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Exploring Viable Upstream Fiscal Policy Options for Developing Unconventional Natural Gas: The Case of the UK's Shale Gas

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Abstract: *The work contained in this research is an extension of the work by Acquah-Andoh et al. (2020) and explores viable fiscal strategies to attract investments and realise both government and industry objectives of developing UK unconventional natural gas from shale. Based on discounted cash flow (DCF) analysis and parameter sensitivity analysis (PSA), the research argues a fair share proposition of UK fiscal regime, premised on a pragmatic attainment of national objectives for the resource while ensuring attractive investment climate through an equitable balance between risk and reward for hard-to-attract early investments in an uncertain operational environment that characterises unconventional natural gas exploitation. Two fiscal policies were simulated and evaluated: the existing 30% Ring Fence Corporate Tax Policy and an Open-Door Policy with a 20% tax rate. The empirical evidence reveals that an open-door policy is most suitable for new unconventional natural gas development projects. In particular, the evidence shows that redefining capital allowance to include replacement well costs, implementing a tax rate of no more than 20%, is most likely to instil early investor confidence as risks and rewards are best balanced within this framework for investment in UK natural gas from shale. This fiscal strategy removes the potential administrative burden associated with the existing ring fence corporate tax regime and renders the tax policy simple to implement. The policy is recommended for developing unconventional natural gas worldwide. The study argues for policymakers to discontinue the application of fiscal regimes for conventional natural gas to unconventional natural gas. "Priority", "resource virginity" and "resource type categorization" are novel principles and contributions from this research, for the design of fiscal regimes for unconventional natural gas.*

Key Words*: *Open-door policy, shale gas investment, unconventional natural gas, upstream fiscal regime, royalty-tax, Ring Fence Corporate Tax

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1. INTRODUCTION

The oil and gas sector is marked by constant change. One area of change is the upstream fiscal regime (Stevens and Hulbert 2012). Traditionally, fiscal changes have emanated from responses to exogenous factors such as oil and or gas price, operating costs, capital costs, geological viability, among others. Endogenous factors motivated by government desire to change fiscal regimes are also common. Whether induced by endogenous or exogenous factors, one of the fundamental features of any nascent oil and gas sector is changes to legislation intended to optimise sector performance. Indeed, fiscal changes are a known custom of the oil and gas industry (Plourde 1989; Mommer 1999; Nakhle 2004; Tordo 2007; HM Treasury 2014; Yun et al. 2020). Shale gas is relatively new to the UK and risky; resource potential is uncertain (BGS-DECC 2013), public opinion is against its extraction as it is for conventional gas due to extraction techniques and climate change arguments (McGlade et al. 2018; Department for Business, Energy and Industrial Strategy (DBEIS) 2019; DBEIS 2021), and fiscal regime is untested (HM Treasury 2013). Research on the economics of UK shale gas is limited. Nevertheless, extant research suggests that the regime appears economically less competitive, and Acquah-Andoh et al. (2020) believe that the tax rate for UK shale gas is relatively high for a nascent industry and suggested readjustments.

The current research extends the research by Acquah-Andoh et al. (2020) to test and validate the proposed fiscal recommendations of removing the supplementary charge, reducing the ring fence corporate tax rate to a maximum of 20% and redefining capital allowance to include replacement well costs. The overall aim is to explore viable fiscal design strategies to create a regime of upstream tax design options and best practice to attract early investment for developing unconventional natural gas.

The rest of the paper is organised as follows: Section 2 describes the nature and risks of unconventional natural gas investments; Section 3 describes the research methods; Section 4 discusses the findings; and Section 5 concludes the research.

2. THE NATURE AND RISKS OF UNCONVENTIONAL NATURAL GAS INVESTMENTS

Unconventional oil and gas are riskier to exploit, and more so when operations occur in a country or region that has a previously unexplored or less explored commercial history (Mommer 1999; Boshoff 2010; Johnston 2015). Investment in unconventional resources in such "emerging" jurisdictions is thus generally riskier. Consequently, it may be logical to expect that the potentially high investor risks are compensated with a more liberal fiscal design for unconventional resources exploitation to guarantee the recovery of investments and banking of reasonable profits, to attract early investments (Bindemann, 1999). Yet, fiscal design and tax regimes for unconventional resource extraction tend to be random, often lacking a unified direction of principles and appearing to satisfy more of the tax/financial objectives of host governments for the development of conventional oil and gas resources. For example, the UK's "fiscal regime for shale gas" is based on the same Ring Fence Corporate Tax regime that regulates conventional oil and gas. Similarly, the fiscal regime for Indonesia's coalbed methane is the same for its conventional gas (Yun et al. 2020; Nugroho 1993; Sumarno et al. 2019). Expectedly, Acquah-Andoh et al. (2020) found that despite the effects of Pad Allowance – a shale gas development incentive – the effective tax rate for shale gas operations in the UK was still very high at 35% (the same rate for conventional oil and gas companies) whilst the much more successful US shale was taxed at 21% (see Acquah-Andoh et al., 2020). Relatedly, Sumarno et al. (2019) record the decline of the Indonesian CBM industry is due to the lack of a supportive fiscal regime.

