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TAXATION AND VOLATILITY EFFECTS ON REAL OPTION MODELS: A STUDY OF NORTH SEA OIL FIELDS

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Abstract

Real option and dynamic asset valuation techniques are becoming established as standard methods for evaluating investment decisions that are subject to quantifiable uncertainty. This has been particularly the case in natural resources industries. In the UK oil industry there is renewed interest in oilfield valuation techniques - the 22nd UK Offshore Licensing Round was held in 2004 with a total of 97 licences offered to 58 companies in 2004, of which 15 were new entrants to the UK Continental Shelf. Many firms involved in these bid processes now routinely use dynamic modelling and real option valuation to assess oilfield value premiums in differing operating and taxation enviroments.

Literature on PV and real option valuation is clear that models should accommodate tax effects but is unclear about its universal treatment in dynamic models. We examine the impact of the North Sea oil industry's tax regime on the valuation of shelf real options by using a sample of forty oil fields that for the period 1970 to 2001 had initial estimated reserves greater than 75 million barrels of oil. Our sample uses Wood Mackenzie primary source field data updated quarterly by analysts using bottom up field research.

Our findings are that the tax enviroment of itself will cause asymmetrical movements in both free cash flow models and option values. These results are of interest to both academics and practitioners in that that tax plays an important role in the valuation process of real options in the oil and gas sector. Our results show that North Sea valuation models that treat taxation as a deterministic function systematically overstate DCF valuation results, understate volatility estimates and undervalue real options. Specifically our analysis suggests that failure to incorporate the variable nature of tax into the valuation process leads to an 18 percent over valuation of asset PV and an under valuation of the option price by 19.5 percent.

The increased usage of real option techniques in assessing oil field bids highlights the need for valuation models to incorporate the country specific nature of tax terms. This is especially important for oil fields in the North Sea where field exploration block bidding interest remains high and the legacy of tax changes is long; demanding from financiers a new way of assessing bid values in the face of future cash flow uncertainty.

Key words: real option valuation, volatility, taxation
JEL classification: G12; G31

I. Introduction

Real option valuation (ROV) techniques are rapidly becoming an established technique for dealing with quantifiable uncertainty. Since Dixit and Pindyck (1994) introduced practical option pricing tools into capital budgeting, the adoption of ROV has been particularly widespread in natural resource industries. Many firms in the oil and gas sectors now routinely use option pricing as part of their analysis of reserve holdings or in evaluating portfolios of prospective investments.[1]

The importance of tax in valuation techniques means that several issues need further investigation. One of these issues is the role of tax in the valuation process and another is its impact on the volatility of free cash flows. In real options, as distinct from financial options, the liability for tax resides with the field and our study specifically examines the field valuation effects of the complex UK Continental Shelf (UKCS) tax terms.

Tax, or government-take (not only direct taxes but others effected through revenue sharing agreements, Value Added Tax, Petroleum Revenue Tax and royalties) remains one of the single most material factors in commercial decision-making and therefore theoretical valuation models need to reflect this.[2] Neimann and Sureth (2002) emphasise the materiality of taxation in valuation models. They consider that the correct treatment of tax in ROV models is a critical element in determining capital budgeting, investment thresholds and tax. Their view is that tax is at least as important as the risk-adjusted discount rate in the evaluation process. We concur and expand on the Niemann and Sureth (2002) findings in which they demonstrate that in general there is no consistent pattern between pre- and post-tax cash flow symmetries.

Central to the debate about the appropriate treatment of tax in valuation models is the requirement that valuation tools should be able to deal with variations in operating and fiscal conditions relating to the underlying asset. The problem of modelling taxation is a problem similar to that identified by Dickens and Lohrenz (1996) in their discussion of the underlying asset certainties essential to the option valuation process. Models that calculate the impact of taxation on project and corporate asset values need to be flexible enough to cope with 'regime specific' rates of government take.

In this study, using a unique sample of forty oil fields in the North Sea, we examine the role of tax on the valuation of oilfields and its impact on the volatility of free cash flows. Our dataset provides an ideal basis to examine this issue because of the complexity of the North Sea tax regime with its long tail of legacies and variations in tax terms.[3] Oil fields in our sample use location-specific platforms and pipeline infrastructure allowing us to treat their sunk cost element as irreversible capital expenditure, extending and building on the approach outlined by Panteghini (2003).

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[1] See Schwartz and Trigeorgis - Real Options and Investment under Uncertainty (2001)- for a wide ranging discussion of the use of ROV methods in natural resource industries.

[2] For example, the tax take for oil producing countries ranges from 40 per cent for the UK to 75 per cent for Kazakh fields.

[3] Our North Sea analysis shows that rates of government-take are not constant over time, are capable of being varied overnight as the 2005 budget showed in the UK and BP and Yukos discovered in Russia, and are inherently variable.

The renewed interest in the UKCS is reflected in the increase in North Sea bid interests where the first UK Offshore Licensing Round took place in 1964 with a total of 348 blocks, encompassing an area of 81,000 square kilometres, being awarded to 51 companies. Most recently, the 22nd UK Offshore Licensing Round was held in 2004 and during the intervening period tax terms have changed dramatically. A total of 97 licences were offered to 58 companies in 2004, of which 15 were new entrants.

Our database, provided by Wood Mackenzie, contains primary source data updated quarterly by bottom up field research.[4] The database contains among other information estimates of future production, operating expenditure, capital expenditure, reserve size and geotechnical assessments. An additional integrity check in our North-Sea-dataset is that many of the exploration blocks are held piecemeal, allowing data to be cross-referenced between corporate holdings for accuracy. This adds academic rigour to our research in that our analysis is based on data with minimal management and research bias. Using information, from the aforementioned dataset for forty oil fields in the North Sea, we show that tax specificities make it unrealistic to apply models of constant taxation under dynamic operating conditions.

In our analysis we use the actual valuation model of Wood Mackenzie, Global Economic Model (GEM), which takes into account the varying nature of tax terms. In other words, each stochastic run of variation goes through a tax filter that captures the full history of taxes applicable to cash flows. This, together with the completeness of our dataset, allows us to avoid modelling complexities encountered by the approaches proposed by Neimann and Sureth (2002).

