Modelling the costs of non-conventional oil: A case study of Canadian bitumen.

Aurélie Méjean*, Chris Hope

Judge Business School, Trumpington Street, Cambridge, CB2 1AG, UK.

Abstract

High crude oil prices, uncertainties about the consequences of climate change and the eventual decline of conventional oil production raise the issue of alternative fuels, such as non-conventional oil and biofuels. This paper describes a simple probabilistic model of the costs of non-conventional oil, including the role of learning-by-doing in driving down costs. This forward-looking analysis quantifies the effects of both learning and production constraints on the costs of supplying alternative fuels. The results show large uncertainties in the future costs of supplying synthetic crude oil from bitumen deposits, with a 90% confidence interval of $7 to $11 in 2025, and $6 to $13 in 2050. The influence of each parameter on the supply costs is examined, with the minimum supply cost, the learning rate, and the depletion curve exponent having the largest influence. Over time, the influence of the learning rate on the supply costs decreases, while the influence of the depletion curve exponent increases.

Keywords: Climate change; Non-conventional oil; Exhaustible resources; Technological change; Uncertainty.

JEL Classification: C15, Q55, Q42, Q32

---

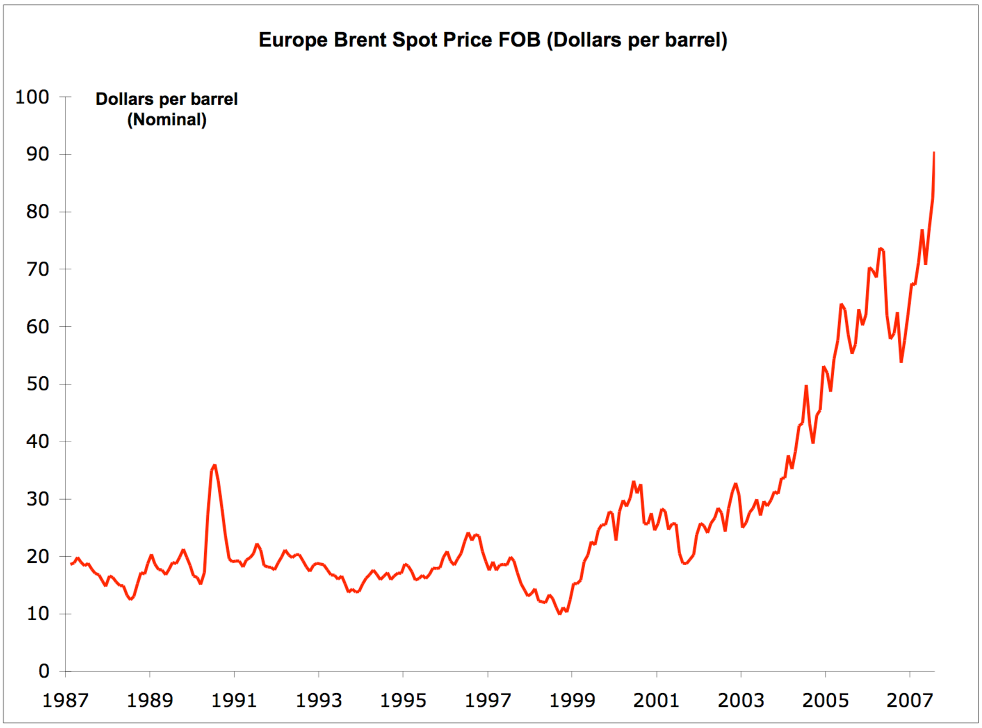
* a.mejean@jbs.cam.ac.uk. The authors acknowledge the financial support of the ESRC Electricity Policy Research Group (EPRG). The authors also wish to thank the members of the Electricity Policy Research Group and the anonymous reviewer for their comments on this paper.

1 Introduction

There are growing concerns about whether a petroleum-based economy can be sustained in the coming decades, (Greene et al., 2005). High crude oil prices, uncertainties about the consequences of climate change and the eventual depletion of conventional oil resources raise the issue of alternative fuels, such as non-conventional oil and biofuels, (Farrell and Brandt, 2006). In particular, bitumen can be extracted to produce substitutes to conventional oil, (AEUB, 2006). This paper describes a simple probabilistic model for projecting the cost of extracting synthetic crude oil from bitumen, and sketches how this model can be expanded and generalised to project the costs of other alternatives.

Crude oil prices

Crude oil prices have increased dramatically in the past few years, with Europe Brent prices rising from below $30 per barrel in 2001 to over $90 per barrel in 2007.



Source: (EIA, 2007a)

Figure 1 - Europe Brent spot price FOB

While some observers argue that high oil prices have been driven by cyclical changes, all drivers pushing in the same direction, others argue that current high oil prices are a consequence of structural transformations of the oil market, including the erosion of spare capacity due to lack of investment and strong world economic growth driven by China, the U.S. and the Middle East (EIA, 2007b), see also (Stevens, 2005). Some analysts claim that the recent oil price rise is the first sign of oil supply constraints, (Grubb, 2001), and high oil prices have raised concern about oil scarcity, (Fattouh, 2007).

Climate change

Climate change is a "serious and urgent issue" (Stern, 2006). The transport sector is the fastest growing source of CO_2 emissions in Annex I countries[1] and remains fundamentally dependent upon petroleum (Grubb, 2001 and UNFCCC, 2005). These anthropogenic CO_2 emissions accumulate in the atmosphere, leading to enhanced greenhouse effects and climate change. There are large uncertainties associated with this issue, from the scale of the impacts of climate change to the costs of mitigation (Stern, 2007 p33), but a growing consensus that this is an issue that the oil industry cannot ignore, (Browne, 2006).

Resources

Climate change analysts have traditionally focused on the aggregate carbon content of global fossil energy resources to argue that the extended use of fossil fuels is not compatible with atmospheric stabilisation targets for CO_2. However, the distribution of resources across the different fossil fuels also matters, as even a 450ppm target for CO_2 concentrations would allow total carbon emissions over the next century to be substantially larger than those which would be produced by burning the total estimated resource base of conventional oil and gas:

> "It implies that even the more ambitious targets for stabilising the atmosphere are not necessarily inconsistent with using all the gas and oil in conventional deposits. The longer- term problem of climate change arises from the fuller and longer-term use of coal, and of unconventional deposits such as heavy oils, tar sands and oil shales." (Grubb, 2001)

As conventional oil becomes scarcer, the transport sector will remain fundamentally dependent on petroleum resources, if no oil substitute is available. Fuels from non-conventional oil resources are therefore likely to become the 'backstop fuel'.

[1] Annex I Parties include the industrialised countries that were members of the OECD in 1992, plus countries with economies in transition (the EIT Parties), including the Russian Federation, the Baltic States, and several Central and Eastern European States, (UNFCCC, 2007).

However, these resources involve higher CO_2 emissions per unit of energy produced than conventional oil and gas, as they require more energy use in their extraction and upgrading, (Grubb, 2001).
In terms of investments in energy technologies, oil companies are expected to push towards ‘the frontier of petroleum exploitation’ rather than towards the renewable frontier, (Grubb, 2001). With growing concerns about climate change, its social and economic consequences and the decline of conventional oil production (starting with non-OPEC oil supplies, see for instance IEA, 2007), to the choice for solving the problem of energy supply for transport could lie between non-conventional oil and lower-carbon alternatives like biofuels.

Technological change

The role of technological change and learning has been well studied for low-carbon and other energy technologies (see for instance Grübler et al., 1999 and McDonald and Schrattenholzer, 2001). As is the case for most emerging technologies, the cost reduction resulting from experience or cumulative production is an argument in favour of investing in new, less carbon intensive energy technologies. Growing importance has been given to the role of learning curves in modelling as a way to “identify technologies that might become competitive with adequate investment” (Grübler et al., 1999). As stated in Grubb (2001), the study carried out by Grübler et al. (1999) shows that “innovation in renewable energy sources potentially makes them competitive compared to long-term fossil fuel resources as the conventional cheap petroleum resources deplete”. However, this study omits the possibility of resource extension through the use of non-conventional oil and coal-to-liquids and, according to Odell (1999), there is “an inherent internal contradiction” when accepting the status quo of the future of oil supply and at the same time insisting on “incentives for innovation (...) to enable new energy technologies (such as solar and nuclear) to diffuse into widespread use”, (Grübler et al., 1999). The role of learning-by-doing in driving down costs has not normally been taken into account for non-conventional oil in climate change modelling. Odell (1999) recommends that this inherent contradiction should be eliminated in order to “build an internally consistent model for the evolution of the global energy market”. Developing accurate experience curves for non-conventional oil is essential for calculating their potential competitive position against biofuels.

2 Theoretical framework and literature review

2.1 Decision theory, uncertainty and subjective probabilities

Decision theory is “designed to help a decision maker choose among a set of alternatives in light of their possible consequences”; each alternative is associated with one or more probability distributions (Web Dictionary of Cybernetics and Systems, 2007).

One approach to measure the uncertainty of events is to use subjective probabilities that are based on reasonable assessments by experts. Those probabilities are subjective as they depend on the subject making the judgements, (Lindley, 1985 p20). Bayesian theory uses these probabilities to represent the degree of belief of a subject. According to Lindley, probabilities are assumed to express a relationship between a person and the world. In practice, two observers may assign different probabilities to the same event and Lindley suggests that this difference arises due to different levels of information available to the observers.

