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Effects of higher required rates of return on the tax take in an oil province

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ABSTRACT

For different reasons the oil companies might apply higher required rates of return than they did some years ago, and this has consequences for investments and tax revenue in oil provinces. By applying various required rates of return as well as various oil prices, this study derives future Norwegian tax revenue during 2018–2050 by using a partial equilibrium model for the global oil market. An important contribution is a detailed modelling of the supply side including the complete petroleum tax system. The model explicitly accounts for reserves, development and production. Both investment in new reserves and production are profit driven. With rising required rates of return fewer of the high cost reserves become profitable to develop and investments decline. Intuitively one would think that lower activity and investments will lead to lower tax income for the government. However, because the government in practice carries a large fraction of the investments because of favourable possibilities for deductions of capital expenses for the oil companies, less investment in a period increases the tax base and the tax income. The initial effect is offset by a subsequent reduction in production which has a negative effect on future taxes. The result is that increasing required rates of return will lead to small variations in net present value of total tax revenue. Further, with lower oil prices, tax take increases significantly when required rates of return rise.

1. Introduction

The government's tax revenues from petroleum activities can be defined as the tax take. This paper looks at the effects on the tax take of an assumed rising required rate of return (RRR) in the petroleum sector. There are various reasons why the RRR (or the discount rate) for the oil companies may be higher today than only some years ago. First, since the oil price drop in 2014 many oil majors have moved from high-cost undeveloped resources to lower-cost areas where resources can be brought on stream relatively quickly (PIW-Petroleum Intelligence Weekly, 2018). There have also been changes in the types of projects that are executed. Companies increasingly focus on projects that deliver high rates of return rather than high reserve volumes (IEA-International Energy Agency, 2017a). There has also been a shift towards projects with shorter investment cycles. The clearest example of this is investment in light tight oil reserves, but also in conventional crude oil projects with shorter time lags, i.e. lags between development approval and production (IEA-International Energy Agency, 2017b). In a recent study The Oxford Institute for Energy Studies (2019) shows that investors now are demanding a much higher minimum required RRR (hurdle rate) to invest in long cycle oil projects than they did before. Thus, the result is higher RRR in provinces with long lead times like the Norwegian continental shelf (NCS).

A second trend is the rising awareness within the business community of climate risk to the economy (Carbon Tracker, 2017). Future investment opportunities can consist of assets that might be undeveloped. Oil companies (and energy companies in general) are under scrutiny from investors about the impact of climate policies on their future earnings. Pension funds globally have increasingly begun pulling out of fossil fuel companies over fears that their assets could become "stranded", or worthless, if governments across the world introduce stricter rules to tackle global warming (Financial Times, 2018). This can lead to more near-sighted investment strategies by the oil companies and hence, a higher RRR. This is confirmed by the study of The Oxford Institute for Energy Studies (2019) which concludes that higher RRR in general is due to concerns of the energy transition.

A possible threat to the future oil demand is that the cost of electric vehicles (EV) is expected to be at par with the cost of cars with internal combustion engines, according to Randall (2016) by as soon as 2022. The largest emerging economies, China and India, have signalled high ambitions for EV (Reuters, 2017) and car producers have pledged to end the production of cars with only internal combustion engines (The Guardian, 2017a, 2017b). Once electrification of transport takes hold, why should it stop at cars? Technological breakthroughs in battery technology could also reduce the oil demand from trucks, ships and

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aircrafts. In addition, the petrochemical sector is vulnerable to environmental concerns as an emerging "war on plastics" is taking place (Energy Intelligence, 2018). This could also lead to reduced demand for oil, thus raising the uncertainty about the prospects of oil suppliers. It must be emphasized that some of the effects described above are linked to an environment of both higher RRR for the oil companies as well as lower future oil prices.

There are different opinions on the appropriate RRR to apply in petroleum analyses. The rate of return shall reflect the return on capital in the best alternative use, while the oil company at the same time is compensated for taking risk. Hence, the real rate of return is the risk-free rate plus a risk premium (because it may not be possible to diversify the risk). The Ministry of Petroleum and Energy in Norway has set the discount rate in petroleum projects to be 7% (Riksrevisjonen, 2015). Based on the discussion above, I analyse the effects of higher (real) RRR for producers outside OPEC. Historically oil companies often have applied a real discount rate of 10% in their cash-flow analyses. This has been considered an average RRR or a "rule of thumb" in the industry (Harden, 2014). Wood Mackenzie regards the standard industry benchmark for the internal rate of return for a robust project to be around 15% or even somewhat higher (Upstream, 2016). In addition, BP has recently disclosed a RRR of 15% at an oil price of USD 60 per barrel of oil equivalent (boe)[1] for new greenfield oil investments (BP, 2018). Further, according to The Oxford Institute for Energy Studies (2019) the RRR is now being stated at closer to 20% by investors for new international oil projects, especially deep-water oil and long cycle projects. Hence, this study looks at the effects of increasing the RRR from 7% to 10, 15 and 20%. However, the risk of projects may differ across regions worldwide because of factors such as e.g. infrastructure, human capital, political and institutional risk. In this case, it is not clear that increases in the RRR will be uniform e.g. across provinces. I will discuss this in the sensitivity analysis.

As will be clear later, in the model I apply, when the RRR rises, less of the high cost reserves become profitable to develop and investment declines and cash flow increases. Effects of RRR (or the discount rate or the interest rate) on investment and production of non-renewable resources have been discussed in various studies. Farzin (1984) finds that an increase in the rate of' discount brings about two counteracting effects. First, because the discount rate reflects the rate of time preference, an increase acts to move forward the use of' resources to the present, and second, to the extent that it reflects the cost of capital services, it increases the unit costs and hence induces a slower rate of resource depletion. Under certain assumptions, inter alia regarding the backstop technology, Farzin finds the result could be to decelerate depletion. Lasserre (1985) finds that even if an increase in the interest rate leads to impatience and increased production, the result of an increase in the discount rate may be to slow down extraction if capital is relatively scarcer than the resource (and the user cost of capital increases). Hartley and Medlock III (2008), which follows Pyndick (1978), show how an increase in the (political) discount rate reduces investment in the short run, with the aim to increase cash flow. This resembles the effects in the present study.

Many analysts argue that it may prove beneficial for the government to carry a large fraction of the initial investment to secure higher tax revenue later in the project life cycle (e.g. Osmundsen et al., 2017). Summers (1987) argues that when the governments weigh present revenue against future income, they must consider that companies use a substantially higher discount rate, and he concludes that governments would win by introducing accelerated depreciation. I contribute to the discussion by showing how rising RRR affects the tax income on the NCS, which can be described as an oil province with favourable deductions of capital expenses and a high net tax rate. This entails that a large part of the revenue is collected by the government in periods where annual revenue exceeds total costs. This is a central feature of a progressive tax system which we will discuss later. When RRR rises, fewer of the high cost reserves are profitable to develop and investment declines. Because the government indirectly carries a large fraction of the investments, because of a high net tax rate and favourable possibilities for deductions of capital expenses, less investment in a period increases the tax base and the tax income. This initial effect is offset by a subsequent reduction in production which has a negative effect on future taxes. Hence, this results in only marginal changes in the net present value (NPV) of total tax take with increasing RRR. I also show that with a low oil price the tax revenue increases significantly when RRR rises. This is counterintuitive as one would think that more near-sighted investment strategies by the oil companies, and, hence, higher RRR would be negative for tax income of the government. This somewhat surprising result could possibly be carried over to other oil provinces with relatively high costs and a high net tax rate.

Oil prices are of course important for the profitability of investments. Oil prices over 100 USD per barrel in the period 2011–14 brought about large increases in supply from Non-OPEC producers and consequently oil prices fell sharply in 2014. Following reductions in production in both OPEC and some Non-OPEC countries, the oil price was somewhat higher in 2019 than in the beginning of 2016. In 2020 the spread of the corona pandemic lead to a dramatic drop in demand and oil prices. How changes in the RRR will affect future investment, production and total tax revenue in an oil province will clearly vary with the oil price level. Therefore, this study applies three oil price scenarios based on IEA-International Energy Agency (2017a). This is a high, a middle (reference) and a low oil price trajectory ranging from 125 USD to 58 USD per barrel (2012-USD) in 2040, which will be described later.

