Fiscal Provisions of the Nigerian Petroleum Industry Bill

A not-so-quick and dirty assessment

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Table of Contents

1. What's the background gist of it?

After what can be described as a very, very long wait, the Nigerian Government has forwarded the Petroleum Industry Bill ('PIB' or 'the Bill') to the National Assembly. This follows a series of drafts, disputes and revisions as the Government, the international oil companies ('IOCs'), and the legislature failed numerous times to agree on previous versions.

The Ministry of Petroleum Resources ('the Ministry') describes the PIB as potentially "*one of the most important pieces of legislation in the history of the oil industry in Nigeria, changing everything from fiscal terms to the make-up of the state-oil firm*". It is clearly an ambitious document, one which in our assessment could change, fairly significantly, the way in which the oil and gas business is conducted in Nigeria if passed into law as-is.

The industry has greeted the PIB with mixed reactions. For some upstream E&P players, it does not appear that there is satisfaction with the fiscal terms as stated in the Bill. For others, there appears to be a certain degree of confusion as to what would apply when, and how. International organisations appear to have taken a position of quiet optimism for now, while the team of economists at Bargate Advisory is just keen to get stuck into it. And we have.

At over 220 pages, the PIB is a daunting read for most non-lawyers. It does however try to simplify what is currently a difficult petroleum legislative and regulatory framework to explain to the untrained eye (*lawyer's paradise, anyone? We love lawyers, really we do. We are even friends with some*). Highlights of such attempts at simplicity are the apparent amalgamation of the relevant petroleum sector laws into one piece, and a reduction of the points of fiscal burden to a handful of fiscal instruments. The Bill in fact defines fiscal rent as "*the aggregation of **royalty**, **Nigerian Hydrocarbon Tax** and **Companies Income Tax** obligations arising from upstream petroleum operations*"[1]. This simplicity may not however translate to reduced fiscal burden, mind. We hold the view that at least three separate pieces of legislation could have been submitted to the National Assembly, rather than one, but this is not the purpose of this particular exercise of ours.

2. What's the aim of this note?

Our team of economists at Bargate has briefly reviewed and assessed the fiscal provisions within the PIB, focussing first on upstream E&P issues, and summarised our findings in this note. We have considered the individual fiscal instruments on their own merit, and have then carried out a *quick-and-dirty* (as the note's sub-title frankly insinuates) assessment of the level, incidence and responsiveness of fiscal burden imposed by this new arrangement.

[1] Bold highlights for emphasis

We have deemed it useful to point out the obvious, as many caveats go these days: given the experience of the previous versions of the PIB since 2008[2], it is not impossible that the eventual law, if passed, could be different from this version before the National Assembly, with varying degrees of significance. We therefore do not encourage bets to be placed on this assessment at this stage.

3. What main fiscal measures are in the Bill?

3.1. Royalty

For the 21 references to the word *royalty* or *royalties* in the Bill (*not all economists are sad people, honest*), we find that not much is stated in terms of tangible numbers to work with in an analysis. Our assessment is that royalty rates from previous legislation will continue to hold, subject to subsidiary legislation or new regulations specifying otherwise. This is confirmed in section 354 (3) of the Bill.

What are these previous rates? Bargate assumes that the rates as prescribed in the Petroleum Drilling and Production Regulations made pursuant to the Petroleum Act, as amended from time to time and the rates as prescribed in other pre-PIB legislation continue to apply until subsidiary legislation or regulations are made to void them. For illustrative purposes, the following classification is representative of the rates as adapted from fiscal terms on offer during the 2007 bid round, and from information available on the Nigerian National Petroleum Investment Management Services ('NAPIMS') website. They are based on the Deep Offshore and Inland Basin Production Sharing Contracts Act, and the Petroleum Drilling and Production Regulations.

[2] For example, a joint presentation was made in 2009 by IOCs to the Nigerian legislators stating that the first version as proposed in 2008 would make exploration "uneconomical". These IOCs included Shell, Chevron, Exxon Mobil, Total and Eni.

