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Petroleum Industry Fiscal Bill 2018 – Major Highlights

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INTRODUCTION

The Nigerian parliament which comprises of the House of Representatives and the Senate would be holding public hearings on the following bills in the coming days (i) Petroleum Industry Fiscal Bill 2018, (ii) Petroleum Industry Administration Bill 2018 and the (iii) Petroleum Host and Impacted Communities Development Bill 2018. Considering the fiscal regime has been a source of great debate in the previous versions of the Petroleum Industry Bill, this briefing note provides highlights and key provisions of the Petroleum Industry Fiscal Bill (the "Bill" or "PIFB") and our remarks on the new introductions of the Bill.

The objective of the Bill is to establish a progressive fiscal framework that encourages substantial and progressive investment in the petroleum industry by balancing rewards with risk and enhancing revenues of the Federal Government of Nigeria while ensuring a fair return for the investors. Also, the Bill seeks to provide a clear distinction between legislative aspects of the fiscal regime and negotiable aspects of contractual obligation.

We have examined the provisions of the Bill in no order but on the basis of provisions we consider key and important with the potential of altering the fiscal position of exploration and production companies.

A FEATURES OF THE BILL:

1	Title:	A Bill for an Act to provide for the Fiscal Framework for the Petroleum Industry and for other Related Matters.
2	Principal Purpose:	Establishment of a fiscal framework that expands the revenue base of government while ensuring a fair return for investors. The Bill shall repeal the Petroleum Profit Tax Act Cap P13 LFN 2004 ("PPTA"); and the Deep Offshore and Inland Production Sharing Contract Act Cap D3 LFN 2004 ("PSC Act").
3	Tax Base:	Chargeable profits of companies engaged in Upstream, Midstream and Downstream Petroleum Operations.
4	Nature of Tax:	Direct Tax.
5	Principal Tax Payer:	Companies engaged in Upstream, Midstream and Downstream Petroleum Operations.
6	No. of Sections and Schedules:	77 Sections and 3 Schedules.

B EXECUTIVE SUMMARY

1 Applicable tax rates:

The PIFB appears to have granted reduced income tax rates in general. The most significant reduction appears to be the tax rate for shallow waters which is at 50%. Apparently, this has been introduced to encourage petroleum operations in this terrain. As expected, the Bill maintains the Companies Income Tax ("CITA") rate of 30% for all upstream gas operations irrespective of terrain. Also, the Bill does not recognize the current provisions of the PPTA with regards the reduced tax rates for companies which are yet to fully amortise all pre-production expenses. Perhaps the draftsmen are of the view that the reduced tax rate should compensate for this.
Furthermore, the Bill interestingly does not provide for a separate tax rate for Marginal Fields. This means that the terrain of operation where a Marginal Field is located, would determine its applicable tax rate (i.e. onshore, shallow water or frontier basin).

2 Assessment of additional Petroleum Income Tax:

The Bill introduces another layer of Petroleum Income Tax in the event price of crude oil or gas exceeds the threshold of $60 per barrel and $6 per mmbtu for crude oil and gas respectively. In effect, government take would increase in the event of rise in prices of hydrocarbon. However, there is no corresponding provision which allows for a reduced tax rate where there is a slump in prices of hydrocarbon.

3 Ring-fencing of Taxes in accordance with Operational Terrain:

The Bill seeks to ring fence taxes in accordance with operational terrain and entitles companies to consolidate operations within the same terrain except for Production Sharing Contracts and Service Contract involving the National Asset Management Company.

This provision would have significant impact on Joint Ventures particularly the IOCs who have interests in assets spread over different terrains. Therefore, there may be need for restructuring of the current JV entities through which IOC hold their JV interests. In effect, "terrain-SPVs" would need to be created to hold terrain specific interests.

4 Separation of Crude Income & Expenses from Gas Income:

The PIFB is silent on what would happen in the event certain expenses which are common to both crude and gas operations cannot be easily separated or isolated. This is a practical issue and a potential source of litigation if not properly addressed. We believe that the following provisions of Section 11(2)(c) of the PPTA which provides as follows should form part of the Bill:

"The incentives specified under subsection (1) of this section be subject to the following conditions, that is:
(c) the company shall, where practicable, keep the expenses incurred in the utilization of associated gas separate from those incurred on crude oil operations and only expenses not able to be separated shall be allowable against the crude oil income of the company under this Act."