With this point of departure, I analyse how future Norwegian oil production and investment might develop. This study seeks to answer the following questions:

- How robust is supply and investment to future oil price development?
- How will variations in RRR affect investment and production under different oil price assumptions?
- What will be the effects on the government's tax take over the shorter and longer term?

To answer these questions, this study applies a comprehensive and transparent global oil model with prices, costs and reserves. An important contribution of the paper is the detailed modelling of the supply side. Oil producers base their investment and production decisions on profit maximization and detailed information about the access to fields worldwide. The producers might invest in new reserves, which are both new fields and increased oil recovery from existing fields. The assumption that investments first target the most profitable reserves leads to a geographical spread of oil extraction worldwide. Gradually less profitable resources are developed until the internal rate of return is equal to the RRR.

Many studies on resource taxation do not deal with the complete tax system of a country, but on more partial and often theoretical effects of taxes. Lund (2009) surveys distortionary effects of taxation on investment and extraction in the nonrenewable resource sector, under different assumptions regarding company behaviour. He searches for an optimal tax policy when uncertainty is taken into consideration. Smith (2013) surveys different studies on taxation in general and presents the strengths and limitations of different modelling frameworks regarding resource taxation. He emphasizes that anticipating the taxpayer's behavioural response is primarily what economic analyses add to the accounting discussion of tax policy, which I do in this study. Kemp and Stephen (2017) disregard taxes, but look at how different rates of return (discount rates) affect investment and production on various undeveloped fields on the UK continental shelf. They apply Monte Carlo techniques on data for field size, development and operational costs over

[1] The boe is a unit of energy based on the approximate energy released by burning one barrel of crude oil. Both conventional oil (crude and natural gas liquids) and unconventional oil in this study are measured in boe.

two exogenous future oil (and gas) prices. In contrast to my approach, they do not apply a model where the oil companies base their investment and production decisions on profitability. Among the empirical studies of oil taxation, Berg et al. (2018) look at various planned Norwegian petroleum fields and study to what extent a lower uplift on capital costs will make the shareholders reduce investment and production. The authors only apply a given discount rate of 8%. In line with my approach, Helmi-Oskoui et al. (1992) assume that the oil producers maximize the present value of future profits. They look at a given reservoir in the U.S. and study how different discount rates affect production and investment. The model output is not only the number of wells, but also their location. However, the result does not seem credible as a lower discount rate will make the operator postpone any development for 17 years followed by only three years of extraction. In addition, like Kemp and Stephen (2017) and Berg et al. (2018), they do not explore the effects on petroleum tax payment, which is the focus of my study. Further, I have not been able to find studies that analyse effects on the total tax revenue in an oil province in a *global* environment. Many empirical studies focus on specific characteristics of oil tax systems in an *isolated country*, e.g. Mansour and Nakhle (2016) survey fiscal stabilization in oil and gas contracts in 20 countries. This means that they cannot take into consideration e.g. a possible tax competition between countries in the form of redirection of investments to a more favourable investment environment.

The next section describes the numerical oil market model, which is called FRISBEE. I present simulations of different scenarios to 2050 in Section 3. In Section 4 the sensitivity analyses are discussed, and I conclude in Section 5.

2. Model description

The FRISBEE[2] model is a partial equilibrium model of the global oil market, 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. Other versions of the model also include global gas, coal, and electricity markets. In the present version I include the Norwegian petroleum tax system. The world is divided into 16 regions, including Norway, where oil companies produce oil. The time periods in the model are one year and the base year is 2012, while the terminal year is 2050. Prices are thus stated in year 2012-USD and exchange rates are held constant over time. The world market price of oil is exogenous, but different price scenarios are considered. 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. The only focus of the Non-OPEC companies is to invest in reserves that give an internal rate of return that is higher or equal to the RRR. Therefore, the model description will focus on the supply side of Non-OPEC in general and of Norway in particular.[3] The present model version has three different Norwegian geographical areas,[4] which are the North Sea, the Norwegian Sea and the Barents Sea.[5] FRISBEE has previously been used for studies of petroleum production (Lindholt and Glomsrød, 2018), emission from shipping and petroleum activities in the Arctic (Peters et al., 2011) and impacts of petroleum industry restructuring (Aune et al., 2010). In Section 2.1 I look at the model's production and investment decisions and Section 2.2 contains a short description of the demand side. This leads to a discussion of the Norwegian tax take in Section 2.3.

2.1. Production and investment

For 15 of the 16 FRISBEE regions (r) there are 4 field categories/geographical areas. In addition, Greenland is one region with only one field category (see Table A1 in Appendix A). The model separates between oil companies' investment and production decisions in the 14 regions outside the two OPEC regions, which consist of ($4 \times 13 + 1 =$) 53 field categories, based on profit maximization and detailed information about the access to fields worldwide.[6] In each region, oil companies produce oil, which they sell on the global market and all trade between regions goes through a common pool. Regional supply, demand and trade flows are among the outputs of the model.

Expected future price is based on history and are set equal to the average oil price during the previous six years. Price expectations are thus continuously updated along the simulated scenarios. Hence, I apply adaptive oil price expectations in the following way:

$$E_t[P_j] = \frac{1}{6}\sum_{n=0}^{6-1} PP_{j,t-n} \tag{1}$$

where $E_t[P_j]$ is the expected (real) oil price and $PP_{j,\,t}$ the actual oil price in year t in field group j which is equal over the field groups j. The oil price each year t follows the scenarios in IEA-International Energy Agency (2017a).

The model assumes that the basic incentive for oil companies is to invest in provinces and field types with the highest expected return and apply the traditional NPV method, which Graham et al. (2015) suggest is the predominant principle in investment decisions. NPV are calculated for the 53 field categories, based on adaptive price expectations described above and a pre-specified required rate of return, which is set to 7, 10, 15 and 20% in real terms.

Neglecting subscript t for simplicity of exposition, investments in new reserves in Non-OPEC are derived from the following maximization problem (see Appendix B for details):

$$Max_{R_j}\pi^e\{R_j, E[P_j], RRR_j, CO_j, CC_j(R_j, UR_j), GT_j, NT_j, TD_j, \overrightarrow{F_j}\} \tag{2}$$

where π^e is expected discounted profits, R_j denotes investment in new reserves (new fields and reserve growth in existing fields) in field group j, $E[P_j]$ is expected (real) price which is equal over the field groups j, RRR_j is the required rate of return which is also equal over field groups, CO_j and CC_j is operating and capital costs, respectively, GT_j and NT_j are gross and net tax rates on oil production, respectively, which also are equal over field groups and TD_j is tax deductions which in Norway are depreciation, uplift and interest expenses and these are equal over field groups (see Section 2.3 for further elaboration on this). $\overrightarrow{F_j}$ is a vector of field characteristics that differ across field groups (notably decline rates and time lags). Note that capital costs are convex in the short term. This may reflect capacity constraints in the short run as e.g. a shortage on the availability of oil rigs, personnel etc. Further, marginal capital costs increase in investment activity (R_j) and when the pool of undeveloped reserves available for new reserve investment declines (UR_j). In this manner the exhaustibility constraint partly reflects that the scarcity rent is higher the less undeveloped resources there are. The investment cost function also takes into consideration that large current production modifies the rising trend in field development costs because of economies of scale, and that a large regional activity level modifies the rising trend in development costs. These factors make it more attractive to stay in an area rather than entering new locations with a lower degree of reserve

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

[3] A more formal and detailed description of the model is given in Aune et al. (2005).

[4] See map: https://www.npd.no/en/facts/publications/co2-atlases/co2-atlas-for-the-norwegian-continental-shelf/2-petroleum-activity-age/

[5] I ignore Lofoten/Vesterålen/Senja as this area at present is closed for petroleum activity.