The current research is the last in a series regarding the design of fiscal regime for exploiting UK shale gas. It is to be noted that whilst public views about shale gas are relevant, that is not a focus of this research. The focus of this research is to explore and test viable tax strategies, to build upon the work contained in Acquah-Andoh et al. (2020), to create a more complete set of proposed fiscal terms, which could improve the overall appeal of the UK's shale gas fiscal regime to attract investments and provide useful reference for upstream fiscal policy for unconventional oil and gas development, globally.

By completing this research, we shed insights on the tax design principles and practices framework that works for the development of unconventional oil and gas in an emerging country like the UK. Finally, the research would fill a critical gap in the literature on petroleum economics and fiscal studies and offer valuable fiscal policy design guidance to emerging countries looking to monetise their unconventional oil and gas resources.

3. METHODS

This section presents the assumptions and models that underpin the research. Specifically, we detail the geological basis for production decline for three development concepts in subsection 3.1 and present the resulting production curves (subsections 3.2 and 3.3). We also present economic and fiscal assumptions as well as the models that were used to generate the results of the study (subsections 3.4 to 3.6). Of the three development concepts, cases one and two arguably produce the production curves that best align with current research and industry data about the UK's shale gas production (UKOOG 2019, Cuadrilla Resources, 2019, Acquah-Andoh 2015; Institute of Directors (IoD) 2013). Nonetheless, to validate the results further, case three was also considered for its economic and fiscal implications.

3.1. Development Concepts and Data

A multi-pad drilling was assumed for the development of a hypothetical UK shale gas field, The Midland Valley

Shale, due to its cost efficiency and popularity within the fracking industry. Preliminary development considerations are summarised as development concepts in Table 1.

Table 1: Field Development Concepts and Production Curve Scenarios

Parameter	Concept/ Case 1	Concept/ Case 2	Concept/ Case 3
Drilling	10 well pads with 10 laterals	10 well pads with 40 laterals	10 x 10 well pads with 40 laterals per pad
Drilling schedule	1 well pad per year	1 well pad per year	10 well pads per year
Exploratory wells	4	4	4
Well flow rate	2mmcf per day	3mmcf per day	4mmcf per day
Gas recovery/ well	4.9 billion cubic feet	7.4 billion cubic feet	9.87 billion cubic feet
Estimated ultimate recovery	1.8 trillion cubic feet	2.8 trillion cubic feet	3.8 trillion cubic feet

As Table 1 demonstrates, the technical considerations for well pad density adopted are aimed at achieving an average of 10-15% recovery rate. The average well spacing ranged 40-150acres/well. The average surface well pad requirement was 5 acres (2ha) (IoD 2013). The drilling and fracturing of development wells follow a phased yearly approach, with 1-40 average number of pads drilled per year. Similar economic simulations have been considered in the work of Acquah-Andoh (2015). Overall, these development concepts result in various production curves as shown in Figures 1 and 2.

3.2. Production Curves

Production profiles were modelled based on three initial flow rate (Qi) scenarios and varying total number of wells drilled throughout the proposed field life. Guoa et al. (2017) and Wachtmeister et al. (2017) in a study of US shale gas wells production data found that a hyperbolic decline based on the Arps's decline equation best explained the decline behaviours of US shale gas wells. Hyperbolic decline based on Arps's equation was thus used to construct the production model for the UK shale gas, in line with the reasoning in authoritative research on UK shale gas resource potential (BGS-DECC 2013; IoD 2013; Regeneris Consulting & Cuadrilla Resources, 2011). B-factor of 0.6377 and average monthly initial decline (Di) factor of 0.0325, were assumed from the Fayetteville Field of the US to generate a 45-year well production profile. For this model, the abandonment production rate (economic limit) was assumed to be 0.09mmscfd. It is important to note that the average well production decline generated with a hyperbolic model decreases a well's production life. The consequent decline trend was analogous to those from Regeneris Consulting and Caudrila's work on the Bowland shale of the UK in 2011 (Regeneris Consulting & Cuadrilla Resources, 2011).

Figures 1 and 2 show the resulting production curves for the single well and multi-well full field development concepts for cases one, two and three. The yearly drilling requirements imply a need for substantial yearly CAPEX and will also imply a percentage increase in OPEX. This is typical of shale gas development projects because costs tend to be much higher in the early years of exploration and development.

3.3. Initial Production

The production profiles displayed in Figures 1 and 2 present three scenarios of estimated ultimate recovery (EUR) of reserves based on assumed initial production of 2 million cubic feet per day (2mmcfd) to 4mmcfd. The EUR is affected by the value of the decline and hyperbolic constant used in modelling. Average well production per year for the 45-year period ranged from 4.9 to 9.8 bcf. This rate is similar to that reported in earlier work by Regeneris and Cuadrilla (2011), IoD (2013), Hughes (2014), Acquah-Andoh (2015) and more recently by UKOOG (2019).