ROYALTY		RATE
Onshore	Oil	20%
	Gas	7%
Offshore depths of less than 100 metres		18.5%
Offshore depths of between 101 – 200 metres		16.67%
Offshore depths of between 201 – 500 metres		12%
Offshore depths of between 501 – 800 metres		8%
Offshore depths of between 801 metres – 1 kilometre		4%
Offshore depths of over 1 kilometre		4%

We find the following sections of the Bill to be relevant, as far as preparation for the working of royalties into any economic model of the Nigerian upstream petroleum sector is concerned:

- Definition of the royalty in Section 362, as "*the amount of any rent as to which there is provision for its deduction from the amount of any revenue under a Petroleum Prospecting Licence or Petroleum Mining Lease to the extent that such rent is so deducted*" and "*the amount of any royalties payable under any such licence or lease less any rent deducted from those royalties*";
- Section 197 which requires royalties to be paid by law; and
- Section 190 (2) (a) (ii) which includes a royalty percentage **in addition to** the relevant subsisting royalty percentage as one of the assessment criteria for awarding licences to bidders.

Also worthy of note is Section 174 on confidentiality clauses, which attempts to void all existing clauses contained in licences, leases, agreements or contracts in respect of any payments of royalties and other fees. We are not lawyers, but we suspect this may prove interesting, depending on what exists in the conditions for termination/amendment of those existing contracts.

3.2. Deductions and allowances

Sections 305 – 307 of the PIB address, for the purpose of determining the base for the imposition of the Nigerian Hydrocarbon Tax ('NHT'), matters concerning deductible and non-deductible outgoings and expenses incurred in the E&P exercise. Bargate finds the following deductible items worthy of mention in this note:

- Rents and royalties;

- Customs or excise duty for machinery, equipment and goods used in upstream activity;
- Interest payments on loans (except for PSCs);
- Expenses for repair of premises, plant, machinery etc;
- Bad or doubtful debts owed to the company and due to have been paid prior to the commencement of the licensing period;
- All drilling-related expenditure for one exploration well and two appraisal wells;
- Expenditures linked to drilling and appraisal of development wells, excluding qualifying expenditures in the Fourth Schedule;
- Contributions to pensions, provident or other societies, schemes or funds; and
- Contributions made to the Petroleum Host Communities Fund (PHC Fund).

With regard to the non-deductible items, we feel the following are worthy of mention:

- Signature bonuses, production bonuses or other bonuses;
- Capital withdrawn or sum intended to be employed as capital;
- Depreciation (premises, buildings, structures, work of permanent nature, plant, machinery or fixtures);
- Customs duty on goods for resale or personal use;
- Customs duty on goods which are of the same quality and standards as locally produced and locally available goods;
- Expenditure on purchase of information;
- Expenditure for the purpose of fees and penalties;
- General, admin and overhead expenses incurred outside Nigeria in excess of 1% of total annual capex;
- Insurance costs earned by both company and company affiliate;
- Cost of obtaining and maintenance of performance bond (for PSCs).

In general, we find most of these provisions to be fairly consistent with international practice. We also find them quite explicit, which leaves both Government and investor parties in little doubt as to what is allowed or otherwise, during preparation and assessment of bids.

Things get more interesting in the provisions for General Production Allowances ('GPA') as outlined in the Fifth Schedule to the Bill. For starters, they are wrongly referenced as an "*allowance provided for under the Third Schedule to this Act*", when they should in fact be in the *Fifth* Schedule. It is not a big deal, but we get pedantic sometimes, especially after being sent on a wild goose chase to the Third Schedule.

This provision seeks to replace the Investment Tax Credit ('ITC') or Investment Tax Allowance ('ITA'), the main beneficiaries of the GPA being companies with executed PSCs with the NNPC, as interpreted from Section 314 of the Bill. The essential thrust of the allowance, as set out in the Fifth Schedule, is to enable companies protect a portion of production revenues before the imposition of NHT.

In the spirit of keeping things *quick-and-dirty*, we have prepared four tabular summaries of the GPAs in terms of who they benefit, and what the beneficiaries are entitled to.

