COMPARATIVE RISK ASSESSMENT OF NATURAL GAS UTILIZATION PROJECTS UNDER PETROLEUM PROFIT ACT AND PETROLEUM INDUSTRY BILL 2018

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Summary

Nigeria has been in a long process of passing into law the Petroleum Industry Bill (PIB) expected to replace its outdated petroleum laws. The PIB will redefine the governance of the petroleum industry and propose new fiscal terms under which investors in the petroleum industry in Nigeria will operate. Successive iterations of the bill have identified natural gas development and utilization, as a key component of the cocktail of initiatives for economic development. A major plank of the bill is to provide explicit terms for gas development and utilization amongst other objectives. Specifically, the Petroleum Industry Fiscal Bill (PIFB) 2018, consistent with the its previous versions, proposes to repeal the Associated Gas Framework Agreement (AGFA) in Sec. 11 & 12 of the PPTA. The AGFA incentives which allow for the cost of gas utilization projects to be defrayed against oil income, have birthed projects such as the Escravos Gas To Liquids (EGTL) Plant, the Offshore Gas Gathering System (OGGS) pipeline, the West African Gas Pipeline (WAGP) and the Nigerian Liquified Natural Gas (NLNG) plant. The objective of this study, therefore, is to assess the change in the risk profile of gas utilization projects if the AGFA provision is repealed as intended in the proposed PIFB 2018. There is significant opportunity for gas utilization projects especially for domestic purposes and this corresponds to the global view that Nigeria ought to be a gas rather than oil province given that at the current gas production rates (~8.22BCFD), and the gas reserves, gas production can be sustained 33% longer than oil production can. As at 2015, the Gas R/P ratio stood at ~ sixty – four (64) years. This study therefore develops the comparative economics for a 150mmscfd gas plant on a 250mmboe marginal field using Discounted Cash Flow (DCF) model in recognition of the extant fiscal provisions in both the Petroleum Profit Tax Act and the PIFB 2018. The DCF is expressed in nominal terms with sensitivity and stochastic modelling. By focusing on stochastic modelling, the risk reward profile of both investor and government is assessed and compared under the current terms and the PIFB 2018 in which AGFA is repealed. The outcome from the model shows that on the gas plant, government suffers a decline in tax receipts. Inflow to government under the PPT amount to $625.51Million which will reduce to $504.24Million under the proposed PIFB 2018 system. This is just as the investor value (NPV10) declines to $335.12Million under the proposed fiscal (without AGFA) compared to the value of $626.63Million under the current PPT system. Furthermore, the repeal of AGFA shifts the Investor Risk in the Gas Plant Upward. By repealing AGFA under PIFB, the chance of an investor loss increases six (6) times to approximately 45% from approximately 7% under the current terms. The repeal of the AGFA provision in the proposed bill will increase the investor risk profile in gas plant investment, lower the value derived therefrom and perhaps nudge investor behaviour toward cost effectiveness in executing gas utilization projects. However, in what is apparently seen as a way to compensate for this risk increase, the PIFB proposes to allow projects sanctioned under AGFA to continue until the gas projects' capital allowances have been fully enjoyed. Additionally, although there is a wider tax base available from upstream oil from not imposing gas development costs, the reduced tax rates in the upstream ensure the investor value is enhanced on an upstream and midstream portfolio basis – an improvement in portfolio value is seen from ~$480Million to ~$740Million.

Introduction

This paper is inspired by the long standing policy intent to excise the Associated Gas Framework Agreement (AGFA) found in Sec. 11 & 12 of the Nigerian Petroleum Profit Tax Act (PPTA). It is note worthy that while the Petroleum Industry reforms have long lingered, going through several iterations, the repeal of AGFA has been a consistent theme which also finds expression in the recent Petroleum Industry Fiscal Bill (PIFB) 2018. Specifically the AGFA provision stipulates that costs incurred in the development of gas utilization projects will be recovered against oil income. Consequently, the existence of AGFA has seen the materialization of projects such as the Escravos Gas To Liquids (EGTL) Plant, the Offshore Gas Gathering System (OGGS) pipeline, the West African Gas Pipeline (WAGP) and the Nigerian Liquified Natural Gas (NLNG) plant (Dada, 2018; Akinjide, et. al., 1998). However, despite these projects, policy makers through the years of have been determined to repeal the provision arguing that it encourages excess gas project spend, erodes the tax base, delays government take and acts as an avenue for investors to shift profits (Sec. 4.4.2 & Sec. 4.4.4, National Gas Policy, 2016; Sec. 5.4.2 & Sec. 5.4.4, National Oil Policy, 2016). Furthermore, the argument goes on to point that AGFA tends to favour players who possess significant oil portfolios against players with limited oil portfolios. By possessing significant oil portfolios, these players have the capacity to defray gas related investments while those without or limited oil portfolio will struggle (Sec. 4.4.2, National Gas Policy, 2016). The consequence of this bias against non-oil producers is that the self sustaining growth of a mid-stream industry segment is stunted.