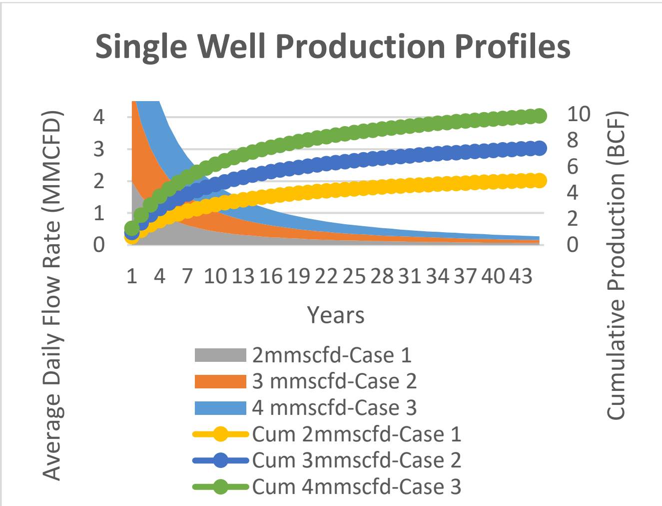

Figure 1: Production Curves/Profiles for a Single Lateral Well

Figure 1 shows the full range of production curves based on initial well flow rates of 2mmscfd, 3mmscfd and 4mmscfd. The graph also illustrates the estimated ultimate recovery EUR for all three production concepts at 4.9 bcf, 7.4 bcf and 9.8 bcf for a single lateral well. These production profiles translate into the total pad production profiles presented in Figure 2 below for all lateral well production scenarios.

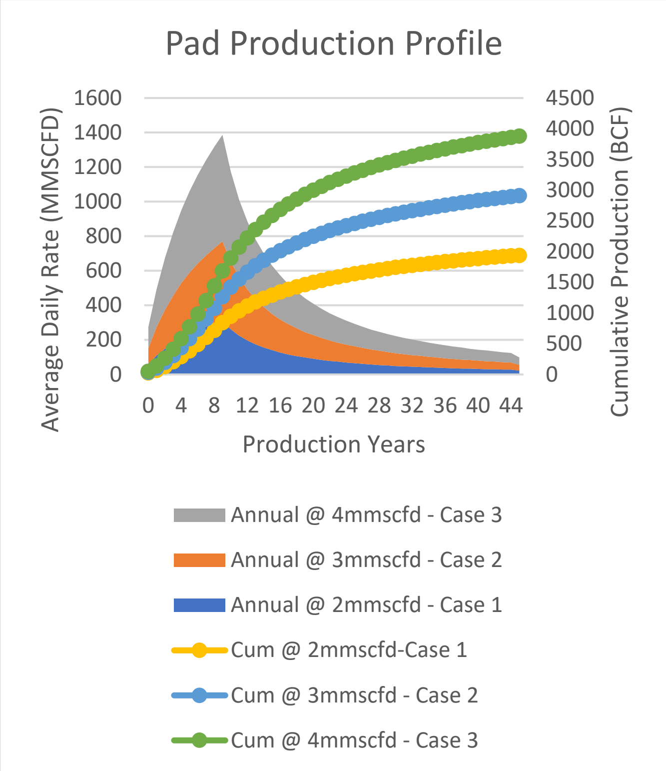

Figure 2: Pad Production Profiles Showing Annual Cumulative Pad Rates

3.4. Field Abandonment

In this research, we assume that wells will be abandoned at an economic rate of 0.09mmscfd or after 45 years of production, whichever occurs first. This is because production rates for a well are expected to be so low, leading to a negative cash flow on a well-by-well basis, a situation typical of shale gas wells (Hughes 2014). We also assumed that 10 well pads with 40 laterals would use 2 hectares of land (Acquah-Andoh 2015; Kaiser 2012).

3.5. Capital and Operating Expenditures

CAPEX comprises drilling, completion, fracturing cost, license, land acquisition and facility costs (Kaiser 2012). Costs from the US Haynesville shale wells were used as a guide in CAPEX assumptions for this study. Abandonment costs are included in the cost of wells. Community benefits are not a legal requirement of the shale gas fiscal regime of the UK; industry players who are members of the UKOOG have signed up to this proposal by UKOOG as a way of earning community trust to operate. As it has been argued, industry players are not obliged to pay these fees; hence this has not been captured in our models as the study attempts to capture and measure the implications of the UK fiscal regime as it exists by law. Exploration expenditure was immediately depreciated, and all other CAPEX was depreciated at 10% using the reducing balance method.

Because shale gas is still at an early stage in the UK, and it is difficult to obtain OPEX data, fixed OPEX and Variable OPEX were assumed based on inputs from the IoD (2013) estimates. Therefore, OPEX is escalated at 3%. Gas price of 32.12 pence per therm was used in our models and converted to its $/mmbtu equivalent of $4.69/mmbtu. Table 2 summarises our cost references for this research.

Table 2: Comparative CAPEX and OPEX References

Cost	Reference Project	Cost/Source
Drilling & Completion	Haynesville shale, US	$7–$10 million (Kaiser & Yu 2011); $5–$15 million (Kaiser 2012)
Drilling and Completion	Bowland shale, UK	£8–£12 million (DECC 2014); £10.5 million (Regeneris Consulting & Cuadrilla Resources, 2011); $15–$20 million (Acquah-Andoh 2015)
Facility Costs	Bowland shale, UK	15% of drilling and fracturing costs (Regeneris Consulting & Cuadrilla Resources, 2011); £5 million (Peel & Ocean Gateway 2014)
Operating costs	Bowland shale, UK	Fixed OPEX = £0.5 million per year; variable OPEX 2.5% of cumulative CAPEX (IoD 2013); $1.50/Mcf variable; $25,000 fixed plus 15% overheads (Acquah-Andoh 2015)
Operating costs	Haynesville shale, US	2008 = $0.85; 2009 = $0.80; 2010 = $0.50 (Kaiser 2012)