5 Incentives for Gas Operations:

Section 4(6) of the Bill grants a bullet tax incentive period of 5 years for companies engaged in upstream gas operations without more. This means that the extensive incentives for utilization of upstream gas (associated and non-associated) under Sections 11 and 12 of the PPTA would no longer be available to petroleum companies.

Please note that a company engaged in the development and operation of strategic gas transportation infrastructure and distribution pipelines as approved by the Commission shall be entitled to a tax-free period of 10 years.

6 Tax treatment of Condensates:

Upon enactment, condensate produced and not spiked into crude oil shall be subject to tax at the CITA rate of 30%.

7 Change in Law, Stablisation Claims and "Grand-Fathering"

The Bill provides for periodic review every 7 years. However, there are provisions in the Bill that ensures that current operators are not affected by a change in law. Also, operators have a right to elect to be subject to a new law in the event there are benefits which can be taken as a result of a change in law. This provision prevents Government's exposure to stabilization claims under PSCs in the event of change in legislation. That said, stabilisation claims can still be brought upon enactment of the PIFB to the extent the PIFB effects the economics of the contractor parties.

8 Marginal Field

The Bill has amended the definition of what would be regarded as a Marginal Field to mean a field which has booked and reported reserve but which remains unproduced for a period of 7 years.

Also, it is noteworthy to mention that there are no separate royalty rates for Marginal Fields. There is need for clarification in this regard as the PIFB does not repeal the Marginal Fields Operations (Fiscal Regime) Regulations. This is particularly important considering that the Marginal Fields Operations (Fiscal Regime) Regulations appears to have more favourable rates.

C HIGHLIGHTS OF AND REMARKS ON THE BILL

Subject & Reference	Relevant Provisions	Remarks
Applicable Tax Rate – Section 13(1) & Section 58(1)	The proposed Section 13 (1) of the Bill provides that "the assessable tax for any accounting period of a company shall be a percentage of the chargeable profit for that period aggregated separately as follows: (a) 65% for onshore areas crude oil profit. (b) 50% for shallow water areas crude oil profit. (c) 30% for onshore areas natural gas profit. (d) 30% for shallow water areas natural gas profit." As it relates to deep offshore operations, the proposed Section 58 (1) provides that "the assessable tax for any accounting period of a company shall be a percentage of the chargeable profit for that period aggregated separately as follows: (a) 40 % for deep offshore upstream crude oil operations. (b) 30 % for deep offshore upstream gas operations." Section 62(2) provides that "the assessable tax rate for Frontier Basin operations shall be 30% for crude oil and upstream gas operations."	The PIFB appears to have granted reduced income tax rates in general. The most significant reduction appears to be the tax rate for shallow waters which is at 50%. Apparently, this has been introduced to encourage petroleum operations in this terrain. As expected, the Bill maintains the Companies Income Tax ("CITA") rate of 30% for all upstream gas operations irrespective of terrain. Also, the Bill does not recognize the current provisions of the PPTA with regards the reduced tax rates for companies which are yet to fully amortise all pre-production expenses. Perhaps the draftsmen are of the view that the reduced tax rate should compensate for this. Furthermore, the Bill interestingly does not provide for a separate tax rate for Marginal Fields. This means that the terrain of operation where a Marginal Field is located, would determine its applicable tax rate (i.e. onshore, shallow water or frontier basin).

Subject & Reference	Relevant Provisions	Remarks
Assessment of additional Petroleum Income Tax – Section 16	The new Section 16 introduces additional Petroleum Income Tax to be levied where: (a) "the average official selling price for crude oil in a particular accounting period exceeds US$60 per barrel; or (b) the average official selling price for gas in a particular accounting period exceeds US$6 per mmbtu of gas"	This provision introduces another layer of Petroleum Income Tax in the event price of crude oil or gas exceeds the threshold of $60 per barrel and $6 per mmbtu for crude oil and gas respectively. In effect, government take would increase in the event of rise in prices of hydrocarbon. The rationale behind benchmarking Petroleum Income Tax in the event of a jump in pricing appears logical on the side of government as it intends to benefit from price increase. However, there is no corresponding provision which allows for a reduced tax rate where there is a slump in prices of hydrocarbon.
Valuation of production for royalty – paragraph 10 of the Third Schedule to the Bill	According to the new proposed paragraph 10 of the Third Schedule to the Bill, The value for the purpose of royalty calculation for crude oil and condensates, or various grades thereof, shall be based on the official selling price at the export terminals and shall be adjusted taking into consideration: (a) any quality differentials; and (b) any transportation costs from the point of production to the measurement point.	The valuation of production assumes perfect conditions. The PIFB is silent on what happens in the event where there is sabotage between the measurement point (i.e. the point where the hydrocarbon leaves the License Area) and the export terminal. The provision on valuation of production does not provided for this. It is arguable that the intention of the provisions of paragraph 10 of the Third Schedule is to impose royalty on quantity of hydrocarbon at the export terminal, a close reading of the provisions of paragraph 10 suggests otherwise. Paragraph 10 only states that for the purpose of valuation of royalty, the official selling price ("OSP") at the export terminal shall be used. The question that arises is, what is the base upon which the OSP is to be applied?