The aim here is to express our uncertainty about the future costs of supplying alternative liquid fuels. Uncertainty about future energy prices and technological developments is at the core of the economics of climate change, as the pace of technological change will greatly influence the costs of mitigating greenhouse gas emissions. 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 (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, 2006 p33). The uncertainty associated with the validity of the input data is looked at, together with the influence of each parameter on the output.

2.2 Learning

Learning curves have been used in several areas to identify technologies that could become competitive with adequate investment, (Grübler et al., 1999). To build a consistent model for energy supply, technological change should be taken into account for non-conventional oil as well as for renewable energy technologies.

Experience curves are a powerful tool for energy policy making, they are used to “assess the prospects for future improvements in the performance of a technology”, (IEA, 2000). They give an indication of the investments that are needed to make a technology competitive, i.e. to bring technology costs to the break-even point, (IEA, 2000). Experience curves are normally described by the following mathematical expression:

$$C_t = C_0 \cdot \left(\frac{X_t}{X_0} \right)^{-b}$$

with C_t = unit costs at time t

C_0 = initial unit costs

X_t = cumulative production at time t

X_0 = initial cumulative production

t = time

b = experience curve parameter or learning coefficient (no unit), $b \geq 0$.

The experience curve parameter b characterises the slope of the curve, (IEA, 2000). The learning rate (LR) is a parameter that expresses the rate at which costs decrease each time cumulative production doubles, and is given by: $LR = 1 - 2^{-b}$. Cost reductions are ultimately limited by physical constraints, and a ‘bottom line cost’ (Tsuchiya and Kobayashi, 2003) should be introduced. The equation becomes:

$$C_t = C_{\min} + (C_0 - C_{\min}) \cdot \left(\frac{X_t}{X_0} \right)^{-b} \quad \text{with } C_{min} = \text{minimum unit costs}$$

2.3 Depletion

Depletion should also be taken into account when assessing the prospects for the costs of supplying fossil fuels.

Economists have used various models of extraction cost functions to calculate the optimal extraction path of mineral exhaustible resources. The simplest model assumes that the costs of extracting the resources are constant and independent of the remaining stock and of the extraction rate (Hotelling 1931). Alternative models assume increasing marginal extraction costs as the resource is depleted or increasing marginal extraction costs with the extraction rate, or both, (Sweeney, 1992 p13).

Krautkraemer and Toman argue that Hotelling's basic model wrongly assumes fixed and homogeneous resources and no change in extraction technology[2] (2003 p6). Non-renewable energy resources are in fact heterogeneous, as their quality and difficulty of extraction vary within and among deposits. They suggest incorporating the remaining stock of resources in the extraction cost function as a way to account for resource heterogeneity, (Krautkraemer and Toman, 2003 p7).

Sweeney suggests that extraction costs decrease with remaining stock. Sweeney argues that the marginal extraction costs are expected to increase for physical reasons in single deposits. According to Krautkraemer and Toman, "cost conditions for extraction in a specific petroleum reservoir change over the economic life of the reservoir", (2003). In addition, oil extraction costs are dependent upon the quality of the resource, and Sweeney shows that low-cost, high-quality resources will be produced before high-cost, low-quality resources: under competition, it is economically rational to produce the low cost, high quality resources first, (see also Hartwick, 1978). It follows that under a given state of knowledge, the oil industry shows increasing costs, as an increase in output means that more is produced from high cost, low quality resources, (Adelman, 1993 p9).

This view has been criticised for instance by Rehrl and Friedrich who argue that producers can't in practice extract resources in order of increasing costs because of the nature of the discovery process, i.e. "cheapest oil is not necessarily found first", (Rehrl and Friedrich, 2006). Adelman argues that in reality, "cheaper sources tend to displace more expensive ones, but this is a question of more or less, not of yes or no", c.f. (Adelman, 1993 p.19).

The approach taken by modellers is to try to reflect how costs could evolve with the growing difficulty of obtaining the resources under a given state of knowledge. In the RICE-99 model, Nordhaus (1999) introduced a carbon-energy supply curve with carbon fuels available at rising costs.

$$q(t) = \xi_1 + \xi_2 \cdot \left(\frac{CumC(t)}{CumC*} \right)^{\xi_3}$$

q(t) is the cost of extracting carbon-energy (1000$/ton)

CumC(t) is the cumulative production (GtC)

ξ_1 is the marginal costs, independent of exhaustion (1000$/ton)

[2] In this section we assume no technological change in extraction technologies. The learning effect will be treated separately.

$\xi_1 + \xi_2$ is the maximum costs of extraction before reaching CumC* (1000$/ton)

ξ_3 is the convexity of the curve

CumC* is the point of diminishing returns in carbon-energy extraction (GtC)

ξ_1 is the costs of extraction when CumC(t)=0. The second term is a rising cost function. A high value for ξ_3 means that the cost function for carbon fuels is relatively price-elastic in the near term. CumC* is the limited quantity of carbon-energy beyond which marginal costs of extraction rise very sharply, (Nordhaus, 1999).

This model seems to be compatible with Adelman's view that "the amount of a mineral that is in the ground has no meaning apart from its cost of extraction and the demand for it", (2004 p16), as the amount of recoverable resources is used to assess extraction cost as a function of the growing difficulty of the resources. The authors in Chakravorty (1997) also expect the marginal extraction costs to increase with cumulative production. Chakravorty and Roumasset have shown that a rising and convex extraction cost function predominates in the oil industry, (1990).

To conclude, both depletion and technological advances are driving the supply of exhaustible energy resources and both need to be taken into account to forecast future non-conventional oil extraction costs. As Sweeney summarises:

"extraction rates rise over time, perhaps rapidly, as the technology develops and demand increases (…). However, at some time, rising costs due to depletion of the resource start overtaking the decreasing costs due to technology advances. The extraction rate declines until ultimately all of the economical resource stocks are depleted", (Sweeney, 2004).

The combination of both effects results in a U-shaped cost curve for non-conventional oil. Nordhaus' equation provides a general framework for modelling the extraction of fossil fuel resources. This form is very flexible thanks to its four parameters. The simpler models can be seen as special cases of this general cost function, c.f. (Sweeney, 1992 p94), including the first Hotelling model of constant extraction costs.

2.4 Resources and Costs

This study aims to assess the future costs of supplying liquid fuels. Supply costs are the sum of capital costs and operating costs per unit of production, allowing for a

return on the producer's investment. They include all costs associated with exploration, development and production, (NEB, 2004). At present these costs do not include any costs to society associated with environmental impacts that have not been mitigated, such as greenhouse gas emissions.
There is no universally agreed terminology for hydrocarbon reserves and resources. The oil in place is defined by the Canadian Grand Dictionnaire Terminologique as the quantity of oil estimated to be in a reservoir, (2007). This terminology is used is several studies, including (Rogner, 1997), (USGS, 2003) and (WEC, 2001). The amount of oil that can be recovered depends on the recovery factor. Total oil in place multiplied by the recovery factor gives the total recoverable oil resource.

Different views exist on the amount of oil in place and on the amount that can be ultimately recovered. Geologists see resources as a fixed stock that will eventually deplete. They are rather pessimistic about the technological potential of bringing non-conventional oil resources to the market and therefore they mainly focus on the occurrence of conventional oil, (UNDP, 2000). Unlike geologists, economists consider hydrocarbon occurrences as 'neutral stuff' (Odell, 1998) that become a resource only if there is a demand for it, (UNDP, 2000), see also (Adelman, 1990). Economists see the distinction between conventional and non-conventional oil as irrelevant. Non-conventional oil is sometimes defined as any hydrocarbons that require production technologies significantly different from the mainstream in currently exploited reservoirs, (IEA, 2005a). This definition is clearly time-dependant, as technology development, driven by sufficient demand, may bring non-conventional oil out of the margin and radically change the definition of 'mainstream', (UNDP, 2000) and (IEA, 2005a).

Non-conventional oil

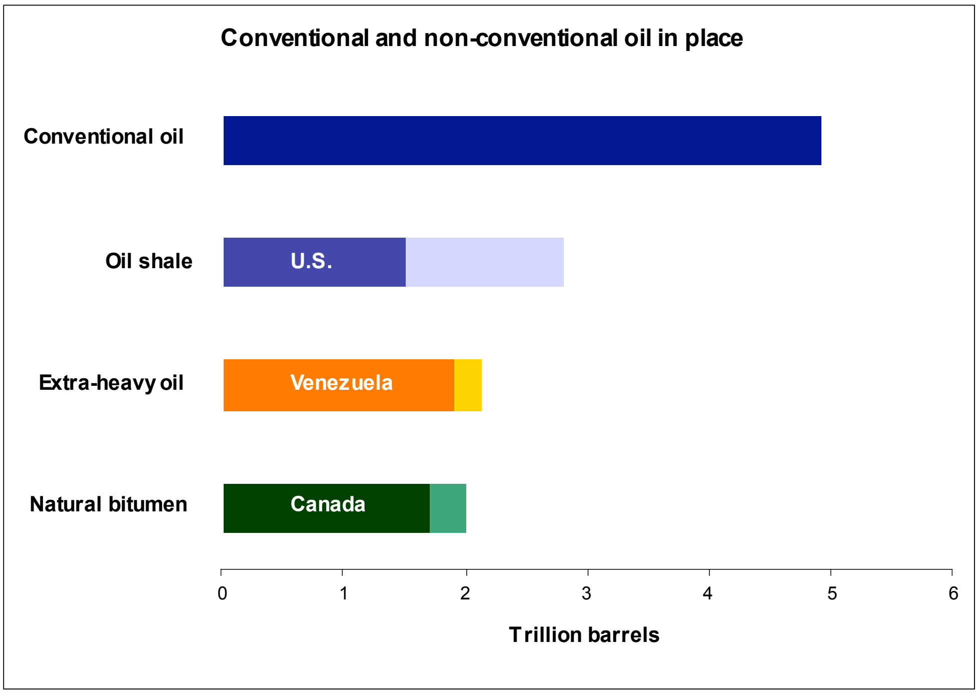
Conventional and non-conventional oil are usually distinguished by their physical properties: viscosity and density. Viscosity is a measure of the fluid's resistance to flow. It varies greatly with temperature. The oil viscosity at reservoir temperature determines how easily oil flows to the well for extraction, (USGS, 2003).

