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Maximizing the discounted tax revenue in a mature oil province

Abstract:
Using a partial equilibrium model for the global oil market, we search for the producer tax that maximizes the government's discounted tax revenue in Norway. The oil market model explicitly accounts for reserves, development and production in 4 field categories across 15 regions. The oil companies optimize their profit and we study how different tax rates influence their investment and production profiles over time. Our results show that a net tax rate in the range of 83 to 87 percent gives the highest tax revenue over a wide range of oil prices and government's discount rates. However, to avoid premature policy recommendations based on assumptions that are more or less uncertain, we carry out various sensitivity analysis in the favor of lower taxes. These analysis show that it is generally never optimal to reduce the prevailing net tax rate of 78 percent. Only in a very pessimistic scenario regarding costs and exploration is it optimal with a minor reduction in the tax rate. Hence, even if many regard Norway as a high tax province, a robust conclusion seem to be that reducing the present tax level on oil production will not boost investment and production to such a degree that discounted tax revenue increases. We emphasize that such a conclusion holds whether the oil companies are constrained by credit or not.

Keywords: oil market, tax revenue, equilibrium model

JEL classification: H21, Q31, Q38

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Introduction

Because oil is a non-renewable resource, it gives rise to resource rents. These rents are income beyond what is needed to cover all costs including a normal return on capital. In order to obtain the rents, the resource has to be discovered and extracted. If private oil companies execute these activities, they require compensation for their costs and a remuneration of the risks involved. The taxation of the oil rents must on one hand leave sufficient incentives to the oil companies for exploration and extraction, while at the same time distribute an appropriate part of the rents to the state (Mulder et al, 2004).

The Norwegian Continental Shelf (NCS) is often described as a mature oil province. The term mature implies various characteristics as is described in, e.g., Kemp and Stephen (2005): a) falling average size of discovery and development, b) declining production, c) failure to replace depletion by new additions to reserves and d) declining exploration interest. Some of these characteristics apply to the NCS. Some argue that part of the reason why many oil producing countries suffer from either a decline or a slow down in production and exploration activity, is that they fail to implement appropriate fiscal regimes, c.f. Lee (2006).

Oil prices have increased significantly over the last 3-4 years, from an average of $28 in 2003 to $65 per barrel in 2006, reaching around $72 per barrel of Brent Blend in 2007. The Norwegian petroleum net tax rate of 78 percent was much criticized by the oil industry as late as 2003. The oil industry argued for a reduction of the Special Petroleum Tax from 50 percent to 25 percent, which is added to the general corporate tax of 28 percent (see Kon-Kraft, 2003). Parts of the oil industry argued that the after-tax return on investment, above all on small fields, was not sufficient to generate interest in the maturing NCS[1].

Along with the steep increase in oil prices since 2004, the criticism of the Norwegian tax system has calmed. Many analysts believe that it is highly unlikely that the global price of oil in the medium-term will revert to the mean of around $15 to $20 for Brent Blend, which characterized most of the 1990s (see , e.g., Ghalib and Knapp, 2005). The reason for this is firstly that there appears to have been a marked and unanticipated structural shift upward in global demand for oil primarily in Asia, led by China and India, and partly in the US. Secondly, the expansion of the supply outside OPEC is unlikely to be sufficiently rapid so as to satisfy anywhere near all the projected growth in oil demand.

[1] The authorities did not introduce a lower petroleum tax. Some reforms were introduced, however, as paying back exploration expenditure for companies without tax shelter.

However, new large oil discoveries, the introduction of alternative energy sources, a weaker OPEC or a reduction in demand in large oil consuming countries might possibly lead to lower oil prices. To study how the effects of tax changes on future investment and production on the NCS vary with the oil price level, we look at a wide range of oil prices.

In this study we employ the FRISBEE model, which is recursively dynamic, i.e. the model is solved in sequential periods, and equilibrium within each period depends only on past and contemporaneous variables (see, e.g., Gately et al, 1977, and Burniaux et al, 1992). The model incorporates both short and long run effects of changing oil prices in various regions on both the demand and supply side. We separate between oil producers' investment and production decisions in 4 field categories in 13 different regions outside OPEC, based on profit maximization and detailed information about the access to fields worldwide. Expectations about future oil prices are based on past history, and the basic incentive for oil companies is to invest in provinces and field types with the highest expected return. To sort out the most profitable among projects, net present value (NPV) is calculated for investments in each of the 52 Non-OPEC provinces/field types over the entire project lifetime. The producers might invest in new fields or increased oil recovery from existing fields.

We focus on Norway and examine how different net tax rates influence the cash flow of the oil companies and, hence, future investment and production on the NCS up to 2030. From these scenarios we derive the tax take of the Norwegian government, in search for the producer tax that maximizes the discounted tax revenues. We have also taken into consideration taxation rules governing depreciation, uplift on capital and interest payments on loans. As will be clear later, as opposed to a cash flow tax system under certain assumptions, the Norwegian tax system is not neutral in the sense that the investment decisions will be affected by changes in the net tax rate.

In line with the fact that during the last years many international oil companies have not been able to replace the already produced oil with new reserves, the governments in the resource rich countries outside OPEC seem to have strengthened their negotiating position vis-à-vis the international oil companies (Ghalib and Knapp, 2005). Both the high oil price level and fewer and smaller discoveries outside OPEC seem to have led countries to introduce higher oil taxes (as Great Britain and Russia) or a strengthening of the government's control over the petroleum resources (e.g., Venezuela, Bolivia, Ecuador and Kazakhstan). As we apply a global model with updated taxes in the different regions, we are able to take account of a possible tax competition between the different provinces. In our analysis tax competition manifests itself as a change in production and investment in other regions if Norway alters its taxes, and this will only take place if the oil companies face a cash flow constraint that is binding in their investment decision. We have not been able to find studies that search for producer taxes that maximizes the tax revenue in a petroleum province in a *global* environment. Many studies focus on how *specific tax reforms* affect the tax income in an *isolated country*. Manzano (2000) applies traditional theoretical models to review the effects of tax reforms in Venezuela on the development of oil fields. Kunce et al (2001) use state-specific estimates of Pindyck's (1978) widely cited model of natural resource supply to simulate effects of changes in tax policy on the development of exploration and output by firms in the U.S. oil industry. Mulder et al (2004) examine whether the introduction of accelerating depreciation of investments in the gas sector on the Dutch Continental Shelf leads to a higher level of investments and a possible higher tax base. Nakhle and Hawdon (2002) analyze how a reintroduction of a Production Revenue Tax and a 10 percent higher corporation tax affect the investment decisions in the UK North Sea.

The nest section describes the oil market model. In Section 3 we present the results for the Norwegian oil market. Section 4 presents the sensitivity analysis and Section 5 concludes.

Model description

The FRISBEE[2] model is a recursively dynamic partial equilibrium model of the global oil market. The world is divided into 15 regions where oil companies produce oil. The time periods in the model are one year and the base year is 2000. Prices are thus stated in year 2000 US dollars and exchange rates are held constant over time. The world market price of oil price is exogenous in the model. OPEC satisfies the residual demand at the prevailing oil price, determined as the difference between world demand and Non-OPEC supply. The fixed price assumption implies that demand and Non-OPEC supply are determined independently of each other. Therefore, our model description will focus on the supply side of Non-OPEC in general and of Norway in particular. A more formal and detailed description of the model is given in Aune et al (2005), primarily regarding the demand side[3].

For each of the 15 FRISBEE regions (*r*) there are four field categories (see Table A1 in Appendix A). These are constructed based on different characteristics such as geological conditions (e.g.,

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[2] FRISBEE: Framework of International Strategic Behavior in Energy and Environment.

[3] We have developed an extended version of the original model. Norway and the UK are now separate regions and not a part of Western Europe as in the older model version. In addition, the model has a more thorough and realistic representation of the tax system. We have now included other deductions in the oil companies' tax base than depreciation as uplift on capital and interest payments on loans. The numerical specification of various variables has also been updated so that the production levels in the different regions fit relatively closely the true development up to 2007.

offshore/onshore, deep water/shelf) and field size (measured in million barrels of oil equivalents, Mboe). This means that there are sixty combinations of regions and categories, which we name field groups (*j*). Within each field group we do not distinguish between specific fields and thus only refer to how much is produced and developed in each field group, without specifying the size or number of fields.

The Norwegian tax take

Taxation in Norway in period t consists of an ordinary corporate tax NT^C of 28 percent which is levied on revenue less operating costs, capital allowances and interest expenses over all four field groups j in Norway:

$$(1) \qquad NT^{C}_{Norway,t} \cdot \left[\sum_{j \in Norway} (PP_{Norway.t} \cdot S_{j,t} - C^{R}_{O,j,t}(S_{j,t}) - D_{j,t} - IE_{j,t}) \right]$$

where $PP_{Norway,t}$ is the producer price in Norway at time t, $S_{j,t}$ is production in field group j and $C^{R}_{O,j,t}$ is operating costs from existing production. IE is interest expenses on loans that finance the investment. $D_{j,t}$ is the depreciation of total capital costs (TC), which is made linearly over six years in Norway:

$$(2) \qquad D_{j,t} = \frac{1}{6} \sum_{i=0}^{6-1} TC_{j,t-i}$$

A Special Petroleum Tax NT^S of 50 percent is applied to the offshore oil industry and is levied on the same amount as the ordinary tax except for an extra capital allowance:

$$(3) \qquad NT^{S}_{Norway,t} \left[\sum_{j \in Norway} (PP_{Norway.t} \cdot S_{j,t} - C^{R}_{O,j,t}(S_{j,t}) - D_{j,t} - IE_{j,t} - UP_{j,t}) \right]$$

where UP is a 30 percent uplift on capital investment (TC), which is treated as a 4-year straight-line depreciation (7.5 percent per year). We refer to the expression between the brackets as the tax base.

