pessimistic than a few years ago. However, the lower price projections for LNG are seen as the early signs of a reconfiguration of the global LNG market, which is expected to lead to some degree of convergence between the higher prices in the Asian market and lower prices in the U.S. and European markets.[4] Long-term forecasts are also colored by expected global responses to climate change and an anticipated transition to alternative energy sources.[5] The recent price collapse, coupled with projections of sustained low prices, have forced both companies and Tanzanians to reassess the country's gas future.

1 World Bank, *Tanzania Mainland Poverty Assessment: Executive Summary* (2015), 12.
2 See, for example: Andrew Warner. *Natural Resource Booms in the Modern Era: Is the curse still alive?* (IMF, 2015).
3 "World Economic Outlook Database," IMF, last modified April 2017, http://www.imf.org/external/pubs/ft/weo/2017/01/weodata/index.aspx.
4 Currently global gas markets are relatively unintegrated due to limited gas production and difficulties in transport. Prices can therefore differ significantly between markets. Unlike Asian prices—which are indexed to oil prices—U.S. and European prices are determined in the spot market and have been lower in recent years.
5 James Cust, David Manley and Giorgia Cecchinato, "Unburnable Wealth of Nations," *Finance and Development*, 54(1) (2017), accessed 15 May 2017, http://www.imf.org/external/pubs/ft/fandd/2017/03/pdf/cust.pdf.

If these forecasts hold and prices stay low, the future of Tanzania's offshore gas sector may be in serious doubt. Companies deciding whether to invest over the next few years will be taking these forecasts into consideration. However, commodity prices are inherently unpredictable, and the post-2014 downturn is just the latest example of volatility that few predicted. Therefore, while the current outlook represents a considerable challenge to the development of Tanzania's offshore reserves, interest in them is still likely to remain significant. The country still has much to gain from establishing effective policies—and much to lose if it does not.

In this brief we focus on one part of the government's policy. Specifically, we look at selected aspects of the HGA that is currently being negotiated between the government and companies for the multibillion-dollar LNG project.[6] The HGA will govern the LNG plant and coordinate the arrangements between the offshore blocks, the LNG plant and the various pipelines. We assess four decisions that will be made during the HGA negotiation:

- How the HGA will segment the gas value chain between the upstream and midstream for the purposes of regulation, including taxation.
- How much the upstream and midstream will be taxed.[7]
- How any transactions between the upstream and midstream will be priced.
- How gas will be allocated between the export and domestic markets.

We consider different options and estimate how the investment decision and the government's revenue are likely to change in each case. We discuss a fifth decision—requiring the participation of the local workforce and local suppliers—in a separate brief.[8]

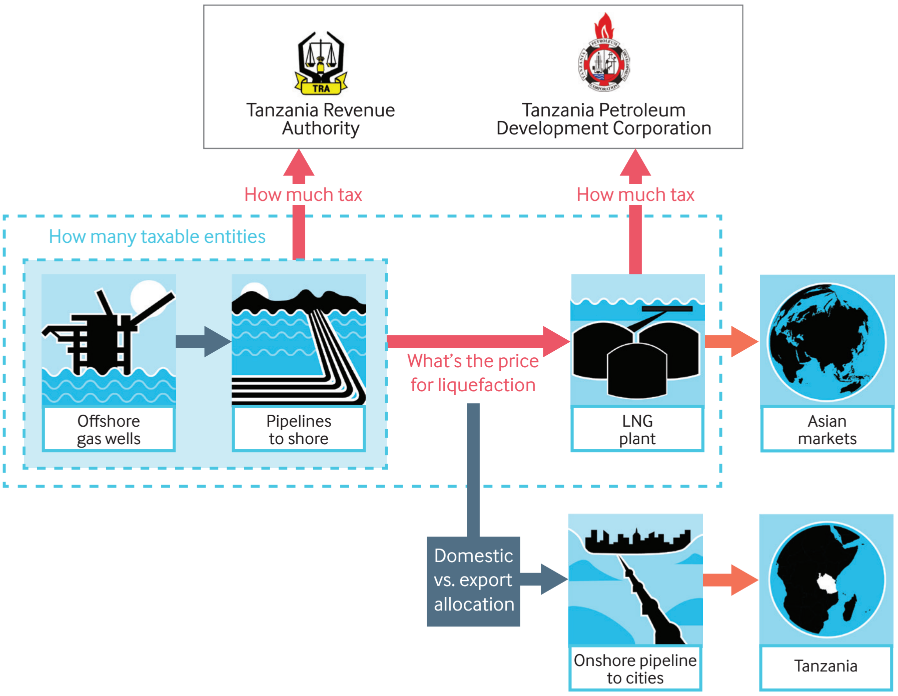


Figure 3. The LNG project's value chain

6 Fumbuka Ng'wanakilala, "Tanzania hopes for LNG plant agreement with oil majors by 2018," Reuters, 24 January 2017, accessed 15 May 2017, http://www.reuters.com/article/us-tanzania-gas-idUSKBN1581F4

7 While royalties and production sharing are not "taxes" and should be treated differently in any formal analysis, in this brief we use "tax" to refer to all fiscal instruments for simplicity's sake.

8 Thomas Scurfield and Nicola Woodroffe. *Localizing Tanzania's gas sector* (Natural Resource Governance Institute, 2017).

BACKGROUND: OFFSHORE NATURAL GAS SECTOR AND REGULATORY FRAMEWORK

The HGA will mainly govern the development and operation of the LNG plant, but it is also crucial to the operations of the entire offshore sector. In this respect, the government officials tasked with negotiating the HGA face two challenges: (1) the decisions they make on how to govern this LNG plant affect everything else in the sector—the parts of the system are interdependent; and (2) the offshore blocks are already regulated by PSAs, meaning that negotiators will have to work with the terms already set in the PSAs or renegotiate them.[9]

The offshore gas value chain: gas deposits, pipelines and AN LNG plant

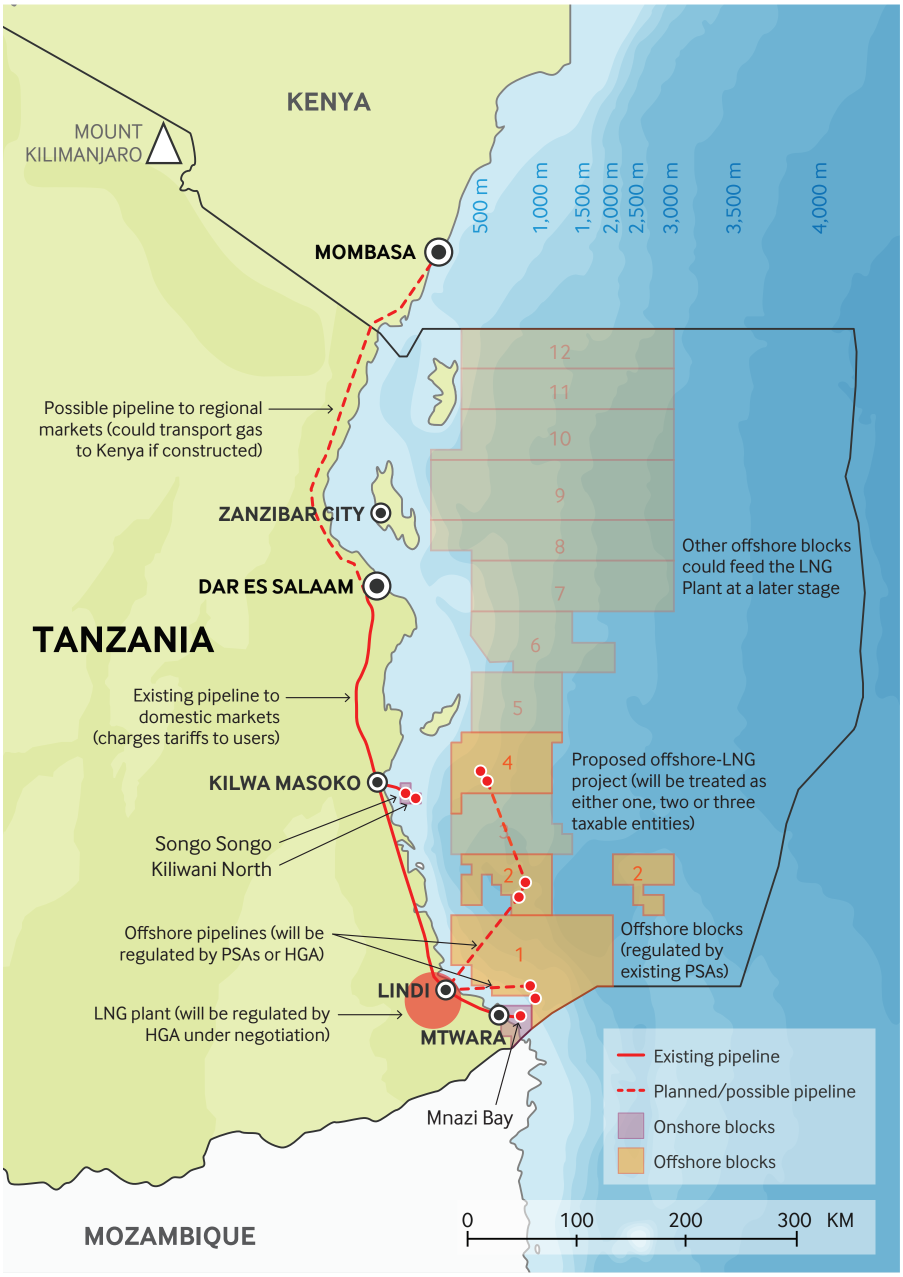


Figure 4. Map of natural gas projects in Tanzania

Source: Government of Tanzania exploration activity map; Natural Resource Governance Institute.

9 As is discussed below, the government has recently passed the Natural Wealth and Resources Contracts (Review and Renegotiation of Unconscionable Terms) Act 2017, which allows it to renegotiate these PSAs if they are deemed to contain "unconscionable terms."

The LNG project comprises three parts, all of which will be the subject of the HGA negotiation: the offshore blocks, the offshore pipelines and the LNG plant.[10] The offshore blocks (numbered 1, 2 and 4) hold the great majority of Tanzania's discovered natural gas. Cumulatively, the blocks are estimated to contain proved and probable reserves of 27 trillion cubic feet (tcf).[11] The gas from these blocks will be piped through a network of three offshore pipelines to an onshore terminal. At this point, most of the gas will flow to the LNG plant for processing and onward export to Japan, China and the rest of the Asian market, while the remainder will flow through the existing onshore pipeline network to the Tanzanian market.