Extra-heavy oil is more viscous and dense than conventional oil, it is still mobile at reservoir conditions: density < 20°API and 100cP < viscosity < 10,000cP.
Bitumen is more dense and more viscous than extra-heavy oil, it is not mobile at reservoir conditions, (Cupcic, 2003): density < 12°API and 10,000cP < viscosity.

Oil shale is a fine-grained sedimentary rock rich in organic matter, (USGS, 2005): oil shales contain kerogen, which is a solid, insoluble organic material.

Conventional oil can also be defined as oil produced by primary or secondary recovery methods, while non-conventional oil is not recoverable in its natural state through a well by ordinary oil production methods, (Grand Dictionnaire Terminologique, 2007). Some types of heavy oil can flow very slowly but most require heat or dilution to flow to a well, (Centre for energy, 2007a). Bitumen does not flow at reservoir conditions and usually occurs in oil sands.

On the economists' side, the IEA estimates that resources of heavy oil and bitumen worldwide amount to around 6 trillion barrels, of which 2 trillion barrels are ultimately recoverable, (IEA, 2005a). The USGS estimates that 651 billion barrels of natural bitumen and 434 billion barrels of heavy oil are ultimately recoverable worldwide, (USGS, 2003). The USGS estimates the total oil shale resources to be at least 2.8 trillion barrels. This figure is conservative as several deposits haven't been explored sufficiently and some deposits were not included in the USGS survey, (USGS, 2005 p1). The chart below shows one view on the conventional and non-conventional oil in place.



Source: Adapted from (WEC, 2001) and (Meyer and Attanasi, 2004)

Figure 2 – Conventional and non-conventional oil in place

Non-conventional oil in place in known heavy oil and bitumen accumulations approximately equals the remaining conventional light oil in place (API > 22°).

Bitumen resources are concentrated in Canada and extra heavy oil resources are concentrated in Venezuela, (Gielen and Unander, 2005): at least 85% of the world total bitumen occurs in Canada while 90% of world extra-heavy oil resources in place occur in Venezuela. Major oil shale resources are in China, Estonia, the United States, Australia, and Jordan, (UNDP, 2000 p141). World coal resources in place are estimated at over 20 trillion barrels of oil equivalent (boe), of which over 3.6 trillion boe would be recoverable (BGR, 2005 p7).

The figures presented on the graph above could suggest that non-conventional oil resources are known precisely and are highly concentrated geographically. But this graph only shows the estimates from one source: the amounts of non-conventional oil in place are not known precisely, and there is huge uncertainty on the amount of oil that will be ultimately recovered. Non-conventional oil resources could benefit from sustained high oil prices, and a renewed interest in those resources could boost the discovery effort and allow for the development of new deposits. The issue about non-conventional oil is less the size of the resources than the rate and costs at which they can be produced, (ASPO, 2003).

3 Research design

3.1 Methodology

Model - Learning and depletion

This is a forward-looking analysis of the upstream liquid fuel industry, which aims to describe the effects of both learning and production constraints on the costs of supplying fuels. The equation below summarises the first version of the cost model for non-conventional oil, including both learning and depletion effects.

$$C_t = C_{\min} + \underbrace{(C_0 - C_{\min}) \cdot \left(\frac{X_t}{X_0}\right)^{-b}}_{\text{Learning}} + \underbrace{C_{\max} \cdot \left(\frac{X_t}{X_u}\right)^{\gamma}}_{\text{Depletion}}$$

With X_t = Cumulative production at time t

X_0 = Cumulative production at time 0

C_t = Costs at time t

C_0 = Costs at time 0

And the six parameters:

C_{min} = minimum costs of producing the resources

b = learning coefficient

Q = total oil in place

C_{max} = maximum cost of the depletion

γ = exponent of the depletion

With X_u = Ultimately recoverable resources with $X_t \xrightarrow[t \to \infty]{} X_u$

And $X_u = Q \cdot R$

Where R = recovery factor

The first part of the model translates the effect of learning on costs; the second part describes the effect of depletion on costs and is derived from Nordhaus. The depletion and learning effects are additive as the study aims at assessing their relative influence on the cost trend. Learning and depletion are driven by production (X_t). Learning drives costs down, and depletion drives costs up, as the resources become depleted and become more difficult to extract. X_u is obtained by multiplying two parameters: the total oil in place (Q) and the recovery factor (R). The learning coefficient b defines the pace at which technological change is driving costs down.

C_{min} is the minimum cost of supplying the resources
C_{max} is the maximum cost of the depletion.
C_{max}+ C_{min} is the cost of extracting the last resources, i.e. when the resources get depleted.

Finally, the exponent of the depletion cost curve gamma defines the pace at which depletion is driving costs up. The cumulative production at time t (X_t) is exogenous. The exponential form of the depletion part of the cost function is flexible as its parameters can be changed to fit simple as well as more sophisticated models.

Production

The cumulative production at time t (X_t) is obtained by summing over time the production rate at time t (x_t). The production rate is assumed to follow an S-curve: it grows exponentially before reaching a plateau (see Soderbergh, 2006). The production rate is modelled as follows:

$$x_t = \frac{a}{c + e^{-d \cdot t}}$$

x_t is the production rate (barrels/y)

$\frac{a}{c}$ is the maximum production rate

t_1 is the inflexion point, it determines d

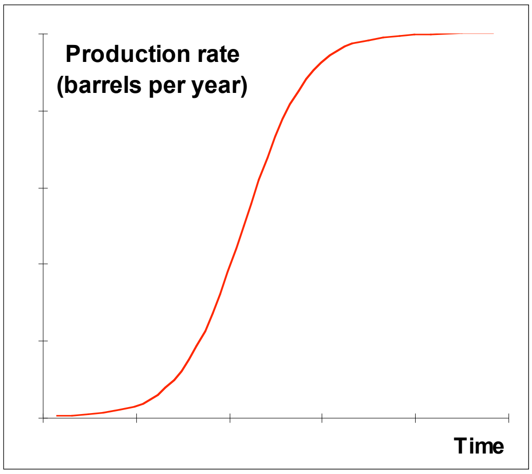


Figure 3 - Production rate (illustration)

The S-curve above is drawn for a=c=d=1, here t_1 = 0. Parameters a and c are defined by the upper bound of production capacity when time tends towards infinity and the actual production at time 0.

$$\lim_{t \to \infty} x_t = \frac{a}{c} \quad ; \quad x_0 = x_{t=2005}$$

The speed of increase in production is also considered. The third parameter d is defined using the second derivative of the function. The speed of increase is influenced by the time t_1 when the slope of the logistic function stops increasing and starts decreasing (i.e. the inflection time).

$$\frac{d^2 x_t}{dt^2} = \frac{-d^2 \cdot a \cdot e^{-dt} \cdot (c - e^{-dt})}{(c + e^{-dt})^3}$$

$$\frac{d^2 x_t}{dt^2} = 0 \Leftrightarrow c - e^{-dt} = 0 \Rightarrow t_1 = \frac{1}{d} \cdot \ln\left(\frac{1}{c}\right)$$

As x_0 is given, t_1 and $\lim_{t \to \infty} x_t$ are the only parameters that vary.

This model is not entirely satisfactory, as the production rate is determined exogenously. In practice, the production rate will depend on conventional and non-conventional oil prices, which in turn can be influenced by the cost of producing oil.

The learning, depletion and production parameters described above are not known precisely. The effect of uncertainty associated with these input variables on the resulting supply costs should be explored: uncertainty is introduced in the model by assigning subjective probability distributions to the model parameters.

3.2 Parameters for Canadian bitumen

In the first approximation, a triangular distribution is assigned to each parameter. Each distribution is defined by a minimum, a maximum and a most likely value. The direction of the skew of the triangular distribution is set by the size of the most likely value relative to the minimum and the maximum, (Palisade, 2007). A literature review is conducted in order to define the ranges of estimates associated with each parameter.

Learning

The learning effect is first considered separately and the learning coefficient b is calculated using the simple learning model described in the theoretical framework. The simplest approach is to consider the logarithmic form of the equation:

$$Ln(C_t - C_{\min}) = Ln(C_0 - C_{\min}) - b \cdot Ln\left(\frac{X_t}{X_0}\right)$$

Plotting $Ln(C_t - C_{\min})$ as a function of $Ln\left(\frac{X_t}{X_0}\right)$ and estimating a linear regression give the learning coefficient b as the slope of the regression. The learning rate obtained is compared to values found in the literature in order to define a plausible range for that parameter.