Total tax take TAX_t in year t is the sum of Eq. (1) and (3). The net present value of the tax take is:

(4) $$TAX = \sum_t \frac{TAX_t}{(1+d)^t}$$

where d is the government's discount rate. We assume that changes in the net tax rate imply changes in the Special Petroleum Tax as from 2008. Keeping the rules governing depreciation, uplift and interest payment allowances constant, we study the effects of changes in NT^S on the tax take TAX over different oil prices and discount rates.

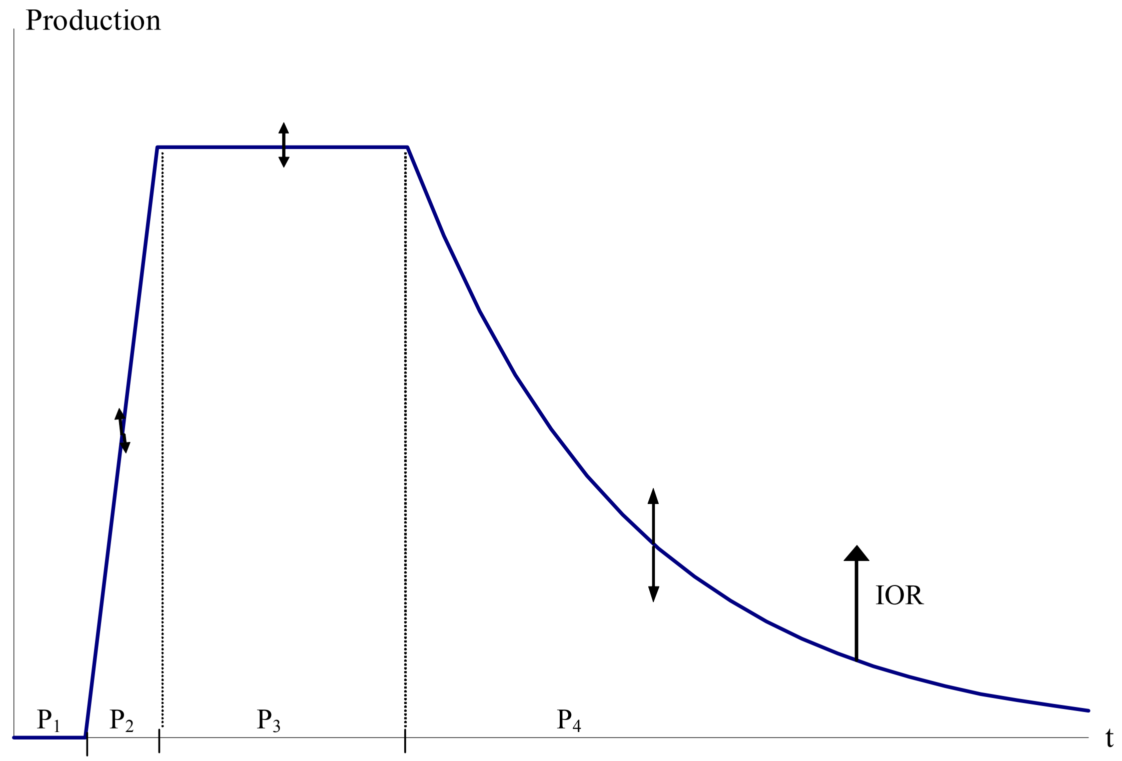
A cash flow tax, where the tax base is the difference between payments and outlays, is under certain assumptions neutral, in the sense that the investment decision is not affected by changes in the net tax rate (see, e.g., Brown, 1948). In the Norwegian tax system investments are not posted as outgoings, but activated and written-off. In addition. there are other deductions as uplift and interest payments on loans. As will be clear later, the Norwegian tax system is not neutral in the sense that the investment decisions will be affected by changes in the net tax rate. As the production (S) and investment decision (TC) is crucial in determining the tax base, we turn to these equations.

Production and investment

For each of the sixty operational areas we apply a production profile that is more or less prespecified (see Figure 1). The capacity, determined by investments in earlier years, sets the upper limit for production in each of the different phases of production. Actual production can to some degree be altered during the lifetime of the field as indicated by the arrows in Figure 1. The profile is divided into four phases. The first phase (P_1) is the *investment phase* which is the time lag between the investment decision and start of production. At the end of phase 1 capital costs are incurred[4]. The second phase is the *prepeak phase* (P_2), when capacity builds up towards the peak level. The two first phases are quite short, varying between 3 and 5 years in total across regions. The third phase is the *peak phase* (P_3), which lasts 5–10 years and capacity is at a constant and prespecified level. For each field group the time span of phase 1-3 (t_1-t_3) is based on existing data. The fourth and final phase is the *decline phase* (P_4), when capacity declines at a constant rate per year until production is too low to be profitable. Thus, all developed reserves are divided into region, field category and phase (vintage).

[4] In reality, some costs are incurred before and some costs after production starts, but this simplifying assumption seems sensible.

Figure 1. Production profile for oil fields in the FRISBEE model



The initial allocation is based on input from an extensive database of global petroleum reserves in the year 2000. Table 1 below shows some central features of the model. We start with a discussion of how we treat the different developed and undeveloped reserves in the model. Then we turn to the production and investment decision.

Developed and undeveloped oil reserves

The model contains three sets of resources for each field group. The first set consists of developed fields, the second consists of discovered but undeveloped fields and the third set consists of undiscovered, but expected fields/resources (se Table 1). Within each set there is an average recovery rate *REC* that measures the share of total reserves that are recoverable. New discoveries *(DRR)* from the stock of undiscovered resources in Set 3 add to the stock of undeveloped reserves *(UR)* in Set 2 at the end of each year. The average recovery rate in Set 1 may be increased due to recovery rate investments *(RRI)* in existing fields (also called increased oil recovery, IOR) and due to reserve investments through development of new fields from Set 2 *(RI)* ((see B.1 in Appendix B for how capacity and reserves are linked together, and B.2 for how the different variables in Table 1 are updated).

Table 1. Central features of the model

Sets of reserves/ flows	Category	Relationship	Costs	Equations number
Set 3	Undiscovered resources (recovery rate REC_3) ↓			
Flow of	New discoveries (*DRR*) ↓	Exploration: function of oil prices		(10)
Set 2	Undeveloped reserves *(UR)* (recovery rate REC_2) ↓			
Flow of	Reserve investments (*RI*) ↓	Investment decision: Profit maximization wrt. *RI* (and *RRI*)	Capital costs C_C^R and operating costs C_O^R of new fields	(6) - (8)
Set 1	Developed reserves *(RR)* (recovery rate REC_1)	Production decision: Profit maximization wrt. supply (*S*)	Operating costs (C_O)	(5)
Flow of	↑ Recovery rate investments *(RRI)*	Investment decision: Profit maximization wrt. *RRI* (and *RI*)	Capital cost of improved oil recovery C_{IOR}^R	(9)

Production decision

A short-term marginal cost function decides whether it is optimal to produce more or less than the level prespecified by the production profile in Figure 1. In the prepeak and peak phases we assume that marginal operating costs are fairly low and constant except when production is very close to capacity. As shown by the arrows in phases P2 and P3 in Figure 1, there is only a slight possibility of adjusting production up or down in these two periods, as production in any case is close to capacity. In the decline phase, however, marginal operating costs increase more rapidly as production rises. This means that the oil price has a greater impact on the optimal production level in the decline phase, as indicated by the longer arrows in phase P4 in Figure 1. Marginal operating costs are based on detailed information about unit costs in different types of fields in the most important oil producing countries.

Within each year production capacity is fixed and a function of earlier investments. For Non-OPEC regions we assume that oil supply is determined by equalizing the producer price of oil with the sum of the marginal operating cost and the gross sales taxes in each field category (and phase). The producer price of oil in a region is mainly determined by the global crude oil price and transport costs, but may also differ because of crude oil quality. We have for region *r* and field group *j* at time *t*:

$$(5) \qquad c^{r}_{O,j,t}(S_{j,t}) = PP_{r,t}(1 - GT_{r,t}) \qquad \text{if } S_{j,t} > 0$$

where $c^{r}_{O,j,t}$ is the marginal operating costs in field group *j* in region *r* at time *t*, $PP_{r,t}$ is the producer price in the region, which is considered exogenously by the Non-OPEC producers. $GT_{r,t}$ is the gross tax, but for Norway and other regions without gross taxes[5], marginal operating costs simply equal the oil price.

We derive gross and net tax rates for each country (Johnston, 2002 and Wood Mackenzie, 2004). When we estimate the average tax rates for a region which consists of various countries, we apply each country's share of the regional production as weights. As will be clear later, the general level of taxes in other oil provinces than Norway, is only of some importance when the oil companies cannot invest in all projects that are profitable.

Investment decision

We will discuss the investment decision more thoroughly as this decides future capacity, which again sets the upper limit for production. When the oil companies decide to invest, they have to take the operating and capital costs of new fields into consideration. We assume that capital costs for new fields are incurred the year before production starts, whereas operating costs for new fields are evenly distributed over the lifetime of the field.

Let $C^{R}_{O,j,t}$ and $C^{R}_{C,j,t}$ be the operating and capital costs per reserve unit for a new field in field group *j* in year *t* and $C^{R}_{O,0,j,t}$ and $C^{R}_{C,0,j,t}$ the initial values of these costs. The unit operating and capital costs for undeveloped, but discovered fields in Set 2, vary across fields (even within a field group), due to geology, size, location etc. We assume that, without new discoveries, both capital and operating unit costs are a decreasing function in the size of undeveloped reserves, *UR*. However, we rather assume

[5] We disregard area fees and CO_2-taxes, which in 2006 constituted 1.8 percent of total taxes on the NCS (Ministry of Oil and Energy, 2007).

that unit costs are a decreasing function of the ratio between undeveloped reserves and accumulated discoveries (*ADRR*), because it is unreasonable to assume that new discoveries will have lower costs than all existing undeveloped fields. We have[6]:

(6) $$C^{R}_{C,j,t} = C^{R}_{C,0,j,t} \cdot \gamma_j\left(\frac{\overset{-}{UR_{j,t}}}{ADRR_{j,t}}, \overset{-}{\tau_I}\right)$$

(7) $$C^{R}_{O,j,t} = C^{R}_{O,0,j,t} \cdot \gamma_j\left(\frac{\overset{-}{UR_{j,t}}}{ADRR_{j,t}}, \overset{-}{\tau_I}\right)$$

As *UR* approaches zero, unit costs approach infinity. Technological progress (τ_I) may reduce costs exogenously over time. The functions in Eq. (6) and (7) are determined based on available cost data. See B.3 in Appendix B for a detailed description of how operating costs of new fields are updated.

