UNIVERSITY OF CAMBRIDGE
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The Effect of CO_2 Pricing on Conventional and Non-Conventional Oil Supply and Demand

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Abstract

What would be the effect of CO_2 pricing on global oil supply and demand? This paper introduces a model describing the interaction between conventional and non-conventional oil supply in a Hotelling framework and under CO_2 constraints. The model assumes that non-conventional crude oil enters the market when conventional oil supply alone is unable to meet demand, and the social cost of CO_2 is included in the calculation of the oil rent at that time. The results reveal the effect of a CO_2 tax set at the social cost of CO_2 on oil price and demand and the uncertainty associated with the time when conventional oil production might become unable to meet demand. The results show that a tax on CO_2 emissions associated with fuel use would reduce oil demand despite the effect of lower future rents, and would delay the time when conventional oil supply is unable to satisfy demand. More precisely, between 81 and 99% of the CO_2 tax is carried into the oil price despite the counter-balancing effect of the reduced rent. A CO_2 tax on fuel use set at the social cost of CO_2 would delay by 25 years the time when conventional oil production is unable to meet oil demand, from 2019 to 2044 (mean value). The results show that this date is very sensitive to the price elasticity of demand and the demand growth rate, which shows the great potential of demand-side measures to smooth the transition towards low-carbon liquid fuel alternatives.

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1. Introduction

As conventional oil becomes scarcer, advanced economies will remain dependent on petroleum resources if no substitute is available. What would happen if conventional oil production was no longer able to satisfy demand? Fuels from non-conventional oil resources would then become the backstop fuel. These resources involve higher CO_2 emissions per unit of energy produced than conventional oil as they require more energy to be extracted and upgraded (Grubb, 2001), and the social costs of CO_2 would thus have a significant impact on the total marginal costs of supplying non-conventional oil. What would be the effect of CO_2 pricing on global oil supply and demand?

This paper describes a simple probabilistic model for estimating the effect of CO_2 pricing (in this case a CO_2 tax, set at the social cost of CO_2) on oil supply and demand. The competitive price of oil over time is calculated within a Hotelling framework and is derived from the costs of producing non-conventional oil from Canadian oil sands, a substitute for conventional oil. As non-conventional oil is defined as a backstop for conventional oil, the model identifies the time of entry of non-conventional oil in the market as the time when conventional oil production alone is unable to match demand, and determines the competitive price of oil over time. The model describes the behaviour of the oil market under perfect competition, with and without a CO_2 price reflecting its social cost. The social cost of CO_2 emissions associated with the production and use of conventional and synthetic crude oil is included in the model calculations, and this paper investigates the effect of a CO_2 tax set at the social cost of CO_2 on oil prices and demand.

Numerical modelling is used as a tool to help decision-making: a model is introduced that draws on the user's degree of belief about a series of parameters as an input (see for example Hope, 2006). A probability distribution is assigned to these parameters and the basis of these probabilities is "up-to-date knowledge from science and economics" (Stern, 2007 p33). The uncertainty associated with the validity of the input data is looked at, together with the influence of each parameter on the output.

2. Literature review

2.1 Oil substitute and price

Conventional oil producers face the choice of whether to extract oil now or leave it in the ground until a later date. In the first case, oil producers receive at time t_0 the price p_{t0} net of extraction costs c_{t0} for one unit of oil (also defined as the oil rent). At time t, oil producers will have earned $(p_{t0}-c_{t0})\cdot\exp(r\cdot t)$, with r the real rate of interest[1]. In the second case, oil producers postpone oil production until time t, and earn (p_t-c_t) for one unit of oil. According to Hotelling (1931), the optimal production path commands a price net of extraction costs at time t: $p_t - c_t = (p_{t0}-c_{t0})\cdot\exp(r\cdot t)$. A more rapid extraction path would lower the price of oil, and in a competitive market oil producers would then postpone extraction until a later date. Alternatively, a slower extraction path would push up the oil price, and would encourage oil producers to extract more oil earlier. At the equilibrium, the price of oil net of extraction costs will rise at the rate of interest.

Now let's consider the situation where two substitutes of the same product, conventional and synthetic crude oil, are available at differing extraction costs. According to Solow, the low-cost product, in this case conventional crude oil, should be produced first, and "at precisely the moment when the low-cost supply is exhausted, the price has reached a level at which it pays the high-cost producer to enter" (1974 p4). Here, the switch between substitutes is defined as the moment when the low-cost supply is exhausted, but this conclusion can be changed "if there are topographical constraints on the pattern of resource use", (Solow and Wan, 1976, p363).

[1] Under the assumption of perfectly competitive capital markets, the opportunity cost of capital is equal to the consumption discount rate, so that rate is used in the model.

The behaviour of the market is uncertain in the situation where the low-cost supply is constrained. If we consider the case where the conventional oil production rate might reach a peak or a plateau, conventional supply could become unable to meet growing demand for oil before the supply is exhausted. The model described in this paper thus departs from the previous assumption and defines the moment when the high-cost substitute enters the market as the time when conventional oil production is unable to meet demand. At the time when oil demand might outgrow the conventional oil production rate (defined as T), the marginal oil product is the first barrel of synthetic crude oil produced, which sets the oil price, as no Hotelling rent yet occurs for the substitute, which is assumed to be available in large quantities. Synthetic crude oil is effectively a backstop at time T, even though it is not available in infinite quantities. So at that time, the price of oil equals the marginal cost of non-conventional crude oil, which is illustrated in figure 1.

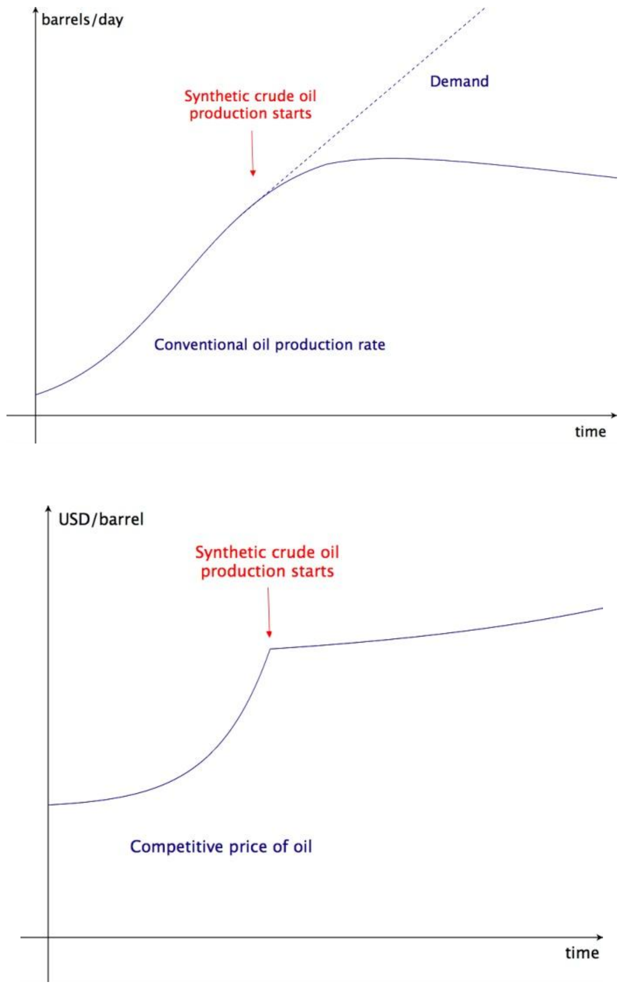

Figure 1: Interaction of conventional and non-conventional crude oil

If the price of oil is determined by the marginal cost of synthetic crude oil after time T defined above, an argument could be made that this situation is impossible as conventional oil producers would anticipate this situation and produce more of their oil at an earlier date, in order to benefit from the oil price growing at the rate of interest. But conventional oil producers face extraction constraints, which are parameterised as the maximum production rate in the model. These supply constraints prevent oil producers extracting conventional oil as rapidly as would be optimal without the constraints, and will result in the substitute, here synthetic crude oil, entering the market early.

To calculate the competitive price of oil, it is assumed that the Hotelling rule holds for conventional oil production before the time when conventional oil production can no longer match demand, i.e. that the price of oil net of its cost of extraction will grow at the consumption discount rate until the oil price reaches the cost of non-conventional oil production at the time conventional oil production alone can no longer meet demand. The model assumes competitive behaviour and perfect foresight, and the analysis is carried out at the global level.

After the time T, the price of oil is determined by the marginal cost of producing synthetic crude oil. The marginal cost of synthetic crude oil is not fixed. After T, it is a function of cumulative production and is driven by learning and depletion effects. Similar supply constraints affect Canadian bitumen.

2.2 Model description

Demand for oil is calculated endogenously, driven by the price elasticity of oil demand and a growth parameter independent of the price. The time T when conventional oil production is unable to meet demand is determined by iterating the model until it converges.

To calculate the competitive price of oil today, it is assumed that the competitive price of oil will be equal to the costs of producing synthetic crude oil when that product enters the market at time T. The rent associated with conventional oil at time T is the difference between the competitive price of oil at time T (i.e. the initial costs of producing synthetic crude oil) and the conventional oil production cost.

The marginal extraction costs of conventional crude oil are influenced by technological change and depletion. The difference between the competitive price of conventional crude oil and the production cost of oil when synthetic crude oil enters the market, or the oil rent, is discounted to the present time, and is used to determine the competitive price of oil today.