The learning rate for non-conventional oil technologies is calculated using historical data of supply costs and production volumes from the Canadian Petroleum Producers Association (CAPP) from 1983 to 1998, shown in figure 4. The determination of the learning rate ignores depletion effects. The resulting learning coefficient is 0.78 giving a learning rate (LR) of 42%, (R^2=98%).

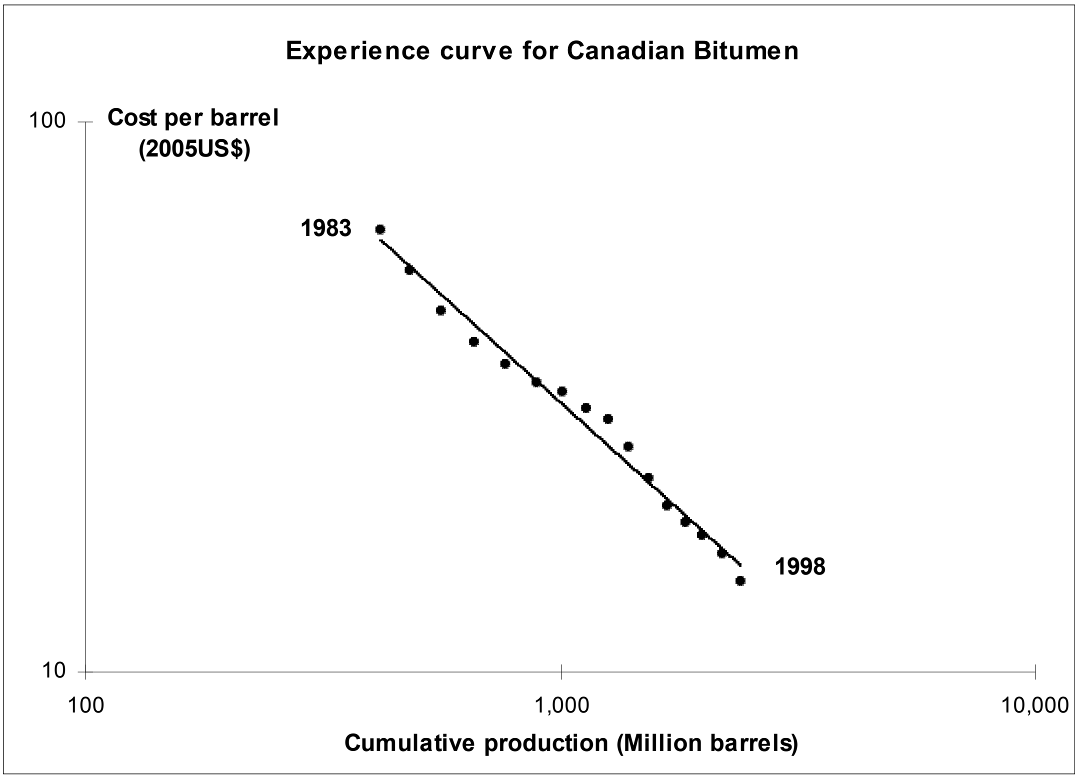


Figure 4 – Costs vs. Cumulative production of Canadian bitumen

The experience curve theory, when used for technology forecasting, assumes that the learning rate will remain constant over time, and the model implies that the rate of learning for emerging technologies will be greater than for mature technologies. According to Margolis (2002), “the process of innovation is inherently uncertain”. The potential for breakthroughs is difficult to quantify and is not fully captured in the experience curve theory. Also, the ability of a technology to continue benefiting from learning is uncertain (IEA, 2000 p92), as the learning curve theory ignores theoretical and technical limitations that may hinder further cost reductions. For these reasons, and in order to capture the uncertainty associated with the future learning pace of these technologies, a range of estimates is assigned to the learning rate parameter.

The calculated learning rate of 42% is rather high compared to other technologies (see McDonald and Schrattenholzer, 2001). Also, the oil sand extraction technologies could have benefited from previous learning from similar technologies in other mining industries. If so, the cumulative production to be considered when calculating the historical learning rate should include the production volumes of these industries. This would result in a lower learning rate for oil sands extraction technologies and less dramatic cost decrease in the future. LR = 42% is therefore chosen as the upper bound of the range.

The IEA used data from the Oil and Gas Journal to estimate that Canadian oil sands show a learning rate of about 20% (this figure is obtained from a local fit, with the global fit showing a learning rate of 27%), (IEA, 2005a p116). The report suggests that production costs, not supply costs, were used to calculate this learning rate. However, it is not entirely clear what these costs include and which period of time was chosen. The 20% value is therefore chosen as the lower bound of the range.

A way to capture the theoretical and technical limitations mentioned earlier is through the parameter C_{min}, the minimum costs of supplying bitumen, see (Anderson and Winne, 2003). 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 usually underestimated, (Anderson, 2005).

Most of Canadian bitumen is mined. Assuming that the mining technologies are similar for bitumen and coal production, a first estimate of C_{min} is given by the costs of mining coal from the world most efficient open pit coal mine. According to the IEA, citing the Association of Coal Importers, the world's lowest-cost coal producer on the Atlantic market is South Africa, with mines producing coal at US$5/ton, (IEA, 2005b)[3]. On average, two tonnes of oil sands are needed to produce one barrel of synthetic crude oil, (Centre for Energy, 2007b), so the upper bound of the range is set at US$10/barrel.

Some heavy oil can be produced using primary recovery, although it is very inefficient. The costs of primary recovery are generally low. In difficult offshore areas, it can range from $2/barrel to $10/barrel, (Roumasset et al, 1983). The lower bound of the C_{min} range is therefore set at $2/barrel. The range for C_{min} should also be compatible with the historical costs of supplying bitumen: production costs of $10 per barrel have been observed (NEB, 2004) so the condition $Cmin \leq 10$ should be satisfied. C_{min} is a very uncertain parameter, which explains its very wide range.

C_0 is the cost of producing the resources at time 0. A single value is assigned to that parameter, derived from CAPP. The costs of supplying Canadian bitumen are not the same for every deposit, depending on particular physical characteristics. The values found in the literature also depend on the assumptions made about the rate of return to the producer. The model will be later improved to include C_0 as a third learning parameter, with a probability distribution assigned to it.

[3] Surface mining techniques are used for coal seams at a maximum depth of 45 to 60 metres (150-200 feet), (EIA, 1996), while oil sands can be recovered by surface mining where deposits are less than 75 metres deep, (National Energy Board, 2000).

Depletion

The estimates of the depletion parameters are obtained using the same method as previously. The logarithmic form of the depletion equation is considered:

$$Ln(C_t) = Ln(C_{\max}) + \gamma \cdot Ln\left(\frac{X_t}{X_u}\right)$$

Plotting $Ln(C_t)$ as a function of $Ln\left(\frac{X_t}{X_u}\right)$ and estimating a linear regression of the curve obtained gives the depletion exponent γ as the slope of the regression. The exponential of the intercept gives the maximum depletion costs C_{max}. Some modelling results on the supply of hydrocarbons in general and non-conventional oil in particular are available in the literature.

Attanasi produced incremental cost function showing “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, (USGS, 1995 p2). These costs are incremental costs, in finding, developing, and producing crude oil from undiscovered conventional oil fields and continuous-type oil accumulations in onshore and offshore areas of the United States. These curves assume no subsequent cost reductions through technology learning (IEA, 2005a), the determination of depletion parameters thus ignores learning effects. The European SAUNER project uses Attanasi’s estimates to produce world oil supply cost curves for various categories of oil, including tar sands and heavy oil. Rogner (1997) also produced similar aggregate quantity-cost curves for global oil resources. These results, including Nordhaus’ (1999), are fitted to the depletion model. The resulting estimates for γ and C_{max} are summarised in table 1.

Parameters	Nordhaus 1999	Rogner 1997	SAUNER 2000 Cat iv-vi	SAUNER 2000 Cat iv
Maximum depletion costs - $C_{\max}$ ($/barrel)	81	105	126	91
Exponent - γ (no unit)	4.0	1.0	1.3	2.1

Table 1 – Estimates of depletion parameters

The lower and upper bounds of the range for the maximum depletion costs (C_{max}) are set at 81 and 126 US$/barrel respectively. The lower and upper bounds of the range for the depletion exponent (γ) are set at 1 and 4, respectively. The alternative assumption of constant extraction costs can also be captured using this modelling framework, thanks to the parameters C_{max} and γ. In that case, learning would drive costs down until they reach C_{min}. The constant extraction costs would be captured in C_0.

Production

The Oil and Gas Journal (2002) estimates the worldwide bitumen in place at more than 3 trillion barrels. This includes Canada's bitumen in place of 1.7 – 2.5 trillion barrels. The Canadian National Energy Board estimates the total bitumen in place in Canada to be between 1.6 and 2.5 trillion barrels (2004): these are chosen as the extreme values of the range for that parameter.

The recovery factor is the percentage of the total oil in place in a reservoir which 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 that could ultimately be produced as a percentage of the total amount of oil in place in bitumen.