By considering a 150MMSCFD gas processing plant developed alongside an onshore 54MMBBLS upstream development and using stochastic modelling, the risk reward profile of both investor and government is assessed and compared under the current terms and the PIFB 2018 in which AGFA is repealed. The scene is thus set against which an investor will pursue a field development as an integrated package across the upstream and midstream value chain segments of the oil industry. It should be noted that "Integrated Package" in the context of this paper does not mean that the upstream and midstream will be ring-fenced for fiscal purposes (Kellas, 2008). However, it is integrated in the sense that the same investor maintains an interest across the value chain while honouring the fiscal boundaries for each link in the chain. Within the context of integrating marginal field development and midstream processing, it is important to understand how the proposed repeal of AGFA can enhance or deter the required investment to provide midstream processing via gas processing/utilization as part of the field development programme.

Objectives

This paper will therefore pursue the objective of performing uncertainty quantification (UQ) to capture the risk – both from investor and government perspective – to which agas processing plant is exposed to by comparing the current fiscal system with the proposed PIFB 2018. The answer to this query is sought against the backdrop that Nigeria has been in the process of passing into law the Petroleum Industry Bill (PIB), a landmark legislation expected to specifically repeal the Associated Gas Framework Agreement (AGFA) amongst other policy intents which include petroleum administration, and governance. By using the proposed terms in the Petroleum Industry Fiscal Bill (PIFB 2018), this paper will model the impact of repealing AGFA on the gas utilization investment and make comparison with the prevailing suite of fiscal terms which provide for gas cost consolidation with oil income as enshrined in the PPTA. It is emphasised that due to the PIFB 2018 proposal to repeal the AGFA, the assessment of investor value and government tax impact is of significant import under this paradigm shift for a value chain investment

Methodology

The framework deployed in this paper follows the typical approach where a field is assumed with given CapEx, OpEx, and production attributes which is then subject to the fiscal system of interest and sensitized at varying oil and gas prices (Adenikinju and Oderinde, 2009; Echendu and Iledare, 2014; Iledare, 2010; Sani and Abdel, 2014; Smith, 2012). A brief survey of literature illustrates the preponderance of this approach and its slight variations to achieve insight into the dynamics of a fiscal system. Echendu, et al (2012) adopts the above default framework of a model asset to test against eight (8No) fiscal regimes of four (4No) countries in the Gulf of Guinea. Nahkle (2008), however in her study of the UK Fiscal System, divides up the different resource plays on the UKCS (United Kingdom Continental Shelf) to investigate the impact the evolving UK tax system on investment. Kaiser, et al (2004) use one field each in the Gulf of Mexico and Angola to quantify the influence that parameter uncertainties have on concessionary and contractual type fiscal systems.
The development plan of the field which contains 54MMBBLS of oil reserves and 1,032BCF of gas will incorporate a 150MMSCFD gas plant. Over a twenty-year period, a total estimate is production of ~930BCF of dry gas, 19MMBBLS of LPG and 17MMBBLS of C5+ is achieved. The wet gas is estimated to shrink by 10% thus yielding the estimated 930BCF of dry gas over twenty years. The liquids drop-out from the wet gas is estimated by multiplying the Liquids Gas Ratio (LGR), by the wet gas through the plant. It is estimated that 53% of the liquids drop-out is the LPG fraction which results in the 19MMBBLS estimate for LPG. Consequently, 47% of the liquids drop out is NGL which lifecycle volume produced is 17MMBBLS.

A Discounted Cash Flow (DCF) economic model is built, which considers the upstream and midstream developments to test the viability of the integrated project at the current terms and the proposed PIFB terms. By switching between the proposed fiscal system (PIFB 2018) and the prevailing one, the response of the viability indices IRR, NPV, and Government Take (GT) are trended and compared for the gas utilization project. The fundamental building block of the cash flow model is shown in (1)

$$\boldsymbol{NCF_t = REV_t - ROY_t - CapEx_t - OpEx_t - TAX_t} \tag{1}$$

The DCF technique is chosen amongst a bouquet of other modelling options such as Modern Asset pricing (MAP), Real Options Valuation (ROV), Systems Dynamic Modelling (SDM) (Blaskovitch, 2013; Nahkle, 2008; Kaiser, 2007; Laughton, et. al., 2007). This choice of the DCF is trade off between achieving simplicity with the objective of model accuracy in view (Ampofo, 2017; Croll et al, 2010; Nahkle, 2008; Dickens and Lohrenz, 1996).

The DCF can be deterministic or probabilistic. Whereas the deterministic DCF takes for granted that all the input variables carry their expected values, E[x], without recognising the uncertainty in those values, the probabilistic DCF (or Monte Carlo Simulation methods) accounts for uncertainty associated with the more impactful input variables such as hydrocarbon prices, reserves production profile, cost of capital, CapEx and OpEx, to provide a probability distribution function of the expected outputs (economic viability indices).

