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THE IMPACT OF TAX SHOCKS AND OIL PRICE VOLATILITY ON RISK – A STUDY OF NORTH SEA OILFIELD PROJECTS

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Abstract

We examine the impact of market volatility and increased fiscal take on risk in strategic natural resource projects. An increase in 2006 UK oilfield taxation is used as a natural experiment for assessing the impact of a fiscal increase on oilfield projects comprising 73% of UK reserves. Stochastic cash flow at risk models combine market volatility and tax-take at the oilfield level to extend earlier North Sea studies. We demonstrate that a 10% Secondary tax increase in a composite UKCS fiscal system with *a-priori* nonlinearity directly increases overall cost structures, resulting in a 14% decrease in project values, and significantly, a 67% risk increase for UK Oilfields. Risk effects are asymmetrical across the size varying sample, marginal prospects are most affected.

1. Introduction

Investments in oilfield projects are expanding as executives and financiers enter new geographic markets, invest in strategic assets, accommodate alliance partners and attempt to immunise corporate entities from new venture risks. Global project finance investments reflect this trend, with general annualised advance growth of 24% from 2001-2005, building on the annual growth of 20% throughout the 1990's (Esty 2004). In value terms, advances declined briefly in the wake of global uncertainty from a high of US$210 billion in 2000 to US$80 billion in 2002 before recovering to US$347 billion in 2004 and 2005, a recovery and growth trend that is set to continue.[1] From a low share of global advances in 2001, the last five years has seen stakeholders use these structures to commit to annualised advance growth in the emerging markets of the Middle East (84%), Africa (68%) and the Indian Subcontinent (168%).

Esty (2004), provided well-reasoned insights into reasons behind the burgeoning growth of project finance that apply equally to the oil and gas sector. He categorised project finance according to the stakeholder principle as involving the creation of a 'legally independent project company financed with equity from one or more sponsoring firms and non-recourse debt for the purpose of investing in a capital asset'. We use insights into the UKCS E&P sector to demonstrate that stakeholder capital structures in natural resource projects are extremely vulnerable to variations in fiscal take and market uncertainties. The standalone nature of oilfield finance structures and their exposure to single assets are shown to be susceptible to specific risks. We examine the impact of two of these; fiscal

[1] Regional Project Finance Activity 2000 – 2005 – Banking League Table, Project Finance Magazine - March 2006

take (measured by the tax impact on overall project leverage) and market uncertainty (characterised in our study by commodity price volatility).[2]

By treating the 2006 UK continental shelf (UKCS) change in supplementary corporate taxation for oilfields (SCT) as a natural experiment, we use stochastic models to determine the impact of fiscal terms on overall risk. We find that, while field values fell, downside risk increased disproportionately for UKCS project stakeholders when in December 2005 Gordon Brown, the Chancellor of the Exchequer, changed the government's take. In his pre-budget statement the Chancellor noted: "*...the tax on new development in the North Sea (is) now lower than in the USA and the Gulf of Mexico, Norway, Italy and Australia, and in order to strike the right balance... ...I will raise the supplementary North Sea charge from 10% to 20%*".

Prior to the increase in Supplementary Corporation Tax (SCT), the taxation rate for new UKCS fields was 40%, made up of Corporation Tax payable at a rate of 30% and of SCT at 10%. With no change in the Corporation Tax rate, the pre-budget statement increase lifted the effective field tax rate from 40% to 50%. We analyse this tax change modelling the interaction between market price volatility, and tax take before and after the tax announcement. Specifically, the blanket 10% SCT increase allows us to examine three questions concerning the combined impact of market uncertainty and taxation on asset cashflow at risk (CFaR).[3]

First, we analyse whether the SCT effect is equitable across all UKCS fields by focussing on the differential impact of tax (and therefore fiscal take) across the

[2] Throughout our analysis we use the term 'goverment take' as understood in the oil industry; namely, as the percentage of present value of tax paid over field life in all forms of government levied taxes after taking account of fixed and operating cost allowances.
[3] We use the term natural experiment as defined in economics, namely the situation where an isolated change in one aspect of the economic environment occurs making it possible to study the effects of that change as if it were an experiment; that is, by assuming that every other exogenous input remains unchanged

sample, finding that fields experienced an average reduction in value of 14.65% and that this reduction varied widely across the sample due to differences in leverage (oilfield size).

Next, we use stochastic CFaR risk measures to analyse the effect taxation on operator risks, demonstrating that while value fell by an average 14.65%, field risks (as measured by the ability of a field to attain pre tax increase present values) increased disproportionately by 67.09%.