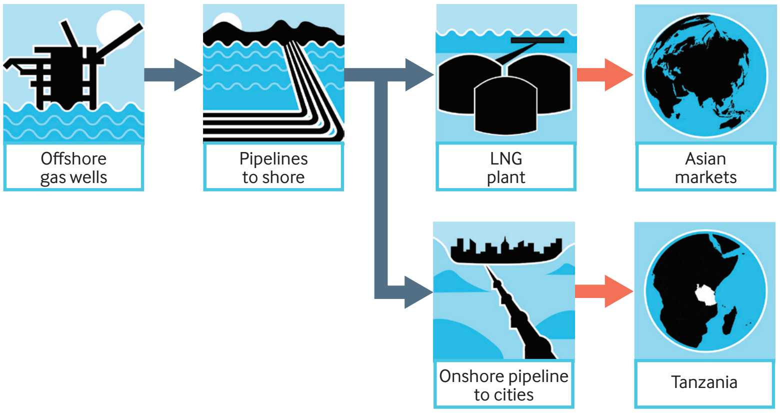


Figure 5. The planned LNG project

These elements are interdependent. Because most of the gas in the offshore blocks can only be monetized by converting it to LNG, companies will only develop the upstream if they can be assured that the LNG plant will go ahead. At the same time, given that onshore reserves are insufficient to serve a LNG plant (and a significant proportion of them are already contracted for domestic supply), the LNG plant will only go ahead if the offshore blocks are developed. Therefore, the investment decision will depend on the commercial viability of all three project components.

Two companies, Statoil and Shell, hold the exploration and production rights to the three offshore blocks (with ExxonMobil, Ophir Energy and Pavilion Energy holding minority interests). These companies have formed a consortium which will also partially own—alongside the government via TPDC—the offshore pipelines and LNG plant.

Table 1. The companies involved in blocks 1, 2 and 4

Block Name	Operator	Other partners
Block 1	Shell (60 percent)	Ophir Energy (20 percent), Pavilion Energy (20 percent)
Block 2	Statoil (65 percent)	ExxonMobil (35 percent)
Block 4	Shell (60 percent)	Ophir Energy (20 percent), Pavilion Energy (20 percent)

Aside from these three parts of the offshore sector, there are three other parts in Tanzania's gas sector that are unlikely to be a focus of the HGA negotiations but are useful to consider in this context.

First are the onshore and shallow basin gas fields that are currently serving the domestic market. These are negligible in comparison with the offshore discoveries, yet more fields may be discovered. Second is a network of onshore pipelines

10 The LNG plant will also have a facility for converting the "wet gas" from the offshore blocks into a form that is suitable for processing into LNG.

11 Wood Mackenzie. *Tanzania Upstream Summary September 2016* (2016), 17. Company representatives have indicated that this estimate may be a little high given some of these reserves have since been ruled out.

through which the onshore blocks supply the domestic market. The primary part of this network is the Mtwara to Dar es Salaam pipeline, in which the government holds a majority share. The government plans for any offshore gas supplied to the domestic and regional markets to use this network. Third, the government is considering building at least one pipeline to export gas to Tanzania's neighbors.[12] However, as the government's Natural Gas Utilisation Master Plan indicates, the viability of this project is yet to be properly assessed.[13]

Our focus in this brief is therefore the LNG project. However, we also keep in mind its implications for the future development of other offshore blocks. As two-thirds of the available area in Tanzania is yet to be explored,[14] companies are likely to discover more gas in other blocks. More gas could result in more companies using the LNG plant, or becoming joint owners of the LNG plant itself. While the LNG plant is likely to have two or three trains for the current discoveries, the plant can be expanded if companies discover more gas. The LNG project will establish the infrastructure and supply chains that future gas projects will most likely rely on, and therefore reduce operational risks in the future. It will also allow the Tanzanian government to develop the policies, regulation and institutional capacity to manage more gas projects, reducing political and regulatory risks. This means that the decisions the government makes now for the initial LNG project will significantly influence the future of Tanzania's entire gas sector.

Negotiation of the HGA and possible renegotiation of the PSAs

The government and companies have reportedly initiated the negotiation of the HGA, with the intention of finalizing it by the end of 2018.[15] Progress with the negotiations will affect when companies can make other important decisions. Both parties must at least agree upon key terms before companies can conduct feasibility studies (what the industry calls "preliminary front end engineering design", or pre-FEED), while more advanced project planning (called "front end engineering design", or FEED) will not take place until parties have signed the HGA. Only once these two planning stages are complete will companies make a final decision on whether to invest. The soonest this will happen is now believed to be 2022.[16]

The other set of legal documents we consider are the PSAs for each offshore block. These PSAs were agreed with BG Group (which has subsequently been taken over by Shell) and Statoil between 2005 and 2007, with an amendment to the latter's PSA in 2012. They include, along with many other terms, the fiscal regime and the DMO that are specific to each block. The government and companies have not disclosed the PSAs, so we have a limited understanding of their content.[17] Our only understanding comes from a leaked addendum to the Block 2 PSA, government

12 The government has suggested it is seeking funding for a pipeline to Uganda. From: Fumbuka Ng'wanakilala, "Tanzania Plans Gas Pipeline to Uganda," Reuters, 4 May 2016, accessed 15 May 2017, http://af.reuters.com/article/africaTech/idAFL5N1816VF. Other analysts have looked at the possibility of a pipeline to Kenya. See, for example: Jonathan Demierre et al. *Potential for Regional Use of East Africa's Natural Gas* (Sustainable Development Solutions Network, 2014).

13 United Republic of Tanzania, *Natural Gas Utilisation Master Plan* (2016), 32.

14 Ministry of Energy and Minerals, *Energy Sector Quarterly Review, Ed. No. 4* (2016), 17.

15 Fumbuka Ng'wanakilala, "Tanzania hopes for LNG plant agreement with oil majors by 2018," Reuters, 24 January 2017, accessed 15 May 2017, http://www.reuters.com/article/us-tanzania-gas-idUSKBN1581F4.

16 Katherine Houreld, "Final Investment Decision On Tanzania LNG Plant Still 5 Yrs Away – Statoil," Reuters, 16 November 2016, accessed 15 May 2017, http://www.reuters.com/article/tanzania-gas-idUSL4N1DH4D6.

17 The Tanzania Extractive Industries Transparency Act of 2015 requires that all new concessions, contracts and licenses be made public, but it is unclear whether this requirement applies to contracts signed prior to 2015. From: Don Hubert and Rob Pitman. *Past the Tipping Point? Contract disclosure within EITI* (Natural Resource Governance Institute, 2017), 16.

statements in 2014 and an assumption that these terms approximate the model PSAs the government has developed for the sector.[18]

Given the interdependency between the offshore blocks and the LNG plant, the concluded PSAs may need to be altered to accommodate the terms established in the HGA. For example, if the parties decide that these components will be treated as one taxable entity, any costs related to the LNG plant that are to be recoverable for production-sharing purposes would need to be agreed to and incorporated in the PSAs. Further, the government or companies may seek to renegotiate more substantive changes. The government has recently passed the Natural Wealth and Resources Contracts (Review and Renegotiation of Unconscionable Terms) Act 2017, which allows the government to renegotiate existing extractives agreements if they are deemed to contain "unconscionable terms". The criteria for defining a term "unconscionable" are quite broad, leaving significant scope for the government to renegotiate the PSAs.[19]

ANALYSIS: THE IMPACT OF HGA TERMS ON INVESTMENT AND GOVERNMENT REVENUES

We use an Excel-based model to assess how the decisions that will be made during the HGA negotiation might affect the investment decision and the amount of revenues the government can expect to earn from the project. To measure these effects, we estimate the changes to two metrics: the internal rate of return (IRR) and the average effective tax rate (AETR).

To measure changes in the profitability of the LNG project and therefore the likely investment decision, we estimate its after-tax IRR. The estimated after-tax IRR is the expected return over the assumed life of the project. IRR calculations are the basis of a common decision rule used by investors. For investment to take place, this rate must be higher than the investor's hurdle rate. Other factors are usually included in their final decisions, but passing the hurdle rate is an important step. In this analysis, we assume a real (i.e., inflation adjusted) hurdle rate of 13 percent based on the 2017 Wood Mackenzie survey of hurdle rates that investors have used for LNG projects across the globe.[20] Investors base their choice of hurdle rates on a variety of factors, including the alternative uses for their capital and the risks they face in a country. For instance, if interest rates were to rise—and thus the return on saving the money in a bank rather than investing in a risky project rose—the hurdle rate would rise. Similarly, if a country is perceived to become particularly risky for investors, the hurdle rate for projects in that country would rise. It is important to note that the estimated IRR is only the *expected* return. Actual returns to a project may be far lower than this rate, or far higher.[21]

18 See, for example: David Manley and Thomas Lassourd. *Tanzania and Statoil: What Does the Leaked Agreement Mean for Citizens?* (Natural Resource Governance Institute, 2014), 8.

19 See Section 6(2) of the Natural Wealth and Resources Contracts Act 2017. Given that the version of this law that was passed is not yet publicly available, this analysis is based on the bill that was introduced in the National Assembly on 29 June 2017.

20 This survey finds that the most common hurdle rate used for LNG projects is 15 percent. While not specified, we assume this rate is in nominal terms, given that other Wood Mackenzie reports quote hurdle rates in nominal terms. We assume long-term global inflation of 2 percent, and so adjust it to get a real hurdle rate of 13 percent. From: Wood Mackenzie. *1st 'State of the Upstream Industry' survey* (2017), 7.

21 Not all projects that have an after-tax IRR that exceeds the investor's hurdle rate will necessarily proceed, as investors must generally choose among multiple options. Where more than one profitable project is possible, the net present value (NPV) of after-tax project income is a more useful decision rule, as it relates directly to investors' objective of maximizing value. Given that we do not have information on the estimated NPV of other potential investments of the companies that comprise the LNG project, and for simplicity's sake, we do not report the impact of regulatory decisions on the LNG project's NPV in this brief.

The second metric we use is the AETR. The AETR shows the share of income generated by the project over its lifetime that goes to the government. It is the ratio of the present value of government revenue over the present value of the pre-tax project income. There is no specific benchmark for AETRs; however, the IMF considers a reasonable discounted AETR for petroleum projects to be between 65 and 85 percent (at a discount rate of 10 percent).[22] Crucially, the discounted AETR takes into account the time value of money.[23]

The baseline from which we measure changes

To understand how changing each of the four elements affects the investment decision and government revenues, we establish a baseline from which to measure these changes. We assume that the negotiators agree to a particular regulatory framework, and that the project produces a particular amount of gas at a particular cost. We have based these assumptions on discussions with government and company officials and our own desk research. The main assumptions are presented in tables 2 and 3. Further assumptions and details are provided in the appendix.

