POTENTIAL GOVERNMENT REVENUES FROM TURKANA OIL

Discussion Paper, April 2016
1. Introduction

This report seeks to provide an estimate of the scale and timing of possible Kenya national government and Turkana county government revenues from Turkana oil.

The series of successful oil exploration wells in the South Lokichar basin has generated high expectations for the country as a whole and for the historically marginalized Turkana region. Published revenue projections suggest that peak annual receipts to the Government of Kenya could range from USD 800 million to as much as USD 3 billion.¹ Provisions in the 2015 draft Petroleum Bill for transfers of government oil revenue to Counties (20%) and Communities (5%) generate additional interest.

It is normal for expectations to be heightened in the wake of an oil discovery. But experiences in other countries show that these expectations are often unrealistic. Finding oil is just the start. Timelines from discovery to development to production are long, often more than a decade. Plummeting oil prices could easily mean further delays and, if sustained, would result in much lower revenues for the government. Project costs often turn out to be higher than originally anticipated resulting in less profit to be shared between the company and the government. And the share of profit that will ultimately flow to the government is determined by terms contained in confidential oil contracts.

The greatest uncertainty surrounding potential government revenues from Turkana oil is the time to first oil production. Exploration drilling suggest that there are roughly 600 million barrels of oil that are likely recoverable from Blocks 10BB and 13T.² Assuming an industry standard production profile, this volume of oil would result in peak production of around 150,000 barrels of oil per day. The challenge is getting the oil to market. Recent media reports suggest that the Government is pushing for export by road and rail in order to speed up first oil exports.³ However, given the remoteness of the Turkana region, the only long-term economically viable option is a pipeline.

The political, technical and financial challenges presented by the pipeline should not be underestimated. The routing challenges that
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appeared to be resolved through the agreement between Uganda and Kenya in August of 2015 are once again open to question due to ongoing security concerns around the northern Kenya route. A feasibility study for routing Ugandan oil through Tanzania is currently underway. Moreover, as the crude from both Kenya and Uganda is waxy (it solidifies at normal temperatures) the pipeline will need to be heated adding technical challenges and considerable expense.

The risks of further delays are high. The engineering work required to generate firm estimates on overall costs, to devise specific plans for overcoming technical challenges, and to establish a per barrel tariff for both Ugandan and Turkana crude, has not yet begun. Furthermore, financing the pipeline, estimated by the Toyota Tsusho Pipeline Report to cost more than USD 5 billion, will also be a major challenge, particularly at a time of depressed oil prices.

The time to first oil production from Turkana likely depends on a simultaneous final investment decision (FID) for the upstream oil operations and for the pipeline needed to get the oil to the coast. FID marks the shift from exploration to development. Tullow, the operator, has submitted a draft Field Development Plan and is currently advising investors that they will consider a final investment decision (also known as project “sanction”) sometime in 2017 at the earliest. The Toyota Tsusho Pipeline Report indicates that the minimum time to build the pipeline is three and a half years. As a result, 2021 is currently the best-case scenario for first oil exports from Turkana. However, the risks of further delays due to pipeline complications and low oil prices are high, making first oil production well beyond 2021 more likely.

Production volumes, oil price and field costs will determine the overall revenue generated by the project. The split of divisible revenue (revenue after costs) will be determined by the terms contained in the Production Sharing Contracts (PSCs). Kenya operates a production sharing system with three principal sources of government revenue: the government share of “profit oil,” a windfall tax imposed when oil is over USD50 per barrel, and the right to acquire an equity stake in the project. In the past, Kenyan PSCs have been confidential. As a result, the specific terms governing Blocks 10BB and 13T are not in the public domain. However, several other PSCs have been disclosed to investors, including those covering neighbouring blocks, providing insight into the likely fiscal terms for the two blocks in question.

Understanding the potential revenues that could potentially accrue to the national and sub-national governments requires an integrated economic analysis comparing
plausible scenarios. Four main inputs are required in order to generate a forecast of potential government revenue: production volumes, oil sale price, field costs and fiscal (tax) terms.

The analysis below is based exclusively on information in the public domain. Previously published analyses of the petroleum sector have been consulted, as have industry analyses and media reports. Particular attention has been given to information provided by Tullow and Africa Oil to their investors.

The economic analysis is based on a simplified version of an industry-standard “discount cash flow” model. The model, constructed in a spreadsheet, incorporates the fiscal terms from Production Sharing Contracts applicable in the Turkana region. These fiscal terms are then applied to a hypothetical project based on information about production volumes and timelines and project costs contained in materials provided to investors by Tullow and Africa Oil, as well as in the Petroleum Master Plan. Where no public domain information is available, assumptions are based on analogous oil fields and industry “rules of thumb.” The various scenarios are then tested against higher and lower oil prices.

