Long Term Prediction of Unconventional Oil Production

S. H. Mohr*

G. M. Evans

University of Newcastle, Faculty of Engineering and Built Environment, Chemical Engineering, University Drive, Callaghan, NSW 2308, Australia

Abstract

Although considerable discussion surrounds unconventional oil's ability to mitigate the effects of peaking conventional oil production, very few models of unconventional oil production exist. The aim of this article was to project unconventional oil production to determine how significant its production may be. Two models were developed to predict the unconventional oil production, one model for in-situ production and the other for mining the resources. Unconventional oil production is anticipated to reach between 18 and 32 Gb/y (49−88 Mb/d) in 2076−2084, before declining. If conventional oil production is at peak production then projected unconventional oil production cannot mitigate peaking of conventional oil alone.

Key words: Unconventional oil, Modeling, Supply

Introduction

There is increasing certainty that conventional oil[1] production has peaked/will peak before 2025 e.g. Aleklett (2004); Bakhtiari (2004); Deffeyes (2002); Mohr and Evans (2007, 2008); Wells (2005a,b). Given the likely peak in conventional

*Corresponding author.

Email addresses: steve.mohr@studentmail.newcastle.edu.au (S. H. Mohr), Geoffrey.Evans@newcastle.edu.au (G. M. Evans)

[1]Conventional oil will be considered to be hydrocarbons which at atmospheric condition are liquid and have a density less than water (API $> 10^{o}$). Conventional oil includes natural gas liquids, deep water oil and heavy oil (density $10 - 20^{o}$ API).

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oil production, it is important to examine unconventional oil resources and possible production. Literature models on unconventional oil production are variable. Edwards (1997) modeled Canadian tar sands, US Shale oil, and Venezuelan Extra Heavy oil and indicated combined production approaching 10 Gb/y ($\sim$25 Mb/d) by 2100. Koppelaar (2007) has unconventional oil reaching a plateau of 4.5 Gb/y (12.5 Mb/d). Söderbergh et al. (2007) indicates Canadian natural bitumen production reaching a peak of 2.2 Gb/y (6 Mb/d) in 2040. Söderbergh et al. (2007) model takes into account factors such as the energy required to extract and process the natural bitumen and the accessibility of the resource, and has been peer reviewed. Contradicting the estimates from Edwards (1997); Koppelaar (2007); Söderbergh et al. (2007) is Caruso (2005) who indicates that Canadian natural bitumen alone will reach a peak of 41 Gb/y (112 Mb/d) in 2078 (and $\sim$8 Gb/y or 22 Mb/d in 2050). The work by Caruso (2005) is simplistic with the assumption that Canadian unconventional oil continues to grow at 6% until 2078 and then decline at the same rate. For these reasons, the work by Söderbergh et al. (2007) has been given higher weighting than that by Caruso (2005). The question therefore to be addressed here is assuming conventional oil production will peak before 2025, what role can unconventional oil have? Specifically is it the case that unconventional oil production can provide a smooth transition when conventional oil peaks, is unconventional oil insignificant compared to conventional oil production or is unconventional oil production significant but too late to mitigate short term effects of conventional oil production peaking?

A critical assessment of unconventional oil resources, and a model of unconventional oil production is developed to determine if unconventional oil can mitigate the effects of conventional oil production peaking. Unconventional oil is limited to extra heavy oil, natural bitumen (oil sands, tar sands) and oil shale, other fuels such as coal and natural gas are not considered as unconventional oil as they are valuable in their original state and hence not likely to be used as major sources of synthetic crude production. Extra Heavy oil is defined as a hydrocarbon with an API of $< 10^{\text{o}}$ and a viscosity of $< 10,000$ cP WEC (2007). Natural Bitumen has a density $< 10^{\text{o}}$ API, the same as Extra heavy oil, but is more viscous than Extra Heavy oil (typically stated as $> 10,000$ cP WEC (2007); Meyer (1998)). Oil shale is kerogen typically in marlstone, it is typically neither a shale nor an oil. A synthetic conventional oil (called shale oil) can be generated by processing the oil shale. The Ultimately Recoverable Resources (URR) reported here refers to the total amount of synthetic crude oil extracted from the resource i.e. natural bitumen, extra heavy oil, shale oil.

The aim of the study is to predict unconventional oil production. First, a supply model is developed which includes in-situ and mining extraction techniques. Second the model is calibrated based on historical Canadian natural bitumen production and “Pessimistic”, “Optimistic” and “Best guess” URR scenarios determined. Finally the model outputs are combined with previously reported conventional oil analysis to obtain combined oil production projections.

