Stabroek Oil Field, Guyana

Narrative Report

Johnny West, March 2018

OpenOil

Context

Stabroek is the first oil field to be developed in Guyana despite interest and exploration in the country since the 1940s. ExxonMobil signed an agreement in 1999 but exploration did not start until 2008. The first discoveries were announced in 2015 and, as several more discoveries were made, the agreement was revised in 2016. ExxonMobil is operator with a 45% stake through local affiliate Esso Exploration and Production Guyana Limited, and the other consortium partners are Hess Corporation (Hess Guyana Exploration, 30%) and Nexen (CNOOC Nexen Petroleum Guyana Limited, 25%).

Over 2016 and 2017, the agreement became controversial in Guyana and the contract was published by the government at the end of 2017 to allow public scrutiny. The financial model and this accompanying narrative are based on that contract, as well as public statements and media reports giving details of reserves, development lead time and costs.

The analysis shows that Guyana's share of profits is low, not only compared to major producers but also to terms agreed in other frontier provinces at a time when they were early stage producers. Government take, or what the IMF calls Average Effective Tax Rate, stands at 52% at today's (March 2018) Brent price and the development plan for 450 million barrels of oil.

Stabroek is also likely to experience considerable reserves growth. As of March 2018 ExxonMobil were stating 3.2 billion barrels of recoverable reserves, and several stages of development are now being considered. Liza Phase I, now underway, is due to produce first oil in 2020, using a Floating Point Storage Operation (FPSO) and reaching a plateau of 100,000 barrels a day. Liza Phase 2 would deploy a second FPSO and could produce an additional 200,000 barrels a day[1]. The base case is modelled only against Liza Phase 1 and a field size of 450 million barrels.

Executive Summary

- Stabroek will yield Guyana at least $5 billion life of project.
- Government take 52% (today's prices), low even for frontier provinces.
- The main fiscal mechanisms – royalty and profit split - are "flat", meaning they cannot capture superprofits.
- Contractor rate of return is 20% (today's prices).
- Field size is currently 450 million barrels but could grow considerably, pushing Contractor profits higher.

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[1] http://corporate.exxonmobil.com/en/company/worldwide-operations/locations/guyana/about-us/project-overview

Even under conservative assumptions, Stabroek will transform Guyana. Government revenues could hit a billion dollars a year by 2024 – more than the entire current government budget.

Key Features & Assumptions

The model has been built according to the FAST financial modelling standard[2]. The model is published under Creative Commons license. All data and assumptions are explicit and sourced.

Economic Parameters	
Life of field	2020-2040 (production)
Production profile	450 million barrels baseline scenario, with 300 "impairment" and 750 million barrel "reserves growth" scenarios, plus user defined field level.
	Schematic production profile: 1 year ramp up, 6 year plateau, 12.5% annual decline.
Forecast price	EIA Reference Price to 2050, Feb 2018
	Constant USD per barrel, user-set parameter
Cost	$500 million of exploration cost
	$4.4 billion of development cost (ExxonMobil published estimate)
	$980 million decommissioning costs
	$3.7 billion operating costs (fixed and variable)
	$0 currently modelled project finance costs

The model constructs future revenue flows in nominal figures, starting from a production profile compiled from the development target of 450 million barrels in Liza 1. Estimates for the Brent benchmark oil have been used since no information is available on a premium or discount for Stabroek crude. The model takes this total and allocates it to a stylised production profile, beginning in 2020, ramping up to a plateau in the mid-2020s and thereafter declining at 12.5 percent a year. Development costs of $4.4 billion for this stage are taken from public statements by ExxonMobil, decommissioning is expressed as 20% of that, exploration is assumed at $500 million given the size and location of work, and scale reported in media outlets. Operating costs are estimated at $50 million a year fixed and $6 variable per barrel, or the equivalent of $8.30 per barrel, in line with estimates in similar projects. There are currently no project finance costs estimated, though it should be noted these are allowable as cost recovery, and if a significant amount of capital expenditure was borrowed could amount to hundreds of millions of dollars.

