bargate advisory

Uganda

Fiscal Implications of Uganda's New Petroleum Law

January 2013

Summary

On Friday 7 December 2012, the Ugandan Petroleum (Exploration, Development and Production) Bill was passed into Law. The Bill is currently undergoing minor amendments before the finalised document is made available to the general public.

Bargate Advisory has carried out a not-so-quick-and-dirty analysis of the key fiscal features of this new law in the context of the Ugandan petroleum fiscal regime, and has had a bit of fun carrying out the exercise.

The major elements of the fiscal regime (which reside mostly outside of the petroleum law) have been considered on their own merit, and have then been assessed as a whole package in terms of the level, incidence and responsiveness of the fiscal burden they would impose on existing and future operators. We hope you have as much fun reading this report as we have had preparing it.

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Backdrop

So the Ugandan Petroleum (Exploration, Development and Production) Bill has been passed into Law, and we managed to lay our hands on a copy of the Bill – the finalised copy of the Law is not out yet. As was done with the Nigerian Petroleum Industry Bill ('PIB'; if you have not read it yet, please have a look; it is still on our website http://www.bargateadvisory.co.uk/#!reports/ck0q), we decided to have a go at reviewing the new legislation in the context of fiscal aspects of Uganda's upstream petroleum sector.

Why are we doing this?

We are not bored, yet. We have followed oil and gas exploration activity in Uganda for a while now, and determined that the discoveries made in the Albertine Graben region of the country have not only changed the game for Uganda's economy and polity, but also caught the attention of global capital. And that takes some doing, especially after the global recession and all the naughtiness that caused it.

The aim of this note is therefore to analyse the main economic features of the new law and determine their implications on the existing fiscal package for petroleum exploration and production in Uganda.

How have we analysed this?

Bargate has carried out a not-so-quick-and-dirty analysis of the key features of this new law, and as you would imagine, a bit of fun has been had carrying out the exercise. The major elements of the fiscal regime (which reside mostly outside of the petroleum law) have been considered on their own merit, and have then been analysed as a whole package in terms of the level, incidence and responsiveness of the fiscal burden they would impose on existing and future operators.

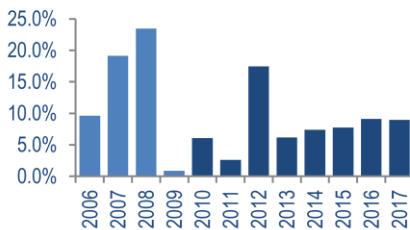
A bit of a disclaimer

While we are confident that our analysis is based on internally consistent parameters and employs a strong level of rigorous assessment, our views are based entirely on the data we have independently sourced and verified where necessary. Also, we are still waiting for the finalised document (the actual Law) so there is a slight chance some sections of the new law could have been moved around, just to make things more fun. So, we are not saying you should not place bets based on our analysis. But we are also not saying you should. Finally, we are not lawyers. We therefore will not always recite specific sections of the legislation before providing analysis. Sorry.

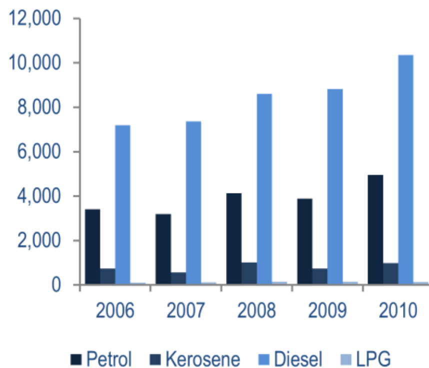
Uganda at a glance

Population: 34.5 million
GDP (current prices, 2011 est.): US$17.43bn

Annual GDP Growth
(Source: IMF; 2010 onwards estimated**)**



Total Oil Consumption (2010): 16,430 b/d
(Source: Uganda Bureau of Statistics)



Did you know?
John Akii-Bua (1949 – 1997) was the first ever Olympic gold medal winner from Uganda, setting a world record in the 400m hurdles event at the 1972 Games in Munich. There is a fascinating story about him on YouTube. Have a look, preferably not during office hours.
http://www.youtube.com/watch?v=LY2s6ihFrvk

Main economic features of the new law

Background

It really is just an enabling legislation; the meaty stuff is still in other odds and sods.