We apply the following relationship for the total (undiscounted) capital costs, remembering that *RI* is investments measured in oil reserves:

(8) $$TC_{C,j,t}(RI_{j,t}) = C^{R}_{C,j,t} \cdot RI_{j,t} \cdot \alpha_{C,j}\left(\frac{\overset{+}{RI_{j,t}}}{UR_{j,t}}, \frac{\overset{+}{RI_{j,t}}}{S_{j,t}}, \frac{\overset{+}{RI_{j,t}}}{S_t}\right)$$

We assume that there are increasing marginal costs of investments within each time period. This may reflect capacity constraints in the short run as e.g. shortage on the availability of oilrigs, personnel etc.

We also assume that marginal total capital costs rise faster the less undeveloped resources.
The oil companies takes into consideration that fields that are not developed this year can be developed in another year, which may be more profitable if the current investment rate is already high and pushing up the costs. Thus, the fewer resources left in the ground, the higher the investment costs. Because oil is a nonrenewable resource this partly reflects that the scarcity rent is higher the less undeveloped resources there are.

[6] A plus or a minus over a variable indicates the effect from an increase in the variable on the dependent variable.

Increased production in a particular field group (S_j) and total production in the region leads to lower capital costs. The reason is that when companies are already operating in a region, there may be economies of scale[7]. There are also fixed information costs associated with entry into a province. The overall level of petroleum activity in the area may further contribute to increased competition in the markets for inputs and services directed towards the oil industry. All these elements may imply that it is somewhat profitable for companies to stick to provinces where there is already exploration and production activity rather than move to new ones. The parameters in the α_C-function are based on comparing model results with the actual outcome in 2000-2004.

IOR-investments can only take place in the decline phase of the capacity profile. When IOR investment is carried out, the recovery rate increases and the reserves of the decline phase are increased. The cost occur immediately, and we only consider capital and not additional operating costs. The revenues occur during the remaining lifetime of the field.

(9) $$TC_{IOR,j,t}(RRI_{j,t}) = C^R_{IOR,j,t} \cdot RRI_{j,t} \cdot \alpha_{IOR,j}\left(\frac{\overset{+}{RRI}_{j,t}}{R_{0,j,t}}, \overset{+}{REC}_1, \overset{-}{\tau}_I\right)$$

Following the reasoning above, we assume that marginal IOR-costs are increasing in the amount of IOR (*RRI*) and decreasing in the amount of initial reserves in the decline phase ($R_{0,j,t}$). Marginal costs are an increasing function of the recovery rate (REC_I). We apply the same technological progress here as for undeveloped fields. The parameters in the α_{IOR}-function are partly calibrated to fit the projections made by IEA (2004) regarding the potential for IOR in different counties. It is now clear that total capital costs (*TC*) that decide the capital allowances, uplift and interest expenses in Eq. (1) and (3) are the sum of TC_C and TC_{IOR}.

When new fields are developed, the stock of undeveloped reserves declines. We assume that new discoveries *(DRR)* are made each year in every region and field category. The volumes of new discoveries are assumed to be a linear function of the expected oil price in the region (PP^e), and to fall exponentially over time at a constant oil price:

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[7] We also assume that a certain share of the remaining fields are cheaper that the unit cost C_C^R, because some fields may utilise the infrastructure etc. of existing fields.

(10) $$DRR_{j,t} = DRR_{0,j} PP^{E}_{r,t} e^{-\delta t}$$

This means that for a given oil price, accumulated discoveries are limited and approaches $DRR_0 PP^E/\delta$ when time goes to infinity[8].

The basic incentive for oil companies is to invest in provinces and field types with the highest expected return. To sort out the most profitable projects, net present value (NPV) is calculated for investments in each of the 52 Non-OPEC provinces/field types over the entire project lifetime. The discount rate is set to 10 percent (see Antill and Arnott, 2002). To maximize the oil companies' expected profit of investments, we have to rely on assumptions concerning the future oil price. Expected future oil price PP^E is set as equal to the average oil price during the previous six years. Price expectations are equal to the exogenous level as from 2015.[9].

(11) $$PP^{E}_{j,t} = \frac{1}{6}\sum_{i=0}^{5} PP_{j,t-i}$$

We stress that when the oil companies invest in field group j, they know how the capacity profile and the amount of reserves are linked together, as well as how the operating and capital costs develop over the lifetime of the field. The present value of the oil companies' expected profit from new investment in field group j is:

(12) $$Max_{RI_{j,t},RRI_{j,t}}\ \Pi^{e} = \sum_{t}^{T_j}\left[\sum_{j'(j)}\left\{\begin{array}{l}\left[\begin{array}{l}\left(PP^{E}_{j,t}(1-GT_{j,t}) - C^{R}_{O,j,t}\right)(1-NT_{j,t}) - \\ \dfrac{TC_{C,j,t}}{RI_{j,t}} + \dfrac{D_{C,j,t}}{RI_{j,t}} NT_{j,t} + \dfrac{OD_{C,j,t}}{RI_{j,t}} NT_{j,t} - RISK_{j}\end{array}\right] RI_{j,t} \\ + \left[\begin{array}{l} PP^{E}_{j,t}(1-GT_{j,t})(1-NT_{j,t}) - \\ \dfrac{TC_{IOR,j,t}}{RRI_{j,t}} + \dfrac{D_{IOR,j,t}}{RRI_{j,t}} NT_{j,t} + \dfrac{OD_{IOR,j,t}}{RRI_{j,t}} NT_{j,t}\end{array}\right] RRI_{j,t}\end{array}\right\}\right] \cdot \left(\frac{1}{(1+r)^{t}}\right)$$

[8] This discovery function is calibrated for each region so that, if the oil price stays at \$40 per barrel, total accumulated discoveries over the time horizon (i.e., until 2030) equals USGS's (2000) mean estimate of potential new discoveries over a 30 year period.

[9] We apply different exogenous oil prices in our tax scenarios. We assume that the price gradually moves from the historical levels in 2000-2006, reaching the target in 2010.

$NT_{j,t}$ is the net tax rate, r is the discount rate and T_j is terminal year of production for field group j. As operating costs are distributed over the lifetime of the field, we have $C^R_{O,j,t} = C^R_{O,j} / T_j$. Linear capital allowances are made over i years for both types of investment:

(13) $$D_{C,j,t} = \frac{1}{d}\sum_{i=0}^{d-1} TC_{C,j,t-i} \quad \text{and} \quad D_{IOR,j,t} = \frac{1}{d}\sum_{i=0}^{d-1} TC_{IOR,j,t-i}$$

These deductions are made over six years in Norway[10]. $OD_{C,j,t}$ and $OD_{IOR,j,t}$ is other deductions of capital cost for new reserves and increased recovery rate, respectively. In Norway these deductions are interest expenses on loans that finance the investments and a special Norwegian uplift on capital expenses (see above). FRISBEE incorporates an exogenous risk premium *(RISK)* to account for variations in risk assessment in different provinces and field types. Risk can be political, fiscal or directly related to exploration and production[11]. The risk-premium is relatively low and equal in provinces like UK and Norway.

To sum up, there are three ways to increase the scale of production. First, the oil companies might raise production above the prespecified production profile in all phases of ongoing production. Second, they may invest in new fields with specific production profiles. Finally, there is the option to invest in IOR, which increases the reserves and lifts the production profile in the decline phase. In the absence of constraints on investments, all three options will be used so that the marginal rates of return are equal.

We define the net cash flow (*NCF)* as revenues less current operating costs and total taxes.

(14) $$NCF_t = \sum_{j \in J} \left(PP_{r,t} S_{j,t} - C^R_{O,j,t} - TNT_{j,t} - TGT_{j,t} \right)$$

where *TNT* and *TGT* are total net and gross taxes paid, respectively. Our starting point is that total expenditure on capital is limited to 50 percent of net cash flow (before subtracting exploration costs). According to OGJ (2001) the oil industry has historically reinvested a remarkably consistent 60

[10] Depreciation over six years is the rule in Norway and seems to be a reasonable average period over different fiscal regimes. However, there are exceptions, as e.g. UK where total capital costs are deductible the first year.

[11] The risk premium is expressed in terms of additional US dollars per barrel that is required to make the investment project attractive as a risk-neutral project.

percent of cash flow (includes expenditures on exploration). Hence, the following restriction applies in the reference scenario:

$$(15) \qquad \sum_{j\in J}\left(TC_{j,t}(RI_{j,t}) + TC_{IOR,j,t}(RRI_{j,t})\right) \leq 0.5\cdot NCF_t$$

We stress that our results show that this cash flow constraint is only binding for some or all of the years in the period 2008-12, and for marginally higher constraints it is never binding. In our sensitivity analysis we apply a wide range of cash flow constraints from no constraint to a 30 percent constraint. Hence, it seems reasonable to disregard how financial flows may affect the net cash flow. In addition, outside debt will not affect the cash flow if interests and repayments on loans equal the loan amount each year[12]. Hence, we only take into consideration the effect of debt through interest payments, which is included in other deductions (*OD*) in Eq. (12). We assume a serial loan that is paid back over the lifetime of the field. We assume that the oil companies borrow 50 percent of their outlay on capital.