Finally, we analyse the impact of taxation on field leverage (measured as: the present value of total field revenue/ the present value of fiscal take) on risk, and the UK government's objective of encouraging new UKCS investment. Our results provide strong evidence that value reduction and the impact on risk characteristics has the most effect on marginal oilfields and hence is likely to run counter to the government's aim of stimulating tertiary developments in the North Sea.

We begin by reviewing prior studies of value at risk models and UKCS fiscal terms before introducing our data set. We then focus on our stochastic valuation and CFaR methodology before concluding by reviewing our results.

2. CFar and Taxation in Oilfield Finance Literature

Esty (2004) in his review of project finance observes that there is a paucity of research in this area. We agree with his insight that project finance studies provide rich scope to study market volatility and risk.[4] To cover the latter two attributes, we draw on both corporate finance studies assessing risk measures and on economic literature, covering the desirable characteristics of taxation models in oilfield investment decision making.

Research on appropriate measures of market risk for non-financial firms have recently focused on extending the value-at-risk (VaR) method initially developed for financial institutions into general corporate use (Froot, Scharfstein and Stein 1993, Stulz 1996, and Stein et al, 2001). Applied studies of VaR suggest it (and by extension CFaR) can be estimated from modelling the uncertainty of a firm's future cashflows and consequently can be used to compute the total variability of value to market and project-specific risks. In an approach close to that adopted in this paper, Jobst, Mitra and Zenios (2005) extend VaR into a multiperiod analysis, a measure of risk more appropriate for untraded and illiquid assets held over long periods of time. Andren, Jankensgard and Oxenheim (2005) propose a measure for estimating the amount 'at risk' using a cashflow-at-risk (CFaR) approach that, like ours, estimates the maximum shortfall in cash at a given confidence level (within dynamic models).

Lund (2003) makes the point, in the context of the cash flow modelling problem, that taxes have imperfect loss offset; noting that if an oilfield's tax base is negative one year, there is no immediate refund to offset taxable losses, but only the ability to set current losses against future profits. He expands the point that imperfect loss offset tax claims are analogous to (fiscal) call options on future cashflows. [5] Lund (2006), also observes in a later work that the economic theory of neutral business taxation under uncertainty is fairly well developed, but that there are several obstacles to its practical application in the petroleum sector. Not least of which is the existence of composite tax charges, the UKCS for instance

[4] Esty (2004) traces the history of project finance from the 1299 financing of a Devon silver mine through the 1930 wildcat financing of oilfields. He finds that modern project finance has its roots in the natural resource and the independent power producers financing of the late 1970s and 1980s.
[5] Under UK tax rules losses in one fiscal period for UKCS fields may be carried forward but there are limitations to this and the present value is not maintained

has PRT, corporate taxation, SCT and royalty taxation. Early oilfield studies of risk avoided this difficulty and often dealt with taxation as a constant function ratio (that is, 1 – tax rate) with little regard to field-specific tax conditions, dynamic operating conditions and commodity prices.

In North Sea studies, Favero, Pesaran and Sharma (1992a) for instance emphasized that the prerequisite to omit tax from an econometric model was tax neutrality, a condition that does not hold for the UKCS. They gave two reasons for the non-neutrality of pre-1992 UKCS tax terms: (1) the lack of progressiveness (PRT is ad hoc, not progressive) and (2) the ring fencing of losses on exploration from other field profits; early insights that provide a clear indication of the asymmetrical effects of UKCS fiscal terms. In a later study, Favero, Pesaran and Sharma (1994) extended their earlier paper and considered the consequences of irreversibility of capital expenditure and valuation difficulties involved in the investment decision by examining the valuation of a single North Sea oilfield. In an in depth study, Bradley (1998) notes that when policy makers consider a new fiscal system (like SCT) a primary concern is to maintain royalty and tax receipts rather than project investment.

In a study that examined the tax effects for North Sea oilfields, Hahn and Rowland (1986) criticized the uneven effect of PRT which led to ad hoc tax treatment for some less profitable fields. In another analysis of PRT and UKCS tax related changes, Jacoby and Laughton (1992) noted that the nonlinearities and asymmetry in the then prevailing UK offshore fiscal regime moved risk from the operators onto the government. A more recent study by Zhang (1997) provided a contra perspective on the impact of PRT, where he argued that PRT, by uplifting the tax rate on revenues after the upfront development allowances are depleted, could lead to a neutral tax effect. Like Lund (2003), Neimann and Sureth (2002) emphasise the materiality of taxation in valuation models. They consider that the correct treatment of tax in dynamic models is a critical element in determining capital budgeting but find that tax specificity and asymmetry prevent dynamic models reaching universal formulaic solutions.