The Monte Carlo Simulation (MCS) is a class of computational techniques that rely on generating random numbers that fit defined probability distributions for a range of inputs into a system. Following the input of the random variables, several iterations are run to generate a distribution of the relevant output. By this technique, the uncertainty associated with the input variables into the system are translated into the output to capture its probability distribution and hence a quantification of its uncertainty; Figure 1 illustrates interaction of inputs, which are random variables, with the model to yield an output with a probability distribution. Note that $g(x_1)$, $g(x_2)$ and $g(x_3)$ are the distribution functions of the input quantities and g(y) is the distribution function of the output. The model, represented as f(x), is a function of x_1, x_2, and x_3.

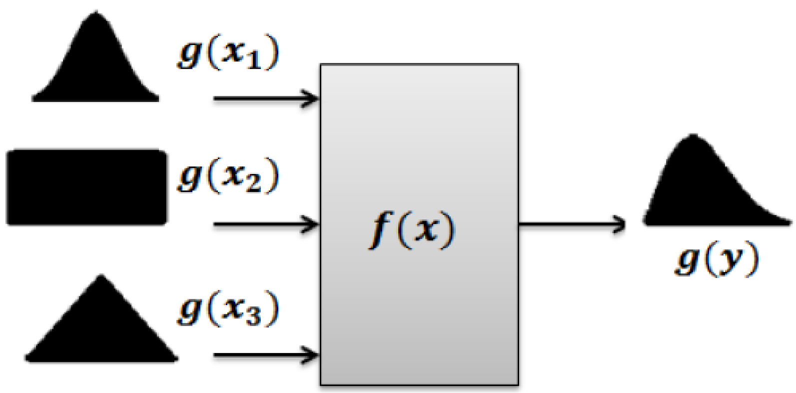


Figure 1: Monte Carlo Simulation Illustrated (Source: Paulo, et. al., 2016)

From the foregoing therefore, the discussions on project risk – from investor or government perspective – is really a discussion on the outcomes described by the probability distribution of g(y).

Description of Fiscal Systems – PPT/MFR vs PIFB 2018

The key attributes of the PPT/MFR and PIFB 2018 fiscal systems are compared in the Table 1, with details of specific fiscal rates in Appendix.

Table 1: Comparison of Fiscal Terms of PPT/MFR and PIFB2018

FISCAL INSTRUMENTS		PPT/MFR	PIFB 2018
Fees			
	Fees and Levies	YES	YES
	Signature Bonus	YES	YES
	Production Bonus	YES	YES
Royalty			
	Royalty by Water Depth	YES (0% - 20%)	NO
	Royalty by Terrain	YES	YES
	Royalty by Daily Production	YES (for Marginal)	YES
	Royalty by Price	NO	NO
Cost Treatment			
	Cost Recovery Limit	NO	YES (80%)
	Cost Consolidation (Gas and Oil)	YES	NO
	Cost Efficiency Factor	NO	YES
Allowances			
	Petroleum Investment Allowance	YES (5%)	NO
	Production Allowance	NO	YES
Tax			
	PPT	YES (65.75% - 85%)	NO
	NHT	NO	NO
	CIT	NO	NO
	PIT	NO	YES
	APIT	NO	YES

The two fiscal systems are differ in several areas. For example, while the current fiscal system has the MFR (Marginal Field Regulations) which stipulates the applicable royalty schedule, carved out specifically for marginal fields, the proposed PIFB 2018 incorporates all the applicable rates that will be applied across different field categories thus adhering to the principle of providing a single omnibus legislation for the oil industry in the PIB. It should be noted that the royalty schedule under the MFR is production based (same basis as the proposed fiscal) and different from the terrain/hydrocarbon type/water depth segregated royalty schedule of the primary PPT. Furthermore, under the current system, there is the provision to deduct spend on gas utilization project from upstream oil income (AGFA, Sec. 11 PPTA) while this provision is excised from the PIFB 2018 – the so-called oil/gas cost consolidation provision. The incentives granted under the section 39 of the CITA for gas utilization projects are captured in

Table 2.

Table 2: Gas Utilization Incentives in S. 39 of CITA Extended to all Mid-Stream Assets in PIFB 2018

FISCAL ASSUMPTIONS: PIFB 2018 (Midstream)		
Tax Holiday	**NO**	**YES**
Years of Tax Holiday	0	5
Education Tax	2%	2%

Annual Allowance	90%	90%
Investment Allowance	35%	15%
% of Ass. Profit available for CA recovery	66.67%	66.67%
CITA	30%	30%

