Petroleum tax competition subject to capital rationing

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Abstract

The recent dramatic fall in oil prices has led to extensive capital rationing in international oil companies, and subsequent fierce competition between resource extraction countries to attract scarce investment. This situation is not adequately addressed by the large literature on international taxation and multinational companies, since it fails to take account of capital rationing in its assumption that companies sanction all projects with a positive net present value. The paper examines the effect of tax design on international capital allocation when companies ration capital. We analyse capital allocation and government take for four equal oil projects in three different fiscal regimes: the US GoM, UK upstream and Norway offshore. Implications for optimal tax design are discussed.

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Key words: Taxation, international companies, project metrics, project valuation, oil projects
JEL classification: H21; H25; F23; Q4, G12, G31

1. Introduction

The tax competition literature assumes that the aim of company investment decisions at all points in time is simply to realise every project with a positive net present value (NPV). See, eg, Olsen and Osmundsen (2011), Kind, Midelfart and Schjelderup (2005), and Haufler and Wooton (1999). However, tax competition is often exacerbated by capital rationing. Countries must now struggle to attract investment from limited company investment budgets. The assumption made in the current literature precludes a vital element in tax competition. Capital rationing amplifies the intensity of tax competition. In addition, the capital rationing metrics applied by multinational companies alter the nature of the localisation game.

The challenge of optimal tax design when companies ration capital is of relevance in many industries. We apply a case from the petroleum sector, where a volatile oil price imposes dramatic capital rationing at times. According to Wood Mackenzie Ltd,[1] because of the slump in prices, the oil and gas industry will cut USD 1 trillion from planned spending on exploration and development. Worldwide investment in the development of oil and gas resources will be cut by 22 per cent, or USD 740 billion, from 2015 to 2020. This is lower than was anticipated before prices plunged in 2014, with the deepest cuts in the USA. A further USD 300 billion will be eliminated from exploration spending. Oil companies ration capital even when the oil price is rising, since they know from experience that overly rapid growth leads to lower quality, inadequate project management and cost overruns (Osmundsen et al (2006)).

Several reasons may prompt companies to delay or refrain from investing in projects with a positive NPV. In the current situation, oil companies have cut investment budgets in response to a dramatic reduction in cash flow owing to an oil price reduction which reached 70 per cent at the most. Since companies prefer to fund a considerable part of new investment from their cash flow, they therefore cut capital spending. They are reluctant to cut back on dividends promised to shareholders, and are careful not to increase debt levels due to credit rating

[1] http://www.bloomberg.com/news/articles/2016-06-15/oil-industry-to-cut-1-trillion-in-spending-after-price-slump

concerns and fear of financial stress. Another main reason for refusing to sanction projects with positive NPVs, which does not relate to the market or to any financial position the company might occupy, is the organisational aspect of using resources other than financial ones in an optimal way. In other words, the decision may be linked to capacity constraints with regard to experienced project personnel and managers. Given continued low prices and great uncertainty about the future level of oil prices, this tightening of investment requirements may be the only way to avoid large losses. It is also a signal to the organisation that it needs to find new technical solutions which may reduce costs and make projects more robust at lower price levels. Large nonlinearity from possible losses probably exists, and is perceived much greater than losses from not sanctioning projects with positive NPVs based on very uncertain expected prices. This may make it appropriate for companies to delay or refrain from sanctioning projects with positive NPVs.

At a general business level, a literature demonstrates that internal funds are an important determinant for company investment. See, eg, Hubbard et al (1995). Several studies compare different upstream petroleum fiscal systems, but without accounting for capital rationing – eg, Blake and Roberts (2006). Not much can be found in the academic literature on capital rationing. Instead, it largely addresses the evaluation of investment projects involving both uncertainty and flexibility (see, eg, Bjerksund and Ekern, 1990). The focus here is on an investment opportunity where the deferrable investment decision may be made contingent on future information emerging about the risky output price. Decision criteria take the form of adjusted breakeven prices (BEPs). The real option approach is relevant in the current situation, where an increase in oil price volatility may call for investment deferral, but does not come close to explaining the level of capital rationing we experience in the petroleum industry. The Norwegian-based oil company AkerBP recently announced that new projects must satisfy a BEP of USD 35 per barrel, while most analysts estimate a real oil price of USD 60 per barrel. A large difference in project value exists between an expected price scenario of USD 60 per barrel and the AkerBP sanction criterion of a BEP below USD 35/bbl. Where projects with a positive NPV at the expected price of USD 60/bbl are concerned, the option value of waiting (based on any reasonable oil price model) can only justify a minor part of this project value difference. The remainder represents capital rationing. The current dramatic fall in oil prices has prompted the oil companies to impose strict capital constraints, with cancellations and delayed project decisions as the result. In Norway, for example, Statoil as operator for the

Snorre Extension and Johan Castberg oil projects has again postponed a green light on the grounds that it needs to undertake additional optimisation and evaluation.

For a discussion of current issues pertaining to petroleum investment projects in the absence of capital constraints, see Osmundsen et al (2015). The investment decision when some constraint exists becomes rather more complicated than accepting all projects with an NPV greater than zero (Ingersoll and Ross, 1992). Myers (1974) showed that the weighted average cost of capital is not appropriate when capital constraints apply, and that a solution must be found at the corporate portfolio level.

In this paper, we describe the actual investment policy of multinational oil companies and the effect of tax design on investment location decisions. Oil companies apply capital rationing – ie, a positive NPV is not sufficient to get a project sanctioned. We describe the profitability hurdles (metrics) which projects must surpass and, by applying them to model petroleum fields, analyse how tax design affects capital allocation between countries in a context where capital is being rationed. According to Wood Mackenzie, the international petroleum companies have a high level of requirements for the internal rate of return (IRR) in new projects, "with 15 per cent considered the standard industry benchmark for a robust project".[2] This is way above the cost of capital for oil and gas projects, which is about nine per cent.[3] Capital rationing is typically implemented not only by the IRR, but also by imposing BEPs below the expected oil price or a hurdle for NPV in the form of an NPV index (NPVI). We describe these decision criteria and analyse their effect on capital allocation across countries with different tax systems.

According to economic theory, the correct solution when an investment regime with constraints has been is introduced is to apply a portfolio model for choosing the combination of projects in the opportunity set with the highest overall NPV. We look at solutions with two levels of capital constraint for four different projects in three different fiscal regimes. These projects are categorised as large, large marginal, medium and small. The UK offshore, the US Gulf of Mexico (GoM) and Norway offshore are the fiscal regimes chosen. The optimising solution, which may only be applied at the highest corporate level, is often simplified by looking at key metrics such as the IRR, the NPVI and the BEP of the projects (Emhjellen et al, 2006). This is done to achieve decentralised evaluation in organisations which make investment decisions on

[2] https://www.woodmac.com/analysis/12134873
[3] Osmundsen et al (2015).

a daily basis and in different countries with varying fiscal regimes. The reasoning is that formal optimisation of the project portfolio can only be undertaken at the highest corporate level, and that the organisation therefore needs simplified metrics for decentralised testing of project profitability. These also function as financial targets for the organisation and create discipline, with a reduced number of projects being presented to management for decisions.