While this categorisation of allowances could be so much simpler, we feel they are explicit in most cases and easily understood. However, there are a number of issues to flag, a big one being the absence of a clear expression of what provisions exist or do not for new entrants. While we are not uncomfortable admitting to have missed it perhaps, Section 314 seems pretty explicit on whom the GPA beneficiaries are, and the Fifth Schedule is also clear on who is not. We were perhaps hoping for too much for this clarity to include whether or not the GPAs applied to the newcomers. But what is life without hope?

There is another position to consider in the assessment of the GPA. It is argued that the provisions in Section 312 of the Bill essentially qualify new entrants as beneficiaries of the GPA. Section 312 (1) states that "*The chargeable profits of any company for any accounting period shall be the amount of the assessable profits of that period after the deduction of any amount to be allowed in accordance with the provisions of this section*". Section 312 (2) then states that "*There shall be computed the aggregate amount of all allowances due to the company under the provisions of the Fourth and Fifth Schedules to this Act for the accounting period*". On this basis therefore, and without incorporating interpretations from any other provisions in the PIB, the implication from these provisions is that every (or 'any', as is clearly stated in 312 (1)) company is entitled to GPA.

We have a problem with this implication, especially after considering Section 314 on Chargeable Tax. Section 314 states that "*A company engaged in upstream petroleum operations which executed a Production Sharing Contract with NNPC. a shall be entitled to a general production allowance as applicable in the Fifth Schedule to this Act*". Our quest for simplicity tells us that while companies may compute their allowances for tax purposes as guided by the Fourth and Fifth Schedules, Section 314 clearly defines the club of eligible beneficiaries of the GPA to be companies "*engaged in upstream petroleum operations which executed a Production Sharing Contract with NNPC*". We argue therefore that any company outside this exclusive club, except for those mentioned in the Fifth Schedule (such as existing JV partners in the case of gas production), does not benefit from the GPA provisions.

Or is it a case of everybody plus existing PSC holders, JV partners and the others as defined in the Fifth Schedule? We do not see it this way. If it is indeed this way, it is our view that it could be more clearly worded.

General production allowances 1

		What does the PIB say for…?			
		Newbie	Existing PSC holder	Existing JV partner with NNPC	Existing PSC holder not benefiting from ITC or ITA
Oil production	Onshore	Nothing specific	You get the lower of US$30/bbl or 30% of official selling price, up to cumulative max of 10 million barrels You get the lower of US$10/bbl or 30% of official selling price, for volumes over 10 million barrels up to cumulative max of 75 million barrels	You get nothing, sorry	You get US$5/bbl or 10% of official selling price, for all production volumes
	Shallow waters	Nothing specific	You get the lower of US$30/bbl or 30% of official selling price, up to cumulative max of 20 million barrels You get the lower of US$10/bbl or 30% of official selling price, for volumes over 20 million barrels up to cumulative max of 150 million barrels	You get nothing, sorry	
	Bitumen deposits, frontier acreage, deep water	Nothing specific	You get the lower of US$15/bbl or 30% of official selling price, up to cumulative max of 250 million barrels per PML You get the lower of US$5/bbl or 30% of official selling price, for volumes over 250 million barrels per PML	You get nothing, sorry	

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General production allowances 2

		What does the PIB say for…?			
		Newbie	Existing PSC holder	Existing JV partner with NNPC	Existing PSC holder not benefiting from ITC or ITA
Gas fields with liquid yield of >5bbls/mcf of gas	Onshore	Nothing specific	You get the lower of US$1/MMBtu or 50% of value of natural gas, up to cumulative max of 1,000 bcf per PML You get the lower of US$0.50/MMBtu or 30% of value of natural gas, for volumes (over?) 1,000 bcf per PML	You get US$0.30/MMBtu or 30% of value of natural gas per PML for all production volumes, regardless of liquid yield	You get US$0.50/MMBtu or 30% of value of natural gas per PML for all production volumes, regardless of liquid yield
	Shallow offshore	Nothing specific	You get the lower of US$1/MMBtu or 50% of value of natural gas, up to cumulative max of 2,000 bcf per PML You get the lower of US$0.50/MMBtu or 30% of value of natural gas, for volumes (over?) 2,000 bcf per PML		
	Bitumen deposits, frontier acreage, deep water	Nothing specific	You get the lower of US$1/MMBtu or 50% of value of natural gas, up to cumulative max of 3,000 bcf per PML		