Finally, the Hotelling rent is added to the cost to obtain the competitive price of oil over the whole period. A loop is introduced in the model, as the demand for oil depends on the oil price, which is calculated from the time when conventional oil production is unable to meet demand. The simplified structure of the oil demand and price components of the model is summarised on figure 2. The starting point of the model iterations is the oil price over time, shown in red.

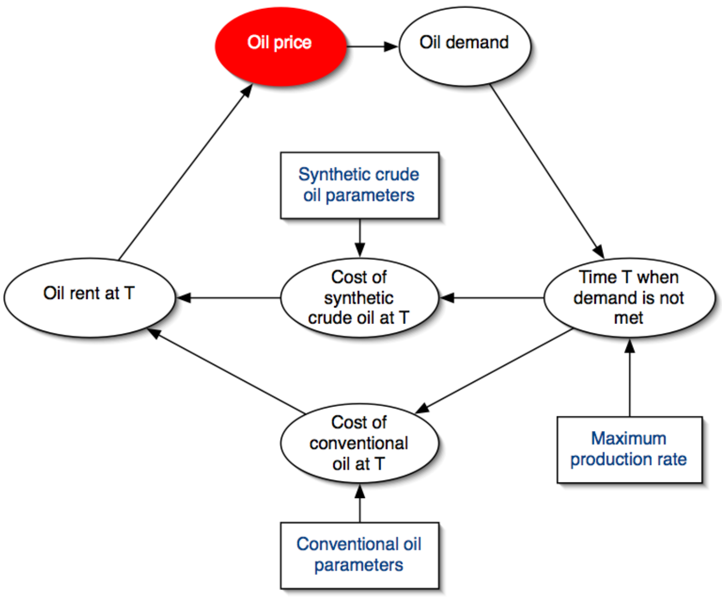

Figure 2: Model structure of the oil price and demand components

The model is used to compare the prices and demand obtained after a few iterations in two cases: in the first case prices are calculated with a CO_2 tax on production and fuel end-use, and in the second case prices only include a CO_2 tax on emissions associated with fuel production.

The model is set up as follows: a tax is added to the price of oil, which lowers demand through the price elasticity of demand. Lower demand delays the time when conventional oil production only is no longer able to satisfy demand, and thus lowers the oil rent, which reduces the oil price today and drives up demand and extraction. As the model converges, one effect takes over, leading to either higher or lower demand and extraction. It should be noted that the model is designed so that fuel extraction satisfies demand as long as this is physically possible. Figure 3 below shows an illustration of the model used.

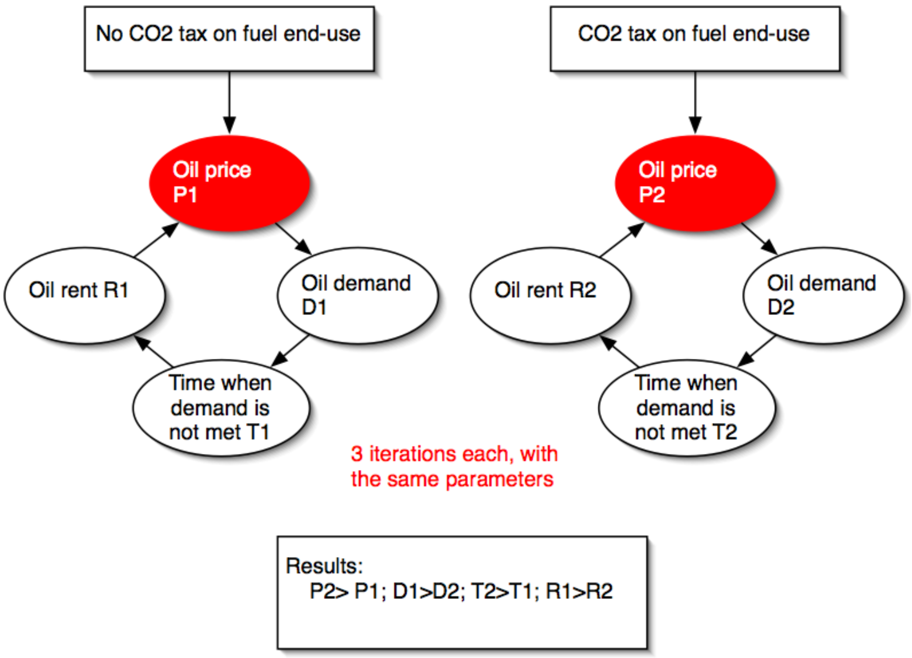

Figure 3: Model setting to compare oil demand with and without a tax on CO_2

Three iterations of each model set up, one with a CO_2 tax on fuel end-use and the other without such a tax, are performed to obtain the results presented in section 5. Three iterations are sufficient, as the results converge and differ of less than 0.001% between iterations 2 and 3 in the case of the mean price in 2050. The following equations show in further details the structure of the model.

3. Methods: Equations and parameters of the model

3.1 The social cost of CO_2

The social cost of CO_2 is the increase in future damage, discounted to the present day, that occurs if current emissions of CO_2 are increased by one tonne. The price of CO_2 should be rising with time in order to reflect this increase in the social costs of CO_2, (Yohe et al., 2007 p813) and (Stern, 2007 p232).

The social cost of CO_2 is increasing with time at the rate α, to account for the increasing damage costs over time.

$$C_{CO_2,t} = C_{CO_2,t_0} \cdot e^{\alpha(t-t_0)} \tag{1}$$

$C_{CO2,t}$ is the social cost of emitting CO_2 at time t (USD/tCO_2)

$C_{CO2,t0}$ is the social cost of emitting CO_2 at time t_0 (USD/tCO_2)

α is the rate of increase of the social cost of CO_2 with time t (per year)

The specific costs of CO_2 from bitumen production are calculated from the process unit emissions e as follows:

$$C^{CO_2}_{Bitumen,t} = C_{CO_2,t} \cdot e_{Bitumen,t} \tag{2}$$

$C^{CO_2}_{Bitumen,t}$ is the CO_2 cost associated with the production of one barrel of bitumen (USD/barrel)

$C_{CO2,t}$ is the social cost of emitting CO_2 at time t (USD/tCO_2)

$e_{Bitumen,t}$ is the CO_2 emissions to produce one barrel of bitumen (tCO_2/barrel)

Unit emissions are assumed to decline with cumulative emissions according to the following equation:

$$e_{Bitumen,t} = e_{\min} + (e_{Bitumen,t_0} - e_{\min}) \cdot \left(\frac{E_{Bitumen,t}}{E_{Bitumen,t_0}} \right)^{-b_e} \tag{3}$$

$e_{Bitumen,t}$ is the CO_2 emissions to produce one barrel of bitumen at time t (tCO_2/barrel)

$e_{Bitumen,t0}$ is the CO_2 emissions to produce one barrel of bitumen at time t_0 (tCO_2/barrel)

$E_{Bitumen,t}$ is the cumulative CO_2 emissions from bitumen production at time t (tCO_2)

$E_{Bitumen,t0}$ is the cumulative CO_2 emissions from bitumen production at time t_0 (tCO_2)
e_{min} is the minimum CO_2 emissions to produce one barrel of bitumen (tCO_2/barrel)
b_e is the learning coefficient (no unit)

The same equations apply to the CO_2 costs and emissions associated with upgrading bitumen into synthetic crude oil.

The parameters used in the model to define the social cost of CO_2 are exogenous, they don't depend on the pathway of emissions that results from the model. Hope (2006) shows that the social cost of CO_2 is independent of the path of emissions: this result might seem counter-intuitive at first, it is caused by "the interplay between the logarithmic relationship between forcing and concentration, the nonlinear relationship of damage to temperature, and discounting".

3.2 The cost of conventional oil

The structure of the cost model for conventional and non-conventional oil was first presented in (Méjean and Hope, 2008) and (Méjean and Hope, 2010), and is briefly described below. The long-term costs of producing conventional oil are assumed to be driven by depletion, learning and CO_2 emissions (equation 4).

$$C_{conv,t} = \underbrace{C_{conv,\min} + \left(C_{conv,t_0} - C_{conv,\min}\right) \cdot \left(\frac{X_{conv,t}}{X_{conv,t_0}}\right)^{-b_{conv}}}_{\text{learning}} + \underbrace{C_{conv,\max} \cdot \left(\frac{X_{conv,t}}{X_{conv,U}}\right)^{\gamma}}_{\text{depletion}} + \underbrace{e_{conv,t} \cdot C_{CO_2,t_0} \cdot e^{\alpha(t-t_0)}}_{CO_2} \quad (4)$$

$X_{conv,t}$ is the cumulative production at time t (barrels)
$C_{conv,t}$ is the cost at time t (USD/barrel)
$X_{conv,t0}$ is the cumulative production at time t_0 (barrels)
$C_{conv,t0}$ is the cost at time t_0 (USD/barrel)
$C_{conv,min}$ is the minimum cost of producing the resources (USD/barrel)
b_{conv} is the learning coefficient (no unit)
R_{conv} is the recovery factor (no unit)
Q_{conv} is the total oil in place (barrels)
$C_{conv,max}$ is the maximum cost of the depletion (USD/barrel)
γ is the exponent of the depletion curve (no unit)
$C_{CO2,t0}$ is the social cost of emitting CO_2 at time t_0 (USD/tonne CO_2)

α is the rate of increase of the social cost of CO_2 with time (per year)

$e_{conv,t}$ is the CO_2 emissions to produce one barrel of oil at t (tCO_2/barrel)