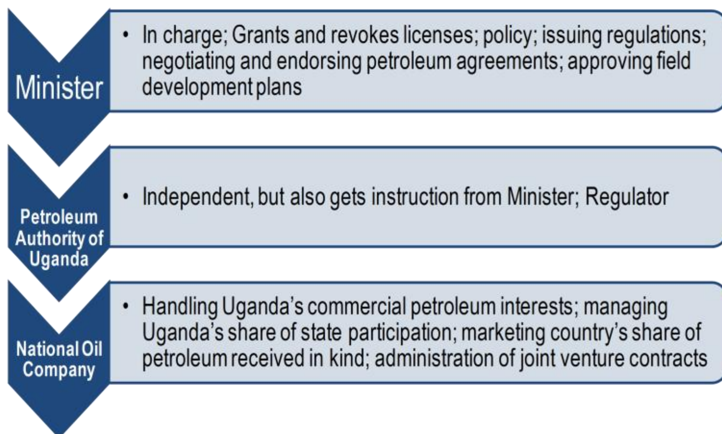
We started off by asking what aspects of the existing petroleum legislation the new legislation was intended to fix. We found some text to this effect in the explanatory memorandum attached to the Petroleum (Exploration, Development and Production) Bill which was submitted to Parliament. We believe very strongly in equal opportunity, so we thought to provide you with an equal opportunity to be as bored as we were from reading it:

The explanatory Memorandum sets out the policy and principles of the new legislation, the defects in the existing law, the remedial actions taken and reflected in the new legislation, and a summary of the provisions in the new law.

"*The objects and principles of the Petroleum (Exploration, Development and Production) Bill, 2012 are- to give effect to article 244 of the Constitution; to regulate petroleum exploration, development and production; to establish the Petroleum Authority of Uganda; to provide for the National Oil Company; to regulate the licensing and participation of commercial entities in petroleum activities; to provide for an open, transparent and competitive process of licensing; to create a conducive environment for the promotion and exploration of Uganda's petroleum potential; to provide for efficient and safe petroleum activities; to provide for the cessation of petroleum activities and decommissioning of infrastructure; to provide for the payment arising from petroleum activities; to provide for the conditions for the restoration of derelict lands; to repeal the Petroleum (Exploration and Production) Act, Cap 150; and for related matters.*"

Our initial assessment is that the new legislation does not change much as far as the fiscal arrangements are concerned. It is essentially an enabling legislative instrument which attempts to make more of an impact with regard to the institutional arrangements than with how the fiscal carve-up is, well, carved.

Institutional arrangements for the regulation of Uganda's petroleum sector



Licensing cycle

The table below summarises the petroleum licensing structure as defined in the new legislation. Three major licenses can be granted over the course of a petroleum exploration and production life cycle.

Uganda's petroleum licensing cycle

Licence type	Reference	Duration	Renewal	Comment
Reconnaissance Permit	Section 49	18 months	Doesn't say. No renewal presumed	Application made to Minister; granted by Minister within 90days of application. Data to be given to Minister free of charge.
Petroleum Exploration Licence	Section 53	2yrs	2yrs; 2 renewals	Minister announces bid round; 3-month application period. BUT, Minister may also take direct applications in exceptional circumstances, which are listed in the Act. Application to Minister; 180days' processing time. Minister grants licence.
Petroleum Production Licence	Section 69	20yrs	5yrs; additional period depending on circumstances	Application made to Minister; granted by Minister. 180days' turnover time for processing. Clearly set criteria for granting applications.

Taking the number of allowable renewals into consideration, the new law clearly allows for a maximum licensing cycle of 32.5 years. The minimum licensing cycle is 23.5 years, although it is difficult to contemplate using only two of those years to complete a rigorous exploration programme. The only area of some ambiguity lies in the Reconnaissance Permit, which carries a duration of 18 months. As there is no clear statement as to whether or not renewals are permitted, we assume that there is none in this case.

Acquisition of exclusive rights

We thought this aspect of the legislation was worth mentioning. Section 135 requires the owner of a petroleum production licence to obtain a lease of the land and meet all the necessary conditions for obtaining such a lease, if he/she requires the exclusive use of the area (in whole or in part).

Now, our understanding is that this process – i.e. securing the land to achieve exclusivity – is not guaranteed by the Government. Therefore there is a fair bit of discussion to hold with the landowner, which also means quality time spent understanding Uganda's Land Act. Our best wishes.