We believe that our findings are of interest to both academics and practitioners in that we provide evidence that tax plays an important role in the valuation process of real options in the oil and gas sector. Additionally we show that the conventional assumption of a deterministic and constant tax rate on cash flows leads to misleading valuations of real options. More specifically our analysis suggests that failure to incorporate into the valuation process the dynamic nature of tax and PRT leads to an 18 percent PV overvaluation in field prices and an undervaluation of the option price of about 19.5 percent. Given the increasing usage of real option techniques in assessing oil fields the need to develop valuation models that incorporate the dynamic nature of tax is vital. This is especially important for the oil fields in the North Sea where the field exploration block bidding interest remains high demanding from financiers a new way of assessing bid values in the face of future uncertainty.[5]

The remainder of the paper is organised as follows. In section II we provide a brief overview of the UKCS tax regime as at the end of April 2004. In Section III, we review previous literature covering the treatment of tax and volatility in ROV models. In Section IV we outline our data set, UK tax terms and methodology for examining the tax impact on DCF, volatility and real option valuation. We present and discuss our results in section V and we present our conclusion in section VI .

[4] Wood Mackenzie has been a respected adviser to the energy industry for over 30 years. They combine experience with industry knowledge & list oil majors and investment banks among their client base.

II. Overview of UKCS Tax Regime - As at end 2004[6]

The UK has operated a number of different tax regimes for companies extracting oil from the North Sea. While companies developing fields have been subject to normal corporate tax, there have also been special tax arrangements for offshore development. These have variously aimed at encouraging exploration and maximising the tax-take. The principal form of corporate tax is Corporation Tax (past tax rates are given in Table 1), payable by all UK registered companies. But oil developments in the UK have, in addition, been subject to Petroleum Revenue Tax (PRT) and other impositions. [7]

Table 1: History of UKCS Corporation Tax rates

Historical tax rates	Corporate tax rate
2002 - present	40%
1999-2002	30%
1997-1999	31%
1991-1997	33%
1990-1991	34%
1986-1990	35%
1985-1986	40%
1984-1985	45%
1983-1984	50%
Pre-1983	52%

Source: Wood Mackenzie Global Economic Model notes

For current and future cash flows, we use the current standard rate of Corporation Tax in the UK, which at 30 per cent, is reduced from 31 per cent in April 1999.[8] With immediate effect from April 2002, the UK Government announced the introduction of a 'Supplementary Charge' payable on upstream profits from oil extraction. The current rate of this tax is 10 per cent. The combined effect of Corporation Tax and the Supplementary Charge raises the level of tax on upstream profits to 40 per cent.

Corporation Tax is chargeable on the upstream profits of a company. The normal deductions apply when calculating Corporation Tax profits including operating costs, capital allowances (tax depreciation), and any losses brought forward from previous years and interest costs. In addition any PRT payable is also deductible against Corporation Tax profits (see Table 2).

The rules governing the relief for losses are complex. For instance, losses from offshore operations can be relieved against profits arising from onshore activities,

[6] Fiscal tax terms are extracted from the Wood Mackenzie GEM model and cross referenced to promulgated legislation.
[7] Note that our tax tables do not include the March 2005 Budget changes.
[8] There are special lower taxation rates for small companies, giving the corporate tax structure in the UK an element of convexity.

although anti-avoidance ‘ring fence’ provisions prevent onshore losses from reducing offshore profits.

In our study, fields are impacted by legacy taxation and this requires an understanding of past terms. For accounting periods ending after 1 July 1999 large fields (defined as companies under our simplifying assumption, with profits in excess of £10,000,000) pay Corporation Tax in four instalments starting six months from the start of the accounting period and ending three months after the end of the accounting period. Transitional arrangements apply for the first three years. Companies that do not qualify as large companies continue to pay tax on the same basis as before these changes were implemented i.e. nine months in arrears.

Table 2: Petroleum Revenue Tax rates for the UKCS

Historical PRT rates	PRT Rate
1993 - present	50% / 0% *
1983-1993	75%
1980-1983	70%
1979-1980	60%
1975-1979	45%

Source: Wood Mackenzie Global Economic Model notes
*0% on fields developed after March 1993

In April 2002, the UK Government announced the introduction of a 'Supplementary Charge' at a rate of 10 per cent effectively increasing the tax on upstream profits to 40 per cent. By way of alleviating this additional tax the UK Government now allows most future capital expenditure to be fully depreciated in the year incurred, instead of the previous 25 per cent per annum declining balance under the Writing Down Allowance (WDA), see Table 3.

Table 3: Write Down Allowance rates for the UKCS

Historical rates	WDA rates
Prior to 14 March 1984:	100%
14 March 1984 31 March 1985:	75%
1 April 1985 31 March 1986:	50%
On or after 1 April 1986	0%

In the November 1996 Budget, changes were announced affecting the tax treatment of long-term assets. In cases where the working life of an asset treated as plant and machinery is more than 25 years, the rate of relief was reduced from 25 per cent per annum to 6 per cent per annum. The rules did not apply to expenditure, which was incurred prior to 1 January 2001 under a contract entered into before 26 November 1996. In the 2002 Budget, the UK Government partially reversed the WDA treatment of these long-life assets and the WDA was increased to 25 per cent in the first year.

Prior to 26 November 1996 the cost of drilling development wells (such as incremental manpower cost and rig hire) was also eligible for 100 per cent relief in the year in which the expenditure was incurred, under the so called "New Brunswick" rules. However, any such expenditure incurred on or after 26 November 1996 only qualifies for relief at the normal rate of 25 per cent per annum.

Prior to 1986 first year allowances were granted on assets during their first year of life at various rates in place of the WDA. The normal WDA was then applied in subsequent periods.

Exploration costs are treated as scientific research expenditure and are eligible for the scientific research allowance. This allowance is at the rate of 100 per cent enabling the write-off of such costs in the year in which the expenditure was incurred.

