POTENTIAL PETROLEUM REVENUES FOR THE GOVERNMENT OF KENYA

IMPLICATIONS OF THE PROPOSED 2015 MODEL PRODUCTION SHARING CONTRACT

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SUMMARY

The Petroleum (Exploration, Development and Production) Bill, 2015 and associated model production sharing contract (PSC) are currently in the final stages of Parliamentary review. The development of a new regulatory framework for the petroleum sector was driven by the need to modernize a regime that was first established in 1986 and to take into account recent discoveries of both oil and natural gas.

Of the changes proposed in the 2015 Bill and model PSC, the focus of this analysis is on the fiscal terms; that is the sources of Government revenue and the specific terms applicable to them. The new fiscal system that would apply to PSCs negotiated in the future will be significantly different than the one that applies to all existing PSCs, including those for the promising blocks in the Turkana region.

Attention is given to the three main differences between the existing and future fiscal terms. First, the 2015 model PSC proposes to replace the existing approach to the sharing of profit petroleum from one based on the daily rate of production (DROP) combined with a windfall profits tax imposed when oil prices are higher, to one based on a measure of profitability (r-factor). Second, under the 2015 model PSC, corporate income tax would become tax paid by the company rather than paid out of the government's share of profit oil. Third, the 2015 model PSC changes a significant investment incentive by replacing the cost recoverability of interest on debt incurred for development costs with a 15% uplift on development spending.

As it is difficult to comprehend the significance of the proposed changes in the abstract, both sets of terms are applied to a potential oil project based on public domain data for Blocks 10BB and 13T in the South Lokichar region. It is important to note that past PSCs contain stabilization clauses and as such there is no suggestion that the 2015 terms would be applicable to the Turkana project. The objective of applying the 2008 and 2015 terms to this hypothetical oil project is to allow for a direct comparison of project economics and potential government revenue under varying scenarios of production, price and costs.

Two clear conclusions emerge. The adoption of the R-factor and the development cost uplift are both consistent with best practice and provide modest economic benefits for the government. The adoption of an R-factor profit split as set out in the 2015 model contract generates some additional revenue for the government and is economically more efficient than the combination of the DROP profit split combined with the windfall tax. Similarly, the development cost uplift generates some additional revenue and closes significant potential loopholes.

In contrast, the shift from a "deemed" corporate income tax to one actually "paid" by the company has a profound effect on project economics and the proportion of revenue that would flow to the government. The inclusion of a paid income tax increases the government by roughly 10%. It could add billions of dollars to government coffers over the lifecycle of a project. The additional revenue however also constitutes a significant extra burden on the contractor.

Following successful oil discoveries, countries often tighten fiscal terms for future contracts. The change from a deemed to a paid corporate income tax may be appropriate in light of the Turkana oil finds. But it is a choice that should be made deliberately, with full awareness of the significant change that it represents to the Kenya's petroleum fiscal regime.

CONTEXT

Traditional analyses of petroleum regimes draw a sharp distinction between three different fiscal systems: royalty and tax (concession), production sharing and service agreements.[1] In a royalty and tax system, the company takes ownership of the petroleum as it reaches the surface with the government securing its revenue through royalty payments and the assessment of various taxes. In the production sharing system, the company takes ownership of petroleum only at the delivery point with the government being allocated a share of "after-cost" petroleum production. Under a service contract, the contractor never acquires the title to the resource and is simply paid a fixed or variable fee for oil production services. Table 1 shows the regional distribution of these three main systems.[2]