Transfer of licence

Things start to get a bit lively here. Section 84 makes specific provisions pertaining to the transfer of licences, such as the standard requirement for notification to be made to the Minister, and the detailed explanation of what constitutes a transfer of licence, which is particularly useful.

However, there is no mention of the financial consequences of such transfers if there is a capital gain made from them. Not many lessons appear to have been learnt from the Tullow-Heritage-Uganda Revenue Authority 'misunderstanding' then. If they had been learnt, there would be tighter provisions in the law at least hinting that lunch will be held with the taxman if a transfer of licence or rights resulted in some profit or capital gain. In similar vein, there would be deduction allowances made available to the acquirer for tax purposes. Perhaps all this will not be missed in subsequent agreements or in the Model PSA when it is prepared.

In July 2010, Heritage Oil sold its stake in exploration licences in the Albertine Rift to Tullow Oil (Heritage Oil Plc, official Website http://www.heritageoilplc.com/uganda_heritage.cfm). The deal was reportedly valued at US$1.45 billion. The Uganda Revenue Authority promptly requested 30% in capital gains tax. Heritage disputed it, their argument being that there was nothing in the existing petroleum law or the Production Sharing Agreement (PSA) they signed which required them to pay. It got quite messy before it got resolved. The taxman doth rule.

Decommissioning plan + decommissioning fund

For reference purposes, the specific sections dealing with these provisions are 109 and 110. These sections have clear requirements for a detailed decommissioning plan to be submitted to the Uganda Petroleum Authority (the Authority) either before a petroleum production licence or facilities licence expires/is surrendered/ before the use of a facility is terminated permanently.

We find it curious that the requirement is not for payments to be made much sooner. We would expect the requirements for contribution towards a decommissioning fund to commence from production.

The current arrangement does have positive cash flow impact, albeit minimal, in that the cash flow requirements for contributions toward decommissioning are postponed to the latter – probably more profitable – stages of the project life.

State participation

The key provision pertaining to state participation as a fiscal tool in Uganda's petroleum fiscal regime can be found in Section 121 of the legislation. We cannot help but feel that some excitement has been dodged here. This is because all the section says is that the Government may participate through acquiring participating interest or through a joint venture, and the Minister shall specify the Government's share.

There is no specific reference to the limit to which the Government can participate. This is not such a big deal. Most petroleum fiscal regimes with state participation usually have the requirement in the law, and then specify the terms in a model agreement or in the petroleum regulations. There is reference in the legislation as to where the Minister will state the state participation parameters (in the contract).

LIBOR – London interbank offered rate. Like you did not know what it was already. There has been some drama with the fixing of this rate but that discussion is probably worth a report in itself.

In terms of the level and type of state participation, we have considered previous petroleum agreements entered into by the Government of Uganda and understand that the maximum level of state participation is 15%. We also understand this level of state participation to be carried through to production, and the licensee will recover all costs of carrying the Government to production, in addition to an interest (LIBOR); all this through the cost recovery process.

Royalty on petroleum

Royalty regime from previous agreements

Gross total daily production (b/d)	Royalty
Not more than 2,500	5%
More than 2,500 but less than 5,000	7.5%
More than 5,000 but less than 7,500	10%
More than 7,500	12.5%

The specific reference for the royalty provision in the new Law is Section 151. It imposes an obligation on the licensee to pay royalty to the Government. This payment could be in cash or in kind. There is no specific reference to the type of royalty (for example, if it is based on the gross value of production, or if it is a function of varying production thresholds, or if it is linked to a rate of return) in the legislation. This is not abnormal.

There is reference to a petroleum agreement where the specifics of the royalty regime will be applied. We are not aware of a current model petroleum production sharing agreement (PSA), but we have seen the royalty rates agreed on five previous occasions, and there is remarkable consistency in the latter four. We are confident that these are the royalty percentages and production thresholds that will be inserted into the Model PSA whenever it is ready.

Annual rentals from previous agreements

Rental categories	US$/km^2
First exploration period	2.50
Second exploration period	5.00
Third exploration period	7.50
During production	500.00

1997 annual rentals in real terms

Rental Categories	US$/km^2	Today's Money
First exploration period	2.50	1.83
Second exploration period	5.00	3.65
Third exploration period	7.50	5.48
During production	500.00	365.11

Annual fees

Section 152 requires the holder of a petroleum exploration or production licence to pay annual fees which will be prescribed in the regulations. These fees mainly relate to surface rentals, training and research.