From the above it is clear that the legacy nature of corporate tax (Table 1), petroleum revenue tax (Table 2), and capital expenditure allowances (Table 3) is highly variable and is likely to impact both cash flow volatility and value of oil fields.

III. Literature Review

Prior to the comprehensive treatment by Neimann & Sureth (2002) and Agliardi (2001), approaches to modelling tax effects in dynamic models varied widely. These authors provided a framework for examining the stochastic effect of taxation in ROV models. Early approaches to integrating taxation into models followed the approach taken by Paddock, Siegel and Smith (1988) who dealt with taxation by adjusting pre- and post-tax cash flows by a deterministic coefficient, representing the effect of corporate taxation over time.

The seminal paper on ROV applied to natural resources by Brennan & Schwartz (1985) made use of the simplifying assumption that cash flows and costs follow production while reserve valuation 'follows' Brownian motion. Little is mentioned about taxation. This assumption simplified the analysis and allowed them to model real options as decision strategies for exploration.

Panteghini (2003) explored the dynamism of the effective tax rate with application to the investment timing decision and flexibility and ended by accepting the shortfalls of current theory in dealing with taxation in a universal way.

This simplification is not confined to academic literature. Mun (2002) in his practitioner's guide, when discussing the development of ROV models, recommends running lognormal volatility estimations based on stochastic or expected after-tax cash flows, presuming their accuracy and prior computation. This approach is in line with other respected textbooks on real options. For instance Amram and Kulatilaka (1999) also make no specific mention of the asymmetrical tax effects in dynamic models.

There are some authors who have grappled with this topic; a detailed treatment on the issue of government take is given by Salhor (1998) who explicitly models the impact of ad valorem royalties and the timing of project capital expenditure and its tax treatment. He does not extend his analysis to the impact on dynamic project values.

Bradley (1998), Laughton (1998) adopt a 'corporate level' analysis of the tax problem, illustrating a project and an income approach to the treatment of taxation. Both are valid approaches but nonetheless do not develop the concept of taxation at the level of the real asset.

In a paper that examines pre- and post-tax effects across tax regimes for Norwegian oilfields, Lund (1992) provides important insights into the comparability of fiscal regimes and their relative efficiencies. He finds that the tax treatment is a key factor in determining return and investment. However, he does not extend his analysis to study the impact on dynamic volatility distribution and project values.

Paddock, Siegel and Smith (1988) create a parsimonious model for valuing offshore leases (in the Gulf of Mexico) where they treat the impact of taxation as a linear function of the tax rate. They highlight three important issues concerning the impact of tax on project value that also characterise our dataset. First, they indicate that only about 10 per cent of project costs in their sample were capital investments. This is a material percentage deserving more correct treatment than write off, and an approach that cannot be applied to the North Sea. Comparable-sized fields situated in the North Sea require significantly greater investments as a proportion of future cash flows since fields are often in less sheltered water, operating at greater depth and distance from established pipelines. Second, they highlight the important timing differences between initial capital investment and subsequent income, and third, that tax should be included in calculating the distribution of project cash flows.

Dickens and Lohrenz (1996) in an excellent general critique of ROV methods identify practical problems with the models. As part of their general analysis, they mention the problem of tax in the context of before and after-tax cash flows, but do not extend their analysis into the impact of tax on dynamic models of variance.

Neimann and Sureth (2002) in their examination of taxation in dynamic models find that tax specificity and asymmetry prevent dynamic models reaching universal solutions. They attempt to model non-linearity by first integrating taxation into a generalised contingent claims analysis framework and then by using dynamic analysis. They conclude that both methods fail to lead to a universal model.

IV. Data and Methodology

Data

Summary reserve statistics for the (UKCS) as a whole are given in Table 4. Larger fields were selected, restricting the sample to mature 'in production' fields allowed us to minimise the cash flow and tax effect of initial capital expenditure. Loss making fields were eliminated on the basis that tax losses distort field cash flows by reflecting tax as a subsidy.[9]

[9] In restricting ourselves to the larger North Sea fields, we are guided by the observation in Jacoby and Laughton (1992) that there is an element of taxation cross-subsidy for smaller oil fields within the UK continental shelf.

Table 4: Summary statistics for UKCS oilfields (1)(3)*

Oil Reserves (million tonnes)	Proven	Probable	Proven & Probable
Ultimate Recovery(2)			
Fields in production or under development(4)	3383	223	3605
Other significant discoveries not fully appraised	0	63	63
Cumulative Production from decommissioned fields	98		98
Total Ultimate Recovery(2)	3481	286	3767
Cumulative Oil Production to end 2003(5)	2910		
Oil Reserves in million tonnes(2)(4)	571	286	857
Oil Reserves in million barrels(2)(6)	4487	2227	6713

*Data source: DTI
Notes:
(1) Includes onshore as well as offshore fields. All figures include condensate, gas liquids and liquefied products.
(2) All entries are rounded to the nearest one million tonnes or one million barrels.
(3) The maximum reserve estimate is the sum of proven, probable and possible reserves.
(4) The oil reserves include 64 proven, 65 probable and 94 possible million tonnes in approved fields under development but not yet producing.
(5) Cumulative production to end of 2002 has been revised upwards by 5 million tonnes- DTI website adjustment.
(6) The conversion factors used are 7.5 barrels/tonne for oil, 8.5 barrels/tonne for condensate and 11.5 barrels/tonne for natural gas liquids – in valuing fields we only value the oil.

In valuing oilfields for this study, we translate reserves into production profiles by field making use of field specific production and operating profiles from the Wood Mackenzie (2005) Global Economic Model (GEM). This extensive and well-researched bottom up database allowed clear and consistent models to be constructed for all fields included in the study, a summary of aggregated sample values and field lives is set out in Table 5.

Table 5: Summary valuation statistics* of UKCS oilfields sample

Sample of 40 North Sea Fields	No. of years (average)	Pre-tax (US$ million)	Post-tax (US$ million)
Full life	36	1,281,703	303,830
Remaining life	11.9	34,301	14,702

*Only Oilfields with initial Department of Trade and industry (DTI) reserve estimates in excess of 75 million barrels (mmbbl) and still in production in 2005 were considered for inclusion in the sample. The study only includes fields whose development plan had been approved before 2001.