The U.S. Geological Survey (USGS) estimates the recovery rate for North American natural bitumen at 32%, (2003). The Canadian National Energy Board estimates that about 12% of the bitumen in place is recoverable, (National Energy Board, 2004 p4). According to the Alberta Energy and Utilities Board, 315 billion barrels of bitumen will be ultimately recoverable, "under expected technology and economic conditions", which also corresponds to a recovery factor of 12%. This figure is consistent with the IEA estimates of 300 billion barrels ultimately recoverable out of 2.5 trillion barrels of bitumen in place in Canada. The values 40% and 10% are chosen as the upper and lower bounds of the parameter range. However, the issue about non-conventional oil is less to do with the size of the resources than the rate at which they can be produced, (ASPO, 2003).

According to the 2004 World Energy Outlook (IEA, 2004a), total non-conventional oil production is projected to grow from 1.6 Mb/d in 2002 to 3.8 Mb/d in 2010 and 10.1 Mb/d in 2030. Table 2 shows the range of projections available for Canadian production capacities of bitumen and synthetic crude oil to year 2040.

Production capacity (Mb/d) – Canadian non-conventional oil								
Year	NEB 2006 All-projects	NEB 2006 Base case	NEB 2006 Low case	OGJ 2003	CAPP 2006	Knapp 2002	Hirsch 2005	Soderbergh 2006
2000				1				
2005	0.9	0.9	0.9	1.3	1	1.3	1	1.3
2010	2.8	2.0	1.7	2		2.6		3
2015	4.5	3.0	1.9		3.5	3.1	3.5	
2020				2.8	4			4
2030							5	5
2040								6

Table 2 – Production estimates for Canadian bitumen

The combination of the production parameters t_1 and x_{max} should cover this whole range of estimates.

There are several constraints that can hinder the growth of the production rate. First, the physical properties of the deposits can prevent oil from being extracted at a higher rate. Bitumen production is also constrained by the significant amounts of natural gas that are required to recover and upgrade bitumen into synthetic crude oil, (IEA, 2004a). More generally, higher bitumen production is bidding up the price of inputs, such as steel, electricity and natural gas, (Joint Economic Committee – US Congress, 2006), consequently inflating the costs of producing bitumen. Developing and extracting fossil fuels is capital intensive, and the timing of investment in production capacity depends on the cost of capital, (Krautkraemer and Toman, 2003). The IEA estimates the capital cost of creating new capacity in Canada is about US$5 billion for 0.2 Mb/d, and argues that “mobilising the capital for exploitation of a significant fraction of the resources is likely to take several decades”, (IEA, 2005a). The production of bitumen in Canada has also raised environmental issues linked to energy and water consumption, greenhouse gas emissions and land degradation.

These constraints are acknowledged, but whether all of them will persist is uncertain. According to Soderbergh, the long-term future of the Canadian oil sands industry relies on in situ production, (the initial volumes in place suitable for in situ production is twenty times that of mineable bitumen, EUB 2006), and in situ projects require lower investments than mining projects. It follows that more rapid development might also be possible. Although Soderbergh assumes supply growth to 2020 to be unconstrained by availability of investment capital, his estimate for 2040 could still be conservative as it only includes proposed oil sands projects. Also, according to the Joint Economic Committee of the U.S. Congress, the price of inputs should stabilise and decline in the longer-term. Advances in extractive technologies should lower the amount of inputs (e.g. natural gas) consumed per output unit, allowing production costs to decline again, (Joint Economic Committee – US Congress, 2006). With supply costs as low as US$10 -17 for bitumen and US$20 - 25 for synthetic crude oil, (NEB, 2004), the constraints on energy and water resources could be seen as a frictional effect which could be overcome with investment and adequate policies.

Summary

Table 3 summarises the ranges that are assigned to each parameter in the model. The wide ranges translate the large uncertainty on these parameters. These ranges are illustrative: the figures are better than guesses, as the above discussion shows, but they are not the result of a formal elicitation exercise.

Parameters	Min	Most likely	Max
Resources			
Total oil in place (Trillion barrels)	1.6	2.0	2.5
Recovery factor (no unit)	0.12	0.26	0.4
Production			
Inflection time t1 (year)	2010	2025	2040
Maximum production rate x_{max} (Mb/d)	4	5.5	7
Depletion			
Maximum depletion costs C_{max} (US$/barrel)	82	104	126
Depletion exponent γ (no unit)	1	2.5	4
Learning			
Learning rate LR (%)	20	31	42
C_{min} (US$/barrel)	2	6	10

Table 3 – Parameters ranges

It is assumed that all these parameters are independent. These ranges are fed into the model to obtain some preliminary results.

3.3 Illustrative results - Canadian bitumen

a. Production

The cumulative production at time t (X_t) in the model is obtained by summing the daily production rate (x_t) over time. The graph below shows the cumulative production of oil from Canadian bitumen deposits over time.

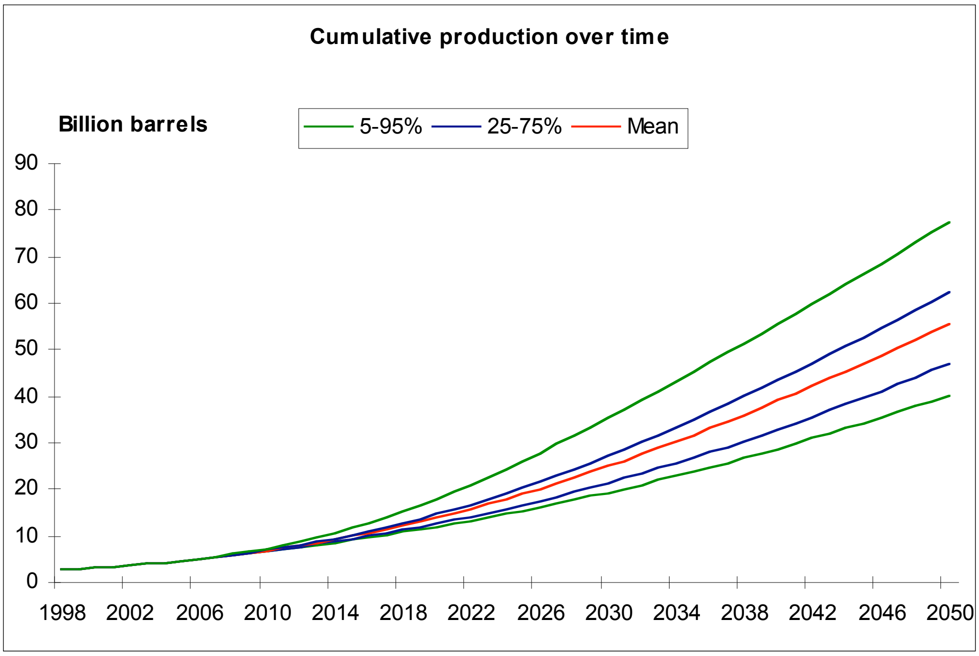


Figure 5 – Bitumen cumulative production over time

The centre line represents the trend in mean value. The two outer bands above the mean are the 75th and 95th percentiles. The two outer bands below the mean are the 25th and 5th percentile: the narrower the band, the less the uncertainty about the cumulative production, so the uncertainty about future production volumes increases with time.

The mean cumulative production reaches 55 billion barrels in 2050. This is only about 10% of the 'most likely' ultimately recoverable resource in Table 3, and less than 10% of the USGS estimate of bitumen recoverable resources worldwide of 651 billion barrels, (2003). The cumulative production curve is used as an input in the supply cost function below.

b. Supply costs

Using the model described earlier, the parameter ranges summarised above and the cumulative production shown above, the results shown in figure 6 are obtained for the supply costs of Canadian bitumen over time.

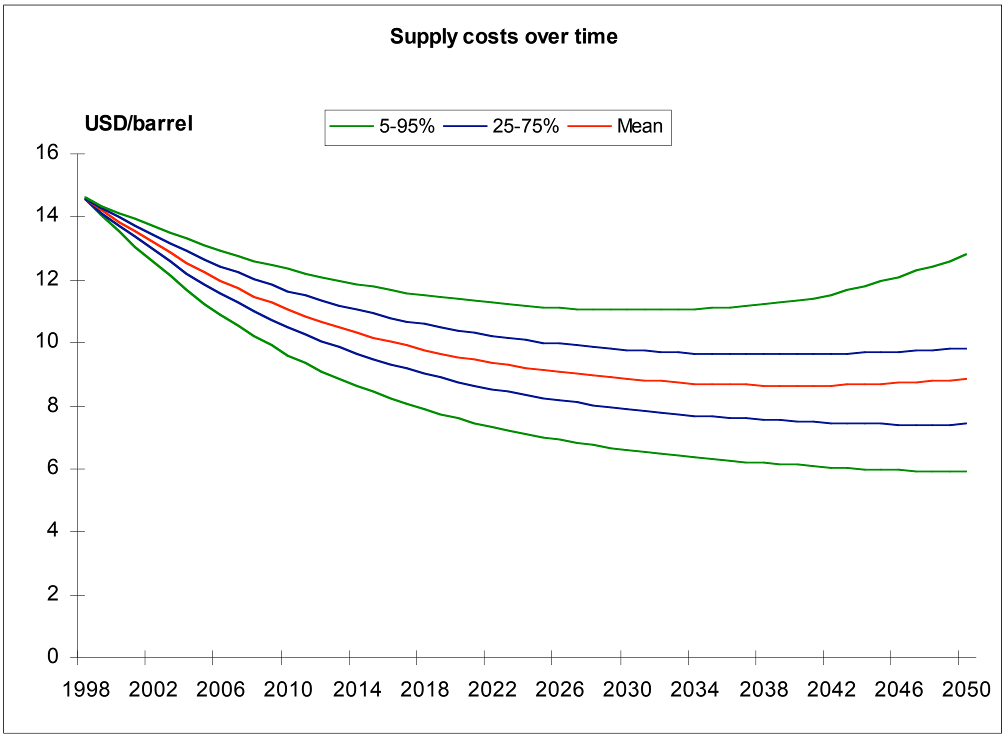


Figure 6 – Bitumen supply costs over time

This model reveals the kind of uncertainties that need to be dealt with when designing policies. The results show large uncertainties on future supply costs, with costs falling in the range of \$6 to \$13 in 2050. Learning dominates in the 5th percentile curve until 2050, as costs continue to decrease: supply costs fall by around 60% over the 50 year time period. Mean supply costs decrease by 40% over the same period. However, the 95th percentile curve shows increasing costs in the second half of the time period due to the takeover of the learning effect by the depletion effect.