3.6. Economic Modelling

3.6.1. Cash Flow Modelling

Net Cash Flow (NCF) is the summation of all cash received, less all associated expenses, taxes and investment on an annual basis over the life of a project. Equation (1) specifies the cash flow model for our analysis.

$$NCF_t = [GR_t - RF\,Exp_t - RFCT_t - FinCost_t - (SupCharge_t + PA_t) - OtherCosts_t - CAPEX_t * (1 - B) - OPEX_t] \quad \text{...... (1)}$$

Where NCF_t is the net cash flow in year t, GR_t is the gross revenues in year t, $RF\,Exp_t$ is the ring fence expenditure in year t, $RFCT_t$ is the RFCT charge in year t, $FinCost_t$ is finance cost in year t, $SupCharge_t$ is a SC in year t, PA_t is the PA in year t, $OtherCosts_t$ is all other costs incurred by an operator, but which do not qualify as ring fence expenses under the fiscal regime in year t, $CAPEX_t$ is the capital expenditures in year t, B is proxy for the investment credit/ capital allowance, such as the RFES, and $OPEX_t$ is for all qualifying operating expenditures in year t. From left to right, equation (1) also illustrates the point at which various variables entered the determination of NCF in our modelling. RFCT was charged at 30%, before SC at 10%, in line with current UK upstream oil and gas fiscal policy.

It is important to highlight that the cash flow model adopted in this study has been applied by other researchers (e.g. Iledare 2004; 2010; Kaiser 2012; Sain, Rai & Sen 2014). Whereas Iledare (2004; 2010) applied a similar modelling concept to model a progressive development strategy for oil and gas in Nigeria, Kaiser (2012) applied a similar concept to analyse the profitability of Haynesville shale in the US. Similarly, Sen (2014) and more recently Mardiana et al. (2019) applied the same modelling concept to analyse India's and Indonesia's fiscal regimes for petroleum exploration, respectively.

3.6.2. Gross Revenues and Royalty

Gross revenues in year t are proceeds from the sale of gas. This was modelled using equation (2) below.

$$GR_i = \sum g_t^i P_t^i Q_t^i \qquad \text{...... (2)}$$

Generally, P_t^i, and Q_t^i each represents the conversion factor of commodity *i* in year *t*, projected price of commodity *i* and total production of commodity *i*, respectively. In this research, the saleable unit of gas is MMBtu. Gas is not converted; hence equation (2) was adapted as:

$$GR_i = \sum 1 \; x \; P_t^i Q_t^i \qquad \text{..... (3)}$$

Royalty is a percentage payment from gross revenues or production to the holder of mineral rights. In most countries where title to subsurface mineral resources is held by the state, royalty payments are payable to the state. In our models, royalty is represented as:

$$ROY \quad = \sum GR \; x \; Roy \; \% \qquad \text{..... (4)}$$

Where *ROY* is the calculated total royalty due government, *Roy %* is the predetermined percentage rate of royalty, and *GR* is gross revenues from the sale of natural gas.

3.6.3. Investment Decision Criteria

Petroleum fiscal modelling, discounted cash flows (DCF), and parameter sensitivity analysis were applied as data analysis methods. Principal decision metrics used were thus PBP, NPV, IRR, breakeven price and government take (GT). PBP is the time it takes for project investments to be fully recovered. Subsequent revenues received after the PBP are considered profits generated by the project. As reported earlier, according to Forbes (2018) and the IEA's chief economist Fattouh (2019), oil and gas companies now prefer projects with shorter payback periods to mitigate uncertainties in the sector, a view which was recently affirmed by the chief executive officer of the Norwegian Upstream Oil and Gas company, Equinor (Upstreamonline.com 2021). Equation (5) represents our PBP model as follows:

$$PBP = Cumulative - ve\ NCF\ years + \frac{1}{(+ve\ NCF - (-ve\ NCF)) * (-ve\ NCF)} \qquad \text{..... (5)}$$

Where *Cumulative -ve NCF* years represents the cumulative negative net cash flows years; *+ve NCF* represents positive net cash flows and *-ve NCF* represents negative net cash flows.

NPV is the summation of all future project cash flows discounted back into the present values to recognise the time value of money (Clews 2016). It represents the worth of future cash that would be invested today at a specified interest rate to yield that cash at that time in the future. Considering our analysis is based on a 45-year well life, it was necessary to convert future costs and revenues into present worth for valid and reliable economic reasoning. Equation (6) represents our NPV model as follows:

$$NPV = \sum_{t=1}^{k} \frac{NCF_t}{(1+r)^t} \qquad \text{..... (6)}$$

Where NCF_t is the net cash flow, *t* is the reference period (years) and *r* is the discount rate.

The IRR is the discount rate at which the NPV of the project cash flow reduces to zero. It is an important parameter in measuring the profitability of projects. Equation (7) represents our IRR model as follows:

$$IRR = \sum_{i=1}^{n} \frac{NCF_t}{(1+r)^t} = 0 \qquad \text{..... (7)}$$

Where IRR represents the internal rate of return, NCF_t represents the net cash flows in time t, *r* represents the discount rate, and *t* represents the time in years.