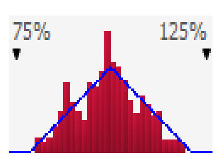
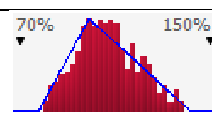
Investment Tax Credits/Allowances or Petroleum Investment Allowances provisioned under the current system are replaced with Production Allowances under the PIFB 2018. Measures to introduce cost discipline is adopted in the proposed system and ties the production allowances to a "Cost Efficiency Factor" defined as 20% of the ratio between Revenue and OpEx. The proposed fiscal system sets forth a single tax called the PIT (Petroleum Income Tax) to replace the current PPT (Petroleum Profit Tax) at lower rates. In addition to the PIT, the proposal suggests an APIT (Additional Petroleum Income Tax) intended to capture more take, on a post – tax basis, for government when oil prices increase beyond a given threshold. It should be noted that the introduction of the the single PIT is a departure from the dual tax system which has been historically proposed in the other bills. Another introduction to the fiscal system is a cost recovery limit of 80% which doesn't feature in the current fiscal system.

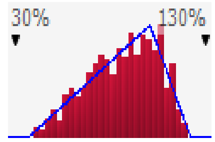
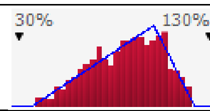
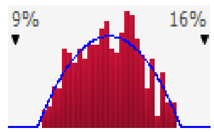
Probability Distributions

To capture the uncertainty of viability metrics, critical input variables are described by their probability distributions which are summarised in the Table 3 which includes the justification for the choice of distribution.

The arguments of the Triangular distribution function are the Minimum, Mode and Maximum respectively, while the arguments of the General Beta distribution, which describes the distribution for discount rate (Macdonald, 1996) are α_1, α_2, Minimum and Maximum respectively, where α_1, and α_2 are shape factors. The choice of the probability distribution to describe the uncertainty in the input variables is founded on a combination of theoretical, empirical considerations.

Table 3: Probability Distributions of Input variables

S/N	Variable	Probability Distribution	Graphs	Justification
1	Upstream field CapEx	Triangular (0.8, 1.0, 1.2)		Based on the observed distribution for lifecycle CapEx less than or equal to $2,000Million
3	Gas plant CapEx	Triangular (0.8, 1.0, 1.4)		Basis derived from Upstream CapEx

4	Upstream field OpEx	Triangular (0.4, 1.0, 1.2)		Based on the observed distribution for lifecycle OpEx less than or equal to $2,000Million
6	Gas plant OpEx	Triangular (0.4, 1.0, 1.2)		Basis derived from Upstream OpEx
7	Discount rate	General Beta (2, 2, 0.10, 0.15)		Based on price distributions of securities according to McDonald (1996)

Oil and Gas Pricing

Given the historical volatility of oil prices, the forward-looking oil price is modelled as a Moving Average order 1 (MA1) process. Figure 2 shows the historical as well as the forward-looking profile of oil prices, with the forward-looking profile and its stochastic envelope representing the oil price outlook for this project. However, the deterministic average forward curve oil price is ~$60/bbl.

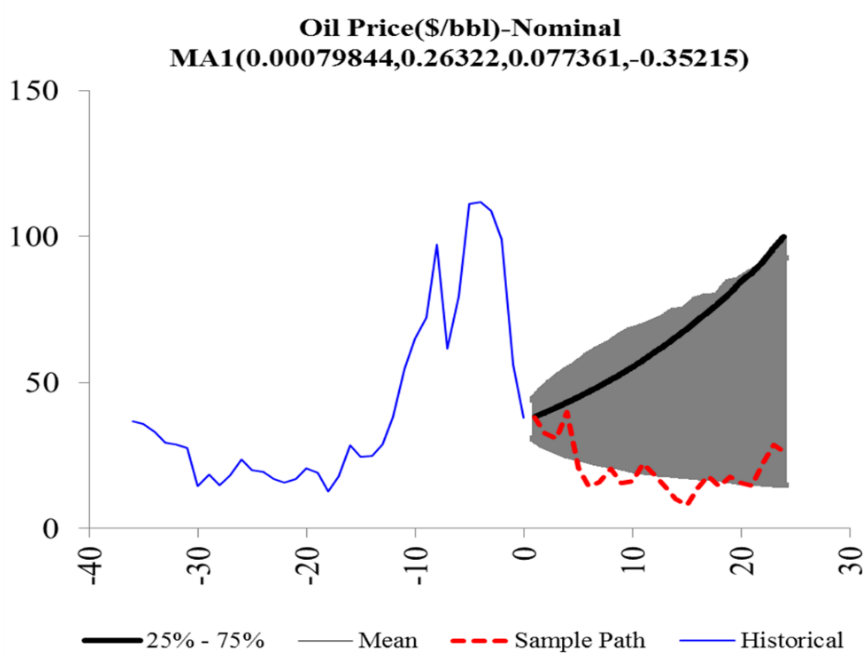


Figure 2: Projected and Historical Oil Price Path

Wet gas produced from the upstream field is "transfer priced" to the gas plant, while the gas plant produces dry gas by stripping the liquids – LPG (Liquified Petroleum Gas) and C5+ (Pentanes plus known also as condensate) – thus three streams of products, each attracting its own value, are produced. The dry gas price, expressed as a net back from the oil price assuming