[6] For this modelling work I have benefited from access to the comprehensive IHS Energy field database, see www.ihs.com.

development. Data on reserves (both producing, developed and undeveloped) and operational and capital costs are based on the extensive database of global petroleum reserves in the year 2012.[7] The parameters in the cost function are based on available cost data.

I derive gross and net tax rates for each country by data from Wood Mackenzie (2016) and EY (2019). When I estimate the average tax rates for a region which consists of various countries, I 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 importance when the oil companies are constrained by credit and cannot invest in all projects they find profitable.

A simpler approach is applied for exploration investments. The model assumes that the process for discovered reserves R_{Ej} is a function of the expected oil price, remaining undiscovered reserves in each region and the RRR, and captured by the following function (cf. Appendix B), and subscript t is still subdued:

$$R_{Ej} = R_{Ej}(E[P_j], U_j, RRR_j, \overline{F}_j) \tag{3}$$

where U_j denotes (expected) remaining undiscovered reserves. A lower expected price and/or a higher RRR_j will decrease the level of discoveries. When new fields are developed, the stock of undeveloped reserves is reduced. New discoveries add to the stock of undeveloped reserves at the end of each year in every region and field category (see Appendix B for details). Expected undiscovered oil reserves are mainly based on (USGS (U.S. Geological Survey), 2000, USGS, 2008, USGS, 2012) as well as Norwegian Petroleum Directorate (2016, 2017).

The reserves additions from Eq. (2) determines the production capacity in each field group each year.[8] For developed Non-OPEC fields the model assumes that oil production 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. 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. From profit maximization we get for region r and field group j at time t:

$$CO_j^r = PP_r(1-GT_r) \quad \text{if} \quad S_j>0 \tag{4}$$

where CO_j^r is the marginal operating costs in field group j in region r, PP_r is the producer price in region r, which is considered exogenously by the Non-OPEC producers. GT_r is the gross tax in region r, but for Norway and other regions without gross taxes,[9] marginal operating costs simply equal the oil price. S_j is production in field group j. Operating costs are increasing functions of production, but are generally low unless production is close to the fields' production capacity; then they increase rapidly. The parameters in the cost function are based on available cost data. To sum up, the oil companies make new discoveries as described in Eq. (3). We get the profitable reserves additions from these discoveries by Eq. (2) each year. The size of these reserves determines the production capacity. In Eq. (4) production is then determined so that marginal operating costs are equal to the oil price (adjusted for gross taxes).

In short, oil companies invest in the development of new reserves, which is the sum of investment in new fields and in efforts to increase oil recovery from producing fields. As Non-OPEC production is profit-driven, a higher oil price path (compared to a reference path) will gradually increase Non-OPEC supply. Extraction from existing capacities (Eq. (4)) is fairly fixed, but investing in new reserves (Eq. (2)) will in the medium to long term lead to more fields being developed. In the longer term new fields are discovered and appraised for development (Eq. (3)).

The oil and gas companies only invest in projects with a *RRR* above or at the pre-specified level. The assumption that investments first target the most profitable reserves leads to a geographical spread of extraction. Gradually, reserves that are costlier to extract become candidates for investment, and the cost of development will rise as reserves are depleted. On the other hand, new discoveries add to the pool of undeveloped reserves.

FRISBEE operates with constraints on the scale of investments to modify the dynamic effect in periods with high profits. Reinvestment of a certain share of the cash flow into the oil industry varies over time, and it is difficult to get hold of reliable and updated estimates of this share. In an earlier study OGJ-Oil and Gas Journal (2001) claims that the oil industry historically had reinvested a remarkably consistent 60% of cash flow (includes expenditures on exploration). Hence, I limit total expenditure on capital to 50% of total cash flow in the oil industry (as the model does not include exploration costs). The cash flow constraint is generally not binding in the various scenarios, and lower levels of constraints are tested in the sensitivity analyses.

2.2. Demand

The model distinguishes between three end-users of oil products, i.e., industry, households (including services) and power producers. Industries and households consume both transport oil and stationary oil (including processing), whereas power producers consume fuel oil. The regional end-user prices are the sum of producer price, transport, distribution and marketing costs, VAT and a carbon tax, and are mainly taken from IEA-International Energy Agency (2012a), IEA-International Energy Agency (2012b) and GIZ (2013). Demand from the final end-users are log-linear functions of price, population, GDP per capita and autonomous energy efficiency improvements (AEEI). The per capita income elasticities vary between 0.1 and 1.1 in the long run (weighted averages are around 0.6 for both households and industries). The long-run direct price elasticity varies between −0.1 and −0.6 with a weighted average of −0.30 for households and −0.21 for industries. The elasticities are mainly taken from Liu (2004), IEA-International Energy Agency (2007), Tsirimokos (2011) and Burke and Yang (2016). Demand for fuel oil from power producers is simply set fixed and constant over time (IEA-International Energy Agency, 2017a).

2.3. The Norwegian tax take

Petroleum is important to the Norwegian economy. In 2012 the gross product of oil and gas extraction in Norway amounted to nearly 25% of GDP of which 67% was resource rent (Cappelen et al., 2013). Following the drop in oil prices in 2014, the gross product of oil and gas extraction was down to 14% of GDP in 2017 (Ministry of Finance, 2018). Almost all the oil and gas produced on the NCS is exported, and the present export value of oil is marginally higher than for gas.

One of the overall principles of Norway's management of its petroleum resources is that it shall lead to maximum value creation. Since the resources belong to society as a whole, the Norwegian state secures a large share of the value creation through taxation (Norwegian Petroleum, 2019a). In 2018, Norway's tax revenues from petroleum activities are about 112 billion NOK (Ministry of Finance, 2018). This amounts to 44% of the government's total income from the petroleum sector. Further, the contribution to total petroleum income from the State Direct Financial Interest (SDFI) is around 47% and dividends of the state oil company Equinor (former Statoil) around 6%. The remaining 3% of the petroleum income comes from environmental taxes and area fees. The importance of oil and gas is evident as the income from this sector (i.e. 256 billion) constitutes approximately 19% of total governmental revenues from all sources.

[7] The initial regional costs from IHS have been updated with data on break-even prices from Rystad Energy, see https://www.rystadenergy.com/newsevents/news/press-releases/Rystad-Energy-ranks-the-cheapest-sources-of-supply-in-the-oil-industry-//.

[8] The relation between reserves additions and capacity is explained in Appendix B in Aune et al. (2005).

[9] I disregard area fees and CO_2-taxes because these taxes in 2018 are estimated to constitute only 3% of total taxes on the NCS (Norwegian Petroleum, 2019a).

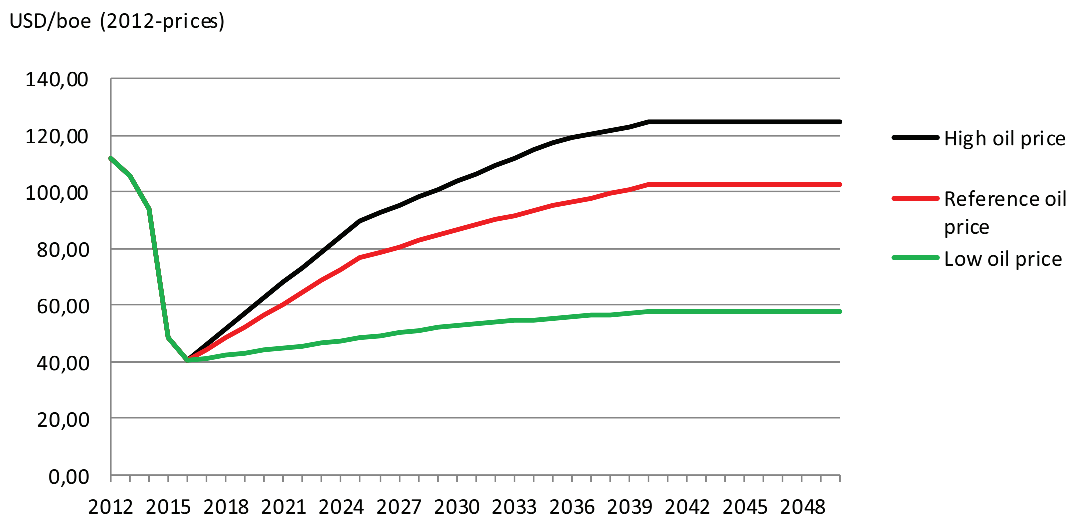

Fig. 1. Oil price assumptions. USD (2012-prices)/boe.