The oil companies only invest in projects with an internal rate of return (IRR) of at least 10 percent, which means that they invest in all fields with a positive NPV when the discount rate is 10 percent (if they are not constrained by credit). The assumption that investments first target the most profitable reserves leads to a geographical spread of oil extraction. Gradually, the oil companies invest in reserves that are more expensive to extract, and the cost of oil production will rise as reserves are depleted. However, new discoveries and technological change reduce the costs of developing new fields.

As the Norwegian tax system is not based on cash flow taxation, the system is (probably) not neutral in the sense that the investment decision will be affected by changes in the net tax rate. However, on theoretical grounds alone we cannot say that higher taxes lead to lower capital investments, because even if a high tax reduces the amount of projects that is profitable it *also* increases the value of depreciation, uplift and interest payment allowances per invested reserve unit. However, as we shall see later, higher taxes lead to some extent to reduced investment on the NCS.

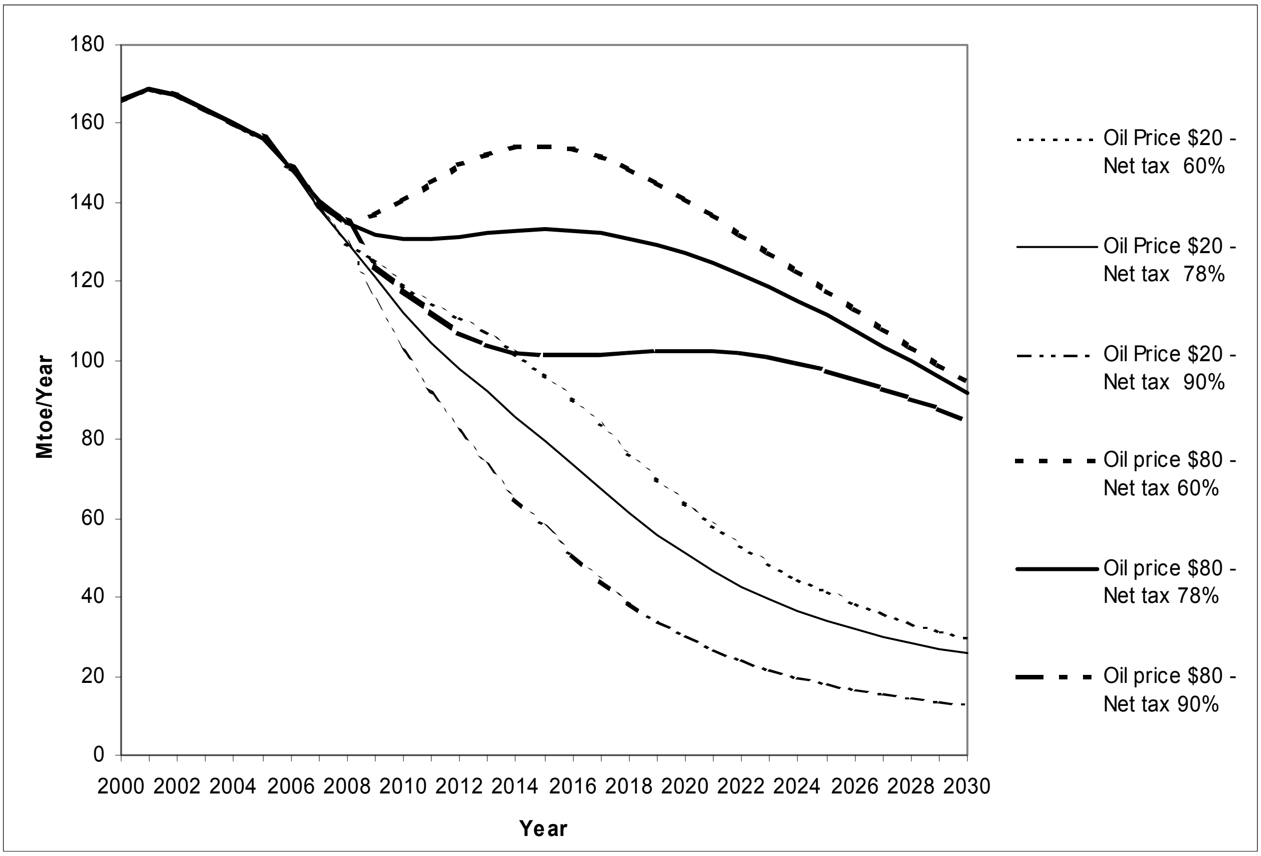
[12] Actually the net present value of future interest and repayments on loan is equal to the loan amount each year.

The Norwegian oil market towards 2030 with different tax rates

In the model we examine how different tax rates as from 2008 influence investment and production on the NCS towards 2030. Then we derive the tax take of the Norwegian government each year, in search for the producer tax that maximizes the discounted tax income in the period 2008-2030. Of the government's total income from the petroleum sector in 2006 net taxes amounted to 61 percent. The contribution to total income from the State Direct Financial Interest (SDFI) was 36 percent and dividends of the state oil company Statoil (now StatoilHydro) was around 3 percent (The ministry of Oil and Energy, 2007). In the sensitivity analysis we take into consideration that changes in the net tax affect the profits of the Norwegian oil producers (where StatoilHydro is dominant). The SDFI is an arrangement where the government owns shares in various oil (and gas) fields, and like the oil companies covers its shares of investments and costs. If increased taxes reduce the profits of the oil companies on the NCS and if the SDFI's share of these profits is held constant (to the level in 2006), the government's income from this source will be reduced. However, in our study we disregard possible impacts of the taxes on the SDFI. The guidelines for the SDFI is to have larger shares in fields that are more profitable and possibly no share in marginal fields. As a change in the tax rate first will affect the latter type of fields it seems reasonable to ignore the effects on the SDFI. In addition, the SDFI's share of the total governmental income from petroleum production has declined over the last years.

We apply four different oil prices, which are held constant over time in real terms, and these are $20, $40, $60 and $80 per barrel (2000$). The price we apply corresponds to the OPEC basket price, which is slightly below the average world market price. We refer to the development of production and investment with the present tax level as reference scenarios. Figure 2 shows the Norwegian oil production towards 2030 in the reference scenario with an oil price of $80 and $20, and the corresponding production profiles when the net tax is increased to 90 percent and reduced to 60 percent. We apply these to tax scenarios to demonstrate how changes in the tax rate influence production (and investment), and to indicate whether the tax that maximizes revenue lies above or below the present tax rate. The production level fits relatively closely the true development up to 2007. We see that in the reference case with a high future oil price production only declines somewhat for a couple of years initially and then stays more or less constant for around a decade, before it declines somewhat up to 2030. At the end of the projection period the production level is 65 percent of the level in 2007. The low oil price reference scenario implies a quite different development, where the oil production declines steadily over the period and in 2030 reaches a level of 17 percent of the present production[13].

Figure 2. Projection of Norwegian supplies towards 2030



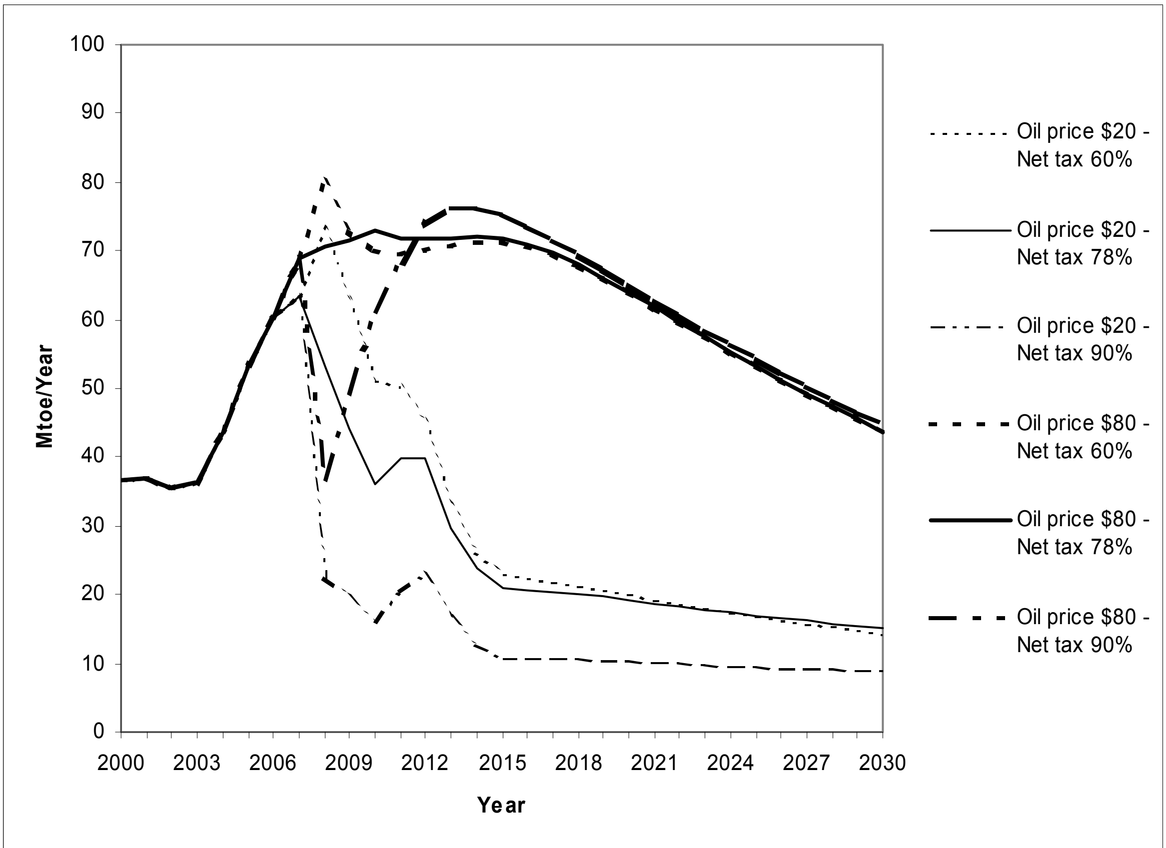
We see that taxes are clearly distortionary as production in both scenarios changes after the introduction of new taxes. This is because taxes affect investment in the capacity profiles, which again influence the production levels. In the high oil price scenario a net tax reduction to 60 percent leads to 10 percent higher accumulated production over the period and following a tax increase to 90 percent production declines by 16 percent. The relative changes in production increase up to around the middle of the next decade and thereafter gradually diminish so that production almost approaches the reference level in 2030. When the oil price is $20 per barrel the tax reduction leads to an increase in accumulated production of 17 percent, while raising the tax results in a decrease of 28 percent. To sum up, changes in taxes have a relatively larger and more persistent effect on production when the oil

[13] In governmental papers such a scenario is often refered to as a degradation scenario, where oil production is more or less halved around the middle of the next decade.

price is low. A tax increase (by 12 percentage points) has a larger absolute effect on aggregated production than a tax reduction (of 18 percentage points).