This report is structured into five main sections. The first section offers an analysis of the Kenyan production sharing contracts (PSCs) as well as the wider context in which they are situated. The second section contains a detailed overview of the sources of government revenue that apply to Blocks 10BB and 13T. The third section draws on publicly accessible data in order to generate plausible scenarios for production volume and timelines, potential oil prices and the main categories of costs (exploration, development, operations and the pipeline tariff). The fifth section contains the economic analysis including the timing and volume of potential government revenue; the relative importance of the various fiscal instruments applied to the project; as well as the allocation of after-cost revenue between the company and the government.
2. Production Sharing Contracts

Oil contracts establish the terms under which private companies explore for oil. There are common interests between the private company and the government. Both obviously hope that exploration results in the discovery of large, commercially viable oil fields. However, the two parties to the contract also have conflicting objectives – both want a substantial share of the profits. The challenge for the government is to offer contract terms that maximize government revenue but also attract private companies to take the exploration risk. Tough terms might look good on paper, but they are of no value if credible companies are not willing to sign up to them. At the same time, highly generous terms may attract exploration, but can leave the government with only a small portion of the economic benefits. The challenge in negotiating contracts, and in designing the broader fiscal regime, is to get the balance right.

2.1 The Hierarchy of Laws and Contracts

Oil contracts cannot be understood in isolation. They are only one component of the broader framework that determines the government’s share of potential oil revenue (See Figure 2).

In most countries, the constitution provides the foundation on which the rest of the legal framework is based. The Kenyan Constitution indicates that sub-soil resources are the property of the State. The specific legal framework for Kenya’s petroleum sector is set out in the Petroleum (Exploration and Production) Act, Cap 308 of 1986, and the accompanying Regulations under Section 6.

The specific detail on company rights and responsibilities, and the financial terms that govern oil operations, are contained in a contract. Oil operations are complex and typically require dozens of individual “contracts.” The main contract (sometimes called the “host country agreement”) is the foundational agreement between the government and the company. In Kenya, these contracts are called “production sharing contracts” or PSCs. The PSC governs the full lifecycle of the oil project. It gives the company the right to explore for oil within a specific area, and, if exploration efforts are successful, it also sets the terms for 25 years of production.

Although the specific terms are negotiated for each contract, the negotiators do not start from square one each time. Rather a model contract is prepared that defines
the vast majority of the parameters, leaving only a few terms open to negotiation. Since the Petroleum Act was put in place in 1986, Kenya has produced three different model contracts (1986, 1999 and 2008).

Traditional analyses of petroleum fiscal regimes draw a sharp distinction between three different types: royalty and tax, production sharing, and service agreements. Table 1 shows the regional distribution of these three main systems.9

The specific model chosen, however, is less important than is often thought. Governments can ensure that they secure a fair share of the overall revenues whichever model is chosen. It is the specific terms within the system, rather than the system itself, which determine whether the government has negotiated a good deal. Furthermore, over time the distinctions between these models have blurred and so-called hybrid models (adding royalties and/or income tax to a production-sharing system) are now common.

2.2 Contract Disclosure

The fiscal terms governing Blocks 10BB and 13T are contained in production sharing contracts (PSC). The specifics are shown in Table 2 below.

Unfortunately, neither the contracts themselves nor a summary of the core fiscal terms are available in the public domain. Most, but not all, Kenyan PSCs state that the contracts themselves are confidential and can only be disclosed by mutual consent, except as required by law.

However, more recently the Kenyan Government has committed at the highest levels to make the Production Sharing Contracts public. In the Joint Communiqué emerging from
President Obama’s visit in July 2015, the President of Kenya agreed to “adopt a transparent policy and legislative framework” for the oil and gas sector, including publication of contracts between oil companies and the government.¹⁰ One year earlier, while on a visit to the United States, President Kenyatta responded to a direct question about whether Kenya would disclose the production sharing contracts by saying “absolutely.”¹¹ And the new Petroleum Bill (2015) is explicit that in the future the PSC is “a public document and that the Government shall have the right to publish and keep it publicly available.”¹²

Even where governments are unwilling to disclose oil contracts, companies sometimes disclose the document (or at least a summary of the core terms) to their investors. Tullow, for example, has disclosed all oil contracts for their projects in Ghana.¹³

Africa Oil has not publicly disclosed its PSCs, but through two separate processes they could have already disclosed the contracts for 10BB and 13T. First, Africa Oil is publicly listed on the Toronto Stock Exchange (TSX) in Canada. Disclosure obligations there require companies to provide to their investors all contracts “so significant that the reporting issuer’s business depends on the continuance of the contract,” though crucially there are some exemptions.¹⁴ Canadian oil companies routinely disclose production sharing contracts as a result of this provision, but Africa Oil has not. Second, in August of 2015, Africa Oil received $50 million from the International Finance Corporation (IFC) specifically to support the further investment in Blocks 10BB and 13T in Kenya. As a matter of policy, the IFC calls on their clients to disclose “the terms and conditions agreed with host governments under which a resource is being developed.”¹⁵ Yet the contracts for 10BB and 13T have yet to be disclosed.