Significantly, the development and profitability of shale gas plays depend on a range of factors that influence the field economics, which include the gas price, production volumes, CAPEX and OPEX (Kaiser 2012). Table 3 summarises the input parameters used in this research. Consistent with previous literature, a discount rate of 10% was applied to our cash flows. For example, the Society of Petroleum Evaluation Engineers' [SPEE] (2015; 2023; 2024) survey of the oil and gas industry's asset valuation practices has reported the application of an average of 10% discount rate as common practice. This is indeed confirmed by the application of 10% in most oil and gas economics research (see Kaiser 2012; Wang et al. 2018; Acquah-Andoh 2015, 2019).

Table 3: Summary of Input Parameters

Parameter	Assumed Rate
Well drilling, completion and abandonment costs	\$15–\$25 million
Facility costs	\$10–20 million
Variable OPEX, including overheads	2% of CAPEX
Fixed OPEX	\$25,000 per annum
Gas price	\$4.69/mmbtu
Land acquisition cost	\$0.43 million/acre
Well spacing	40 acres
Cost of capital	10%
Ring fence corporate charge	30%
Supplementary charge	10%
Pad Allowance activated	100%

Initial production – Gas	2 mmcfd to 4 mmcfd
Gas price escalation	3%
OPEX escalation	5%
CAPEX escalation	5%
Crude oil production per day	50Mbbl/d
Crude oil price ($/Bbl)	35
Crude oil totex ($/Bbl)	30

In this study, the effects of the parameters in Table 3 on project profitability were examined and tested against three fiscal policy regimes, and we now present and discuss the results in Section 4.

4. RESULTS

In this section, results of the economic analysis for an "Open-Door fiscal policy" for shale gas are compared with the RFCT regime. An analysis of the geological potential for the "resource type" then follows for "gas-oil mix" production to explore opportunities for redesigning fiscal regimes for shale gas.

4.1. Economic Impacts of Different Fiscal Strategies/Frameworks

Fiscal Strategy 1: Ring Fence Corporate Tax Regime with Pad Allowance and RFES

Features of this strategy: 30% RFCT, 10% SC, PA of up to 100%, RFES 10% for ten years, Capital allowance applies to only new well drilling costs, but not abandonment of existing wells to be retired/replaced. This is the existing government policy.

Table 4: Economics results

Case/Model input parameters	Results	Pre-tax	Post-tax
Case One: EUR = 2mmcfd; CAPEX = $100M/well; OPEX = $1.2/Mcf; IP = 2mmcfd; FRCT = 30%; SC = 10%; PA = 100%; Gas price = $4.9/mmbtu	NPV ($Million)	-2,732	-2,732
	IRR (%)	-9.6	-9.6
	Average yearly EUR per well (Bcf)	4.9	4.9
Case Two: EUR = 3mmcfd; CAPEX = $110M/well; OPEX = $1.5/Mcf; IP = 3mmcfd; RFCT = 30%; SC = 10%; PA = 100%; Gas price = $4.9/mmbtu	NPV ($Million)	-1,189	-1,189
	IRR (%)	4	4
	Average yearly EUR per well (Bcf)	7.4	7.4
Case Three: EUR = 4mmcfd; CAPEX = $120M/well; OPEX = $1.5/Mcf; IP = 4mmcfd; RFCT = 30%; SC = 10%; PA = 100%; Gas price $4.9/mmbtu	NPV ($Million)	2,517	2,098
	IRR (%)	22	18
	PBP	13	19
	Average yearly EUR per well (Bcf)	9.8	9.8

As stated previously, this paper is the last in a series about the UK's shale gas and sets out to validate the propositions made by the author in Acquah-Andoh et al (2020). The results shown in Table 4 present the economics of shale gas exploitation in the UK and indicate unfavourable economics for a typical recovery of 3mmscfd as previously recorded in Acquah-Andoh et al. (2020). In the ensuing sections, the impacts of the Open-Door Policy are presented.

Fiscal Strategy 2: The Open-Door Fiscal Policy

The Open-Door Policy was devised based on the petroleum fiscal principles of simplicity, stability and neutrality. A simple petroleum fiscal regime has been defined as one that is easy to implement without administrative burden. It has been described to be more viable and ideal where the host government has limited institutional capability to regulate the oil and gas industry (Tordo 2007). The stability of petroleum fiscal regimes refers to the ability to preserve the economic value of contracts through the inclusion of stabilization or equilibrium clauses, which either restrict changes or allow for renegotiation of the agreement to ensure mutual benefit between the state and the investor (Cottarelli 2012; Mommer 1999). The benefit of the stability feature of fiscal regimes is that it preserves the economic value of the contract (Nakhle, 2016). For an investor, this is significant as they can forecast their cash flows and measure the risks to their investment effectively; leading to their increased confidence in investing in a country's resources (Johnston, 2010). An unstable fiscal regime which often manifests through the regular tinkering of the tax regime leads to reduced investor confidence in government policy, increased investor minimum required return due to perceived higher risk of the property/ resources, which could deter investment. In 2022, following an increase in windfall profit tax on UK North Sea oil and gas operators, the Association of British Independent Exploration Companies (Brindex) cautioned the government how the raise in energy profits levy, a charge on offshore oil and gas operators from 20% to 30%, just months after another set of tax changes had caused fiscal uncertainty and diminished investor appetite in the UK North Sea oil and gas (Aberdeen Grampian Chamber of Commerce [AGCC], 2025).