[2] www.fast-standard.org/the-fast-standard/

Fiscal Regime	
Royalty rate	2% of gross sales
Profit Petroleum	Flat 50%/50% split of profit oil
Cost Recovery	75% ceiling
Income tax	Paid on behalf – no Contractor obligation
Exemptions	Dividend Withholding Tax, Interest Withholding Tax, Import Duties, VAT
Miscellaneous	Signature Bonus, surface rentals, fees

Stabroek's fiscal regime is relatively straightforward. The key revenue stream for the government is a 50% split of profit petroleum[3], which is derived after costs have been recovered, up to a ceiling of 75% per year of turnover[4], and a royalty of 2% has been subtracted[5]. A signature bonus, surface rentals and fees add another $51 million over the life of the project.

The Contractor is exempt from Corporate Income Tax, which functions on a "pay on behalf" system. There are also broad exemptions for withholding taxes, import duties on entry of capital goods, and value added tax.

Stabroek has been compared to seven other frontier province projects in Africa and Asia using an adapted version of the IMF's FARI model. This operates at a high level without entering into detailed questions of project-level interpretation and some schematic assumptions, producing comparative statistics on government take which are indicative.

[3] 2016 Petroleum Agreement Article 11.4
[4] 2016 Petroleum Agreement Article 11.2
[5] 2016 Petroleum Agreement Article 15.6

Findings

Stabroek yields relatively low government take by almost any standard. Under a $55 constant price assumption and 450 million barrel field size, the government would receive $7.79 billion over the life of the field, representing 52% of positive cash flows.

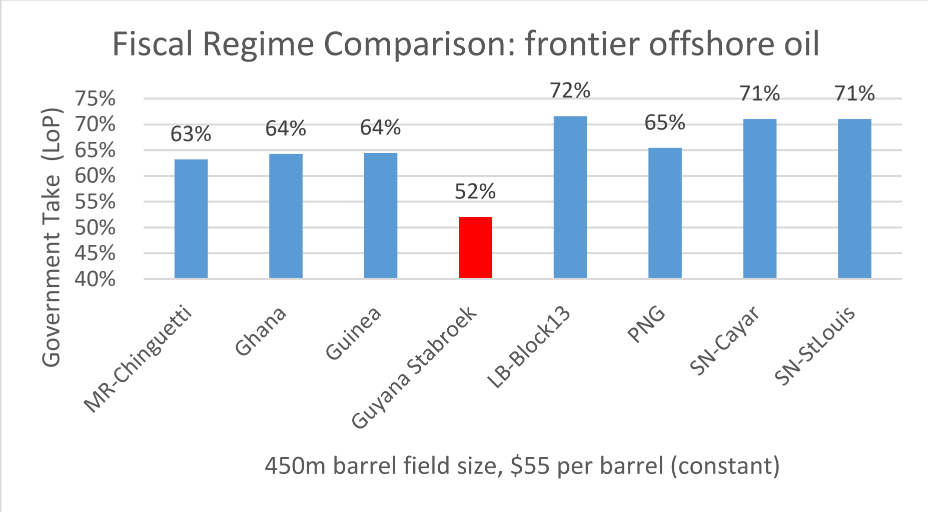


Figure 1: Comparative NPV0 government take

This is considerably lower than a general rule of thumb of 60% to 80% government take in oil projects, and also from a range of frontier projects in Ghana, Senegal, Papua New Guinea, Mauritania and Guinea, which were comparable at the time of signature. A more detailed description of the methodology is laid out in the Annex to this report.

Moreover the regime is not progressive, but remains flat, as is consistent with the royalty and profit split mechanisms, under increasing profitability from both price and field size. For example, at 750 million production and a price of $80 per barrel, Guyanan state revenues triple to $24.76 billion. But government take actually drops fractionally, to 51%.