Oil prices in valuation models are the topical subject of macroeconomic uncertainty but are not the focus of this paper – we attempt to normalise price to future expectations and have therefore assumed pricing to be constant across all fields[10]. The result of standardising across all fields is that in our pre- and post-tax ROV values differ only by the impact of volatility.

Our study assumes tax terms for the UKCS as at the end of fiscal 2004, where post-2004 all upstream operations are governed by concessions. Fields with development prior to 16 March 1963 are modelled as being subject to Petroleum Revenue Tax at a rate of 50 per cent in addition to Corporate Tax and the Supplementary Charge. Valuations are carried out in US dollars with sterling field expenses translated at a fixed exchange rate of US$1.8 to the pound.

The maturity profile of North Sea fields and the current UK tax regime means that in 2005 fields effectively operate in a profit-based tax system. To simplify the analysis we treat each field as a standalone asset and taxpaying entity.

Methodology

We conduct our study in three stages. Firstly, using the tax terms set out in the previous section, we establish our DCF valuation model in order to obtain the pre- and post-tax DCF valuations. Secondly, we use the DCF results to perform embedded and deterministic calculations for volatility. Finally we perform ROV valuations using volatilities derived from embedded and deterministic tax models developed in stage two.

Stage 1: Valuation

We adopt the Wood Mackenzie Global Economic Model (GEM) for field valuations in order to calculate the DCFs. GEM is a deterministic DCF valuation model that we use to highlight the potential tax based modelling difficulties. Pre and post-tax valuations are obtained for each oilfield in our sample. The GEM model provides us with the net present value of each field from the time of its inception until 2005 (takes into account initial costs) and also provides us with the expected present value of each oilfield for the remaining of its life.

At this stage we modify the model in order to take into account the fact that tax changes over time. Therefore we develop two sets of post-tax models: the *deterministic models*, where tax coefficient is constant, and the *embedded models*, where tax coefficient changes over time.

Using a deterministic/constant coefficient for taxation the post tax value of the field will be

$$\sum_{t=1}^{n} FCF(1-t)$$

[10] A model assumption - of a mean reverting price with a future pricing of $37.50 for 2005,$33.00 in 2006, decreasing to $28.00 in 2007, normalising to $25 in 2008 and increasing by the rate of inflation of 2.5 per cent thereafter

Where:
FCF is expressed in present value terms and
t is a constant tax rate of 30 per cent plus the Supplementary Charge of 10 per cent, as introduced in 2002. [11] Note that PRT is not uniformly applied across all fields and therefore is not dealt with in the deterministic model. We do however aggregate the impact of PRT across our sample and use these results to analyse our results and findings.

Under the embedded model approach the post tax value of the field will be

$$FCF1 \times (1–t_1) + FCF_2 \times (1–t_2)\ldots FCF_n \times (1–t_n)$$

In the embedded model t changes over time. For the period 2002 until 2005 we use the rate of 30 per cent plus the supplementary charge of 10 per cent, as introduced in 2002.[12] For historic flows, we use the historic tax rates from Tables 1 and 2.

Using this method, dynamic analyses are possible since time period specific tax terms (t_n) are embedded in our field model. In the embedded model legacy taxes are also levied on 'in place' revenue streams, as is Petroleum Revenue Tax. Cash flows are therefore made up of revenues less PRT (not applied to fields granted approval post 1993), Corporation Tax, operating costs, and capital allowances. Actual historical exchange rates have been used.

Stage 2: Estimation of Volatility

At this stage we estimate the volatility of cash flows under both approaches: deterministic and embedded. We provide evidence that pre- and post-tax volatility under the deterministic approach is identical whereas under the embedded approach is different before and after tax.

We use the above principles to model longitudinal volatility, comparing pre- and post-tax DCF volatilities at differing stages of the field life, highlighting the asymmetrical nature of the relationship between taxation and cash flows that exists over time.

We then establish cross sectional volatility and tax asymmetry using dynamic variations in production, varying the base case both up and down by 20 and 40%.[13]

Stage 3: ROV Results

We conduct real option valuation valuations for 40 oilfields using base case EV and DV measures for the remaining life of the field (i.e. from 2005 to the end). Advanced valuation models would perhaps assume stochastic behaviour for volatility; however

[11] We make the simplifying assumption that each field is a standalone entity instead of using the actual corporate field holdings
[12] For analytic purposes, we make the simplifying assumption that each field is a standalone entity instead of using the actual corporate field holdings. This does not change our results. It is worth noting that those companies which can benefit from tax offsets would be able to create value by acquiring fields that best accelerate tax recovery and hence would value these fields more highly.
[13] This has the academic merit of allowing operating expenditure to vary with production and thereby isolates the tax effect. Varying price volatility by 20 per cent and 40 per cent would have added to the tax asymmetries- since price increases do not carry associated field extraction costs.

for the purpose of this paper we content ourselves with the lognormal ‘point’ form measure for volatility and multiple step binomial lattice calculation that is common in the literature (Mun, 2002, Trigeorgis 1991). As with most work in this area, the classic closed form equation proposed by Black and Scholes (1973) underpins the basic structure of our valuation process. The only difference in our approach is that we work not in continuous time, nor closed form models, but in lattice models.

The benefit of this approach is that the volatility measure is based on representative after tax figures for each field. Due to the cost of rehabilitation and abandonment in the North Sea we consider limited expansion and contraction options.[14] We allow these to vary up to 20 per cent on the upside and 20 per cent on the downside from the base case.[15] This option gives the holder the ability to choose one of the following actions at any time within a particular period: contract existing operations by a contraction factor to create savings in a market downturn or expand operations at an expansion factor by spending an appropriate implementation cost in a market upturn.

V. Results and Discussion

We summarise our results in three stages. First we report the results of the DCF approach to oilfield valuation pre-tax and post-tax. Then we review the results of the cash flow analysis for volatility calculations and finally we analyse and contrast ROV values derived using embedded and deterministic volatilities.