A solution designed to correctly account for tax terms and price uncertainty in stochastic CFaR measures is proposed by Kretzschmar, Moles and Charalambos, (2005), they use an approach where *each pre-tax simulation* is passed through a detailed tax adjustment to cash flows 'inside the field model' using composite calculations for UKCS government take, that is, PRT, SCT and Corporate Tax terms – for each simulation of after tax cash flow. This approach correctly specifies the tax effect at the field level and the computation of CFaR for all iterations by calculating the field tax applicable to each price assumption.

3. Valuation and Sample Field Characteristics

The O&G industry, and in particular producing fields, provides a useful testing ground for assessing project risks. Projects are based on definable assets which require predictable initial and ongoing capital investments. Assets also have a specific life during which the resource is exploited and ultimately abandoned with a largely homogenous and actively traded O&G output. Finally global oilfield tax terms, or at least elements of them, are often clearly aligned with the field as opposed to the corporate entity, an important feature of our UKCS natural experiment. Ironically it is this very homogeneity that makes it possible for the government to target the O&G sector with specific taxation measures without affecting other corporate taxpayers.

Sample selection was determined by eliminating all UKCS fields below 6 million barrels of oil equivalent (mmboe) remaining.[6] Thereafter the remaining O&G reserves as at January 2006 were ranked according to descending reserve size. In order not to bias the sample remaining fields were ranked, split into quartiles with 10 fields randomly selected from each quartile to obtain an additional sample of 40 smaller fields. In analysing the total sample of 70, one small field was rejected on the basis of having extraordinarily high levels of abandonment expenditure, leaving 69 in the final analysis.

Summary statistics for the field valuations are given in Table 1 and show that the average life of a field in our sample is 21 years and represents 66.55% of total UKCS O&G remaining reserves, 73.16% of oil reserves and 59.07% of gas reserves. The extent of our sample allows us to analyze the size varying effects of government take for 'in production' oilfields and to reach general conclusions not possible from single field studies. We also use stochastic modeling to identify the risk characteristics for our sample. Our analysis is simplified by the fact that there is little technical and exploration risk for producing oilfields.

[Insert Table 1 about here]

A comparison of initial and remaining reserves in columns 5 and 8 of Table 1 indicates that with less than a quarter of reserves remaining, most fields have been in-production for a number of years. The UKCS petroleum province saw oil production peak at 934 million barrels in 1999 and since then has declined at around 6% per annum (Department of Trade and Industry). Our Quartile 1 fields have on average 36 mmboe of oil and 84 mmboe O&G remaining and are less than 2% the size of Top 30 fields. In this context, the UK Offshore Operators

[6] Fields below 6mmboe are not sampled as they display very high degrees of specificity and are generally close to abandonment

Association (UKOOA) notes that the average size of discoveries in the UKCS between 1995 and 2004 was 26 mmboe, comparable to about one-tenth of the size of average discoveries in the first ten years of the sector's life, putting new finds firmly into the risky Quartile 1.

4. Method

We use detailed oilfield data to empirically model the effect of the increase in SCT on after-tax value distributions and risk profiles and how these relate to operational and fiscal specificities. Detailed field cashflow models incorporating oil and gas price volatility are used in a two-step process to highlight tax effects on present values. First, for all 69 fields, as at January 2006 pre-tax estimates of cashflows are derived followed by post-tax field values prior to and after the proposed 2006 increase in SCT. Second, we create dynamic models to estimate CFaR by adding price volatility to the underlying deterministic present value model, deriving whole life expected present value (PV) distributions. By treating each oilfield as a separate project we are able to avoid making assumptions about tax efficiency or the composition of the corporate portfolio. Guided by Esty (2004) we assume standalone equity structures and non-recourse debt to focus on fiscal and operational leverage.

Our estimates of CFaR are derived using a bottom-up approach in line with that proposed by *RiskMetrics* (1999) where the stochastic behaviour of production volumes, revenues, field operating and capital costs are used to derive a probability and frequency distribution of oilfield expected value over the lifetime of the field (both before and after the 2006 tax term change). In simulating the effect of government tax on field risk under conditions of oil price volatility we incorporate Bessembinder et al (1995) - prices commence in 2006 at US$52.50 per barrel and ‘mean revert’ over 4 years to $37.50 before increasing by an assumed rate of inflation of 2.5%. Each annual price is subject to a lognormal volatility distribution of 25%.[7] We run 2500 simulations for each of the 70 fields under each condition and use the results to derive a cashflow distribution for field value and CFaR, which by extension becomes a key feature of our analysis.