When comparing fiscal regimes for the petroleum sector, the concept of government take is often applied. This is defined as the percentage of net cash flow accruing to the government over the life cycle of a project, including income taxes, royalties, profit petroleum share, bonus payments, value-added taxes, excise duties, excess profit taxes, remittance taxes, state oil company carried interests, import duties, etc. These payments differ in their timing, so a discounted government take needs to be calculated.

We examine the extent to which NPVI, IRR and BEP will yield different project selections than those obtained by optimising portfolio NPV, given the capital constraint of USD 70 billion in investment.

Project robustness in terms of resilience to a fall in oil price is currently the focus of attention in the oil companies. A low BEP gives an indication, but we also examine the changes in the after-tax return for the projects in the three fiscal regimes with high and low oil prices. We find that the tax systems in the UK and Norwegian fiscal regimes help to alleviate the effects of the price drop on the projects.

The paper is organised as follows: Section 2 presents the data and calculates the NPV before and after tax in order to illustrate the difference in government take between Norway, the UK and the US Gulf of Mexico. We also find the solution for the portfolio which maximises NPV given two natural limits on capital budgets, USD 40 billion and USD 70 billion in investment, when total possible investments are 117 billion USD. In section 3, we describe the three different metrics we use to evaluate the projects in terms of ranking. Section 4 examines the portfolio ranking of model oil and gas projects on the basis of the metrics, and juxtaposes these against those obtained by maximising total portfolio NPV, given the constraints. Section 5 presents the analysis of project returns with changes in prices and discusses company behaviour in terms of project robustness and project selection. We conclude in section 6.

2. The data, government take and project selection

The data consist of four oil projects which we have named "large", large marginal", "medium" and "small", reflecting the barrels of oil equivalent they can produce. These are representative of the industry. The large and medium fields are typical in that they are stand-alone developments, while the small field is typical in that it is tied back to an existing development for fluid processing. The large marginal field has less volume compared with total cost. This is often related to greater water depth, higher temperature, more difficult geology or a combination of such factors. Table 2.1 summarises the total Capex cost and total volume.

Table 2.1: The oil projects

	CAPEX(Mill USD)	Oil(Mill Bbl)
Large	15000	1200
Large Marignal	15000	840
Medium	8000	500
Small	1000	35

As can be seen from table 2.1, the projects have not only very different capital investment requirements but also varying volumes to produce. Investment ranges from USD 1 to 15 billion, while production volumes vary from 35 to 1200 million barrels. The complete data for the projects, including the calculations, are provided in appendix I. Although some could argue that the effect of debt financing through interest deductions will differ for the three fiscal regimes, we have chosen to use the same weighted average cost of capital (WACC) at a nominal 10 per cent. This is because financing is undertaken at the corporate level. Debt level is evaluated and decided, and the most reasonable financing independent of country is evaluated. The WACC chosen is reasonable for the industry, although some analysts might consider it to lie at the lower end of what is applied in the upstream sector.

The fiscal regimes of the three countries differ. The US offshore tax regime has a royalty of 12.5 per cent on gross production income and a corporate tax rate of 35 per cent. Depreciation depends on the type of investment but is typically front-end loaded within eight years, but no earlier than production start. In our analysis, we have chosen depreciation rules for the "facilities" category with the following annual percentages from the first year of production to year eight: 14.3, 24.5, 17.5, 12.5, 8.9, 8.9, 8.9 and 4.5. Operating cost is expensed. No deduction is made for interest, since this is assumed to be included in the cost of capital.[4]

The UK tax system has an ordinary tax rate of 30 per cent and an offshore tax rate of 32 per cent. All operating and investment costs are expensed in the year they occur. In addition comes an additional depreciation allowance against the offshore tax of 62.5 per cent for investments in the year they are made. There is no deduction for interest.

In Norway, the ordinary tax rate is 25 per cent while the additional offshore tax rate is 53 per cent. Operating costs may be deducted from these taxes, while investment is depreciated on a straight-line basis over six years from the year of investment. In addition comes an extra depreciation allowance of 22 per cent of investment against the offshore tax (5.5 per cent annually for four years). Interest on upstream investment is deductible from both corporate tax and offshore tax, restricted to the maximum interest payable on a loan equal to 50 per cent of the remaining tax value of the capital expenditure. Interest payments can be deducted from the total tax of 78 per cent. In our analysis, only the interest against offshore tax is included in the valuation. The interest deduction from ordinary tax is assumed to be included in the cost of capital.

A tax analysis for the three regimes is performed on four model fields. See appendix I. We apply a real oil price of USD 60 (2015) per barrel and a two per cent inflation rate. Table 2.2 below presents NPV and the government take for the consolidated case and a ringfenced case. A consolidated case is one where a company in a taxpaying position can let the cost of the project be offset against its other income for tax purposes. A ringfenced case is one where the company is not in a tax position and the costs must be carried forward for offsetting against future project income. The latter position is relevant for new entrants as well as some of the existing companies in the current circumstances, given the large drop in product prices.

[4] It is normal in the GoM fiscal regime with signature bonuses applicable to large prospective areas. We do not account for these, since the data is privileged and the proportion of an area bonus applicable to a particular project is difficult to assess.

Table 2.2: NPV and government take

		NPV Before tax	NPV after tax Consolidated	NPV after tax Ring fenced	NPV tax Consolidated	NPV tax Ring fenced	Gov. take % Cons.	Gov. take % Ringf.
USA GoM	Large maginal	4863	456	381	4407	4482	90,6 %	92,2 %
Norway	Large marginal	4863	1002	337	3861	4526	79,4 %	93,1 %
Norway	Small	483	107	74	376	409	77,8 %	84,7 %
Norway	Medium	5978	1392	1211	4586	4767	76,7 %	79,7 %
Norway	Large	12600	2982	2530	9618	10070	76,3 %	79,9 %
USA GoM	Small	483	133	106	350	377	72,5 %	78,1 %
USA GoM	Medium	5978	2140	2132	3838	3846	64,2 %	64,3 %
USA GoM	Large	12600	4812	4786	7788	7814	61,8 %	62,0 %
UK Up.	Large	12600	6529	6049	6071	6551	48,2 %	52,0 %
UK Up.	Medium	5978	3227	2997	2751	2981	46,0 %	49,9 %
UK Up.	Small	483	332	307	151	176	31,3 %	36,4 %
UK Up.	Large marginal	4863	3393	2671	1470	2192	30,2 %	45,1 %

Project calculations are displayed in Table 2.2. The first observation is that the government take for the large field is very high in Norway, at more than 76 per cent of the project's NPV, and considerably lower in the UK at 48.2 per cent consolidated. The US GoM lies in between at 62 per cent. The second observation is that the US tax for the large marginal field is very high, with a government take of more than 90 per cent. The Norwegian tax for the large marginal field is 79.4 per cent given a consolidated tax position and considerably higher when ringfenced (93.1 per cent). The UK has by far the lowest tax burden for this project, at 30.2 per cent consolidated and 45.1 per cent ringfenced. Where the medium-sized field is concerned, Norway again has by far the highest government take – about 10 per cent above the USA and roughly 30 per cent higher than the UK. With the small field, Norway's government take is about five per cent higher than the USA, and the UK again shows very low percentages of 31.3 and 36.4 per cent (ringfenced).

