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**Do High Oil Prices Justify an Increase
Taxation in a Mature Oil Province?
The Case of the UK Continental Shelf**

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February 2007



SEEDS 116
ISSN 1749-8384

Department of Economics
University of Surrey

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ABSTRACT

In response to the structural shift in oil price coupled with greater import dependency, concerns about security of supply have once again emerged as a major policy issue. The UK, the largest producer of oil and natural gas in the European Union, became a net importer of natural gas in 2004, and, according to Government estimates, will become a net importer of oil by the end of the decade. A weakened North Sea performance means extra reliance, both for the UK and Europe as a whole, on global oil and gas network and imports. In 2002, the UK Government introduced a 10 per cent supplementary charge and in 2005, doubled the charge to 20 per cent in an attempt to capture more revenues from the oil industry because of the increase in the price of crude oil. However, higher tax rates do not necessarily generate higher fiscal revenue and in the long term may result in materially lower revenues if investment is discouraged. It is therefore argued that the increase in the fiscal take came at the wrong time for the UK Continental Shelf and that the UK Government's concern should have been to encourage more oil production from its declining province, especially in the light of the rising concern surrounding the security of supply.

Key Words: Petroleum Taxation, Energy Security, Oil Price

Do High Oil Prices Justify an Increase in Taxation in a Mature Oil Province?

The Case of the UK Continental Shelf

by

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1. INTRODUCTION

After reaching an average of \$12 per barrel (Brent) in 1998, oil prices began to climb from the depressed levels during the last 15 years of the twentieth century to average \$54 per barrel in 2005 (BP Statistical Review of World Energy, 2006). In response to this structural shift in the crude oil price coupled with greater import dependency, concerns about security of supply have once again emerged as a major policy issue (Helm, 2005). The USA, the world's largest oil consumer, identified reduced dependence on imported oil as an urgent energy, economic and national security issue that should be tackled principally by promoting the development of domestic resources (National Energy Policy Development Group, 2001).

The situation is little different in Europe. The UK is the largest producer of oil and natural gas in the European Union. However, after years of being a net exporter of both fuels, the UK became a net importer of natural gas in 2004, and according to Government estimates the

***Acknowledgments**

I am grateful for comments received following the presentation of earlier draft of the paper at the 29th IAEE International Conference in Potsdam, Germany, 2006. I am, of course, responsible for all errors and omissions.

country will become a net importer of oil by the end of the decade (EIA, 2006). UK's oil production peaked in 1999 at 2.8 million barrel a day (mmbbl/d) (DTI, 2005), but has since declined steadily, as the discovery and development of new reserves failed to keep pace with the maturation of existing fields (EIA, 2006). In 2004, the UK Continental Shelf (UKCS) oil production declined 228 million barrel (mmbbl) faster than any other major oil production province in the world. Lower North Sea production has meant additional reliance, both for the UK and Europe as a whole, on rising imports.

Security of energy supply is one of the main goals of the UK energy policy, as set out in the 2003 Energy White Paper "*Our Energy Future – Creating a Low Carbon Economy*" (DTI, 2003). While indigenous production from the UKCS will continue to make an important contribution to overall security of energy supply, the UKCS is a mature province and needs considerable investment to sustain production. Loss of investment, rising costs or an inappropriate fiscal or regulatory policy could stop this industry dead in its tracks (UKOOA, 2006).

It is against this background that the recent increase in taxation on upstream oil activity in the UK will be examined in this paper. In 2002, the UK Government introduced a 10% supplementary charge on top of the standard 30% Corporation Tax and in 2005, doubled the charge to 20%. The latter changes to the North Sea tax regime were introduced in order to maintain a balance between oil producers and consumers, by promoting investment and ensuring fairness to taxpayers in view of the recent significant increases in oil prices and the upwards shift in expectations of the medium term outlook for future oil prices (HM Treasury and Customs, 2006). The Government expected to generate an additional £2billion (bn) from oil activity in 2006-2007 as a result of the increase in tax. However, six months after the increase in tax, estimates were revised and the UK Government wrote off three-quarters of the £2bn originally expected revenues, in the light of the decreasing North Sea production (Giles and Hoyos, 2006). Then, in the space of further six months following the March 2006 Budget

the UK Government further reduced the yield expectations from the North Sea by £2.8 bn in the tax years 2007-8 (HM Treasury, 2006). This illustrates that an over reliance on North Sea tax revenues creates instability in the general tax regime as inherent volatility in North Sea tax revenues undermines Budget arithmetic creating the need for tax rises elsewhere in the economy if revenue forecasts prove over optimistic.

The objective of this paper is to analyse whether high oil prices justify an increase in taxation applying to exploration and production activity in a mature province. The paper critically evaluates the impact of the 2005 fiscal changes on Government revenues and oil field profitability and in particular the attractiveness of the regime from an investment standpoint. It also examines the way in which the UK Government, through the design of its petroleum fiscal regime and the subsequent amendments, has affected the trade-off between the State and the oil companies.

Furthermore, the paper presents an up-to-date analysis of petroleum taxation, which from a global perspective is the most commonly used mechanism for sharing the benefits of petroleum resources between the host Government and the international oil companies (Blinn et al, 1986). In the mid 2000s, many major oil-producing countries suffer from either decline or a slow down in production and exploration activity because they failed to implement appropriate fiscal regimes (Lee, 2006). Countries, such as Iraq, are looking for new fiscal frameworks in which to develop or restore their oil production sectors. Although there will always be a controversy surrounding how precisely to share “the cake”, the contents of this paper suggests a basis for changing or creating a new fiscal structure, by aligning more closely the interests of both the Government and the oil industry.

The remainder of the paper proceeds as follows. Section 2 examines the current status of the UKCS. Section 3 reviews the controversy surrounding the UK petroleum fiscal regime.

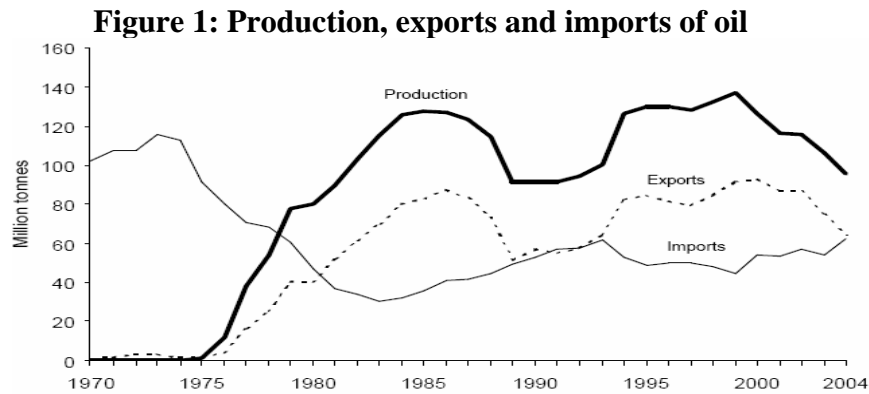
Section 4 presents the methodology and assumptions used in this paper. Section 5 summarises and analyses the main findings. Section 6 is devoted to the concluding remarks.