Table 1: Overview of Fiscal Systems

AREA	ROYALTY/TAX	PRODUCTION SHARING	SERVICE
AFRICA	Nigeria (Shelf),Chad, Congo, Ghana, Madagascar, Morocco, Namibia, Niger, Senegal, Somalia, Sierra Leone, S. Africa, Tunisia (old)	Nigeria (Deepwater), Algeria, Angola, Benin, Cameroon, Congo, Cote D'Ivoire, Egypt, EG, Ethiopia, Gabon, Gambia, Kenya, Liberia, Libya, Madagascar, Mozambique, Sudan, Tanzania, Togo, Tunisia (new), Uganda, Zambia	Nigeria (JV)
EUROPE	Italy, France, Ireland, UK, Faroes, Spain, Ireland, Netherlands, Norway, Poland, Portugal, Romania, Spain, Denmark	Poland, Turkey, Malta, Albania	
ASIA	Australia, Brunei, S. Korea, Nepal, New Zealand, Thailand, Timor	Bangladesh, Cambodia, China, Georgia, India, Indonesia, Laos, Malaysia, Mongolia, Pakistan , Vietnam	Philippines
FSU	Russia	Azerbaijan, Georgia, Kazakhstan, Russia, Turkmenistan, Uzbekistan	
LATIN AMERICA	Argentina, Bolivia, Brazil, Columbia, Paraguay, Trinidad	Belize, Cuba, Guatemala, Nicaragua, Panama, Trinidad (off), Venezuela	Chile, Ecuador, Panama, Peru, Honduras, Mexico
MID EAST	Abu Dhabi, Dubai, Turkey	Bahrain, Iraq, Jordan, Oman, Libya, Qatar, Syria, Yemen	Iran, Kuwait, Saud Arabia
N. AMERCIA	US, Canada		

Over time the distinctions between these types of agreements have blurred and so-called hybrid models (adding royalties and income tax to a production-sharing system) are now also common, having been adopted in neighbouring countries including Uganda, Tanzania and Mozambique.

Governments can ensure that they secure a fair share of the overall revenues independent of the model chosen. It is the combination of fiscal terms within the system, rather than the system itself, which determine whether the government has negotiated a good deal.[3] The challenge facing governments, of course, is to offer terms that encourage companies to explore for oil while at the same time seeking to maximize government revenues should those exploration efforts be successful.

The Petroleum Exploration and Production Act of 1986 (Chapter 308, Revised Edition 2012) currently governs exploration and production in Kenya's petroleum sector. As is the case in many developing countries, Kenya has selected to operate a production sharing system where a private oil company is responsible for oil exploration and production and the government receives a proportion of oil produced after costs have been paid.

The specific fiscal terms are set out in a production sharing contract or PSC. 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.

As is common, model production sharing contracts were published in 1986, 1999 and 2008. These template documents provide standardized language for the majority of the contract while leaving only a few key provisions open for negotiation. The basis for this analysis then is a comparison of the fiscal terms set out in the 2008 model PSC and the proposed 2015 model PSC.

In keeping with good practice in the sector, Kenya is moving towards establishing most of the terms governing petroleum operations in the law and the model contract, leaving only a few key elements for project-by-project negotiations. The 2015 model PSC therefore describes not only the fiscal instruments that generate government revenue; it also contains the specific terms necessary for an economic analysis.

The 2008 model contract also sets out the fiscal instruments that generate government revenue but important negotiable elements were left blank. Unfortunately, most Kenyan production sharing contracts contain confidentiality clauses and the government has yet to put them in the public domain. Fortunately, international oil companies have disclosed a number of full PSCs to their investors (Blocks 1, 2B, 11A, L1B, L16, L27, and L28), while others have disclosed a summary of the core fiscal terms (Blocks 9, 10A, 10BA, 11A, and 12B). A review of these published terms suggest that there is relatively little variation between them. The analysis below is based on the terms applicable for Block 10A.

Three main differences between the 2008 and 2015 fiscal regimes are analyzed below, including:[4]

1. The replacement of a daily rate of production allocation of profit oil combined with a windfall tax with a r-factor allocation of profit oil in the 2015 fiscal regime;
2. The replacement of a "deemed" corporate income tax paid out of the government's share of profit oil with a corporate income tax "paid" by the company; and,
3. The replacement of the investment incentive allowing for the cost-recoverability of interests on company borrowing, to a 15% capital investment "uplift" for five years following an approved development plan.

ALLOCATING PROFIT OIL

The fiscal system set out in the 2008 model PSC would be considered, in most respects, a classic production sharing system. The regime does not include either a royalty or corporate income tax. The principal source of government revenue is the share of petroleum production allocated to the government after costs have been paid. One additional feature is the inclusion of a windfall tax imposed when oil prices exceed a specified threshold.

The first significant difference between the 2008 and 2015 fiscal terms is the way in which petroleum production is shared. As is the case in all production sharing systems, oil is first allocated to allow the operator to recover its costs.[5] Once this "cost oil" has been allocated, the remaining "profit oil" is split on a sliding scale between the company and the government.