c. Influences

The influences of each parameter on these results are examined more formally by using the correlation sensitivity analysis in Palisade's @RISK. The higher the correlation between the input and the output, the more significant the input is in determining the output values, (Palisade, 2007). The correlations shown in figure 7 are obtained from a simulation of 10,000 iterations.

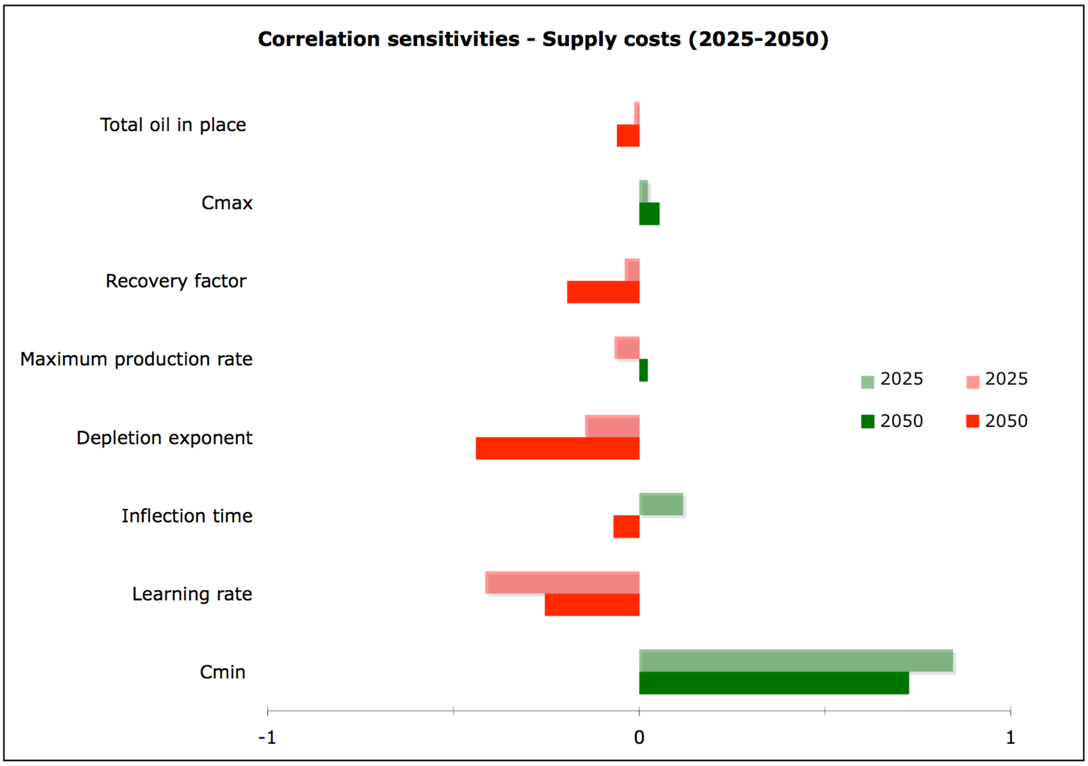


Figure 7 - Correlation sensitivities - Supply costs

The longer bars represent the most significant variables. Only the values significantly different from zero (at the 1% level) are included: with 10,000 iterations, the critical value is 0.02 (t-statistic = 2.33). This means that influences down to +/- 0.02 are included in the results.

Learning and depletion parameters

The results show that C_{min} has the biggest influence on supply costs in 2025. This is mainly explained by the fact that quite a wide range is assigned to that parameter (c.f. Table 3). A higher C_{min} constrains the potential decrease in costs due to learning, which explains the positive sign of the correlation sensitivity.

The second most influential variable is the learning rate. The sign of the sensitivity associated with the learning rate parameter is negative, as a higher learning rate will induce costs to decrease further.

The third most influential parameter is the depletion exponent. As $\frac{X_t}{X_u} \leq 1$, a higher exponent (γ) means lower costs, hence the negative sign of the sensitivity.

By year 2050, costs have started rising: in many runs, the depletion effect is comparable to the learning effect. C_{min} still has the biggest influence on supply costs in 2050, due to the large uncertainty on that parameter.
The exponent of the depletion cost curve γ is now more significant than the learning rate. Again, because $\frac{X_t}{X_u} \leq 1$ supply costs are negatively influenced by γ.

Production parameters

Around year 2025, learning is the dominant effect so supply costs are decreasing (see Figure 5), with learning being driven by production. The inflection time t_1 is the time when the growth of the production rate starts to decline, therefore a smaller t_1 means that production, and learning, happen sooner, hence the positive sign of the sensitivity. The same applies for the second production parameter x_{max} (maximum production rate). A higher maximum for the production rate means that more oil is produced, driving costs further down through learning.
Depletion, like learning, is driven by production. A smaller t_1 means that production and depletion happen sooner, driving up supply costs in 2050 once depletion effects start to bite. The same applies to the maximum production rate x_{max}. A higher value will increase supply costs in 2050.

Resource parameters

X_u is the ultimately recoverable resources and only appears in the depletion term of the model. If the recovery factor R increases, X_u increases, postponing depletion and its upward effect on costs, hence the negative signs of the correlation sensitivities.
The resources variables (total oil in place Q and recovery factor R) are more significant in 2050 than 2025 while the sign of their sensitivities remain the same. This is explained by the fact these parameters only appear in the depletion part of the model and that the depletion effect dominates over the learning effect in 2050.
Looking at these influences will help us to concentrate on the most influential parameters, in order to start refining the study. The most influential parameters appear to be C_{min}, γ and the learning rate. The inflection time is less influential, but shows the interesting characteristic of changing sign between 2025 and 2050. Let's have a closer look at the influence of these parameters over time.

d. Evolution of correlation sensitivities over time

The graph below shows the evolution of the influence of the learning rate (red), the depletion exponent γ (yellow), C_{min} (blue) and the inflexion time t_1 (green) on the supply costs between 2010 and 2050.

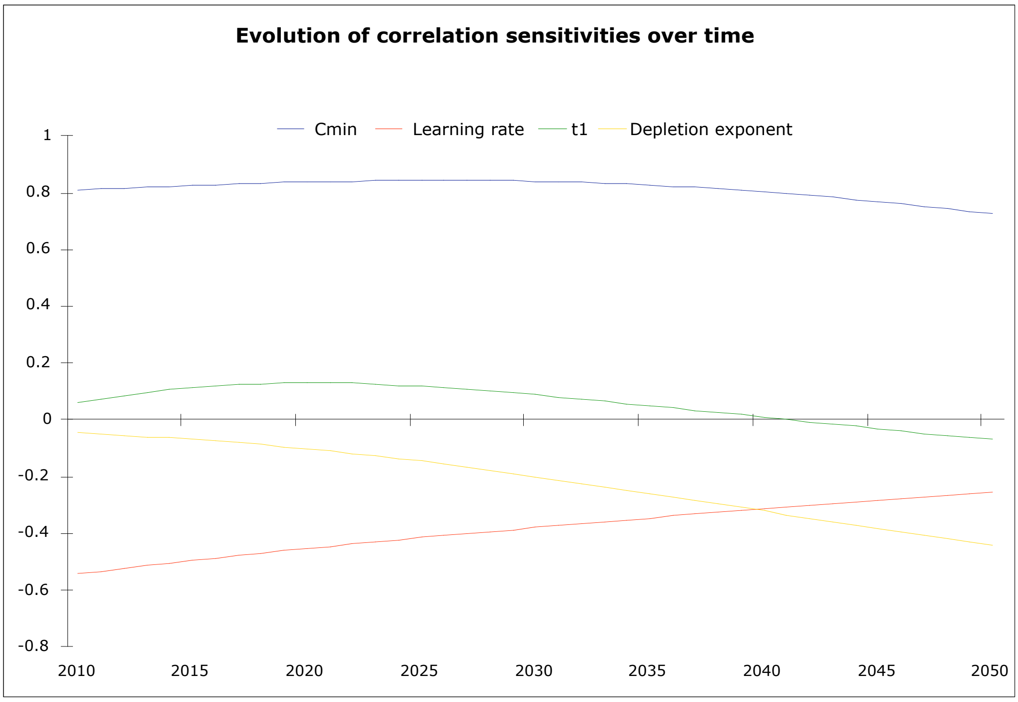


Figure 8 – Evolution of correlation sensitivities over time

Over time, the influence of the learning rate on the supply costs is decreasing, while the influence of the depletion parameter increases. The learning effect is gradually overtaken by the depletion effect.