6% as a netback factor, is the price paid at the gas plant outlet by the customer for the dry gas. The other two products from the gas plant – LPG and C5+ – are priced at import parity using the North West Europe market as reference and obtained from regression models specified as function of oil price. Price of Naphtha is used as proxy for C5+ in developing the C5+ price model. (2) shows the price model.

$$\begin{bmatrix} \boldsymbol{P_{LPG}} \\ \boldsymbol{P_{NGL}} \end{bmatrix} = \begin{bmatrix} \mathbf{0.7800} \\ \mathbf{0.8682} \end{bmatrix} \boldsymbol{X\, P_{BRNT}} + \begin{bmatrix} \mathbf{5.8600} \\ \mathbf{6.8842} \end{bmatrix} \qquad (2)$$

where:

1. $\boldsymbol{P_{LPG}}$ and $\boldsymbol{P_{NGL}}$ are the Import Parity Price of product LPG and NGL (C5+) respectively in **$/bbl**
2. $\boldsymbol{P_{BRNT}}$ is the Price of Brent oil in **$/bbl**

The wet gas price however, which is the price paid by the gas plant to the upstream (in honour of the transfer pricing principles) for its feedstock is also obtained on the net back pricing principle. This principle stipulates that the upstream wet gas supplier will receive, as its price for the wet gas, a fraction of the price at which the gas plant monetizes its products. This is best illustrated by (3) below where the variables K1, K2, and K3 are collectively known as K-factors.

$$\boldsymbol{P_{WG/US} = K_1\alpha_1 P_{NG} + K_2\alpha_2 P_{LPG} + K_3\alpha_3 P_{NGL}} \qquad (3)$$

where:

1. $\boldsymbol{P_{WG/US}}$ is the Price of wet gas paid to the upstream by the midstream gas processing plant in **$/mscf**
2. $\boldsymbol{K_1}$ $\boldsymbol{K_2}$ and $\boldsymbol{K_3}$ are the respective fractions of Natural Gas, LPG and NGL (C5+) midstream gas processing revenue collectively paid to the upstream
3. $\boldsymbol{\alpha_1}$ $\boldsymbol{\alpha_2}$ and $\boldsymbol{\alpha_3}$ are the respective volume fractions of Natural Gas, LPG and NGL (C5+) produced by the midstream gas processing
4. $\boldsymbol{P_{NG}}$ $\boldsymbol{P_{LPG}}$ and $\boldsymbol{P_{NGL}}$ are the respective prices of Natural Gas, LPG and NGL (C5+) earned by midstream gas processing

Results and Analysis

The deterministic result of the economic analysis for the upstream and gas plant components are shown in Table 4. These results derive from the model developed to capture interaction of the project with the fiscal systems of interest under the relevant assumptions. Considering the metrics of the value chain component parts shown in Table 4, it can be estimated that the gas plant economics contribute 64.34% of the overall investor Net Cash Flow for the integrated project with the upstream making up 35.65% under the current system. However, under the proposed PIFB, the bulk of the contribution to investor NCF will come from the upstream at 57.60% while the gas plant will contribute 42.40%.

Table 4: Results of Analysis

GAS PLANT PROJECT	Units	PPT/MFR	PIFB 2018
Revenue	$MM	5,727.60	5,727.60
CapEx	$MM	-	385.00
OpEx	$MM	3,297.79	3,297.79
Gov't Take	$MM	625.51	504.24
NCF	$MM	1,804.29	1,540.57
NPV 10%	$MM	626.63	335.12
IRR	%	NA	20.85%
MCR	$MM	NA	(360.71)
Payout	Yrs	NA	7.00
Gov't Take (%)	%	26%	25%
UPSTREAM PROJECT	**Units**	**PPT/MFR**	**PIFB 2018**
Revenue	$MM	5,461.03	5,461.03
CapEx	$MM	1,612.98	1,227.98
OpEx	$MM	1,155.16	1,155.16
Gov't Take	$MM	1,693.06	985.04
NCF	$MM	999.83	2,092.86
NPV 10%	$MM	(149.27)	405.52
IRR	%	7.54%	19.39%
MCR	$MM	(1,129.97)	(649.81)
Payout	Yrs	11.00	9.00
Gov't Take (%)	%	63%	32%

The profile of the Cumulative Net Cash Flows (CNCF) for the upstream and gas plant is shown in Figure 3. It can be seen in Figure 3 that under the PPT/MFR system, the upstream is heavily exposed, with a maximum cash in red at ($1,129.97Million), which compares with ($649.81Million) under the PIFB 2018. For the gas plant, however CNCF under the PPT/MFR, shows no negative exposure due to the provision of AGFA, however under the PIFB 2018, due to the excise of the AGFA provision, the maximum cash in red of the gas plant is ($360.71Million).