Under the terms of the 2008 model contract, profit oil is allocated based on the volume of production. This traditional approach for allocating profit oil is commonly referred to as "daily-rate-of-production" (DROP). The terms for Block 10A, for example, are set out in Table 2. In this case, the government would receive 55% of production for the first 10,000 barrels of oil per day (bopd), while the company receives 45%. For production exceeding 10,000 bopd up to 40,000 bopd, the split changes to 60% for the government and 40% for the company.

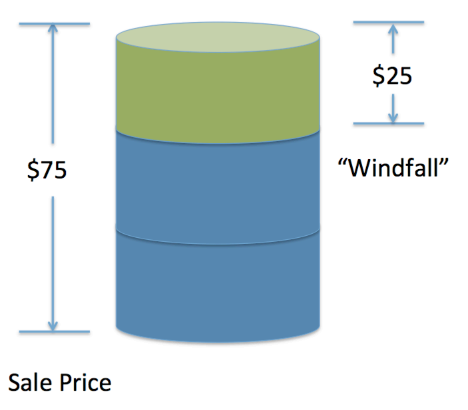
Table 2: Profit Oil Split – Block 10A

Incremental Production Tranches	Government Share	Company Share
1-10,000 barrels per day	55%	45%
Next 30,000 barrels per day	60%	40%
Next 50,000 barrels per day	63%	37%
Next 50,000 barrels per day	68%	32%
Above barrels per day	78%	22%

One important objective of fiscal regime design is securing a higher proportion of after-cost revenues for the government as profitability increases. While easy to administer, this traditional sliding scale is based on volume of production 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.

The 2008 model contract however includes a "windfall tax" specifically designed to capture additional revenue when the price of oil rises. The windfall tax is assessed against the company share of profit oil that is generated from oil prices that exceed the "threshold price." There is some variation among existing PSCs with the threshold price ranging from $50 (as shown in Figure 1) to $65 per barrel and the tax rate applied on contractor profit oil above that threshold ranging from 20% to 26%. Basing the windfall tax on the price of oil gets closer to targeting profitability, though once again high cost projects may still not be highly profitable even when oil prices are high. The Block 10A PSC sets the threshold price at $50 (inflated from the contract signing date) and a tax rate of 20%.

Figure 1: Windfall Tax at $75/bbl



Following advice from both the IMF and World Bank-funded consultants,[6] the daily-rate-of-production allocation of profit oil combined with the windfall tax are replaced in the 2015 model PSC with an allocation of profit oil based on a direct measure of profitability, an "R-factor." An R-factor is simply the ratio of total project revenues to total project costs. As such, it can be considered a measure of "payback." When the R-factor is less than 1, total project costs exceed total project revenues. When the R-factor is greater than 2, total project revenues would be more than double total project costs.

Figure 2: 2015 Profit Oil Allocation

R-factor	Government's Share	Contractor's Share
Less than 1	50%	50%
1 to 2.5	65%	35%
Greater than 2.5*	[75%]	[25%]

Profit oil under the 2015 model PSC would be allocated according to the terms set out in Figure 2. Until total project revenues are greater than total project costs, the government and contractor would each receive 50%. When total project revenues exceed total project costs, 65% of profit oil would go to the government. Note that the third tranche is indicative only and would be subject to contract-by-contract negotiation.

By design, the R-factor system would allocate a higher proportion of profit oil to the government as the project becomes more profitable. In this way, the r-factor approach can replace both the DROP profit split and the windfall tax. It has also been suggested that the R-factor approach would more easily accommodate higher-cost natural gas projects.

ASSESSING CORPORATE INCOME TAX

The second main change between the 2008 and 2015 fiscal regimes relates to the applicability of corporate income tax.

Some analyses of Kenya's petroleum fiscal system mistakenly identify corporate income tax as an independent revenue stream for the government. If this were accurate, the impact would be a 30% tax on company net income. However, the 2008 model PSC, as well as the signed PSC in the public domain, are clear that corporate income tax is paid on behalf of the company from the Government's share of profit oil.

According to 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" (emphasis added). This means that the provisions of the Finance Act, and specifically the Ninth Schedule on *Taxation of Petroleum Companies*, were relevant for accounting procedures. Each year, companies are required to complete income tax returns. But they do not actually pay the income tax as reported on these returns. Instead, the tax is actually "paid" by the government from its share of profit oil.