Subject & Reference	Relevant Provisions	Remarks
		Is it hydrocarbon produced from the License Area? or hydrocarbon which gets to the export terminal less transportation costs from the point of production to the measurement point? The provisions of paragraph 15 suggests that metering is expected to be done at the flowline where the hydrocarbon leaves the license area. IF this were to be the case, then it can be reasonably inferred that the OSP shall be applied on the hydrocarbon produced from the License Area. The PIFB does not address the practical challenge of the possibility of transportation losses from the measurement point to the terminal. Would such losses be excluded in the computation of royalties? If yes, how would such losses be quantified/measured?
Administration – Section 2	By the proposed new Section 2 to the Bill, the Federal Inland Revenue Service (the "Service") and the Nigerian Petroleum Regulatory Commission (the "Commission") shall have the function of administration and collection of government revenue in the petroleum industry as follows: (a) The Service shall be responsible for the assessment and collection of Petroleum Income Tax; (b) The Service shall be responsible for the assessment and collection of Companies Income Tax in respect of taxable petroleum operations; and (c) The Commission shall be responsible for the determination and collection of rents and royalties in accordance with the provisions of the Act.	Currently administration and collection of royalties is currently within the remit of the Department of Petroleum Resources ("DPR") however, the PIFB contemplates that the DPR's role would be taken over by the Commission by virtue of the provisions of the Petroleum Industry Governance Bill ("PIGB"). That said, in the unlikely event that PIFB becomes law before the PIGB, the PIFB provides that the DPR shall carry out the functions of the Commission pending establishment of the Commission.

Subject & Reference	Relevant Provisions	Remarks
Charge of Tax – 4 (1), (2) and (3)	Section 4 of the Bill provides that: (1) There shall be levied upon the profits of any company engaged in upstream petroleum operations a tax to be known as Petroleum Income Tax which shall be charged, and assessed upon its profits and payable during each Accounting Period in accordance with the provisions of this Act. (2) Where a company has operations spanning different terrains, the tax shall be charged and assessed separately on the operations in each terrain. (3) Companies shall be entitled to consolidate operations within the same terrain except Production Sharing Contracts and Service Contract involving the National Asset Management Company.	This provision essentially replaces Petroleum Profit Tax with Petroleum Income Tax. Also, the provisions of Section 4 seek to ring fence taxes in accordance with operational terrain and entitles companies to consolidate operations within the same terrain except for Production Sharing Contracts and Service Contract involving the National Asset Management Company. This provision would have significant impact on Joint Ventures particularly the IOCs who have interests in assets spread over different terrains. Therefore, there may be need for restructuring of the current JV entities through which IOC hold their JV interests considering that their interests cut-across various terrains. In effect, "terrain-SPVs" would need to be created to hold terrain specific interests.
Tax Split by PSC Parties – Section 61	By the proposed new Section 61 to the Bill, "the chargeable tax on upstream petroleum operations in the terrain shall be split between the parties engaged in upstream petroleum operations in the deep offshore and inland basins in the same ratio as the split of profit oil or gas as defined in any agreement or arrangement between them and in the absence of any such agreement, as may be advised by the Commission."	This appears to be a slight variation of the concept that taxes are imposed on the Contract Area under PSCs. This provision assumes that the tax receipts to be issued by the FIRS with respect to the applicable taxes paid by PSC parties would be dependent on the profit oil or gas split amongst the PSC parties.