$X_{conv,U}$ is the ultimately recoverable resources (barrels) with $X_{conv,U}= R_{conv}* Q_{conv}$

3.3 Oil demand

Demand is assumed to be sensitive to price, through the price elasticity of oil demand. Demand also has an exogenous component independent of the oil price.

$$d_t = d_{t_0} \cdot \left(\frac{P_t}{P_{t_0}} \right)^{pe} \cdot e^{d(t-t_0)} \tag{5}$$

d_t is the oil demand at time t (barrels per day)

d_{t0} is the oil demand at time t_0 (barrels per day)

P_t is the price of oil at time t (USD/barrel)

P_{t0} is the price of oil at time t_0 (USD/barrel)

pe is the price elasticity of oil demand (no unit)

d is the growth rate of oil demand independent of the price of oil (% per year)

3.4 Oil price

It is assumed that the competitive price of oil at the time when conventional oil production is unable to meet demand ($P_{CONV,T}$) is the cost of producing synthetic crude oil from in-situ bitumen ($C_{SCO,T}$):

$$P_{CONV,T} = C_{SCO,T} \tag{6}$$

with $$C_{SCO,T} = \frac{C_{IS,t_0} + e_{IS} \cdot C_{C0_2,T}}{Y_U} + (C_{U,t_0} + e_U \cdot C_{C0_2,T}) \tag{7}$$

and $$C_{CO_2,T} = C_{CO_2,t_0} \cdot e^{\alpha(T-t_0)} \tag{8}$$

Y_U is the upgrading efficiency (barrel SCO per barrel bitumen)

$C_{IS,t0}$ is the cost of producing in-situ bitumen at time t_0 (USD/barrel bitumen)

$C_{U,t0}$ is the cost of upgrading bitumen into one barrel of SCO at time t_0 (USD/barrel SCO)

$C_{CO2,T}$ is the social cost of CO_2 at time T (USD/barrel SCO)

With a CO_2 tax on fuel use, the costs also include the emissions associated with burning the oil.

The assumption was made earlier that synthetic crude oil could not enter the market while conventional oil production could still satisfy the demand for oil. It follows that the cost of producing synthetic crude oil at time T is the cost of producing synthetic crude oil today plus the CO_2 costs of producing synthetic crude oil at time T. Also, no Hotelling rent is included in the cost of synthetic crude oil as that rent is not significant for the initial exploitation of very large fossil fuel resources, which is the case for non-conventional oil. The difference between the price and cost of conventional oil at T, discounted to the present time (also called the oil rent at time T discounted to the present time, defined as OR), is calculated as follows:

$$OR = \left(P_{CONV,T} - C_{CONV,T}\right) \cdot e^{-r \cdot T} \quad (9)$$

OR is the oil rent at time T discounted to the present time (USD/barrel)
$P_{CONV,T}$ is the price of conventional oil at time T (USD/barrel)
$C_{CONV,T}$ is the cost of conventional oil at time T (USD/barrel)
r is the consumption discount rate (% per year)
T is the time when conventional oil production is unable to meet demand

This equation translates Hotelling's rule (1931) that the oil rent should grow at a rate equal to the interest rate. The competitive price of oil at time t_0, $P_{CONV,t0}$, is then obtained from the oil rent:

$$P_{CONV,t_0} = C_{CONV,t_0} + OR \quad (10)$$

$P_{CONV,t0}$ is the price of conventional oil at time t_0 (USD/barrel)
$C_{CONV,t0}$ is the cost of conventional oil at time t_0 (USD/barrel)

The following equation summarises the calculation of the competitive price of oil at time t_0:

$$P_{CONV,t_0} = C_{CONV,t_0} + \left(C_{SCO,T} - C_{CONV,T}\right) \cdot e^{-r \cdot T} \quad (11)$$

4. Data: estimation of the parameters

4.1 Oil demand

4.1.1 Price elasticity of oil demand (pe)

The price elasticity of oil demand is "the responsiveness or sensitivity of oil demand to changes in price" (Cooper, 2003 p3). It is defined as the ratio between the percentage change in demand for oil and the percentage change in the price of oil:

$$pe = -\frac{P}{Q}\frac{dQ}{dP} \tag{12}$$

pe is the price elasticity of oil demand (no unit)
P is the price of oil (USD/barrel)
Q is the quantity of oil demanded (barrels)

The following table shows some estimates of the price elasticity of oil demand from seven studies, as reported in (Fattouh, 2007).

Study	Short run	Long run	Region	Period
Dahl, 1993	-0.05 to -0.09	-0.13 to 0.26	Developing countries	
Pesaran et al., 1998	-0.03	0 to -0.48	Asian countries	
Gately and Huntington, 2002	-0.05 -0.03	-0.64 -0.18 -0.12	OECD Non-OECD Fast growing non-OECD	1971-1997
Cooper, 2003	0.01 to -0.11	0.038 to -0.56	23 countries	1979-2000
Brook et al., 2004		-0.6 -0.2 -0.2	OECD China Rest of world	
Krichene, 2006	-0.02* to -0.03**	-0.03* to -0.08**	Various countries	*1984-2005 **1970-2005
Rehrl and Friedrich, 2006		-0.46***	World	

Adapted from (Fattouh, 2007, p10), except***

Table 1: Price elasticity of oil demand

The long-run price elasticity of oil is appropriate for this study. The range for the price elasticity of demand is chosen between 0 and -0.6. The lower bound of this range is above -1.0: as the demand for oil is increasingly driven by the demand for transport, it should become relatively less responsive to prices, as few substitutes are available (IEA, 2006). Oil demand is also driven by exogenous growth, independent from the response to oil prices.

4.1.2 Exogenous oil demand growth (d)

Oil demand is driven in the model by exogenous growth, independent from the response to oil prices. Some estimates of the overall demand growth for oil were found in (UKERC, 2009a). These estimates are listed in table 2.

Model	Oil demand growth	Type
IEA	1.3%/year 2008-2015 0.8%/year 2015-2030	Detailed demand modelling
OPEC	1.14%/year after 2012	Detailed demand modelling
EIA	1.16%	Detailed demand modelling
Shell	No growth after 2020 Decline after 2020	Detailed demand modelling
Meling (StatoilHydro)	1.6%/year	No detailed demand modelling
Total	1.4%/year	No detailed demand modelling
Exxon Mobil	1.4%/year	Detailed demand modelling
Energyfiles	1.8%/year	Demand not modelled, exogenous rate

Adapted from (UKERC, 2009a)

Table 2: Demand growth estimates found in the literature

The range used for the demand growth rate (d_{CONV}) is chosen to be between 1% and 2.5% per year.

4.2 Resources

4.2.1 Ultimate volume in place (Q)

A distinction must be made between the amount of oil physically occurring underground, and the amount of oil that will eventually be recovered from the deposits. The ultimate volume in place is defined as the amount of oil physically occurring underground before any extraction has taken place.
The IEA (2005b p25) estimates the conventional oil resources in place at 7 to 8 trillion barrels, of which 3.3 trillion barrels are considered ultimately recoverable.

4.2.2 Recovery factor (R)

The recovery factor is the percentage of the total oil in place in a deposit that can be recovered by a combination of primary, secondary and tertiary techniques (Grand Dictionnaire Terminologique, 2007). In this study, the ultimate recovery factor is the amount of oil or bitumen that could ultimately be produced as a percentage of the total amount of bitumen in place.

The estimates of the recovery factors available in the literature are closely linked to the performance of current technologies, and to current or anticipated economic conditions. Ideally this study should be conducted independently of these considerations, as it is very difficult to anticipate future technological breakthroughs and economic conditions. In Rogner's hydrocarbon resource assessment "the broadest possible dimensions were applied without immediate reference to recoverability", (1997 p220). Rogner points out the "difficulty of incorporating future development efforts, technology change, and uncertainty into reserve assessments" and argues for the inclusion of all hydrocarbon occurrences, as the "a priori exclusion of presently subeconomic or geologically uncertain occurrences would certainly underestimate the hydrocarbon occurrence potentially available to humankind", (1997 p236). Rogner thus adopts the highest plausible value for the occurrences of conventional oil resources, as his objective is to assess "the ultimately available resource base beyond short-term techno-economic recovery limitations" (1997 p253). Rogner (1997 p231) uses a recovery rate of 0.4 for conventional oil with enhanced oil recovery, while the IEA (2005a) estimates the recovery rate of conventional oil between 0.41 and 0.47. The recovery rate is chosen to lie between 0.35 (Rogner, 1997 p231) and 0.55.

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The model introduces a depletion cost component that is solely based on the growing physical difficulty of producing bitumen. The recovery factor used to determine the costs associated with the depletion of the resources should therefore be set at the highest possible value.

4.3 Conventional oil production

4.3.1 Initial production rate (x_{t0}) and initial cumulative production (X_{t0})

The initial production rate of conventional oil is derived from (EIA, 2009). The total world supply of oil in 2005 was estimated at about 84 million barrels per day (annual average), i.e. 3.07E+10 barrels per year. The IEA estimates that 1.0 trillion of the 7 to 8 trillions barrels of conventional oil in place had been produced in 2005, (2005a p25).

4.3.2 Maximum production rate (x_{MAX})

The range for the maximum production rate of conventional oil is derived from data collected in the 2009 UKERC report on global oil depletion, and summarised in table 3.