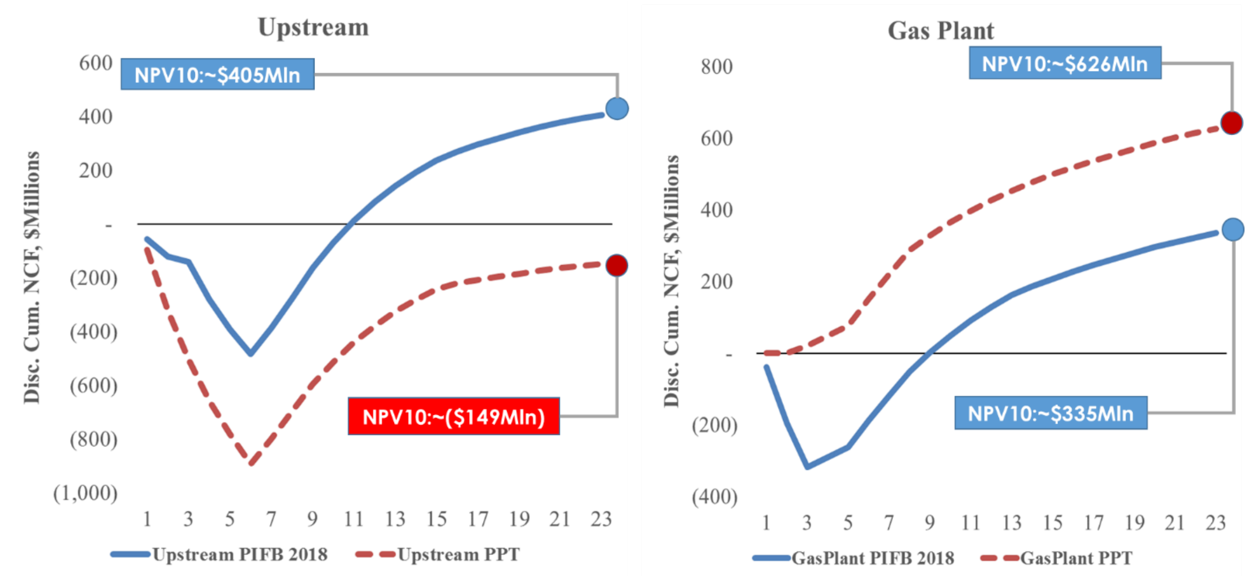


Figure 3: The Upstream and Midstream Gas Utilization Discounted Cumulative NCF

Note that the profile of the upstream under the PPT returns a negative NPV10 due to the fact that the upstream economics subsidises gas utilisation project. However, upon the excise of AGFA note that the upstream economics returns a positive NPV10 of $405Million.

The impact on GT for the gas plant is that under AGFA in the current PPT, GT is $625Million which is $121.27Million higher than under the proposed PIFB2018. The reason for the decline in tax receipts under the PIFB is the inclusion of gas plant CapEx as a deductible cost against the gas plant income. This works ultimately in both ways to shrink the tax base and hence the taxes paid out, as well as to decrease the net cash flow available to the investor. On the upstream side, GT decreases from $1,693Million under the PPT to $985Million. This is due to the decrease tax rate between the PPT (at 85%) and PIFB2018 (65% for onshore). Consequently, GT across the upstream and gas plant project reduces from $2,318.57Million (under PPT/MFR) to $1,489.29Million (under PIFB2018), a 36% reduction.

By taking a probabilistic view of the investor NPV on the gas utilization project it is found specifically, that the repeal of AGFA in PIFB 2018 shifts the Investor Risk in the Gas Plant Upward as seen in Figure 4.

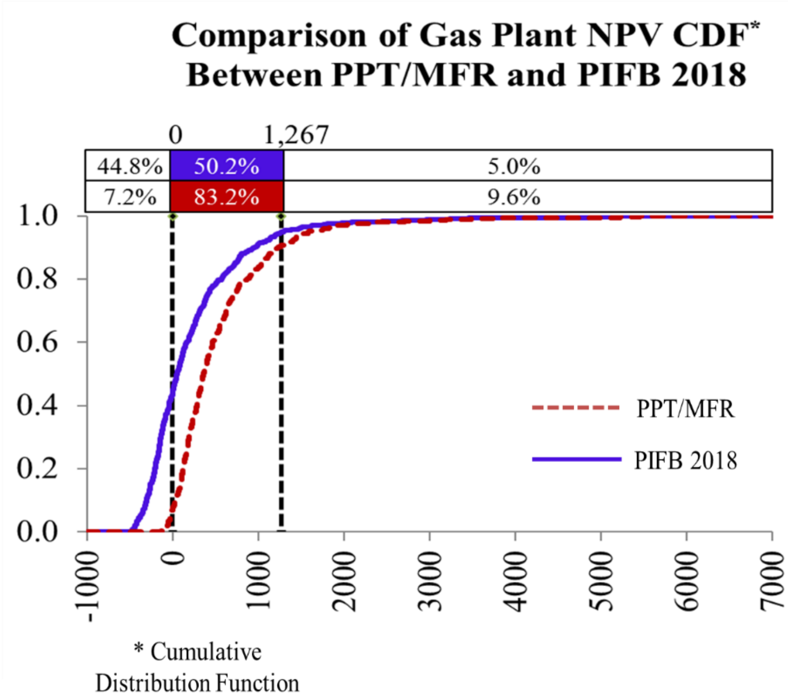


Figure 4: Probability Distribution of Midstream Investor Value Compared between PPT and PIFB2018