Subject & Reference	Relevant Provisions	Remarks
Separation of Crude Income & Expenses from Gas Income – Section 14(2)	The proposed new Section 14 (2) provides that except as provided in section 75, income and expenses relating to gas shall be separate from those relating to crude oil.	The provision as is creates a lacuna as it is silent on what would happen in the event certain expenses which are common to both crude and gas operations cannot be easily separated or isolated. This is a practical issue and a potential source of litigation if not properly addressed. We believe that the following provisions of Section 11(2)(c) of the PPTA which provides as follows should form part of the Bill: *"The incentives specified under subsection (1) of this section be subject to the following conditions, that is:* *(c) the company shall, where practicable, keep the expenses incurred in the utilization of associated gas separate from those incurred on crude oil operations and only expenses not able to be separated shall be allowable against the crude oil income of the company under this Act."*
Taxation of funding mechanisms and transaction services in petroleum operations – Section 18	The new Section 18 provides that in the taxation of any partnership, joint venture, or scheme or arrangement in upstream operation, a company that provides financing and technical service not being under a farm –in and farm-out arrangement and with an understanding to be paid in cash for such services provided under the arrangement shall be taxable under the Companies income Tax Act, LFN21, 2004 or any successor Act.	Before now, there have been some grey areas with regards to the tax position of certain funding and technical services arrangements with respect to whether such arrangements are subject to PPT or CIT. Historically, there has been mischievous interpretations to the effect that certain funding and technical services arrangements should be regarded as Petroleum Operations under the definition of the Petroleum Profit Tax Act. This provision attempts to provide clarification on the tax position of some of these arrangements albeit in a weak manner.

Subject & Reference	Relevant Provisions	Remarks
		We consider this provision weak because certain parts of the provision are unclear. The provision assumes that cash can only be paid as consideration for financial and technical services. This assumption is quite myopic bearing in mind that there are several financial and technical services arrangements in the industry where the consideration is in kind. A strict interpretation of the relevant provisions of the PIFB suggests that a funding mechanism in which crude oil or natural gas is consideration may be subject to the Petroleum Income Tax ("PIT") regime and not CIT. Also, a pertinent question which requires clarity is, "Would a Financing or Technical Services Arrangement with the nomenclature of a Farm-in or Farm-out arrangement qualify to be treated as being subject to the PIT regime"
Incentives for Frontier Basin Exploration – Section 4(4) and (5); Section 62	The new proposed Section 4(4) and (5) provide as follows: (1) "Notwithstanding anything to the contrary in this Act, the Commission may, for the purpose of incentivizing Frontier Basin exploration and development, subject to the approval of the Minister responsible for petroleum operations, direct or allow consolidation of costs and income from Frontier Basin operations with costs and income from operations in a different terrain. (2) The consolidation granted pursuant to subsection 4 of this section shall be for a period of time stipulated by the Commission."	This provision is seeking to incentivize petroleum operations in the Frontier Basin by allowing consolidation of costs and income from Frontier Basin with cots and income from operations in a different terrain. The PIFB defines "Frontier Basin" to include inland basins, other basin defined as frontier in a regulation issued by the Commission or a basin where exploration activities have not been carried out. The ability to consolidate shall be subject to conditions imposed by the Commission.

Subject & Reference	Relevant Provisions	Remarks
	In a bid to encourage investment, Section 62 also provides – (1) "The Minister of Petroleum Resources upon the recommendation of the Commission may by an Order published in a gazette grant suspension of royalties for operations in Frontier Basin for a period of time. (2) The assessable tax rate for Frontier Basin operations shall be 30% for crude oil and upstream gas operations."	Under the PIFB, the Minister also has powers upon recommendation of the Commission to grant suspension of royalties. In addition, the assessable tax rate for Frontier Basin operations is 30%.
Incentives for Gas Operations – Section 4(6), Sections 66 and Section 69	Section 4(6) provides that companies engaged in upstream gas operations shall be entitled to a tax-free period of five years commencing from the date of production provided that the provision of this subsection 6 shall not apply to a company to which subsections 2 and 3 of section 75 apply. Section 66(2) outlines incentives under the Act as follows: (a) "an initial tax-free period of five years; (b) as an alternative to the initial tax free period granted under paragraph (a) of this subsection, an additional investment allowance of 35 per cent which shall not reduce the value of the asset, so however that a company which claims the incentive provided under this paragraph shall not also claim the incentive provided under paragraph (c) (ii) of this subsection; (c) accelerated capital allowances after the tax-free period, as follows, that is- (i) an annual allowance of 90 per cent with 10 per cent retention, for investment in plant and machinery; (ii) an additional investment allowance of 15 per cent which shall not reduce the value of the asset;	Section 4(6) grants a bullet tax incentive period of 5 years for companies engaged in upstream gas operations without more. This means that the extensive incentives for utilization of upstream gas (associated and non-associated) under Sections 11 and 12 of the PPTA would no longer be available to petroleum companies. That said, please note that the incentives for the utilization of Associated Gas under sections 11 and 12 of the PPTA shall continue to apply to projects which have been approved by the NNPC or DPR prior to the commencement of the PIFB and in respect of which significant investment has been made prior to the commencement of the Act. What constitutes "significant investment" shall be at the discretion of the Commission.