The simulation output is shown in Figure 1 with the results for one field simulation pre- and post-tax in Figure 1a and 1b with Figure 1c showing the difference between the post-tax likelihood of achieving the base case after the SCT change. The downside CFaR tails for both the pre- and post-tax change distributions were calculated using the pre-simulation base case value in our field model; for the field in Figure 1 deterministic PV values were US$2696.15 million pre-tax with post-tax US$961.17 million before the budget change and US$817.36m afterwards (a decline of 15%).

[Insert Figure 1a, 1b and 1c about here]

Figure 1 illustrates the pre- and post-tax certainty distribution for a field that is not subject to PRT. It is apparent that for non-PRT fields, before the tax change, the certainty of achieving the deterministic field value is approximately the same pre- and post-tax with certainty levels of 86.89% and 85.62% respectively. As will be discussed in the results section, for fields subject to PRT there is not the same equivalence between pre- and post-tax certainty. For the above field, the 10% increase in the SCT changes the CFaR in the field so that the probability of achieving the after-tax but pre-SCT increase value of US$961.17 million falls from 85.62% to 21.82%.

5. Results

[7] Note we tested oilfields under different price scenarios, including down shocks, and the principle findings do not critically depend on these modelling assumptions. Our scenarios imply a generally

The above preliminary findings indicate that for operators and financiers the field value and risk profile have been dramatically altered by the tax change. A summary of the descriptive statistics for all field simulations (by quartile) is contained in Appendix 1. Our results are summarised in two stages: first, the tax effects of operational and fiscal leverage on field values are presented and analysed. We then present and examine fiscal effects on field risk.

5.1 Operational and Fiscal Leverage Risk effects

Table 2 summarises for the sample the PV for pre-tax revenue, operating costs and capital expenditure and net cashflow by quartile, both in value terms and as a percentage of gross revenue. The analysis shows that, given indivisibilities in rig and pipeline investments and to a lesser extent operating expenditures, Quartile 1 which consists of the smallest fields, has an average pre-tax PV of US$104.57 million and the highest operational and capital expenditure leverage at 1.36 and 1.51 respectively.

[Insert Table 2 about here]

In comparison the Top 30 have an average PV of US$2565.11 million (column 4) and operational and capital expenditure leverage ratios of 1.09 and 1.24. On these measures, Quartile 1 fields are less than 5% the value and 27% more operationally leveraged than the Top 30 group. That said, Quartiles 2 to 4 have similar operational leverage characteristics and show evidence of declining capital expenditure leverage in line with field maturity profiles. Although indicative of a mature and developed regime this suggests fields greater in size than the average smallest field (that is with a PV of pre-tax cashflows around US$400

favourable outlook for the oil price

million) do not suffer from the indivisibility of capital expenditures and have operational advantages of scale, with leverage characteristics more in common with the largest fields.

Table 3 considers the effect of government take on field outputs. As discussed earlier, part of the tax asymmetry effect is caused by older fields subject to legacy PRT, which was unaffected by the tax increase and the average amounts of this prior tax for each group is shown in column 2. Using the tax terms prevailing prior to the December 2005 increase in SCT, columns 2 and 3 give the present value of the government take. Column 4 calculates the pre-budget PV of post-tax cashflows which can be taken to be an estimate of the commercial field values under the modelling assumptions. The effective tax take (namely, the ratio of all forms of tax to pre-tax cashflow) for the sample is 49.13% and shows the average impact of UKCS tax terms. There are differences across the sample with a tax take for small fields of 34.46% compared to larger fields which pay, depending on the extent to which they are subject to PRT or not, between 40.74% and 50.79%. It should be noted that the low Quartile 1 tax take needs to be read together with high operating leverage for this group. Even though tax take is lower, it is from a lower base given that gearing levels of 1.36 and 1.51 ensure that more pre-tax cashflow is spent on managing the field. Hence the tax take is based on a narrower residual cashflow stream, making these fields more sensitive to government take rates.