With AGFA under PPT, probability of NPV<0 is ~7%. Without AGFA under PIFB, this probability of NPV<0 increases to ~45%. Consequently, under the PIFB2018, which removes AGFA, the gas utilization project has a risk six times higher of making a negative NPV than under the current PPT scheme where AGFA is in place. However, taking the probabilistic view of government receipts from the gas plant, there is a 66% probability that government receipts will be less than the expected $625Million and $504Million under the PPT and the PIFB2018 respectively. Consequently, while government receipts from the gas plant decline as a result of the excise of AGFA, the probability distributions of the receipts are inured against the fiscal changes.

The repeal of AGFA also impacts the riskiness of investor value in the upstream oil project as shown in Figure 5.

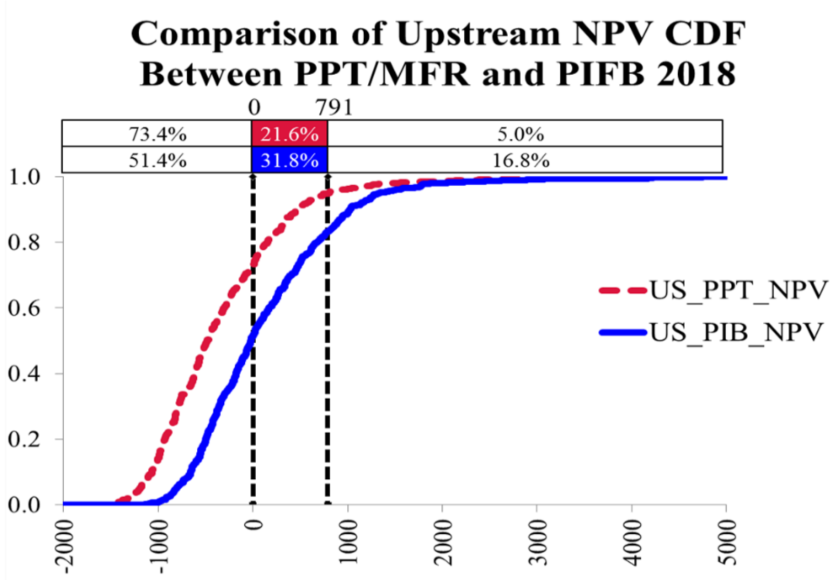


Figure 5: Probability Distribution of Upstream Investor Value Compared between PPT and PIFB2018

For the upstream, the investor under the PPT with AGFA in place has a 73.4% chance of returning an NPV < 0; however by adopting the proposed PIFB2018, that probability of returning an NPV < 0 declines to 51.4%.

Policy Implication, Conclusion and Recommendation

The determination of policy makers to excise the AGFA provisions from the petroleum laws in Nigeria have been consistent across the iterations of reform recommendations/proposals. The consideration for this are to do with the intent of the policy makers to develop a self sustaining midstream segment which will not rely on the performance and ability of oil projects to "carry" them. Furthermore, the AGFA provisions effectively reduce tax receipts due to government. Consider that gas costs when added to upstream costs to be deducted against oil income will inevitably lead to a reduction of the tax base; and given the 85% tax rate on upstream oil projects compared to 30% tax rate applicable to gas projects it is tempting to cost gas projects excessively and pass the costs to the upstream – this has also been another reason policy makers may have consistently targeted AGFA for repeal. As has been demonstrated in this paper, the repeal of AGFA will dramatically increase the riskiness of midstream gas utilization projects, while decreasing the riskiness of upstream oil projects on which gas projects are currently allowed to draw fiscal support from. A possible consequence of this repeal are for potential investors with oil portfolios to shun project developments in midstream gas utilization as gas projects' risk profiles are heightened at the same time that upstream oil projects are further "derisked". A further consequence could be that investors in the gas utilization projects will seek higher cost or market reflective prices and/or tariffs for processed gas, optimised costs for gas projects, improved contracting cycle times for projects all in a bid for a self sustaining midstream segment.