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General production allowances 3

		What does the PIB say for…?			
		Newbie	Existing PSC holder	Existing JV partner with NNPC	Existing PSC holder not benefiting from ITC or ITA
Gas fields with liquid yield of <5bbls/mcf of gas	Onshore	Nothing specific	You get the lower of US$1/MMBtu or 100% of value of natural gas, up to cumulative max of 1,000 bcf per PML You get the lower of US$0.50/MMBtu or 50% of value of natural gas, for volumes (over?) 1,000 bcf per PML	You get US$0.30/MMBtu or 30% of value of natural gas per PML, for all production volumes, regardless of liquid yield	You get US$0.50/MMBtu or 30% of value of natural gas per PML, for all production volumes, regardless of liquid yield
	Shallow offshore	Nothing specific	You get the lower of US$1/MMBtu or 100% of value of natural gas, up to cumulative max of 2,000 bcf per PML You get the lower of US$0.50/MMBtu or 50% of value of natural gas, for volumes (over?) 2,000 bcf per PML		
	Bitumen deposits, frontier acreage, deep water	Nothing specific	You get the lower of US$1/MMBtu or 100% of value of natural gas, up to cumulative max of 3,000 bcf per PML		

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General production allowances 4

		What does the PIB say for…?			
		Newbie	Existing PSC holder	Existing JV partner with NNPC	Existing PSC holder not benefiting from ITC or ITA
Condensate production from gas fields (of US$20/bbl or 30% of official selling price, whichever is lower)	Onshore	Nothing specific	You get the lower of US$10/bbl or 20% of official selling price, up to cumulative max of 100 million barrels You get the lower of US$3/bbl or 10% of official selling price, for volumes over 100 million barrels	Nothing	You get US$5/bbl or 10% of official selling price, for all production volumes
	Shallow waters	Nothing specific	You get the lower of US$10/bbl or 20% of official selling price, up to cumulative max of 200 million barrels You get the lower of US$3/bbl or 10% of official selling price, for volumes over 200 million barrels	Nothing	
	Bitumen deposits, frontier acreage, deep water	Nothing specific	You get the lower of US$10/bbl or 20% of official selling price, up to cumulative max of 300 million barrels per PML You get the lower of US$5/bbl or 10% of official selling price, for volumes over 300 million barrels per PML	Nothing	

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Other notable provisions under the GPA include the following:

- Carry-forward feature: the GPAs can be cumulated and carried over to the next accounting period if there is "*an insufficiency of or no assessable profits*" in the current accounting period. As no limits have been set, we assume this feature to be indefinite, until assessable profit levels are reached.
- All existing crude oil, condensate and gas production from PSCs in existence prior to this Bill's Effective Date will be eligible for a GPA of US$5/boe.
- Marginal fields benefit also, under the same scheme, up to the cumulative amounts as outlined in each category.

3.3. Nigerian Hydrocarbon Tax ('NHT')

Section 299 of the PIB provides for the imposition of the NHT, and this tax is payable to the Federal Inland Revenue Service ('the Service' or 'FIRS') who is responsible for the administration of the tax. The NHT, which seeks to replace the key provisions of the previous Petroleum Profits Tax Act, is one of the big ticket instruments in this regime.

The NHT rates are simple enough; 50% for onshore and shallow water areas; 25% for bitumen, frontier and deep water areas (deep water areas defined as areas offshore Nigerian waters with water depth in excess of 200 metres), as provided for in Section 313 of the Bill.

The base on which this tax is levied is the amount of assessable profits (i.e. revenues less royalties, costs and allowable deductions), and losses can be carried over to the next accounting period indefinitely, as the PIB does not clearly set limits for losses to be carried forward.