Tullow and Africa Oil both indicate that they are willing to disclose the contracts once they receive the agreement of the Kenyan Government. Unfortunately, it is not uncommon for both companies and government to indicate a willingness to disclose with the agreement of the other party without disclosure ever actually taking place.

Although the PSCs for Blocks 10BB and 13T remain confidential, there are seven Kenyan PSCs in the public domain including Blocks 1, 2B, 11A, L1B, L16, L27, and L28. In addition, companies have provided investor summaries of the core PSC fiscal terms for Blocks 9, 10A, 10BA, 11A, and 12B. An analysis of the fiscal terms applying to the blocks listed above suggests that there is only modest variation in fiscal terms.

As the fiscal terms for Blocks 10BB and 13T are not in the public domain, the analysis below adopts the fiscal terms applicable to the neighbouring Block 10A.
3. Fiscal Terms

Kenya operates a fairly traditional production sharing system. The bulk of government revenue would be expected to come from a share of oil production that is allocated to the government. In addition, the contracts contain a “windfall tax” that is applied on oil when prices are greater than $50 per barrel. The government also holds the right to participate (hold an equity stake) in all oil operations, whether directly or through the National Oil Company of Kenya.

The core of the fiscal regime for Turkana oil results in three main sources of government revenue:

1. Production Sharing
2. Windfall Tax
3. State Participation

Figure 3 illustrates the sequence in which the three main fiscal elements are engaged. It is important to note that the implications of the various fiscal instruments cannot be assessed in isolation. The benefits to the government of a stringent provision in one area can easily be offset by a more generous provision in another area. Fiscal instruments must be assessed comprehensively, in order to understand how they interact. Ultimately, fiscal instruments only become meaningful in the context of plausible scenarios on production volumes, oil price and expenses, as in Section 5 below.
3.1 Production Sharing

The principal source of government revenue for Turkana oil is the government share of the oil produced. The production-sharing system was developed by Indonesia in the 1960s and has since been widely adopted, particularly in the developing world. In this system, the oil company acts as a “contractor” to the government. There are two steps in the allocation of oil produced: first, the contractor recovers costs, and second, the remaining oil is divided between the contractor and the government.

Production sharing systems allow the contractor to recover their costs through an allocation of an initial amount of production termed “cost oil.” Costs that can be recovered include those related to exploration for oil, the development of the facilities to produce oil and the operation of those facilities and their ultimate decommissioning. Capital costs can be recovered at a rate of 20% per annum from the start of production.

In the first years of production, accumulated costs normally exceed the value of total production. If production in these early years were allocated exclusively to the recovery of costs, none would be left to split between the company and the government. In many (though not all) production-sharing systems therefore a limit is placed on the proportion of production that can be devoted to costs. With such a “cost recovery limit” in place, a proportion of production is always available to be split between the company and the government.

It is important to note, however, that the cost recovery limit has an impact only on the timing of reimbursements to the company. Where limits are imposed, the costs that exceed those limits are carried-forward and claimed in subsequent years. According to one noted authority, cost recovery limits for production-sharing contracts around the world often range from between 40-60%. The cost recovery limits for Kenyan concessions in the Turkana region are 60%.

Once costs have been recovered, the remaining oil production, known as “profit oil”, is split between the company and the government. In some countries, the division is based on a set percentage, but most PSAs use some kind of sliding scale. More specifically, many PSAs seek to provide the government with an increased percentage of production as the project becomes more successful.

The Kenyan fiscal system employs a traditional “production-based” allocation. For production up to 10,000 barrels of oil per day (bopd), the company receives 50% of profit oil and the government receives 50%. For production exceeding 10,000 bopd up to 40,000 bopd, the split changes to

<table>
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<tr>
<th>Table 3: Profit Split – Block 10A</th>
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<tr>
<td><strong>Incremental Production Tranches</strong></td>
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<tr>
<td>1-10,000 barrels per day</td>
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<td>Next 30,000 barrels per day</td>
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<td>Next 50,000 barrels per day</td>
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<td>Next 50,000 barrels per day</td>
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<td>Above barrels per day</td>
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40% for the company and 60% for the government. The full set of tranches and percentages is set out in Table 3.

3.2 Windfall Tax

It is not uncommon for fiscal systems to incorporate what are known as “windfall” taxes designed to ensure that the government receives an increasing share as projects become very profitable. Major spikes in oil prices in the 1970s and 2000s have demonstrated the importance of fiscal systems that capture a greater proportion of the upside benefits for governments.

Existing Kenyan PSCs contain a “windfall tax.” The tax is applied to the company share of profit oil that is generated from oil prices that exceed the “threshold price” of $50 per barrel. In the example shown in Figure 4, an additional tax of 26% would be applied to the $25/bbl of windfall profit.