2. IMPORTANCE AND REALITY OF THE UKCS

2.1. Production

The UK ranks high in the global league of oil and gas producers. It is a major non-OPEC oil producer. In 2006, it had 4.0 billion barrels (bnbbbl) of proven crude oil reserves, the most of any EU member country (EIA, 2006) and between 16 and 27 bnbbbl of oil equivalent of overall oil and gas resource potential (UKOOA, 2005). In 2004, the UK produced more oil and gas than Venezuela, Nigeria, Indonesia or Kuwait (Crawford, 2006); producing 1.3bnbbbl of oil and gas from the UKCS, sufficient to provide over 80% of the nation's total energy needs (UKOOA, 2006).

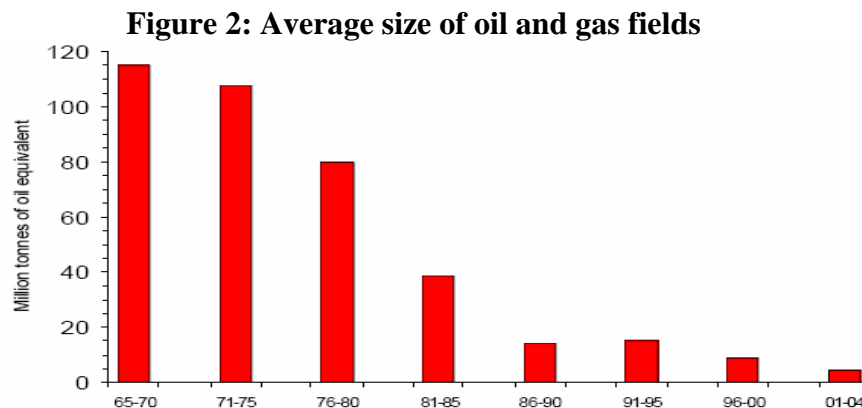
Oil production in the UK peaked in 1999. The Government expects the production decline to continue, reaching 1.38mmbbl/d by 2009 (DTI, 2005). The two main reasons for this decline are firstly the overall maturity of UKCS oil fields, and secondly the declining field sizes for new discoveries and developments. Additionally, increasing unit extraction costs, in what is acknowledged to be one of the highest cost basins in the world, are damaging project economics and basin competitiveness. A shift of basin production to more remote and inhospitable areas of the UKCS is also a factor (DTI, 2005). Crude oil exports have followed a similar path to production albeit that they initially levelled off between 1999 and 2000 before slowly declining. Crude oil imports have risen steadily to substantially narrow the gap with exports although the UK remains a net exporter of crude (DTI, 2005). Figure 1 illustrates the trends in production, exports and imports of oil from 1970 to 2004.



(Source; DTI, 2005)

2.2. Fields Distribution

Since 1975, the UKCS has undergone major changes. One fact that clearly emerges is the decline in the average size of fields during the 1990s, compared with the early development of the North Sea, as Figure 2 shows.



(Source; DTI, 2005)

A minority of fields account for the majority of aggregate reserves. The largest five fields account for 37%, the largest 10 for 52% and the largest 20 for 71% of the total reserves (Watkins, 2000). However, 29 of the UK major UK fields peaked prior to 1994 (DTI, 2005). By 2000, they had total oil production declines of more than 50% from their maximum production levels (Blanchard, 2000).

To counteract the rapid decline of mature fields, new but smaller fields are being brought on-line at an increasing rate. From 1985 to 2006, the number of producing fields on the UKCS has increased three-fold. Although it took 25 years for the first 100 fields to be brought on-line, it took only 6 years to bring the second 100 fields on-line (Blanchard, 2000). As might be expected, however, the fields found during subsequent periods have become progressively smaller, with an average discovery size of 25 to 30 mmbbl of oil equivalent. That is small compared to the larger UK fields, like Forties and Brent, with an average size above 2,400 mmboe (Sem and Ellerman, 1997). Although there is no official definition for fields' size, Table 1 illustrates the main classes adopted in previous studies, according to the size of recoverable reserves¹.

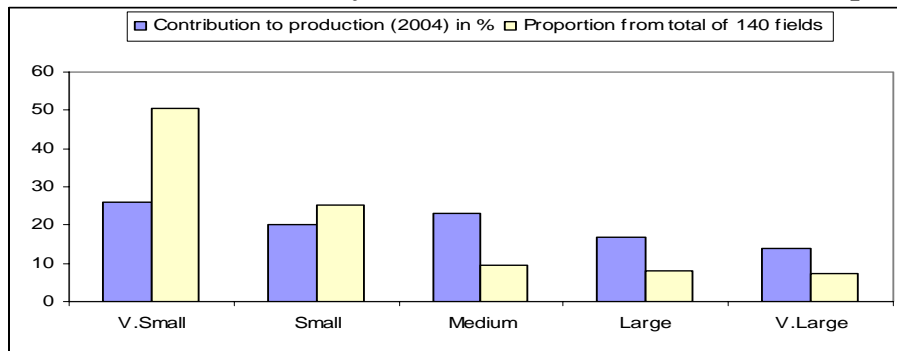
Table 1: Fields' classification by size

Study By	Very Small	Small	Medium	Large
Robinson & Morgan (1978)		100-250	250-350	>350
Kemp & Stephens (1997)	<100	100-250	250-500	>500
Sem & Ellerman (1998)		<100	100-400	>400
Watkins (2000)		<100	100-400	>400
Ruairidh (2003)	<100	100-200	200-400	>400

Furthermore, many of the new smaller fields have lifetimes of 10 years or less. In an extreme example, Dauntless field was brought on-line in August 1997 and was terminated in April 1999 (Blanchard, 2000). Figure 3 illustrates the distribution of fields by size, and the contribution of those fields to total production.

¹ Recoverable reserves are "that proportion of the oil and gas in the reservoir that can be removed using currently available techniques" (DTI, Oil & Gas Glossary, 2003)

Figure 3: Distribution of fields by size and their contribution to total production²



2.2. A Challenging Situation

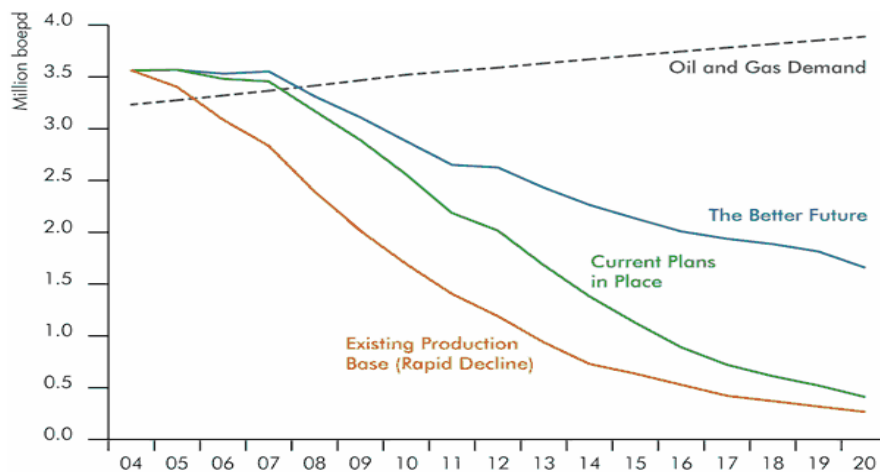
Clearly, the UKCS is a mature oil and gas province, which has been in production for nearly 40 years. However, this reality does not necessarily mean that "North Sea oil, the precious resource that has contributed hundreds of billions of pounds to the UK economy, is now slipping into history" (Reuters, 2004, p.1). Other basins, such as the Gulf of Mexico, have undergone similar evolutions and seen activity actually increase, few years after it has been declared a "dead sea" (Ruairidh, 2003).