Contractor Internal Rate of Return (IRR) stands at 19.6% after tax at $65 constant oil price and 450 million barrel field size. But this starts to appreciate rapidly as field size goes up. ExxonMobil statements refer to over 3 billion barrels of recoverable reserves. At even a third of that, a field size of a billion barrels, Contractor IRR rises to 39.7%. This would need to be modified by assumptions for additional capital expenditure, but the timing and potential scale of those extra costs still means IRR would rise.

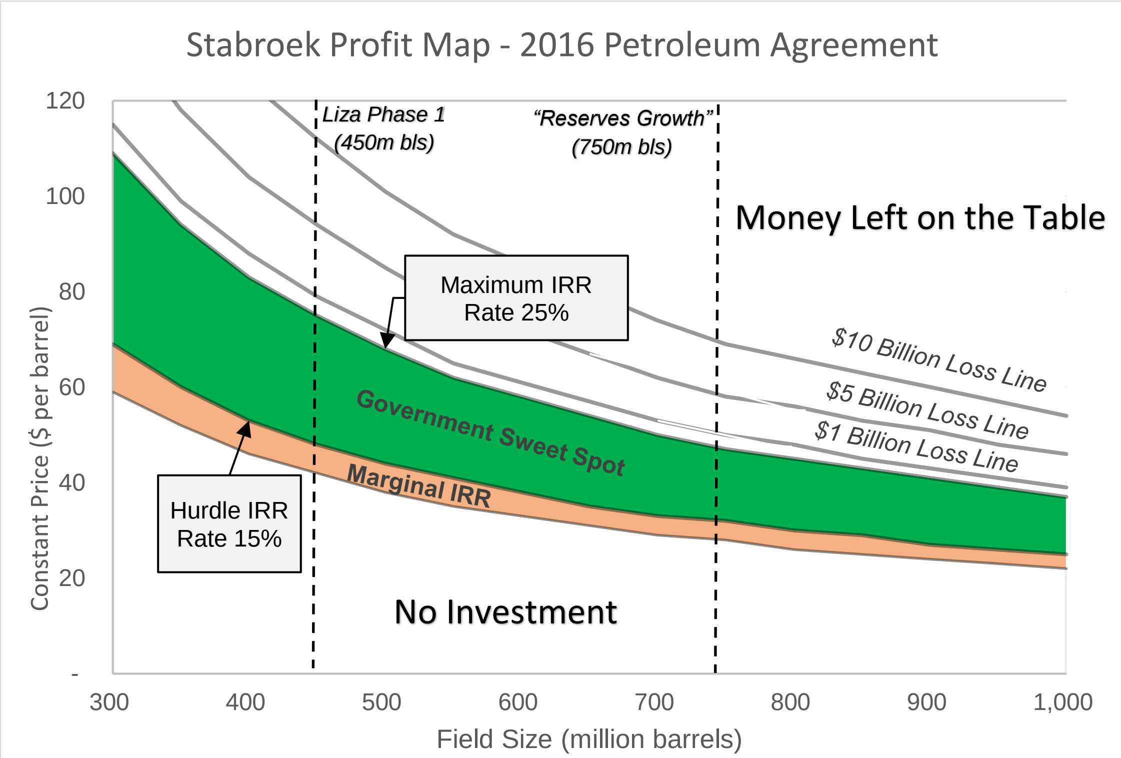


Figure 2: Stabroek Profitability Map: IRR analysis under different price and field size assumptions.

Figure 2 shows how the model predicts investor returns in Stabroek through various price points and field sizes. The lower "No Investment" zone depicts a range of outcomes where the rate of return is too low to justify the capital investment. The oil industry has traditionally operated at a 15% hurdle rate, with a certain margin beneath that (here assumed to be 12%) considered marginal. An area of company return between 15% and 25% might therefore be described as a government "sweet spot" – ensuring investment goes ahead, but without windfall profits to the company.