While it might seem strange for the contractor not to actually pay its share of corporate income tax, the provision is not uncommon and exists in order to allow international companies to secure a tax credit in their home jurisdictions. In a production sharing system, the profit oil share paid to the Government is not understood as a "tax" from the perspective of other countries and is therefore not eligible for a tax credit. 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. The result is known as a "deemed" tax that has no impact on company cash flow and generates no additional government revenue.

The approach to corporate income tax changes completely according to the terms of the 2015 model contract. In future PSCs, corporate income tax would be "paid" rather than "deemed." According to Article 39(3) "It is understood and agreed that the portion of each category of the Profit Petroleum which the Government is entitled to take and receive for a given fiscal year, and which is calculated under clause 37 shall be **exclusive** of all taxes payable by the contractor" (emphasis added).

Under the terms of the 2015 model contract, the Finance Act, 2014 and the new Ninth Schedule on *Taxation of Extractive Industries* would now be directly applicable to upstream oil companies. The impact can be expected to be significant, as it will add a 30% tax on the contractor's net income to be paid from the contractor's share of profit oil. In addition, companies would be subject to a dividend withholding tax of 10%.

FINANCING COSTS

It is common for oil companies to finance at least part of their operations through debt. Interest on that debt is commonly accepted as an income tax deduction. There is however significant potential for abuse (so-called "thin capitalization"), particularly for intra-firm lending where one subsidiary of the company lends to another. In order to avoid profit shifting where high levels the bulk of costs are financed through debt at high interest rates, countries often put in place limits on both the ratio of company debt to company equity in combination with limits on the rate of interest or withholding taxes. In Kenya, for example, under the terms of the 2014 Ninth Schedule, the debt to equity ratio cannot exceed 2:1 and a 15% withholding tax is imposed.

Within production sharing systems, it is relatively unusual for interest on contractor debt to be allowed as a cost recoverable expense. This is a significant investment incentive as it means the contractor would be repaid through cost oil for the interest that they incur in borrowing for pay capital costs.

Both the 2008 model contract and the existing PSCs in the public domain provide for this investment incentive. Specifically, the Accounting Procedures (Appendix B) state "Interest incurred on loans raised by the contractor for capital expenditure in petroleum operations under the contract at rate not exceeding prevailing commercial rates may be recoverable as petroleum costs." (Section 2.12.2)

As mentioned above, in order to avoid abuse, restrictions are needed on both the ratio of debt (borrowed money) that can be used in comparison to equity (company cash) as well as the rate of interest on the debt that can be claimed. In the case of the existing Kenyan PSCs, there is no limit on the ratio of debt to equity, only the general restriction that the interest cannot exceed prevailing commercial rates.

The 2015 model PSC changes the investment incentive for companies by removing the cost recoverability of interest on borrowing and replacing it with a development cost "uplift." The idea of an "uplift" is that the government encourages investment by allowing the company to recover an additional percentage of their capital expenditures. Specifically, the 2015 model PSC states that "An amount equal to fifteen percent (15%) of the development costs" shall be cost recoverable for five years following the approval of a development plan. This means that the company recovers 115% of their development costs over the first five years. For example, if capital costs in the first year of the development plan were $200 million, the company would be allowed to recover not only the $200 million that was spent but also an additional $30 million due to the uplift. The provision then functions as an investment incentive, though in this case it is much less vulnerable to manipulation by the contractor that the recoverability of interest costs

COMPARATIVE ECONOMIC ANALYSIS

The description above of the main fiscal changes proposed in the 2015 model PSC provides only a very general sense of the actual implications for project economics and potential government revenue. Applying the existing and proposed terms to a hypothetical oil project can provide a more comprehensive understanding of the impact of the proposed changes.

An economic model has been developed for Cordaid and the Kenya Civil Society Platform on Oil and Gas (KCSPOG) in order to assess the potential government revenue from Turkana oil under the terms disclosed for Block 10A . That model has been adapted in order to compare the Block 10A terms as described above with those contained in the 2015 model contract.

It is important to note that there is no indication that the 2015 terms would ever be applied to the Turkana projects. The contracts for Blocks 10BB and 13T contain stabilizations clauses that provide for sanctity of the original fiscal terms in the signed production sharing contracts.