Source	Peak daily rate (Mb/d)	Forecasted peak	Reference
IEA 2008	97.6 in 2030 (excl. non-conventional oil)	"Conventional oil production levels off towards 2030"	IEA (2008 p251) UKERC (2009b p5)
EIA 2008	113.3 in 2030 (all oil) 99.3 in 2030 (conventional oil only)	No peak	UKERC (2009b p21)
OPEC 2009	95 in 2030 (reference case) (excl. non-conventional oil)	No peak	OPEC (2009 p61)
OPEC 2008	102 in 2030 (reference case) (excl. non-conventional oil)	No peak	OPEC (2008 p37)
OPEC 2008	121 in 2030 (demand) (demand, incl. non-conventional oil)	No peak	UKERC (2009b p51) OPEC (2008 p112)
Shell 2008	91.4 in 2030 (blueprint) (assumed moderate growth of unconventional oil and gas)	"By 2015, growth in the production of easily accessible oil and gas will not match the projected rate of demand growth."	UKERC (2009b p33)
ExxonMobil 2008	101 in 2030 (excl. non-conventional oil)	No peak before 2030	UKERC (2009b p51)

Table 3: Maximum production rate from various oil supply models

Two models (IEA 2008 and Shell 2008) acknowledge or predict a peak before 2030. Most of the estimates of the production rate in table 2.4 fall roughly into the range 90 – 100 million barrels per day, with the exception of one OPEC estimate: in its World Oil Outlook 2008, OPEC estimates that demand for oil could reach 121 million barrels per day in 2030, and argues that the resource base would be sufficient to meet demand in that scenario, assuming the necessary investments are made to support additional non-OPEC supply, including non-conventional oil. In its reference scenario, OPEC estimates the supply of non-conventional oil (non-OPEC) to reach about 11 million barrels per day in 2030, so the higher bound of the range for the maximum conventional oil production rate is thus chosen as 110 million barrels per day, and the range is set at 91 – 110 million barrels per day.

This higher estimate for the conventional oil maximum production rate is included in the range, as the model aims at reflecting the absolute maximum production rate that could possibly be reached.

4.3.3 Decline rate (α_{CONV})

The post-peak production decline rate parameter, i.e. the decline rate in conventional oil production after the maximum production rate has been reached, is derived from estimates gathered in (UKERC, 2009a p150-151). The decline rate is here defined as the overall decline rate, which is associated to all fields, including the fields that haven't passed their peak (this is in contrast to the post-peak decline rate which only refers to the fields where production is declining), (UKERC, 2009c p4). This decline rate is the production-weighted aggregate decline rate of all fields, including post-peak fields, fields that are showing a plateau and fields that are still in the phase of build-up. Data gathered by UKERC shows aggregate post peak decline between 0.2% and 4.0% per year. The range is chosen to be between 0.0% and 4.0% per year, to allow for the possibility of a plateau.

4.4 Depletion

The estimates of the depletion parameters are obtained using the method described in (Méjean and Hope, 2008). Estimates from Attanasi (used in the SAUNER project), Rogner and Nordhaus and Boyer are used to determine the depletion parameters' ranges. The incremental cost function from which some of these estimates are derived expresses ''the quantity of resources that the industry is capable of adding to proved reserves or cumulative production'' as a function of long-term marginal costs (Attanasi, 1995, p2). These curves assume no subsequent cost reductions through technology learning (IEA, 2005b). The European SAUNER project uses Attanasi's estimates to produce world oil supply cost curves for various categories of oil, including oil sands.

Rogner (1997) also produced similar aggregate quantity–cost curves for global oil resources.

C_{max} is the maximum cost of oil, i.e. the cost of producing the last barrel of oil (assuming no technological change), and γ is the exponent of the depletion curve. The resulting estimates for γ and C_{max} are summarised in table 4.

Source	SAUNER 2000	Rogner 1997 p254	Nordhaus and Boyer 1999 p40
Category	Conventional oil	Global oil resources (conventional)	Carbon fuels
γ (no unit)	1.41	1.04	4
C_{max} (2005)USD/barrel	60[a]	86[b]	121[c]

[a]50(1998)USD; [b]58 (1990)USD; [c]81 (1990)USD.

Table 4: Literature estimates for depletion parameters

Rogner values all resource categories are as if "all future productivity gains were realized immediately" (p253). In his analysis, "a productivity gain in the upstream sector of 1% per year is assumed (...) a resource that presently commands production costs of, for example, \$40 per barrel of oil equivalent (boe) would, over a period of 50 years, drop gradually to \$24", (Rogner, 1997 p251).

The high end of the conventional oil spectrum is 35 (1990) USD/barrel (including EOR). Taking out the 1% per year productivity gains, this is equivalent to 58 (1990) USD/barrel, or 86 (2005) USD/barrel (Rogner, 1997 p254). The highest conventional oil production costs are 50 (1998) USD/barrel, (SAUNER, 2000), or 60 (2005) USD/barrel. The estimate of the maximum cost of oil from SAUNER is considered too low for the cost of producing the last barrel of conventional oil, as some conventional oil production costs are already approaching this value, and the lower bound of the range is chosen as 86 USD/barrel.

The maximum depletion cost parameters are chosen between 60 and 86 USD/barrel for conventional oil production. The depletion exponent is chosen between 1 and 4.

4.5 Costs and learning

4.5.1 Initial costs (C_{t0})

a. Bitumen and synthetic crude oil

Table 5 summarises the operating and supply costs of bitumen recovered using cold production, various in-situ techniques and surface mining. Upgrading costs are also included.

USD(2005) per barrel at the plant gate	Output	Operating costs	Supply costs	Source
In-situ (cold production)				
Wabasca, Seal	bitumen	5 - 7	12 – 15	NEB, 2006
Wabaka	bitumen	3.5 – 7.5	8.5 – 12	Cliffe, 2002
CHOPS - Cold Lake	bitumen	7 – 8	13 – 16	NEB, 2006
Cold Lake	bitumen	7 – 11	12 – 16	Cliffe, 2002
In-situ (thermal)	bitumen			
Cyclic Steam Stimulation (CSS)	bitumen	8 – 12	17 – 20	NEB, 2006
CSS	bitumen	7 – 12	12 – 19	Cliffe, 2002
CSS	bitumen	6 – 10	10 – 15	IEA, 2002
CSS	SCO	4.5 – 7.5		NRCan, 2003
Steam Assisted Gravity Drainage (SAGD)	bitumen	8 – 12	15 – 18	NEB, 2006
SAGD	bitumen	6 – 11	10 – 17	Cliffe, 2002
SAGD	bitumen	5 – 9	7 – 13	IEA, 2002
SAGD	SCO	3.5 – 7		NRCan, 2003
Upgrading				
Stand-alone upgrader	SCO	12 – 15	22 – 27	Cliffe, 2002

Sources: (Cliffe, 2002) and (IEA, 2002) are adapted from (Greene et al., 2005); (NEB, 2006)

Table 5: Literature estimates for initial costs

It should be noted that the model does not include a parameter that reflects the losses occurring at the extraction stage. Bitumen is extracted from the mined oil sands before it is sent to the upgrader to be transformed into synthetic crude oil. These losses currently come close to about 10 to 13% of the initial amount of bitumen occurring in the mined oil sands (Alberta Chamber of Resources, 2004 p20). These losses have an impact on the bitumen production rate and the unit costs of producing bitumen. In fact, these losses are already included in the model, but in an implicit way. The estimates used to construct the ranges for the initial costs are found in the literature in dollars per barrel of bitumen, not in dollars per barrel of oil sand. These costs therefore already account for the losses occurring at the extraction stage. Similarly, the estimates obtained for future production rates are found in barrels of bitumen, and not in barrels of mined oil sands. Also, the estimation of the minimum mining costs (C_{min}) takes these losses into account.

On average, two tonnes of oil sands are needed to produce one barrel of synthetic crude oil, (Centre for Energy, 2007). Oil sands contain about 10% bitumen (Government of Alberta, 2006) (the rest is sand, clay and water) and the density of bitumen is between 5.8 and 6.4 barrels per tonne, giving an upgrading efficiency Y_U between 0.78 and 0.86 barrel of synthetic crude oil per barrel of bitumen.

b. Conventional oil

The initial conventional oil production costs $C_{CONV,t0}$ are derived from the estimates of upstream costs of oil by region in 2005 USD/barrel (EIA, 2007) shown in table 6.

Region	Upstream costs (2005 USD per barrel)	
	2004-2006	2005-2007
US	23	26
Canada	26	20
Europe	30	38
Africa	32	44
Middle East	14	14
Other Eastern Hemisphere	19	27
Other Western Hemisphere	47	34
Total, excluding US	26	28
Worldwide	24	26

Upstream costs are finding costs plus lifting costs.

1.000 (2005) USD = 1.044 (2007) USD

Table 6: Upstream costs by region for FRS companies

It appears that the offshore US and Africa were the regions with the highest upstream costs in the period 2005 to 2007. The highest estimates are used here for the initial marginal cost parameter, as other producing regions with lower costs will be able to obtain oil rents. The initial marginal cost of producing a barrel of conventional oil is chosen to lie between 34 and 44 (2005) USD.

The ranges shown in table 7 are assigned to the initial costs of producing bitumen using mining and in-situ techniques, to the initial upgrading costs and to the initial cost of producing conventional oil. These costs don't include CO_2 costs associated with fuel production and use.