According to Norwegian Petroleum (2019b) taxation in Norway in period t consists of an ordinary corporate tax NT^C of 23% which is levied on revenue less operating costs, capital allowances and interest expenses over field groups j in Norway. Reintroducing subscrip t:

$$NT^C_{Norway,t}\left[\sum_{j\in Norway}(PP_{Norway,t}\, S_{j,t} - CO_{j,t} - D_{j,t} - IE_{j,t})\right] \tag{5}$$

where $PP_{Norway,t}$ is the producer price in Norway at time t which is equal over field groups, $S_{j,t}$ is production in field group j at time t and $CO_{j,t}$ is operating costs in the various field groups at time t. $IE_{j,t}$ is interest expenses in field group j on loans that finance the investment. Deduction of interest is restricted to a loan of 50% of the remaining tax value of the offshore production factors. Hence, I assume that the oil companies borrow 50% of their outlay on capital each year. In the actual valuation of the financial costs the authorities apply the companies' average interest rate paid on loans. I select an interest rate of 3.5% in the calculations as is also done by Ministry of Finance (2013). $D_{j,t}$ is the depreciation of capital costs ($CC_{j,t}$) in field group j at time t, which is made linearly over six years in Norway.

$$D_{j,t} = \frac{1}{6}\sum_{n=0}^{6-1} CC_{j,t-n} \tag{6}$$

A Special Petroleum Tax NT^S of 55% is applied to the offshore oil industry and is levied on the same amount as the corporate tax except for an extra capital allowance:

$$NT^S_{Norway,t}\left[\sum_{j\in Norway}(PP_{Norway,t}\, S_{j,t} - CO_{j,t} - D_{j,t} - IE_{j,t} - UP_{j,t})\right] \tag{7}$$

where $UP_{j,t}$ is a 21.2% uplift on capital investment ($CC_{j,t}$), which is treated as a 4-year straight-line depreciation (5.3% per year).

$$UP_{j,t} = \frac{1}{4}\sum_{n=0}^{4-1} 0.212 CC_{j,t-n} \tag{8}$$

I refer to the expression in Eqs. (5) and (7) between the brackets as the tax base. Total tax take TAX_t in year t is the sum of Eqs. (5), (7). The NPV of the tax take is:

$$TAX = \sum\nolimits_t \frac{TAX_t}{(1+d)^t} \tag{9}$$

where d is the government's discount rate, which is set to 4%. I follow the Ministry of Finance (2014) which states that the risk-adjusted discount rate should be at this level in socioeconomic analyses. However, I also derive the results with a 7% rate which is used by the Ministry of Petroleum and Energy.

It is important to bear in mind that both changes in production (through gross income) and investment (through deductions of capital depreciation, uplift and interest expenses) affect the tax take, c.f. Eqs. (5), (7). Lower investments for a period, ceteribus paribus, mean lower deductions and a higher tax base and tax take. Further, lower investments will eventually lead to lower production and this drives down the future gross income which is taxed by the government. These two opposing effects are central in this study.

3. The Norwegian oil market to 2050

I assume that changes in petroleum prices and RRR imply changes in production and investment as from 2018. Keeping the rules governing depreciation, uplift and interest payment allowances constant, I derive the tax take of the Norwegian government each year, and calculate the discounted tax take over the 2018–2050 period.

3.1. Oil price scenarios

The supply of oil is calculated for three price trajectories. I first develop a reference oil price scenario based on the New Policy Scenario of IEA-International Energy Agency (2017a). Fig. 1 shows that the real oil price (2012-USD) is expected to increase to 77 USD per barrel in 2025 before rising to reach 102 USD in 2040. As I study the effects until 2050, I simply keep the oil price constant after 2040. In addition to the reference scenario, IEA considers a low oil price scenario, where the oil price reaches 58 USD per barrel in 2040.[10] Such a development relates to rapid growth of electricity use in transport as well as increased OPEC production and higher supply of light tight oil in the US and other regions. Moreover, this low oil price scenario is relatively close to the new scenario due to the corona pandemic called The Delayed Recovery Scenario in IEA-International Energy Agency (2020). However, continued high economic growth in large developing economies combined

[10] This corresponds to an oil price of almost 70 USD in 2020-prices.

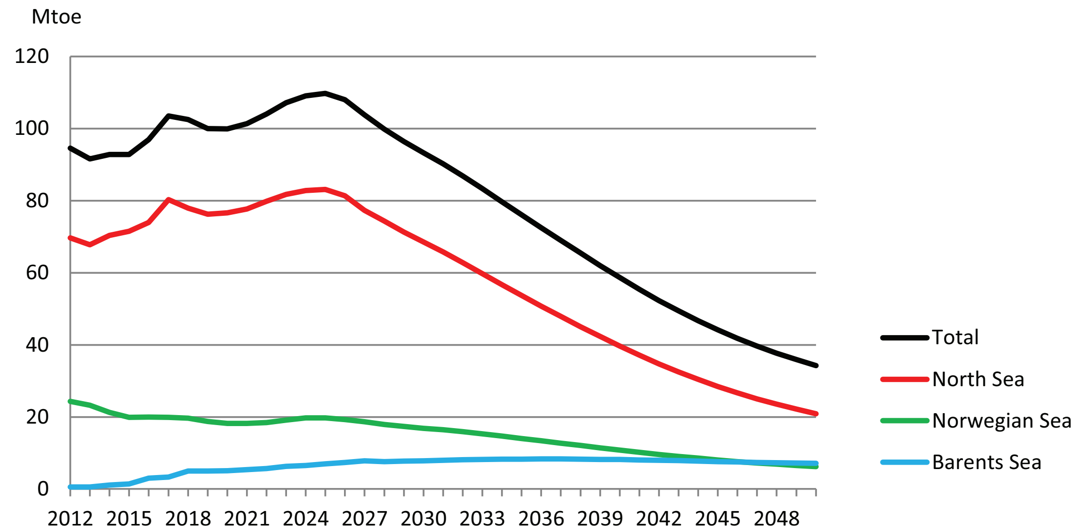

Fig. 2. Projections of Norwegian supplies to 2050 in various regions. Reference oil price scenario and a rate of return of 7%.

with higher decline rates at existing fields and the need to gradually move to less productive provinces might sustain a high oil price. This is the background of the high oil price scenario, where oil prices reach 125 USD per boe in 2040.

The oil investors do not know these price paths due to the assumption of adaptive expectations. However, when the real price of oil is increasing, the assumption of adaptive expectations will lead investors into a rising expected price path that is lagging somewhat behind the real price development.

3.2. Production, investment and tax revenue

Fig. 2 shows Norwegian oil production to 2050 with a RRR of 7% in the reference oil price scenario in Mtoe (million tonnes of oil equivalent).[11] The production level fits relatively closely the true development up to 2018. We see that production increases from around 2020 in the North Sea and this is consistent with projections from Norwegian Petroleum (2019c). The reason is the start-up of the giant oil field Johan Sverdrup. However, as from around 2026 both North Sea production and total supply decline steadily over the projection period.[12] In 2050 the production level in the North Sea is one quarter of the level in 2018. Production in the Norwegian Sea is almost constant before it starts to decline from around 2027. At the end of the period, production in this region is one-third of the present level. Production in the Barents Sea increases slightly up to the mid-30s and then remains more or less constant. Remember that behind such a constant supply level many fields are emptied and new fields come into production. Aker (2018) estimates that *total Norwegian oil and gas* production is down 50% in 2040 from 2018. In comparison, I find that total *oil* supply shows a reduction of 40% in 2040 compared to the present level.