The annual surface rentals have been consistent in the latter four of the five PSAs we have looked at, which is remarkable. There is, however, potential for this consistency to change in the subsequent agreements or even in the Model PSA when it is ready. Why, you may ask. Well, the agreements we refer to were made over a 10-year span between 1997 and 2007. A lot has happened to the value of the US Dollar since then. US$2.50 in 1997 is worth US$1.83 today in real terms. And US$500 in 1997 is worth US$365.11.

As annual rentals constitute a relatively tiny part of the potential revenue to be generated by the Government, not a great deal of attention is usually paid from an analytical viewpoint to how they are prepared. Maybe some attention should be paid to this, as there is a currency valuation risk which usually works to the disadvantage of the host government. Someone will notice it.

The same analysis applies to the annual training requirement. We understand the training requirements in the latter three of the five agreements we have considered to have been US$75,000 during exploration and US$200,000 during production.

"In this section, 'signature bonus' means a single, nonrecoverable lump sum payment by the licensee to the Government upon the granting of the petroleum exploration or production licence."

- Section 153 (2)

Signature bonus

Section 153 of the new legislation requires a licensee to pay a signature fee upon grant of an exploration or production licence. The section further describes what a signature bonus is, which is always helpful. The section also indicates that the signature bonus will be prescribed by regulations.

Signature bonuses tend to vary widely – and wildly – from fiscal regimes of one jurisdiction to another. The tendency for fiscal regimes which use this fiscal instrument is to reflect the level of geological prospectivity in the signature fee to be paid. So a frontier jurisdiction seeking a US$900million signature bonus will probably be laughed at, while other known jurisdictions like Iraq and Angola will be looking to push such fees beyond the US$1billion mark.

Signature bonus comparison

Signature bonus paid	Year	US$m
Uganda – EA1, EA3A	2004	0.3
Angola - Sinopec	2006	1,100.0
Uganda – Heritage/Tullow	2007	0.3
Iraq – BP, CNPC	2010	500.0
Indonesia - Total	2011	5.0

We understand that the latter two of the five petroleum agreements were signed with bonuses of US$300,000 respectively. The one before this was US$200,000, and there were no bonuses at all in the earlier two.

What is unclear from both legislation and the petroleum agreements is whether or not the signature bonuses are cost-recoverable. It will be helpful to clarify this in the Model PSA or in prescribed regulations.

We do not expect the signature bonus requirements to increase substantially in the medium term. This is purely because of the fact that Uganda is at a comparatively early stage of the development of its petroleum sector. In addition, work programme commitments tend to carry more weight than signature bonuses as far as host governments of frontier jurisdictions are concerned. This depends, however, on the policy objectives of the host government. Short-term objectives and 'other pressures' make

signature bonuses very attractive, while policies geared towards rapid exploration and exploitation of petroleum acreage focus more on work programme commitments. This is not to say that both cannot be aggressively pursued.

Cost recovery

There is no specific reference in the new legislation to the type of contractual arrangement between the Government and licensees. However, based on the agreements we have looked at, Uganda operates a production sharing system.

According to the existing PSAs, all exploration, development, and operating costs can be recovered from 60% of gross production (70% for gas) after deduction of royalty. This includes the costs of the Government or its nominee (if there is a state participation element).

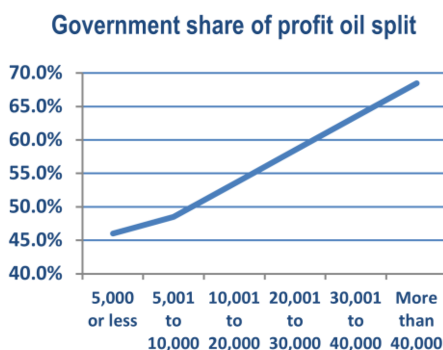
In addition, ring fencing applies. All recoverable costs are ring-fenced around each contract area, and cannot be consolidated.

There is nothing particularly remarkable about the cost recovery provisions; other than that, the 60% limit can be viewed as comparatively tight. More generous regimes have higher cost recovery ceilings (70%-80%), the consequence being positive on the licensee's cash flow.

Production sharing

Again, this bit is not referred to in the legislation, although the terms are clearly set out in previous agreements between the Government and other licensees. The profit-oil split is set out on an incremental basis in favour of the Government based on daily production thresholds.