Stage 1: Valuation

Our DCF analysis compares field valuations from inception using pre- and post-tax cash flows under both the deterministic and embedded tax treatment approaches. As Table 7 shows, for the whole sample we find that in general, deterministic results consistently overvalue fields by 30.7 per cent for full life valuations and 32.8 per cent for remaining life. One caveat to the results is that due to PRT and its inconsistent application across oilfields, these overvaluations are themselves overstated by approximately 12 percent across the sample. When PRT at 50% is included in the deterministic calculations, the overvaluation falls to 18.7% for full life and 20.8 for remaining life valuations. Table 6 excludes this PRT effect since it is inconsistent across fields in that only pre 1993 field attract PRT. Table 6 is therefore a homogenous PV comparison and highlights at a sample level the divergence between pre- and post-tax figures from full field life to remaining life.

Table 6 read together with Figure 1 shows at a field level that deterministic post-tax project valuations systematically underestimate government-take over the full life of the fields. Using embedded tax, the post-tax valuations indicate an average government take of 77 per cent over the life of the field, leaving a post tax/pre tax valuation ratio of 23 per cent. Using the deterministic approach gives a ratio of 31 per cent. The results suggest that initial capital expenditures adversely affect after-tax valuations. Since companies pay field capital expenditures and taxes, initial PV

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[14] To standardise the impact of implementation costs and savings across the sample, both expansion and contraction option scenarios are based on 12.5 per cent of remaining life base case valuations.[14] The 12.5% was based on the UKCS sample ratio of Capex to total project value.
[15] Included in Wood Mackenzie data

valuation ratios are therefore low as companies are in effect funding the government's take.

In an attempt to isolate these factors, we model both whole life and remaining life field values starting from 2005 for the remainder of the expected reserve life. The maturity of our fields minimises the effect of initial investment expenditures that are included in the whole life valuation estimates. This step improves the average pre- and post-tax valuation ratio from 23.71 to 42.86 per cent, still 14.05 percentage points below the 56.91 per cent ratio obtained using the deterministic method. Figure 1 shows the summary by field and demonstrates the consistency with which values are overstated using the deterministic approach.

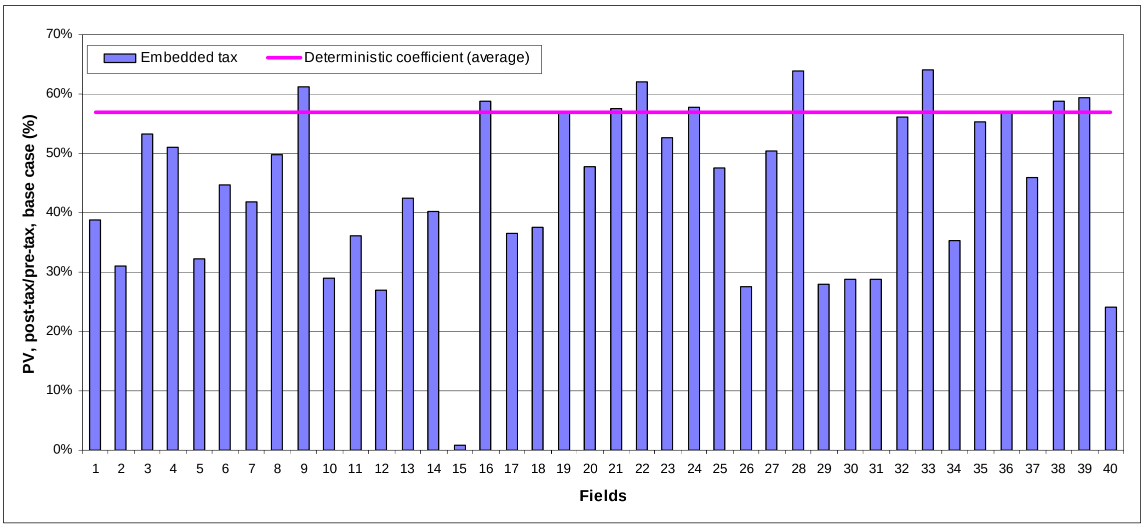
Table 6: Total UKCS sample present value - based on pre-tax and post-tax cash flows calculated for full field life* (and for the remaining life of fields as of 2005)

PV (US$ million)		Pre-tax	Post-tax	Post-tax/Pre-tax
Embedded tax method	Full life	1,281,703	303,830	23.71%
	Remaining life	34,301	14,702	42.86%
Deterministic coefficient tax method	Full life	1,281,703	397,841	31.04%
	Remaining life	34,301	19,521	56.91%
% difference (embeded vs. deterministic)	Full life	0.00%	30.94%	
	Remaining life	0.00%	32.78%	

*All values re-based and expressed in 2005 terms

At field level, our results provide support for the findings of Neimann and Sureth (2002) that a pattern of asymmetry exists in underlying cash flows. Figure 1 shows that only 9 out of 40 fields had embedded values above the average deterministic valuation. Tax effects vary considerably by field, with the embedded post-tax valuation ratio for fields on average 9 per cent less than those derived using the deterministic model. These results strongly suggest that the pre-/post-tax valuation ratio is dependent on many field specific factors such as initial capital expenditures, historic write down allowances, life to expiration, exposures to PRT and historic tax rates.