From now on I call the scenario with a RRR of 7% the reference return scenario. Fig. 3 shows that when we move from the reference return scenario to a situation with a RRR of 10%, production is lower up to 2032. From then on extraction is higher in the 10% scenario. This may be somewhat surprising at first glance. To explain this, we start by looking at Fig. 4 which shows that in the reference return scenario investments in new reserves generally are on a declining trend, except for an increase in 2022 when a relatively larger amount of reserves is developed. Thereafter investment declines over the projection period. Since investments first target the most profitable reserves, introducing a higher RRR means that it is optimal to reduce investments, because more of the high cost reserves become unprofitable to develop. In the 10% scenario investments are lower than in the reference scenario initially, but they are higher as from 2023. The reason is that lower investments in an initial period entail lower future capital costs, both because of reduced investment activity in itself and also because the pool of undeveloped reserves decline more slowly (cf. the discussion following the introduction of Eq. (2)). This means that it will be profitable to invest in these fields at a later stage. Investments decline in the 10% scenario as from 2025, but are higher than in the reference return case over the rest of the projection period. Due to long lead times from investment to actual extraction,[13] this explains why production is higher after 2032 in the 10% case compared to the reference return scenario (see Fig. 3). This pattern repeats itself moving to the 15 and to the 20% scenario. Oil companies reduce initial reserve investments to a larger extent and for a longer period when the RRR rises. Again, this drives down the capital costs and makes it profitable to invest in these reserves at a later stage. Because of this, extraction is higher as from 2038 with RRR of 15% than in the reference return case. Likewise, after 2042 production is higher with a RRR of 20% compared to the reference scenario.

We see that even if the increasing oil price has a positive impact on new discoveries as described in Eq. (3), adding continously to the stock of undeveloped reserves, total oil production declines as from around 2026 independent of the level of the RRR. The reason why production declines can be illustrated by the ratio between investments in new reserves and the production level (in Mtoe). A ratio above one means that the extracted reserves are more than replaced by added (developed) reserves. Comparing Figs. 3 and 4 we see that the ratio is less than one in all scenarios, which explains the significant contraction in supply after 2025.

Turning to the effects of variation in the RRR on the undiscounted Norwegian tax take, it is important to bear in mind that both changes in production (through gross income) and investments (through deductions of capital depreciation, uplift and interest expenses) affect the tax take, c.f. Eqs. (5) and (7). Fig. 5 shows the effect of increased RRR on the tax take in the reference oil price scenario.

We can differ between three stages. In an initial stage moving to a higher RRR only to a small extent lowers production up to around 2025 due to long lead times as shown in Fig. 3, and therefore the

[11] 1 toe is equal to 7.49 boe.

[12] At peak, the Sverdrup field will produce around one third of the present oil production in Norway.

[13] The average lead time is 12 years, but varies greatly from project to project (Norwegian Petroleum Directorate, 2018)

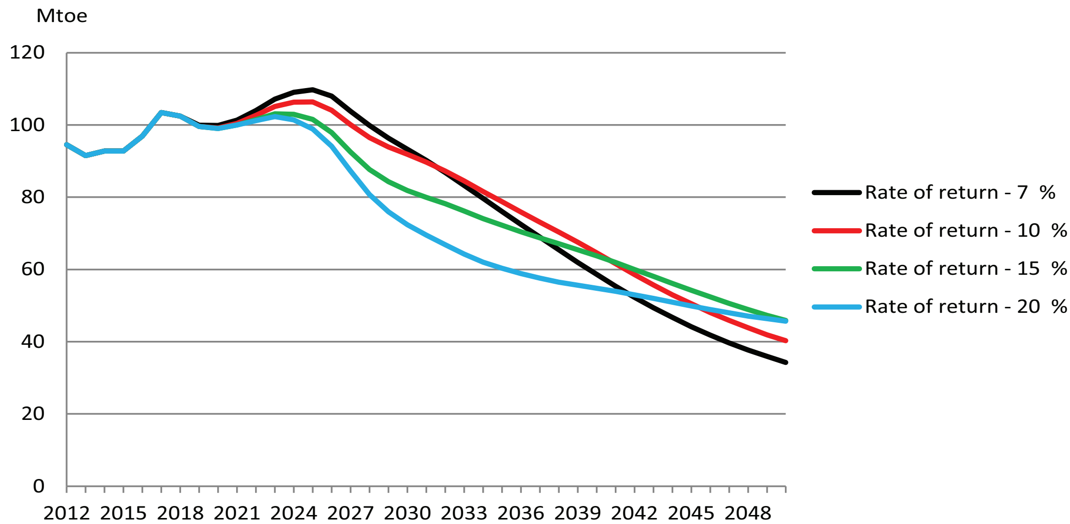

Fig. 3. Projection of supply on the Norwegian continental shelf to 2050 with the reference oil price scenario and with various rates of return.

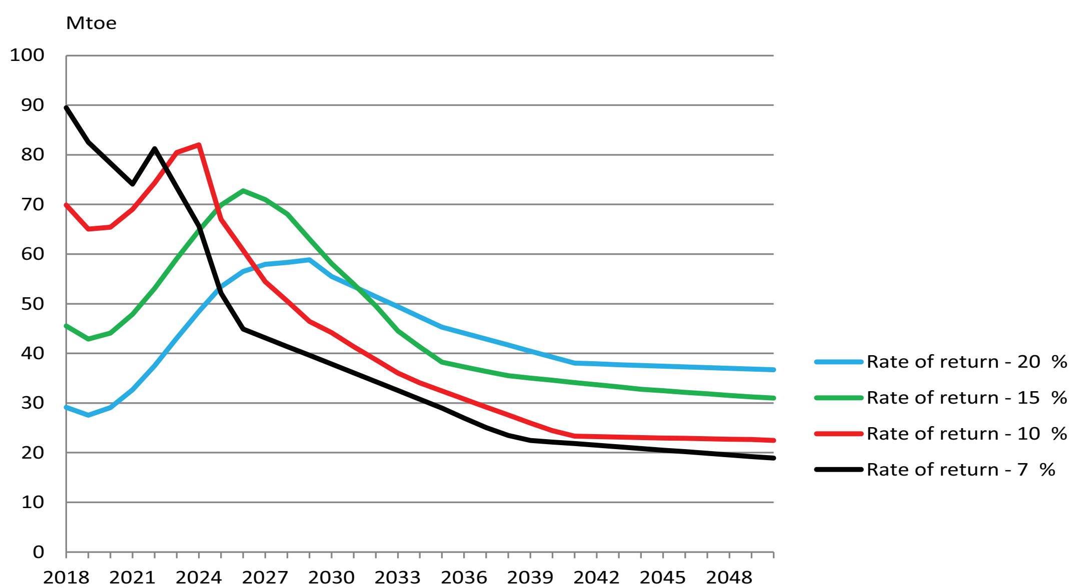

Fig. 4. Investment in new reserves to 2050 with the reference oil price scenario and with various rates of return.

negative effect from lower production on the tax take in this period is relatively small. The reason why the tax take is higher in this initial stage when RRR rises as Fig. 5 shows, is that investments are lower and this leads to smaller depreciation, uplift and interest payments allowances, which in turn increase the tax base in Eqs. (5) and (7).[14] In the second stage Fig. 5 shows that both reduced production and increased investment have a negative effect on the tax take, and the effect is stronger as RRR rises. The postponement of investment is the reason why production eventually becomes higher when there is an increase in RRR, and the various tax take scenarios approach each other at this third stage towards the end of the projection period.

A fiscal regime is said to be "progressive" if the government's share of total rents increases with the overall profitability of a project (Smith, 2013). Regimes that include tax instruments closely linked to profits are more likely to be progressive, and the government's share will increase as e.g. oil prices rise. Let us look at how the tax take share of cash flow, i.e. the government take, develops in our reference oil price scenario. Fig. 6 shows that until around 2025 the tax take share increases with higher RRR. Because of reduced investment in this period, profitability and cash flow increases, Since the tax take increases relatively more than the cash flow, the tax system can be described as progressive. After 2025 gradually the tax take share declines with higher RRR, both because production declines and investment becomes higher when RRR increases (the increase in oil price is equal over the various RRR-scenarios). Again, the tax system shows its progressive features because the government's share of cash flow declines when profitability of the project (taxes plus cash flow) goes down. These effects are also described in Glomsrød and Lindholt (2004); In a high-tax license regime where taxes are closely linked to profits, the oil company will not lose much of the NPV from a reduction in oil price (or production), and not gain so much from an oil price (or production) increase.