A neutral fiscal regime defines a regime that, according to Tordo (2007), does not impact resource allocation. Based on the foregoing principles, the ODP removed all taxes and restrictions in the UK's fiscal regime presented above, except for the RFCT of 20%. This was in line with the recommendations by Acquah-Andoh et al (2020). Table 5 presents the resulting economics.

Table 5: Economic results of the open-door policy

Features: 20% RFCT; 0% SC; 0% RFES; 100% PA; redefined capital allowance to include all well replacement costs to breakeven point.

Case/Model input parameters	Results	Pre-tax	Post-tax
Case One: EUR = 2mmcfd; CAPEX = $100M/well; OPEX = $1.2/Mcf; IP = 2mmcfd; RFCT = 20%; SC = 0%; PA = 100%; Gas price = $4.69/mmbtu	NPV ($Million)	15.4	3.2
	IRR (%)	10.2	8.7
	PBP (Yrs)	38	44
	GT:CT (%)	44:56	50:50
	Breakeven Price $/mmbtu	22.61	25.32
	Average yearly EUR per well (Bcf)	4.9	4.9
Case Two: EUR = 3mmcfd; CAPEX = $110M/well; OPEX = $1.5/Mcf; IP = 3mmcfd; RFCT = 30%; SC = 0%; PA = 100%; Gas price = $4.69/mmbtu	NPV ($Million)	1,113	640
	IRR (%)	11.2	10.3
	PBP (Yrs)	16	19
	GT:CT (%)	43:57	49:51
	Breakeven Price $/mmbtu	8.97	13.52
	Average yearly EUR per well (Bcf)	7.4	7.2
Case Three: EUR = 4mmcfd; CAPEX = $120M/well; OPEX = $1.5/Mcf; IP = 4mmcfd; RFCT = 30%; SC = 10%; PA = 100%; Gas price $4.69/mmbtu	NPV ($Million)	3,894.36	2,433.46
	IRR (%)	22	15
	PBP (Yrs)	8	11
	GT:CT (%)	30:70	32:68
	Breakeven Price $/mmbtu	6.98	7.65
	Average yearly EUR per well (Bcf)	9.8	9.6

As shown in Table 5, the economics of shale gas turned around with the removal of the additional taxes from the supplementary charge and the reduced RFCT rate to 20%. As demonstrated in Acquah-Andoh et al. (2020), the tax rate for the UK's shale gas when compared to more mature industries, like Canada, USA and China, was too high at an effective rate of 40% when the USA's much successful shale gas was taxed at 34% as noted by Daniel et al. (2017). The OPD regime's benefit of simplicity and along with the reduced taxes turns all the project development cases viable with 3mmscd production, resulting in a pre-tax NPV of $113 million and a post-tax NPV of $64 million. Pre-tax IRR was 11.2% versus post-tax IRR of 10.3%, etc. We argue in this study that the reduced tax rates and removal of the multiple taxes as demonstrated in the ODP could is good lesson to boost investor confidence and guarantee reasonable certainty of risk capital. The ODP, thus, demonstrates that a redesign of the UK's fiscal regime to improve its simplicity and the removal of its rent-seeking tendencies through its relatively high taxes for its fledgling unconventional natural gas sector could improve its competitiveness.

4.2. Fiscal implications of resource potential/ resource type Gas-Oil Mix

A unique perspective of the research is its consideration of a gas-oil mix potential for the design of unconventional fiscal systems. Gas is a regional commodity unlike crude oil and its market; price, demand and supply dynamics are markedly different to crude oil's, which is global. Crude oil commands higher prices, and its presence in an unconventional gas project could catalyse the viability of a purely gas project. In this paper, three differing EURs of oil-gas mix (Table 6) were simulated for their impacts on unconventional natural gas projects to learn new insights that shed light on the design of fiscal regimes for any unconventional natural gas and oil project.

Economic impact of all fiscal Regimes for an Oil-Gas Property Scenario

Table 6: Economics results

Economic impact of fiscal policy		RFCT		Open-door	
Case/Model input parameters	**Results of economic analysis**	**Pre-tax**	**Post-tax**	**Pre-tax**	**Post-tax**
Case Two: EUR = 3mmcfd; CAPEX = $110M/ well; OPEX = $1.5/ Mcf; IP = 3mmcfd; RFCT =20%; SC =0%; PA = 100%; Gas price = $4.69/mmbtu; Crude oil production 50Mbbl/d; Crude oil price $45/Bbl; Crude oil totex $28/Bbl	NPV ($Million)	11,130	1,400	11,130	4,593
	IRR (%)	162	20	162	53
	PBP (Yrs.)	1	9	1	3
	GT:CT (%)	10:90	53:47	10:90	64:36
	Breakeven price $/mmbtu	-8.5	2.5	-8.5	-2.2
	Average yearly EUR per well (Bcf)	8.7	8.7	8.7	8.7

The economics for an ODP for the existing RFCT regime was turned around under the "gas-oil" mix Scenario. Pre-tax NPV was very strong at $11.4 billion, IRR was 162%, payback period was 1 year, and breakeven price was -$8.8/ MMBtu. Post-tax economics were significantly reduced due to maintaining the existing tax rates for the RFCT. Post-tax NPV was $1.4 billion, IRR was 20%, etc., as in Table 6.