Previous investments decide the more or less prespecified production profile described in Figure 1, i.e. the production possibilities each year. Therefore we now examine the effects of tax changes on investments in new fields and investments in IOR. Again we refer to the development in investments with the prevailing tax level as reference scenarios. We point out that the cash flow constraint is binding for some or all of the years in the period 2008-12, which means that the oil companies cannot invest in all projects they are interested in. We see in Figure 3 that in the reference scenario with a future oil price of $80 investment in new field development stays fairly constant during the first decade, before it declines somewhat towards 2030. Even if undeveloped fields are developed continously and at a high rate, the high oil price also results in a stream of new fields being discovered each year as described in Eq. (10), adding continously to the stock of undeveloped reserves.

Figure 3. Investments in new fields in Norway



A tax reduction leads to increased investments because more of the high cost fields become profitable to develop, c.f. Eq. (12). This is the case although the value of depreciation, uplift and interest payments allowances per invested reserve unit declines, which in isolation leads to a lower optimal investment level. We see from Figure 3 that the tax effect on new field development is relatively small and temporary as the oil companies move some of the investments from the reference scenario nearer in time (and accumulated investments over time are practically unchanged). The result is higher investments the first three years than with the present tax level, and less investments thereafter. Increasing the development of new fields initially from the reference scenario leads to even higher operating and capital costs and this in turn leaves little room for a sustained higher investment level (i.e. we are on the very steep part of the marginal cost curve in Eq. 8). As we shall see later, when taxes are reduced from the present level there is more room for increasing the IOR-investments.

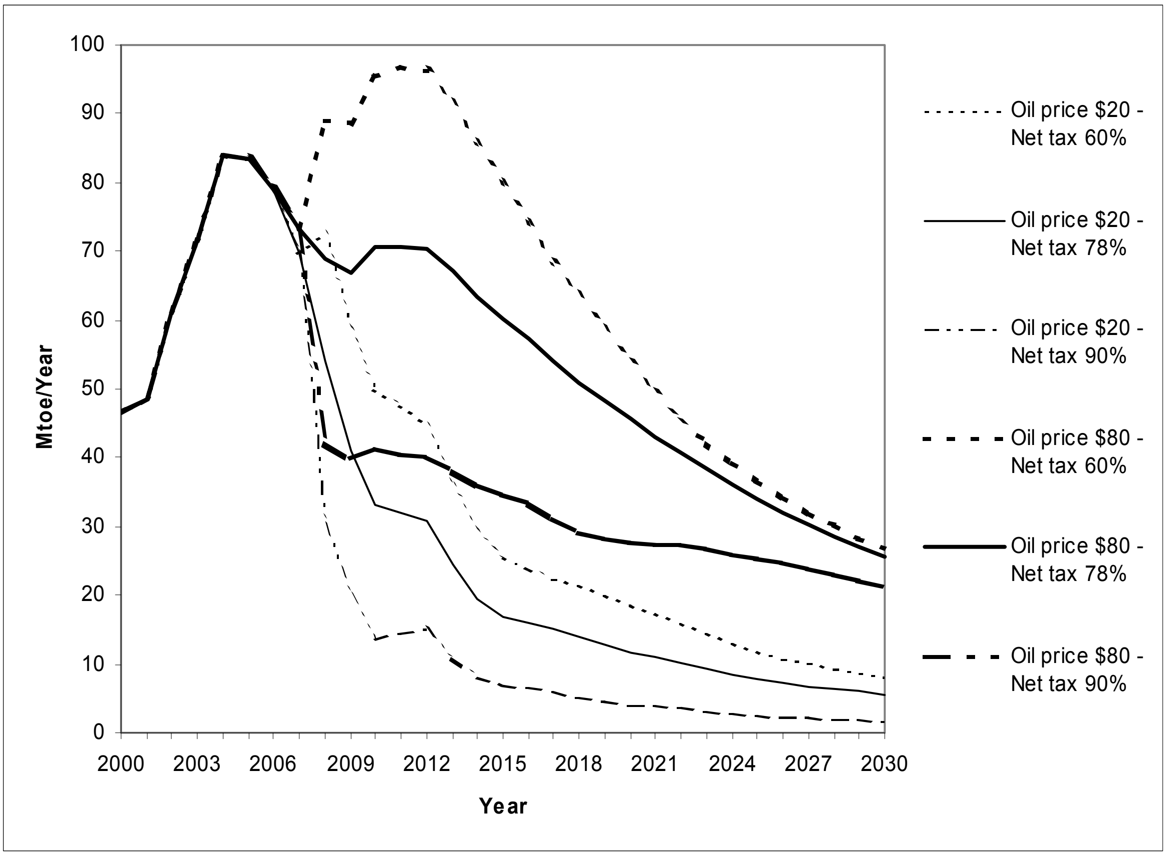
Since investments first target the most profitable reserves, introducing a *higher* tax means that it is optimal to reduce investments, because more of the high cost reserves become unprofitable to develop. We see that a tax increase results in a postponement of the oil companies' initial investments to later years compared to the reference scenario (and the accumulated reduction in investments is only 3 percent over the whole period). The reason for this effect is the same as in the scenario with a tax reduction, although the effect has opposite sign. To sum up, when the oil price is high a change in the tax level has only a relatively small and temporary effect on the investment in new fields as there is little room for a sustained higher or lower investment level compared to the reference scenario.

We see from Figure 3 that the investments in new fields with the present tax level is quite different when the oil price is $20. Now investments decline sharply up to 2015 (with a temporary increase around 2010-2012) and from then on decline only somewhat over the projection period. The lower oil price as from 2008 leads to fewer new discoveries than in the high oil price scenario and the costs of developing new fields rise faster.

With a lower oil price the tax changes have a larger and more lasting impact on the investments relative to the reference scenario. The pace of new discoveries is slower than with a high oil price, and changes in the net price of oil have a higher effect on the volume of investment as we are on the flatter part of the marginal cost curve of new fields investment. A tax reduction now leads to higher investments in new fields practically over the whole period compared to the reference case, but the effect is clearly largest the first 6-7 years. We also see from Figure 3 that a tax increase with an oil price of $20 per barrel leads to a relative reduction in investments from the reference scenario that is practically constant and large over the whole period (around 40 percent). A lower investment level leads only to a certain degree to lower costs of developing new fields compared to the reference scenario, and this effect is not strong enough to prevent a large reduction in the number of profitable projects over the whole period.

We now turn to the investment in increased oil recovery as shown in Figure 4. We see that the two reference scenarios with the present tax level to some degree resembles the new fields scenarios, except that the IOR-investments decline somewhat faster. A lower tax over the projection period

Figure 4. Investments in improved oil recovery (IOR) in Norway



when the oil price is high means that more IOR-investment projects become profitable and investment increases (again an increase in the value of depreciation, uplift and interest payments allowances per invested reserve unit counteracts this effect to some extent). Even if increased investments to some degree push up the capital costs of IOR in Eq. (9), it is still optimal to keep a higher investment level over the whole period, although the level of investments gradually is approaching the reference level towards 2030. Increased investment is now only pushing up the capital costs and not both capital and operating costs as is the case with new reserve investment. This means that the marginal cost curve is not so steep when we compare to the situation with new reserve investments and, thus, there is more room for keeping a lasting higher investment level than in the reference case. Likewise, a higher tax means that fewer IOR projects are profitable to undertake over the whole period compared to the reference scenario. This leads to a lower investment level and a higher absolute relative change in investments (-55 percent) than the corresponding effect of the tax reduction (+25 percent) over the period.