[14] Higher RRR will lead to both lower investments and lower discoveries, which is shown by Eq. (2) and Eq. (3). However, exploration *costs* are not included in the model. These costs are deductible in full in Norway, as opposed to other capital outlays which are activated and written-off. Including exploration costs would probably strengthen the increase in tax take.

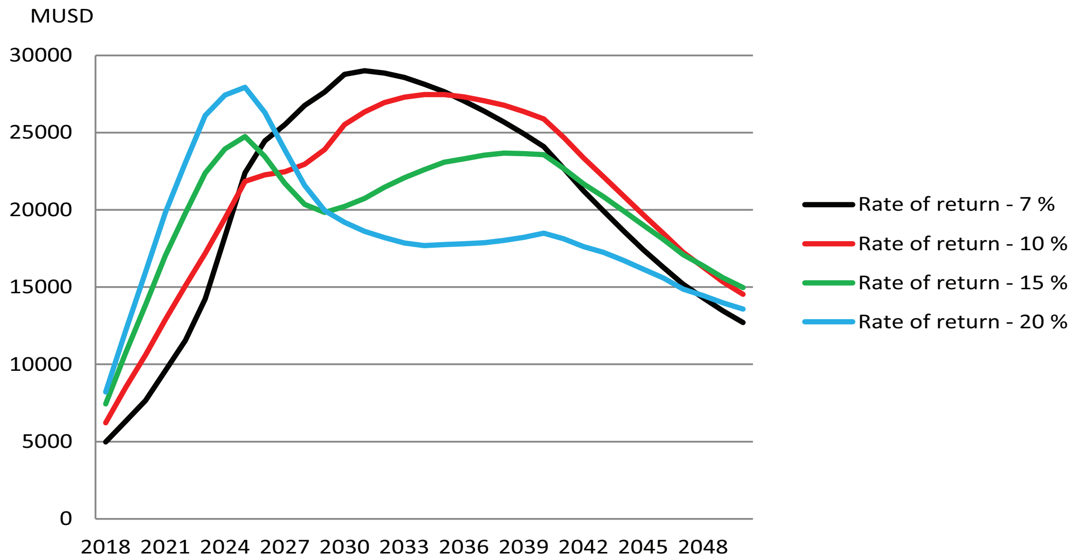

Fig. 5. Tax take to 2050 with the reference oil price scenario and with various rates of return.

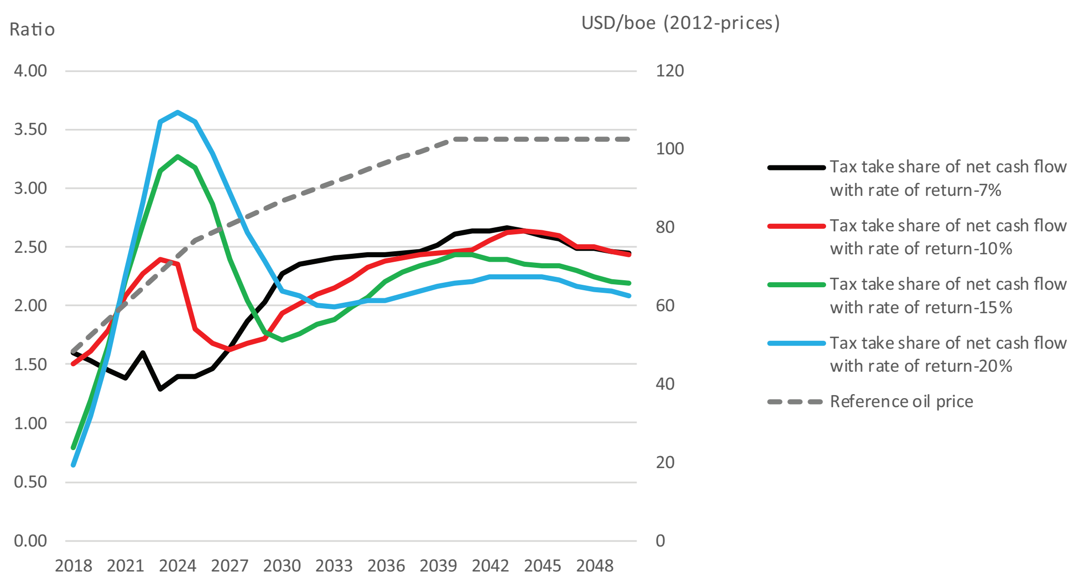

Fig. 6. Tax take share of net cash flow to 2050 with the reference oil price scenario and with various rates of return. Ratio on left axis. Reference oil price on right axis.

Before we turn to the NPV of the tax take, I emphasize that in all RRR scenarios the initial positive effects of reduced investment on the tax take are offset by the later negative effect of reduced production (and increased investment). Because of this the NPV of the tax take only changes marginally when we move to a scenario with a higher RRR. Table 1 shows that the change in NPV of the tax take from the reference scenario is +3, +1 and − 3% in the 10, 15 and 20% scenarios, respectively. We also see that with a reference oil price and a RRR of 7% the NPV of the tax take is 353 billion USD with a government discount rate of 4%.[15] If we apply a discount rate of 7%, the NPV of the tax take is down one-third to 235 billion USD. When RRR rises the relative change in the NPV of the tax take is now slightly more positive than with a 4% discount rate as it increases by +3, +4 and + 4% in the 10, 15 and 20% scenarios, respectively. The reason is that the positive initial tax effect of lower investments weighs more with a higher discount rate.

With a high oil price, the NPV of the tax take increases to 460 bn USD, 30% above the reference scenario. Higher prices lead to more discoveries as shown in Eq. (3), which subsequently can be developed and extracted. A higher price also leads to increased investments because more of the high cost fields become profitable to develop, c.f. Eq. (2). However, following an initial period of increasing investments they gradually start to fall significantly, similar to the pattern in Fig. 4, despite new discoveries. As with the reference oil price, we experience declining production after around 2025–26. Likewise, for an initial period lower investments result in a larger tax take when RRR rises. In addition, lower investments lead to both lower production and tax take only gradually. As in the reference scenario, the result is marginal changes in the NPV of tax take over various RRR as is shown in Table 1. If we apply a discount rate of 7% the NPV of the tax take is again down with

[15] In comparison the Government Pension Fund in 2018 amounts to around 1070 billion USD, when we include revenue from both oil and gas. To put this in further perspective with a back-of-the-envelope calculation, it can be assumed that the NPV of the tax take from natural gas comes to the same amount as oil (around 350 bn USD). The other important component of the government's net cash flow from petroleum, mainly SDFI, is in 2018 roughly equal to the total tax income from oil and gas. If the SDFI and other components develop in tandem with the future oil and gas income, total NPV of future revenue from the oil and gas sector is around 1400 bn USD, 40% above the present value of the Pension Fund.

Table 1
Net present value of tax take with a governmental discount rate of 4%. Billion USD when the rate of return is 7%. Deviation from the 7% return case with various oil prices and various returns.

	Required rate of return			
	7%	10%	15%	20%
		Change from 7%		
High oil price	460 bn USD	0%	1%	−3%
Reference oil price	353 bn USD	3%	1%	−3%
Low oil price	114 bn USD	18%	19%	42%

Table 2
Net present value of tax take with a governmental discount rate of 4%. Deviation from the 7% return case in various scenarios and various returns. Reference oil price.

Sensitivity scenarios	Required rate of return		
	10%	15%	20%
	Change from 7%		
1. No link between investment and future capital costs	2%	1%	−2%
2. Lower costs	2%	0%	5%
3. Binding cash flow constraint	1%	2%	2%

around one-third. As with the reference oil price, when RRR rises the relative change in the NPV of the tax take is now slightly more positive than with a 4% discount rate.