[Insert Table 3 about here]

5.2 The Fiscal Leverage Impact

We now consider the effect of the increase in SCT and recalculate the tax take at the now higher rate. For non-PRT fields, the total tax rate rises by 10%, from

40% to 50%, for PRT fields, the combined effect is to raise tax from 70% to 75%. For the whole sample the total average tax take rises from $653.13 million to $748.80 million, that is, an increase of 14.65%, as shown in column 9. So while the average tax take pre-budget was 49.13% and rises to 56.32%, fiscal leverage raises the government take by much more than the announced tax increase, a finding in line with Salahor (1998). Paradoxically, as the Top 30 group show, as suggested by Zhang (1997), PRT acts to mitigate this leverage since the increase in tax take for this group at 13.77% is the smallest and accords with the Favero, Pesaran and Sharma (1992b) view about the ad hoc effect of PRT on field value. At the other extreme Quartile 1 fields with marginal economics due to high operating and capital costs relative to revenues are the worst affected with an 20.31% increase in the tax take. Hence these fields have suffered disproportionately from the increase in SCT with adverse effects on their risk characteristics. Size and leverage effects will be shown to be important factors in interpreting the stochastic analysis.

The above analysis suggests that operational and capital leverage combine to create significant value shifts from fiscal changes due to complex multiplier and interaction effects between field specificities and the way that the tax system operates. The after-tax field value and CFaR clearly depends on the effective tax rate that is applicable. What is evident is that the 10% increase in tax has affected the economics of fields in very different ways depending on their size, future life, and their operational and capital leverage characteristics.

Full life field value is calculated in Table 4 by combining the earlier valuation analysis in Table 2 with the tax effects from Table 3. Across the sample, the PV of pre-tax cashflows (column 1) averaged US$1,329.53 million. Prior to the change in SCT, the average PV of post-tax cashflows was US$676.39 million, representing 50.87% of pre-tax cashflow. Following the tax increase the average post-tax cashflow is now US$580.87 million, or 43.68% of pre-tax cashflow. Due to fiscal leverage, fields have lost 14.14% of after-tax cashflow from the 10% tax increase. As with the government take discussed earlier, the effect is not uniform across the different sub-groups. The effect of the tax increase is most marked for larger fields where values are reduced by 14.99% (for the Top 30 this is 14.22% due to the PRT effect and starting from a higher tax rate). The smallest Quartile 1 fields experience a 10.68% drop in after-tax value.

[Insert Table 4 about here]

Note the difficulty of assessing the impact of tax take in isolation of field characteristics, most notably its operational leverage, is to understate the amount of additional tax taken from free cashflow. A particular feature of investment in these assets is that operational costs and future capital expenditure have to be financed by the field owner since government take only offers capital allowances and deferred tax credits for operating losses. The effect of this asymmetry is that it falls to the field operator to meet fiscal cashflows after meeting operating and capital expenditure.

5.3 CFaR Measures

The previous section considered how fiscal leverage affects the post-tax value of the fields in our sample and how operating and capital spend interacts with taxation to affect the lower bound tail values for fields. A key issue is the effect of these factors on the distribution of after-tax value when we consider future uncertainty. In this section, we compare estimates of field risk, namely CFaR that we derive from our stochastic analysis, noting variations caused by field characteristics and operational risks.

In Table 5, we use the results of our stochastic analysis to compute the CFaR certainty of achieving the PV of after-tax cashflow value pre-budget and the same value post-budget. As discussed earlier, for the sample as a whole, the ratio of pre-tax to post-tax cashflow falls from 50.87% to 43.68% (Table 5); a reduction in after-tax value of 14.14% (Table 5 columns 1 to 3). Before the tax change, using our modelling assumptions, the probability of achieving the after-tax value with an uncertain future oil price is 81.83% for the whole sample. There are minor variations for the sub-groups where, for instance, Quartile 2 has the lowest probability with 77.72% and Quartile 3 the highest with 84.61%.

After the tax increase, the probability of achieving the same after-tax value is shown in column 5 and drops to 26.93% for the sample as a whole, a fall of 67.09%.[8] That is, a 10% change in tax rates has led to a drop of two thirds in the likelihood of achieving the pre-tax set of after-tax cashflows. As with our earlier analysis, this effect is not uniform across the sample. The worst affected group is Quartile 4 with a 69.92% change and the least affected group is Quartile 1 with a 45.46% drop. There is a clear multiplier link between the reduction in after-tax cashflows shown in column 3 and the resultant loss of certainty shown in column 6, an interesting result and one that provides rich scope for further research.