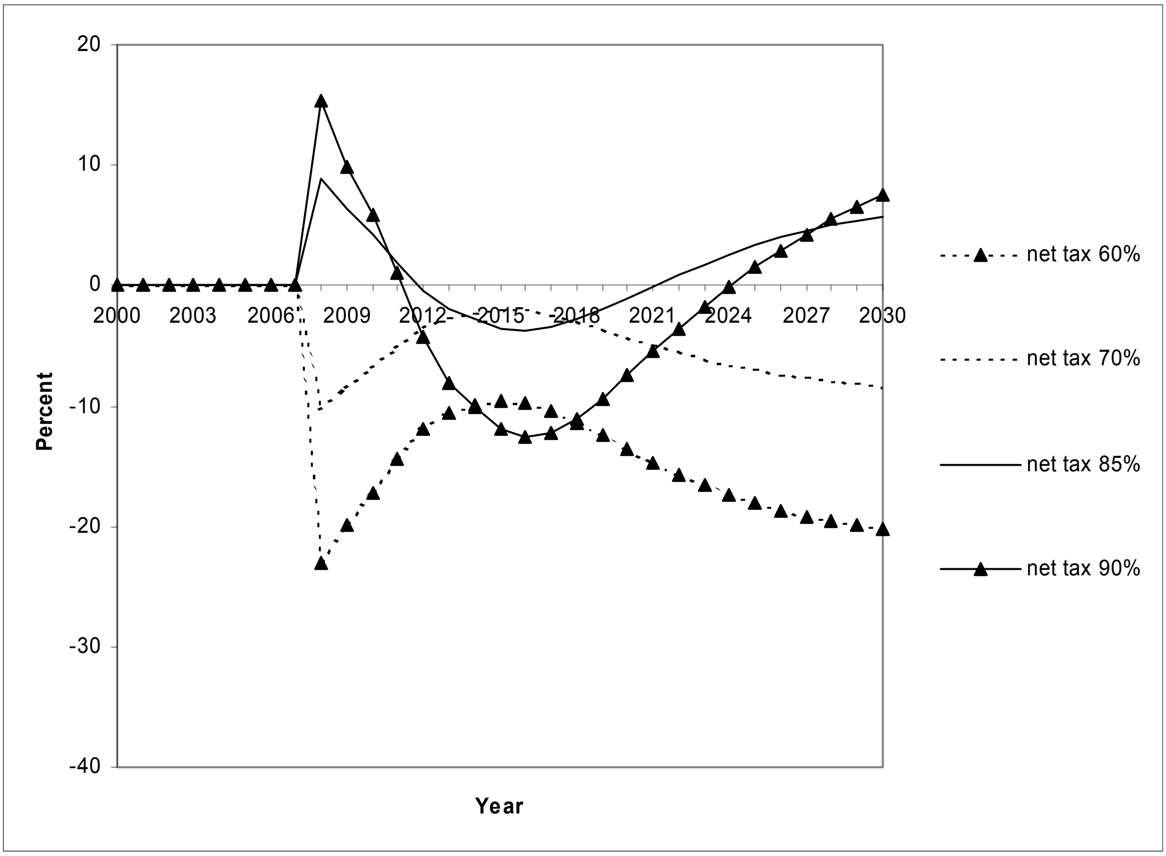
We also see from Figure 4 that the relative effects of tax changes on IOR- investments in the low oil price scenario resemble the high price scenarios. The only difference is that the relative changes now are somewhat larger (-57 and +47 percent) and more persistent over the whole period, as the relative changes do not diminish towards the end of the period as was the case with a high oil price. When the oil price is lower the investment level is lower, and the marginal cost curve of IOR-investments is somewhat flatter. This means that a relative change in the net price of oil after tax has a larger effect on the IOR-investments.

To sum up, we see from Figure 2 that when the oil price is low changes in the taxes have larger and more lasting effect on *production* than with a high oil price. The reason is that when the oil price is low, the tax impact on new field development is stronger and the effect on the IOR-investments is larger and more persistent.

Turning to the effect of tax changes on the undiscounted Norwegian tax take, it is important to bear in mind that both variations in production and investments (through capital depreciation, uplift and interest expenses) affect the tax take, c.f. Eq. (3) . Figure 5 shows the effects of tax changes with a future oil price of $80 per barrel. We show the effects on the tax take with a net tax increase to 85 and 90 percent and a reduction to 60 and 70 percent. An increase in the tax to 90 percent do not change production in 2008, but we see that the tax take is around 16 percent higher than the prevailing tax income. The tax take is higher than the increase in the net tax of 12 percentage points, because investments already have been reduced and this leads to smaller depreciation, uplift and interest payments allowances, which in turn increase the tax base in Eq. (3). The change in tax income relative to the present level follows closely the relative loss in production, which is largest around 2015-16 and from then on declines. At the end of the period the tax take gradually becomes higher with a higher net tax compared to the reference case, because the reduction in production diminishes. We see that a tax increase to 85 percent implies similar relative changes in tax income over time, but the effects are more moderate.

Figure 5 also shows that a reduction in the tax to 60 percent leads to an initial tax loss of more than the 18 percentage points reduction (actually around 24 percent). The reason is that although production is unchanged, the investment level has already increased (above all the IOR-investments), which leads to increased depreciation and interest payment allowances and thus a smaller tax base relative to the reference scenario. Again, the curvature on the relative change in tax income follows closely to the relative increase in production, which rises up to 2014-15, before it gradually declines towards 2030.

Figure 5. Tax take relative to the present net tax of 78 percent. Percent change. Oil price $80/boe



In 2030 the tax loss is only marginally lower than the reduction in net tax of 18 percentage points, as both the relative increase in investments and production from the reference scenario is small. A tax reduction to 70 percent leads to the same relative development, but the relative loss in tax income from the reference case is smaller over the projection period. While the tax take is higher when the net tax increases both during the first years and at the end of the period relative to the reference scenario, the tax income is never higher compared to the reference case when the net tax declines. The reason is that a smaller tax burden does not boost production, even after several years, to such degree that the tax income increases. In addition, increased investments leads to a smaller tax base. We see from Table 2 that with a cash flow constraint of 50 percent and an oil price of $80, the net tax that maximizes discounted tax revenue is 84 percent if the authorities' discount rate is 12 percent. If the discount rate is reduced to 1 percent the preferred net tax rate on the NCS is around 83 percent. Clearly, with a high oil price our model results show that it is optimal to increase the net tax level in Norway, at least to a certain extent.

We now turn to the changes in tax income when the oil price is $20 per barrel as depicted in Figure 6. The effects are similar to the scenario with an oil price of $80. However, at the end of the period the higher net tax does not increase the tax take compared to the reference scenario, as was the case with a higher oil price. The reason is that the production loss now increases somewhat relative to the reference case over the whole period. We see from Table 2 that the tax that maximizes tax revenue varies between 83 and 87 percent, dependent on the discount rate.

Figure 6. Tax take relative to the present net tax of 78 percent. Percent change. Oil price $20/boe

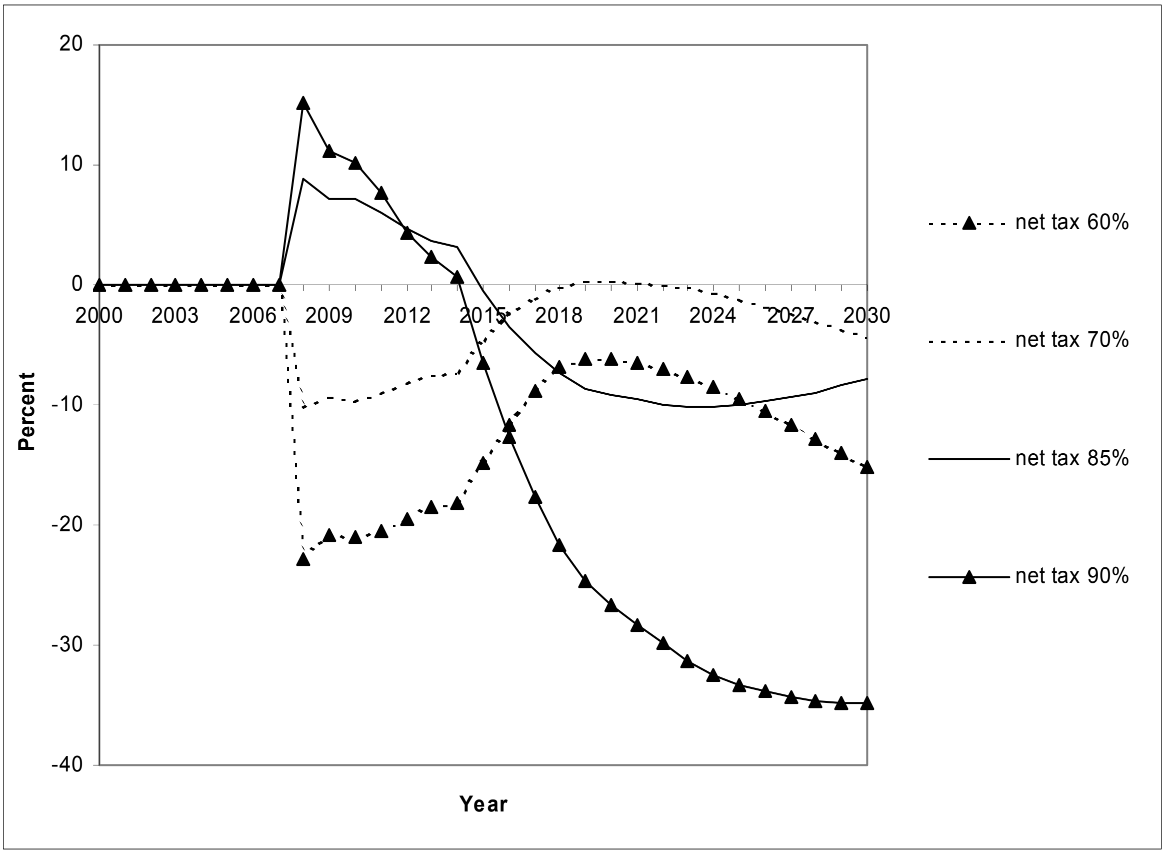


Table 2 also shows the preferred net tax rate with other oil prices. We see that the tax varies between 83 and 87 percent with a cash flow constraint of 50 percent for all oil price scenarios. It turns out that the impacts on production and investment in the $40 scenario resemble the $20 scenario, but the impacts are smaller. Likewise, the effects of the taxes in the $60 scenario resemble those in the $80 scenario, but the effects on investment and production are somewhat larger. The tax that maximizes tax revenue is generally marginally higher with a low oil price of $20. Even if the increased taxes have a more persistent reducing effect on production when the oil price is low, the investment level declines already from the first year and to a larger degree than production, and this latter effect increases the tax base. We also see that the preferred tax rates are marginally higher with a higher discount rate for all oil prices. The reason is that a tax increase leads to higher tax take for an initial period compared to the reference scenario, and this effect counts more when the discount rate is high.

To conclude, a tax reduction never results in a sufficient (and early enough) increase in production so as to increase the tax take. At the same time a tax reduction leads to increased investments already from the start and, thus, increased deduction of depreciation, uplift and interest expenses allowances, which in turn reduces the tax base. The same argument but with different sign holds for a tax increase. But increasing the net tax as high as 90 percent reduces the production to such an extent after some years that the present value of tax income is reduced compared to the present tax level. With our assumptions it is optimal to increase the net tax rate to some extent independent of oil prices and government's discount rate.