Subject & Reference	Relevant Provisions	Remarks
	(d) tax free dividends during the tax free period, where- (i) the investment for the business was in foreign currency; or (ii) the introduction of imported plant and machinery during the period was not less than 30 per cent of the equity share capital of the company; (e) Interest payable on any loan obtained shall be tax deductible." Section 66(5) provides that "a company engaged in the development and operation of strategic gas transportation infrastructure and distribution pipelines as approved by the Commission shall be entitled to a tax-free period of 5 years in addition to an initial tax-free period of 5 years, bringing the total tax-free period to 10 years." The new proposed Section 69 to the Bill provides that the following companies shall also be entitled to the incentives outlined in Section 66 (2) above: (a) Companies engaged in the production and distribution of liquefied petroleum gas and other gas related products for domestic market; (b) Companies engaged in manufacturing of LPG cylinders as well as LPG related infrastructure; and; (c) Companies operating downstream crude oil processing facilities, including refineries, lube plants and related infrastructures.	With respect to incentives for Midstream Operations, Section 66 of the Bill grants incentives to Midstream Petroleum Operations through an initial-tax free period of 5 years. This is different from the current provisions on gas-utilisation incentives under the Companies Income Tax Act ("CITA") which provides incentives only to downstream operations. Unlike the current provisions of the Bill, the CITA grants an initial tax -free period of three years which may, extended for an additional period of two years subject to satisfactory performance of the business. The incentives granted to Midstream Operations shall also apply to companies carrying out downstream petroleum operations such as: • Companies engaged in the production and distribution of LPG and other gas related products for domestic market; • Companies engaged in manufacturing of LPG Cylinders as well as LPG related infrastructure; and • Companies operating downstream crude oil processing facilities including refineries, lube plants and related infrastructure. Please note that a company engaged in the development and operation of strategic gas transportation infrastructure and distribution pipelines as approved by the Commission shall be entitled to a tax-free period of 10 years.

Subject & Reference	Relevant Provisions	Remarks
Ascertainment of profits, adjusted profits, assessable profits and chargeable profits – Section 5(1)(c)	Section 5 (1) (c) provides that "Condensate spiked into crude oil shall be treated as an upstream petroleum operation and condensate not spiked into crude oil shall be taxed at downstream tax rate."	This provision is a new introduction which tries to deal with the tax treatment of condensate in petroleum operations. Upon enactment, condensate produced and not spiked into crude oil shall be subject to tax at the CITA rate of 30%.
Allowability of Inter-Company Loan – section 6(1)(f)	By the proposed new Section 6 (1), "in computing the adjusted profit of any company of any accounting period from its petroleum operations, there shall be deducted all outgoings and expenses wholly, exclusively and necessarily incurred, whether within or outside Nigeria, during that period by such company for the purposes of those operations, including but without otherwise expanding or limiting the generality of the foregoing: (a) sums incurred by way of interest upon any money borrowed by such company including inter-company loans, where the interest was payable on capital employed in carrying on its petroleum operations: Provided that where the rate of interest, fees or charges payable on such loans are excessive by reference to terms prevailing in the open market, that is the London Inter-Bank Offer Rate plus market determined rate, by companies that engage in crude oil production operations in the Nigerian oil industry, the deductions shall be limited to such commercial rate."	This provision appears to clear the confusion with regards to the allowability or otherwise of the Inter-Company Loans which has continued to be an unsettled area under the current tax laws. That said, in order to prevent profit shifting as a result of inter-company loans, the PIFB proactively caps the applicable interest rate on inter-company loans to "commercial rates" which is determined by reference to the prevailing open market rate of LIBOR plus market determined rate. In effect any amount above the "commercial rate" shall be disallowed.
Allowability of Abandonment Contributions – Section 6(1)(m)	Section 6(1) (m) provides that "any amount contributed to any fund, scheme or arrangement approved by the Commission for the purpose of providing for abandonment and decommissioning of petroleum installations."	This is a new introduction which ensures that amounts contributed by a company with respect to its abandonment obligation under an Abandonment Agreement or any other arrangement approved by the Commission with respect to abandonment and