3.3 State Participation

Many countries with production sharing systems provide an option for the host government to “participate” in the project as a joint venture partner. This is also sometimes called state participation or “working interest.”

The rationale for state participation is not purely economic. In fact, economic benefits equal to those provided by state participation can be achieved through conventional taxes. In illustration the shift from a production based sharing model and the inclusion of paid income tax in Kenya’s new 2015 PSCs will lead to an increase of 10% in government take in the petroleum sector.

In some cases, the rationale for state participation is driven by a sense of national pride: governments sometimes believe that it is essential that they have a direct role in the development of their national resources. Another justification for state participation, particularly when taking a very small stake, is the additional insight into the commercial dimensions of the operation gained from being part of the decision making process. Taking an equity interest in a project means that the State participates on essentially the same terms as other joint venture partners. There is, however, one important difference between the government and a normal commercial partner. It is unusual for the government to participate during the exploration phase. Rather, the company takes all the risk associated with exploration and the government can “back-in” to a percentage stake after waiting to see if
exploration efforts are successful. From this point, it is not uncommon for the private companies to “carry” the costs of the state until production begins. Given the large up-front expenses required to develop an oil project, governments frequently require the company to finance project development with repayment being made from government revenues once oil production begins.

The Kenyan production sharing contracts all provide for the participation of the state under a “partial carry.” The minimum state share is 10%; for some contracts it is as high as 22%. The company is solely responsible for costs associated with the exploration phase. If exploration is successful the project moves to the development phase. From this point onwards, the State is required to pay its share of all costs.

In February 2015, it was reported that the National Oil Corporation of Kenya (NOCK) was seeking to raise $1.2 billion through internal sources, external debt and other equity partners in order to finance its share of oil development costs including for Blocks 10BB and 13T.

While state participation generates revenue for government entities, it is not immediately obvious that it is “revenue” similar to a payment to the Treasury. In some countries, state participation is managed out of a ministry and all payments are made to the Ministry of Finance. In such a case, state participation is simply one among several sources of government revenue. However, in cases like Kenya where at least a portion of the equity stake will be held by a state-owned enterprise (the National Oil Corporation of Kenya), the answer is not so obvious. NOCK is an “operational” oil company. It has mid-stream and downstream operations and it aspires to be active in upstream operations including its exploration activities in Block 14T. Under these circumstances, the actual revenue to government is limited to the corporate income tax and dividends that NOCK pays to the Treasury.

We assume that the State will take up an equity stake of 20% in 10BB and 22.5% in 13T.

### 3.4 Secondary Sources of Government Revenue

The list above identifies the central fiscal instruments used in this analysis of potential government revenues from Turkana oil. There are other measures that could be relevant but have been excluded from the economic analysis included in this report.

<table>
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<tr>
<th>Costs</th>
<th>Full Equity</th>
<th>Partial Carry</th>
<th>Full Carry</th>
</tr>
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<tbody>
<tr>
<td>Exploration</td>
<td>Company pays all costs. (State may pay back)</td>
<td>Company pays all costs (State rarely pays back)</td>
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<tr>
<td>Development</td>
<td>State pays full share of costs as incurred.</td>
<td>State pays full share.</td>
<td>Company pays all costs (State normally pays back from production)</td>
</tr>
<tr>
<td>Production</td>
<td>State pays full share.</td>
<td>State pays full share.</td>
<td>State pays full share.</td>
</tr>
<tr>
<td>Examples</td>
<td>Norway, Venezuela</td>
<td>Kenya, Mozambique</td>
<td>Egypt, Ghana, Angola</td>
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Article 27(5) of the production sharing contracts indicates “Each Contractor shall be subject to and shall comply with the requirements of the income tax laws in force in Kenya, which impose taxes on or are measured by income or profits.” Some analysts have interpreted this to mean that oil companies are liable for corporate income tax assessed at 30% of net profits. While the language of the contract is somewhat confusing, a subsequent paragraph indicates that it is “deemed” paid for by the Government out of its share of profit oil and not by the company. This type of provision is not uncommon in production sharing agreements. International companies are normally given a tax credit in their home jurisdiction for taxes paid abroad. In a production sharing system, the profit oil share paid to the Government is not understood as a “tax” from the perspective of the company’s home jurisdiction. In order to provide the company with an acceptable tax receipt, the Government “pays” corporate income tax on behalf of the company out of its share of profit oil. Importantly, this tax sleight-of-hand has no impact on company cash flow and generates no additional government revenue.

Other sources of potential government revenue are either explicitly excluded in the PCSs or are of marginal importance to an analysis of government revenues. Companies have the right to sell petroleum “without restriction and free of taxes, charges, fees, duties or levies of any kind.” The Kenyan production sharing contracts also explicitly exempt the company from costs associated with importing goods including customs duties, VAT and import declaration fees. Signature bonuses and surface fees have been excluded from the analysis because they do not have a material impact on government revenues.
4. Inputs and Assumptions

The objective of this analysis is to provide a sense of the scale and timing of revenues that could accrue to the Government of Kenya from Turkana oil. Assessments of potential government revenue from oil projects ultimately rest on four main components: the fiscal terms, the volume of oil that might be produced, the price at which the oil will be sold, and the costs incurred in production. The fiscal terms have been described in detail above. Details on input assumptions for production, price and costs are set out below.