Model description

Mining production

The unconventional oil model is based on previous work Mohr and Evans (2009) applied to coal production. Briefly the coal production model was based on an individual mine production, with a maximum production, mine life and a 4 year ramp up and down. For a given mine the production profile is shown in Figure 1

Figure 1 hereabouts

Production for a mining basin, is determined by the sum of the individual mines currently on-line in the basin. Mathematically the production from the b-th basin from the mining model ($P^{Mb}(t)$) is shown in equation 1

$$P^{Mb}(t) = \sum_{l=1}^{n^{Mb}(t)} P_l^{Mb}(t) \tag{1}$$

where $n^{Mb}(t)$ is the number of mines on-line at year t in the b-th basin and $P_l^{Mb}(t)$ is the production of the l-th mine in the b-th basin. The production profile of a mine $P_l^{Mb}(t)$ is shown in Figure 1.

The number of mines on-line at time t, $n^{Mb}(t)$ depend on the cumulative production so that:

$$n^{Mb}(t) = \left\lceil N^{Mb} + (1 - N^{Mb}) \exp\left[-k^{Mb}\left(\frac{\sum_{l=1}^{n^{Mb}(t-1)} C_l^{Mb}(t)}{URR^{Mb}}\right)\right]\right\rceil, \quad t \geq t^{Mb} \tag{2}$$

Where $n^{Mb}(t)$ is the number of mines on-line, N^{Mb} is the total number of mines, k^{Mb} is the proportionate constant, $C_l^{Mb}(t)$ is the cumulative production of the l-th mine at time t, t^{Mb} is the year the basin came on-line and URR^{Mb} is the mining ultimately recoverable resources in the b-th basin.

In-situ production

The in-situ model is identical to the mining model, only instead of production from a mine, production is from a SAGD/CSS plant. The production profile of a SAGD/CSS plant is shown schematically in Figure 2.

Figure 2 hereabouts

It can be seen that a SAGD/CSS plant has a ramp up phase, a maximum production, p_M and a decline period.

As with the mining model, the production from the b-th basin, $P^{Ib}(t)$ in the in-situ model is shown in equation 3

$$P^{Ib}(t) = \sum_{l=1}^{n_S^{Ib}(t)} P_l^{Ib}(t) \tag{3}$$

Where $n_S^{Ib}(t)$ is the number of SAGD/CSS plants on-line in year t, $n_{wl}^{Ib}(t)$ is the number of wells on-line in the l-th SAGD/CSS plant, and $P_l^{Ib}(t)$ is the production from the l-th SAGD/CSS plant.

Again, like the mining model, the number of SAGD/CSS plants on-line in the b-th basin $\left(n_S^{Ib}(t)\right)$ is determined from equation 4

$$n_S^{Ib}(t) = \left\lceil N_S^{Ib} + (1 - N_S^{Ib}) \exp\left[-k_S^{Ib}\left(\frac{\sum_{l=0}^{n_S^{Ib}(t-1)} C_l^{Ibo}(t)}{URR^{Ib}}\right)\right]\right\rceil \tag{4}$$

where $N_S^{Ib}(t)$ is the total number of SAGD/CSS plants in the t-th year, $C_l^{Ibo}(t)$ is the cumulative in-situ production from the l-th SAGD/CSS plant, k_S^{Ib} is a proportionality constant and URR^{Ib} is the in-situ ultimately recoverable resources; and are all variables for the b-th basin.

Now it is necessary to describe the production from a SAGD/CSS plant. As shown in Figure 2, the production of an individual SAGD/CSS plant, is calculated as the sum of the production from the individual wells in the plant, or mathematically:

$$P_l^{Ib}(t) = \sum_{i=1}^{n_{wl}^{Ib}(t)} P_{li}^{Ib}(t) \tag{5}$$

Where $P_{li}^{Ib}(t)$ is the production from the i-th well in the l-th SAGD/CSS plant and $n_{wl}^{Ib}(t)$ is the number of wells on-line at time t. The number of wells on-line is determined from equation 6

$$n^{Ib}_{wl}(t) = \left[N^{Ib}_{wl} + (1 - N^{Ib}_{wl}) \exp\left[-k^{Ib}_{wl}\left(\frac{\sum_{i=1}^{n^{Ib}_{wl}(t-1)} C^{Ibo}_{li}(t)}{URR^{Ib}_{l}}\right)\right]\right], \quad t \geq t^{Ib}_{l} \tag{6}$$

Where N^{Ib}_{wl}, is the total number of wells, k^{Ib}_{wl} is the proportionality constant, $C^{Ibo}_{li}(t)$ is the cumulative production of oil at time t from the i-th well and URR^{Ib}_{l} is the Ultimately Recoverable Resources, and all of these terms are for the l-th SAGD/CSS plant, in the b-th basin. Note at times to keep production below the maximum production p_m, equation 6 only puts a new well on-line if there is a sufficient gap between actual production and the maximum allowed production.