With a low oil price the NPV of the tax take is 114 bn USD, one third of the value in the reference case. Lower prices lead to less discoveries which subsequently means less resources are being developed and extracted. When the oil price is low, variations in the RRR have larger and more lasting effects on *production* somewhat earlier on than with a reference oil price. However, higher RRR has a larger and more persistent impact on the *investments*. The reason is that because the capital cost function of new reserves is convex, we are on the flatter part of the cost curve when the oil price is low, i.e. variations in the RRR have a stronger effect on the investment volume (and on production with a lag). Further, as the oil price is more or less constant, production gradually declines relatively more with higher RRR than in the reference oil price case when the price is increasing. However, because of discounting, the positive effects on the tax take from much lower investments earlier on weigh stronger than the somewhat later negative effect of reduced production. The result is that the tax take now increases more and for an extended period initially when RRR rises. Table 1 shows that when we move from a situation with a RRR of 7%, the increase in NPV of the tax take is +18, +19 and + 42% in the scenarios with a RRR of 10, 15 and 20%, respectively. With a 7% governmental discount rate, the relative change in the NPV of the tax take is even more positive when RRR rises than with a 4% discount rate. The NPV of total tax revenue now increases by +24, +37 and + 63%. The reason is that the positive initial tax effect of lower investments weighs more with a higher RRR due to a higher governmental discount rate.

4. Sensitivity analyses

I carry out the sensitivity analyses in the reference oil price scenario. The first three sensitivity analysis are: 1) No link between investment and future capital costs, 2) change in costs and finally 3) introducing a binding cash flow constraint. The results are summarized in Table 2. First, it could be questionable to assume that reserves that are not developed in one period to a large extent could be developed at a later stage by the oil companies. Thus, we now ignore the effect that lower investments in an initial period entail lower future capital costs, and a subsequent postponement of investment. When we move from the reference return scenario to a situation with a RRR of 10%, production is now lower over the whole production period (than in Fig. 3). Production gradually declines more from the reference return scenario so that production is around 40% lower in 2050. However, higher RRR means that also investments are lower over the whole period (than in Fig. 4). Hence, the positive effect on the tax take from less investment is larger and lasts longer when we move from the reference return scenario to a situation with a RRR of 10%. However, as production declines even more the negative effect on the tax take from reduced production is even larger.[16] All in all, again the two effects to a large extent cancel each other out, and the NPV of the tax take increases by 2% when we move from the scenario with a RRR of 7% to the situation with 10%. This pattern repeats itself moving to the 15 and to the 20% scenario. The result is marginal changes in the NPV of tax take over various RRR, similar to the numbers in Table 1. Even if this shows that the results are not dependent on the effect of postponing investment, it seems unreasonable to assume that that none of the reserves that are not developed in one period can be developed at a later stage by the oil companies.

Assumptions regarding costs are quite uncertain. The costs have declined over the last years (Norwegian Petroleum Directorate, 2018), and we may see further cost reductions in the future. Hence, I have tested the effects of lower operating and capital costs on the NCS. I carry out the cost sensitivity analyses in the reference oil price scenario including a cash flow constraint of 50%. First, I reduce the capital costs by 20%. The increase in NPV of total tax revenue compared to the situation with original capital costs is around 10–12% over the various RRR scenarios. Lower capital costs lead to somewhat higher investment over the whole period and lift the production profile upwards. However, moving to higher RRR levels has by and large the same effects as with the original costs. Compared to the 7% case, higher RRR leads to changes in the NPV of total tax revenue with +2, 0 and −5% in the scenarios with a RRR of 10, 15 and 20%, respectively. In a situation with 20% lower *production* costs, we get a relative change in the total tax revenue in the same magnitude as with a lower capital costs.

Following the fall in oil prices since 2014, oil companies cut investment budgets in response to a dramatic reduction in cash flow. Some argue that since companies prefer to fund a considerable part of new investment from their cash flow, they therefore cut capital spending. Further, they may be reluctant to cut back on dividends promised to shareholders, and be careful not to increase debt levels too much due to credit rating concerns and fear of financial stress (Osmundsen et al., 2017). As I apply a global model with oil producer taxes in different regions, I can take account of a possible tax competition between the different provinces. In the analysis (static) tax competition can only manifest itself if oil companies cannot invest in all projects with an internal rate of return of at least the prevailing RRR. So far I have applied a 50% cash flow constraint and this is not binding for any year in the reference oil price scenario, which means that the oil companies can invest in all oil fields they find interesting. However, if the oil and gas companies limit their investments to 30% of cash flow in the reference oil price scenario, the cash flow constraint is binding for some or all of the years in the 2018–2050 period. Then the companies may redirect their investments from the NCS to other provinces with lower costs and more profitable investment environment. However, this effect is somewhat dampened by the cost function modelling which makes it more attractive to stay in an area where the company already has production rather than entering new areas. However, the results show that with a 30% constraint, Norwegian production and investment decline faster compared to the non-binding situation, leading to a lower tax take in each RRR scenario. The reduction in NPV of total tax revenue from the situation with no cash flow constraint is around 10–15% over the various RRR scenarios. However, the relative effects of higher RRR are similar as in the non-binding case. Again, a rise in RRR gradually leads to reductions in production. As the tax effects of reduced investments initially on one side and gradually lower production on the other offset each other, the

[16] Compared to the reference return case, with a RRR of 10% the undiscounted tax take is lower as from 2031 (than in Figure 5).

result is marginal changes in NPV of tax revenue as in the reference oil price scenario without a cash flow constraint. Compared to the 7% case, higher RRR increases the NPV of the tax take by +1, +2 and + 2% in the scenarios with a RRR of 10, 15 and 20%, respectively.

The risk of projects may differ across regions worldwide because of factors such as e.g. political and institutional risk. E.g. Medlock III (2009) argues that on projects in regions of the world where governments are not stable, the fully risked RRR could be quite high. This could result in a low cost deposit being produced later than some higher cost projects in more stable regions (such as Norway). In this sense, the reduction in investment at the beginning of the period may not be necessarily large if the alternatives outside of Norway become much riskier (such as e.g. OPEC countries). This would mean that the increase in tax take due to lower investment initially would decline. Another effect is that when RRR rises, total Non-OPEC production declines. Because the oil price is exogenous in the model, OPEC increases their production correspondingly. In reality OPEC might not offset the reduction in production completely, and this would lead to higher oil prices. Due to this price effect, a rise in RRR could lead to even higher tax take compared to the situation with an exogenous oil price. If effects of higher fully risked RRR outside the NCS as well as a higher oil price come into play at the same time, the effects on the initial tax take in Norway would counteract each other.

This study has not modelled uncertainty in an explicit way. However, by changing RRR and prices, I have studied potential upside and downside scenarios alongside the reference case. Further, the oil companies are in a way cautious as the modelling of the cost functions imply that it is somewhat more profitable for companies to hold on to provinces where they already have exploration and production activities, rather than plunging into new ones. In addition, companies can be said to behave more cautiously when RRR rises, as they demand higher returns due to more risky investments. However, a future research task could be to implement uncertainty explicitly into the oil company's investment decisions, e.g. into the expected oil price function in Eq. (1). Further, if we instead of adaptive expectations had forward looking producers, we could see lower future backstop prices accelerating depletion. This "green paradox" or intertemporal leakage happens because suppliers find it profitable to accelerate extraction if they foresee reduced demand in the future. In our study a lower backstop price could be compatible with a low oil price environment. However, as we have seen higher RRR in a low oil price scenario reduce investment in the short run, with the aim to increase cash flow.

5. Conclusions

For various reasons the required rate of return for the oil companies may be higher today and in the future, than only some years ago. Because of lower oil prices, many oil majors have moved to lower-cost areas where resources can be brought on relatively quickly. This could mean less interest in relatively high cost areas with long lead times like the Norwegian continental shelf. There may also have been a shift from volume to value, i.e. the increasing focus by companies on projects that deliver high rates of return rather than high reserve volumes. In addition, companies may have become increasingly anxious that their assets could become "stranded", or worthless, if governments across the world introduce stricter rules to tackle global warming. This can lead to more near-sighted investment strategies by the oil companies and hence, a higher required rate of return. In this study I show that this does not necessarily mean lower tax take for the government.