Table 2. Baseline assumptions (in 2016 USD)

Element	Assumption
Real hurdle rate	13 percent
LNG plant trains[24]	
Number of trains	3
Capacity of each train	5 million metric tons per annum
Domestic market allocation	Up to 10 percent
Value chain segmentation	Partially segmented
Upstream-LNG plant arrangement	Tolling
LNG plant tolling fee/rate of return ceiling	8 percent
Exploration capital expenditure	$2,700 million
Development capital expenditure[25]	
Upstream (blocks and pipelines)	$19,800 million
Midstream (LNG plant)	$15,000 million
Operating expenditure	
Upstream (blocks and pipelines)	$0.59/mmBtu
Midstream (LNG plant)	$1.19/mmBtu
Domestic pipeline tariff	$0.40/mmBtu
LNG shipment cost	$2/mmBtu
Domestic market price	$4/mmBtu
LNG export price	Variable
Fiscal regimes	See Table 3

22 IMF, *Fiscal Regimes for Extractive Industries: Design and Implementation* (2012), 6.
23 This is important because a shilling received in a year's time is worth less than a shilling received today. First, a shilling received today rather than in the future can be immediately put to use. And two, because the future is uncertain, and no one can be sure that they will receive that shilling in the future. To make money received in the future comparable to money received today, a "discount rate" is applied to money expected in the future.
24 A "train" is the term given to the unit in which the liquefaction process takes place. Each train can produce a specific volume of LNG a year.
25 It is not only the amount of capital expenditure that is important for cash flow estimates but also the timing. As discussed in the appendix, we use the expenditure profile assumed by the IMF. From: IMF, *IMF Country Report No. 16/254* (2016), 59.

Table 3. Baseline fiscal regimes for the upstream and midstream

Fiscal term	Upstream (blocks and pipelines)	Midstream (LNG)
Royalty	5 percent	-
Cost gas limit	70 percent	-
Government share of profit gas	30-50 percent	-
Royalty paid from govt. profit gas?	Yes	-
Income tax	30 percent	30 percent
Royalty deductible from taxable income?	Yes	-
Depreciation of development capital	Straight-line for 5 years	Straight-line for 5 years; expires after ten years of production
Loss carry forward	Unlimited	Max 70% taxable income to be offset per year; no expiration
Additional profit tax	No	No
Dividend withholding tax	10 percent	10 percent
Interest withholding tax	10 percent	10 percent
Debt:equity ratio	70:30	70:30
TPDC equity share		
Share	10 percent	12 percent
Type	Carried—repaid through TPDC's production share	Fully paid
Carried interest rate	6.5 percent	-

Result 1. Unless expectations around the project's economics change, it is unlikely that companies will invest in the LNG project.

We estimate that the project's after-tax IRR would be only 5 percent if the current forecasts of long-term LNG prices in East Asia of $8 per mmBtu are correct.[26] Even if prices recover and remain at their 15-year average of $11, the project's rate of return may be only 10 percent. This is below our assumed hurdle rate of 13 percent, but within the range of hurdle rates used in LNG project decision-making around the world (see page 30 in the appendix). To generate an after-tax IRR greater than 13 percent, our results indicate that the project would require a long-term price of at least $14 per mmBtu over its lifetime. $14 is therefore our estimated break-even price—the long-term price needed to deliver the return investors require to invest—which is significantly higher than current forecasts. Unless costs are less than what we assume (for example, if cost efficiencies are generated through a different configuration of the LNG plant[27]), or the terms in the HGA and PSAs are more favorable to the companies, the project is not likely to go ahead.

Furthermore, these projections may actually be optimistic. Company officials suggest that the cost of developing the offshore blocks and pipelines may be closer to $30.5 billion, more than half as much again as our baseline assumption of $19.8

26 We use the price of Indonesian LNG delivered to Japan, including cost, insurance and freight.

27 Both the government and companies have indicated the possibility of the plant being smaller than the three trains of 5 mmtpa capacity that we assume in our baseline. A smaller LNG plant means lower development costs, but also that production and therefore project revenues are spread over a longer time period. Therefore, a smaller plant may not necessarily increase the project's viability. However, cost efficiencies may be generated from the trains having a larger capacity (e.g., two trains of 6 mmtpa) or from increasing the plant from two to three trains once the initial investment has been recovered. Alternatively, the government and companies may reconsider a floating LNG plant. Many LNG plants that have either recently received a positive investment decision or are currently under development—such as Australia, Malaysia and Mozambique—are floating facilities; some because of expected cost advantages. See: International Gas Union. *IGU World LNG Report 2017* (2017), 23-25.

billion. However, it is not clear whether this $30.5 billion includes replacement capital, or when this expenditure would occur.[28] Assuming this figure does not include replacement capital expenditure, and using a timeline of expenditure similar to that in our baseline, we estimate that the project would deliver an after-tax IRR of only 7.5 percent with an average LNG price of $11. To clear the hurdle rate, a long-term price of at least $17 may be needed.

Of course, investors will have their own expectations of future LNG prices, and expectations may change between now and the investment decision. Further, as Figure 6 shows, LNG price forecasts have changed considerably over just two years. The future may look different again.

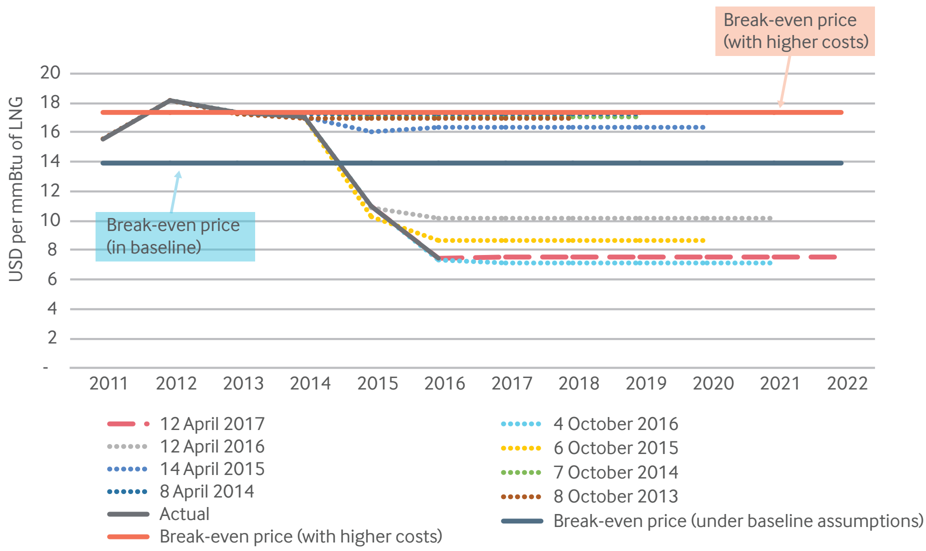
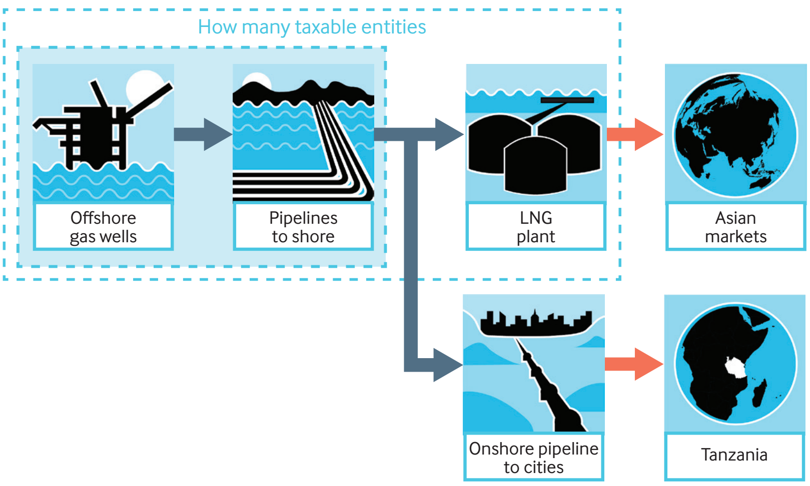


Figure 6. LNG price forecasts and estimated break-even prices

Source: IMF World Economic Outlook
Notes: Price for Indonesian LNG at point of delivery to Japan including cost, insurance and freight.

Segmenting the value chain



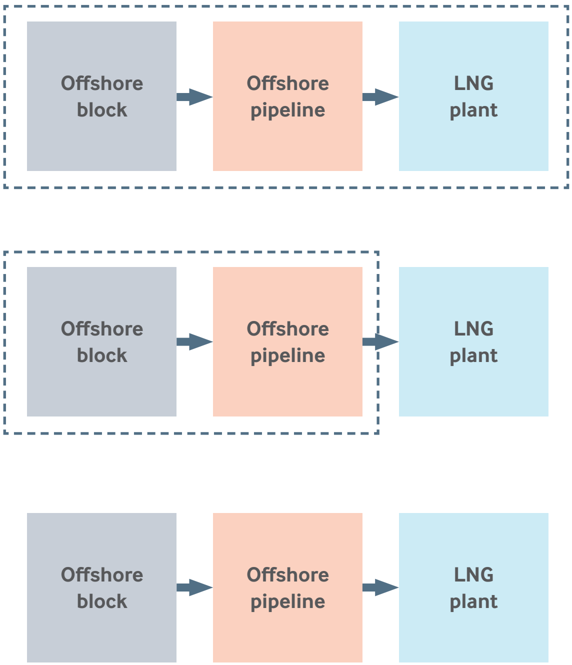
One task for the HGA negotiators will be to determine how the different components of the LNG project are grouped or segmented. They will establish which components are defined as the upstream and which as the midstream, and how they will be regulated.

28 Replacement capital expenditure is included in our estimate of operating expenditure.

This grouping of components is important because, though they are expected to have common ownership, different segments will operate under different regulatory frameworks, including different fiscal regimes. Defining what is in each group, and what is not, determines which components are subject to what rules and taxes, and also determines how transactions between the different components of the project are to be regulated.

Figure 7 shows that segmentation will likely follow one of three approaches.

Figure 7. Three approaches to segmenting the project value chain



In an **integrated structure**, the three components are treated as a single taxable entity. With three offshore blocks, there would thus be three taxable entities, each comprising one of the blocks, the connecting pipeline to shore, and a proportional share of the LNG plant.

In a **partially segmented structure**, each offshore block and related pipeline is treated as one taxable entity but the LNG plant is treated as a separate entity. The offshore blocks and pipelines are therefore treated as the "upstream", and the LNG plant as a "midstream" entity.