We now analyse the optimal portfolio with the goal of maximising portfolio NPV. The total portfolio consists of these nine projects, and we allow for the oil companies holding only a partial equity interest in the projects, since this is often the real position given the presence of other partners and the ability to alter the equity interest through purchase or sale. We also focus on consolidated NPV, since this predominantly is the situation – at least for mature oil companies. Total investment and NPVs are presented in table 2.3.

Table 2.3: Project NPV and investments

		Capex Mill USD	NPV Consolidated
Norway	Large	15000	2982
Norway	Large Marignal	15000	1002
Norway	Medium	8000	1392
Norway	Small	1000	107
USA GoM	Large	15000	4812
USA GoM	Large Marignal	15000	456
USA GoM	Medium	8000	2140
USA GoM	Small	1000	133
UK Up.	Large	15000	6529
UK Up.	Large Marignal	15000	3393
UK Up.	Medium	8000	3277
UK Up.	Small	1000	332
Sum	Total	117000	26555

We first analyse this on a wholly owned basis. Since all the projects have a positive NPV after tax, they would all be sanctioned and developed in a world with no constraints. The total investment would be USD 117 billion and generate an NPV of USD 26.6 billion. Capital budgets permit all the projects analysed – ie, tax competition in this instance is instigated by capital constraints.

The value of the portfolio of projects may be written as:

$$NPV_p = \sum_{i=1}^{N} V_i \; X_i$$

In equation 2.1, V_i denotes the NPV of project *i*, and X_i the relative percentage invested in project *i*, (i=1,..N).

We introduce partial ownership and a budget constraint. By allowing for a reduced equity share in the projects, the mathematical optimising solution will indicate the attractiveness of the projects for a company in the different fiscal regimes given the capital budgeting constraint. We examine first a limit of USD 40 billion on the capital budget. With this investment constraint, equation 2.1 is maximised subject to:

$$X_i \geq 0$$

$$X_i \leq 1$$

and

$$\sum_{i=1}^{N} I_i X_i \leq 40.000 \, ,$$

where I_i is the undiscounted investment (capital expenditure – Capex) in project I, and X_i is the percentage invested in *i*.

Table 2.4 presents the portfolio optimisation result with a capital constraint of USD 40 billion.

Table 2.4 NPV optimisation given constraint of USD 40 billion

		Capex Mill USD	NPV Consolidated	Percentage Included	NPV given constraint	Capex given constraint
UK Up.	Large	15000	6529	100 %	6529	15000
USA GoM	Large	15000	4812	100 %	4812	15000
UK Up.	Medium	8000	3277	100 %	3277	8000
UK Up.	Small	1000	332	100 %	332	1000
USA GoM	Medium	8000	2140	13 %	268	1000
Norway	Large	15000	2982	0 %	0	0
Norway	Large marignal	15000	1002	0 %	0	0
Norway	Medium	8000	1392	0 %	0	0
Norway	Small	1000	107	0 %	0	0
USA GoM	Large marignal	15000	456	0 %	0	0
USA GoM	Small	1000	133	0 %	0	0
UK Up.	Large marignal	15000	3393	0 %	0	0
Sum	Total	117000	26555		15218	40000

The first observation is that no Norwegian project is included. These projects do not have a sufficiently high NPV after tax compared with the investment needed. All projects in the UK are included except the large marginal field. The US large project is included 100 per cent and the US medium project absorbs the rest of the investment and is included with 13 per cent of the project. The total NPV is USD 15.2 billion.

If the capital limit is raised to a higher level, 70 USD billion, the result changes to the one presented in table 2.5.

Table 2.5 NPV optimisation given constraint of USD 70 billion.

		Capex Mill USD	NPV Consolidated	Percentage Included	NPV given constraint	Capex given constraint
UK Up.	Large	15000	6529	100 %	6529	15000
USA GoM	Large	15000	4812	100 %	4812	15000
UK Up.	Large marignal	15000	3393	100 %	3393	15000
UK Up.	Medium	8000	3277	100 %	3277	8000
USA GoM	Medium	8000	2140	100 %	2140	8000
Norway	Large	15000	2982	53 %	1590	8000
UK Up.	Small	1000	332	100 %	332	1000
Norway	Large marignal	15000	1002	0 %	0	0
Norway	Medium	8000	1392	0 %	0	0
Norway	Small	1000	107	0 %	0	0
USA GoM	Large marignal	15000	456	0 %	0	0
USA GoM	Small	1000	133	0 %	0	0
Sum	Total	117000	26555		22073	70000

The optimisation selects all the projects in the UK, the large and medium US projects and the large Norwegian project (but with only 53 per cent). The Norwegian fiscal regime is not favourable when companies operate with a before-tax capital constraint. However, the US tax on a large marginal field is the highest and almost no NPV is left in the project after tax. That makes it very unattractive for capital allocation with a constraint.

Simple metrics like the NPVI, the IRR and the BEP per barrel are used as project sanction criteria in the industry. We now analyse how project choice based on these metrics, with the same capital constraint, might differ from project optimisation solutions obtained by mathematical programming. First, we present the three metrics.

3. The three metrics

International oil companies do not use formalised portfolio models for decision making. This is too bureaucratic. Instead, simplified project metrics are calculated by individual divisions and communicated to central management. Projects must reach certain metric thresholds to be sanctioned.

The first metric we present is the IRR, which is described in many finance textbooks (see Brealey and Myers, 2011, and Copeland and Weston, 2005). It is defined as the rate of return which gives an NPV of zero:

$$NPV = \sum_{t=0}^{T} \frac{X_t}{(1+IRR)^t} = 0\,, \tag{3.1}$$

where X_t is the expected net cash flow after tax in period *t*.

The second metric is the NPVI, defined as the after-tax NPV of the project[5] divided by the before-tax NPV of investment (Kind, Tveteras and Osmundsen, 2005):[6]

$$NPVI = \sum_{t=0}^{T} \frac{X_t}{(1+r)^t} \Big/ \sum_{t=0}^{T} \frac{I_t}{(1+r)^t}\,, \tag{3.2}$$

where I_t is expected investment in period *t* and *r* is the WACC. It is our understanding that this metric is used by the dominant international oil companies in periods when oil prices are fairly stable.

The third metric is the BEP of the project (Jovanovic, 1999). It is often used by the oil industry in times like the present, when oil prices are volatile.[7] This is a variant of (3.1) in that the variable to be estimated, BEP, is in the numerator:

$$NPV = \sum_{t=0}^{T} \frac{(x_t P)(1-s) - C_t}{(1+r)^t} = 0\,, \tag{3.3}$$

Where x_t is production in period *t* and *s* is the marginal tax rate, C_t is total cost – ie, the sum of investment and operating cost – and *r* is the WACC. P is the constant price which gives an NPV equal to zero after tax – ie, the BEP. The solution is obtained by iteration.