The comparative 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 - $65 low price and $85 high price (with $10 discount);
- Costs are: exploration ($1.8b), development ($6/bbl), operating (6% of development); pipeline tariff ($15.20);
- Existing fiscal terms based on Block 10A (60% cost recovery, interest costs recoverable, DROP profit oil split starting at 55% for government; windfall tax threshold of $50/bbl and tax rate of 20%; state participation at 20%); and,
- 2015 fiscal terms based on model PSC (60% cost recovery limit, 15% development cost uplift, R-factor profit oil split starting at 50% for government, paid corporate income tax; state participation at 20%).

The analysis below will first seek to assess the independent effects of the three main fiscal changes outlined above. It will then combine the three changes to provide an overall comparison of the 2008 and 2015 fiscal regimes.

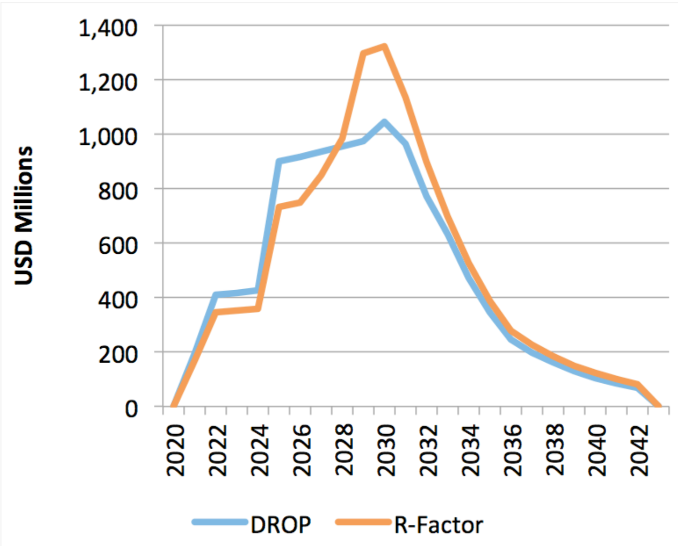
DROP v R-factor

The first change to assess is the difference between the DROP and R-factor allocation of profit oil.[7]

For the base case as set out above, the revenue impact of this change is modest. For the government, the 2015 R-factor generates marginally better results than the 2008 DROP. In terms of overall government take, the difference is about 2%, amounting to an extra $500 million on total government revenues of about $13.5 billion over the lifecycle of the project (See **Figure 3**).

At the higher price of $85/bbl, the differences are even smaller with the government take differing by less than 1%. The 2015 terms would generate an additional $500 million for the government over the lifecycle of the project, but in this case on total revenues of about $24.5 billion.

Figure 3: Comparing DROP and R-Factor



There is a modest difference in the timing of revenues between the 2008 and 2015 terms. At both prices, the DROP generates additional government revenue in the first 5-6 years before cumulative project costs are recovered and the R-factor moves into the second tranche.

The Turkana project used in this analysis can be considered a higher cost oil project due to the substantial per barrel costs of the anticipated heated pipeline. Under lower-cost high-price assumptions, the benefits to the government of the 2015 terms would increase significantly as the split of profit gas would enter the third tranche.

The modest differences in government revenue from the change between the combination of the DROP and windfall tax to the R-factor are reflected in the company position as well. While the overall revenues to the government grow under the r-factor, the timing changes help company economics and make the difference between the two sets of terms even smaller.

Table 3: Comparing Tranche Proportions

2008		2015	
DROP	Gov't Share	Gov't Share	R-factor
1-10,000 bbls	55%	50%	Less than 1
Next 30,000	60%		
Next 50,000	63%	65%	1 - 2.5
Next 50,000	68%		
Above 140,000	78%	75%	More than 2.5

The shift from the DROP to the R-factor as the mechanism for determining the sliding scale share of profit oil to be split between the company and the government generates the anticipated results. The company benefits from a larger portion of revenues in the very early years of the project while the government share of divisible revenues grows as the project becomes more profitable. The overall impact on the size of government revenues however is modest. The reason is that while the mechanisms for determining movement through the sliding scale tranches has changed, the proportions allocated to the company and the government within those tranches remains largely unchanged. Under both the 2008 and 2015 model contracts, the percentage share allocated to the government ranges from around 50% at the low end to around 75% at the high end.