In a **fully segmented structure**, the offshore blocks, offshore pipelines and LNG plant operate and are taxed independently from one another. The offshore blocks are therefore treated as the "upstream", and the offshore pipelines and the LNG plant as "mid-stream" entities.

If the project has an integrated structure, we expect the fiscal regimes in the PSAs to be applied to the whole project (although this would require some revision of the PSAs to account for any additional issues raised by this structure). If the project has a fully or partially segmented structure, we expect the government to continue to levy the PSA fiscal regimes on the upstream, and levy separate fiscal regimes on any midstream entities. A midstream fiscal regime is likely to have a lower tax take than the upstream regimes, given the expectation that more rent will be generated in the upstream than the midstream (as discussed in the next section).[29]

There will be market transactions between the upstream and midstream in a fully or partially segmented structure. The type of transaction will depend on the arrangement that these entities have. One of two possible arrangements is likely. The first is an owner-buyer arrangement, in which ownership of the gas is transferred along the value chain (e.g., the upstream operators sell their gas to the LNG plant operators who sell it overseas). The second is a tolling arrangement, in which the upstream operators retain ownership of the gas until it is sold in the domestic or export market and pay a service fee to the LNG plant and any other operators in the chain.

29 Rent is the before-tax profits that companies make above what the companies require to invest.

Result 2. The modelled financial benefits point to the government benefiting more from an integrated value chain, but the practicalities of other projects linking to the LNG project—and TPDC's role in the project and sector—point to a partially segmented structure.

We estimate that the after-tax IRR is slightly lower and the AETR is slightly higher if the LNG project has an integrated structure. This result runs counter to the impact of segmentation typically observed in large LNG projects.

In other large LNG projects globally, companies have tended to prefer integrated structures.[30] This is because they can write off the costs of developing LNG plants against the higher taxes of the upstream fiscal regime rather than against the lower taxes of the midstream fiscal regime. A segmented structure enables companies to reallocate some income from the higher-taxed upstream entities to the lower-taxed midstream entities through the payment of a tariff or tolling fee (in a tolling arrangement).[31] However, these payments are spread out over the project's lifetime. Therefore the tax savings are typically not as great, in present value terms, as the tax savings available in an integrated structure from the writing off of upfront development costs.

This appears to be different in the case of Tanzania's LNG project. In the proposed regulatory framework presented here, unless the project is significantly more profitable than expected, companies might actually prefer a segmented structure (with little difference between fully and partially segmented structures).

Table 4. Estimated impact of project segmentation on after-tax IRR and AETR at a LNG price of $14

Project structure	After-tax IRR	Undiscounted AETR	Discounted AETR (at 10 percent)
Integrated	12.5 percent	59 percent	79 percent
Partially segmented	13 percent	56 percent	75 percent
Fully segmented[32]	13 percent	56 percent	75 percent

The reason for this atypical result is that upstream revenues in Tanzania are unlikely to be large enough for the upfront development costs to be written off quickly. It will therefore take several years for companies to write off the additional midstream development costs against the upstream fiscal regime and to realize the tax savings in the integrated structure. This delay significantly reduces the value of these tax savings.

It stands to reason that, based solely on this tax analysis, the government would prefer an integrated structure. However, there are other factors at play.

The Petroleum Act 2015 stipulates that costs incurred from processing and liquefaction activities cannot be recovered from revenues generated by the offshore blocks, presumably prohibiting use of an integrated structure.[33,34] There is likely to be two reasons behind the government's choice of this rule. One, because taxing the

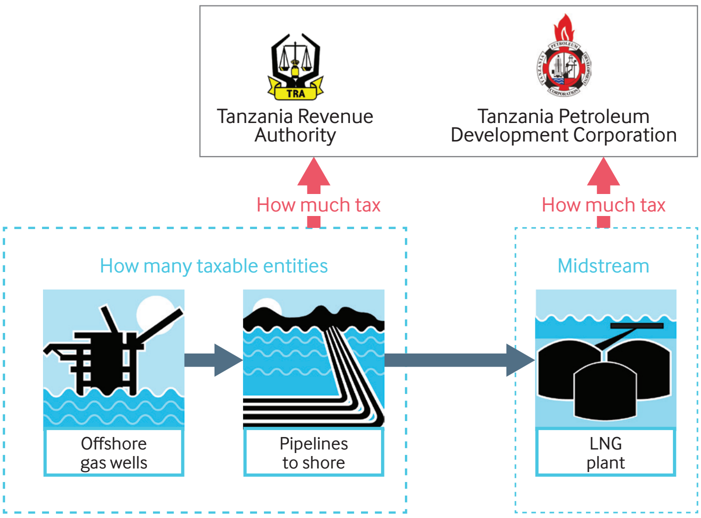
30 Graham Kellas, "Taxation of Natural Gas Projects" (presentation at the IMF Conference on Taxing Natural Resources: New Challenges, New Perspectives, Washington D.C., U.S.A., 25 September 2008).
31 In an owner-buyer arrangement, income would be reallocated through the sale of gas at a price lower than the LNG price. The transfer price has to be lower than the LNG price to enable the LNG plant operator to cover its costs from the sale of LNG.
32 The estimated after-tax IRR is slightly higher and the AETR is slightly lower in a fully segmented structure compared to a partially segmented structure—the payment of a tariff to the pipeline operators reduces the amount of income taxed under the upstream fiscal regime. However, as this tariff represents a small proportion of total cash flows, the effect is relatively minor.
33 Section 117 of the Petroleum Act 2015.
34 The addendum to the Block 2 PSA indicates its contractor has the sole discretion to select the structure it operates under, but we understand that the Block 1 and Block 4 PSAs do not have this provision and it is expected that the different blocks will operate within the same structure.

LNG plant as a separate entity makes it easier for other companies to use it or "farm in" to become partial owners in the event of further discoveries. Two, it would also enable TPDC to have a different role in the LNG plant than it does in the upstream. For example, if the project is segmented, TPDC can have a carried interest of 10 percent in the upstream and fully-paid equity of 12 percent in the midstream. If the project is integrated, TPDC will participate in the project as a whole and therefore its participation in the upstream and midstream will be the same.

Full segmentation also seems unlikely. As noted above, one driver of segmentation could be the ability of midstream entities to service other upstream operators. However, the offshore pipelines are expected to serve individual blocks and not be made available to other blocks. In that case, a fully segmented structure would entail additional regulatory and commercial complexity without adding much value for either the government or companies.

Because of this result, we think it is likely that the government and companies choose a partially segmented value chain, with the LNG plant governed by the HGA and each of the offshore blocks and their connecting pipelines governed by the applicable PSA. We assume a partially segmented structure in our calculations in the remainder of this brief.

Taxing the value chain



Alongside segmenting the value chain, another decision the HGA negotiators will make is how to tax each segment. As we expect the project to have a partially segmented structure, the fiscal regimes in the PSAs are likely to be levied on the upstream (which will comprise both the offshore blocks and the offshore pipelines) and a different regime to be agreed to and levied on the LNG plant.

Because the government and companies have not disclosed the PSAs, we have a limited understanding of the existing fiscal regimes for the upstream. The fiscal regime in our baseline is our best guess at the terms in the Block 2 PSA (see Table 3 above). We assume that this fiscal regime is similar to the fiscal regimes for blocks 1 and 4.

The PSAs indicate that Tanzania's upstream is to be taxed more heavily than a normal business entity. This is because, in common with most other oil and gas projects, the upstream is likely to generate most of the rent in the gas value chain. As a result, the LNG plant is likely to have a lighter fiscal regime than the upstream.

We assume that the LNG plant will be taxed as a normal business entity (i.e., under the standard income tax regime) but with some differences. The Finance Act 2016 defines the midstream as a petroleum operation for tax purposes.[35] The LNG plant is therefore likely to be subject to specific tax rules—e.g., accelerated depreciation of capital (but with a time limit for development expenditure) and a loss carry forward limit.

Both companies and the government will be principally focused on the overall tax burden for the project as a whole, rather than the tax burden for any one segment. We expect that both parties may seek to alter the overall take in the course of the HGA negotiations. Any meaningful alteration may be difficult to achieve solely through operation of the LNG plant fiscal terms (since the bulk of the rent will be generated in the upstream). Therefore, it seems reasonable to expect that some renegotiation of the PSAs may be sought.

While companies can be expected to argue that a lower tax take is needed for the project to have a better chance of going forward, developments since the PSAs were signed suggest that the government might seek to impose higher taxes on the sector. The generally applicable regime set out in the prevailing model PSA and legislation—which would be used as the starting point for negotiation of any new PSA—has evolved significantly in the last few years.[36] The model PSA of 2013 imposes a much higher tax take on offshore operations than the assumed regime in the existing PSAs. Provisions in the Finance Act 2016 and the Written Laws (Miscellaneous Amendments) Act 2017 have further tightened the generally applicable regime. Provisions in the Finance Act relevant to the oil and gas fiscal regime include a limit on the carrying forward of losses.[37] The Written Laws Act prohibits development capital expenditure from being deducted from taxable income after ten years of production. The Written Laws Act also appears to prohibit the deduction of royalty from taxable income (though other provisions in the Income Tax Act may still allow royalty to be deducted). For the purposes of our analysis of the impact of this act, we assume that royalties will not be deductible under general law. Finally, the Written Laws Act excludes cost gas and costs recouped through cost gas from the calculation of taxable income.[38]

The main instruments that comprise these fiscal regimes, and the estimated AETR they would impose on the upstream of the LNG project, are set out in Table 5.

35 Section 17 of the Finance Act 2016.

36 In Tanzania, the model PSAs are just guides; the government is not required to follow them in any way when negotiating an actual PSA. Therefore, while we would expect any fiscal terms in legislation to be included in a new PSA, fiscal terms that only exist in the model PSA may or may not actually be included.

37 Section 26 of the Finance Act 2016.

38 Section 35-38 of the Written Laws (Miscellaneous Amendments) Act 2017, respectively. Section 36 removes the word "royalties" from Section 65N(1) of the Income Tax Act, which previously stated that royalties are deductible from the taxable income of petroleum operations. However, Section 65N(1) also states that any amounts are deductible if they are allowed by other provisions in the Income Tax Act. Given that royalties are not explicitly excluded elsewhere in the act, Section 11(2) on the general principles of deductions could be interpreted as allowing royalties to continue being deducted. Given that the version of this law that was passed is not yet publicly available, this analysis is based on the bill that was introduced in the National Assembly on 29 June 2017.