In a survey carried out by Nakhle (2005), 40% of respondents agreed that despite the maturity of the UKCS, the UK North Sea era has not ended yet. Similarly, according to a study carried out by UKOOA and WoodMackenzie in 2004, there are still substantial opportunities to be accessed if the UK remains internationally competitive and can sustain current investment. If successful the UK could still be producing the equivalent of 65% of its total oil requirements in 2020 and delay decommissioning by 10-15 years, making a major contribution to the UK's security of energy supply. In stark contrast if the UK becomes less attractive to new investment, then the UKCS will only provide the equivalent of 15% of total UK oil demand by 2020 (UKOOA, 2005). Consequently, as Figure 4 shows, the UKCS can either face a rapid decline, hence exposing the UK to an increasing dependence on oil imports, or production can be sustained for a longer period of time, hence extending the benefits to

² Author's estimates based on data from DTI (2005)

consumers, companies and Government alike. The future of the North Sea depends on a combination of factors. The petroleum fiscal regime is a major determinant.

Figure 4: UKOOA UK North Sea Production Scenarios



3. The UK Petroleum Fiscal Regime

3.1. Importance of the fiscal regime

In examining the attractiveness of an oil or gas province, a prospective investor will take into many factors which include:

- Basin prospectivity (the chance of finding oil or gas)
- Volumetric potential (how large are the discoveries)
- Basin cost structure (overall finding, development and operating costs per billion of oil equivalent)
- Access to infrastructure and opportunities
- The fiscal regime - its evolution, complexity and stability

The balance of the above factors will enable the investor to assess the basin competitiveness.

In a survey undertaken by Mohiuddin and Ash-Kuri (1998) based on 30 companies, 83% of these argue that prospectivity is the most important factor while fiscal terms come second and political stability third. Martin (1997) argues that the changes made to the UK petroleum

fiscal regime are the most important factor that led to the 1985 and 1995 peaks in oil production, while technological progress, which came second, is significant only when combined with high oil prices. Similarly, Nakhle (2005) found that, in a mature province, taxation is a principal determinant of future levels of activity and profitability. Some countries, like Indonesia, with very tough fiscal regimes still attract substantial investments because of their favourable prospectivity. According to Raja (1999), although the UK is believed to have a very attractive fiscal regime, Indonesia comes second to the UK in terms of the number of wells drilled.

There tends to be a relationship between Government tax take and prospectivity, high take is generally sustainable only if the basin offers high volumetric potential. In the case of the UK, the high basin cost structure adds a further dimension. The volumetric potential is critical for large international companies, which need to replace their production with new discoveries and or field growth. In a mature basin such as the UK large discoveries are no longer possible and the basin attraction has shifted from volume to value.

The reduced average size of finds in the UKCS coupled with the relatively high costs of exploration and development has meant that there is an insufficient resource base to attract larger oil company investment particularly when other international opportunities are in keen competition for funds (Sassoon, 2003). In 2002, the UKCS ranked 19th globally in terms of the average commercial discovery size. Additionally, with \$10 a barrel operating costs in the UK North Sea compared with \$5 in Angola and \$6 in Gulf of Mexico, it is going to be harder to continue to attract investment in competition with the larger and more commercially attractive opportunities available elsewhere in the world (Morgan, 2000). In the light of such developments, taxation could be used as an instrument to compensate for the decreasing attractiveness of the UKCS, with respect to prospectivity and costs.

3.2. Structure of the UK petroleum fiscal regime

Petroleum taxation has received considerable attention since the discovery of oil in the 1960s in the UK sector of the North Sea. The structure of the current fiscal regime was first set out in a 1974 White Paper and was formally legislated through the Oil Taxation Act of 1975. The regime consisted of three main instruments, Royalty, Petroleum Revenue Tax (PRT) and Corporation Tax (CT). At the outset the Government had two key objectives. These were to secure a fairer share of profits for the nation and ensure a suitable return for oil companies on their capital investment (Inland Revenue, 2003).

The Royalty rate was fixed at 12.5% on the gross revenues of each field with a deduction for conveying and treating costs, which represent the cost of bringing the petroleum ashore and its initial treatment. Royalty was abolished in 1983 on fields that have received development consent after 1983, and then abolished on all fields in 2002.

PRT is a special petroleum profits tax assessed on a field-by-field basis with all fields treated equally irrespective of ownership. PRT was charged initially at a rate of 45% on the value of oil and gas produced. The tax base broadly equates to revenue receipts less the expenditure incurred in developing and operating the field. PRT was introduced to capture economic rent from the more profitable fields. Less profitable projects were shielded from the tax as a result of various allowances and reliefs, namely uplift, oil allowance and safeguard. Uplift is an additional allowance equal to 35% of capital expenditures. The oil allowance grants 250,000 tonnes for each six month to be exempt from PRT up to a cumulative maximum of 5Mt. The safeguard provision was introduced to limit the PRT liability in any chargeable period to 80% of the amount by which gross profits exceed 15% of cumulative expenditure. As such, the safeguard limited the PRT liability for part of the field's life and allowed fields to achieve a minimum level of return on investment prior to incurring any PRT liability. In 1993, PRT was reduced to 50% on existing fields and abolished on all fields receiving development consent after April 1993. Incentives for Exploration and appraisal drilling were also removed.

CT was initially set at 52% then reduced to 30% on company profits. Exploration costs were deemed fully deductible, while development costs were made subject to various tax depreciation allowances. CT is the standard company tax on profits that applies to all companies operating in the UK. However, in the case of petroleum activity, there is a ring fence that prohibits the use of losses from other activities outside the ring fence to reduce the profits originating from within the UKCS ring fence. Nonetheless, losses and capital allowances inside the ring fence may be set against income arising outside the ring fence.

In 2002, the UK Government introduced a 10% supplementary charge on profits subject to CT. This charge was calculated on the same basis as normal CT, but there was no deduction for financing costs. Additionally, a 100% capital investment allowance was introduced against both CT and the supplementary charge, replacing the previous 25% per annum writing down allowance.

In 2005, in view of the recent significant increases in oil prices, the upwards shift in expectations of the medium term outlook for future oil prices and the dramatic increase in public spending, the Government decided to increase the level of the Supplementary Charge by 10%, with effect from 1 January 2006.

3.3. Controversy surrounding the UK petroleum fiscal regime

Since the establishment of the UKCS tax system in 1975, the regime has been repeatedly reviewed and many amendments applied. Rowland and Hann (1987) argue that no other sector in the UK economy has been subject to such fiscal instability. Kemp and Rose (1982) argue that a tax system subject to continuous “tinkering” tends to increase political risk and reduce the value placed by investors on future income streams.

In the late 1970s and early 1980s, the UK Government leaned towards generating high revenues from the oil industry, whereas from 1983 to 2002, the emphasis was on encouraging new developments and increasing production. These various changes have generated much controversy. Researchers and specialists have either criticised or defended the regime following each change, with extreme views being expressed. For example, Bland (1988) describes the UKCS fiscal regime as a patchwork of separate taxes, each amended and adjusted in response to changing circumstances and forming less than a cohesive whole. In concurring with Bland, Rutledge and Wright (1998) describe the fiscal regime in the UK as the weakest in the world. Opposing such views, Martin (1997) argues that Government action, in particular that in 1983 and 1993, was responsible for the two production peaks in the pattern of the UKCS oil production. Johnston (2003) debates that although Government actions since 1983 appeared crazy and irresponsible they led to hyperactivity in the UK sector of the North Sea and made the UK offshore the most active offshore province in the world.