C_{t0}, 2005 USD/barrel	Minimum	Most likely	Maximum
Bitumen (in-situ)	7	14	20
Bitumen (upgrading only)	22	25	27
Conventional oil	34	39	44

Table 7: Initial costs – summary

4.5.2 Learning rate (LR)

The learning rate associated with crude oil at the well is estimated at 0.05 by (Fisher 1974) in (McDonald and Schrattenholzer, 2001 p258). The learning rate associated with oil extraction in the North Sea is estimated at 0.25 by (Blackwood, 1997) in (Köhler et al., 2006 p32). The following range is thus associated with the learning rate for conventional oil production: 0.05 - 0.25.

4.5.3 Minimum costs (C_{min})

A way to capture the theoretical and technical limitations mentioned earlier is through the parameter C_{min}, the minimum costs of supplying bitumen. There is little information about what the minimum costs of supplying oil from non-conventional deposits will be in the future, as potential cost reductions are underestimated most of the time, (Anderson, 2005).

Upstream costs for conventional oil production remained in the 10-35 USD/barrel range between 1980 and 2005, (EIA, 2007). Although upstream costs in the Middle-East can be as low as 5 USD/barrel (Maurice 2001 in (OECD, no date)), the model is focusing on the marginal cost of producing oil, and C_{min} is defined as the minimum marginal oil cost, independent of depletion effects. The minimum costs C_{min} from conventional oil are taken to be between 10 and 30 USD/barrel.

4.6 CO_2 emissions

4.6.1 Initial unit emissions (e_{t0})

a. Bitumen and synthetic crude oil

The literature estimates for unit CO_2 emissions for mining recovery, in-situ recovery and upgrading are summarised in table 8.

Type of process	Initial unit emissions tCO_2/barrel	Source
In-situ	0.06	Alberta Chamber of Resources, 2004 p62
In-situ	0.081	CAPP, 2004 p30
In-situ	0.07 – 0.085	LENEF and T.J.McCann & Associates in (Alberta Chamber of Resources, 2004 p62)
In-situ (SAGD)	0.065 – 0.115	Cupcic, 2003 p24
Upgrading	0.075 – 0.09	LENEF and T.J.McCann & Associates in (Alberta Chamber of Resources, 2004 p62)
Upgrading	0.038	Cupcic, 2003 p24
Light/medium crude	0.022 (0.18tCO_2/m^3)*	CAPP, 2004 p30

*1 barrel = 0.12 m^3

Table 8: Literature estimates for unit emissions

CO_2 emissions are expected to increase when natural gas is replaced by residues to produce steam for recovery and hydrogen for upgrading. Flint provides some estimates for CO_2 emissions per barrel of synthetic crude oil produced, shown in table 9.

Emissions (tCO_2/barrel SCO)	In-situ (SAGD) + upgrading		Mining + upgrading	
Process	Natural gas	Residue	Natural gas	Residue
Total recovery only (tCO_2/barrel bitumen)	0.049-0.054	0.077-0.086	0.027-0.030	0.037-0.041
Total upgrading only	0.045	0.085	0.045	0.085

Table 9: Comparison between natural gas and residue fuelled upgrading processes

CO_2 emissions from direct land-use change should also be taken into account. Direct land-use change emissions from oil sand and conventional oil production are summarised in table 10, adapted from (Yeh et al., 2010).

Product	**SCO (mining)**	**SCO (in-situ)**
CO_2 emissions		
Carbon in soil (% released) (tC/ha)	438 (70-90%)	438 (20-40%)
Carbon in vegetation (tC/ha)	78	78
Emissions from tailing ponds (tCH_4/ha/yr)	0-44	
Total (tCO_2/ha)	1410-2655	607-924
Land-use intensity		
Extraction (m^2/m^3SCO)	0.33-0.63	0.070-0.16
Upgrading (m^2/m^3SCO)	0.0075-0.023	0.0075-0.023
Natural gas (extraction and upgrading)	0.03-0.11	0.070-0.26
Total (m^2/m^3SCO)	0.37-0.76	0.15-0.44
Total (ha/barrel SCO)	4.4-9.2E-06	1.8-5.3E-06
CO_2 intensity (tCO_2/barrel SCO)	0.006 – 0.024	0.001-0.005

1 barrel = 0.12 m^3, Global warming potential of CH_4: 1 tCH_4 = 21 tCO_{2eq}

Table 10: Direct land-use emissions from oil sand production

The former land cover of the land area used for synthetic crude oil (SCO) production is assumed to be 23% peatland and 77% boreal forests (Yeh et al., 2010). Yeh et al. consider the production of SCO from mining and in situ recovery as "marginal as the technologies are relatively new", (pS12). The CO_2 emissions from land-use change are very small compared to the unit emissions associated with synthetic crude oil production.

b. Conventional oil

The initial CO_2 emissions ($e_{CONV,t0}$) associated with conventional oil production are derived from the estimates of upstream greenhouse gas emissions from ExxonMobil and CAPP (Canadian Association of Petroleum Producers) are summarised in table 11.

Year	tCO_{2eq}/boe	Source
2004	0.029	Exxon-Mobil, 2009
2005	0.029	Exxon-Mobil, 2009
2006	0.031	Exxon-Mobil, 2009
2007	0.029	Exxon-Mobil, 2009
2004	0.022	CAPP, 2004 p30

1.0 toe = 7.3 boe; 1 barrel = 0.12 m^3

Table 11: Greenhouse gas emissions from the production of conventional crude oil

The range of CO_2 equivalent emissions associated with the production of one barrel of conventional crude oil is chosen as 0.022 - 0.029 tCO_2. As a comparison, the CO_2 emissions associated with the production of synthetic crude oil from in-situ bitumen are estimated between 0.092 and 0.160 tCO_2 per barrel of synthetic crude oil. The following table summarises some estimates, as reported in (Méjean and Hope, 2010). These estimates only account for the production processes of the fuels, and exclude LUC emissions and the CO_2 emissions from burning the oil.

Step/output	Minimum	Maximum	Unit
In-situ bitumen	0.049	0.115	tCO_{2eq}/barrel
In-situ synthetic crude	0.067	0.108	tCO_{2eq}/barrel
Conventional crude oil	0.022	0.029	tCO_{2eq}/barrel
Upgrading (SCO)	0.038	0.090	tCO_{2eq}/barrel SCO

Table 12: CO_2 emissions associated with the production of oil

4.7 The social cost of CO_2

Equation 13 shows the calculation of the consumption discount rate r.

$$r = ptp + EMUC \cdot \left(GDP_{growth} - POP_{growth}\right) \tag{13}$$

r is the consumption discount rate (% per year)

EMUC is the elasticity of marginal utility of consumption (no unit)

ptp is the pure time preference rate (% per year)

GDP_{growth} is the growth of GDP (% per year)

POP_{growth} is the growth of population (% per year)

Stern (2007) locates the lower bound of the pure time preference rate as low as 0.1% per year. The ranges used in PAGE2002 (Hope, 2008b) for the four parameters above are summarised in table 13. These estimates are used to calculate the consumption discount rate.

Parameter	Minimum	Most likely	Maximum	Unit
EMUC (absolute value)	0.5	1.0	2.0	%
ptp (pure time preference rate)	0.1	1	2	% per year
Growth of GDP per capita (EU, US, OT)	1.7	1.8	1.9	% per year
Growth of population (EU, US, OT)	0.1	0.5	0.8	% per year

Table 13: Ranges used in PAGE2002 to calculate the consumption discount rate

Finally, the range of the consumption discount rate (r) used in the model is chosen as 0.9 - 4.2%.

The following range for the social costs of CO_2 in 2008 is obtained from PAGE2002 with Stern review assumption: 25 – 300 (2000) USD/tCO_2 (Hope, 2008a p20). The social cost of CO_2 is assumed to grow at a rate of about 2 to 3% per year in real terms (Hope, 2008a p19). It should be noted that the social cost of CO_2 increases at a slightly different rate than the discount rate. The social cost of CO_2 at year 0 (2005) is estimated at about 23 to 283 (2000) USD/tCO_2, i.e. 26 - 3222 (2005) USD/tCO_2.

4.8 Summary

Table 14 summarises the ranges that are assigned to conventional and non-conventional oil parameter in the model.

Parameters	Minimum	Most likely	Maximum	Standard deviation	Unit
Synthetic crude oil initial cost					
Upgrading efficiency *(Y_U)*	0.78	0.82	0.86	0.02	no unit
Initial in-situ costs *($C_{IS,t0}$)*	7	14	21	2.9	USD/barrel
Initial upgrading costs *($C_{U,t0}$)*	22	25	27	1.0	USD/barrel
Synthetic crude oil CO_2 emissions					
Initial CO_2 costs *($C_{CO2,t0}$)*	26	85	322	64	USD/tCO_2
CO_2 costs growth rate *(α)*	0.02	0.025	0.03	0.00	per year
In-situ initial emissions *($e_{M,t0}$)*	0.049	0.038	0.115	0.02	tCO_2/barrel
Upgrading initial emissions *($e_{U,t0}$)*	0.038	0.064	0.09	0.01	tCO_2/barrel SCO
Conventional oil resources					
Resources in place (Q_{conv})	7.0E+12	7.5E+12	8.0E+12	2.0E+11	barrels
Recovery rate (R_{conv})	0.35	0.43	0.50	0.04	no unit
Conventional oil demand and production					
Oil demand growth rate (d)	1.0	1.8	2.5	0.4	% per year
Initial demand (d_{t0})	3.00E+10	3.05E+10	3.10E+10	2.04E+08	barrels/year