Fiscal term	Assumed regime in PSAs	2013 MPSA	2013 MPSA and subsequent legislative changes
Royalty	5 percent	7.5 percent	7.5 percent
Cost gas limit	70 percent	50 percent	50 percent
Govt. share of profit gas	30-50 percent	60-85 percent	60-85 percent
Royalty paid from govt. profit gas?	Yes	No	No
Income tax	30 percent	30 percent	30 percent
Royalty deductible from taxable income?	Yes	Yes	No
Cost gas revenues and costs included in taxable income?	Yes	Yes	No
Depreciation of development capital	Straight-line 5 years; no expiration	Straight-line 5 years; no expiration	Straight-line 5 years; expires after 10 years of production
Loss carry forward	Unlimited	Unlimited	Max 70% taxable income to be offset per year; no expiration
Additional profit tax	No	Yes	Yes
Dividend withholding tax	10 percent	10 percent	10 percent
Interest withholding tax	10 percent	10 percent	10 percent
TPDC equity option	10 percent	Up to 25 percent	Up to 25 percent
Estimated AETR at $14 per mmBtu			
Undiscounted	60 percent	83 percent	85 percent
Discounted, at 10 percent	69 percent	99 percent	104 percent

Table 5. The evolution of Tanzania's offshore fiscal regime

Notes: We use an LNG price of $14 to illustrate the relative tax take of the different regimes because this is the average price we estimate is required for investment in the LNG project with our set of baseline assumptions. Given that the MPSAs only provide a ceiling for state participation and not a required amount, in these calculations we assume that TPDC has the same level and type of participation across the regimes.

We consider the implications of both tax increases and decreases on the investment decision and government revenues. We do so by analyzing revisions to the upstream regime and variants of the possible midstream regime. However, under all scenarios considered in this brief, we assume TPDC participation consists of a 10 percent carried interest in the upstream and fully paid equity of 12 percent in the midstream.[39]

Result 3. Imposing the stricter 2013 MPSA fiscal terms and more recent changes to the generally applicable regime would significantly reduce the likelihood of investment, but changes to the composition of the current regime could still be beneficial.

Our calculations confirm that if the government levies standard rates of income tax on the LNG plant, the specific design of its fiscal regime is likely to have a lesser impact on the investment decision and government revenues than potential changes to the upstream regime.[40]

39 Because the level and type of TPDC participation across the value chain affects how returns are shared between the companies and government, the amount of financing that companies need to provide for the investment to go ahead, and the incentives for TPDC and the companies, we will take a closer look at the implications of TPDC's participation for the LNG project in a separate, forthcoming analysis.

40 For example, we estimate that the LNG plant would start paying corporate income tax in 2031 under our baseline fiscal regime. Removing the loss carry forward limit delays the start of these payments until 2034, while lengthening the depreciation schedule from 5 to 10 years results in them starting earlier, in 2027. However, because the LNG plant generates less profit and faces a lower tax burden than the upstream, our estimates suggest that these timing changes may not have a significant impact on the estimated after-tax IRR or AETR of the overall LNG project. The impact would be larger if the LNG plant earned a higher return (e.g., through a higher tolling fee), but this result does still appear to hold.

A rise in taxes on the upstream equivalent to the terms established in the 2013 MPSA would make investment in the LNG project even less likely than it currently is. Levying the recent legislative changes in addition to the 2013 MPSA regime amplifies this result. Table 6 shows these results. The AETR when future cash flows are discounted is so high that the companies would be paying all of their profit and more to the government.

Table 6. Estimated impact of the upstream fiscal regime on after-tax IRR and AETR at a LNG price of $14

Fiscal regime	After-tax IRR	Undiscounted AETR	Discounted AETR (at 10 percent)
Current PSAs	13 percent	56 percent	75 percent
2013 MPSA	9 percent	76 percent	105 percent
2013 MPSA and recent legislation[42]	8 percent	78 percent	109 percent

Figures 8 and 9 show the same results for after-tax IRR and undiscounted AETR across a range of LNG prices. While the government would get a much larger share of the project's returns, imposing the regime in the 2013 MPSA would make it unlikely that the after-tax IRR reaches the hurdle rate under the prices shown. Indeed, we estimate that the long-term LNG price would need to be at least $21 (without costs increasing as well) for the project to generate sufficient return to clear the hurdle under this regime.

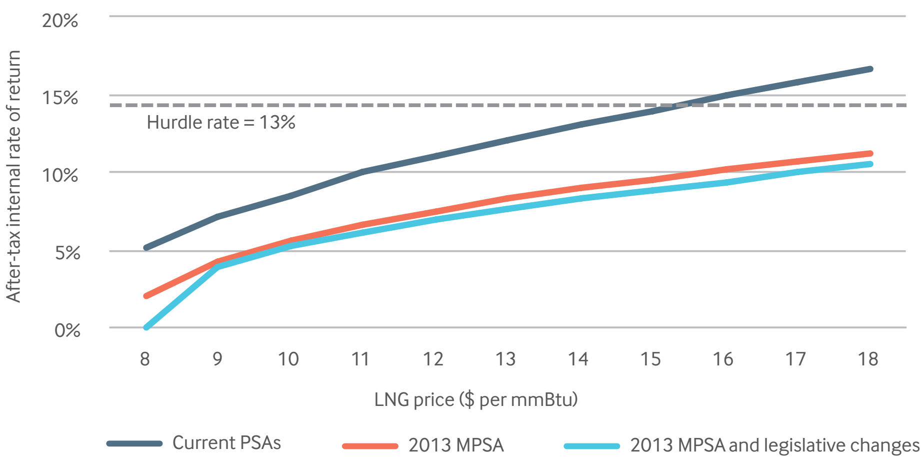


Figure 8. Estimated after-tax IRR with the current PSAs, 2013 MPSA and recent legislation

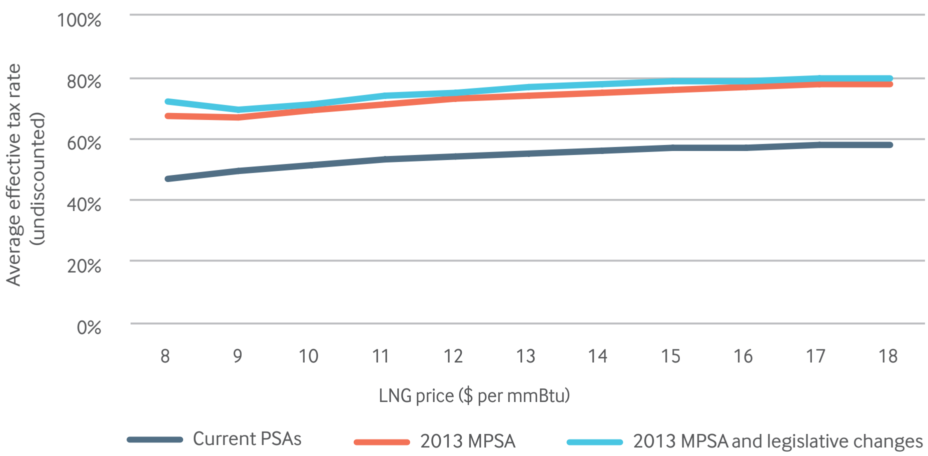


Figure 9. (Undiscounted) estimated AETR with the current PSAs, 2013 MPSA and recent legislation

41 Of the recent legislative changes, royalty no longer being deductible from taxable income has the largest impact. The exclusion of cost gas revenues and costs from the calculation of taxable income appears to make relatively small changes to the timing of tax payments and does not significantly change the project's estimated after-tax IRR or AETR.

This result is consistent with analysis by Global Data. Global Data estimated that Tanzania's 2013 MPSA regime is significantly higher than other African gas producers. Although their assumptions no doubt differed from ours in some ways, their estimate of upstream tax take under the 2013 MPSA is similar to our estimates (see Table 5).

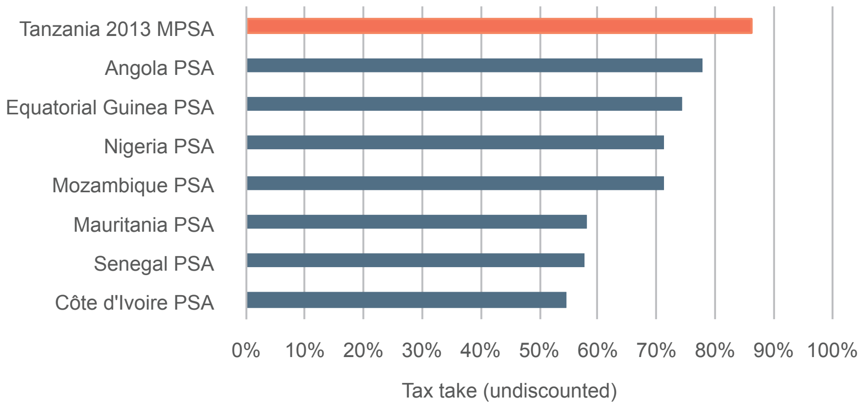


Figure 10. Government share of upstream returns across African gas producers

Source: Global Data

While factors influencing the outcomes of a licensing round are complex, this relatively high tax take (for the region) may help to explain the lack of interest in Tanzania's most recent licensing round in 2013-14. The round only attracted four bids for the eight blocks on offer.[42] The fall in the gas price toward the end of the bidding period is likely to have had an impact, but some believe the low interest was partly a result of the stricter fiscal regime in the 2013 MPSA.[43]

These three independent results suggest that renegotiating the PSAs to align with the 2013 MPSA and the recent legislative changes may significantly reduce the chances of companies deciding to invest. However, succumbing to company pressure to reduce taxes is also fraught with risk, as the history of Tanzania's taxation of the mining sector illustrates.

42 One bid was withdrawn and two were disqualified for being below the bidding threshold. The status of the fourth bid is unknown.

43 Peter Bofin and Rasmus Hundsbœk Pedersen. *Tanzania's Oil and Gas Contract Regime, Investments and Markets* (Danish Institute for International Studies, 2017), 24.

Box 1. Taxing the mining sector without knowing the future

To encourage investment when gold prices were low, the government with advice from the World Bank agreed a number of Mineral Development Agreements (MDAs) with a particularly low tax take between 1994 and 2003.[45] Given gold price forecasts at the time, that decision may have been sensible; but, as we have established, forecasts are rarely accurate. Indeed, gold prices rose by 206 percent (in real terms) between 2005 and 2011. This should have resulted in government revenues from large-scale gold projects increasing significantly over this period. However, most of these projects were still not paying corporate income tax in 2011—in large part because of the low taxes in their MDAs.[46] While both legislation and the MDAs have since been revised to increase the tax take, the repercussions of overly generous terms being provided in the original agreements are still being felt by the country and companies alike.