By applying various required rates of return as well as various oil prices, I derive future Norwegian oil production, investment and tax payment during the 2018–2050 period by using a partial equilibrium model for the global oil market. A central feature of the Norwegian tax system, among others, is that the government in practice carries a large fraction of the oil companies' investments, because of a high net tax rate and favourable possibilities for deductions of capital expenses. An important consequence of this is that lower investments over a period will increase the tax take in that period.

One would think that more near-sighted investment strategies by the oil companies, and, hence, higher RRR would be negative for tax income of the government. However, I show that rising required rate of return generally will lead to small variations in the net present value of total tax revenue. The main reason is that when return rises, less of the high cost reserves become profitable to develop and investment declines for an initial period. However, declining investments mean lower capital outlay and hence lower tax deductions, which in turn increase the tax base and the tax income. Lower investments have a negative effect on future production with a time lag due to long lead times. Although lower production gradually has a negative effect on tax revenue, this is offset by the positive effect on revenue from lower investment initially. I show that with a relatively low oil price, higher required rates of return are beneficial for the government. As the required rate becomes higher, the present value of future tax revenues increases significantly. The reason is that the initial positive effect of reduced investment outweighs the negative tax effect from lower production later on. The results are supported by sensitivity analyses. One policy implication from this study is that more near-sighted oil companies with higher required rate of returns does not necessarily mean that the government should stimulate activity and investment to increase the tax take. Such a conclusion is probably dependent on a fiscal regime that can be described as "progressive", i.e. the government's share of cash flow increases with the overall profitability of the project. The findings could possibly be carried over to other oil provinces with relatively high costs and a high net tax rate. Nevertheless, governments might be required to use fiscal instruments to incentivize investment based on higher required rate of returns for other reasons, one of them being a regressive tax system.

Credit author statement

Lars Lindholt is a single author.

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Appendix A

Table A1
List of oil regions and field categories/geographical areas in the FRISBEE model.

	Oil field category/geographical area			
	1	2	3	4
Africa	Onshore	Offshore deep < 400 Mboe	Offshore deep > 400 Mboe	Offshore shallow
Canada	Arctic	Non-Arctic conv.	Unconventional Open Pit	Unconventional In Situ
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
Eastern Europe	Onshore < 100 Mboe	Onshore > 100 Mboe	Offshore < 100 Mboe	Offshore > 100 Mboe
Greenland	All			
Latin America	Onshore	Offshore deep < 1000 Mboe	Offshore deep > 1000 Mboe	Offshore shallow
Norway	Arctic Barents Sea	Arctic Lofoten-Vesterålen-Senja (currently closed for activity)	Arctic Norwegian Sea	Non-Arctic
OECD Pacific	Onshore	Offshore deep	Offshore shallow < 100 Mboe	Offshore shallow > 100 Mboe
OPEC Core	Onshore <400 Mboe	Onshore > 400; < 1000 Mboe	Onshore > 1000 Mboe	Offshore
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	Offshore shallow
Russia	Non-Arctic Onshore & Offshore	Arctic offshore	East Arctic Onshore	West Arctic Onshore
USA	Non-Arctic Onshore	Alaska	Non-Arctic Offshore deep	Non-Arctic Offshore shallow
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

Appendix B

Following Eq. (3), the expanded specification of discoveries (R_{Ej}) is given by (reintroducing subscript t)

$$R_{Ej,t} = R_{Ej,t}\left(E_t\left[P_j\right], U_{j,t}, RRR_{j,t}\right) = \alpha_{E_{j,t}} E_t\left[P_j\right]^{0.5} U_{j,t} e^{-RRR_{j,t}\left(t_{0_j}+2/3t_{1_j}\right)} \tag{B1}$$

where t_0 is the length between exploration and the actual development decision, t_1 is the investment phase and $\alpha_{Ej,t}$ is a calibrated parameter. See Aune et al. (2010) for a more thorough description of the discovery function. Undiscovered reserves are based on (USGS (U.S. Geological Survey), 2000, USGS, 2008, USGS, 2012) and the figures for Norway are based on Norwegian Petroleum Directorate (2016, 2017).

A more detailed outline of the modelling of investment behaviour for Non-OPEC producers is presented below. For the complete formal structure of FRISBEE, see Aune et al. (2005). The present model version has been updated with data from 2012. In addition, the field categories in Norway now reflect geographical areas and not size/depth of fields. Further, expected profit for Norway in Eq. (B2) now contains the complete Norwegian tax system and not only net taxes as the similar equation in Appendix B in Aune et al. (2005) does.

With access to all Non-OPEC regions and field categories, oil companies maximize expected discounted profits from investments. Choice variable are given by reserve additions (R_j) from field development in the various field categories outside OPEC (see Table A1). It must be emphasized that when the oil companies invest, they know how the capacity profile and the amount of reserves in field group j are linked together, as well as how the operating and capital costs develop over the lifetime of the field. Expanding the profit function of Eq. (2), the present value of the oil companies' expected profit from new reserve investment in field group j is (introducing subscript t):

$$\begin{aligned} &Max_{R_{j,t}} \pi^e\left(R_{j,t}, E_t\left[P_j\right], RRR_{j,t}, CO_{j,t}, CC_{j,t}\left(R_{j,t}, UR_{j,t}\right), GT_{j,t}, NT_{j,t}, TD_{j,t}, \overline{F}_{j,t}\right) \\ &= \sum_t^{T_j} \left[\sum_{j(j)} \left[\left\{\left(E_t\left[P_j\right]\left(1-GT_{j,t}\right)-CO_{j,t}\right)\left(1-NT_{j,t}\right)-\frac{CC_{j,t}}{R_{j,t}}+\frac{D_{j,t}}{R_{J,t}}NT_{j,t}+\frac{OD_{j,t}}{R_{j,t}}NT_{j,t}\right\}R_{j,t}\right]\right]\frac{1}{\left(1+RRR\right)^t} \end{aligned} \tag{B2}$$

where $E_t[P_j]$ is the expected (real) oil price in field category j at time t, RRR is the required rate of return (discount rate), and $CO_{j,t}$ and $CC_{j,t}$ are operating costs and capital costs in field category j at time t, respectively. $GT_{j,t}$ and $NT_{j,t}$ are gross and net tax rates on oil production, $\overline{F}_{j,t}$ is a vector of field-specific characteristics in field category j at time t and T_j is terminal year of production for field group j. Linear capital allowances, $D_{j,t}$, are made over a certain number of years. These deductions are made over six years in Norway.[17] OD_j is other deductions of capital cost. In Norway these deductions are interest expenses on loans that finance the investments and a special uplift on capital expenses (see Section 2.3).

The model defines the net cash flow (NCF) over all field groups j as revenues less current operating costs and total taxes.

$$NCF_t = \sum_{j\in J}\left(PP_{r,t}S_{j,t}-CO^r_{j,t}-TNT_{j,t}-TGT_{j,t}\right) \tag{B3}$$

where TNT and TGT are total net and gross taxes paid, respectively. My starting point is that total expenditure on capital is limited to 50% of net cash flow. Hence, the following restriction applies in the reference scenario:

$$\sum_{j\in J}\left[CC_{j,t}\right] \le 0.5NCF_t \tag{B4}$$

[17] Depreciation over six years is the rule in Norway and seems to be a reasonable average period over different fiscal regimes.

I emphasize that this cash flow constraint generally is not binding in the period 2012–2050. The model assumes that outside debt will not affect the cash flow, and this is true if interests and repayments on loans equal the loan amount each year.[18] Hence, the model only takes into consideration the effect of debt through interest payments, which is included in other deductions (*OD*) in Eq. (B2). It is assumed that the oil companies borrow 50% of their outlay on capital.

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[18] Actually, the NPV of future interest and repayments on loan is equal to the loan amount each year.