The controversy surrounding the UK petroleum fiscal regime and its various amendments arises from the need to balance the two chief but competing objectives of taxation. These are to capture a large share of economic rent while stimulating private investment in the sector (Bond, et al, 1987). Further, since there is no objective yardstick for sharing economic wealth between the various interests involved in the petroleum activity, controversy will always prevail. A trade off will always exist, since both Government and oil companies want to maximise their own rewards. Mercier (1999) argues that tax rates that are set too low leave the Government, the owner of the resource, a small and inequitable portion. Yet, if tax rates are too high, investment will be discouraged, not only in new projects, but in sustaining the capital investment required to maximise future value added from existing operations (Crowson, 2004).

However, the exploration and exploitation of oil requires significant financial resources. Further, the high risk involved, as a result of geology and oil price volatility, renders a purely

national approach to the exploitation of petroleum difficult. "Exploration and exploitation activities present delicate legal, technical, financial and political problems and any solution requires a balancing act between the respective interests of the producing countries and the oil companies" (Blinn et al, 1986, p.15). In the absence of a healthy and financially successful oil industry, the Government cannot realize the full benefit of resource extraction (Watkins, 2001).

That said such a trade-off could be improved if an appropriate tax system is adopted. Such a regime can generate a positive rather than a zero-sum outcome. In the former, both the Government and investors benefit respectively from a fair share of revenues and appropriate profitability whereas, in the latter, the return to Government cannot be increased without reducing the incentive to private firms (Stauffer and Gault, 1985). The analysis below evaluates the extent to which the UK Government has succeeded in establishing a suitable regime that generates a fair share of revenues for themselves whilst simultaneously providing sufficient incentives to encourage investment, in a mature, declining province.

4. METHODOLOGY AND ASSUMPTIONS

4.1. Economic rent

Dickson (1999) defines economic rent as "the true value of the natural resource, the difference between the revenues generated from resource extraction and the costs of extraction; these costs include the costs of employing factors of production and their opportunity costs" (p.1). Similarly, Banfi, et al (2003) define economic rent as "the surplus return above the value of the capital, labour and other factors of production employed to exploit the resource. It is the surplus revenue of the resource after accounting for the costs of capital and labour inputs" (p.2). In addition to the capital and labour inputs referred to, further inputs in respect of entrepreneurial reward and risk taking need to be incorporated.

Consequently, economic rent can best be considered as "a bonus, a financial return not required to motivate desired economic behavior" (Raja, 1999, p.2). In this sense, previous studies presume a tax based on economic rent is an ideal tax (Dickson, 1999). Since the magnitude of such profits is not relevant to economic decisions, they constitute a justifiable base for taxation (Rowland and Hann, 1987). Furthermore, if the tax seeks to capture economic rent, then the tax-take falls when economic rent decreases and rises when it increases. As such, the tax base responds in the appropriate direction to variations in costs and crude oil prices (Kemp, et al 1997). Kemp and Rose (1982) argue that a stable system increases the possibility of substantial economic rent, while Rowland and Hann (1987) maintain that a fair progressive tax, aimed at absorbing economic rent, is neutral and stable.

In their definition of economic rent generated from petroleum extraction activity in the UK North Sea, Rowland and Hann (1987) provide a practical measure of that rent. "The economic worth of a license to produce oil from a tract of the UKCS may be measured by the present value of the flow of the future revenues from that tract's production less the present value of associated future costs, where the costs include monetary items such as equipment as well as non-monetary items such as exposure to risks. The difference between these two amounts, the net present value (NPV), is the economic rent of that tract. It may be positive, negative or zero. If it is positive, it implies that the licensee is enjoying profits in excess of those necessary to induce the production of petroleum (pure profits)" (p.4). Similarly, Raja (1999) argue that taxes should be aimed at taxing positive NPV because the NPV method discounts all future cash flows and incorporates all the relevant rewards to factors of production.

4.2. Evaluation technique

To value oil fields' profitability, the Discounted Cash Flow (DCF) technique is adopted here. This technique involves three steps. Firstly, the field's project net cash flows that will occur at each time period in a particular scenario are estimated. Secondly, the project cash flows are

discounted using a certain discount rate, incorporating a risk premium. Finally, the discounted cash flows are added to form the project value, also called the Net Present Value (NPV) (Jacoby and Laughton, 1992).

The DCF technique has been (and still is) the most commonly used method in evaluating expected future cash flow. It is usually used by oil companies (Emhjellen and Alaouze, 2001) and a study undertaken by Siew (2001) found that 99% of oil companies use this technique because it is a cash flow based technique, which takes into account the time value of money and it is quick and relatively easy to understand and calculate. Furthermore, the majority of previous studies³ utilized this traditional technique to evaluate the profitability of an oil field. To value their projects, oil companies estimate the after tax present value of their total expected net cash flows discounted for both time and risk. For the purpose of the analysis carried out in this paper, the discount rate is assumed to be 10% in real terms, as applied in the majority of published studies⁴, to mirror the industry's discount rate.

4.3. Assumptions

Different sizes of fields generate different levels of profitability. In relative terms, small and medium fields do not generate the same levels of economic rent as large fields. Consequently, different tax instruments have a varying impact on field profitability in so far as 'one size does not fit all'. To illustrate this variable impact, a sample of oil fields is selected and classified according to the size of their recoverable reserves into very small, small, medium, large and very large categories, as in the following:

³ Among others, Robinson & Morgan (1978), Rowland & Hann (1987), Kemp & Rose (1982), Kemp & Stephens (1997), and Martin (1997).

⁴ See Kemp & Rose (1982), Rowland & Hann (1987), Kemp & Stephens (1997), Martin (1997) and Bradley (1998).

Table 2: Fields Size

Fields Size	Recoverable reserves (mmbbl)
Very Small	<100
Small	100-200
Medium	200-400
Large	400-500
Very Large	>500

A sample of 25 oil fields is selected for investigation on the basis of their providing a representative sample of post 1993 (pre-2004) producing oil fields in the UK North Sea⁵. Quota sampling is used to ensure that unit subgroups are represented in the sample in approximately the same proportions as they are represented in the population (Ghauri, et al. 1995).

For the purpose of this analysis, the data set includes 10 very small, 9 small, 4 medium and 2 large fields. No very large fields are incorporated in the analysis because there has not been any UK discovery of this size for the last 20 years. Further, the very large fields that are in production are currently in their final stages of decline.

Six tax scenarios are adopted. These, with the exception of Scenario 0 (the base pre-tax scenario) are used to calculate profitability, Government revenues and take under different combinations of tax instruments and tax rates. They are summarised in Table 3.

Table 3: Tax Scenarios

Scenarios	Package (%)			Marginal rate (%)	Period	Application
	CT	ST	PRT			
S0	0	0	0	0		Pre-tax base
S1	30	0	50	65	pre-02	on fields that received development consent before 93
S2	30	10	0	40	02/05	on fields that received development consent after 93
S3	30	20	0	50	Post 05	on fields that received development consent after 93
S4	30	10	50	70	02/05	on fields that received development consent before 93
S5	30	20	50	75	Post 05	on fields that received development consent before 93

⁵ Except Argyll field, which was decommissioned in 1992, but it is included in the fields' sample as a model field that can represent the production life cycle of many very small newly developed fields.