Subject & Reference	Relevant Provisions	Remarks
		decommissioning of petroleum installations shall be allowable as tax deductions to the extent that any residue or surplus of such fund after decommissioning will be subject to Petroleum Income Tax.
Allowability of Contributions to the Petroleum Host Community Development Trust Fund – Section 6(1)(n)	Section (6) (1) (n) provides any amount contributed to a host community development trust pursuant to the provisions of the Petroleum Host Community Development Trust Act shall be allowable.	The proposed contributions to the Petroleum Host Community Development Trust Fund as contemplated by the Host and Impacted Communities Development Bill 2018 shall be allowable as a deduction for tax purposes.
Deductions not allowed – Section 7(1)(k) & (l)	The proposed new section 7 (1) (k) (l) to the Bill introduces additional non allowable deductions for the purpose of ascertaining the adjusted profit of any company of any accounting period from its petroleum operations as follows: (k) any expenditures incurred as a penalty; (l) twenty percent of any expense, incurred outside Nigeria, except where such expenditure relates to the procurement of goods or services which are not available domestically in the required quantity and quality.	The effect of this provision is that controversial costs such as demurrage which has hitherto been a subject of litigation will no longer be allowable for tax purposes. Also, only 80% of all oversees costs incurred shall be allowable for tax purposes.
Restriction of Capital Allowances – Section 12(3)	By the proposed amendment, the amount to be allowed as a deduction for the purpose of ascertaining chargeable profits shall be: (a) the aggregate amount computed under subsection (2) of this section; i.e. the aggregate amount of all allowances due to the provisions of the First Schedule and Second Schedule to the Act for the accounting period; or (b) a sum not more than 80 % of the assessable profits of the accounting period whichever is less.	This provision appears more straight forward if compared to the existing provisions of Section 20(4) of the PPTA which provides restricts capital allowances to the lower of: a. the aggregate amount of capital allowances or: b. 85% of the assessable profits less 170% of the total amount of the deduction allowed as petroleum investment allowance.

Subject & Reference	Relevant Provisions	Remarks
Periodic Review and "Grand Fathering" – Section 73	By Section 73, "the provisions of the Act shall be liable to review after a period of seven years provided that any new fiscal terms (other than administrative and enforcement provisions) introduced following such review shall not apply to existing investments or projects sanctioned by the Commission prior to the commencement of the legislation introducing the new fiscal terms unless: (a) The affected Company or Companies have elected in writing to the Service within 6 months of the fiscal terms becoming effective to be bound by such new fiscal terms; or (b) In the case of a new project sanctioned prior to the commencement of the new legislation, the affected company or companies have not made significant investment in respect of the project within 12 months of the commencement of the new legislation introducing the new fiscal terms. For the purposes of this section, significant investment means such level of investment as determined by the Commission. (2) Any new rates or fiscal terms (other than administrative and enforcement provisions) introduced following such review shall not apply to existing investments or projects sanctioned by the Commission, the Asset Management Company or the National Oil Company prior to the effective date of such new rates or fiscal terms unless; (a) the affected company or companies have elected in writing to the Commission within 6 months of the new rates or fiscal terms becoming effective to be bound by such new fiscal terms;	This provision prevents Government's exposure to stabilization claims under PSCs in the event of change in legislation. That said, such claims can still be brought upon enactment of the PIFB to the extent the PIFB effects the economics of the contractor parties. Also, by this provision the "Grand-Fathering" concept has been introduced into Nigeria's petroleum fiscal laws. Furthermore, the ability of companies to elect in writing to the FIRS of its desire to be subject to a new law gives companies the ability to take advantage of a new law or amendment that would be of benefit to such companies.