Deemed v Paid Corporate Income Tax

While, the differences between the DROP combined with the windfall tax and the R-factor are very modest, the differences between a “paid” rather than “deemed” income tax are significant.

Under the base case assumptions, with an oil price of $65/bbl, the imposition of a 30% corporate income tax results in a total government take of around 80%, an increase of about 10% compared with the 2008 terms. Over the lifetime of the project, a paid corporate income tax could be expected to generate roughly at least $2.5 billion dollars in additional government revenue.

At higher prices, the imposition of corporate income tax continues to generate an additional 10% in overall government take. As the project would generate greater profit with higher prices, government revenues would increase by more than $3.5 billion over the lifecycle of the project.

From the company perspective the difference between a deemed and a paid corporate income tax is very significant. As there is relatively little difference in impact of the production sharing splits between the 2008 and 2015 terms, the addition of a new source of government revenue in the form of a paid corporate income tax results in a significant reallocation of after-cost revenues.

Development Cost Uplift

Allowing interest to be cost recoverable under the terms of the 2008 model PSC is a significant investment incentive. The provision allows for the company to recover the costs in interest that it incurs in borrowing for capital expenditures. How significant depends on the proportion of capital costs financed through debt as well as the interest rate that would be applied.

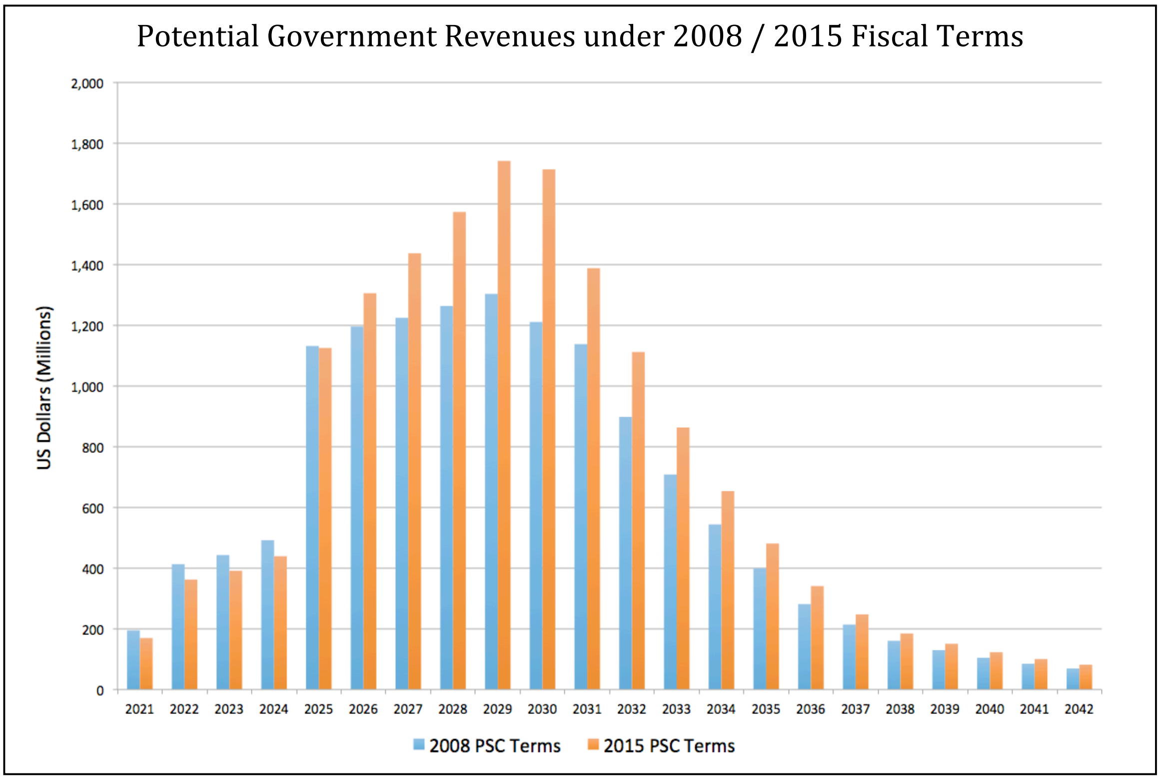
Under the base case assumptions listed above, including a debt to equity ratio of 2:1 (66.6% of capital costs financed through debt) and a 10% rate of interest, the company would be allowed to recover roughly $1.5 billion in interest costs. In terms of the impact on government revenue, allowing interest to be cost recoverable would result in a decrease over the lifecycle of the project of about $800 million.