The general principles of fiscal policy for extractive industries, as proposed by the International Monetary Fund[6] and others, are to agree terms which provide enough return on capital to provide the incentive for investment, while capturing windfall profits or, in technical terms, economic rent. The upper red zone therefore represents "money left on the table" from the government's point of view, with a maximum desirable company IRR of 25%.

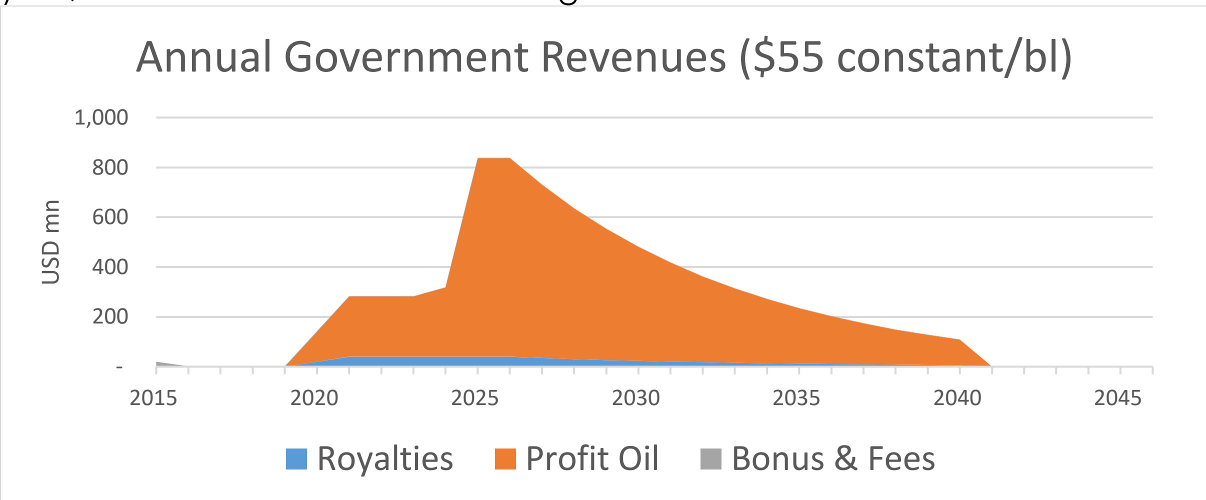
What is significant here is to understand the role reserves growth scenarios could play in increasing company rates of return. At the currently stated field size of 450 million barrels in Stabroek, for example, the company does not reach "maximum IRR" until a price point of $75. But if the field size increases only modestly in relation to recoverable reserves, to 750 million barrels, maximum IRR is reached at $50 per barrel – below today's prices.

[6] https://www.imf.org/en/Publications/Policy-Papers/Issues/2016/12/31/Fiscal-Regimes-for-Extractive-Industries-Design-and-Implementation-PP4701 pp 13 ff. The goal of capturing windfall profits is related to the fact that in most countries of the world, including Guyana, the owner of the natural resource at the time of signing a commercial agreement is the state, and the resource is therefore a public good in economic terms.

The contour lines above the maximum IRR represent quantified revenue loss to the government. Since the model predicts government revenues at each point, it can also predict the price and field sizes of points above the maximum IRR line for the company, where potential lost revenues equal $1 billion, $5 billion or $10 billion.

Here also sensitivity is high. At the mid-March 2018 Brent price of $65 per barrel, every increase in field size of a million barrels in Stabroek represents a potential $30 million in government revenue, while a $1 increase in the constant price assume would raise life of project revenues by $200 million. At the Reserves Growth field size level of 750 million barrels, government stands to lose a billion dollars of revenue with a rise in oil price of $3 per barrel.

Under any realistic scenario revenues from Stabroek will transform the Guyanan economy and public finances. Sizeable revenues will hit government accounts within two or three years of production starting in 2020 and by the middle of the decade revenues could approach a billion dollars a year, more than the entire 2018 budget.



This suggests that most of the issues in the resource governance agenda need to be addressed in the short to medium term: Dutch disease, inter-generational equity, debate about a potential wealth fund, and governance structures to minimise rent seeking behaviour.