Table 2. Tax rates that maximize tax revenue

Government's discount rates	Future oil price per barrel			
	$80	$60	$40	$20
1 %	83 %	83 %	83 %	83 %
12 %	84 %	85 %	85 %	87 %

It is important to note that with our assumptions the change in taxes on the NCS has (almost) no effect on the investments and production in other Non-OPEC regions in the scenarios with a cash flow constraint of 50 percent or higher. When the oil companies are (almost) not constrained by credit, they manage to invest in all projects that are interesting, i.e. all projects with an internal rate of return of at least 10 percent. We now turn to the sensitivity analysis, where we among other things strengthen the cash flow constraint.

Sensitivity analyses and caveats

To avoid premature policy recommendations based on assumptions that are more or less certain, we carry out various sensitivity analysis in the favor of lower taxes.

When the cash flow constraint is 50 percent it is only binding for some or all of the years in the period 2008-12. If the oil companies reinvest 75 percent of their cash flow, the constraint is never binding, and the tax that maximizes the tax revenue is almost identical to the 50 percent scenario (see Table 3). Our reasons for choosing the 50 percent cash flow constraint is that the oil industry historically has reinvested around 60 percent of their cash flow (see above), and this includes expenditure on exploration which we assume amounts to 10 percent. One interpretation of applying a scenario with a 30 percent constraint, can be that exploration costs will be higher in the future. As fewer new fields are found per exploration well in the future, it seems reasonable to assume that exploration costs will increase and possibly constitute a larger share of total capital costs in the future. In addition, there may be other constraints that push up the costs of certain input factors, e.g. highly qualified personnel, rigs etc. This was exactly one of the arguments that parts of the oil sector presented some years ago, when they argued for lower net taxes, above all on small fields. Hence, in our a 30 percent cash flow scenario the sum of exploration costs and increased costs due to other constraints constitute 30 percent of the cash flow[14], i.e. equal to the sum of the cost of investing in new fields and IOR. Our results show that if only 30 percent of the cash flow is reinvested in capital in the oil upstream sector, the constraint is binding over the whole period. With this constraint, production and investment with the present tax level is lower than with a higher constraint. Again, the relative tax effects on production are largest when the oil price is low and now changes in the taxes in Norway influence the investment and production level in other oil provinces (our results show that with an increase in the prevailing tax rate to 85 percent in the scenario with an oil price of $60, a little less than one tenth of the reduction in Norwegian production shows up as increased production in other Non-OPEC regions). With this low cash flow constraint, the tax that maximizes tax revenue is only marginally lower than in the other scenarios. The reason is that a tax increase leads to larger reductions in production. Again, even if production declines so do investments, and the latter effect has a positive impact on the tax base. Hence, the preferred tax rate is only marginally lower in the 30 percent constraint scenario.

[14] We stress that in our model there are increasing marginal costs of investments within each time period. This may reflect capacity constraints in the short run.

Table 3. Tax rates that maximize tax revenue with other cash flow constraints

Share of oil companies' cash flow reinvested	Government's discount rates	Future oil price per barrel			
		$80	$60	$40	$20
0,75	1 %	83 %	83 %	83 %	84 %
0,75	12 %	85 %	85 %	85 %	88 %
0,3	1 %	80 %	79 %	79 %	81 %
0,3	12 %	82 %	82 %	83 %	86 %

In our model tax competition implies that a reduction in taxes in one region attracts investment from other regions and vice versa. Tax competition really only takes place in the scenario with a cash flow constraint of 30 percent and we now look at this scenario with an oil price of $60. In our model it is somewhat profitable for companies to hold on to provinces where there already is exploration and production activity rather than to plunge into new ones, and this may imply less tax competition between regions than in reality, although the companies to a large extent are tied to a geographically immobile reserve base which constitute most of their capital stock. We will study how a weaker effect of this inclination "to stay where you are" influence the results through the production effects in Eq. (8)[15]. When it is not so profitable to stick to a region if taxes increase (and likewise more profitable to move into new regions), our result show that the preferred tax rate declines, and it is never optimal to increase the prevailing tax rate (to 79 percent) when the discount rate is less than 5 percent. When the discount rate is larger than 10 percent, it is at least optimal to increase the net tax rate to 82 percent (see the results of the various sensitivity analysis in Table 4).

We carry out the rest of the sensitivity analysis in the $60 scenario with a cash flow constraint of 50 percent. So far, when we change the tax rate new fields are discovered in the same pace as before. Although we have not included exploration costs in the model, we might argue that the exploration effort is not influenced because outlays on exploration costs are deductible in full in Norway (as opposed to other capital outlays, which are activated and written-off). In addition, the Norwegian government takes a large part of the exploration risks, as oil companies without tax shelter are paid back 78 percent of the exploration expenditure. However, let us to check the model results in a situation where changes in taxes influence the discovery rate of new fields. We want to check, when the discount rate is 7 percent, how strong must the effect from taxes on discoveries be so that it is

[15] A tax increase leads to a larger relative reduction of *RI* than *S* (and S_j) in Eq. (8) and therefore an increase in the ratio *RI/S*. When we double the effect of a change in RI/S_j and *RI/S* on investment costs of new reserves, a higher tax therefore leads to higher capital costs for new field development.

never optimal to increase the present tax in Norway. Our sensitivity analysis show that if a one percentage point increase in the tax from the prevailing level of 78 percent leads to a reduction in discoveries of 2.5 percent, then it is never optimal to increase the tax. It is difficult to conclude whether such an effect is realistic or not. We simply confine ourselves with characterizing such an effect on exploration as rather strong. In addition, it must be pointed out that because exploration costs incurred are deductible in full, a tax change should not change the exploration effort.

Assumptions regarding the capital cost of developing new fields and increased oil recovery are quite uncertain. We test the effects of a doubling of the these costs in Norway both in the short and the long run. Even if a certain tax increase with these higher capital costs leads to a larger reduction in production, it is still optimal to increase the net tax rate, although to less extent compared to the original cost scenario.

We also introduce a scenario with a more pessimistic outlook towards exploration on the NCS. We replace the mean estimate of new discoveries in USGS (2000) with the average of the mean and the 95 percent estimate (i.e., 95 percent probability of discovering at least this amount). Less discoveries tighten the resource constraint for Norway and this effect increases over time. The preferred tax rate declines compared to the original discovery scenario, above all for low discount rates. However, it is still optimal to increase the net tax to a certain extent.

It may be argued that we should take into consideration the effects of the taxes on the sum of the tax revenue of the government and the Norwegian producers' surplus (as is done in a simple static model in Lund, 2002). Increased taxes reduce the profits of the oil companies on the NCS and if the Norwegian companies' share of these profits is held constant (to the level in 2006), the Norwegian profits will be reduced. Taking the sum of the effects on tax revenue and Norwegian producers' surplus into consideration, our results show that even if the tax level that maximizes tax revenue is somewhat lower than when we only focus on the tax revenue, it is still optimal to increase the rates to 78-80 percent.

We also want to check the results of the combined effects of some of these changes in model assumptions that leads to lower taxes. Hence, we apply a scenario with a doubling of the capital costs, lower discovery rate and in addition we take into consideration the tax effects on the Norwegian producers' surplus. If the discount rate is less than 7 percent is it optimal with a reduction of 2-3 percentage points in the prevailing tax rate.

Table 4. Sensitivity analysis. Oil price $60 per barrel

Scenario	Tax rate that maximizes tax revenue
1) Increased tax competition	> 78 percent
2) Tax rate affects discoveries	Never optimal to increase tax if one percentage point increase in the tax rate leads to 2.5 percent reduction in discoveries
3) Doubling of capital costs	> 79 percent
4) Less discoveries	> 79 percent
5) Maximizing the sum of tax revenue and producers' surplus	> 78 percent
6) Combination of scenario 3), 4) and 5)	75 - 76 percent

Some argue that a high net tax rate in itself leads to increased costs, either because of waste or tax adjustments to increase the effect of the tax relief (compared to other oil provinces with lower taxes). We are not able to take such effects into consideration. However, this makes us inclined to stress that a more robust conclusion is that it is not optimal to reduce the present net tax level, instead of recommending a certain increase in the tax rate in the range of 83 to 87 percent as our reference scenarios actually show.

When parts of the oil industry argued for a reduction in the net tax rate on the NCS some years ago, the focus was above all on the production from new fields. A topic for future research could be on one hand to find the tax rate that maximizes the tax revenue from existing fields with ongoing production and on the other hand the preferred tax rate for the production from new fields.

Conclusions

In our model oil producers base their investment and production decisions on profit maximization and detailed information about the access to fields worldwide. The oil companies invest in all projects with an internal rate of return (IRR) of at least 10 percent, if they are not constrained by credit. The producers might invest in new fields or increased oil recovery from existing fields. The assumption that investments first target the most profitable reserves leads to a geographical spread of oil extraction. Gradually, the oil companies invest in reserves that are more expensive to extract, and the cost of oil production will rise as reserves are depleted. However, new discoveries and technological change reduce the costs of developing new fields.

We focus on Norway and examine how different tax rates as from 2008 influence the cash flow of the oil companies and, hence, future investment and production on the NCS up to 2030. From these scenarios we derive the tax take of the Norwegian government, in search for the producer tax that maximizes the discounted tax revenues. We apply exogenous oil prices of $20, $40, $60 and $80 per barrel (2000$).

Our results show that a tax reduction never results in a sufficient (and early enough) increase in production so as to increase the tax take. Likewise, a certain tax increase does not curb production so that the discounted tax income declines. With our assumptions it is optimal to increase the net tax rate to a level of 83 - 87 percent over different oil prices and governments' discount rate. Increasing the net tax beyond this level reduces the production to such an extent after some years that the discounted tax income declines.

When the oil price is high a change in the tax level has only a relatively small and temporary effect on production and investments in new fields and IOR, as there is less room for a sustained higher or lower investment level than with the present tax level. The reason is that the marginal costs of both new field development and IOR-investments are increasing in the investment level. Hence, when the oil price is high the investment level is high. We are on the steeper part of the marginal cost curve and a change in the net price of oil after tax has little effect on the volume of investments. However, when the oil price is low there is more room for increasing the investments as we are on a flatter part of the marginal cost curve, meaning that increased investment does not push up costs to such a degree as with a high oil price.