Production sharing split



Production b/d	Government share	Licensee share
5,000 or less	46.0%	54.0%
5,001 to 10,000	48.5%	51.5%
10,001 to 20,000	53.5%	46.5%
20,001 to 30,000	58.5%	41.5%
30,001 to 40,000	63.5%	36.5%
More than 40,000	68.5%	31.5%

There are two issues we have with the profit-oil split, but we will start off with what we like about it. The production share percentages for the Government are progressive, in that they increase as production volumes increase. This means that the Government should be able to capture economic rent from increased economies of scale as a result of production-volume-linked profitability increases.

Now, for what we do not like. The first issue we have is that it is unclear whether the above rates apply to gas. This is typical of many sub-Saharan African petroleum legislative and regulatory arrangements. There is usually not a lot of detail when it comes to what to do with gas. Most contractual provisions for oil say something along the lines of "ok so let's come back and talk about it if you find gas. Run along now". Greater detail pertaining to arrangements for gas may not be absolutely necessary in the case of

Uganda, but it would be useful to have some clarity on what provisions exist for natural gas.

The second issue we have is that we note a consistency problem as far as the profit production splits are concerned. Of the five agreements we have looked at, the most recent ones have the same share percentages as stated in the table and chart above. This is not the case with the previous three. What struck us was that two agreements were signed in the same year but with different production sharing splits. Let's have that Model PSA out as quickly possible then, eh?

Taxation

"All central, district administrative, municipal and other local administrators' or other taxes, duties, levies, or other lawful impositions applicable to the Licensee shall be paid by the Licensee in accordance with the laws of Uganda in a timely fashion."

- Article 14 of Heritage 2007 PSA

Curiously, the new legislation does not say very much in this regard. In fact, we have forgiven ourselves already for thinking that nothing is said in the legislation at all. Section 154(2) does mention that the discharge of a licensee's obligations with regard to a number of things – income tax inclusive – shall be made in accordance with the licence. Now, we were really hoping to not be sent on a wild goose chase trying to understand the Ugandan tax system. We shall not cause distraction by delving into the pitfalls of hope and hoping.

We have looked at the Ugandan Income Tax Act to see what provisions are applicable to petroleum operations. Specifically, we considered Section seven (and Part II of the Third Schedule) which makes provisions for general corporate income tax and specific taxes for mining operations. For our analysis, we have deemed the applicable tax rate for petroleum exploration and production operations in Uganda to be 30%, the same as any other industry other than mining exploration and production companies.

We are very curious about how the allowable and non-allowable deductions are treated. We believe there is a gap here. Section 36 of the Income Tax Act makes for specific allowable deductions pertaining to minerals. There is none for petroleum. The beauty of the production sharing system is that there may be little to worry about after going through the cost recovery process. The beast of it also lies in this very advantage. It must be robustly defined to clarify what costs are deductible, and what are not. These costs must also be consistently articulated for ease of application by the taxman. We have not seen evidence of this in the law or the agreements.