A comprehensive understanding of project economics, and the relative benefits accruing to the company and the government, can only be completed after the project is finished and the books are closed. Nothing therefore can be said with any certainty about the future economics of the project, or of the revenues that could accrue to the government. The best that can be done is to get a sense of what the project economics might look like under differing scenarios. These varying inputs are fed into a spreadsheet model in order to generate projections of potential government revenue.

4.1 Potential Production Volumes and Timelines

Overall production volumes and annual production profiles are normally based on estimates of recoverable oil reserves.

The size of an oil field is measured on two dimensions: uncertainty and commerciality. Exploration drilling generates estimates of “contingent resources” (See Figure 5). Oil has been discovered, but there is still either technical or commercial uncertainty about whether it can be recovered. Oil can only be classified as “reserves” rather than “resources” when these technical and/or commercial uncertainties have been overcome. Resources and reserves are categorized by the degree of confidence that they can be recovered – proven, probable and possible – under existing technical, legal and commercial conditions. Proven reserves (1P) means that the estimated amount of oil has a greater than 90% chance of being recoverable. Probable reserves (2P) mean a 50% chance of being recoverable, while possible (3P) means a 10% chance.
of being recoverable.

Based on publicly accessible information, Turkana oil (South Lokichar Basin) is currently classified as “contingent resources,” rather than reserves. Converting these resources to reserves will require both overcoming geological uncertainty through further data interpretation and appraisal, and overcoming uncertainty surrounding the pipeline. According to data published by Africa Oil, an independent assessment undertaken by Gaffney Cline in 2014 estimated just over 600 million barrels of probable (2C) contingent resources. 25

Resource and reserve estimates provide insight into how much total oil might be produced but not when it might be produced. The timing of potential oil production depends on two assumptions: the year of first oil and the anticipated production profile.

Publicly reported timelines to first oil from Turkana are frequently unrealistic. While considerable uncertainty remains, information in the public domain is quite clear on the minimum amount of time required. The construction of the pipeline is the main limiting factor. Even without the recent uncertainty of the possible “Tanzanian route” for Ugandan oil, there are many steps to be taken before pipeline construction could begin, including the “front end engineering and design” (FEED) and the bringing together of the financiers for what will be a $4-5 billion project. Only when these pieces are in place can the companies involved in the Turkana oil fields and the pipeline take what is known as a final investment decision (FID).

In documents provided to investors, Tullow currently estimates that the earliest possible date for an FID (called project “sanction”) would be sometime in 2017 (See Figure 6). All indications suggest that pipeline construction will take at least three and a half years. The earliest start date for Turkana oil therefore would be 2021. It is important to recognize that this is the minimum time that would be required. There is of course no maximum amount of time. Negotiation over pipeline routing with Uganda and within Kenya as well as the challenges of pipeline financing, particularly in a period of depressed oil prices, could easily result in the project being delayed much longer.
When oil production begins it is likely to follow a standard profile involving a ramp-up phase, a plateau, and then a long decline. In the case of Turkana oil, it is widely assumed that production will be developed in two phases. The Petroleum Master Plan, for example, assumes a first phase of development allowing for production of around 50,000 barrels per day, with a second phase coming on stream four years later allowing for total production of around 120,000 barrels per day. We assume somewhat higher levels of production, based on the contingent reserve estimates published by Africa Oil, with the first phase peaking at 75,000 barrels per day and the second phase peaking at 150,000 barrels per day. We allocate production across Blocks 10BB and 13T in proportion with those same estimates.

4.2 Oil Price

Annual production volumes are only one of two components necessary to calculate gross revenue; the other is the future sale price of oil. It is widely accepted that even the best oil price forecasts are little better than educated guesses. According to former BP CEO John Browne, the future oil price is “inherently unpredictable.” The unexpected plummeting of oil prices through 2014 starkly illustrates this point (See Figure 8).

Plausible estimates of future oil price are required for estimating future government revenue. The common technique is to select a base price and assume modest price increases over time. This is not designed to be an accurate reflection of future prices but rather allows the fiscal system to be tested under a range of potential prices. Specific scenarios are
based on oil prices of $45/bbl, $65/bbl and $85/bbl. The lower price of $45 has been used, even though prices are currently much lower, because in our assessment the project requires oil prices in this range to just break even. The higher price of $85 has been selected due to widespread scepticism that oil prices will return to levels of more than $100/bbl.