[2] with 1 (2000)USD = 1.138 (2005)USD

Price elasticity of demand (*pe*)	-0.6	-0.3	0	0.12	no unit
Maximum production rate ($x_{conv,max}$)	3.32E+10	3.67E+10	4.02E+10	1.42E+09	barrels/year
Decline rate ($\alpha_{decline}$)	0.0	2.0	4.0	0.8	% per year
Initial cumulative production ($X_{conv,t0}$)	1.0E+12	1.0E+12	1.0E+12	0.0E+12	barrels
Conventional oil depletion costs					
Maximum depletion costs ($C_{conv,max}$)	60	73	86	7.14	USD/barrel
Depletion exponent (γ)	1	2.5	4	0.6	no unit
Conventional oil learning					
Initial costs ($C_{conv,t0}$)	34	39	44	2.04	USD/barrel
Learning rate (LR_{conv})	0.05	0.15	0.25	0.004	no unit
Minimum costs ($C_{conv,min}$)	10	20	30	4.08	USD/barrel
Conventional oil CO_2 emissions					
Initial emissions ($e_{conv,t0}$)	0.022	0.026	0.029	0.0014	tCO_2/barrel
Other					
Consumption discount rate (r)	0.9	2.6	4.2	0.7	% per year

Table 14: Parameters ranges - Conventional and non-conventional oil

5. Results: The impact of CO_2 pricing on conventional and non-conventional oil supply

The impact of a CO_2 tax on oil demand and on the time when conventional supply alone is unable to meet demand is examined. Two cases are considered. In the first case, a CO_2 tax is applied to emissions occurring when producing conventional and non-conventional crude oil, while the second case also includes CO_2 costs associated with fuel end-use.

5.1 The impact of a CO_2 tax on fuel demand

A tax on CO_2 emissions would depress oil demand, which would in turn result in lower oil prices than intended with the addition of the tax and drive up oil demand. Two countervailing effects of demand reducing measures on the production of fossil fuels were identified by Sinn (2007 p19): these measures could either reduce the incentive to extract fossil fuels, as they would depress today's oil prices, or increase the incentive to extract, as the anticipated decline in demand and price would reduce the opportunity cost of the resource in-situ. The model presented here is used to study the impact of a CO_2 tax on fuel use on oil demand in a Hotelling framework.

Figure 4 shows the evolution of the modelled oil prices over time, with and without a tax on CO_2 fuel use. The average WTI spot prices between 2005 and 2009, presented in red dots as a reference, fall roughly within the range of modelled competitive oil prices without a tax on CO_2.

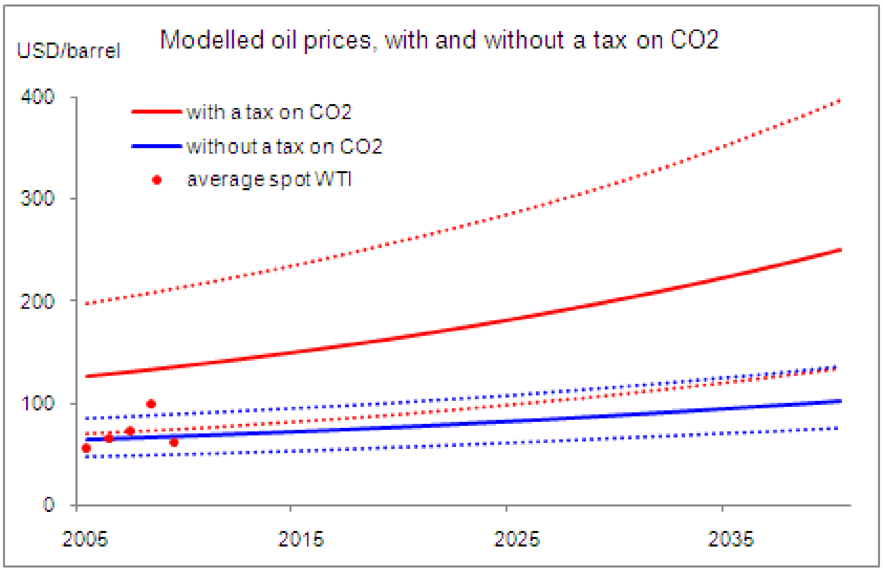

Figure 4: Oil prices with and without a tax on CO_2 associated with fuel use

Higher oil prices are expected to reduce demand. Figure 5 shows the evolution of demand for oil over time with and without the introduction of a CO_2 tax on fuel use.

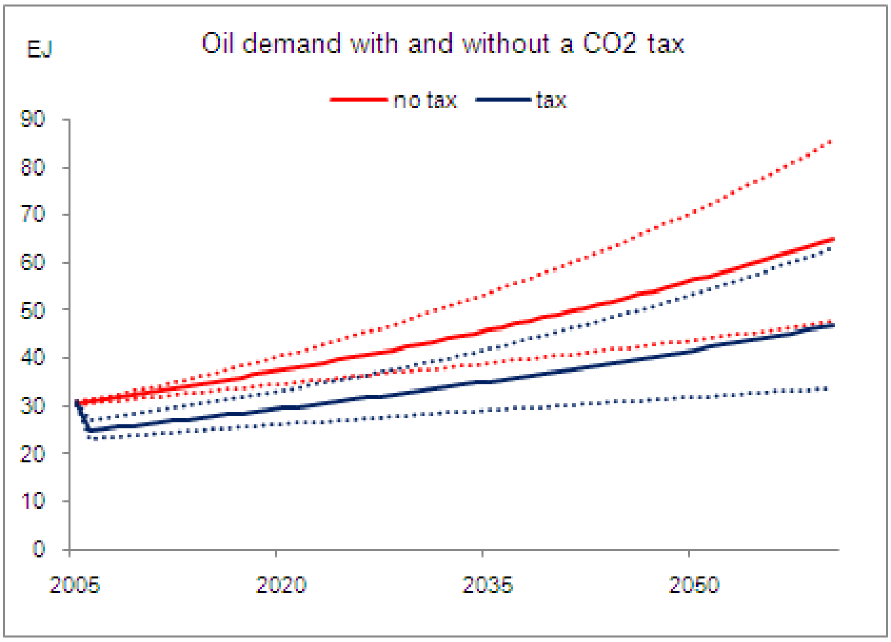

Figure 5: Oil demand, with and without a CO_2 tax on fuel end-use

The results show the mean and 90% confidence interval of demand without a tax on CO_2 emitted by fuel end-use in blue, and demand with a tax on CO_2 emitted by fuel end-use in red. The detailed simulation data shows that demand for oil is always higher without a CO_2 tax than with a CO_2 tax. The results show that a tax on CO_2 would reduce demand and extraction, despite the effect of the reduced rent.

5.2 Is the CO_2 tax carried over into the final price?

In order to estimate the amount of CO_2 tax which is carried over into the final oil price, we look at the difference between the initial price with a tax and the initial price without a tax, divided by the CO_2 cost associated with burning the fuel at the first year of analysis.

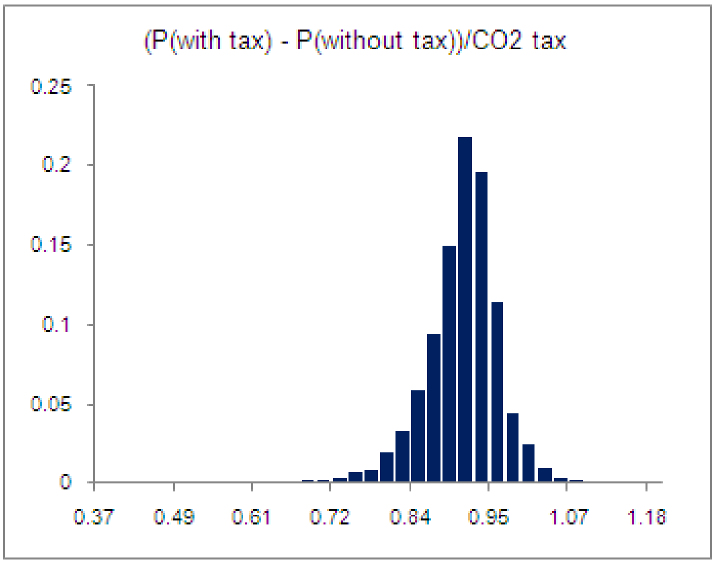

Figure 6: Difference between the price with tax and the price without tax, divided by the CO_2 tax

The ratio presented in figure 6 has a mean value of 0.91, with a 90% confidence interval between 0.81 and 0.99. This result means that between 81 and 99% of the CO_2 tax is carried in the oil price, despite the effect of the lower rent on the price due to reduced demand[3]. From these results it can be concluded that demand-reducing measures will be largely effective despite the smaller scarcity rent.

[3] There is a possibility that that ratio is greater than one, although this occurs in few cases (less than 5% of the runs). This occurs when the rent in the scenario with a tax is higher than the rent in the scenario without a tax, although the time of switch with a tax is later than the time of switch without a tax (cf. calculation in the appendix).

5.3 Time when conventional supply is unable to meet demand

5.3.1 T with no CO_2 tax on fuel end-use

a. Probability distribution

Figure 7 shows the probability distribution of the time when conventional oil production is unable to meet demand. This time corresponds to the entry of non-conventional oil production on the oil market.