Even if the increased taxes have a more persistent reducing effect on production when the oil price is low, it is important to notice that the investment level declines already from the first year and to a larger relative extent compared to production. Reduced investments means reduced deduction of depreciation, uplift and interest expenses allowances, which in turn increases the tax base and this counteracts the negative effects of the increased tax on the discounted tax income. This is the reason why the preferred net tax rates are marginally higher when the oil price is low. Thus, even if the criticism against the Norwegian tax level has calmed in line with the increase in oil prices the last years, we show that it is still optimal to increase the tax level if the oil price declines to $20 per barrel.

Our sensitivity analysis show that suspending the cash flow constraint leads to practically the same preferred tax level, as the cash flow constraint is only binding for a few years initially in the reference scenario. In our sensitivity analysis we further introduce scenarios for Norway with an increase in the capital costs and a reduction in the volume of new discoveries. In addition we strengthen the cash flow constraint on the part of the oil companies, we let the increased taxes have a strong and negative effect on the discovery rate and we make it more profitable to move to other oil provinces if Norway increases its tax rate. We also take into consideration that changes in the tax rates affect the Norwegian producers' profits. All these changes in model assumptions in favor of lower taxes reduce the preferred tax rate towards the present net tax level, but generally never below. Only in a scenario where we double the capital costs, introduce a pessimistic assumption on discoveries and in addition take the tax effects on the Norwegian producers' surplus into consideration, is it optimal with a net tax rate of 75-76 percent if the government's discount rate is less than 7 percent. Thus, a robust conclusion seems to be that reducing the prevailing tax level on oil production in Norway will not boost investment and production to such a degree that discounted tax revenue increases.

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Appendix A

List of regions and field categories

Table A1. List of regions and field categories in the FRISBEE model

	Field category			
	1	**2**	**3**	**4**
Africa	Onshore All	Offshore deep < 400 Mboe	Offshore deep > 400 Mboe	Offshore shallow All
Canada	Onshore All	Unconventional All	Offshore < 400 Mboe	Offshore > 400 Mboe
Caspian region	Onshore < 400 Mboe	Onshore > 400 Mboe	Offshore < 400 Mboe	Offshore > 400 Mboe
China	Onshore < 100 Mboe	Onshore >100; < 1000 Mboe	Onshore > 1000 Mboe	Offshore All
Eastern Europe	Onshore < 100 Mboe	Onshore > 100 Mboe	Offshore < 100 Mboe	Offshore > 100 Mboe
Latin America	Onshore All	Offshore deep < 1000 Mboe	Offshore deep > 1000 Mboe	Offshore shallow All
OECD Pacific	Onshore All	Offshore deep All	Offshore shallow < 100 Mboe	Offshore shallow > 100 Mboe
OPEC Core	Onshore < 400 Mboe	Onshore > 400; < 1000 Mboe	Onshore > 1000 Mboe	Offshore All
Rest of Asia	Onshore < 400 Mboe	Onshore > 400 Mboe	Offshore < 400 Mboe	Offshore > 400 Mboe
OPEC Rest	Onshore < 400 Mboe	Onshore > 400 Mboe	Offshore deep All	Offshore shallow All
Russia/Ukraine/ Belarus	Onshore < 400 Mboe	Onshore > 400 Mboe	Arctic < 400 Mboe	Arctic > 400 Mboe
USA	Onshore All	Alaska All	Offshore deep All	Offshore shallow All
Western Europe	Offshore deep < 400 Mboe	Offshore deep > 400 Mboe	Offshore shallow + Onshore < 100 Mboe	Offshore shallow > 100 Mboe
United Kingdom	Offshore deep < 400 Mboe	Offshore deep > 400 Mboe	Offshore shallow < 100 Mboe	Offshore shallow > 100 Mboe
Norway	Offshore deep < 400 Mboe	Offshore deep > 400 Mboe	Offshore shallow < 100 Mboe	Offshore shallow > 100 Mboe

Formal model description

B.1. Relationship between capacity and reserve base

To keep track of when fields (i.e., reserves) are moving from one phase to another we introduce field vintages. Vintage *0* are the fields in phase 4, and these fields may be grouped together without specifying the year of development. Vintage *n* are the fields that turn into phase 4 in *n* years. This means that when the oil companies decide to develop a certain amount of reserves in a field group of a region, these reserves are placed in Vintage ($t_1 + t_2 + t_3$) of that field group. From one year to the next all fields in Vintage *n* (n>0) are moved to Vintage n-1. The exogenous levels of $(t_1 - t_3)$ decide the relationship between the size of production capacity and the reserve base in each vintage.

We make the following assumptions regarding the development of capacity during the lifetime of the field (see Figure 1). In phase 2 the production capacity is half the peak capacity. Peak production capacity is an exogenous share (η) of recoverable reserves, based on existing data. In phase 4 the production capacity declines exponentially with a constant rate α. Without changes in the recovery rate, this decline rate follows directly from the exogenous level of t_1 and t_2, and the exogenous peak share mentioned above. However, improved oil recovery (IOR) investments in phase 4 might increase the recovery rate and leads to a reduction in the decline rate or an indirect prolongation of the peak phase.

It is straightforward to show from these assumptions that we get the following expressions for the relationship between remaining reserves in Vintage *n* (R_n) and its capacity (CAP_n):[16]

$$CAP_n = \begin{cases} \alpha R_0 & n = 0 \\ \dfrac{\alpha R_n}{(1+\alpha n)} & 0 < n \le t_3 \\ \dfrac{\alpha R_n}{(2+\alpha(n-t_3)+2\alpha t_3)} & t_3 < n \le t_3 + t_2 \\ 0 & t_3 + t_2 < n \le t_1 + t_2 + t_3 \end{cases}$$

[16] Note that this function applies to all field groups (j) at all time periods (t), but the indices j and t are not included in the expression here. This omission also applies to later equations in this appendix.

When the model runs from year t to t+1, the reserve bases of the vintages are updated in the following way:

$$R_n = \begin{cases} R_0(1-\alpha) + R_1 - CAP_1 + RRI & n = 0 \\ R_{n+1} - CAP_{n+1} & 0 < n < t_1 + t_2 + t_3 \\ RI & n = t_1 + t_2 + t_3 \end{cases}$$

where *RI* and *RRI* denote new reserve investments and recovery rate investments (IOR), respectively, which are both determined by producers at the end of each year.

B.2. Updating of central variables

We have the following updating of *REC* in Set 1, 2 and 3:

$$REC_{1,t+1} = \frac{AS_t + R_t + RI_t + RRI_t}{RR_t + \dfrac{RI_t}{REC_{2,t}}}$$

where *AS* is accumulated supply, *R* is total remaining recoverable reserves in developed fields (i.e., the sum of all R_n), and *RR* is total resources in developed fields (incl. produced resources). For simplicity we assume that the recovery rate is equal for all fields in Set 2 and 3.

$$REC_{2,t} = REC_{2,t+1} = REC_{3,t} = REC_{3,t+1}$$

RR and *AS* is updated in the following way:[17]

$$RR_{t+1} = RR_t + \frac{RI_t}{REC_{2,t}} + \sum_n CAP_{n,t} - \sum_n S_{n,t}$$

$$AS_{t+1} = AS_t + \sum_n S_{n,t}$$

[17] If production is less than capacity, the difference is assumed to be shifted to the unrecoverable part of the resources (that is, before possible IOR investments).

In Set 2 undeveloped reserves (*UR*) are updated in the following way:

$$UR_{t+1} = (UR_t - RI_t) + DRR_t \cdot REC_{2,t+1}$$

where *DRR* is discovered resources last period (this is endogenous). Accumulated discoveries (*ADRR*), including initial undeveloped reserves, are then given by:

$$ADRR_t = UR_0 + \sum_{i=1}^{t} DRR_i$$

B.3. Operating costs

Let $C^{R}_{O,j}$ be the initial unit operating cost in field group *j*, i.e. total operating costs divided by total reserves in the field. Thus, $C^{R,n}_{O,j}$ is the initial unit operating costs for a field in Vintage *n*. Because operating costs vary across vintages, the cheapest fields are developed first. We assume that annual unit operating costs for a field with ongoing production are constant over time. We introduce the following marginal operating cost function for fields with ongoing production in the pre-peak, peak or decline phase:

$$c^{n}_{O,j,t}(S_{n,j,t}) = C^{R,n}_{O,j} + \phi_j \left(\frac{S^{+}_{n,j,t}}{CAP_{n,j,t}} \right)$$

where $S_{n,j,t}$ and $CAP_{n,j,t}$ is supply and capacity in vintage *n* and field group *j* in year *t*[18][19].

We introduce the following relationships that keep track on the operating costs in different vintages (the relationship applies between periods, and is of course region/category specific):

[18] The function is calibrated so that marginal costs in the pre-peak and peak phase equal the base year oil price of \$28 when 99 percent of capacity is produced and \$100 at full capacity. Most fields in the peak phase produce at approximately full capacity.

[19] For fields in the decline phase the function is calibrated with a lower capacity utilization at the base year price than in the peak phase (and this ranges from 0.87 to 0.94 percent in Norway).

$$C_O^{R,n} = \begin{cases} \dfrac{R_0(1-\alpha)C_O^{R,0} + (R_1 - CAP_1)C_O^{R,1}}{R_0(1-\alpha) + R_1 - CAP_1} e^{-\tau_P} & n = 0 \\ C_O^{R,n+1} e^{-\tau_P} & 0 < n < t_1 + t_2 + t_3 \\ C_{O,t}^R & n = t_1 + t_2 + t_3 \end{cases}$$

Here τ_P denotes the technological progress for fields in production ($\tau_p = \tau_I$), and $C_{O,t}^R$ denotes the unit operating costs of new fields, which change over time, c.f. Eq. (7).