[Insert Table 5 about here]

The fall in cashflow which varies between 10.68% (Quartile 1) and 14.99% (Quartile 4) in turn gives rise to an increase in downside uncertainty of 45.46% and 69.92% respectively. This relationship suggests that oilfield value certainties are extremely sensitive to changes in after-tax cashflows. An examination of the Top 30 shows this is due to fiscal leverage and the level of tax take. For this

[8] We recognize that there are a number of ways of estimating field risk that will lead to different values, but which will lead to the same conclusion: that the tax increase raises risk. To simplify the

group, while fall in cashflow is 14.22%, slightly less than that for Quartile 4, but the loss in certainty is higher at 74.03%. Recall from Table 2 that this Top 30 group has the least operational and capital expenditure leverage, so the loss of certainty is being generated by the tax change (which for most of this group is only 5% due to PRT). This is in line with Bradley (1998) who notes that tax effects depend on the degree of sensitivity of fields to relatively small changes in after-tax cashflow. Using CFaR in this way, clearly allows us to see the consequence of the fiscal leverage effect on oilfield values and risk.

When these results are read together with Esty's (2004) observation that financial leverage in project finance averages 70%, our CFaR analysis clearly highlights the combined effects of tax leverage and market volatility on the certainty of payback for debt providers. The average downside increase of 67.07% clearly increases the risk of default as a result of tax take directly impacting residual cashflows available to project financiers. Our results indicate the large impact of fiscal leverage on the risk of investment in UKCS O&G fields where small changes in tax rates have a multiplier and knock-on effect on field values.

6. Conclusions

Our findings are relevant in three significant respects. First, blanket taxation increases in an *a priori* asymmetrical fiscal regime, impacts total leverage and risk unevenly across projects, significantly reducing the incentive to operate marginal projects. In our study, Quartile 1, with small reserves relative to required capital investment and operational costs has the highest operating leverage and capital expenditure and the greatest sensitivity to fiscal leverage. As a consequence, our results show that under these conditions the increase in fiscal

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analysis and in recognition of the downside effect of the tax increase, we use the probability of obtaining the pre-tax change value as our benchmark take will not deliver to the UKOOA objective which identified marginal field development as strategically important to UKCS shelf productivity.

Second, our CFaR results suggest that, from an investment perspective, higher confidence levels are achievable for projects with low operational and fiscal leverage, and that these are to be favoured. Across our sample, an average reduction in value of 14% resulted in leveraged changes in certainty levels of 67% making it likely that financiers will react to these increased risk measures in the time honoured banking manner, by reducing the amount of committed UKCS risk capital and lowering the amount of debt finance available to projects (or at minimum hedging against downside risks). Our findings are in line with Bradley (1998) who showed that fiscal systems are capable of impacting certainty in cashflows. Differences between quartiles and fields occur because of direct market risk effects acting on projects with differing operating and fiscal leverage.

Finally, in a homogenous investment setting, when tax terms increase and are combined with market uncertainty, disposable cashflow is impacted and new projects are the first to suffer financier and executive scrutiny. The irreversible nature of oilfield rig and capital investment in our study ensures that while existing operator decisions are unlikely to be reversed, potential new project entrants will view the UKCS differently and marginal Quartile 1 developments in particular will be delayed or abandoned. With imperfect loss offset and call options on future cashflows in the hands of the Chancellor, changes in fiscal terms are incapable of being hedged. Certainty losses of 67% read together with financing leverage of 70% that is the norm in project finance, suggest that the new tax terms are likely to directly impact the UKOOA objective of encouraging US$15Bn worth of new UKCS investment.

In summary, following a natural experiment, our research examined one type of natural resource asset in one jurisdiction under conditions of commodity price uncertainty. While our findings are specific to UKCS offshore projects, we believe that the CFaR approach to modelling the risk effects of fiscal take in industrial settings with commodity price risk has a general applicability to project finance and hedging arrangements underlying strategic assets. This holds particularly in industries such as natural resources where composite tax terms attach to assets or projects and are (themselves) capable of causing asymmetries between investment-alternatives.

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AVERAGE	Total field life *years*	Remaining field life *years*	Initial Liquids (mmbbl)	Initial Gas (bcf)	Initial Oil Equivalent (mmboe)	Remaining Liquids (mmbbl)	Remaining Gas (bcf)	Remaining Oil Equivalent (mmboe)
UKCS TOTAL			27882	96498	44863	5395	27151	10172
TOTAL SAMPLE	21	12	16409	37269	22966	3947	16039	6769
QUARTILE 1	15	9	153	770	289	36	274	84
QUARTILE 2	15	7	353	1615	636	103	387	171
QUARTILE 3	13	9	420	1056	604	158	701	280
QUARTILE 4	17	13	407	1831	729	238	1381	483
TOP 30	28	15	15076	31997	20708	3412	13296	5751
SAMPLE AS % of TOTAL UKCS RESERVES			58.85%	38.62%	51.19%	73.16%	59.07%	66.55%