Learning and depletion are driven by production. A smaller inflexion time t_1 means that production, and therefore learning and depletion, happen sooner. The results show that the influence of the production parameter t_1 decreases as the learning effect becomes less dominant. It becomes negative when the influence of the learning rate is smaller than the influence of the depletion exponent.

C_{min} is the most influential parameter over the whole time period. Its influence starts decreasing slowly as the depletion effect overtakes the learning effect around year 2040. This can be explained by the fact that as costs start to increase (in the 95% range of the supply cost curve, see Figure 5), C_{min} becomes less of a constraint on the evolution of the costs of supplying liquid fuels.

4 Further work

The ultimate aim of this research is to reveal the effects of investments, learning, depletion and production constraints on the costs of supplying alternative fuels. Developments of this first model will allow more progress to be made.

Addressing uncertainty

The correlation sensitivities previously presented in the case of Canadian bitumen showed that the most influential parameters were C_{min}, γ and the learning rate (LR). Various technologies are used to produce oil from non-conventional deposits (e.g. mining and in-situ extraction technologies for bitumen). In order to address the uncertainty associated with the learning parameter C_{min}, the learning rate and the depletion parameter γ, the model will be developed to treat those technologies separately. As a complementary approach, the uncertainty associated with the depletion parameter γ for non-conventional oil will be addressed by looking at historical costs of producing conventional oil. For the case of Canadian bitumen, some extraction techniques are very similar to those used when producing coal. The historical costs of supplying coal from European mines will therefore be examined.

Biofuels

The learning model will be applied to worldwide biofuels resources. In order to assess future supply costs of conventional biofuels, the research will focus on improvements in crop yields and potential economies of scale at the conversion plant. Second generation technologies can be highly efficient but are immature and involve high costs, (IEA, 2005a p20). For second generation biofuels, the emphasis will be put on technological change and learning in advanced conversion processes. The cost and production functions of biofuels will depend on a number of key parameters associated with levels of uncertainty, e.g. land value, crop yield and learning rate of conversion technologies. The aim is to build a probabilistic distribution for the costs of biofuels in order to compare them with the costs of supplying liquid fuels from non-renewable resources.

Global oil market

The supply of alternative fuels needs to be considered in the wider context of world oil market. According to Gielen and Unander, “the prospect of alternatives to conventional oil sources (...) reduces the incentive for oil producers to collaborate to raise prices", (2005 p3). Non-conventional supplies are therefore likely to be a major contributor to market stability, (Bencherif, 2002).

Whether new supplies from non-conventional resources, including biofuels, will affect the world oil price depends on the scale of those supplies. Non-conventional production could have an influence on the global oil market in either one of two cases: First if potential production volumes from non-conventional sources have been underestimated, second if future oil supply from OPEC has been overestimated.

The present model assumes no effect but this will be explored in further work. The potential impact of new supplies on the oil price would complicate the analysis as the actual rents would be lower than those expected by the producers, as additional supplies would lower the price of oil. Also, as learning and depletion are driven by production, the impact of new supplies on oil prices would affect the supply costs of producing liquid fuels, further impacting on the rents. However, from a social point of view, an increase in fuel supplies would be beneficial in sustaining lower oil prices.

The model will also be improved to include endogenous production rates, which will depend on conventional and non-conventional oil prices. Oil prices will in turn be influenced by oil production costs.

CO_2 constraints

The environmental costs associated with the production of bitumen are not included in the cost estimates available in the literature. In particular, the cost of carbon should be considered when assessing the cost-competitiveness of oil from non-conventional deposits. Current greenhouse gases emissions from the oil sands industry range from 0.12 and 0.17 tCO_2eq per barrel of synthetic crude oil, including bitumen recovery and upgrading, (Alberta Chamber of Resources, 2004). With a shadow price of carbon at 45 US$/$tCO_2eq$ (2005US$, corresponding to 25.5 £/CO_2eq in 2007, DEFRA 2007), the carbon costs would amount to 5 to 8 US$/barrel and would add a third to current supply costs. In 2050, the shadow price of carbon is estimated at 105 US$/$tCO_2eq$ (59.6£/tCO_2eq), which would correspond to 12 to 18 US$/barrel (2005) with current CO_2 emissions, thus doubling the supply costs for synthetic crude oil in 2050 (see Figure 6).

High carbon prices would add to the costs of supplying carbon intensive fuels, either conventional or non-conventional, and would therefore stimulate the development of low carbon alternative fuels. The question remains whether carbon prices will be high enough to stimulate investment and induce technical change in low carbon energy technologies, including carbon capture and storage technologies, (IPCC, 2007 p44-45).

In a carbon constrained world, carbon taxation or trading is very likely to play an increasing role in assessing investment risks and therefore carbon costs will have to be taken into account in investment decisions. Like high oil prices, high carbon prices will impact on investment into alternative fuels supplies, and will therefore influence the scale of production and trend in supply costs. From this perspective, there might be an economic case for including carbon capture and storage in non-conventional oil production under sufficient levels of carbon constraint.

5 **Conclusion**

This research ultimately aims to reveal the effects of investments, learning, depletion and production constraints on the costs of supplying alternative fuels. In this paper, a first model describing the effects of learning and depletion on the costs of supplying oil from non-conventional deposits has been introduced. The learning, depletion, production and resources parameters of the model are not known precisely, and uncertainty was introduced by assigning a distribution to each parameter: the results show large uncertainties on the future supply costs of oil from bitumen. The most influential parameters appear to be C_{min}, γ and the learning rate. Uncertainty on these parameters will be further addressed through model development, data collection and expert elicitation.

The supply of biofuels and carbon intensive fuels will also be considered in the wider context of the world crude oil market. The potential impact of additional liquid fuel production on the world oil market and world oil prices will be assessed. The political, social and economical acceptability of a tax on fuels from non-conventional oil and biofuels will also be studied. Finally, the study will explore the consequences of the above on the development of international investments and markets for biofuels and non-conventional oil.

It is expected that the study will inform decision makers on the type of policy and the scale and timing of investments that will be needed to meet the growing demand for liquid fuels while satisfying CO_2 constraints, and the first model described here is a step in this direction.

References

Adelman, M.A., 2004. The Real Oil Problem. *Regulation*. 27 (1) 16-21
Available from: http://web.mit.edu/ceepr/www/R2004-171.pdf

Adelman, M. A., 1993. Mineral Scarcity and Depletion: Theory and Measurement, in *The Economics of Petroleum Supply*, MIT Press Cambridge, MA.

Adelman, M. A., 1990. Mineral Depletion, with Special Reference to Petroleum. *The Review of Economics and Statistics.* 72 (1) 1-10.
Available from: http://links.jstor.org/

Alberta Energy and Utilities Board (AEUB), 2006. Alberta's Energy Reserves 2005 and Supply/Demand Outlook 2006-2015. Alberta Energy and Utilities Board, Calgary, Alberta.

Anderson, D., 2005. Lecture notes on renewable energy and experience curves. Imperial College, London.

Anderson, D., Winne, S., 2003. Innovation and Threshold Effects in Technology Responses to Climate Change. Tyndall Centre for Climate Change Research
Available from: http://www.tyndall.ac.uk/publications/working_papers/wp43.pdf

Association for the Study of the Peak Oil (ASPO), 2003. Newsletter 26 – February 2003.
Available from: http://www/peakoil.ie

Bencherif, R., 2002. The Impact of Non-Conventional Oil Developments on Conventional Crude Oil Markets. IEA conference on Non-Conventional Oil: Prospects for Increased Production.
Available from: http://www.iea.org

Browne, J., 2006. Energy Security and Climate Change – Speech of BP CEO to Columbia Business School, New York, U.S.A.
Available from: http://www.bp.com/genericarticle.do?categoryId=98&contentId=7025859

Bundesanstalt für Geowissenschaften und Rohstoffe (BGR), 2005. Reserves, Resources and Availability of Energy Resources 2005 – Annual Report.
Available from: http://www.bgr.bund.de

Canadian Association of Petroleum Producers (CAPP), 2006. Canadian Crude oil production and supply forecast 2006 – 2020.
Available from: http://www.capp.ca/raw.asp?x=1&dt=NTV&e=PDF&dn=103586

Canadian Energy Research Institute (CERI), 2005. Economic Impacts of Alberta's Oil Sands Volume 1
Available from:
http://www.ceri.ca/Publications/documents/OilSandsReport-Final.PDF

Centre for Energy, 2007a. What are oil sands and heavy oil?
Available from: http://www.centreforenergy.com

Centre for Energy, 2007b. How are heavy oil and bitumen processed?
Available from: http://www.centreforenergy.com

Chakravorty, U., 1997. Endogenous substitution among Energy Resources and Global Warming. *The Journal of Political Economy*

Chakravorty, U., Roumasset, J., 1990. Competitive oil prices and scarcity rents when the extraction cost function is convex. *Resources and Energy*. 12, 311-320.