3.4. Companies Income Tax ('CIT')

Again without being too fastidious (*is there such a thing, really?*), we observe some curious sequencing in the PIB. Our plan was to start off this section with the words "*Section xyz of the PIB provides for Companies Income Tax to be…*"), but we do not have a sequential reference for this. We would apologise for it, but we are saving this apology for errors that can actually be attributed to us.

That said, Part B of the tax provisions imposes a corporate tax on "*all companies, concessionaires, licensees, lessees, contractors and subcontractors involved in upstream operations*", subject to the Nigerian Companies Income Tax Act. 2004. As is the case with the NHT, the tax is to be administered by the FIRS.

What is the CIT rate? As is the case with the NHT, the rate is straightforward at 30% of taxable income.

Notable provisions in the PIB include the following:

- NHT is not deductible for the purpose of calculating CIT;
- The PIB makes provisions to address transfer pricing issues through amendments to Section 22 of the Companies Income Tax Act ('CITA');
- Section 24 of the CITA is to be amended to include "*rents and royalties payable on upstream petroleum operations*" among allowable deductions for CIT;
- There is a clear delineation of incentives available. Therefore the incentives under Section 39 of the CITA will apply to the following:
  - Companies engaged in gas production for LNG exports
  - Companies engaged in downstream gas distribution
  - Companies operating gas extraction facilities
  - Companies operating downstream crude oil processing facilities e.g. refineries

3.5. Other fiscal impositions

Nigerian Host Community Fund

The PIB introduces the Nigerian Host Community Fund ('the NHC Fund') at Section 116, which is to be "*utilized for the development of the economic and social infrastructure of the communities within the petroleum producing area*". Thankfully, companies are not expected to engage directly in these responsibilities which do not exactly feature as high on the priority list in their exploration work programmes. They do however have to contribute to it by way of tax.

Section 118 requires every upstream petroleum producing company to remit 10% of its net profits in this regard. Net profits for this purpose have been defined as "*the adjusted profit less royalty, allowable deductions and allowances, less Nigerian Hydrocarbon Tax less Companies Income Tax*".

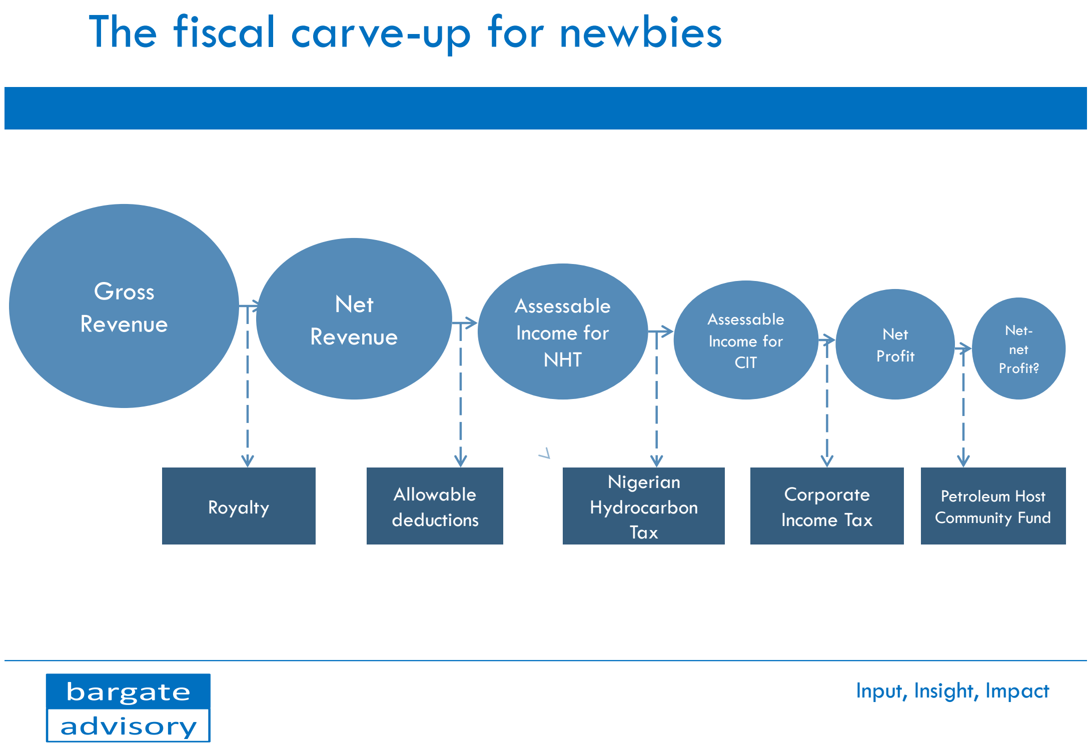
This is fine, until an attempt is made at crunching the numbers. A circular reference problem is inevitable. However, Section 304 might provide us with some respite. Section 304 (3) states that "*The adjusted profit of an accounting period shall be the profits of that period after the deductions allowed by subsection (1) of section 305 of this Act and any adjustments to be made in accordance with the provisions of section 307 of this Act.*" However, this has not quite helped. We were hoping for something simpler; more along the lines of claiming as allowable deduction over the next accounting period, the NHC Fund contributions made in this accounting period. If only life were as simple. We expect this to cause some bother, except for accountants, who may enjoy it. However, seeing as the payments are expected to be monthly, they could perhaps count as allowable deductions in the following month, for payments made in the previous month.