Oil fields' profitability and Government revenues are further evaluated under two price scenarios:

- A low oil price scenario, where a \$19.5/barrel Brent price is assumed in the base year (2000). This value represents the average oil price achieved in the 1990s. It also represents the low case scenario assumed by the EIA (2006) in its oil price expectations for 2020.
- A high oil price scenario, taking into consideration the average annual Brent prices achieved in 2000-2005 (\$28.5 in 2000, \$24.4 in 2001, \$25 in 2002, \$28.8 in 2003, \$38.7 in 2004 and \$54.3 in 2005 (BP Statistical Review, 2005).

These two scenarios are considered because on the one hand, the increase in oil price triggered the increase in taxation on oil activity in the UK (HM Treasury, 2005) and on the other hand, oil companies do not base their investment decisions on assumptions of \$50/barrel but far less (Crawford, 2006). According to UKOOA (2005), in response to the recent increase in oil prices, companies have raised the prices they use to evaluate new investment opportunities.

The analysis is undertaken in nominal terms and subsequently deflated. All figures are expressed in million US\$ and in real terms, assuming a constant annual inflation rate of 2.5% as from 2000. The inflation rate used represents the UK Retail Price Index and the five years average US deflator (Bank of England, 2006). Furthermore, a constant exchange rate of US\$1.6 = £1STG is used and which represents the five years average exchange rate (2000-2005) (Barclays Bank, 2006). Due to the individual characteristics of each oil field, such as water depth, size, costs and life, which are specific to each field, an Excel spreadsheet particular to each oil field was developed.

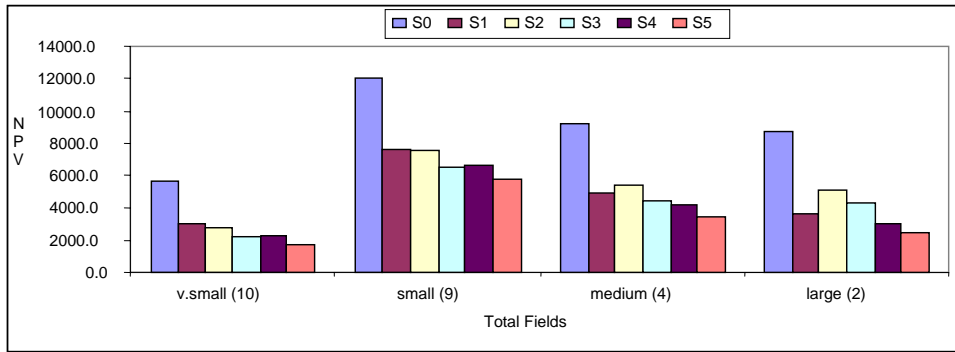
5. RESULTS AND DISCUSSION

5.1. Results

It is not surprising to see that the profitability of each field has decreased under all tax scenarios. However, while higher tax rates are expected to generate lower profitability, such an outcome does not apply in the case of very small and small fields when PRT applies. For instance, by taking into consideration tax rates only, a combination of 30% CT and 20% ST (50% marginal tax rate) is expected to generate a higher profitability than a combination of 30% CT and 50% PRT (S1, 65% marginal tax rate) or even still a combination of 30% CT, 10% ST and 50% PRT (S4, 70% marginal tax rate). However this does not apply to the smaller fields. In the case of 11 fields out of 19 very small and small fields, a combination of 50% PRT and 30% CT (S1) generates a higher profitability than a combination of 30% CT and 10% ST (S2, 40% marginal tax rate).

The largest decrease in profitability of all fields occurs under the combination of 50% PRT, 30% CT and 20% ST (S5, 75% marginal tax rate), highlighting that the impact of the 2005 fiscal changes significantly impact the profitability of the fields that are still paying PRT. For medium and larger fields, a more consistent pattern can be noted. In general, the highest profitability is achieved under a 30% CT and 10% ST (S2), followed by 50% PRT and 30% CT (S1), except for one medium field, Tern, where a combination of 50% PRT and 30% CT (S1) generates the highest profitability. In the case of large fields, tax packages based on income tax only (CT and ST) generate a higher profitability than those where PRT applies. Figure 5 summarises the differing impact of various tax packages on different fields' size.

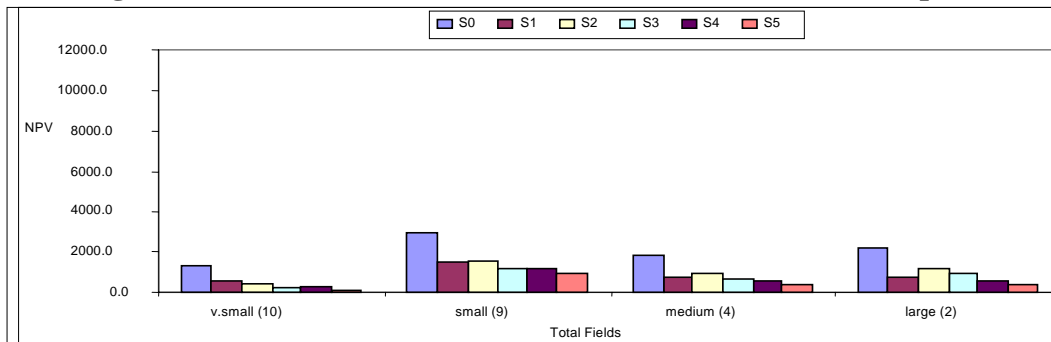
Figure 5: Total fields NPV under different tax scenarios (high price)



Under the high oil price scenario, all fields (except one) have NPV higher than £100 million. Janice is the only oil field which has a negative NPV under all tax scenarios except where 50% PRT and 30% CT apply.

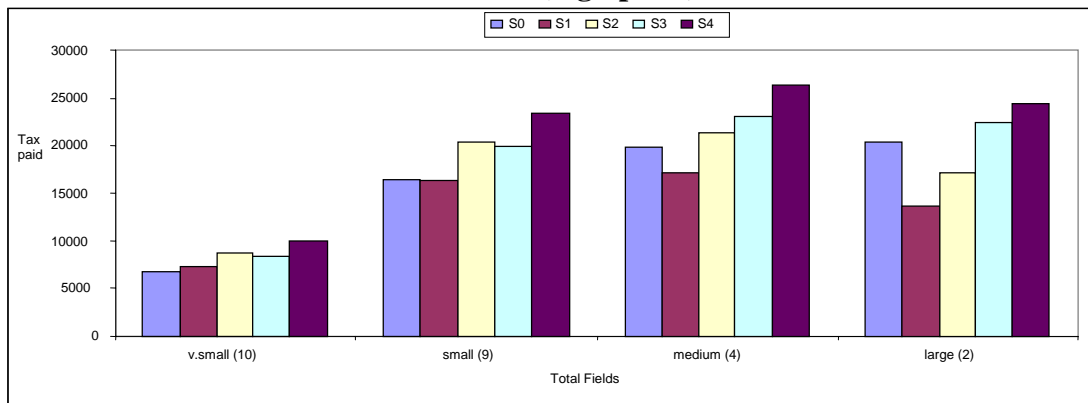
The story is different under the low oil price scenario, where a significant decrease in fields' profitability is noted. Under this scenario, five very small and three small fields suffer from decrease in profitability to below £30 million. Furthermore, a combination of 50% PRT and 30% CT (S1, 65% marginal tax rate) generates a very similar profitability as 30% CT and 10% ST (S2, 40% marginal tax rate). In fact, under the low oil price scenario, an increase in ST on fields led to a negative NPV in the case of two small fields. Figure 6 summarises the impact of the fiscal packages on the profitability of the four fields' groups.