An example of applying BEP as an investment decision criterion is provided by Statoil. The oil company presented a BEP requirement of USD 50 per barrel for all projects at its Capital Market Day in June 2015. This was clearly a capital rationing mechanism, since it operated at the same time with an expected oil price of USD 80 per barrel in its expected NPV estimate.[8]

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[5] For simplicity, we have assumed 100 per cent equity financing.
[6] Companies apply traditional NPV values – ie, all cash flow components are discounted by the same discount rate. For a discussion of differentiated discount rates applied to partial cash flows, see Osmundsen et al (2015).
[7] The financial press frequently reports on BEPs in different extraction regions, and much attention is currently being paid to the BEP of US tight oil. See, eg, http://uk.businessinsider.com/cash-cost-breakeven-oil-prices-2015-12?r=US&IR=T.
[8] *Dagens Næringsliv* (Norwegian Business Daily), 24 August 2015.

4. Maximising portfolio NPV with capital constraints juxtaposed against metric selections

To illuminate the capital allocation problem facing the international oil companies, the marginal tax rates for the projects in the various tax regimes have been estimated. These tax rates differ from the total government-take tax rate estimated in table 2.2, which can be regarded as an average tax rate. The marginal tax rate is estimated by calculating the effect on tax of investing 10 per cent more in each of the projects. With a capital constraint, this is the capital budgeting decision which faces the companies, since they can choose to invest or divest in each of the fiscal regimes. The result is presented in table 4.1

Table 4.1 Marginal tax rate in the fiscal regimes for each project

	Base NPV before tax	New NPV before tax	Base NPV after tax	New NPV after tax	Change NPV after tax	Change PV Capex	Marginal tax rate
Uk, Small	483	406	332	314	-18	77	76,62 %
Uk, Medium	5978	5419	3277	3135	-142	559	74,60 %
Uk, Large marginal	4863	3875	3393	3133	-260	988	73,68 %
Uk, Large	12600	11613	6529	6269	-260	987	73,66 %
Norway Large marginal	4863	3875	1002	725	-277	988	71,96 %
Norway, Large	12600	11613	2982	2705	-277	987	71,94 %
Norway, Medium	5978	5419	1392	1235	-157	559	71,91 %
Norway, Small	483	406	107	85	-22	77	71,43 %
US Gom, small	483	406	134	77	-57	77	25,97 %
US Gom, Medium	5978	5419	2140	1717	-423	559	24,33 %
US Gom, Large margina	4863	3875	456	-299	-755	988	23,58 %
US Gom, Large	12600	11613	4812	4056	-756	987	23,40 %

The results show quite similar marginal tax rates for the three projects in each fiscal regime, but substantial differences between these regimes. While Norwegian and UK marginal tax rates are above 71 per cent, the figure in the USA ranges from 23 to 26 per cent. The results of the metric calculation and juxtaposition with the mathematical optimisation solution are presented in table 4.2. Where the metrics are concerned, it is reasonable to assume that everything will be invested in the project with the best score until the budget limit is reached.

Table 4.2 Maximising the NPV solution with capital constraint
juxtaposed against metric solutions

	N L	NLm	N M	N S	US L	USLm	US M	US S	UK L	UKLm	UK M	UK S	Sum
Capex Musd	15000	15000	8000	1000	15000	15000	8000	1000	15000	15000	8000	1000	117000
NPV a.tax consol.	2982	1002	1392	107	4812	456	2140	133	6529	3393	3277	332	26555
NPV optim solution	**1590**				4812		2140		6529	3393	3277	332	**22073**
Metric 1 IRR	16,0 %	11,0 %	15,9 %	16,3 %	15,1 %	8,8 %	15,1 %	16,6 %	28,2 %	20,1 %	31,4 %	64,4 %	
Capex	15000		8000	1000	6000			1000	15000	15000	8000	1000	70000
NPV a.tax	2982		1392	107	**1925**			133	6529	3393	3277	332	**20070**
Metric 2 NPVI	0,30	0,10	0,25	0,14	0,49	0,05	0,38	0,17	0,66	0,34	0,58	0,43	
Capex	8000				15000		8000		15000	15000	8000	1000	70000
NPV a.tax	**1590**				4812		2140		6529	3393	3277	332	**22073**
Metric 4 BE	35,4	48,9	37,7	44,1	42,4	58,7	44,9	51,6	25,6	34,9	26,5	27,8	
Capex	15000		8000		8000				15000	15000	8000	1000	70000
NPV a.tax	2982		1392		**2566**				6529	3393	3277	332	**20471**

Reading from left to right, the columns provide the information on the projects (project titles abbreviated) with respect to the headings on the left-hand side of the table. On the right-hand side, the sum of the Capex and the total NPV solution (in bold) are given for each of the solutions.

The NPVI metric gives the same investment allocation as the mathematical programming solution (as expected with an undiscounted before-Capex constraint) – ie, it includes the same projects 100 per cent and, at the margin, reduced the investment in the Norwegian large project to 53 per cent. This solution generates a total portfolio NPV of USD 22 073 million. The BEP solution gives a lower total NPV (USD 20 471 million). The IRR metric yields the lowest total NPV solution of USD 20 070 million. It includes two of the smaller projects with a sufficiently high IRR (the US small project and the Norwegian small projects with IRRs of 16.6 and 16.3 per cent respectively). The IRR solution at the margin reduces investment in the US large project to 40 per cent. The BEP allocation also implies a reduction of this project, but only to 53 per cent. All the solutions include the UK projects, even the large marginal project not included for the two other fiscal regimes in any of the metrics.

The capital requirement and investment financing for a company will always be linked to its after-tax cash flow. If a company has real capital constraints and desires to maximise the value of its investment opportunities in different fiscal regimes, it will need to examine after-tax metrics or use after-tax constraints. Before-tax constraints and before-tax metrics like the NPVI do not account for the tax effects of investment. This metric, however, that implicitly presumes a before-tax capital constraint, can be justified if critical personnel is the scarce factor, as the need for personnel is typically linked to the level of before tax investment.

Returning to the present situation, with scarce capital, appendix II displays the optimal portfolio choice – ie, maximum NPV with an after-tax investment constraint corresponding to a before-tax budget limit of USD 70 billion (with marginal tax rates as specified in table 4.1). The optimising solution is given the minimum of the sum of the present value of after tax cost allowed where the corresponding sum of the before tax is 70 billion. This sum of the after tax cost is 22.7 billion USD. The portfolio NPV is now reduced from USD 22 073 million to USD 20 472 million. The reason is that the goal of minimising the sum of the present value of the after tax costs cuts back on investments that have positive NPVs even more than the before tax constraint. The solution is equal to the portfolio investment choice obtained using the BEP metrics in table 4.2. The BEP metric, which is the before-tax price necessary to make the present value of the after-tax cash flow equal to zero, is therefore a reasonable simplifying metric for choosing a portfolio based on after-tax constraint.