Information Gap Analysis and Next Steps

There are several gaps in information that, if filled, would improve the economic model:

- Contractor estimates for exploration, capital expenditure and operating expenditure.

- Current detailed contractor reserves levels, defined using the SPE classification system[7]
- Contractor plans for potential Liza 2 development, including timing, cost and production profile estimates.
- API quality and grade of Stabroek crude extracted in appraisal drilling to refine valuation of the oil relative to the Brent and other benchmarks.
- Project finance: loans and interest rates used by the Contractor.

Because the project is the subject of public debate in Guyana, various alternatives to terms in the fiscal regime have been suggested, such as an increase in the royalty rate, or sliding scale splits of profit petroleum.

OpenOil will shortly publish fuller fiscal regime comparisons with a couple of defined alternative fiscal regimes, measuring performance under the same range of price points and field sizes.

About OpenOil

OpenOil is a Berlin-based consultancy which provides commercial and financial analysis to governments and public policy makers on natural resource assets. OpenOil is a supporter of the FAST financial modelling standard, and is the leading publisher of extractive industry financial models. It is supported by the Omidyar Network.

For further enquiries on this model contact johnny.west@openoil.net

[7] www.spe.org/industry/docs/Petroleum_Resources_Management_System_2007.pdf

Annex A: Fiscal Regime Comparison Methodology

Objective of Fiscal Regime Benchmarking

"Benchmarking" the fiscal regime of a country means analysing its comparability, and financial results, against fiscal regimes applied in other countries. It is a common practise by governments to try and provide information to consider the following questions:

- Is the fiscal regime *in and of itself* clearly a deterrent to foreign investors?
- Is the fiscal regime *in and of itself* clearly excessively generous to foreign investors?

There are so many variables and specificities in the economic, political and technical factors surrounding oil projects that the exercise itself can do no more than determine whether the fiscal regime is an outlier, or broadly "within the range" of outcomes produced by other projects in broadly similar circumstances. **Accordingly, it is important not to overinterpret the results of the high-level interpretation which benchmarking inevitably is across multiple projects, jurisdictions and signature dates.**

This exercise shows that the fiscal regime in Guyana's 2016 Petroleum Agreement is indeed an outlier with regard to "government take", the share of profits a government gets from a project – it's government take of just 52% is significantly lower than any of the peer projects, and this finding applies across all combination of market price and field size.

Study Scope and Framing

This study compares the Stabroek agreement to seven other projects in six other countries. Selection has taken place at the level of project for two reasons.

In practise there are relatively few unified fiscal regimes at a jurisdiction level governing the extractive industries. Many countries strike deals by project-level contracts, and even in general legislation there are changes over time which only apply to new projects since existing projects have their original terms stabilised.

Since investors see fiscal regimes as only one factor in their overall commercial analysis, and decision whether to sign a deal or not, the *moment* at which a deal was concluded, with *then-current* perceptions of prospectivity and costs, are key factors.

Other projects have been selected on the basis of some similarity. But there are so many variables in an individual project that no project is likely to be fully comparable.

Project List

The projects considered as comparables to Stabroek are:

- ***Ghana Deepwater Tano***: A tax royalty agreement signed in 2006 by Tullow, Kosmos and Sabre, this was the contract which opened Ghana's offshore sector. The main tax instruments are an ad valorem royalty, corporate income tax and a resource rent tax based on running profitability.
- ***Guinea offshore:*** A production sharing agreement signed in 2006 by SCS Corporation. The regime is characterised by a flat royalty of 10% and a profit share split.
- ***Liberia Block 13 –*** A renegotiated agreement with ExxonMobil in 2013, after prospectivity was confirmed but before any commerciality or development. Profit split, and state participation by Liberian national oil company NOCAL of 10%.
- ***Mauritania Chinguetti*** – a Production Sharing Agreement signed in 2006 by Woodside and Hardman. Relatively low cost recovery terms, a profit split, income tax, and a resource rent tax linked to oil prices.
- ***Papua New Guinea (the general Petroleum Act)*** – Terms formed at a time when the country had proven oil plays but early stage activity. An *ad valorem* royalty, income tax and a Resource Rent tax applied to the Contractor's cumulative rate of return throughout the project.
- ***Senegal – Saint Louis –*** A PSA signed in 2012 for a block in the northern sector, with PetroTim. This PSA follows a similar structure to the earlier Sangomar, but with profit split raised to 35%-58%, and income tax lowered from 33% to 25%.
- ***Senegal – Cayar Offshore -*** Another PSA signed in 2012 with Petrotim with identical fiscal terms to Saint Louis.