The assessment conducted in this paper has shown that under the prevailing PPT, a gas utilization project is not exposed to capital risk, a situation that changes under the proposed PIFB2018. This results in the value of a gas utilization project dropping by $290Million between the PPT(AGFA) and PIFB2018. While these are positive NPV, a stochastic view of the project exposes that the excise of AGFA will increase by six-fold the risk of a negative NPV. Given the 45% probability of a negative NPV for the gas utilization project under PIFB2018, this is consistent with the probability levels for upstream projects. It is also shown that while government receipts are less from the gas utilization project under PIFB2018 than they are under the AGFA provisioned PPT, the probability distributions are same, hence government receipts are not any more or less risky by the excise of the AGFA provision. For the upstream, the investor under the PPT with AGFA in place has a 73.4% chance of returning an NPV < 0; however by adopting the proposed PIFB2018, that probability of returning an NPV < 0 declines to 51.4%. The significance of these results is the demonstration that by the excise of AGFA, and other fiscal changes, the risk profile of investor value in the upstream and midstream segments appear to “equilibrate”.

Key recommendations from this assessment therefore include:

1. For a ratification of the fiscal proposal to excise AGFA so as to access the benefits of an independent, sustainable development of the gas midstream segment.

2. For investors keen on midstream gas investments to emplace risk mitigation measures to further reduce the chances of achieving an NPV < 0 in a regime post-AGFA removal.

3. Furthermore, for government to be acutely aware of project cost benchmarking so as to check that projects are executed at the right costs and hence preserve value to be taxed.

4. Government to develop tax expenditure models to track tax benefits implied by the government granted incentives

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APPENDIX – Key Fiscal Provisions of PPT/MFR and PIFB 2018

Key Terms for PIFB 2018

Oil Royalty Rates Based on Daily Production

Oil Royalty Rate/PML	**2.5%**	**5%**	**7.5%**	**10%**	**15%**	**20%**
Onshore (kb/d)	**0 – 2.5**		**>2.5 <=10**		**>10<=20**	**>20**
Shallow Water (kb/d)		**0-10**		**>10<=20**	**>20<=30**	**>30**
D/Water& Frontier (kb/d)		**0-50**	**>50<=100**	**>100**		

Gas Royalty Rates Based on Daily Production

Gas Royalty Rate/PML	**2%**	**4%**	**6%**
Onshore (mmscfd)	**0-400**	**>400<=800**	**>800**
Shallow Water (mmscfd)	**0-600**	**>600<=1000**	**>1000**
Deep Water & Frontier (mmscfd)	**0-600**	**>600<=1200**	**>1200**

Tax Rates (Applicable for Oil & Gas)

	PIT	
	OIL	**GAS**
Onshore	**65%**	**30%**
Shallow Water	**50%**	**30%**
Deep Water & Frontier Acreages	**40%**	**30%**

Additional Petroleum Income Tax Rates Based on Price (Gas)

Gas Price Tranch ($/mscf)	**0-6**	**>6<=16**	**>16**
Additional PIT Rate/PML (gas)	**0%**	**0.5%/$1**	**0.0%/$1**

Additional Petroleum Income Tax Rates Based on Price (Oil)

Oil Price Tranch ($/bbl)	**0-60**	**>60<=180**	**>180**
Additional PIT rate/PML (oil)	**0%**	**0.5%/$1**	**0.0%/$1**

Production Allowance for Oil		**Production Allowance for Condensate**
Onshore	**q > 0MMBBLS**	
The Lower of:	30% of value of Oil Production AND $3/bbl* Oil production	30% of value of Oil Production AND $3/bbl* Oil production
Shallow	**q > 0MMBBLS**	
The Lower Of:	30% of value of Oil Production AND $3/bbl* Oil production	
Deepwater	**q > 0MMBBLS**	
The Lower of:	30% of value of Oil Production AND $3/bbl* Oil production	

Production Allowance for Dry Gas		Production Allowance for Nat. Gas
Onshore	**q > 0BCF**	
The Lower of:	100% of value of Gas Production AND $1.50/mmbtu* Gas production	50% of value of Gas Production AND $1.50/mmbtu* Gas production
Shallow	**q > 0BCF**	
The Lower of:	100% of value of Gas Production AND $1.50/mmbtu* Gas production	50% of value of Gas Production AND $1.50/mmbtu* Gas production
Deepwater	**q > 0BCF**	
The Lower of:	100% of value of Gas Production AND $1.50/mmbtu* Gas production	50% of value of Gas Production AND $1.50/mmbtu* Gas production

Key Rates for PPT/MFR

Production Based Royalty: Onshore OIL(MFR)		Kbd	Rate
	Tranch 1	**5**	**2.50%**
	Tranch 2	**10**	**7.50%**
	Tranch 3	**15**	**12.50%**
	Tranch 4	**25**	**18.50%**
Fixed Royalty: Onshore GAS (PPT/MFR)			
			7.00%

Taxes and Levies		
	NDDC	**3.00%**
	Education Tax	**2.00%**
	PPT Onshore/Shallow New Entrant (Yr 1 – 5)	**65.75%**
	PPT>Yr 5	**85.00%**