Note that the design of the tax systems has a large impact on the cash flow profiles of the companies. The portfolio cash flow resulting from the NPV optimisation with a before-tax constraint and the solution with after-tax constraint in appendix II and the difference in cashflow between these portfolios are given in appendix III. The before-tax constraint gives a much higher financing need in the early years, since the oil company does not account for the fact that the resource extraction countries are carrying part of the investment via the tax system (tax credits). Companies operating in several tax regimes will probably consider the after-tax effect when seeking finance for their activities. In such a situation, fiscal regimes providing early deductions – as in Norway and the UK – will be much more competitive with fiscal regimes like the US GoM which have late deductions. For the first five years, from 2018 to 2022, the accumulated "investments" needed after tax is USD 4 441 million greater for the portfolio with the before-tax constraint on investments than the after tax constraint on investments. However, the return on the difference in the portfolios based on the cash-flow difference for all the years from 2018 to 2047 is 13.7 per cent. With the after-tax constraint, this return is deemed to be insufficiently high. The after tax constraint selection using the IRR metric gives an even lower financing need than the portfolio selection based on the breakeven price metric. The accumulated cashflow need is 7.525 billion USD less in just four years (until 2021) with the IRR metric. However, the return That illustrates how companies with capital constraints may require very high returns for projects to be sanctioned.

All the metrics in table 4.2 are used at times by oil and gas companies when evaluating projects, but companies are now using the BEP metric as the project selection criterion. The BEP seems to attract particular attention when the long-term price pattern represents the major concern. That is descriptive of the current position, with a volatile oil market. The companies seem to follow their expressed strategy of electing to delay projects which do not satisfy their breakeven targets. Attention is concentrated on cost reduction and project optimisation to meet the BEP. On its Capital Market Day in June 2015, Statoil made particular mention of the need for projects to have a positive NPV at USD 50 per barrel. As has been shown above, the BEP gave the same solution as portfolio maximisation with an after-tax constraint. The metric is therefore a good approximation for portfolio maximisation with an after-tax budget constraint.

5. Project return robustness

Since attention at oil companies is focused on the breakeven oil price and project robustness to price risk, it is interesting to examine the robustness of the after-tax return of the projects to a change in the oil price. This may indicate how far the tax system alleviates price risk relative to the before-tax return – to what degree does the tax system change the impact of the after-tax return compared with the before-tax return? The BEPs estimated for the projects give an indication. Based on the IRR before tax, the tax cash flow and the after-tax cash flow, however, a clear indication can be obtained of where the fiscal regime has the biggest or smallest impact on the systematic price risk (given the fact that most of the systematic risk is related to oil price). Given that negative cash flows from the project may be offset against other income (consolidated), a tax regime based on a cash-flow tax would give the same changes in before- and after-tax return. This is not the case for the three fiscal regimes we analyse. In table 5.1 below, we show the IRR for the projects at base price (USD 60/bbl) and at the lower level of USD 40/bbl and the higher of USD 80 /bbl.

Table 5.1 Project returns in fiscal regimes given realised oil prices

	60 Usd B.t.	60 Usd A.t.c.	40 Usd B.t.	40 Usd A.t.c.	80 Usd B.t.	80 Usd A.t.c.	% change 40 B.t.	% change 40 A.t.	% change 80 B.t.	% change 80 A.t.
Norway, Large	22,8 %	16,0 %	12,8 %	9,9 %	30,7 %	21,0 %	-43,9 %	-38,1 %	34,6 %	31,3 %
Norway Large marginal	14,6 %	11,0 %	5,4 %	5,8 %	21,6 %	15,2 %	-63,0 %	-47,3 %	47,9 %	38,2 %
Norway, Medium	24,1 %	15,9 %	12,0 %	9,1 %	33,9 %	21,7 %	-50,2 %	-42,8 %	40,7 %	36,5 %
Norway, Small	39,8 %	16,3 %	6,9 %	6,6 %	70,4 %	27,9 %	-82,7 %	-59,5 %	76,9 %	71,2 %
US Gom, Large	22,8 %	15,1 %	12,8 %	7,3 %	30,7 %	21,1 %	-43,9 %	-51,7 %	34,6 %	39,7 %
US Gom, Large marginal	14,6 %	8,8 %	5,4 %	1,3 %	21,6 %	14,2 %	-63,0 %	-85,2 %	47,9 %	61,4 %
US Gom, Medium	24,1 %	15,1 %	12,0 %	5,9 %	33,9 %	22,3 %	-50,2 %	-60,9 %	40,7 %	47,7 %
US Gom, small	39,8 %	16,6 %	6,9 %	-2,1 %	70,4 %	34,6 %	-82,7 %	-112,7 %	76,9 %	108,4 %
Uk, Large	22,8 %	28,2 %	12,8 %	18,4 %	30,7 %	35,7 %	-43,9 %	-34,8 %	34,6 %	26,6 %
Uk, Large marginal	14,6 %	20,1 %	5,4 %	11,3 %	21,6 %	26,9 %	-63,0 %	-43,8 %	47,9 %	33,8 %
Uk, Medium	24,1 %	31,4 %	12,0 %	19,3 %	33,9 %	40,9 %	-50,2 %	-38,5 %	40,7 %	30,3 %
Uk, Small	39,8 %	64,4 %	6,9 %	30,5 %	70,4 %	98,2 %	-82,7 %	-52,6 %	76,9 %	52,5 %

Results for the return change are displayed in table 5.1. This shows that, while the tax system is dampening the effect of a price change in Norway and the UK, it is actually increasing the risk of oil projects in the USA in terms of a higher change in after-tax returns than before-tax returns. The risk reduction on the after-tax return is somewhat greater in the UK than in Norway, but the return gain with higher prices is also the lowest. For all the fiscal regimes, the return change is highest for the small project.

6. Conclusion

Taxation theory presumes that companies sanction all projects with a positive NPV. This is at odds with reality, where companies ration capital. We examine capital allocation in multinational oil companies by applying model fields in the USA, the UK and Norway, and analyse how capital allocation by international oil companies is affected by the various tax systems.

Starting off with a mathematical portfolio optimisation model, we find that no Norwegian projects are developed with the tightest capital constraint (USD 40 billion), while three in the UK and two in the USA will be. With a less stringent capital constraint of USD 70 billion, the same two projects in the USA are developed, all four in the UK, and only the large project in Norway. One might therefore question the competitiveness of the Norwegian fiscal regime in current market conditions. The US authorities should worry about cream-skimming, since projects perceived to be marginal by capital-rationing oil companies – and which therefore fail to be sanctioned – may be profitable for society.

Capital rationing is often implemented by simple decentralised profitability metrics. We have analysed capital allocation under different metrics and tax systems. Juxtaposing the metric results against the results from portfolio NPV maximisation with capital constraints, we find that the NPVI metric provides the same choice as portfolio optimisation with a before-tax constraint. The IRR metric has its own solution with the lowest portfolio NPV. The BEP metric gives an intermediate solution and the same solution as that obtained with a minimising present value of after-tax cost constraint. The solutions obtained by the NPVI (before tax) and the BEP (after-tax) metrics indicate large differences in the company's financing needs.