Summary of Uganda's petroleum fiscal regime – major instruments

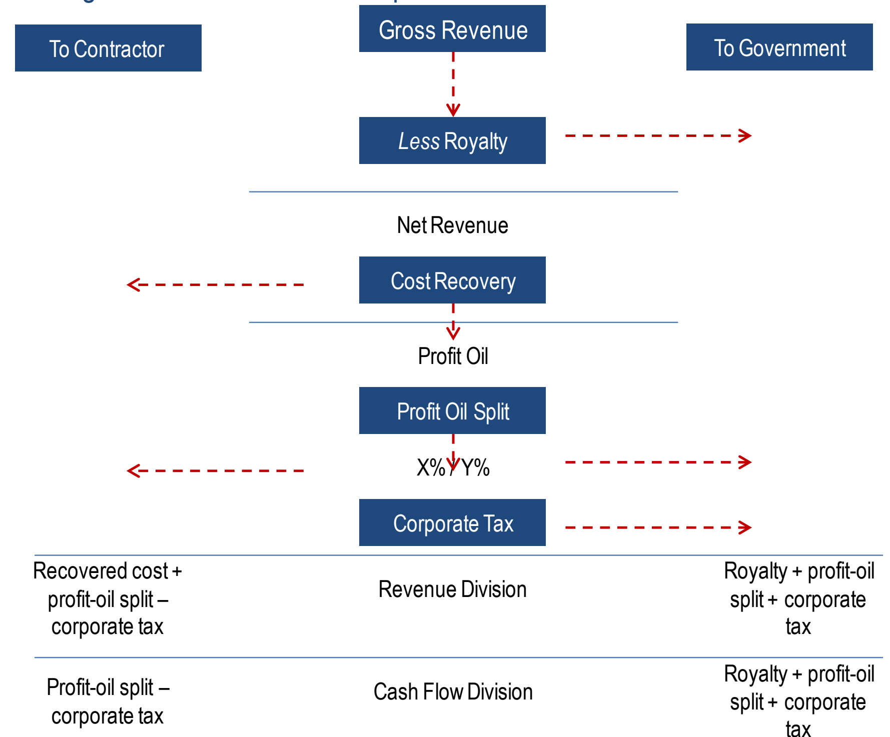
Fiscal Instrument	Source	Rate	
Annual Fees	Section 152	1st Exploration Period	US$2.50/$km^2$
		2nd Exploration Period	US$5.00/$km^2$
		3rd Exploration Period	US$7.50/$km^2$
		Production Period	US$500.00/$km^2$
Signature Bonus	Section 153; PSA	US$300,000	
Royalty	Section 151; PSA		
		Gross daily production b/d	Royalty
		2,500 or less	5.0%
		2,001 to 5,000	7.5%
		5,001 to 7,500	10.0%
		More than 7,500	12.5%
State Participation	Sections 121-124	Maximum 15% carried	
Cost Recovery	PSA	60% oil; 70% gas	
Production Sharing			
	Production b/d	Government share of profit production split	Licensee share
	5,000 or less	46.0%	54.0%
	5,001 to 10,000	48.5%	51.5%
	10,001 to 20,000	53.5%	46.5%
	20,001 to 30,000	58.5%	41.5%
	30,001 to 40,000	63.5%	36.5%
	More than 40,000	68.5%	31.5%
Taxation	PSA; Income Tax Act (Section 7; Part II of Third Schedule)	30%	

What's Bargate's View?

Our view is that nothing in the new law has changed the facts of the existing petroleum fiscal regime to change our minds about the existing petroleum fiscal regime.

The chart below is indicative of the sequence of fiscal impositions on a typical new entrant. It summarises the establishment of net project profits under a simplified version of Uganda's production sharing system.

The Ugandan PSC fiscal carve-up



Bargate's general assessment is that the Ugandan fiscal regime does not change at all under the new legislation, especially in terms of overall economic impact. As was the case with our review of the Nigerian PIB, we warn that we have not carried out a full scale modelling exercise of all the potential scenarios made possible by the various provisions within the Ugandan legislative and regulatory regime, as it is not necessary for this exercise. For example, our analysis has not considered that the Government could exercise a 15% participatory interest in the new venture. We are happy to discuss conducting such a full scale exercise, of course.

The table below is a summary of what we think about the major fiscal terms in the Ugandan fiscal system, as provided for in the new law and existing contractual arrangements. For those readers who are familiar with our review of the Nigerian PIB, feel free to ignore the following lines and go straight to the table. Note however, that we have added a few more criteria, just to make things more fun. For the readers who have not read our PIB report, the following table is essentially a scorecard indicating our take on eight assessment criteria, ranging from clarity of definition within the new legislation and contractual arrangements to fiscal progressivity.

We have classified our assessment scores as follows:

- Yes, if it meets our criteria;
- No, if it does not;
- Not at all, if it really does not;
- Not quite, if it does not but could, depending on who you ask;
- Gosh no, if it really, really, does not;
- Fair;
- Strong;
- Tight, if we find the terms to be stringent by international standards; and
- Depends, if it requires the alignment of other factors to meet our criteria.

What constitutes a sound petroleum fiscal regime? Well, we find that one which happily coasts through the eight principles listed in the table below usually sets itself up for a comparatively bright start.

Ugandan petroleum regime fiscal instruments scorecard

	Clarity of definition	Simplicity	Built-in adaptability	Tax leakage potential	Tax neutrality	International competitiveness of licensee take	Low front-end, profit-based incidence	Fiscal progressivity
Overall	No	Not quite	Fair	Fair	No	Tight	No	Depends
Signature bonus	Yes	Yes	No	No	No	Depends	Gosh no	Gosh no
Royalty	Yes	No	Depends	No	No	Fair	No	No
State participation	Yes	Not quite	No	No	No	Tight	No	Depends
Cost recovery	Yes	Yes	No	No	Depends	Tight	Yes	No
Production sharing	Yes	Not quite	Yes	No	Yes	Fair	Yes	Yes
Taxation	Not at all	Yes	No	Strong	Yes	Depends	Yes	No

Overall, we find that the new legislation does not lend sufficient clarity to the definition of only a few fiscal instruments, chief amongst which is corporate income tax. We understand that it is essentially an enabling legislation, but in the absence of a Model PSA or up-to-date petroleum regulations, a bit more information would not hurt.