Forecast prices are for Brent crude, the world’s most widely used benchmark price. It is clear that Turkana crude will sell at a significant discount to Brent given that it is heavier (Turkana crude range given from 25-35° API vs Brent 38-39° API), less sweet (around 1.5% sulphur vs. Brent <0.5%) and waxy (Turkana crude has a high wax content 24% to >35%). How much of a discount however is unclear.

There are indications that some Kenyan and Ugandan crudes are similar. The 2010 Foster Wheeler feasibility study for a refinery for Ugandan crude oil indicates a “$12 discount against Brent for the Ugandan crude at Mombassa.” Kenyan crude has also been compared to Sudanese crudes where the “Nile blend” discount is reported to be around $2/bbl while the much heavier “Dar blend” discount is around $10/bbl.

Surprisingly, the Toyota Tsusho Pipeline Report does not provide a clear answer to the quality of Turkana crude or an estimate of the likely discount to Brent. The report is clear that “Some crude oils from Uganda and Kenya sources have very low API grades in addition to other challenging properties, like high wax content, very high pour point, etc.” It also suggests that Kenyan crude will have a higher API than Ugandan crude, which would result in a lower discount.

Based on an analysis of the information listed above, we assume a discount to Brent crude of $8/bbl until more reliable data on Kenya crude quality becomes available.

4.3 Costs

The third and final set of assumptions on which to construct plausible scenarios are costs associated with exploration, development, production and transportation.

**Exploration Costs:** Seismic exploration of Blocks 10BB and 13T began in 2009. Exploration drilling began in 2012. Companies do not appear to have reported overall exploration costs for the two blocks. Costs have therefore been generated from a thorough review of Africa Oil reports to investors. We estimate exploration costs through to the beginning of the development phase in 2017 at $ 1.8 billion.

**Development Costs:** For development costs, we assume that the two blocks will be developed along similar timelines beginning with an FID in 2017 and resulting in first production in 2021. We have been unable to find reliable cost estimates in the public domain. We draw therefore on Tullow estimates for Uganda ($6/barrel) as provided to investors in October 2015. The phasing of capital expenditure is also drawn from the same Tullow presentation and modified to take into account the two-phased expansion discussed under production profiles above.
Operating Costs: Given that the project has not yet even reached the development stage, detailed operating cost estimates are not available. The common approach is to generate operating costs as a percentage of total development expenditure. The estimates in the Petroleum Master Plan (10% of development costs) are very high. We have assumed 6% of development costs that results in an average operating cost of $7 per barrel. This compares well with International Energy Agency data on large, onshore oil fields.

Pipeline Tariff: The costs of transporting oil by pipeline to the coast will have a major impact on project economics. We assume that pipeline costs will act like an additional cost of operating within the PSC, and will therefore be cost-recoverable. A reliable estimate of the pipeline tariff will only be available once a full front-end engineering and design (FEED) study is completed. Referring to pipeline costs for Uganda, Mr Daniel Kiptoo, adviser to the Energy and Petroleum Cabinet Secretary, is reported to have said that the “Toyota Tsusho design estimated that the transit fee for oil per barrel would be $15.20.” The corresponding tariff for crude originating in Turkana, according to the Toyota Tsusho Pipeline Report would be $10.70, and we use this rate in the analysis below.

Tullow’s recently provided a cost estimate of around $25 dollars per barrel for Turkana oil. While they did not provide a detailed breakdown, the estimate included capital costs, operating costs and the pipeline tariff. Our combined cost estimate is about the same. It is important, however, to be clear on the significance of this figure. It has been widely reported that Tullow was claiming a “breakeven” price of $25/bbl, a price that would make the project appear to be viable even at today’s low oil prices. A true breakeven price, however, would need to take into account the discount to Brent identified above as well as the profit oil allocation to the government. We provide our assessment on the project’s breakeven price in the company economic section below.
5. Economic Analysis

The results from economic modelling are not predictions of actual government revenue, particularly for projects not yet in the development stage. Rather, they provide estimates of potential government revenue under specific sets of assumptions related to production volumes, oil price and field costs.

The analysis below is based on the following base case assumptions:
- 600 million barrels of recoverable oil;
- First oil production in 2021, production life of 20+ years;
- First phase peaks at 75,000 bopd; second phase peaks at 150,000 bopd;
- Brent crude oil price - $45 low, $65 medium and $85 high (with $8 discount for quality);
- Costs are: exploration ($1.8b), development ($6/bbl), operating (6% of development); pipeline tariff ($10.70);
- Production sharing terms from Block 10A; and,
- State participation for 10BB (20%) and 13T (22.5%).

**Gross Project Revenues:** Under the “best case” assumption of production beginning in 2021, oil production reaches its peak in the years 2025-2030 before beginning a gradual decline. Overall project revenues peak at USD 2.6 billion per year with oil prices at $45/bbl and rise to more than USD 5 billion per year at $85/bbl.