Figure 6: Total fields NPV under different tax scenarios (low price)



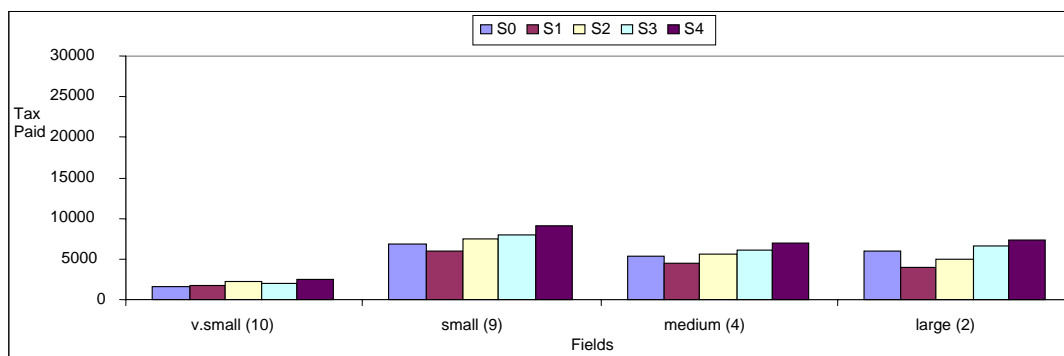
In terms of Government revenues, the lowest fiscal take is generated under the combination of 50% PRT and 30% CT (S1) for very small and small fields (with one exception), followed by 30% CT and 10% ST (S2). The highest take is generated under a combination of 30% CT, 50% PRT and 30% ST (S5), followed by 30% CT and 20% ST (S3). However, in the case of medium and large fields, the larger fiscal takes are generated where PRT applies, and the lowest where only CT and ST apply. Figure 7 summarises the total Government take from various fields' groups under high price scenario.

Figure 7: Total Government take from different fields under different tax scenarios (high price)



Under the low oil price scenario, there is a significant decrease in government revenues. A combination of 30% CT and 10% ST generate the same amount as provided by 50% PRT and 30% CT when applied to medium fields. But in general the latter package generates the lowest fiscal take in the case of smaller fields (with one exception), as shown in Figure 8.

Figure 8: Total Government take from different fields under different tax scenarios



Both Figure 7 and Figure 8 show that the revenues generated from 10 very small fields are by less than those generated from only two large fields.

In terms of Government take, expressed as a percentage of the pre-tax NPV of a field, the following can be noted. Where PRT applies, the effective marginal tax rate is much lower than the imposed rate, especially in the case of very small and small fields. For instance, under S1 (30% CT and 50% PRT) where the marginal tax rate is supposed to be 65%, the effective tax rate barely reaches 42% for very small fields, while the rate varies between 30-56% for small fields, under both high and low price scenarios. For larger fields, the rate is higher; 53-55% for medium fields and around 60% for large fields. As such, the outcome is similar to imposing 30% CT with 10% ST (S2) and even 30% CT with 20% ST (S3), with respective marginal tax rate of 40% and 50%. Similarly, imposing 50% PRT with 30% CT and 10% ST (S4, 70% marginal tax rate), the effective marginal tax rate varies between 40-55% on very small fields, 38%- 50% on small fields, 54-60% on medium fields and reaches 60% in the case of larger fields. Again the outcome is not very different from the scenarios where CT and ST only apply.

The effective tax rates are higher under a combination of 50% PRT, 30% CT and 20% ST (S6, 75% marginal tax rate), where tax rate varies between 50%-60% on very small and small fields, and 60%-69% on medium fields. The full marginal tax rate is captured in the case of one large field only – Schiehallion – under the low price scenario and where the effective marginal tax rate reaches 75%. No striking differences were noted in the marginal tax rates under the two selected price scenarios, especially where CT and ST apply (S2 and S4); in general small differences occurred where PRT applies. This outcome can be attributed to the neutral aspect of the fiscal packages. Among all these findings, there are two exceptions; the Janice field, which shows very high effective marginal tax rates as the field has a negative NPV, and Auk field, which is a small but with a long production profile and all fiscal

packages seem to be regressive as the marginal tax rates are significantly higher under the low price scenario compared with the high price scenario.

5.2. Discussion

In 1998, the UK Government proposed either to re-introduce PRT at a rate of 50% in addition to the 30% CT on fields that received development consent after 1993, or to apply a supplementary charge to the 30% CT. In 2002, it opted for the latter option and further increased the rate of ST in 2005, in the light of the higher oil prices in order to capture a larger share of the resulting economic rents. Several questions arise from such a decision: Was it the most appropriate? What impact would a re-introduction of PRT have generated on both oil fields' profitability and Government revenues? Or is the abolition of PRT recommended given the maturity of the North Sea?

As the results in the previous section show, PRT is better adapted to the size of oil fields than ST. It generates a higher profitability and lower revenues to the Government in the case of smaller fields than in the case of larger fields, as compared to packages where CT and ST apply. PRT has such an impact on smaller fields principally as a result of the oil allowance, which exempts a fixed amount of production from each field from PRT until the total oil allowance for the field is fully utilized. The oil allowance is the most important relief for smaller fields. The effects of the other PRT reliefs, namely the Uplift and Safeguard, depend mainly on the value of the capital expenditures (CAPEX) as well as the payback period. As the larger fields tend to have a longer payback period and larger CAPEX spend than the smaller ones, the Uplift and Safeguard reliefs are of greater significance. Nevertheless, the oil allowance is also important for the larger fields, which have the capacity to maximise all of the available allowance because of their high levels production. More importantly, the fiscal scenarios where PRT applies automatically capture the increased profitability resulting from oil price increases, without the need to alter the PRT rate. This shows that PRT adjusts more flexibly to changes in oil price than CT or ST.

The abolition of PRT on fields that received development consent after 1993 generated much controversy. Zhang (1995) argues that the abolition of PRT in 1993 resulted from either a weakness in UK Government planning or because of unseen distortions. Kemp and Stephens (1997) maintain that PRT was almost neutral and efficient despite the high marginal rates of tax on oil revenues when all allowances were exhausted. The authors further argue that PRT was progressive in relation to variations in the oil price and development costs. Similarly, Kemp et al (1997) argue that PRT could collect a share of economic rents from fields without necessarily endangering the viability of a development project; "it is progressive on its impact on profits" (p.117). In agreement with such a view, Mommer (1999) also argues that PRT is the main excess profit collecting device in the UK, and its several reliefs "ensure that PRT cannot, even accidentally, cut into the normal profits to which the companies are entitled" (p.15). Miller et al (2000) propose that the UK Government should re-impose PRT on the exempt oil fields at the 50% rate.