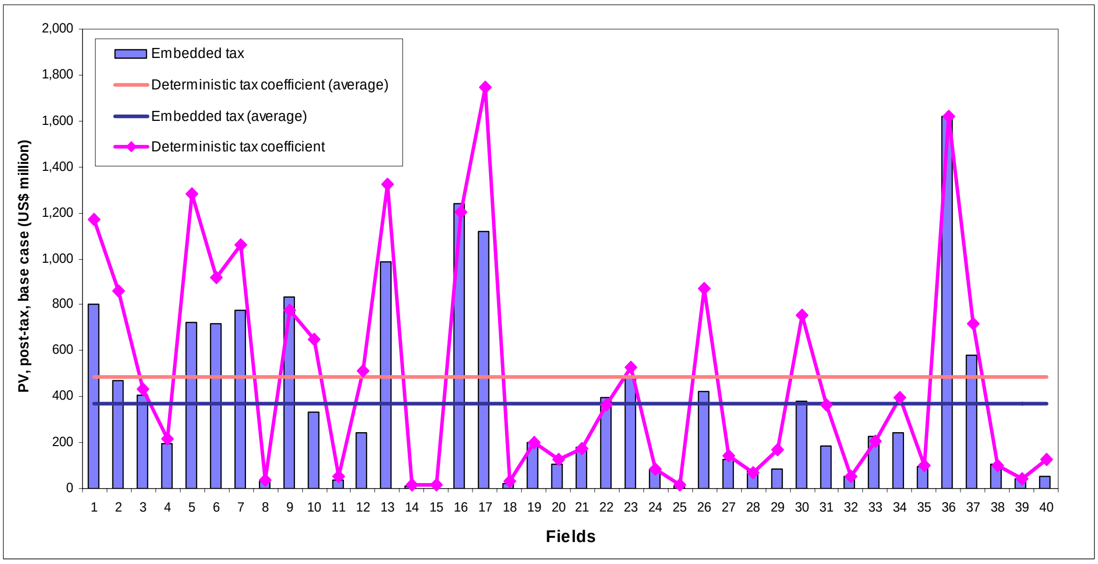
Figure 1: Remaining life embedded post tax PVs by field



Stage 2: Estimation of Volatility
A key element in ROV models is the volatility estimation of the underlying asset flows (PV measure). To avoid bias and distortion in volatility requires a time period of representative cash flows. Therefore we completely exclude the initial capital expenditures and initial write down allowances which allow us to focus on cash flows representative for calculating expansion and contraction ROV scenarios.[16,17]

Figure 2 illustrates the embedded and deterministic valuation results for the remaining life estimates at the field level. It indicates that for the base case cash flows, the embedded 2005 field values are consistently below those derived using the deterministic valuation approach.

Figure 2: PV field values for remaining life from 2005



In summation, the post-tax PV/pre-tax PV valuation ratio varies longitudinally, from 23 per cent over the whole field life to 42 per cent (when we consider only remaining life from 2005) and 44 per cent (when we exclude initial capital expenditures) to 81.6 per cent (when, in addition, we exclude abandonment expenditures).

Valuations are also asymmetrically tax sensitive to variations in field production levels. We demonstrate this by varying the 2005 base case estimates by changing production by up to –/+40 percent.[18] This approach allows us to isolate differences that occur from using the deterministic approach versus the embedded model. Table 7 shows that the results vary asymmetrically from 40.79 per cent to 43.12 per cent. Figure 3 highlights graphically the non-linear nature of the changes. For ease of graphical representation we show only ten fields, six of which show downward sloping PV asymmetries over the production scenarios while three had increased PVs and one remained constant.

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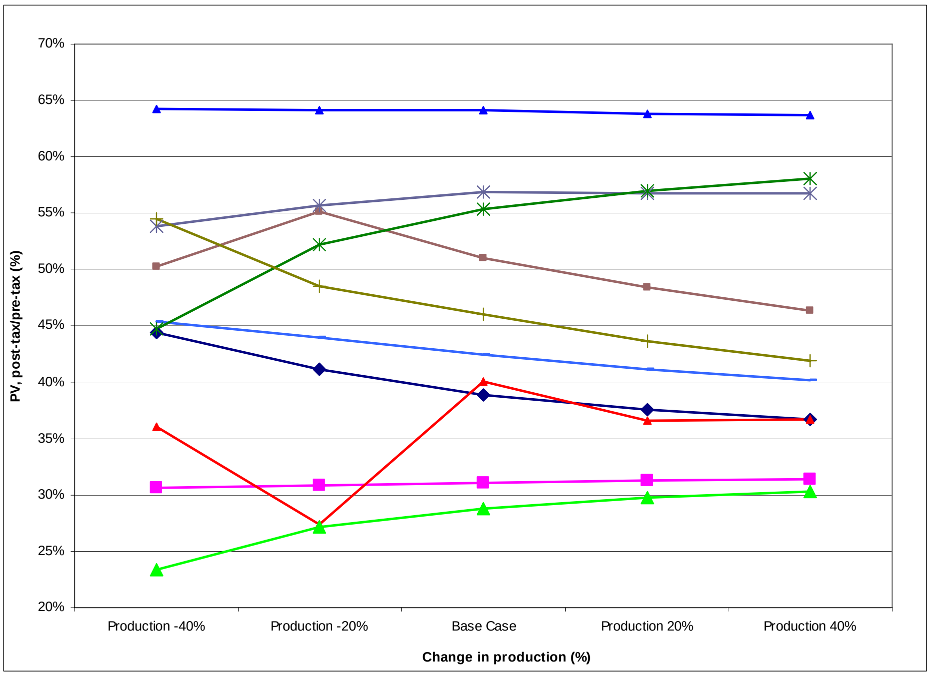
[16] Our estimates also exclude abandonment costs which, otherwise, would significantly affect the asset cash flow volatility estimates.
[17] The result of excluding initial capital expenditure and write down allowances is an increase in the post-tax PV ratio to 44 per cent; when we refine our sample even further by excluding end of field abandonment costs then the resultant valuation ratio increases to 81.6 per cent.
[18] Without the loss of generality we report results only for -40, -20, +20, +40 percent.

Table 7: Sensitivity of sample PV's using the embedded tax method

PV (US$ million) Remaining life	Embedded tax method		
Change in Production	**Pre-tax**	**Post-tax**	**Post-tax/Pre-tax**
-40	18278	7456	40.79%
-20	26299	11151	42.40%
Base Case	34,301	14,702	42.86%
20	42291	18206	43.05%
40	50272	21676	43.12%

It is difficult to draw general conclusions as to causality of differing field PV ratios, but our analysis suggests that projects which are post initial capital expenditure, or have low field capital expenditure with longer field lives (comparable to mature fields) exhibit lower variance in the PV ratio. These fields have asymmetries which are likely to be positive or, as shown in Figure 3, with upward sloping lines. It is also the case that PRT status plays a role in determining the pre- and post-tax cash flow asymmetries.