An impressive observation was that the ODP, combined with gas-oil mix, returned even stronger economics with post-tax NPV of ~$4.6 billion and a breakeven gas price of -$2.2/MMBtu. Impliedly, and in contrast to earlier research by Kaiser (2012), Browning et al. (2015), Hughes (2014) and Daniel et al. (2017), shale gas development is not dependent on gas price alone, but equally fundamental is the fiscal regime. This discovery makes a difference in fiscal regime design theory and practice and re-echoes the role that it plays in the development of unconventional natural gas. In this study, it is thus argued for policymakers to revisit the practice of regulating the exploitation of unconventional natural gas with a one-size-fits-all fiscal regime for both conventional and unconventional gas and sometimes introducing incentives policy which are inefficient as demonstrated through the impacts of pad allowance and RFES in the existing RFCT fiscal regime.

4.3. Implications for the design of fiscal regimes for unconventional natural gas

4.3.1. There is a need for greater government-contractor risk sharing through the fiscal regime design

The design of upstream fiscal regimes must satisfy certain requirements and fulfil certain principles as earlier reviewed.

First, the objectives of government must be clearly outlined for the resource in question. For most governments, this is usually done, and the primary objectives appear to be similar across countries and jurisdictions:

To attract investment to develop their oil and gas resources and or to extract or maximise the remaining reserves of oil and gas, whilst maximising financial receipts for its treasury or wealth from its resource.

(Cottarelli, 2012; Mommer, 1999 & 2000; Bindemann, 1999; Tordo, 2007).

This objective in some ways contradicts the objectives of the investing company, which may want to extract oil and gas to maximise its share of financial gains as identified by fiscal design theory (Cottarelli, 2012). In other words, there is a conflicting interest between the host government and investing company when it comes to investing and developing oil and gas, and an equal ground must be sought through the relevant agreement or contract that establishes the relationship between the state and the operating/investing company. Petroleum contracts are a derivative of the fiscal regime/design, and the state can use them to fulfil its objectives for oil and gas resource development, as noted by Johnston (2003).

Second, government objectives ought to be prioritised, possibly with timelines for when it would want to achieve what from its priority list. As noted by Moore (2012) and Holditch and Madani (2010), unconventional natural gas investments are riskier to commercialise. Traditionally governments typically allocate exploration risks to oil and gas investors in line with sharecropping and principal-agent theories (See Cottarelli, 2012; Tordo, 2007; Mommer, 1999 & 2000). Nevertheless, different to this conventional practice, host governments of unconventional natural gas resources must be more open to risk-sharing through the design of their fiscal regime. For this reason, a blanket application of their more tested fiscal regime for conventional oil and gas may not be efficient for regulating unconventional natural gas, as is the practice in the UK (HM Treasury, 2014) may discourage investment.

It is argued that due to the unique risk characteristics of shale gas and unconventional natural gas in general, fiscal regimes for their exploitation must not be based on conventional principles such as neutrality, progressiveness, simplicity, stability, flexibility, fairness and efficiency in line with fiscal design theory, alone (Tordo, 2007; Johnston, 2003; Nakhle, 2008, Baunsgaard, 2001; Cottarelli, 2012). The following additional principles are therefore proposed in this research.

4.3.2. The principle of "priority" in fiscal regime design for unconventional natural gas

This study proposes a new fiscal design principle of "priority". It argues that the financial and resource development ambitions of government are linked, yet different. For that reason, governments must prioritise resource development over financial gain for any fledgling unconventional natural gas resource. Trade-off between host government financial objectives and resource development objectives may be necessary so that the tendency to achieve both objectives, even when unsupported, may not constitute an obstacle to attracting the needed investment in the resource. This trade-off is especially true for unconventional natural gas and even more critical when the resource in question is virgin, with no previous history of large-scale commercialisation by the state in its territories or territories nearby.

As noted by Moore (2012), Holditch & Madani (2010) and Ikonnikova et al., (2015), unconventional natural gas development is riskier than conventional gas, and this impacts the economic potential of the former. The fiscal regime's design must therefore recognise such uniqueness of unconventional resources, and the regime's structures and parameters ought to be commercially attractive to the investor community through a generous offering of support by the host government to industry, as evidenced through the USA's offering of tax breaks and research and development supports for its shale gas sector in its early years (Stevens, 2010).

Although such incentives may be costly to the state, it could be a significant source of government commitments to enabling industry to overcome the unique challenges that face the commercialisation of unconventional natural gas to spur investment.

Separate from the principles, the design of fiscal regimes for unconventional natural gas must reflect the context of the resource. Fundamental resource contexts that would define the overall risks to an investor would include resource virginity and resource type categorization.

4.3.3. Resource virginity

Fiscal design must address the question of whether the resource is virgin or not. A virgin resource is one without previous commercial history in the host government's territory or territories nearby. This is regardless of whether a history exists for conventional natural gas. Whilst infrastructure may exist in different states within or around the host government's territory, this should not impact the context for Resource virginity.

Where the unconventional natural gas resource is virgin, the reservation utility or the supply price of investments as espoused by Baunsgaard (2001), Bindemann (1999) and

Mommer (1999 & 2000) must be understood to be very high initially for unconventional natural gas to reflect its unique risks noted in the literature (Moore, 2012; Seidle, 2011; Holditch & Madani, 2010). The fiscal design must reflect this reality.