Subjecting project profitability to a robustness test in terms of resilience to a fall in oil prices demonstrates that the British and Norwegian fiscal regimes alleviate some price risk by reducing the change in after-tax return compared with the before-tax return. The opposite is true of the fiscal regime in the US GoM, which increases company risk.

A topic for future research is to expand the strategic tax competition literature to take account of investment metrics in the description of company investment allocation. The current literature so far simply assumes that all projects with a positive NPV are sanctioned. Changing company behaviour in the models is likely to alter investment allocation and optimal tax design.

The international tax literature also implicitly assumes that government and companies have the same requirement for the rate of return. Since capital rationing implies a requirement greater than the opportunity cost of capital, the tax analysis must account for the fact that society may require much lower rates of return than the oil companies. An intertemporal model framework is called for. Norway has a real rate of return requirement of seven per cent, for instance, whereas a current stipulation of international oil company requirements is 15 per cent.[9] Thus, it may prove beneficial for government to carry a large fraction of the initial investment, as is the case in the British and Norwegian petroleum tax systems, and secure higher tax revenue later in the project life cycle. The risk premium demanded by the companies for their capital investment may thereby be reduced and expected government

[9] https://www.woodmac.com/analysis/12134873

revenue maximised. This conclusion is reversed for developing countries with a limited ability to carry risk and an immediate need for revenue. That is also what we observe in the latter countries, with royalty payments, for example, and international oil companies carrying investment on behalf of the state oil company.

In Norway and to some extent the UK, petroleum revenue comprises a significant fraction of government income. Tailoring a special tax system for this industry thus makes sense. In the USA, the petroleum industry is one sector among many, and attention has often focused on production rather than revenue. Tailoring of the petroleum taxation has therefore not been on the agenda to the same extent. In spite of a large capital exposure for the oil companies, the USA attracts big investment and secures substantial revenues. This mainly reflects geological prospectivity, which has been excluded from the present paper, as well as less stringent regulation. Differences in prospectivity are also an important factor when comparing the British and Norwegian tax systems. The UK sector is more mature and less prospective by nature, and must offer more generous fiscal terms to attract investment. Norway's continental shelf has a more diversified maturity, but certain areas seem to fail to attract sufficient new investment and may need improved fiscal terms.

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APPENDIX I: Large field

	Norway Upstream									US Gulf of Mexico							UK Upstream						
	Oil M.bbl	Income M.usd	Opex M.usd	Capex M.usd	B.tax M.usd	Tax ring f.	A.tax ring f.	Tax cons.	A. tax cons.	B.tax M.usd	Roya. ring f.	Co. tax ring f.	A.tax ring f.	Roya. cons.	Co. tax cons.	A.tax cons.	B.tax M.usd	Sp. Tax ring f.	Co. tax ring f.	A.tax ring f.	Sp. Tax cons.	Co. tax cons.	A.tax cons.
Sum	1200	97329	21000	15000	61329	44480	16849	45544	15785	61329	12190	17198	31940	12190	17198	31940	61329	14626	16524	30180	16625	18398	26305
2018				1500	-1500		-1500	-127	-1373	-1500			-1500			-1500	-1500			-1500	-320	-300	-880
2019				2250	-2250		-2250	-446	-1804	-2250			-2250			-2250	-2250			-2250	-640	-600	-1010
2020				3750	-3750		-3750	-955	-2795	-3750			-3750			-3750	-3750			-3750	-1040	-975	-1735
2021				3750	-3750		-3750	-1584	-2166	-3750			-3750			-3750	-3750			-3750	-1200	-1125	-1425
2022	24,0	1654	720	3750	-2816		-2816	-1817	-998	-2816	207		-3023	207	-496	-2527	-2816			-2816	-1354	-938	-524
2023	106,8	7508	1134		6374		6374	434	5940	6374	940	120	5313	940	616	4818	6374			6374	-719	993	6099
2024	106,8	7658	1134		6524	213	6311	2833	3691	6524	959	1030	4535	959	1030	4535	6524			6524	1225	1942	3357
2025	98,4	7197	1092		6105	983	5122	3112	2993	6105	901	1166	4038	901	1166	4038	6105			6105	1976	1873	2256
2026	92,4	6893	1062		5831	2552	3279	3364	2468	5831	863	1270	3698	863	1270	3698	5831		904	4927	1895	1777	2159
2027	86,4	6575	1032		5543	3700	1843	3700	1843	5543	823	1183	3536	823	1183	3536	5543	147	1560	3836	1804	1692	2047
2028	80,4	6240	1002		5238	3961	1278	3961	1278	5238	782	1091	3366	782	1091	3366	5238	1191	1602	2446	1709	1602	1928
2029	74,4	5890	972		4918	3961	957	3961	957	4918	738	1229	2951	738	1229	2951	4918	1608	1508	1803	1608	1508	1803
2030	68,4	5523	942		4581	3705	877	3705	877	4581	692	1361	2528	692	1361	2528	4581	1502	1408	1671	1502	1408	1671
2031	62,4	5140	912		4228	3436	792	3436	792	4228	644	1254	2330	644	1254	2330	4228	1391	1304	1533	1391	1304	1533
2032	56,4	4738	882		3856	3153	704	3153	704	3856	593	1142	2121	593	1142	2121	3856	1274	1194	1389	1274	1194	1389
2033	50,4	4319	852		3467	2856	611	2856	611	3467	541	1024	1902	541	1024	1902	3467	1151	1079	1237	1151	1079	1237
2034	44,4	3881	822		3059	2545	514	2545	514	3059	486	901	1672	486	901	1672	3059	1022	959	1078	1022	959	1078
2035	38,4	3424	792		2632	2219	412	2219	412	2632	429	771	1432	429	771	1432	2632	888	832	912	888	832	912
2036	32,4	2946	762		2184	1878	306	1878	306	2184	369	635	1180	369	635	1180	2184	747	700	738	747	700	738
2037	28,8	2671	744		1927	1604	324	1604	324	1927	335	558	1035	335	558	1035	1927	644	604	679	644	604	679
2038	25,2	2384	726		1658	1398	260	1398	260	1658	299	476	884	299	476	884	1658	559	524	574	559	524	574
2039	21,6	2085	708		1377	1184	193	1184	193	1377	261	390	725	261	390	725	1377	471	441	465	471	441	465
2040	18,0	1772	690		1082	959	123	959	123	1082	222	301	559	222	301	559	1082	378	354	350	378	354	350
2041	16,8	1687	684		1003	813	190	813	190	1003	211	277	515	211	277	515	1003	329	309	365	329	309	365
2042	15,6	1598	678		920	750	170	750	170	920	200	252	468	200	252	468	920	303	284	332	303	284	332
2043	14,4	1504	672		832	683	149	683	149	832	188	225	418	188	225	418	832	276	258	298	276	258	298
2044	13,2	1406	666		740	613	127	613	127	740	176	198	367	176	198	367	740	247	231	262	247	231	262
2045	12,0	1304	660		644	540	104	540	104	644	163	168	313	163	168	313	644	216	203	225	216	203	225
2046	12,0	1330	660		670	513	158	513	158	670	167	176	327	167	176	327	670	212	199	260	212	199	260
2047						261	-261	261	-261									72	67	-139	72	67	-139