Table 1: Summary statistics for fields

Gas is converted to a barrel of oil equivalent measure using the industry standard conversion ratio of 1 billion cubic feet of gas (bcf) = 0.176 million barrels of oil equivalent

AVERAGE	PV Gross Revenue *$M*	PV Operating Costs *$M*	PV Capital Costs *$M*	PV Pretax Cash Flows *$M*	Operational leverage Ratio	Capex leverage Ratio
TOTAL SAMPLE	1,802.34	339.81	133.01	1,329.53	1.10	1.26
QUARTILE 1	194.89	52.87	37.45	104.57	1.36	1.51
QUARTILE 2	361.54	81.49	31.00	249.05	1.12	1.33
QUARTILE 3	609.62	132.92	53.21	423.49	1.13	1.31
QUARTILE 4	1,107.36	234.70	93.49	779.18	1.12	1.30
TOP 30	3,424.50	622.05	237.33	2,565.11	1.09	1.24

Table 2: Estimated present values for revenues, operating costs and capital expenditure

All future cashflows have been present valued using a 10% discount rate

AVERAGE	PV Pretax Cash Flows $M	PV PRT $M	PV Pre Budget Corporate Tax $M	PV Post Budget Corporate Tax $M	PV Pre Budget Total Tax Take $M	PV Post Budget Total Tax Take $M	Pre Budget Tax Cash Flows / Pre Tax Cash Fows %	Post Budget Tax Cash Flows / Pre Tax Cash Fows %	Pre Budget - Post Budget Change in Tax Cash Flows %
TOTAL SAMPLE	1,329.53	198.72	454.41	550.08	653.14	748.80	49.13%	56.32%	-14.65%
QUARTILE 1	104.57	-	36.04	43.35	36.04	43.35	34.46%	41.46%	-20.31%
QUARTILE 2	249.05	5.17	105.51	122.72	110.68	127.89	44.44%	51.35%	-15.55%
QUARTILE 3	423.49	-	165.89	200.81	165.89	200.81	39.17%	47.42%	-21.05%
QUARTILE 4	779.18	1.44	315.98	385.19	317.42	386.63	40.74%	49.62%	-21.81%
TOP 30	2,565.11	454.91	847.88	1,027.32	1,302.79	1,482.24	50.79%	57.78%	-13.77%

Table 3: Effect of 10% increase in the Supplementary Corporation Tax on government take

AVERAGE	PV Pretax Cash Flows $M	PV PRT $M	PV Pre Budget Corporate Tax $M	PV Post Budget Corporate Tax $M	PV Pre Budget Post Tax Cash Flows $M	PV Post Budget Post Tax Cash Flows $M	Pre Budget Post Tax Cash Flows / Pre Tax Cash Fows %	Post Budget Post Tax Cash Flows / Pre Tax Cash Fows %	Pre Budget - Post Budget change in Post Tax Cash Flows %
TOTAL SAMPLE	1,329.53	198.72	454.41	550.08	676.39	580.72	50.87%	43.68%	-14.14%
QUARTILE 1	104.57	-	36.04	43.35	68.54	61.22	65.54%	58.54%	-10.68%
QUARTILE 2	249.05	5.17	105.51	122.72	138.37	121.17	55.56%	48.65%	-12.44%
QUARTILE 3	423.49	-	165.89	200.81	257.61	222.68	60.83%	52.58%	-13.56%
QUARTILE 4	779.18	1.44	315.98	385.19	461.76	392.55	59.26%	50.38%	-14.99%
TOP 30	2,565.11	454.91	847.88	1,027.32	1,262.32	1,082.88	49.21%	42.22%	-14.22%