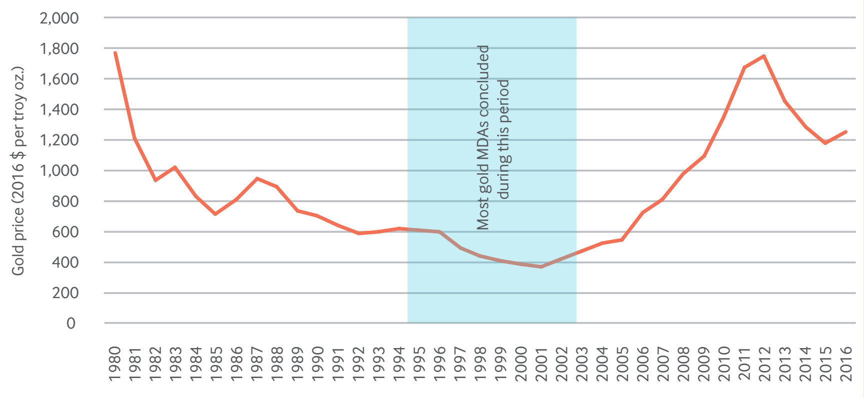


Figure 11. Gold price between 1980 and 2016 (in 2016 USD)

Source: World Bank Commodity Markets 2017[47]

Notes: Gold price on the London Bullion Market, $ per troy ounce

The challenge the government now faces in its gas sector is very similar to what was faced when the mining sector was being developed. Gas prices are currently low. The government could set low taxes to encourage investment, but then may see gas prices rise, missing the opportunity to get more revenues from the industry. An alternative is to levy taxes that are responsive to changing conditions. If prices are low, the tax take is low; if profits are high, the tax take rises. A tax regime with this flexible quality is called "progressive". One practical way to increase the progressivity of the current regime is to relax some of the current terms while introducing instruments designed to capture a greater share of rents as profitability increases—such as a resource rent tax, a variable rate tax on revenues or profits, windfall tax, or other tax on supernormal profits. All these taxes can be designed so that the tax take is higher when the project makes large profits, but is lower when the project makes low profits. The Additional Profits Tax described in the 2013 MPSA may be one example.[47] In addition to this benefit of progressivity, the automatic flexibility that resource rent taxes or similar taxes provide (with government receiving a larger share of returns at higher prices) also reduces the potential for pressure to renegotiate contracts or even expropriate in the future—a key worry for investors.[48]

44 Tonedeus K. Muganyizi. *Mining Sector Taxation in Tanzania* (International Centre for Tax and Development, 2012), 12.

45 BDO East Africa. *Third Reconciliation Report for Tanzania Extractive Industry Transparency Initiative for the year ended 30 June 2011* (2013), 5.

46 "Commodity Price Data (The Pink Sheet)," World Bank, last modified August 2017, http://pubdocs.worldbank.org/en/226371486076391711/CMO-Historical-Data-Annual.xlsx

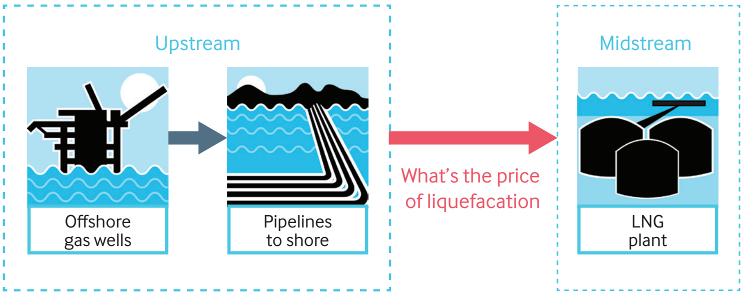
47 However, we have not assessed whether the terms of this tax in particular are suitable as the current description in the MPSA does not contain sufficient details for such analysis.

48 James Gwartney, Robert Lawson and Joshua Hall. *Economic Freedom of the World: 2016 Annual Report* (Fraser Institute, 2016), 4.

However, despite the advantage of these types of taxes, there is a disadvantage to making the tax regime more progressive. While the government receives a greater share of returns when conditions are good, they receive a smaller share when conditions are difficult. It is possible that taxes like a resource rent tax will not generate any revenues for the government over the project's lifetime. In other words, the government becomes more exposed to risk.[49]

The government therefore must balance two concerns. On the one hand, setting a fiscal regime that is progressive and flexible to changing prices, which will increase the likelihood of investment, enhance the ability to tax large profits and potentially make the regime less susceptible to changes in the future. On the other, setting a regime that will still generate a reasonable amount of income for the government even when prices are low.

Regulating prices along the value chain



Because the companies operating in the upstream will also be the majority owners of the LNG plant, there will be an incentive for liquefaction charges to be set so as to minimize the overall tax burden. The more that is charged for liquefaction, the more income is shifted from the higher taxed upstream to the lower taxed LNG plant, and the less tax the companies pay overall. Regulating this price will therefore be critical to ensure that it is consistent with what would prevail in a competitive market, so that profits are split between the upstream and the midstream in a reasonable manner.[50]

In the owner-buyer arrangement, the price for liquefaction is implicit in the price that the LNG plant buys gas from the upstream (the higher the liquefaction price, the lower the gas price). Conversely, in the tolling arrangement, this price is explicit in the tolling fee that the LNG plant charges. Under either structure, the price of these transactions will be regulated as part of the HGA. With an owner-buyer arrangement, the price of gas sold by the upstream to the LNG plant tends to be regulated through establishing a "netback" formula. This netback represents the upstream's share of the final price that the LNG plant receives for its LNG sales.[51] With a tolling arrangement, the tolling fee is generally regulated either in the form of a ceiling on the rate of return that can be earned by the LNG plant or a ceiling on the tolling fee itself. Under a rate of return approach, the fee could be adjusted periodically to ensure that a stipulated rate of return (calculated according to specified procedures) is maintained. Similarly, a stipulated tolling fee might be

49 Bryan C. Land, "Resource rent taxes: a re-appraisal," in *The Taxation of Petroleum and Minerals: Principles, Problems and Practice*, ed. Philip Daniel, Michael Keen and Charles McPherson (Oxford: Routledge, 2010), 241–262.

50 A potential benefit of an integrated project for the government is the reduced risk of transfer pricing abuse.

51 Netback formulas in other countries include a fixed percentage of the final sales price or the final sales price net of any liquefaction and transportation charges.

adjusted at agreed intervals to take into account the rate of inflation (and changes to any other predetermined factors).[52]

We assume that this project will have a tolling arrangement and that the government and companies will agree to set a ceiling on the rate of return for the LNG plant. We now analyze how changes to this regulated return could impact the investment decision and government revenues.

Result 4. Given the difference between the upstream and midstream fiscal regime, the tolling fee established in the HGA is likely to have a significant impact.

We find that changes to the tolling fee could result in significant changes to investor returns and government revenues. Figure 12 shows our results from varying the tolling fee so that it generates a range of returns for the LNG plant, from 1 to 15 percent.

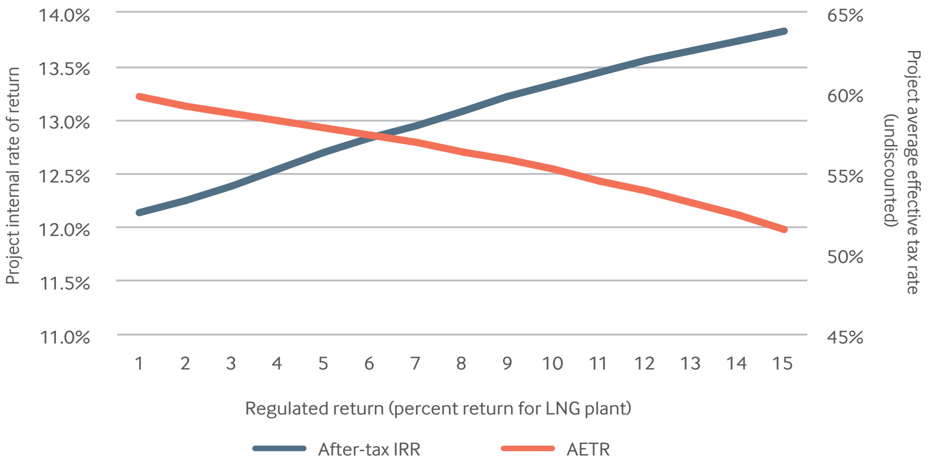


Figure 12. Estimated impact of LNG plant returns on after-tax IRR and AETR at a LNG price of $14

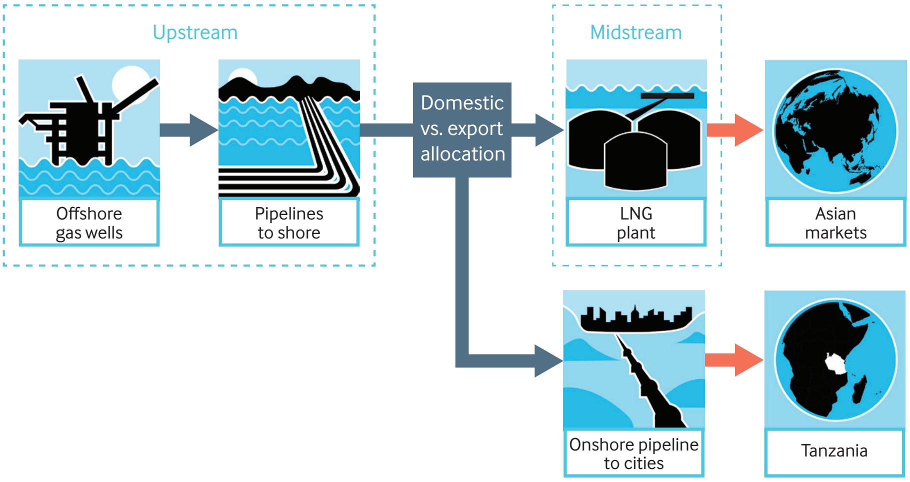
In practice, the negotiators are likely to negotiate over a narrower range, such as a range of 8 to 15 percent. However, even with this narrower range, the different fee levels could have a significant impact on both the investment decision and government revenues.

Ceiling on LNG plant return	After-tax IRR	Undiscounted AETR	Discounted AETR (at 10 percent)
Ceiling of 8 percent	13 percent	56 percent	75 percent
Ceiling of 15 percent	14 percent	52 percent	68 percent

Table 7. Estimated impact of LNG plant returns on after-tax IRR and AETR at a LNG price of $14

52 Experience from the regulation of utilities in other countries suggests that in practice the specific design of these tolling mechanisms can make a difference. See, for example: Ian Alexander and Timothy Irwin. *Price Caps, Rate-of-Return Regulation, and the Cost of Capital* (World Bank, 1996), 1.