Replacing cost recoverable interest with a 15% uplift on capital costs significantly reduces the cost to government of this investment incentive. The 15% uplift adds only about $600 million to cost recovery, less than half the amount that would be allowed under the 2008 terms. The impact on government revenue is also much less. Adding the 15% uplift only costs the government about $250 million over the lifecycle of the project.

Clearly the 2015 terms are more favourable for the government. The amount of money at stake is not particularly large, only about 0.5% of additional government take. But it is important to note that this comparison almost certainly under-estimates the potential benefits of restricting the recoverability of interest. Under the terms of the 2008 model PSC, no limit was placed on the ratio of debt to equity. It is conceivable then that the company could use debt to finance 80%, or even more, of their capital costs. Furthermore, the rate of interest could well exceed 10%, with 12% being commonly used in intra-firm financing in the extractive sector.[8] In contrast, the uplift clearly defines the economic benefit to the company and significantly limits the potential for abuse.

CONCLUSION

The combined impact of the three main changes contained in the 2015 model PSC is a significant increase in the percentage take flowing to the government. Under the base case scenario government take climbs from just under 70% to more than 80%. The difference in overall government revenue is shown below.



The challenge in fiscal regime design is to find the appropriate balance between attracting oil companies to undertake risky exploration while at the same time maximizing the benefits that would accrue to government if the exploration were to be successful.

The terms contained in the 2008 model PSC were based on a fiscal regime first designed in 1980s. Those terms do not reflect existing best practice, particularly in linking the profit split to production rather than profitability. When offered to international oil companies, the terms contained in the existing PSCs were sufficiently attractive to encourage significant, and in some cases successful, exploration. Africa Oil CEO Keith Hill is reported to have said of Kenya: 'There are not many places left on earth where you can put together an acreage portfolio like this ... Good contract terms, good support from the government – there are not that many happy hunting grounds left'.[9]

It is widely accepted that frontier countries – those without existing oil production or any commercially viable discoveries – must offer generous terms in order to attract high-risk exploration. The question facing Kenya as it establishes new terms for future production sharing contracts is whether, in the face of the discoveries in Turkana, the government should be asking for a significantly larger share in future contracts.

Two of the main changes in the 2015 model contract – the R-factor for splitting profit oil and the development cost uplift – are consistent with best practice and will contribute to modest improvements in potential government oil revenue. The third change – the shift from a deemed to a paid income tax – is of a different order. It adds an entirely new source of government revenue and has a major impact on project economics and potential government revenue. The change from a deemed to a paid corporate income tax may be appropriate in the current Kenyan context. But it is a choice that should be made deliberately, with full awareness of the significant change that it represents to the Kenya's petroleum fiscal regime.

NOTES

[1] See Silvana Tordo, Fiscal Systems for Hydrocarbons, World Bank, 2006.
[2] Daniel Johnston, reproduced in Marie Wagner, The Law, Science and Finance of International Energy Projects, Anadarko, 2013.
[3] Different systems do expose the company and Government differently to the upsides and downsides of a project in terms of timing, capital cost, production rate and reserves.
[4] As there are no significant changes in the right of the state either directly of through the National Oil Corporation of Kenya (NOCK) to an equity stake in all oil projects, this additional source of government revenue is not included in this analysis.
[5] A limit is often imposed on the total proportion of oil that can be allocated to recover costs. For existing Kenyan PSCs, this limit has commonly been set at 60%. A 60% cost recovery limit is also included in the 2015 model PSC.
[6] See Kenya Oil and Gas Sector Development: Final Report on Contractual and Fiscal Guidance, 2013 p. 3-4; and Philip Daniel, Generating Extractive Industry Revenues, Nairobi, 2013, p. 12-13.
[7] Note that the base case assumptions, with an oil price of $65/bbl, does not engage the windfall tax because of the discount of $10/bbl for oil quality and the inflation index applied to the threshold price from the contract date.
[8] See for example: "Is a 12% interest rate by Glencore to itself in Mauritania normal?" OpenOil, 2015.
[9] See Luke Patey, Kenya: An Africa oil upstart in transition, Oxford Institute for Energy Studies, 2014, p. 10.