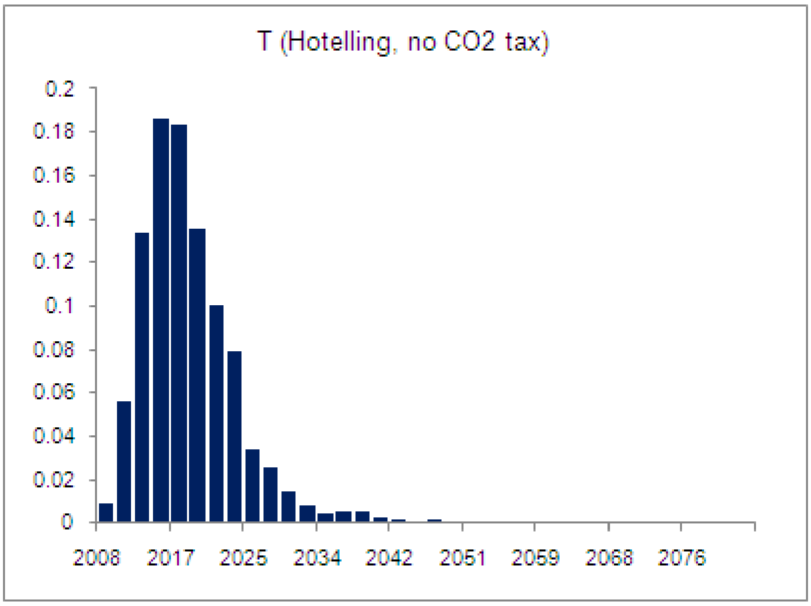

Figure 7: Time T with no CO_2 tax on use - probability distribution

The results show a 90% chance that conventional oil production will be unable to meet oil demand between 2012 and 2030, with a mean value of 2019. This result is in accordance with Shell estimates (2008), according to which the production of easy oil and gas will fail to match demand by 2015. UKERC (2009a) gathered estimates the date of the peak oil (i.e. the date when the world oil production rate would start to decline) ranging from 2006 to 2030. The model shows a different result, i.e. the date when conventional oil production alone is unable to meet demand rather than the date of the peak oil, but the results presented above seem to be in accordance with UKERC estimates. The long tail of the distribution to 2070 is explained by the fact that there is a constraint on the total amount of conventional oil that can be produced, defined from the ultimate volume of conventional oil in place and the recovery factor. The oil supply can follow two paths. In most cases, demand is not too sensitive to prices and increases, so production fails to meet demand when the production rate reaches its maximum value or peak. In a small minority of cases, demand is relatively sensitive to prices, and decreases or remains constant. This effect, combined with a high value of the maximum oil production rate, results in the time when conventional oil production is unable to meet demand only occurring when conventional oil is depleted in a few runs[4].

b. Sensitivity analysis: influences of the main parameters

Figure 8 shows the influences of the main parameters (regression mapped values) on the time when conventional oil production is unable to meet demand. Only the most influential parameters are presented.

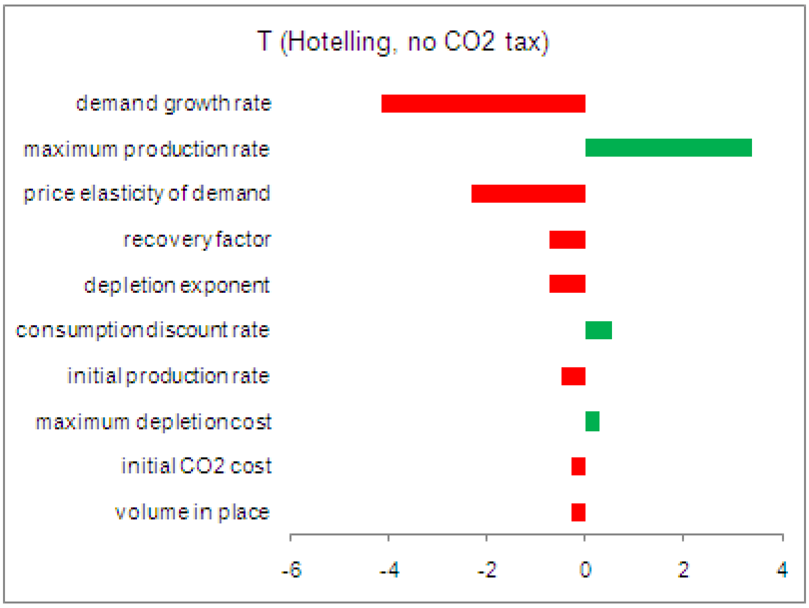

Figure 8: Influences of main parameters - Time T with no CO_2 tax on fuel use

The results show that the demand growth rate, the maximum production rate and the price elasticity of oil demand are the most influential parameters. A higher demand

[4] Some tests were performed to check the consistency of the results. When using a higher price elasticity of oil demand (in absolute values), the resulting probability distribution shows two peaks, one corresponding to the production peak, and the other to the depletion of conventional oil.

growth rate and a lower maximum production rate imply that T will happen sooner. As the range for the price elasticity parameter is negative, a higher value means a smaller elasticity in absolute values. A lower elasticity in absolute values implies that demand is relatively not sensitive to prices and is mainly driven by the demand growth parameter. Although oil demand is not very responsive to prices, the production constraint on conventional oil production is such that the price elasticity still has a significant impact on the time when conventional oil production alone is unable to satisfy demand compared to other parameters: an increase (in absolute values) of one standard deviation (0.12 units) of the price elasticity of demand would delay the date T by over two years.

5.3.2. T with a CO_2 tax on fuel end-use

a. Probability distribution

Figure 9 shows the probability distribution of the date T when conventional oil supply alone might become unable to satisfy demand, when a CO_2 tax is imposed on emissions associated with fuel production and use.

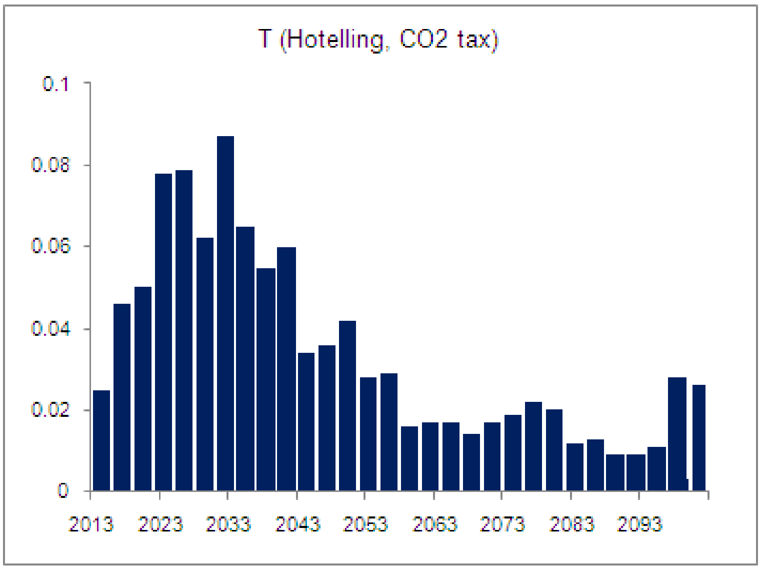

Figure 9: Time T with a CO_2 tax on use - probability distribution

The CO_2 tax on fuel use delays the time when conventional oil production is unable to meet oil demand from 2019 (cf. figure 7) to 2044 (mean value). With a CO_2 tax on use, the results show a 90% chance that conventional oil production will be unable to meet oil demand between 2018 and 2090. The spike at the right of the graph corresponds to the few cases where time T occurs after 2100.

b. Sensitivity analysis: influences of the main parameters

Figure 10 shows the influences of the main parameters (regression mapped values) on the time when conventional oil production is unable to meet demand, when a CO_2 tax on fuel use is included.

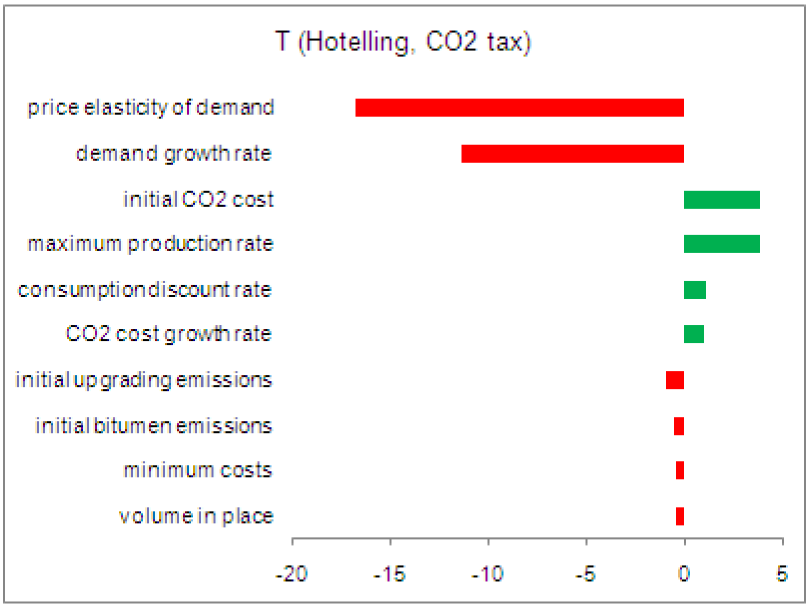

Figure 10: Influences of main parameters - Time T with a CO_2 tax on use

The most influential parameter is the price elasticity of demand, although this parameter was only in third position without the CO_2 tax on fuel use (cf. figure 8): The tax on CO_2 emissions from fuel use drives up the oil price, and thus causes the price elasticity of demand to have a larger influence on demand than in the low price scenario. The results show that an increase (in absolute values) of one standard deviation, or 0.12 units, of the price elasticity of demand would delay the date when conventional oil production alone is unable to meet demand by over 15 years. Also, a reduction of the demand growth rate of 0.4% per year would delay that date by over 10 years. These results show the great potential of demand-side measures to smooth the transition to low-carbon liquid fuels alternatives.