Cupcic, F., 2003. Recovery Factor - The Challenges of Enhanced Recovery
Available from: http://www.peakoil.net/iwood2003/ppt/CupcicPresentation.pdf

DEFRA, 2007. The Social Cost Of Carbon And The Shadow Price Of Carbon: What They Are, And How To Use Them In Economic Appraisal In The UK
Available from:
http://www.defra.gov.uk/environment/climatechange/research/carboncost/index.htm

Energy Information Administration (EIA), 2007a. Spot Prices
Available from: http://tonto.eia.doe.gov/dnav/pet/pet_pri_spt_s1_d.htm

Energy Information Administration (EIA), 2007b. This Week In Petroleum, Released on November 7, 2007
Available from: http://tonto.eia.doe.gov/oog/info/twip/twip.asp

Energy Information Administration (EIA), 1996. U.S. Coal Reserves: A Review and Update.
Available from: http://tonto.eia.doe.gov/FTPROOT/coal/052995.pdf

Farrell, A. E., Brandt, A. R., 2006. Risks of the oil transition *Environ. Res. Lett*. 1 (2006) 014004 (6pp)

Fattouh, B., 2007. The Drivers of Oil Prices: The Usefulness and Limitations of Non-Structural model, the Demand-Supply Framework and Informal Approaches. Oxford Institute for Energy Studies WPM32.

Gielen, D., Unander, F., 2005. Alternative fuels: An energy technology perspective. IEA/ETO Working paper, International Energy Agency.
Available from: http://www.iea.org

Grand Dictionnaire Terminologique, 2007. Definitions
Available from: http://www.granddictionnaire.com/

Greene, D. L., Hopson, J. L., Li, J., 2005. Have we run out of oil yet? Oil peaking analysis from an optimist's perspective. *Energy Policy.* 34 (5), 515-531

Grubb, M., 2001. Who's afraid of atmospheric stabilization? Making the link between energy resources and climate change. *Energy policy*. 29, 837-845.

Grübler, A., Nakicenovic, N., Victor, D.G., 1999. Dynamics of energy technologies and global change. *Energy Policy*. 27, 247–280.

Hartwick, J. M., 1978. Exploitation of many deposits of an exhaustible resource, *Econometrica*. 46 (1)

Hirsch, H.L., Bezdek, R., Wendling, R., 2005. Peaking of world oil production: Impacts, Mitigation, & Risk Management. Report to U.S. Department of Energy.
Available from: http://wwwaspo-australia.org.au//References/hirsch0502.pdf

Hope, C., 2006. The marginal impact of CO2 from PAGE2002: An integrated assessment model incorporating the IPCC's five reasons for concern. *Integrated Assessment*. 6 (1) 19-56

Hotelling, H., 1931. The Economics of Exhaustible Resources*. The Journal of Political Economy*. 39 (2) 137-175

International Energy Agency (IEA), 2007. Statement on the Current Oil Market Situation
Available from: http://www.iea.org

International Energy Agency (IEA), 2005a. *Resources to reserves*. OECD/IEA, Paris

International Energy Agency (IEA), 2005b. Meeting our Energy needs – driving forward coal's role in a clean, clever and competitive energy future, IEA Coal Industry Advisory Board workshop, Paris.
Available from: http://www.iea.org/

International Energy Agency (IEA), 2004a. *World Energy Outlook 2004*. OECD, Paris.

International Energy Agency (IEA), 2004b. Prospects for CO_2 Capture and Storage – Energy Technology Analysis.
Available from: http://www.iea.org

International Energy Agency (IEA), 2000. *Experience curves for energy technology policy*, by Wene, C.O. OECD/IEA, Paris

Intergovernmental Panel on Climate Change (IPCC), 2007. Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change - Technical Summary
Available from:
http://www.mnp.nl/ipcc/pages_media/FAR4docs/final_pdfs_ar4/TS.pdf

Joint Economic Committee – US Congress, 2006. Canadian oil Sands: A new force in the world oil market – A Joint Economic Committee study

Available from: http://www.house.gov

Knapp, D., 2002. Competitiveness relative to Conventional oil, IEA Conference on Non-Conventional Oil: Prospects for Increased Production, Calgary, Alberta. November 25-26, 2002.
Available from: http://www.iea.org

Krautkraemer, J., Toman, M., 2003. Fundamental Economics of Depletable Energy Supply. Resources for the Future. Discussion Paper 03-01
Available from: http://www.rff.org/documents/RFF-DP-03-01.pdf

Lindley, D. V., 1985. *Making decisions*, Second edition. John Wiley and sons, London.

Margolis, R. M., 2002. Experience Curves and Photovoltaic technology policy, Human Dimensions of Global Change Seminar, Carnegie Mellon University.
Available from: http://hdgc.epp.cmu.edu/mailinglists/hdgcctml/mail/ppt00010.ppt

McDonald, A., Schrattenholzer, L., 2001. Learning rates for energy technologies. *Energy Policy*. 29 (4) 255-261

Meyer, R. F., Attanasi, E. D., 2004. Extra-heavy oil and Natural Bitumen: Contribution to Future Energy Supply. Northeastern Section (39th Annual) and Southeastern Section (53rd Annual) Joint Meeting (March 25–27, 2004).
Available from: http://gsa.confex.com/gsa/2004NE/finalprogram/abstract_69910.htm

National Energy Board (NEB), 2006. Canada's Oil Sands - Opportunities and Challenges to 2015: An Update.
Available from: http://www.neb.gc.ca

National Energy Board (NEB), 2004. Canada’s Oil Sands - Opportunities and Challenges to 2015.
Available from: http://www.neb.gc.ca

National Energy Board (NEB), 2000. Canada’s Oil Sands: A Supply and Market Outlook to 2015.
Available from: http://www.neb.gc.ca

Nordhaus, W., Boyer, J., 1999. Roll the DICE Again: Economic Models of Global Warming - Chapter 3
Available from:
http://www.econ.yale.edu/~nordhaus/homepage/web\%20chap\%203\%20102599.pdf

Odell, P., 1998. Dynamics of energy technologies and global change. *Energy policy*. 27, 737-742.

Oil and Gas Journal (OGJ), 2003. Heavy hydrocarbons playing key role in peak-oil debate, future energy supply by Williams, B., *Oil and Gas Journal*. 101, Issue 29 (28th July 2003).
Available from: http://ogj.pennnet.com/

Palisade, 2007. @Risk 4.5 Help.

Rehrl, T., Friedrich, R., 2006. Modelling long-term oil price and extraction with a Hubbert approach: The LOPEX model. *Energy Policy* 34 (15) 2413-2428

Rogner, H-H., 1997. An Assessment of World Hydrocarbon Resources. *Annual Review Energy Environment* 22, 217-62.

Roumasset, J., Isaak, D., Fesharaki, F., 1983. Oil prices without OPEC A walk on the supply-side. *Energy Economics*. 5 (3) 164-170
Available from: http://www.sciencedirect.com

SAUNER, 2000. The SAUNER project: Overview
Available from: http://people.bath.ac.uk/hssam/sauner/overview.html#Methodology

Soderbergh, B., 2006. A crash programme scenario for the Canadian oil sands industry. *Energy policy*. In press.

Stern, N., 2007. *The Economics of Climate Change - The Stern Review*. Cambridge University Press. Cambridge, U.K.

Stevens, P., 2005. Oil markets. *Oxford review of Economic Policy*. 21 (1) 19-42

Sweeney, J., L., 2004. Energy Economics in *International Encyclopedia of the Social & Behavioral Sciences*, 4513-4520
Available from: http://www.sciencedirect.com

Sweeney, J., L., 1992. Economic theory of depletable resources: An Introduction, in *Handbook of Natural Resource and Energy Economics*, Volume 3. Eds. Allen V. Kneese and James L. Sweeney.

Tsuchiya, H., Kobayashi, O., 2003. Mass production cost of PEM fuel cell by learning curve. *International Journal of Hydrogen Energy*. 29, 985-990.

United Nations Development Programme (UNDP), 2000. World Energy Assessment: Energy and the Challenge of Sustainability.
Available from: http://www.undp.org

United Nations Framework Convention on Climate Change (UNFCCC), 2007. Parties and Observers
Available from: http://unfccc.int/

United Nations Framework Convention on Climate Change (UNFCCC), 2005. Greenhouse Gas Emissions Data for 1990 – 2003 submitted to the United Nations Framework Convention on Climate Change.
Available from: http://unfccc.int/

U.S. Geological Survey (USGS), 2005. Geology and Resources of Some World Oil-Shale Deposits, by John R. Dyni.
Available from: http://pubs.usgs.gov/sir/2005/5294/

U.S. Geological Survey (USGS), 2003. Heavy Oil and Natural Bitumen – Strategic Petroleum Resources, by Meyer, R. F. and Attanasi, E. D., United States Geological Survey Fact Sheet 70-03
Available from: http://pubs.usgs.gov/fs/fs070-03/fs070-03.html

U.S. Geological Survey (USGS), 1995. Economics and the 1995 National Assessment of United States Oil and Gas Resource, by Attanasi, E.D., United States Geological Survey Circular 1145

Available from: http://pubs.usgs.gov/circ/1998/c1145/c1145.pdf

Web dictionary of Cybernetics and Systems, 2007. Decision Theory
Available from: http://pespmc1.vub.ac.be/ASC/indexASC.html

World Energy Council (WEC), 2001. Survey of Energy resources 2001 – Natural Bitumen and Extra-heavy Oil.