APPENDIX I: Medium sized oil field

	Norway Upstream									US Gulf of Mexico							UK Upstream						
	Oil M.bbl	Income M.usd	Opex M.usd	Capex M.usd	B.tax M.usd	Tax ring f.	A.tax ring f.	Tax cons.	A. tax cons.	B.tax M.usd	Roya. ring f.	CT tax ring f.	A.tax ring f.	Roya. cons.	CT tax cons.	A.tax cons.	B.tax M.usd	SPTtax ring f.	CT tax ring f.	A.tax ring f.	SPTtax cons.	CT tax cons.	A.tax cons.
Sum	500	37792	7300	8000	22492		6559		-1099	22492	4733	6215	11543	4733	6215	11543	22492	4718	5923	11851	5597	6747	10147
2018				1200	-1200		-1200	-101	-1626	-1200			-1200			-1200	-1200			-1200	-384	-360	-456
2019				2000	-2000		-2000	-374	-1653	-2000			-2000			-2000	-2000			-2000	-640	-600	-760
2020				2400	-2400		-2400	-747	-685	-2400			-2400			-2400	-2400			-2400	-768	-720	-912
2021	20	1351	420	2400	-1469		-1469	-784	2905	-1469	169		-1638	169	-133	-1505	-1469			-1469	-902	-441	-126
2022	55	3791	595		3196		3196	291	2002	3196	475	133	2588	475	267	2454	3196			3196	-145	959	2382
2023	55	3866	595		3271	180	3092	1269	1860	3271	484	486	2301	484	486	2301	3271			3271	1047	981	1243
2024	55	3944	595		3349	737	2612	1489	1378	3349	494	649	2205	494	649	2205	3349			3349	1072	1005	1273
2025	50	3657	570		3087	1446	1641	1709	982	3087	458	670	1959	458	670	1959	3087		926	2161	988	926	1173
2026	45	3357	545		2812	1830	982	1830	599	2812	420	587	1804	420	587	1804	2812	287	844	1681	900	844	1069
2027	40	3044	520		2524	1925	599	1925	371	2524	381	500	1643	381	500	1643	2524	808	757	959	808	757	959
2028	35	2717	495		2222	1851	371	1851	296	2222	340	534	1348	340	534	1348	2222	711	667	844	711	667	844
2029	30	2375	470		1905	1609	296	1609	275	1905	297	563	1045	297	563	1045	1905	610	572	724	610	572	724
2030	26	2120	451		1668	1394	275	1394	216	1668	266	491	912	266	491	912	1668	534	501	634	534	501	634
2031	23	1853	433		1421	1205	216	1205	215	1421	232	416	773	232	416	773	1421	455	426	540	455	426	540
2032	20	1680	420		1260	1046	215	1046	175	1260	210	367	682	210	367	682	1260	403	378	479	403	378	479
2033	18	1500	408		1092	917	175	917	133	1092	188	317	588	188	317	588	1092	350	328	415	350	328	415
2034	15	1311	395		916	783	133	783	153	916	164	263	489	164	263	489	916	293	275	348	293	275	348
2035	14	1226	389		837	684	153	684	-326	837	154	239	444	154	239	444	837	268	251	318	268	251	318
2036					0	326	-326	326															

APPENDIX I: Large marginal oil field

	Norway Upstream									US Gulf of Mexico							UK Upstream						
	Oil	Income	Opex	Capex	B.tax	Tax	A.tax	Tax	A.tax	B.tax	Roya.	Co.Tax	A.tax	Roya.	Co.Tax	A.tax	B.tax	Sp.Tax	Co.Tax	A.tax	Sp.Tax	Co.Tax	A.tax
	M.bbl	M.usd	M.usd	M.usd	M.usd	ring f.	ring f.	cons.	cons.	M.usd	ring f.	ring f.	ring f.	cons.	cons.	cons.	M.usd	ring f.	ring f.	ring f.	cons.	cons.	cons.
Sum	840	68130	19200	15000	33930		11479		9757	33930	8533	8889	16508	8533	8889	16508	33930	5097	7591	21242	7857	10179	15894
2019				1500	-1500		-1500	-127	-1373	-1500			-1500			-1500	-1500			-1500	-480	-300	-720
2020				2250	-2250		-2250	-446	-1804	-2250			-2250			-2250	-2250			-2250	-720	-600	-930
2021				3750	-3750		-3750	-955	-2795	-3750			-3750			-3750	-3750			-3750	-1200	-975	-1575
2022				3750	-3750		-3750	-1584	-2166	-3750			-3750			-3750	-3750			-3750	-1200	-1125	-1425
2023	16,8	1158	684	3750	-3276		-3276	-1997	-1279	-3276	145		-3421	145	-635	-2786	-3276			-3276	-1419	-1030	-827
2024	74,8	5256	974		4282		4282	-562	4843	4282	658		3624	658	-17	3641	4282			4282	-312	529	4065
2025	74,8	5361	974		4387		4387	1184	3203	4387	671	286	3430	671	382	3333	4387			4387	456	1306	2625
2026	68,9	5038	944		4093		4093	1494	2600	4093	631	685	2777	631	556	2906	4093			4093	1310	1257	1526
2027	64,7	4825	923		3902	186	3716	1827	2075	3902	604	625	2673	604	685	2612	3902			3902	1249	1190	1464
2028	60,5	4602	902		3700	570	3130	2229	1471	3700	576	560	2563	576	625	2498	3700			3700	1184	1130	1386
2029	56,3	4368	881		3487	1444	2043	2559	928	3487	547	727	2213	547	560	2380	3487		140	3347	1116	1067	1304
2030	52,1	4123	860		3263	2332	931	2632	630	3263	516	890	1856	516	727	2019	3263		722	2540	1044	1001	1217
2031	47,9	3866	839		3027	2453	574	2453	574	3027	484	815	1728	484	890	1653	3027		932	2095	969	932	1127
2032	43,7	3598	818		2779	2264	515	2264	515	2779	451	736	1592	451	815	1514	2779	126	859	1795	889	859	1031
2033	39,5	3317	797		2519	2067	453	2067	453	2519	415	654	1450	415	736	1368	2519	806	782	931	806	782	931
2034	35,3	3023	776		2247	1859	388	1859	388	2247	379	567	1301	379	654	1214	2247	719	701	827	719	701	827
2035	31,1	2717	755		1961	1641	320	1641	320	1961	340	477	1144	340	567	1054	1961	628	617	717	628	617	717
2036	26,9	2397	734		1662	1413	249	1413	249	1662	300	382	980	300	477	885	1662	532	529	602	532	529	602
2037	22,7	2063	713		1349	1174	175	1174	175	1349	258	327	764	258	382	709	1349	432	436	481	432	436	481
2038	20,2	1870	701		1169	982	187	982	187	1169	234	270	665	234	327	608	1169	374	369	426	374	369	426
2039	17,6	1669	688		981	839	142	839	142	981	209	210	561	209	270	502	981	314	313	354	314	313	354
2040	15,1	1459	676		784	688	95	688	95	784	183	148	453	183	210	391	784	251	255	278	251	255	278
2041	12,6	1240	663		577	531	47	531	47	577	155	131	291	155	148	274	577	185	194	199	185	194	199
2042	11,8	1181	659		522	429	93	429	93	522	148	113	261	148	131	243	522	167	162	193	167	162	193
2043	10,9	1118	655		464	384	79	384	79	464	140	95	229	140	113	210	464	148	145	170	148	145	170
2044	10,1	1053	650		403	338	65	338	65	403	132	75	195	132	95	176	403	129	127	147	129	127	147
2045	9,2	985	646		338	289	49	289	49	338	123	55	160	123	75	140	338	108	108	122	108	108	122
2046	8,4	913	642		271	238	33	238	33	271	114	60	96	114	55	102	271	87	88	96	87	88	96
2047	8,4	931	642		289	218	71	218	71	289	117	0	173	117	60	112	289	93	85	112	93	85	112
2048						113	-113	113	-113										29	-29		29	-29