Allocating gas between the export and domestic markets



Another key decision that the HGA negotiators will have to make is the allocation of gas between LNG exports and the domestic market, and the price of the gas sold domestically.

This allocation is already established within each of the companies' PSAs by a DMO clause. Because the PSAs are not public, it is unclear what DMOs the government and companies have agreed for blocks 1 and 4. The addendum to the Block 2 PSA states that the government can require up to 10 percent of the block's "projected production rate" to be sold to the domestic market.[53] Our estimates of domestic demand are based on projections by Demierre et al. and are lower than those set out in the government's Natural Gas Utilisation Master Plan.[54] However, they still suggest that domestic demand could be significantly greater than what the existing onshore gas operations can supply, particularly toward the end of the project. Based on Demierre et al.'s projections, this DMO, if applied to all three blocks, is likely to be binding.

The Petroleum Act 2015 sets out a larger DMO. It requires the offshore blocks to satisfy domestic demand up to the amount of profit gas.[55] Given this, and given that the current DMOs may not satisfy domestic demand, the government may attempt to negotiate a larger DMO.

Supplying more gas to the domestic market, especially at a low price, could have significant benefits for the economy and human development. However, if the domestic price is much lower than the LNG price, a larger supply of gas to the domestic market will increase the amount of income lost for both companies and the government from not exporting the gas.

The government—through TPDC, the Tanzania Electric Supply Company or an "aggregator"—is expected to purchase a significant amount of the offshore gas supplied to the domestic market, with the remainder sold directly to the private sector.[56] Therefore the price that the government pays for its gas will be a key determinant of how the DMO affects the investment decision and government revenues. This price will be established either through the HGA or long-term gas sales agreements.

53 Article 8.1 of the 2012 addendum to the Block 2 PSA.
54 Jonathan Demierre et al., *Potential For Regional Use Of East Africa's Natural Gas*, 28.
55 Section 97 of the Petroleum Act 2015.
56 In 2016, government entities purchased 86 percent of the gas produced by the onshore blocks. We assume a similar allocation will exist for offshore gas.

We now analyze the effect of different allocations of gas to the domestic market, and how this interacts with the gas's price.

Result 5. The price at which companies sell gas to the domestic market will be an important factor in determining how the domestic market obligation impacts investment and government revenues.

We believe that a DMO larger than the one currently agreed to in the PSAs would make investment even less likely and would reduce government revenues if the project did go ahead. A low price for domestic gas would further increase this effect. However, more analysis is required to support this conclusion.

Our calculations suggest that increasing the DMO from 10 to 20 percent should have a limited impact on the project's profitability (even with a domestic price as low as $2 per mmBtu). This is because the effect of companies earning less from domestic gas sales than from LNG exports is offset by these revenues being earned earlier. Export volumes are constrained by the capacity of the LNG plant, and therefore any production to supply the domestic market adds to the project's annual production level. As a result, the domestic market could provide an opportunity for larger annual sales and an earlier return for companies (if offshore output capacity allows).

However, we expect a larger DMO to affect the project's profitability and the investment decision in other ways that we do not model. The domestic market is not yet fully established and may not develop as expected. It may be difficult to then sell the surplus gas resulting from this domestic demand shortfall (at least on favorable terms) given that most LNG sales are made through long-term agreements. Greater exposure to the domestic market would therefore be expected to result in higher perceived risks for investors, which could increase financing costs and required returns—ultimately making investment even more unlikely.

The impact of a larger DMO on government revenue generated by the LNG project will depend on the domestic gas price and how much lower it is than the LNG price. Our results suggest that with a domestic gas price of less than $4, any DMO will reduce government revenues, and the higher the LNG price, the larger the reduction. A larger DMO amplifies this effect. For example, with a LNG price of $14 and a domestic gas price of $3, we estimate that a DMO of 20 percent would result in government revenue being 3 percent lower than with an obligation of 10 percent.

Some of this reduction in government revenue from the LNG project would be offset by more revenue from taxing gas distributors and domestic consumers as more gas is distributed and consumed in-country. The net impact depends on the balance of these changes. However, since the fiscal regime levied on the LNG project will have a higher tax take than the regimes imposed on domestic businesses, it is likely that the net impact on government revenues from a rise in the DMO would be negative.[57] This expected loss to government revenues may be worthwhile if it allows Tanzanians to benefit from a more reliable energy supply and lower prices, but it might not. Further analysis on this complex question is required.

57 This impact may be even worse depending on how the government agrees to purchase gas from the offshore operators. To make this revenue stream less unpredictable, the companies are likely to want the gas price to be relatively stable. However, if future increases in domestic energy options require the government to lower the gas price for it to remain competitive, the government may be forced to buy gas at a higher price from the offshore operators than it sells it at.

CONCLUSION

Our calculations suggest that companies are unlikely to invest in Tanzania's LNG project under current conditions. If this is indeed true, the government has a few options. First, it could wait for gas prices to recover in the hope that the LNG project then becomes profitable enough for investors. However, this option has a few downsides. It would delay the project's direct and indirect benefits for the country. There is also no guarantee that the prices won't stay at the same low level, or even fall further. The government could seek to negotiate terms in the HGA and renegotiate companies' PSAs in an effort to ease the burden on companies and kick start investment. If the government believes there are more efficient companies willing to invest, it could look to re-license the projects to new investors with different cost structures (though given that the PSAs are not in the public domain, it is unclear what they stipulate around the termination of licenses). Alternatively, the government could change the parameters of the project entirely. For instance, if more onshore gas were discovered (perhaps encouraged by a government policy that further incentivizes exploration), the increase in reserves could free up offshore gas for export—eliminating the domestic market obligations and their associated costs.

The government will need to look for ways to increase the chances of the project going ahead while ensuring that Tanzania still fully benefits if it does. For example, reducing the tax burden might be an obvious way to make the LNG project more viable. However, if conditions change, the government may be repeating the mistake that previous administrations made with the mining sector—setting taxes low to encourage investment only to be caught out when prices rise. One possible solution is to apply a resource rent tax or another highly progressive fiscal instrument that, when combined with changes in the rest of the fiscal regime, produces a relatively low tax burden in years of paucity and a high burden in years of plenty. This option also carries risks, of course, as sustained low prices might mean that Tanzania gives up its extractive wealth in exchange for limited fiscal revenues.

Each of the four decisions we analyze in this brief imply economic trade-offs for the government. However, the government can also improve investment prospects without making a trade-off. Tanzania's competitiveness could be improved by establishing a regulatory framework that is stable and predictable and therefore reduces political risk for investors. Other improvements in the business climate—such as the pace of government decision-making—would also help. Despite offshore gas being discovered in Tanzania and Mozambique around the same time, Mozambique had already concluded the HGAs for its two prospective LNG projects by 2014, and as a result, companies are already starting to develop one of its projects. Finally, some of the provisions in the new laws for the sector will need to be implemented carefully to limit the extent to which they may create further challenges for the business climate.

Another part of the solution is to be more transparent. Greater transparency may help the political classes and the population in general to accept whatever deal the government makes. It will allow government departments and Tanzania's academics and think tanks to contribute to natural gas policy. It will also allow politicians and the public to oversee the process, and, with the right contextual explanation, it will set public expectations that are not wildly inflated. One step toward greater transparency is to disclose the HGA document once concluded—which is already required by Tanzanian law.[58] Other provisions and certain aspects of the negotiation process itself could also be disclosed.[59]

At this juncture, the gas sector's prospects do not look overly promising. However, by taking careful and transparent decisions and making improvements in the wider business climate, the government can give the country its best chance of realizing the benefits offered by its offshore reserves.

58 Section 16 of the Tanzania Extractive Industries (Transparency and Accountability) Act 2015.

59 The following information could be disclosed: the timeline, agreed negotiation process and the actual progress of negotiations; the negotiation participants, including what public consultations may occur; the legal status of the agreement vis-a-vis Tanzania's current legal framework; and ultimately, the agreed HGA contract and how parties arrived at the final decisions.

APPENDIX: OUR BASELINE ASSUMPTIONS

This brief is informed by a financial model with a 50-year horizon that we developed to analyze Tanzania's LNG project and estimate the government revenues it could generate. However, like all models, the results depend crucially on the assumptions used. There are varying degrees of uncertainty around a number of key inputs into the model—including development and operational costs, project design, global and domestic gas prices and the regulatory framework—any of which may have a significant impact on our estimates of investor returns and government revenue. Our specific project and fiscal assumptions are summarized in Table 8 and discussed further below.

Table 8. Assumptions about the LNG project (in 2016 USD)

	Assumption	Source
Reserves (probable and proven)	26.65 tcf	Wood Mackenzie
Real hurdle rate	13 percent	Wood Mackenzie
Final investment decision	2022	Company comments
Commencement of operations	2026	Authors' assumption
LNG plant trains		
Number of trains	3	IMF
Capacity of each train	5 mmtpa	IMF
Gas used up in LNG production	11 percent	Standard Bank (for Moz.)
Domestic market allocation	Up to 10 percent	Block 2 PSA addendum
Exploration capital expenditure	$2,700 million	IMF
Development capital expenditure		
Offshore blocks	$18,700 million	IMF
Offshore pipelines	$1,100 million	IMF
LNG plant	$15,000 million	IMF
Operating expenditure		
Offshore blocks	$0.38/mmBtu	ICF International (for Moz.)
Offshore pipelines	$0.21/mmBtu	Demierre et al. cost model
LNG plant	$1.19/mmBtu	Standard Bank (for Moz.)
Decommissioning cost		
% of capital expenditure	10 percent	Authors' assumption
Treatment for tax purposes	As operating exp.	Petroleum Act
Loan real interest rate	5 percent	Authors' assumption
Domestic pipeline tariff	$0.40/mmBtu	Company reports for onshore
LNG shipment cost	$2/mmBtu	World Bank
Gas price to domestic market	$4/mmBtu	Authors' assumption
LNG price to overseas market	Variable	Authors' assumption
Value chain segmentation	Partially segmented	Authors' assumption
Upstream-LNG plant arrangement	Tolling	IMF
Offshore pipelines tariff (if fully segmented structure)		
Real rate of return cap	8 percent	IMF
Tariff amount	$0.41/mmBtu	Result from model
LNG plant tolling fee (if fully or partially segmented structure)		
Real rate of return cap	8 percent	IMF
Fee amount	$3.78/mmBtu	Result from model
Gas price to LNG plant (if transfer structure)	LNG netback price	Authors' assumption
Fiscal regime		
Offshore blocks	Block 2 PSA addendum	Block 2 PSA addendum
Offshore pipelines (if fully segmented structure)	General legislation	IMF

LNG plant (if fully or partially segmented structure)	General legislation	IMF
"Delivery point" for gas valuation for tax purposes	Offshore pipelines exit	Authors' assumption
TPDC equity		
Offshore blocks		
Share	10 percent	Block 2 PSA addendum
Type	Carried-repaid through TPDC production share	IMF
Carried real interest rate	6.5 percent	Authors' assumption
Offshore pipelines (if fully segmented structure)		
Share	12 percent	IMF
Type	Fully paid	IMF
LNG plant (if fully or partially segmented structure)		
Share	12 percent	IMF
Type	Fully paid	IMF

Reserves

The Ministry of Energy and Minerals (MEM) estimates that 57.27 tcf of gas has been discovered to date.[60] Estimates of recoverable gas vary. MEM estimates a recovery factor of around 70 percent, equivalent to 40.09 tcf. However, this estimate includes reserves for which there are currently no development plans. It is possible that some of these reserves will be developed in the future, but we are relatively conservative and only consider reserves for which there are currently development plans. We use Wood Mackenzie's estimate of 2p (proved and probable) reserves of 27.53 tcf, of which 26.65 tcf is in the three offshore blocks that comprise the LNG project and the remaining 0.88 tcf is onshore.[61]

Production

Our production estimates are based on the size of the LNG plant and the amount of gas we assume is required for it to operate at full capacity; projected domestic demand for the gas; and the estimated output capacity of the offshore blocks. If investment in the LNG project does go ahead in 2022, we estimate that production will commence in 2026, with current commercial reserves running out in 2058.