With regard to the simplicity of the entire package, we have selected the "not quite" score. This is due to a number of issues, some of which include the lack of clarity on what deductions are allowable or not, and little niggly bits like what the specific production sharing rates are for gas.

We have given an assessment finding of "no" for tax neutrality, which may be a bit harsh. But signature bonuses, royalties, state participation and a tight cost recovery limit tend to make it difficult to give any other assessment.

We are happy with the progressive nature of the profit production sharing scheme within the fiscal regime. As mentioned earlier, what this means is that the Government's share of the spoils increases as profitability increases. This is linked to increases in economies of scale from higher production. We are also pleased that it is something the private investors appear happy with, on evidence of the last three agreements signed. However, we have apportioned a score of "depends" because these increases make no difference in relation to upward price movements.

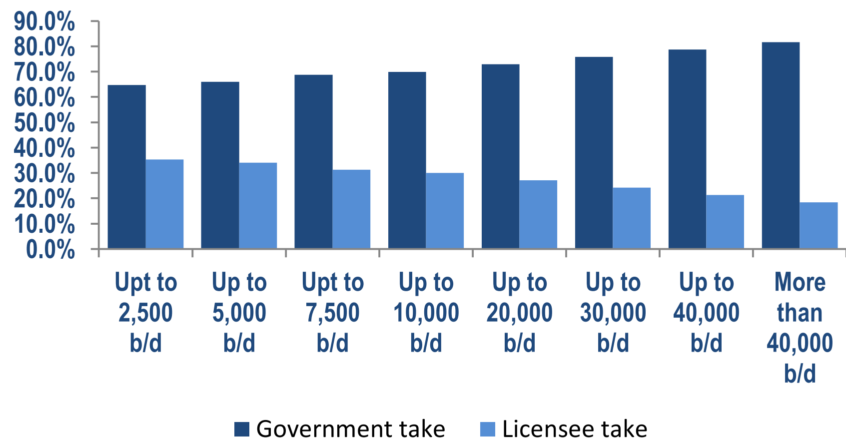
Level of fiscal burden

We will continue to include the following statement in any report we prepare on fiscal regimes, because of its sheer importance. The level of fiscal burden is crucial to the competitiveness of any petroleum fiscal regime. If it is too high, it puts pressure on the economic feasibility of marginally profitable ventures, and even frontier exploration and production. If it is too low by international standards, it bears the risk of becoming politically difficult for a government to sustain it. This is especially the case for acreages considered to be highly profitable, as well as mature jurisdictions for which the geological prospectivity is well known.

Taking all the fiscal impositions into consideration, we find – on rough workings – the level of fiscal burden on the company to be around 64.7% government take for marginally profitable projects. We have defined this level of profitability using the production thresholds set out in the fiscal regime itself for the imposition of royalty and for the distribution of profit production split. So for a production level of an average of 2,500 b/d, we have termed it marginally profitable; and for a production level of more than 40,000 b/d, we have termed it highly profitable.

This level of government take increases to about 81.6% using fiscal terms for production levels of more than 40,000 b/d, which is interestingly almost the same government take percentage we worked out in the Nigerian PIB review. This compares with other international comparators such as Norway, Iran, Kuwait and Egypt (average of about 85%).

Level of fiscal burden with no state participation



It may raise the question of whether or not this level of fiscal burden is sustainable for Uganda to impose, but there are two factors to consider in this regard. First, our assessment is that the oil price outlook in the medium to long term is likely to favour increased appetite for E&P activity in previously unattractive jurisdictions. This would play a part in shifting the bargaining powers to the host governments who are getting much better at setting tighter terms and negotiating good deals. Second, Uganda is already three thriving contracts into this regime; albeit one of them with slightly softer profit production split terms than the latter two.