One way to achieve this match between fiscal regime and risk whilst protecting government's commercial interests later in a project's life is to phase the fiscal regime, beginning with very little to modest financial objective-based or less tax-driven fiscal regime, which prioritises resource development over financial gain. Such trade-off could enable the government to fulfil its objectives on resource development with modest taxes, until it could raise taxes when companies progress onto a transitional fiscal regime and to a final fiscal regime that was designed to target resource rent or windfall profits. Such a design strategy is not discussed in unconventional natural resource development fiscal research and is unsurprisingly lacking in most regimes, including in the UK.

This methodology, based on Resource virginity, is proposed for the UK's fiscal regime for shale gas, to induce some assurance or certainty into the regime to support operators in recovering their costs. It has been suggested that the design of fiscal regimes must satisfy the principle of tax neutrality. While this research does not disagree, it challenges the basic thought that the fiscal regime should not interfere or impact resource allocation (Tordo, 2007).

For unconventional natural gas fiscal regimes, complete neutrality may be unfavourable to resource development as advocated by Johnston (2003) and Tordo (2007) – the state must use the fiscal regime to influence early investment and must continue to affect resource allocation until the industry has matured. Industry maturity times are defined as the point in the industry's development where companies progress from an initial fiscal regime through a transitional fiscal regime to the substantive fiscal regime. It is noteworthy that each fiscal regime ought to include considerations for in-built features to satisfy the principles of fiscal regime design as laid out in this research.

4.3.3. Resource type categorisation – "oil-gas-mix", "gas-only" or "oil-only" matters

A novel discovery in this research is how much the fiscal regime is impacted by the type of resource to be developed. The tax regime for shale gas in the US also applies to shale oil, tight oil and conventional oil and gas (Kaiser, 2012). Nevertheless, as noted by Stevens (2010), the US's fiscal regime for shale has undergone enormous evolution, with the industry receiving significant government support in research and development funding as well as tax breaks until the industry matured and stabilised from 2007. Despite the mature nature of the US unconventional resource industry, the government continues to provide significant fiscal support to the industry with the objective of increasing domestic natural gas production and LNG production and export (IEA, 2023; Erickson & Achakulwisut, 2021).

Similarly, the UK "fiscal regime for shale gas" applies to shale gas and potentially shale oil. Nevertheless, the resource potential of the UK as published by BGS (2013) is for shale gas only. It has been demonstrated in research how the economic viability of unconventional natural gas projects depends on natural gas price, which confirms earlier works by Kaiser (2012) and Browning et al. (2013). In other words, with strong natural gas prices, shale gas investment could be viable, and the resource could be developed in line with government ambitions; and the reverse is also true.

As demonstrated in this research, the impacts of a shale gas-shale-oil resource mix on the viability of unconventional natural gas production cannot be underestimated and this consideration ought to significantly shape the design of the fiscal regime for commercializing the resource.

By implication, when designing the fiscal regimes for unconventional resources, an important consideration should be whether the resource is "natural gas-only", "gas-oil mix", or "oil-only". The fiscal regime for "gas-oil mix" or "oil-only" resource could support a more rent-seeking, tax-based fiscal regime than a natural gas-only regime. On the other hand, a natural gas-only fiscal regime may not have the same capability to support investor cash flows due to the considerably lower price of natural gas compared to oil. These results in Table 6 provide evidence to corroborate the Resource virginity discussion, that the open-door policy, which removed all taxes but ring fence corporate tax (RFCT), and capped effective tax to 30%, was more commercially competitive, resulting in superior economics. This provides a benchmark for the design of simple upstream fiscal regimes for the commercialisation of unconventional natural gas.

5. CONCLUSION

In this research, the impact of PA in the UK's fiscal regime for shale gas was validated, following the work of Acquah-Andoh et al. 2020. Importantly, geological risk to operators represented by unsuccessful well (pads) was simulated for its impact on the risk-reward sharing between the state and investor, using a well drilling success rate of 25% to 75%. This approach warranted a corresponding capture of the risk/lost capital because of pad costs, which would never be recovered due to unsuccessful production results from the operator's license. It also enabled a validation of the impacts of the current fiscal regime's effects, especially PA, on investor risk profiles. Such a risk-reward sharing examination is imperative to the design of any fiscal system, to help to fully embed the regime's overall appeal in its design and consequently illuminate potential opportunities for its designers to prove it and, where necessary, improve or adapt its appeal to attract investment during the most-risky early stages of resource development.

The results suggest that an open-door policy with tax and an effective tax rate of no more than 20% is most viable, allowing government and investor risks to be optimally balanced. The impact of an oil-gas mix in any unconventional energy project is also noted as the oil makes a significant difference to project cash flows and thus investor risk and return. An open-door policy with moderate tax rates is recommended as an ideal fiscal design to initially promote early investor confidence in unconventional natural gas projects. Due to the peculiar risks to such projects, any incentive regime would be a good strategy to attract early investments. At predetermined rate of return, the fiscal regime may be revised to include profit-based strategies such as rate of return or R-factor contracts, which then retrospectively balance investor risk and return and ensure a fairer sharing of project profitability. "Priority", "resource virginity" and "resource type categorization" are proposed as novel principles and contributions from this research, for the design of fiscal regimes for unconventional natural gas.

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