Double taxation

Section 351 of the Bill addresses matters concerning double taxation arrangements with other territories, while Section 352 sets out the method for calculating relief to be allowed in this regard. We find the provisions in this case to be fairly standard, and do not comment further at this stage.

4. What's Bargate's view?

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 concession (or royalty + tax) system.



Bargate's general view is that the fiscal regime, although somewhat simpler in terms of tax instruments and sequence of imposition, does not appear to be significantly different from the current regime in terms of economic impact. This is the point where it is wise to throw in a disclaimer. We have not carried out a full scale modelling exercise of all the potential scenarios made possible by the various provisions within the PIB and the CITA, as it is not necessary for this exercise. We are happy to be commissioned to carry out this exercise.

The table below summarises what we think about the major fiscal terms included in the PIB. It is essentially a scorecard indicating our take on eight assessment criteria, ranging from clarity of definition within the PIB to fiscal progressivity. In keeping with the light-hearted approach we have taken to discussing what some may deem a boring subject, we have classified our assessment scores as follows:

- Yes, if it meets our criteria;
- No, if it does not;
- Depends, if it requires the alignment of other factors to meet our criteria; and
- None, if it just does not exist or is not applicable.

Fiscal instruments scorecard

	Clarity of definition	Simplicity	Built-in adaptability	Tax leakage potential	Tax neutrality	International competitiveness of company take	Low front-end, profit based incidence	Fiscal progressivity
Royalty	No	No	No	No	No	Depends	No	No
Investment recovery period/allowance	Yes	No	Depends	Yes	Depends	Depends	none	none
NHT	Yes	No	No	Depends	Yes	Depends	Yes	No
CIT	Yes	Yes	No	Depends	Yes	Depends	Yes	No
NHC Fund Contributions	Yes	Yes	Yes	Depends	none	none	Yes	No
Additional Profits Tax	none	none	none	none	none	none	none	none

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As an illustration of how the table works, we have been particularly hostile in our assessment of the royalties purely because the PIB does not sufficiently articulate what would apply, when and how. We probably would have let it off if reference were made to specific sections of the current prevailing legislation.

We always check for specific progressive tax instruments[3] when assessing petroleum and mineral fiscal regimes. The most common is an additional profits tax, which is normally taken off the net profits after all fiscal levies have been imposed, based on certain conditions such as attaining particular rate of return thresholds. This explains why we have

[3] See discussion in 4.3 of this *not-so-quick-and-dirty assessment*

included it in this table. We have also done so just so we can have a full row of "*none*" in the table. We remain loyal to the fun side of this exercise.