Supply allocation

The majority of gas will be processed and exported as LNG. We follow the IMF in assuming the LNG plant will have three trains, each with a capacity of 5 million metric tons per annum.[62] However, both the government (in its Natural Gas Utilisation Master Plan) and companies have indicated the possibility of the plant being smaller, at least initially.

Given that the PSAs for blocks 1 and 4 are not public, we base our domestic supply assumption for each of the three offshore blocks on the domestic market obligation in the addendum to the Block 2 PSA.[63] The Utilisation Master Plan estimates that domestic demand will average 0.64 tcf per annum over 2016-45, but presumably with increasing demand over time.[64] This estimate includes demand that would be generated from activities that will involve significant capital expenditure and are not

60 Ministry of Energy and Minerals, *Energy Sector Quarterly Review*, 18.
61 Wood Mackenzie, *Tanzania Upstream Summary*, 17.
62 IMF, *IMF Country Report No. 16/254*, 58.
63 Article 8 of the 2012 addendum to the Block 2 PSA.
64 URT, *Final Draft Natural Gas Utilisation Master Plan*, 32.

yet certain. We use the lower estimates set out in Demierre et al., which are based on projections of GDP and population growth, the energy intensity of GDP and the energy mix.[65] This results in domestic demand averaging 0.45 tcf per annum over 2017-60.

Costs

There is significant uncertainty around the investment costs for the LNG project—both the total amount and the time profile. We take our estimates (which are set out in Figure 13) from the IMF.[66]

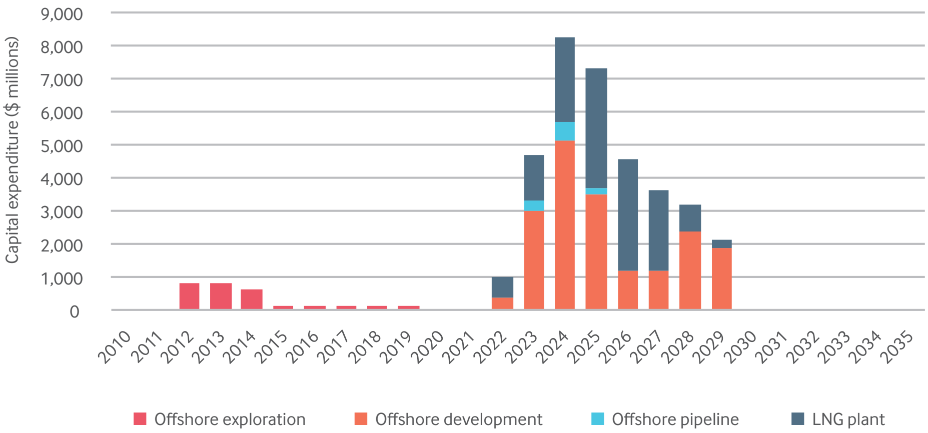


Figure 13. Exploration and development costs

We base our operating cost estimates for the offshore blocks and LNG plant on estimates for Mozambique (since they are publically available) and adjust them upwards in line with the World Bank's assessment that Tanzanian costs will be 25 percent higher due to the smaller field size.[67] We estimate the operating cost for the offshore pipelines using the transmission cost model in Demierre et al.[68]

Sale prices

The target markets for Tanzanian LNG exports are expected to be in Asia, for which Japanese prices are a reliable metric. Given the inherent unpredictability, we do not assume a LNG price in our baseline. Instead, we look at the impact different prices are likely to have on the investment decision and government revenues.

In the absence of gas imports and exports, and with the majority of gas being purchased by the government at a set price, there is currently little correlation between global price dynamics and the price of gas sold to the domestic market in Tanzania. Based on historical prices, we expect the average price for the onshore blocks to be around $4 per mmBtu in the coming years. Offshore operators may be unwilling to accept a lower price than the onshore blocks, but higher prices may be difficult for the government and private sector consumers to meet. We therefore assume that the offshore blocks will receive the same price for domestic sales.

65 Jonathan Demierre et al., *Potential For Regional Use Of East Africa's Natural Gas*, 28.
66 We base our estimates on the investment profile set out on page 59 of the IMF's report, which are lower than the costs specified in the text on page 58. From: IMF, *IMF Country Report No. 16/254*, 59.
67 ICF International, *The Future of Natural Gas in Mozambique: Towards a Gas Master Plan* (2012), 22; Standard Bank, Mozambique LNG: Macroeconomic Study (2014), 52.
68 Jonathan Demierre et al., *Potential for Regional Use of East Africa's Natural Gas*, 23.

Transport costs

Our estimate of shipment costs for transporting LNG from the LNG plant to Asian markets are at the lower end of the range of $2-3 per mmBtu assumed by the IMF. Shipping costs have fallen considerably in recent years and are not expected to recover in the foreseeable future.[69]

The planned location for the LNG plant is relatively close to the existing pipeline network that supplies the domestic market. Gas arriving from the offshore blocks should be able to be transferred to this network with minimal additional cost. On this basis, we assume that the tariff for distributing gas to the domestic market from the onshore blocks and from the exit point of the offshore pipelines is the same. Our assumed tariff of $0.4 per mmBtu was the weighted average of distribution costs for onshore blocks in 2015.[70]

Segmentation of the project value chain

We assume a partially segmented value chain, as we believe that the government and companies are unlikely to agree to either an integrated or fully segmented structure (as discussed on pages 13-14).

Fiscal regime

In a partially segmented structure, we expect the fiscal regimes provided in the current PSAs to be levied on the upstream (which will comprise both the offshore blocks and offshore pipelines), but a different fiscal regime to be agreed and levied on the LNG plant.

Because the government and companies have not disclosed the PSAs, we base our baseline fiscal terms on the contents of the leaked addendum to the Block 2 PSA, government statements in 2014, and an assumption that the terms approximate the model PSAs that the government has developed for the sector.[71] This regime is based on production sharing and income tax with a 10 percent carried interest for TPDC. We assume that the fiscal regimes in the PSAs for blocks 1 and 4 are not significantly different from that in the Block 2 PSA.

We assume that the LNG plant is taxed as a normal business entity (i.e., under the standard income tax regime) but subject to the rules set out in the Finance Act 2016 and Written Laws Act 2017 for oil and gas projects. In line with the IMF's assumptions, we also assume that TPDC has a fully paid interest of 12 percent.[72]

Pricing between project entities

In a partially segmented structure, any gas bought and sold between the upstream and midstream will need to be priced, as too will any services provided between these components. We follow the IMF in assuming that the upstream will have a tolling arrangement with the LNG plant. That is, rather than selling its gas to the LNG plant, it will pay the LNG plant a tolling fee for processing the gas and then sell the LNG itself. We also follow the IMF in assuming that this tolling fee will be regulated through capping the LNG plant's rate of return at 8 percent.[73]

69 IMF, *IMF Country Report No. 16/254*, 49; International Gas Union, *IGU World LNG Report 2017*, 35-44.
70 Company annual reports for 2016.
71 See: Manley and Lassourd, *Tanzania and Statoil: What Does the Leaked Agreement Mean for Citizens?*, 8.
72 IMF, *IMF Country Report No. 16/254*, 59.
73 Ibid., 59.

Project hurdle rate

Our assumed hurdle rate of return of 13 percent (in real terms) is based on the latest Wood Mackenzie survey of hurdle rates used for LNG projects across the globe. The results of this survey are replicated in Figure 14.[74]

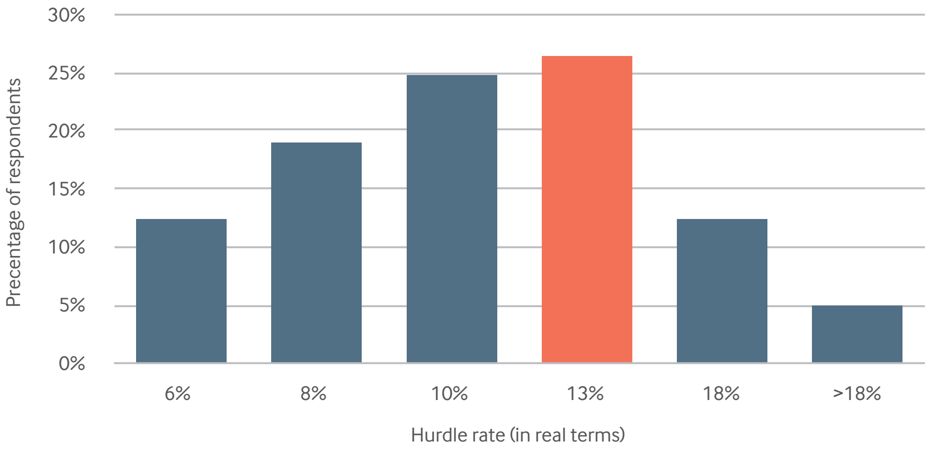


Figure 14. Hurdle rates for LNG projects across the globe as reported by companies

Source: Wood Mackenzie survey of industry

Note: We assume the hurdle rates quoted by Wood Mackenzie are in nominal terms. The rates set out in this figure have been adjusted to real terms using our assumed long-term global inflation rate of 2 percent.

74 Wood Mackenzie, *1st 'State of the Upstream Industry' survey*, 7.

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