The third most influential parameter is the initial social cost of CO_2. The time when conventional oil production is unable to meet demand is closely linked to demand, which is mainly driven by oil prices. A higher initial CO_2 cost drives up the oil rent, which in turn induces higher oil prices. Demand is pushed down by higher oil prices, and lower demand postpones the time when conventional oil production is insufficient, hence the positive sensitivity. Finally, a higher consumption discount rate means a lower initial price of oil, but higher prices in general, therefore lower demand. Lower demand will thus induce time T to occur at a later date.

Some questions have been raised concerning the relevance of the Hotelling rule as the basis for the formation of oil prices. A simple experiment assesses the effect of the choice of the pricing rule on the results, two models are compared: one model assuming the Hotelling rule and the other assuming marginal cost pricing, i.e. the oil price is set to be equal to the marginal costs of producing conventional oil. The results, presented in the appendix, show that the pricing rule has little effect on the time when conventional oil production alone is unable to meet demand as oil demand is not very sensitive to prices. However, the inclusion of a CO_2 tax on fuel end-use has a significant impact on that results, pushing the date from 2019 to 2044 (mean values).

6. Conclusion

A tax on CO_2 emissions associated with fuel use would reduce demand and delay the time when conventional oil supply is unable to satisfy demand.

The analysis shows that despite the effect of the lower rent on the price, a CO_2 tax on fuel use would reduce demand for oil: between 81% and 99% of the CO_2 tax would be added to the oil price. The oil price minus the CO_2 tax would thus fall by 1% to 19% compared to the case without a CO_2 tax. This means that without a global tax on CO_2, countries that remain outside an international agreement to abate CO_2 emissions would benefit from slightly lower oil prices than without the tax, as Newbery points out (2010). Oil prices seen by countries that remain outside the international agreement would be 1 to 19%

lower than without the tax. However, a CO_2 tax enforced worldwide would still reduce oil demand and production, hence CO_2 emissions from oil production and use.

With a CO_2 tax on fuel production and not on fuel use, conventional oil supply alone is expected to be unable to match oil demand between 2012 and 2030 (90% confidence interval), with a mean value of 2019. A CO_2 tax on fuel use set at the social cost of CO_2 would delay the time when conventional oil production is unable to meet oil demand from 2019 to 2044 (mean value). With a CO_2 tax on use, the results show a 90% chance that conventional oil supply alone will be unable to meet demand between 2018 and 2090. The results show that this date is very sensitive to the price elasticity of demand and the demand growth rate: these results show the great potential of demand-side measures to smooth the transition to low-carbon liquid fuel alternatives. Further work will assess the impact of a tax on CO_2 emissions associated with fuel use and production on CO_2 emission pathways and damages.

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8. Appendix

8.1 Difference in the oil price with and without a CO_2 tax

The initial rent is the discounted difference between the costs of synthetic crude oil and conventional oil. The difference between the costs of synthetic crude oil and conventional oil is larger at a later date, as it is mainly driven by CO_2 costs associated with the production of both fuels, and synthetic crude oil production is more CO_2 intensive than conventional oil production. However, in most cases, the discounting terms dominate and the following equation is verified.

$$\left(C_{SCO}(T_{tax}) - C_{CONV}(T_{tax})\right) \cdot e^{-cdr \cdot T_{tax}} > \left(C_{SCO}(T_{no\ tax}) - C_{CONV}(T_{no\ tax})\right) \cdot e^{-cdr \cdot T_{no\ tax}} \qquad (14)$$

The ratio is greater than one when the difference in rents at time T_{tax} and $T_{no\ tax}$ dominates the discounting term.

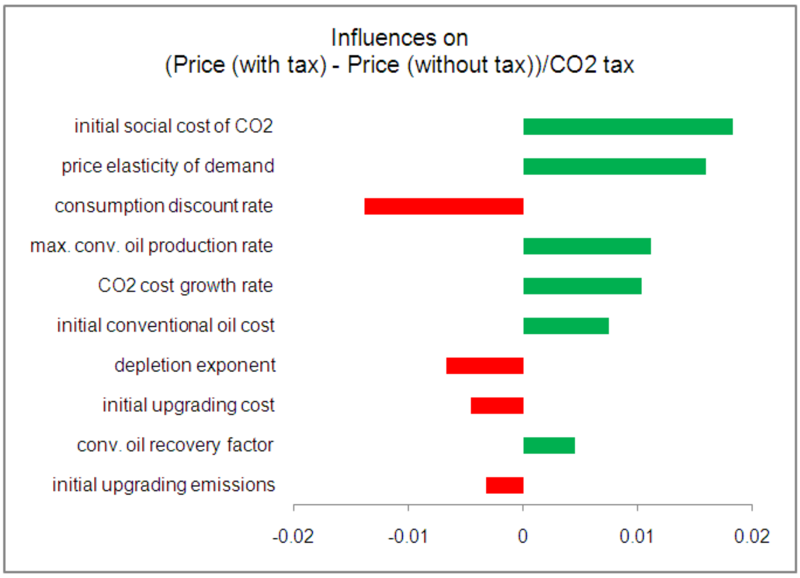

Figure 11: Influences on the difference between the price (with tax) and the price (without tax) divided by the CO_2 tax

8.2 The impact of using prices based on Hotelling v. marginal cost pricing

This section examines the impact of the principle chosen for the formation of oil prices, and more precisely the importance of the Hotelling assumption. Two models are set up using the same uncertain parameters, one assuming the Hotelling rule as the basis for the formation of oil prices (that assumption was used in all the results presented in this paper so far), and the other assuming marginal cost pricing, i.e. the oil price is set to be equal to the marginal cots of producing conventional oil. Figure 12 shows the difference in T between both cases, assuming no CO_2 tax on fuel end-use.

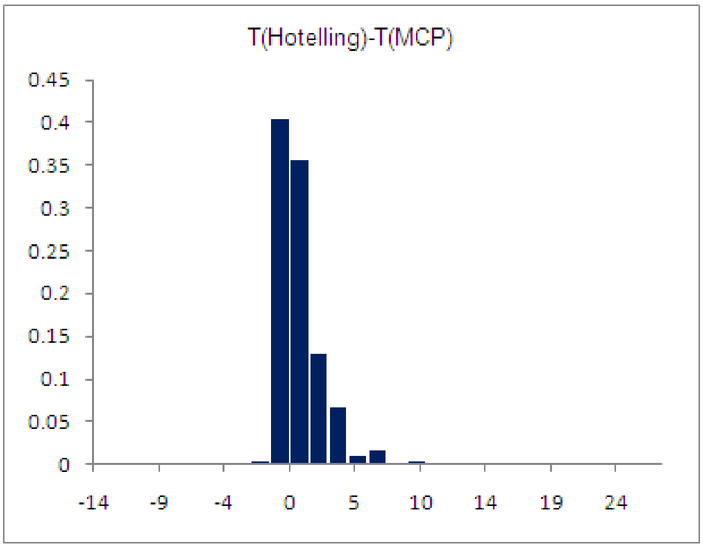

Figure 12: Difference in the time of switch between Hotelling and marginal cost pricing

The difference is quite small, with a mean of 1.1 years and a 90% confidence interval between 0 and 4 years. The small difference between the results obtained by using both methodologies could be explained by the fact that the price elasticity of demand is quite small, therefore the difference between the marginal cost and the Hotelling price has little effect of the final demand, and therefore on the time when conventional oil production alone is unable to meet demand. Figure 13 shows the influences of the main parameters (regression mapped values) on the time difference between Hotelling and marginal cost pricing (standard deviation: 2.4 years).

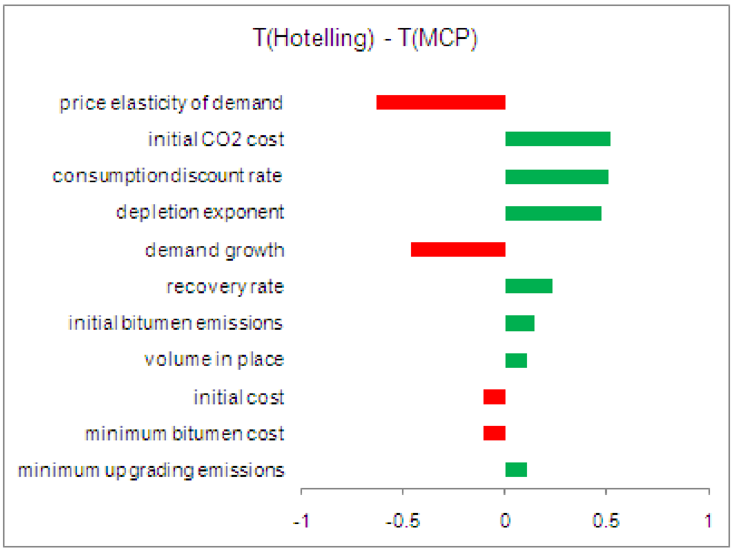

Figure 13: Influences on the difference in the time of switch between Hotelling and marginal cost pricing

As expected, the most influential parameter on the result is the price elasticity of demand. A lower elasticity in absolute values (i.e. a higher elasticity) reduces the difference between the results.