**Government Revenues:** Government revenues from profit oil and the windfall tax follow a profile similar to overall project revenue, but are somewhat delayed due to the effect of cost recovery. Revenues to the government peak in the late 2020s at USD 650 million per year with oil prices at $45/bbl, at USD 1.7 billion at $65/bbl and

![Figure 9: Potential Government Revenues at Differing Oil Prices](image-url)
Potential Government Revenues from Turkana Oil

at USD 2.7 billion at $85/bbl. Importantly, revenues also decline quite rapidly after the peak is reached. Even at $85/bbl, government revenues in 2035 are well under USD 1 billion.

Sources of Government Revenue: The overwhelming source of Government revenue is their share of profit oil. Before looking at the economic benefits of state participation, profit oil generates 80-90% of government revenue at the different price levels. The windfall tax generates significant additional revenue over the lifespan of the project but is of course very price sensitive. At $85/bbl the windfall tax generates a total of more than USD 1 billion accounting for just under 15% of government revenue.

State Participation: Additional revenue would flow to government through its equity participation. Annual revenues from state participation peak at around USD 190 million at $45/bbl, USD 370 million at $65/bbl and more than USD 460 million at $85/bbl. Over the lifespan of the project, revenue from state participation would be USD 1.2 billion at $45/bbl, USD 2.7 billion at $65/bbl, and USD 3.7 billion at $85/bbl. However, these revenue projections do not take into account the significant costs of upfront financing for field development costs. The terms of the PSC are clear: for the state to participate it must pay its proportionate share (20% for 10BB and 22.5% for 13T) of all costs from the start of the development phase. The costs associated with borrowing the funds necessary to make these payments will reduce the cash flow from state participation in the early years. Also, as noted above, to the degree that the equity stake is held by NOCK, actual revenues to government would depend on the payment by NOCK of corporate income tax and dividends that have not been factored into the current analysis.

Government Take: The “government take” is a common if crude metric for assessing how fair a deal the government negotiated. It assesses the percentage of divisible revenue (revenues after costs have been subtracted) that goes to the government as compared to the company over the entire life cycle of the project. Our analysis suggests a total undiscounted government take of around 70%, with 60% coming from production sharing and the windfall tax, and an additional 10% coming from state participation.

How does this compare with other countries? Comparative research suggests that the government take varies widely among different countries with some securing only 40% while others take more than 95%. Based on an analysis of dozens of developing countries, the International Monetary Fund has concluded that the average government take ranges from 65% to 85%. The PSC terms used in this analysis therefore compare reasonably well with international averages, taking into account that Kenya was not an existing oil producer when the contracts were signed.
**Company Economics:** The analysis above has focused on the economic implications from a government perspective. It is also important to understand the economics from a company perspective. As with government revenue, much depends on the price of oil. As mentioned above, the breakeven point depends not only on project costs (capital, operating and pipeline tariff), but also on the discount to Brent crude and the minimum allocation of profit oil for the government. Our analysis suggests a breakeven oil price for companies of around $42/bbl. Although the project would be unlikely to proceed with oil prices at that level, the economics look favourable for companies at higher oil price. The internal rate of return (IRR) is a measure used by companies to assess the attractiveness of an investment. At $65/bbl the company IRR would be around 37%, while at $85/bbl the IRR would be more than 50%.

**Sub-National Payments:** The Petroleum (Exploration, Development And Production) Bill (2015) contains a formula for sharing oil revenues. Article 85(1) states that “the National Government’s share of the profits derived from upstream petroleum operations shall be apportioned between the National Government, the County Government and the local community.” Article 85(2) states that “the County Government’s share shall be equivalent to twenty percent of the National Government’s share” but that this amount “shall not exceed twice the amount allocated to the County Government by the National Assembly.” Article 85(4) states that “the local community’s share shall be equivalent to five percent of the Government’s share and shall be payable to a trust fund managed by a board of trustees established by the County Government in consultation with the local community.” It also states that the total share to local communities “shall not exceed one quarter of the amount due to the County Government.”

Table 6 shows the results in Kenyan Shillings of applying these provisions to the revenue projections set out above. The results show very large potential transfers to both counties and communities. Assuming consistent transfers from the National Assembly of between KSH 10-11 billion, the cap as set out in the draft bill would be reached at both $65/bbl and $85/bbl during the years of peak production.

<table>
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<tr>
<th>Table 6: Sub-National Transfer (KSH billions)</th>
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<td>Total Revenue</td>
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<td>National (75%)</td>
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<td>County (20%)</td>
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<td>Communities (5%)</td>
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6. Concluding Remarks

This report has sought to provide insight into the scale and timing of potential government revenues, national and sub-national, from Turkana oil. The main conclusions – the long timelines to production, the challenges associated with the pipeline and the sensitivity to oil prices – will come as no surprise to industry specialists. However, the purpose of the report is to try to disseminate these ideas much more widely in order to help correct inflated expectations and to highlight some of the key issues and processes to watch in the coming months and years.