Subject & Reference	Relevant Provisions	Remarks
	(b) (b) in the case of a new project sanctioned prior to the commencement of the new rates or fiscal terms the affected company or companies have not made significant investments in respect of the project within 12 months of the effective date of the new rates or fiscal terms. For the purposes of this section, significant investment means such level of investment as determined by the Commission."	

Subject & Reference	Relevant Provisions	Remarks
Definition of Marginal Field – Section 77	By the proposed new Section 77 to the Bill, the following additions are made to the Interpretation Section: "Marginal Field" – means any field that has oil and gas reserves booked and reported annually to the Commission and have remained unproduced for a period of 7 years.	This definition amends the provision of the Petroleum Act in terms of number of years a field would be left unattended for such field to be regarded as Marginal. Under the provisions of the Petroleum Act, a field is regarded as marginal if left unattended for a period of not less than ten years from the first date of discovery of the marginal field. As you can see this has been amended to the effect that a field which has booked and reported reserved but which remains unproduced for a period of 7 years shall be regarded as a Marginal Field.
Expansion of areas to be considered as "inland basin" – Section 77	"Inland Basin" – means any of the following basins, namely; Anambra, Benin, Benue, Chad, Bida, Dahomey, Gongola, Sokoto.	The areas designated has inland basin have been expanded to include Bida and Dahomey.
Transitional Provisions – Section 75(3) Treatment of Unutilised Capital Allowance	The new proposed Section 75 (3) provides that Notwithstanding any provision under this Act, a company shall be entitled to claim under this Act any capital allowances, investment tax allowances and investment tax credits earned under any of the legislations repealed by this Act, but unutilised by the company before the commencement of this Act.	The provision ensures that Companies that have utilized capital allowance assets under the PPTA can utilize same notwithstanding the repeal of the of PPTA.
Production Allowance – Schedule 2 of the Bill	1. There shall be a production allowance for crude oil production by a company determined as follows: (a) for onshore – the lower of US $3 per barrel or 30% of the official selling price. (b) for shallow water areas – the lower of US $3 per barrel or 30% of the official selling price. (c) for deep water areas – the lower of US $3 per barrel or 30% of the official selling price.	The production allowance rate as included in paragraph 1 of the First Schedule does not state whether the lower or higher rate of the applicable $value and the % of official selling price is to be used for crude oil. We note that the Bill states that the lower of the two indices is to be sued for natural gas. It is a lacuna which we expect to be addressed by the draftsmen.

Subject & Reference	Relevant Provisions	Remarks
	2. (a) There shall be a production allowance for natural gas fields of 50% of the value of the natural gas production or US $ 1.5 per million Btu, whichever is lower: (b)there shall be a production allowance for the development of dry gas fields of 100% of the value of the natural gas production or US $ 1.5 per million Btu, whichever is lower: 3. There shall be a production allowance for condensate production from gas fields of US $ 3 per barrel or 30% of the official selling price, whichever value is lower:	The ability of companies to claim production allowance is dependent on its cost efficiency as determined by the Cost Efficiency Factor which is 20% of Total Revenue divided by OPEX. The Cost Efficiency Factor would determine the Production Allowance applicable Factor which is represented as follows:

Cost Efficiency Factor	PA Applicable Factor
CEF < = 0.5	50%
0.5 < CEF < 1.2	50% to 120%
CEF > = 1.2	120%

Also, a company shall be entitled to additional production allowance based on the reserve replace rate for the preceding year which needs to be certified by an independent expert recognised by the Commission and such certification shall be subject to verification by the Commission. The applicable additional production allowance shall be as follows:

Reserve Replacement Ration Range	Additional Production Allowance
RRR = 1	50%
1<RRR<1.25	75%
1.25<RRR<1.5	100%
RRR = > 1.5	125%

Please note that where a field produces oil, gas and condensate, the production allowances shall be taken separately for each hydrocarbon.