Figure 3: Extract of ten fields showing cross-sectional PV (%) sensitivity to change in production - randomly selected from the full sample of 40 fields



This PV analysis supports our contention that the deterministic approach materially oversimplifies the taxation effect on actual cash flows. We therefore reject the deterministic method of taxation as a sound basis for traditional DCF valuation and especially in those cases where legacy charges or capital allowances exist.

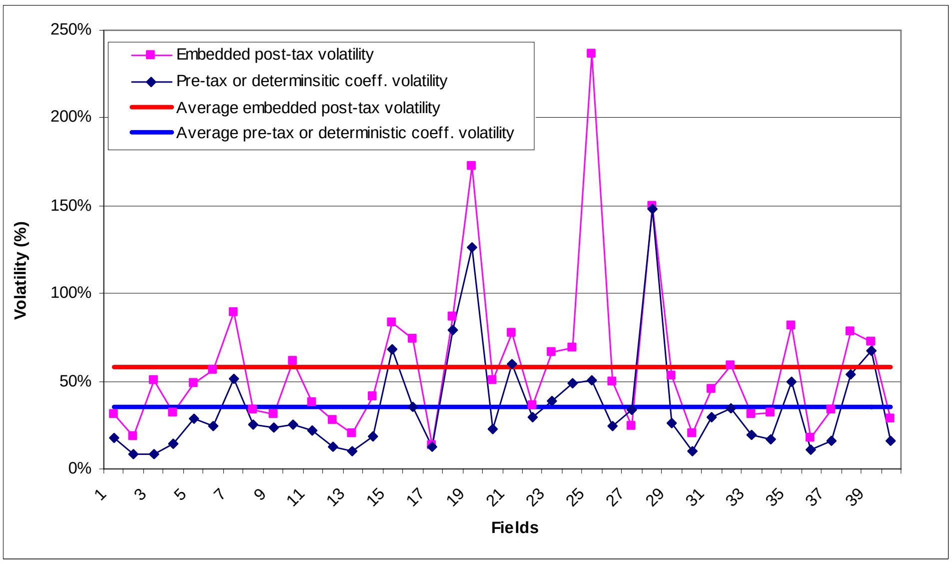
Based on the pre- and post-tax DCF volatility estimations carried out for the remaining life of the field (from 2005 to the end, excluding initial capital investment) we show that embedding tax provides materially differing field measures of expected volatility compared to the deterministic method. The results from the two approaches are given in Table 8. The average of the cash flow volatilities from the deterministic model was 35.46 per cent while the average embedded model volatility was 58.6 per cent. Recall that before and after-tax volatility are the same in the deterministic models.

Table 8: Comparative sample volatility estimates after tax: derived from embedded tax and deterministic approaches

Volatility (%), Remaining life	Pre-tax	Post-tax	Change post-tax to pre-tax
Embedded tax method	35.46%	58.10%	22.64%
Deterministic coefficient tax method	35.46%	35.46%	0.00%

The increase between pre- and post-tax volatility in Table 8 is 22.64 per cent and is a consistent finding across the sample, as shown in Figure 4. At the individual field level, deterministic volatility was consistently below that derived using the embedded model.

Figure 4: Field level results for embedded and deterministic volatility estimates



Stage 3: ROV Results

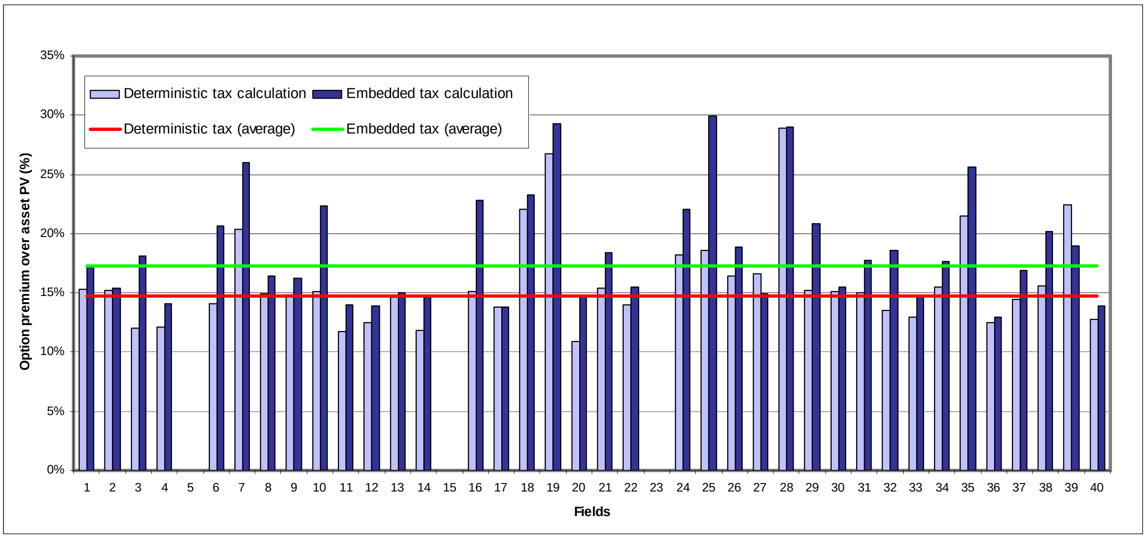
With the ROV approach, as the value of the underlying asset (oilfield) increases with volatility, the right to buy at a fixed price (call) become more valuable and the right to sell at a fixed price (put) will become less valuable. Volatility, and more specifically after-tax volatility, is central to modelling ROV since as the variance of cash flows increases the implied real options to expand (a call) and contract (a form of put) will likewise become more valuable.