There are limits to analysis based exclusively on public domain information. Unfortunately, the Government of Kenya has disseminated very little detailed information on the prospects for Turkana oil. For example, government commitments to contract disclosure remain unmet and comprehensive details of the pipeline feasibility study have not been published. The one important exception is the Petroleum Master Plan, funded by the World Bank and prepared by Price Waterhouse Coopers. Most of the data on which this report is based has come from information that companies have provided to their investors. Surely the citizens of Kenya have as much right to information related to the extraction of their resources as foreign shareholders. While we believe that the results of the analysis are sufficiently reliable to provide a realistic sense of potential government revenues from Turkana oil, greater transparency by the Government of Kenya would allow this type of analysis to be more accurate.

Countering overly inflated expectations is one of the most valuable contributions that this type of economic analysis can make. There are strong incentives for both companies and government officials to adopt optimistic assumptions about the prospects of oil operations. In some cases the predictions based on these optimistic assumptions are met, but in many cases projects are delayed (often by many years) and actual government revenues fall far short of original projections.

For Turkana oil, the complexities of the pipeline, particularly in the face of depressed oil prices, suggests that further delays are likely. While truck/train options are being explored, the full development of the existing oil fields requires a pipeline. Negotiations with the Ugandan government and oil companies active in the Albertine region as well as the challenges of pipeline design and financing are unlikely to be resolved quickly. Depressed oil prices are also likely to push project timelines back as oil companies prioritize expenditures on existing operations rather than new projects.

The most important upcoming milestone for Turkana oil therefore is the final investment decision for both the upstream operations and the pipeline. Assuming a decision in 2017, the earliest possible date for first exports through the pipeline would be late 2021.

Assuming that the project does move ahead, as the analysis above has shown, the oil price will have a profound impact on the volume of revenue flowing to national and subnational governments. While no one can predict what oil prices will be in the
early 2020s when production could begin, it would be prudent for long-term budget planning to assume lower rather than higher prices.

Capacity building should be a priority, both at both national and regional levels and within and outside of government (including for civil society and local communities), as the Turkana oil projects move from discovery towards development and eventual production. The methods used in this paper, cash flow analysis based on production, price and costs scenarios, should be an integral part of these capacity building efforts in order that revenue projections provide a sound basis for national and sub-national decision-making.
More Information

We welcome your feedback on the analysis put forward in this paper. For any comments and suggestions, or for more information about our capacity-building work (including trainings) on revenue analysis and community engagement around oil, gas and mining projects, please contact:

*Kenya Civil Society Platform on Oil and Gas*
Charles Wanguhu, Coordinator: wanguhu@kcspog.org
Tel. 0716159499

*Resources for Development Consulting*
Don Hubert, President: don.hubert@res4dev.com

*Cordaid / Timu-Community Development Associates*
Jeroen de Zeeuw: jeroendezeeuw@gmail.com
Winstone Omondi: joel.omondi@gmail.com
NOTES


4 See Hoima-Lokichar-Lamu Crude Oil Pipeline, Toyota Tsusho, 2015, p. 35.

5 Crude Oil Pipeline, Toyota Tsusho, 2015, p. 38.


7 For a non-technical guide to oil contracts, see Oil Contracts and How to Understand Them, OpenOil, 2012.

8 See Part 2 – Environment and Natural Resources, 69. Obligations in respect of the environment, The State shall ensure sustainable exploitation, utilisation, management and conservation of the environment and natural resources, and ensure the equitable sharing of the accruing benefits.


12 Article 49(5)


17 A 60% cost recovery limit applies to Blocks 9, 10A, 11A, and 12B.

18 The traditional sliding scale is based on volume of production, normally thousands of barrels of oil per day (mbopd). While easy to administer, the approach has begun to fall out of favour, as there is no necessary relationship between production volumes and profitability. Small projects with low costs can generate high profits, while large projects with high costs may not generate much profit at all.

19 Article 27(3)(c).
21 See Article 28.
24 Article 27(5) The portion of the Profit Oil or Profit Gas which the Government is entitled to [...] shall be inclusive of all taxes, present or future, based on income or profits of the Contractor, including specifically tax payable under the Income Tax Act, and dividend tax imposed by Kenya on any distribution of income or profits by the Contractor.
27 See Gaffney Cline, Continent Resource Estimates, 2014, p. 3; and Prospectus, Africa Oil, 2015, p. 54.
31 See Crude Oil Pipeline, Toyota Tsusho, p. 242.
34 See Uganda sets tough terms for Kenya on oil pipeline, Daily Nation, 17 August 2015 (http://www.nation.co.ke/business/Uganda-sets-tough-terms-for-Kenya-on-oil-pipeline/-/996/2836094/-/3yx0ux/-/index.html).
35 See “2015 Full Year Results,” Tullow Oil Plc, 10 February 2016, p. 18.
38 Exchange rate of 1 USD = 102 KSH.