APPENDIX I: Small field

	Norway Upstream											US Gulf of Mexico							UK Upstream						
	Oil	Income	Opex	Capex	B.tax	Sp. Tax	Co. Tax	A.tax	Sp. Tax	Co. Tax	A.tax	B.tax	Roya.	Co. Tax	A.tax	Roya.	Co. Tax	A.tax	B.tax	Sp. Tax	Co. Tax	A.tax	Sp. Tax	Co. Tax	A.tax
	M.bbl	M.usd	M.usd	M.usd	M.usd	ring f.	ring f.	ring f.	cons.	cons.	cons.	M.usd	ring f.	ring f.	ring f.	cons.	cons.	cons.	M.usd	ring f.	ring f.	ring f.	cons.	cons.	cons.
Sum	35	2352	375	1000	977	403	263	310	367	244	366	977	295	293	389	295	239	443	977	71	254	651	113	293	571
2018				400	-400			-400	-25	-8	-366	-400			-400			-400	-400			-400	-85	-80	-235
2019	5,3	341	66	600	-325		5	-330	-17	5	-313	-325	43	31	-399	43	31	-399	-325			-325	-185	-105	-35
2020	12,3	812	101		710	106	73	532	134	81	495	710	102	127	481	102	127	481	710			710	20	110	581
2021	8,8	591	84		507	178	111	219	198	111	199	507	74	90	343	74	90	343	507		73	435	154	173	181
2022	5,3	362	66		296	96	59	141	96	59	141	296	45	44	206	45	44	206	296	7	95	193	117	110	68
2023	3,5	246	58		189	23	16	149	3	6	179	189	31		158	31	-54	212	189	44	67	77	72	67	49
2024									-21	-10	30								0	20	19	-39	20	19	-39

APPENDIX II: Portfolio optimisation with minimum of sum of present value of cost as constraint

		Capex Mill USD	PV after tax cost	NPV Cons.	Percent Incl.	NPV w. constr.	PV a.t. cost w. constraint	Capex w. constr.
Norway	Large	15000	4206	2982	100 %	2982	4206	15000
Norway	Large Marignal	15000	4051	1002	0 %	0	0	0
Norway	Medium	8000	2301	1392	100 %	1391	2299	7994
Norway	Small	1000	290	107	0 %	0	0	0
USA GoM	Large	15000	11479	4812	53 %	2568	6127	8006
USA GoM	Large Marignal	15000	11041	456	0 %	0	0	0
USA GoM	Medium	8000	6200	2140	0 %	0	0	0
USA GoM	Small	1000	751	133	0 %	0	0	0
UK Up.	Large	15000	3948	6529	100 %	6529	3948	15000
UK Up.	Large Marignal	15000	3802	3393	100 %	3393	3802	15000
UK Up.	Medium	8000	2081	3277	100 %	3277	2081	8000
UK Up.	Small	1000	237	332	100 %	332	237	1000
Sum	Total	117000	50386	26555		20472	22700	70000

*PV after-tax cost using the marginal tax rates in table 4.1

APPENDIX III: Portfolio Cash flows

Years		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
CF a.tax	Table 4.2	-5893	-7720	-10647	-8293	1012	19603	13823	10693	9379	8422	7400	6309	5507	4868	4310
CF a.tax	Table 4.3	-5740	-7173	-9547	-6883	2044	19802	13194	9801	8236	6948	5863	5012	4441	3923	3489
CF Difference	Table 4.2-4.3	-153	-547	-1099	-1410	-1032	-198	629	892	1143	1473	1537	1297	1066	946	821
Accumulated diff.	Table 4.2-4.3	-153	-701	-1800	-3210	-4242	-4441	-3812	-2920	-1777	-304	1233	2530	3596	4542	5363

Years		2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
CF a.tax	Table 4.2	3735	3159	2663	1585	1514	1249	983	716	712	630	549	467	384	433	-183
CF a.tax	Table 4.3	3011	2532	2137	1092	1295	1061	826	590	619	547	475	402	329	390	-249
CF Difference	Table 4.2-4.3	724	627	526	494	219	188	157	126	92	83	74	64	55	44	66
Accumulated diff.	Table 4.2-4.3	6087	6714	7240	7734	7952	8140	8297	8424	8516	8599	8672	8736	8791	8834	8900

APPENDIX IV: Portfolio Cashflow comparisons with IRR

Years	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
CF a.tax IRR metric port.	-4793	-6008	-5965	-5052	484	14375	9981	7512	6393	5241	4298	3651	3289	2971	2698
CF Difference with NPVI port.	-1100	-1712	-4681	-3241	528	5228	3842	3180	2986	3180	3102	2658	2217	1897	1612
CF Difference with Breakeven port.	-947	-1165	-3582	-1831	1560	5427	3213	2289	1843	1707	1565	1361	1151	951	790
Accum. Diff. With NPVI port.	-1100	-2813	-7494	-10735	-10207	-4978	-1136	2044	5030	8210	11312	13970	16187	18084	19696
Accum. Diff. With Breakeven port.	-947	-2112	-5694	-7525	-5965	-538	2676	4964	6807	8514	10079	11440	12591	13542	14333

Years	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
CF a.tax IRR metric port.	2373	2032	1740	1671	1844	1542	1226	896	953	860	762	658	550	660	-429
CF Difference with NPVI port.	1362	1126	923	-85	-330	-293	-243	-180	-242	-229	-213	-192	-166	-227	246
CF Difference with Breakeven port.	638	499	397	-579	-548	-481	-400	-306	-334	-312	-286	-256	-221	-271	180
Accum. Diff. With NPVI port.	21058	22184	23107	23022	22692	22399	22156	21976	21735	21505	21292	21100	20934	20707	20953
Accum. Diff. With Breakeven port.	14971	15470	15867	15288	14740	14259	13859	13553	13219	12907	12620	12364	12143	11873	12053