Having established that PV volatility after-tax is neither constant over time nor cross-sectionally, we show in Table 9 and Figure 5 that asymmetric changes in volatility are exaggerated by tax. We do this examining the value of the underlying asset and the option separately. The higher after-tax volatility translates into a higher premium to asset ratio. For individual fields the volatility ranges from 8.57 per cent to 126 per cent before tax. For post-tax, the range of the volatility is 13.64 per cent to 172 per cent. As anticipated by Niemann and Sureth (2002), this prevents the creation of a universal ROV after-tax measure or single treatment for volatility. In our ROV models of field value we use specific post-tax cash flow volatility for remaining life of the field, derived using our embedded model.

Table 9: Option Premium to Asset – sample

	ROV (US$ million) Remaining life	Embedded tax method			Deterministic coefficient tax method			Change in post-tax option price (embedded vs. deterministic)
	Option premium over underlying asset	Pre-tax volatility	Post-tax volatility	Change in option price	Pre-tax volatility	Post-tax volatility	Change in option price	
Base case (NPV US$14,996 million, post-tax)	(%)	1.15	1.18		1.15	1.15		
	US$ million	2249	2712	17.06%	2269	2269	0.00%	19.5%

Figure 5: Summary of field option premiums over underlying assets

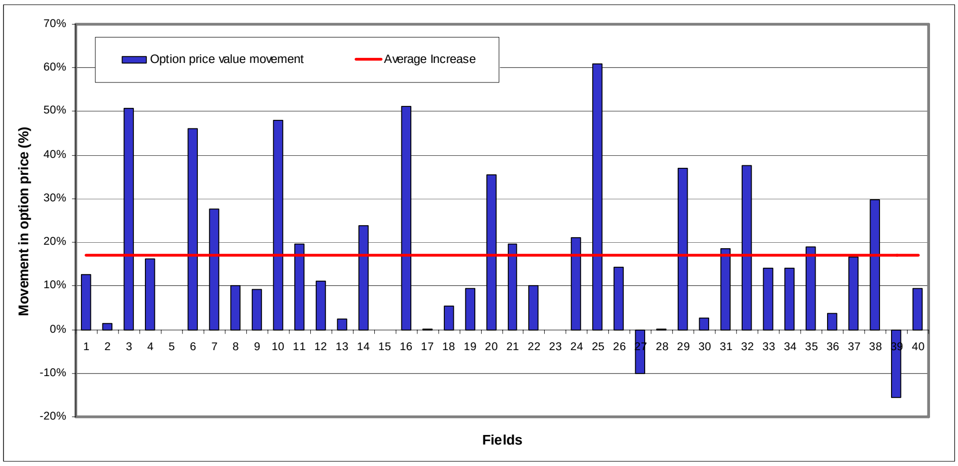


The difference between the pre- and post-tax volatility is the single variation we use in calculating the difference between deterministic and embedded ROV values. The results shown in Table 9 indicate that the post-tax embedded volatility ROV of the base case option varied significantly from that derived from the deterministic method. With the deterministic method, the average premium in value over and above the DCF valuation was 15 per cent. Using the embedded method and the post-tax volatility this premium increased to 18 per cent.[19] At the combined DCF field and ROV valuation level this is an increase in value of 3 per cent. For the real option in isolation, the difference is a more material, being 17.06 per cent.

As shown in Figure 5, our ROV analysis demonstrates that models that do not specifically model the embedded tax effect for the UK North Sea shelf systematically overstate the discounted cash flow (DCF) and understate ROV estimates at sample and field level. Since these differences are not mutually offsetting, the correct approach involves determining the embedded tax effect when valuing the oilfields.

The effect of embedded tax on ROV in isolation is even more dramatic. In 38 out of 40 cases the option value increased simply as result of using embedded instead of deterministic volatilities. In only two cases, fields 27 and 39, the deterministic tax calculation increased the ROV value. The change in ROV value for the sample is shown in Figure 6.

Figure 6: Summary of field option price changes between deterministic and embedded tax volatilities



Note: The average increase in ROV value using the embedded approach is 17.06 per cent.

Given the above results, it is our view that practitioners and interested parties wanting to value North Sea investments will need to adopt a regime-specific embedded model

[19] It is worth noting here that our modelling results, which use a restrictive definition of flexibility value, suggest that 18 per cent or more of field value is due to the existence of project specific 'real options'. While this is not the aim of this paper, we believe this is the first major examination of the impact of such options on the UKCS oilfield sector.

capable of calculating tax effects under dynamic conditions to correctly identify the benefits involved.

VI. Conclusions

In financial market options, the taxation effect of the asset and the option are distinct and separable from the asset, remaining with the taxpayer. By contrast, in oilfield options, taxation effects are an intrinsic part of the asset valuation process. Furthermore, with current North Sea tax at 40 per cent plus PRT legacy charges, current rates of government-take in the UK are a major determinant in quantifying the value of risk, returns, and managerial flexibility. Also the relationship of legacy taxes to movement in underlying asset values is regime and field specific. In situations of progressive or changing government take the pre- and post-tax relationship is asymmetric and dependent on the timing and nature of expenditures and revenues.

When valuation models make use of ROV models to value fields in the UKCS, our analysis indicates an important element has to be considered, namely, that tax asymmetry exists in variable rate tax systems and those with legacy PRT charges. Our findings indicate that, for our sample, models that do not specifically account for tax asymmetries, systematically overstate DCF, understate ROV volatility input, and therefore understate the ROV outcome. More specifically we provide evidence that deterministic DCF values are overstated about 30% compared to embedded DCF values for the full life of the field and by about 32% for the remaining life of the field; when PRT is included in the valuation results, the overstatement falls to 18 and 20 percent respectively. Volatility is understated by about 23% and finally the post-tax value of real option is understated by about 19%.

Exploration and appraisal drilling activity on the UKCS has increased considerably during 2004 compared to 2003. Many exploration and appraisal wells were initiated during the year, marking an increase on 2003 activity levels. The increase is at least partially attributable to the recent high oil price which encouraged companies to appraise near-field accumulations. With the oil price remaining above the long-term average, the North Sea is likely to remain of interest to existing companies and new entrants alike. Therefore the need for dynamically modelling taxation is apparent and will be significantly more representative and useful to practitioners in their bid valuation decisions.

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