Consequently, one wonders why the UK Government firstly abolished PRT in 1993 and secondly did not consider re-introducing PRT as a mechanism to capture higher revenues from oil activity in the UKCS. PRT suffers from several limitations. Authors like Devereux and Morris (1983) and Bond et al. (1987) previously related the main weakness of PRT to its imposition alongside Royalties and CT, both of which are distortionary instruments. However, it is unlikely that PRT would be applied without CT since oil companies in the UK are expected to pay the same corporation tax as all other companies in other sectors. The two other major problems with PRT are firstly, its limited capability to generate high fiscal revenues in the case of smaller fields or a low oil price and secondly its complicated structure and according to Robinson and Morgan (1978), "it is a complicated device and could be abandoned" (p.201).

The Government action in 1993 was driven in part by the need to raise revenues and stem the losses from PRT. In the period 1991-93 the Government discovered that the PRT yield had been virtually eliminated by the expenditure on exploration and certain large investments in large PRT paying fields. According to the Chancellor of the Exchequer, PRT is an expensive tax that cost the Exchequer an estimated £200M in 1991 and 1992 (Inland Revenue, 2000). When the government removed the exploration allowance against PRT revenues were immediately restored. The three main PRT reliefs- Uplift, Oil Allowance and Safeguard are "equally important weaknesses" (Rutledge and Wright, 2000, p.5). Kemp (1990) had previously raised the issue that the uplift provision encouraged more capital-intensive exploitation methods than would a neutral scheme and the interaction of this allowance with the Safeguard provision meant that gold-plating incentives could occur.

Therefore, the reintroduction of PRT would have presented many practical and administrative problems, which probably explains why the UK Government did not pursue this option. Specifically the large number of fields developed since 1993 (when PRT was abolished) would have been brought back into PRT necessitating retroactive PRT field determinations (ring fence coordinates) and the creation of a virtual PRT economic history, which would have produced inevitable complexity in respect of transition rules.

There are also divided views with respect to CT and ST. Robinson and Morgan (1978) maintain that a tax applied on total company profits from UKCS activities is an appropriate instrument. The authors argue that companies can adjust their operations so as to improve the after-tax returns on high-cost projects, rather than dealing with single fields as is the case with PRT. Raja (1999) emphasizes the neutral aspect of CT and describes the UK regime based solely on CT as an example of a highly neutral tax regime. Also, Beckman (1998) argues that CT is simple to administer and in fact is the simplest way for the Government to raise revenues from E&P companies. Nakhle (2005) found that in the light of the decreasing attractiveness of the UKCS, the intellectual case for additional special petroleum taxation is

not sustainable, and that an application of CT only ensures that the upstream industry is treated in the same way as any other industry in the UK. However, Devereux and Morris (1983), Kemp and Stephens (1997), Rutledge and Wright (1998) disagree arguing that CT has an inappropriate tax base, which does not capture economic rent.

6. RECOMMENDATIONS

Government and oil companies are the principal players in the upstream sector of petroleum industry, but their individual focus is one of competing rather than complementary objectives. Governments normally seek to generate high levels of take from oil related activity while oil companies want to ensure an acceptable and sufficient level of profitability in their operations. Since taxation removes a considerable slice of the producers' profits, oil companies prefer fiscal systems that result in a low overall tax level thereby allowing high post-tax returns. The challenge is to design a fiscal regime that meets those two competing objectives. Further, several complications are associated with petroleum taxation.

The principal source of complication is related to the determination of economic rent. Measuring economic rent requires knowledge of the differing costs of the individual factors of production as well as their opportunity costs. The difficulty in measuring each of these components is what makes the determination of economic rent and its capture difficult and controversial (Banfi, et al, 2003). Further, as Kemp and Rose (1982) argue, because the size of a given discovery and its related exploitation costs can vary substantially, economic rent will vary from field to field. Although this problem can be partly overcome by a progressive tax system, it is difficult to make conventional fiscal systems sufficiently flexible and focused on resource rent.

An ideal tax exists just in theory, but is a useful paradigm against which to test actual or proposed fiscal systems (Stauffer and Gault, 1985). Controversy will always prevail since

there is no objective yardstick that determines sharing the oil wealth between the Government and the industry. But fiscal terms could be tailored in such a way as to be attractive for both for large as well as small discoveries while safeguarding the economic long-term interests of the oil companies. From the analysis carried out in this paper, on balance, the following points emerge:

- i. Firstly, stability of the regime should be delivered. Stability is an intangible yet crucial attribute of a fiscal regime. It directly affects the confidence of investors in Government policy, particularly in the case of petroleum extraction activity, where long-term projects are the norm. Typically a project life cycle may last 20 to 30 years from the first exploration discovery through appraisal, development, production and removal. The project will have to be sufficiently robust to endure many commodity price cycles during its life cycle. Fiscal policy, which focuses on 'creaming off' rent at the peak of the each cycle whilst ignoring the pain of the troughs, is unlikely to attract and sustain a basin's full investment potential. A study carried out by HM Treasury found that the majority of companies included in the study (29 of 37) believe that increases in taxation depress exploration activity. Lack of confidence in the future attractiveness of the fiscal regime was cited as the second most significant factor restricting exploration, following the global competition for limited funds (Sassoon, 2003).

Regime modifications should not be undertaken on a frequent basis nor be of a major or structural nature nor undertaken without advanced warning, as they could negatively affect investors' confidence (Nakhle, 2005). Oil prices are volatile and it is almost impossible to track every change. This explains why several authors have criticised the UK Government for changing the regime in response to upward movements in crude oil prices. For instance, Rowland (1983) describes such measures as "an ill-conceived move based on a myopic view of how the oil industry

operates, of the factors affecting the oil industry and of the burdens imposed by the cumbersome North Sea tax structure" (p.202), while Watkins (2001) argues that the number of modifications to which the UK fiscal regime has been subjected are "a testimony to its clumsiness" (p.13). As the previous section showed, a fall in the oil price can generate a significant decrease in oil fields' profitability. Therefore, if the UK Government introduced the 2002 fiscal changes based on the high oil prices, they have to address the corollary that it should reduce the tax rates if oil prices fall. Perhaps, a wiser policy should accept that short-term fluctuations in oil prices should not be the basis for the application of fiscal changes.

- ii. Secondly, the UK fiscal regime suffers from several deficiencies, not least the inability of a fiscal package based on CT and ST to adjust automatically to changes in the oil price, without structural changes being made. Furthermore, the complexity resulting from the application of two different packages in the UKCS - 50% for new fields since 1993 but 75% on many older fields developed before 1993 - distorts decision making and tend to divert investment away from the 75% regime towards the 50% regime. But those investments are needed to sustain the production from older, larger fields and prolong the life of the province.

Therefore, the UK Government could consider the following two options. The first option is the abolishing of ST and the re-introduction of PRT at a 50% rate. However, such a step would lead to lower fiscal revenues generated if there is a decrease in oil price and a reduction in the output of larger fields. Furthermore, because the UKCS is a mature province with the majority of fields falling into the small and very small categories, PRT is unlikely to generate high fiscal revenues. PRT can also lead to an inefficient allocation of expenditures because of its various reliefs and can actually give rise to investment disincentives in larger fields.

This leads to the second option, which is to abolish PRT on all fields and apply a higher ST rate. This would simplify the tax regime and treat all fields and all basin investment on the same basis, as well as possibly generating higher revenues. From the industry's perspective, PRT abolition would be controversial as it would be divisive; some companies pay lots of PRT, others pay none. The losers would complain and the winners would keep quiet. The Government will also need to consider the decommissioning reliefs for PRT if the tax is abolished.