We assess both NHT and CIT to be tax neutral, as they do not appear to interfere with the flow of capital towards its most productive use. In other words, we do not see sufficient evidence in the provisions for these taxes and their allowable deductions to significantly alter the company's economic choices.

4.1. Level of fiscal burden

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 too low by international standards, it bears the risk of becoming politically difficult for a government to sustain it. This is especially so for fields considered as highly profitable, as well as mature provinces 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 **81.7% government take**. We have not compared this with the current level of fiscal burden for this exercise. In terms of international comparators such as Norway, Iran, Kuwait and Egypt (average of about 85%), this level appears to be in good company.

Level of fiscal burden

			Explanation
Gross Revenues		100	*Assumption of one barrel, priced at 100 units*
Royalty	5%	5	*5% of 100 units*
Net Revenue		95	*100 units less 5% royalty*
Costs + Allowable deductions		40	*Assumed costs + allowances amounting to 40% on the barrel*
Chargeable profit for NHT		55	*Net revenue less costs and allowable deductions*
NHT	50%	27.5	*50% of chargeable profit for NHT*
CIT (NHT not deductible)	30%	16.5	*30% of chargeable profit for NHT. Chargeable profit for NHT effectively chargeable profit for CIT*
Net Profit		11	*Chargeable profit for NHT less NHT and CIT*
NHC Fund Contribution	10%	1.1	*10% of Net profit*
Net Profit after NHC Contribution		9.9	*Net profit less NHC Fund contribution*
Company share of profits		11	*Chargeable profit for NHT less NHT, less CIT. NHC Fund contribution added back*
Government share of profits		49	*Royalty + NHT + CIT. Government effectively pays NHC Fund contribution*
Gross profits		60	*Government share + Company share*
% Government take		81.7%	*% Government share of gross profits*
% Company take		18.3%	*% company share of gross profits*

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It is important to point out that a full modelling exercise may account for variations to the level of fiscal burden of about 5%-7%. 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, it gives a pretty sound indication of the level of fiscal burden.

4.2. 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. 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.

On the basis of the provisions in Section 305 on deductions allowed, our understanding is of a fully expensed capital expenditure. This has a positive implication on the payback period and the rate of return on investment.

4.3. Responsiveness of fiscal burden

One of the tests we carry out on petroleum fiscal regimes is to identify factors that could cause the host 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 can be captured from increased production revenues generated from an upside e.g. from sustained higher-than-expected oil prices.

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 find.

We assess the fiscal regime offered by the PIB to be regressive, as shown in the table below. We find that the royalty, NHT, and CIT do not combine to increase government take on increased profitability. We do observe however, that the rate of decline in government take is not steep. If this fiscal regime gets reviewed by international organisations such as the IMF or the Commonwealth Secretariat, this will most certainly be flagged. To demonstrate this regressivity, we have simply held costs constant from the previous table shown in 4.1 of this report, but doubled the price on the barrel in order to see what happens to government take.

Level of fiscal burden: progressivity check

			Price x2
Gross Revenues		100	200
Royalty	5%	5	10
Net Revenue		95	190
Costs + Allowable deductions		40	40
Chargeable profit for NHT		55	150
NHT	50%	27.5	75
CIT (NHT not deductible)	30%	16.5	45
Net Profit		11	30
NHC Fund Contribution	10%	1.1	3
Net Profit after NHC Contribution		9.9	27
Company share of profits		11	30
Government share of profits		49	130
Gross profits		60	160
% Government take		81.7%	81.3%
% Company take		18.3%	18.8%

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5. Ok, so what next?

We sit, and we wait. As earlier stated, we would not encourage placing any bets on the basis of the provisions within the PIB just yet. Other than the cosmetic amendments that must be made, we find that there are issues for which some further reflection may be merited, such as the not-so-great presentation of the royalty regime and the slight annoyance that may occur from working out payment and then claiming deduction allowance for NHC Fund contributions.

We could, however, be spectacularly wrong and the Bill would be passed *as-is*, with amendments, subsidiary legislation, and regulations to follow. We do not rule out this outcome, but we do not class it as the best outcome.

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

For more information, please contact: info@bargateadvisory.com