Fiscal Tool Diversity

The summary of projects above shows how diverse fiscal regimes are in the oil sector. There are two main "families" of contractual arrangements in the comparison group, PSAs and Tax-Royalty agreements, and many variations within each.

An entire fiscal regime is actually a package of a large number of interlocking and interacting items such as: Rate of royalty (quantity, ad valorem, flat, stepped or other), the base upon which royalties are applied (net or gross), Corporate Income Tax rate, rules on losses carried forward in cost recovery, depreciation, thin capitalisation restrictions, Double Taxation treaties, transfer pricing rules, decommissioning fund rules, various Resource Rent taxes (calculated against annual rate of return, project rate of return, price or other), Signature and other bonuses, VAT rates and implementation, import duties, export duties, withholding taxes (on dividends, interest and sub-contractors), and participation by a national oil company.

It is also important to note that the number of fiscal tools and revenue streams does not predict the overall level of profit sharing that comes to the government. It is not the case that all contracts should be treated normatively to see if they have all potentially available fiscal tools included.

No project contains all fiscal tools or identical revenue streams. Below is a table which gives a schematic view of categories of revenue streams in Guyana's Stabroek and comparison group projects:

	SN1	SN2	PNG	MN	Stabroek	GN	LB	GH
Royalty			x		X	x	X	X
Bonuses							x	
Profit Share	x	x		x	X	x	X	
CIT	x	x	x	x			X	X
RRT			x					X
Withholding	x	x	x	x		x	X	X
NOC share	x	x	x	x		x	X	X

Modeling: adaptation of the FARI model produced by the IMF

The diversity of fiscal regimes, with different configurations of fiscal tools present and absent, is one reason why a high level modelling approach has to be applied to get any quantitative benchmarking. A second reason is that different terms in the same contract interact with each other: the higher the royalty, for example, the lower the corresponding corporate income tax, or resource rent tax will be. This means **it is not possible to gain meaningful comparison by "headline term comparison" – the CIT rate in project A is x, the rate in project B is *1.2x*, therefore project B is "better".**

Accordingly, in addition to the FAST compliant project model, this study takes the Fiscal Analysis of Resource Industries (FARI) approach developed by the International Monetary Fund to do benchmark comparison. FARI was developed exactly to make this kind of high-level comparison, without drilling down too far into project specifics, which would be prohibitive in terms of resource across multiple projects and jurisdictions. The study began with the published version of the FARI model, available on the IMF website, but then developed custom functionality within it to accommodate the particular projects already selected. In functional terms, three different kinds of Resource Rent Tax modules were added to accommodate comparison group agreements.

Some of the standard presentation of results has also been altered. For instance, the Average Effective Tax Rate (AETR, sometimes also known as "the government take") results have been charted within a range that begins at 40% and ends at 80%, as the likely lower and upper bounds in these cases, to be able to accentuate the relative performance of the target group within these bounds.

Finally, some basic project economics compatible with the state of knowledge currently available in Guyana have been created. This is the source of another simplifying aspect of benchmarking, since in reality none of the projects have identical economics, either now or at the time they were signed, and differences – which would naturally drive differences in fiscal regimes negotiated – could be large. On the other hand, comparison of the fiscal regimes is only possible against the same project economic assumptions.