As is normally the case with straight-cut petroleum fiscal regime modelling, it is important to point out that a full modelling exercise is likely to account for variations to the level of fiscal burden of between 5%-7%. This is especially the case as we have not factored in state participation into our analysis, as well as a full-fledged production, cost and debt profile. For the purpose of this exercise however, we have only carved up the fiscal impositions on the barrel as demonstrated in the illustration above. Nonetheless, our analysis provides a pretty sound indication of the level of fiscal burden.

Incidence of fiscal burden

The company's payback period and rate of return on investment are best determined when the level of fiscal burden is combined with its incidence. The impact of the fiscal impositions on cash flow positions are as important as the weight such impositions place on the licensee.

Although the level of fiscal burden under different regimes may turn out to be the same over the life of the project, the impact on the company's payback period and rate of return may differ, thus potentially significantly changing the competitiveness of the fiscal regime.

In order to improve the competitiveness of the fiscal regime, we find useful such fiscal tools as accelerated depreciation and import duty exemptions. These help to delay the incidence of fiscal burden to the latter years of the project life, and free up some cash flow for the company.

This is why we are a bit concerned about the manner in which the allowable deductions are determined for the imposition of tax. And this is where we will pretend to be lawyers, only briefly. The new legislation is clearly lacking as a signpost for directions on where to go for tax information. The Income Tax Act says nothing on allowable deductions for the purpose of computing corporate tax for petroleum exploration and production activity. We do not have a model PSA to work with. All we have are provisions from previous agreements which say that all costs can be recovered in the cost recovery scheme. Right. So does this include the cost of exotic pets imported from the home country of the licensee's CEO's second wife? We remain loyal to the fun side of our analysis.

This said, not a lot is missing in this regard. There appears to be an implicit assumption that the recoverable costs will be reasonable and made known to the Authority to furnish the Uganda Revenue Authority or other relevant agency for tax purposes. If this is the case, there is potential for a positive implication on the payback period and the rate of return on investment.

Responsiveness of fiscal burden

We have run a quick test on the Ugandan petroleum fiscal regime to identify potential red flags that could cause the Government to drag everybody back to the negotiation table and either rip up or revise contracts, laws or regulations. We find that a usual suspect lies in the realisation that more economic rent (than was originally agreed) can be captured from increased production revenues generated from an upside e.g. from sustained higher-than-expected oil prices. This tends to not look very good for all the investment climate stability indices out there. We do not have one yet, but we are tempted.

If the fiscal regime is regressive, i.e. the level of fiscal burden reduces as the project becomes more profitable, chances are that a re-negotiation of terms is around the corner. If the fiscal regime is automatically progressive, i.e. there are built-in mechanisms that allow for the level of fiscal burden to react in the same direction as the level of profitability, the likelihood of contractual or legislative interruptions is reduced.

We assess the Ugandan fiscal regime as supported by the new legislation to be progressive, just. The increasing profit split to the Government as production levels increase is evidence of this. However, there is no other in-built mechanism to capture shifts in overall government share of profitable ventures if other sources of profitability (production ramp-up and cost flattening or reduction) are held constant except prices. The fiscal regime is responsive to alteration of production levels, but not to price.

This is not a cause for serious bother, as many proponents of the production sharing system would argue that the opportunity for any gains in price upsides can be realised in the Government's own share of production.

So, what next?

We would have preferred to have the actual finalised copy of the new law to work with. Not that this would make a world of difference to our analysis of the fiscal regime, especially as the essential thrust of the law seems to be to provide a more sound enabling framework for the management of petroleum exploration and production activity in Uganda.

It is not quite the finished article in terms of the entire suite of necessary legislative, regulatory and institutional arrangements for a sustainable push towards the development of Uganda's oil and gas resources, but it is a very good start in our view. The ability of the Government and current licensees to so far agree with not-a-lot-of-hassle on terms of engagement also helps.

We feel amendments must be made to the Income Tax Act to cater for upstream petroleum activity as has been done for the mining sector. We also feel that regulations must follow this new law. It will be interesting to see how the Petroleum Authority of Uganda kicks off, now that it has legislative licence to perform.

Finally, things will need to get a bit more transparent. A good starting point will be to roll out a Model PSA as soon as possible, which will flesh out a lot of missing bits in the regulatory scheme of things, such as the fiscal regime itself.

Bargate is happy to simulate the more detailed economic models of full-project-life-cycle scenarios in order to ascertain, with more degrees of confidence, the findings from this preliminary exercise.

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