Table 4: Oilfield valuation

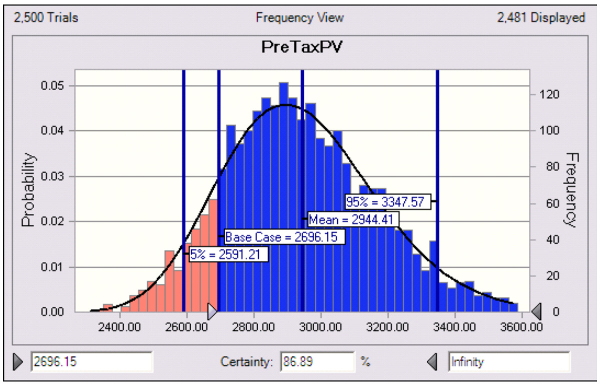
AVERAGE	Pre Budget Post Tax Cash Flows / Pre Tax Cash Flow %	Post Budget Post Tax Cash Flows / Pre Tax Cash Flow %	Pre Budget - Post Budget Change in Post Tax Cash Flows %	Pre Budget Certainty of Pre-Budget Post Tax Cash Flows %	Post Budget Certainty of Pre-Budget Post Tax Cash Flows %	Change in Certainty of Pre-Budget Post Tax Cash Flows %
TOTAL SAMPLE	50.87%	43.68%	-14.14%	81.83%	26.93%	-67.09%
QUARTILE 1	65.54%	58.54%	-10.68%	80.09%	43.68%	-45.46%
QUARTILE 2	55.56%	48.65%	-12.44%	77.72%	25.40%	-67.31%
QUARTILE 3	60.83%	52.58%	-13.56%	84.61%	29.93%	-64.63%
QUARTILE 4	59.26%	50.38%	-14.99%	84.22%	25.33%	-69.92%
TOP 30	49.21%	42.22%	-14.22%	82.13%	21.33%	-74.03%

Table 6: Cashflow at Risk Estimates

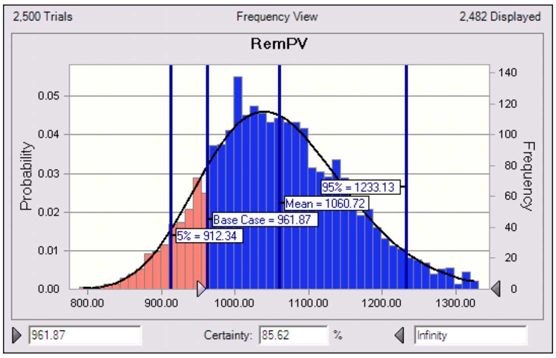
AVERAGE	Pre Budget Certainty of Pre-Budget Post Tax Cash Flows %	Post Budget Certainty of Pre-Budget Post Tax Cash Flows %	Stochastic Mean PV $M	Stochastic Std Dev $M	Stochastic Skewness $M	Stochastic Kurtosis $M	Mean Std Error $M	Percentage Std Error %
TOTAL SAMPLE	81.83%	26.93%	631.18	48.23	0.40	3.29	0.96	0.15%
QUARTILE 1	80.09%	43.68%	70.23	10.13	0.47	3.35	0.20	0.29%
QUARTILE 2	77.72%	25.40%	128.84	14.74	0.42	3.35	0.29	0.23%
QUARTILE 3	84.61%	29.93%	245.52	23.80	0.47	3.38	0.48	0.19%
QUARTILE 4	84.22%	25.33%	438.44	34.56	0.38	3.17	0.69	0.16%
TOP 30	82.13%	21.33%	1,171.99	84.35	0.36	3.25	1.69	0.14%

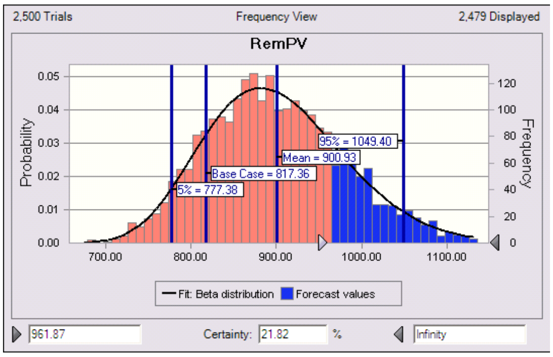
Appendix 1 Summary of Stochastic Simulation Descriptive Statistics

Fig.1. Cashflow value at risk distribution of an oilfield with a pre-tax net present value of US$ 2696.15 and a simulated probability of 86.89% of achieving this value.



1a Pre tax





1b: Post Tax -Pre 2006 Budget Terms 1 c Post Tax - 2006 Budget Terms

	Pre-tax (Figure 1a)	Post-tax old terms (Figure 1b)	Post-tax new terms (Figure 1c)
Certainty level	86.89%	85.62%	21.82%
Certainty range	$2696.15m → ∞	$961.87m → ∞	$961.87m → ∞
Valuation range	$2224.81m — $3908.12m	$763.32m — $1456.03m	$648.73m —$1236.54m
Base case valuation	$2696.15m	$961.87m	$817.36m
Std error of mean after (2500 trials)	4.66 (0.001583%)	1.96 (0.00217%)	1.66 (0.00184%)
Mean	$2944.41m	$1060.72m	$900.93m