Subject & Reference	Relevant Provisions	Remarks
Royalties in kind or cash – paragraph 16(1) – (4)	The new Paragraph 16 of the Third Schedule to the Bill provides as follows: (1) At the option of the Government, the Commission shall inform the Licensee whether the Government elects to take the royalty in kind or in cash. (2) Where the Government elects to take the royalty in kind, the Commission shall, upon 90days notice in writing to the operator of the relevant licence, nominate the Nigerian Petroleum Assets Management Company or the National Oil Company or any other company to lift the royalty crude on behalf of the Government. (3) With respect to crude oil and condensates, the Commission shall inform the Licensee with a three month notice whether the Government shall take the royalty in kind or in cash. Such option may be exercised at multiple times and where no such notice is provided, the Licensee shall pay the royalty in cash. (4) With respect to natural gas, the Commission shall inform the Licensee prior to the granting of the licence whether the Government shall take the royalty in kind or in cash. Such option may be exercised once and where no such notice is provided, the Licensee shall pay the royalty in cash.	The default position is that royalty is payable in cash except the Commission indicates otherwise.

Subject & Reference	Relevant Provisions	Remarks
Royalty rates – paragraph 18 of the Third Schedule	The royalty rates for crude oil per volume is enumerated as follows: a. For onshore areas: Tranches (bpd) — Royalty Rate First 2,500 — 2.5% Next 7,500 — 7.5% Next 10,000 — 15.0% Above 20,000 — 20.0% b. For shallow water areas: Tranches (bpd) — Royalty Rate First 10,000 — 5.0% Next 10,000 — 10.0% Next 10,000 — 15.0% Above 30,000 — 20.0% c. For deep water areas: Tranches (bpd) — Royalty Rate First 50,000 — 5.0% Next 50,000 — 7.5% Above 100,000 — 10.0% The royalty rates for natural gas shall be based on geographical area as follows: a. For onshore areas: Tranches (MMscf) — Royalty Rate First 400 — 2.0% Next 400 — 4.0% Above 800 — 6.0% b. For shallow water areas: Tranches (MMscf) — Royalty Rate First 600 — 2.0% Next 400 — 4.0% Above 1000 — 6.0% c. For deep water areas: Tranches (MMscf) — Royalty Rate First 600 — 2.0% Next 600 — 4.0% Above 1200 — 6.0%	Upon enactment of the PIFB, royalties shall be based on terrain of operations. Also, Weighted Average Royalty is to be used where there is production from multiple terrain. The royalty tranches as contained in the Bill seeks to clear the confusion that had hitherto existed as regards how royalty rates would be determined. For example, the DPR has been at loggerheads with certain Marginal Field operators with regards to how royalties are calculated. For example, the DPR had taken the position that immediately production gets into a band the total production shall be subject to royalties at that band as opposed to the portion of production which falls within that band. For example, the Marginal Field Operations (Fiscal Regime) Regulations 2005 provides that the applicable royalty rate for production below 5,000bopd is 2.5% while the royalty for production between 5,000 bopd and 10,000 bopd is 7.5%. Where production in a Marginal Field is 7,000bopd, the DPR has sought to charge royalty rate at 7.5% as opposed to charging 5,000 barrels at 2.5% and the balance of 2,000 barrels at 7.5% as claimed by marginal field operators. We believe the proposed royalty system addresses this ambiguity. Also, it is noteworthy to mention that there are no separate royalty rates for Marginal Fields. There is need for clarification in this regard as the PIFB does not repeal the Marginal Fields Operations (Fiscal Regime) Regulations. This is particularly important considering that the Marginal Fields Operations (Fiscal Regime) Regulations appears to have more favourable rates.

Subject & Reference	Relevant Provisions	Remarks
	The royalty rates for natural gas shall be based on geographical area as follows: a. For onshore areas: Tranches (MMscf) — Royalty Rate First 400 — 2.0% Next 400 — 4.0% Above 800 — 6.0% b. For shallow water areas: Tranches (MMscf) — Royalty Rate First 600 — 2.0% Next 400 — 4.0% Above 1000 — 6.0% c. For deep water areas: Tranches (MMscf) — Royalty Rate First 600 — 2.0% Next 600 — 4.0% Above 1200 — 6.0% The royalty rates for condensates shall be based on geographical area as follows: a. For onshore areas: Tranches (bpd) — Royalty Rate First 2,500 — 2.5% Next 7,500 — 7.5% Next 10,000 — 15.0% Above 20,000 — 20.0% b. For shallow water areas: Tranches (bpd) — Royalty Rates First 10,000 — 5.0& Next 10,000 — 10.0% Next 10,000 — 15.0% Above 30,000 — 20.0% c. For deep water areas: Tranches (bpd) — Royalty Rates First 50,000 — 5.0% Next 50,000 — 7.5% Above 100,000 — 10.0%	

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