- iii. Thirdly, limiting the evaluation of a fiscal regime to the level of tax rates can be very restrictive. One cannot make judgement about the effectiveness or strengths of a fiscal regime, simply by looking at the tax rate. Several factors, such as fiscal reliefs and the process of calculating the tax base, can lead to significant differences among fiscal packages, while same targets can be achieved with different structures and regimes.

- iv. Finally, a high level of Government take is not recommended in cases of high-risk exploration and high-cost development, or for those provinces with remaining modest petroleum potential, as is the case in the UKCS. The cost of producing oil can overwhelm any price incentive. Large price incentives are needed to increase production while the costs of production are rising. In the UKCS, there are still substantial volumes to come. But this requires very large investment, given the rising costs and the shrinking of fields' size. Besides, the UK Government's priority should be to extend the life of its oil province (Nakhle, 2005). Even at lower oil price, the Government can generate higher revenues if production is sustained. The rapid increase in production during the 1990's resulted in a sharp increase in tax revenues despite the static oil price, which averaged under \$20/bbl.

The appropriate regime would improve the profitability of marginal fields in order to persuade oil companies to develop these discoveries. The application of a 10% ST might have not led to a decrease in activity in the UKCS because it was coupled with an abolition of Royalty - a regressive tax - in 2002, plus an increase in oil price and unattractive conditions in other major oil producing provinces, such as Venezuela, Nigeria or the Middle East, for various political reasons. However, should oil prices fall or political stability be restored in provinces well endowed with large, low cost oil fields oil companies are likely to divert their interests from the UKCS, especially if adverse changes in tax are further introduced and the continued maturity of the basin leads to a rapid erosion of competitiveness.

6. CONCLUSION

This paper examines the effects of the 2005 increase in taxation on oil related activity in the UKCS, introduced as a consequence of the rise in the crude oil price in 2004. The analysis focuses on the impact of such changes on field profitability and Government revenue, using a sample of UKCS oil fields. The implications of such an analysis are applicable to the global oil industry, but in the UK the issue is especially important in the mid 2000s. As long as oil remains a major source of energy and as long as the UKCS continues to produce oil, the issue of the tax 'take' and the balance between Government desire for revenue and the industry's appetite for investment coupled with attractive returns, will remain central to the public debate.

The UK Government has two key objectives from its petroleum fiscal regime. These are to ensure that an appropriate share of UKCS oil profits is taxed whilst continuing to maintain industry interest in future production from the UKCS. These objectives go in parallel with the two principal aims of oil taxation. On the one hand, oil taxation needs to capture a large share of economic rent, while on the other it needs to stimulate private investment in the sector.

Controversy arises from the need to balance these two competing objectives. In the late 1970s and early 1980s, the UK Government leaned towards generating high revenues from the oil industry. From 1983 to 2002 the emphasis was on encouraging new developments and growing production thereby extending a period of UK self-sufficiency. Then, after 2002, squeezing out more revenues from the UKCS became once again a high priority given the need to fund a rapid growth in public expenditure. However, this came at the wrong time in the life of the UKCS, since the Government's concern should have been to encourage more oil production from its declining province, especially in the light of the rising concern surrounding the security of supply (Nakhle, 2005). In fact, it seems strange to hear Britain's Chancellor demanding more oil from OPEC (BBC 2004, 2005) when adjustment to his own tax policies could give a large boost to production right on his doorstep. UK Government fiscal policies have presided over a steep decline in UKCS production; from a peak of 4.6 million barrel of oil equivalent per day (mmbœ) in 1999 it is expected that this will have fallen to 3mmbœ per day in 2006 a decline of 35% one of the highest basin decline rates in the history of the industry (Hall, 2006).

Oil prices have been highly volatile over the past 25 years. Indeed periods of price volatility can be expected in the future principally because of unforeseen political and economic circumstances, demand/supply imbalances and lengthening lead times of many new upstream projects in deep water and remote locations. Uncertainty regarding future global oil resources and economics is so significant that the EIA (2005) considers a wide range of potential world oil price paths, which in 2030 range from \$34 to \$96 per barrel. Short-term oil prices change generally in response to 'news'. As such they rarely take account of the supply/demand balance, which in any case is unknown at the time (Mabro, 2001). Consequently, using the oil price as the basis for taxation is simply inappropriate, especially in a mature province like the UKCS.

Typically, petroleum extraction activity is characterized by long-term projects. New oil field developments take 2-7 years to bring into production and will be producing for 10 – 25 years. Consequently, such investment decisions are not driven by short-term oil and gas price movements, but instead by the longer-term perspective on prices (UKOOA, 2005). This further emphasises the importance of stability. Although the UK offers a stable political environment, the petroleum fiscal regime has witnessed frequent amendments. This has adversely affected confidence especially in that not all the changes can be described as substantial.

It has been argued that the UK fiscal regime suffers from technical deficiencies. However, on balance, if changes are inevitable and in order to sustain production from the UKCS as long as possible, the Government should consider abolishing PRT on those fields that received development consent before 1993 and maintain the stability of a regime based solely on corporation tax. This is particularly important given that production in the UKCS increasingly depends on smaller, high costs fields, future oil prices are almost impossible to predict, and in a mature province like the UKCS economic rents are likely to decrease. Inevitably, as production continues to decline and unit extraction costs rise, tax capacity will be squeezed out of the basin and fiscal policy will need to respond swiftly to sustain competitiveness. In time both PRT and ST will need to be removed returning the basin to the same tax regime as applies to the rest of UK Industry. This is nothing new and prevailed in the period 1993-2002 when 30% CT applied on fields that received development consent after 1993. The success of such a fiscal policy is clear from the statistics; a period of rapid production growth, sustained investment and rising tax receipts in an environment of oil prices averaging below \$20/bbl.

The analysis carried out in this paper focused on the impact of the UKCS fiscal changes on fields that have been developed. The analysis could be expanded to incorporate the impact of the fiscal changes on exploration activity, taking into consideration the next generation of

fields and the need to look at risk-reward balance, where rewards must be seen to balance risks to sustain exploration.

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LIST OF ABBREVIATIONS:

bbl: Abbreviation of one barrel of oil.

b/d: Abbreviation of Barrel per day

bn: Abbreviation of Billion.

bnbbl: Abbreviation of Billion of Barrels

bnbble: Abbreviation of Billion Barrels of oil equivalent.

bnt: Abbreviation of Billion Tonnes

Boe: Barrel of Oil Equivalent

CT: Abbreviation of Corporation Tax

DCF: Abbreviation of Discount Cash Flow Technique.

E&P: Abbreviation of Exploration and Production.

M: Abbreviation of Million.

mmbbl: Abbreviation of Million Barrels

mmbbl/d: Abbreviation of Million Barrels per day

mmboe: Abbreviation of Million Barrels Oil Equivalent.

Mt: Abbreviation of Million Tonnes.

Mboe: Million barrel of oil equivalent

PRT: Abbreviation of Petroleum Revenue Tax

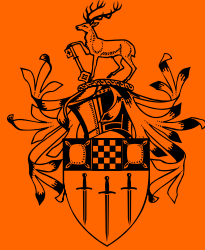
STG: Abbreviation of British Sterling

UKCS: Abbreviation of United Kingdom Continental Shelf

Note:

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