The only thing left in order to determine production from the in-situ model, is an expression for the production from a well. First, assume that production is proportionate to pressure then

$$\frac{dC^{Ibo}_{li}(t)}{dt} = K^{Ib}_{li} Pr^{Ib}_{li} f^{Ibo}_{li}(t), \tag{7}$$

where Pr^{Ib}_{li} is the pressure in the well, $f^{Ibo}_{li}(t)$ is the fraction of oil in the well at time t, K^{Ib}_{li} is the proportionate constant and $C^{Ibo}_{li}(t)$ is the cumulative production of oil from the well at time t, all of these variables are for the i-th well of the l-th SAGD/CSS plant, in the b-th basin.

It will be assumed that all wells have the same initial production rate, p_0. Let $P^{Ib}_{li}(t)$ denote the production as a function of time in the i-th well in the l-th SAGD/CSS plant in the b-th basin, and t^{Ib}_{li} denote the year the well came on-line. When $t = t^{Ib}_{li}$ then $\frac{dC^{Ibo}_{li}(t)}{dt} = P^{Ib}_{li}(t^{Ib}_{li}) = p_0$, and $f^{Ibo}_{li}(t^{Ib}_{li}) = 1$, hence $K^{Ib}_{li} = p_0/Pr^{Ib}_{li}$, and so Equation 7 becomes

$$\frac{dC^{Ibo}_{li}(t)}{dt} = p_0 f^{Ibo}_{li}(t) \tag{8}$$

It is assumed that the fraction of oil produced is directly proportionate to the amount of oil and steam in the reservoir hence

$$f^{Ibo}_{li}(t) = \frac{URR^{Ib}_{li} - C^{Ibo}_{li}(t)}{URR^{Ib}_{li} - C^{Ibo}_{li}(t) + C^{Ibw}_{li}(t)} \tag{9}$$

where $C_{li}^{Ibw}(t)$ is the cumulative amount of water at time t, and URR_{li}^{Ib} is the Ultimately Recoverable Resources, all variables are for the i-th well of the l-th SAGD/CSS plant in the b-th basin. If the pressure is assumed constant, and related to the amount of oil and water in the reservoir, then it is assumed that $C_{li}^{Ibw} = C_{li}^{Ibo}$ and by combining equation 8 and 9 obtain

$$\frac{dC_{li}^{Ibo}(t)}{dt} = p_0 \frac{URR_{li}^{Ib} - C_{li}^{Ibo}}{URR_{li}^{Ib}} \tag{10}$$

Assuming the i-th well in the l-th SAGD/CSS plant in the b-th basin, begins in the year t_{li}^{Ib} then

$$C_{li}^{Ibo}(t) = URR_{li}^{Ib} - URR_{li}^{Ib} e^{-\frac{p_0}{URR_{li}^{Ib}}\left(t - t_{li}^{Ib}\right)}. \tag{11}$$

By differentiating, equation 11 becomes

$$P_{li}^{Ib}(t) = p_0 e^{-\frac{p_0}{URR_{li}^{Ib}}\left(t - t_{li}^{Ib}\right)} \tag{12}$$

and the in-situ model is fully described. More detailed SAGD/CSS models exist e.g. Akin (2005) however the method described here is sufficient.

Model Calibration

URR estimate

Resource estimates are well known with general agreement (Russell, 1990; WEC, 2007). However, estimates for URR values are less certain (e.g. Bartis et al. (2005) has Green River Basin URR estimates of 500 – 1100 Gb) and for this reason three scenarios have been selected for analysis, namely Pessimistic, Optimistic and Best Guess. The Pessimistic scenario will assume a low end URR estimate, the Optimistic estimate will assumed high URR predictions, and the Best Guess will be the Authors best guess. Wherever possible the URR was determined from literature estimates as indicated in Tables 1 – 3. Where a literature estimate was not known then the URR was assumed to be: (1) 15% of resources for natural bitumen and extra heavy oil; and (2) 64% for shale oil. The assumption of 15% for natural bitumen and extra heavy oil was based on Meyer (1998) indicating 10%; Ali (2003) and Williams (2003) indicating 15% and Moritis (2005) indicating 20%. The assumption of 64% for shale oil was based on Bartis et al. (2005) estimate of the recovery percent for the Green River Basin, which dominates the worldwide oil shale resources. The estimate of 64% recovery for shale oil is very optimistic and will most likely over estimate reality. Tables $1-3$ show the resources and URR values assumed.

Tables $1-3$ hereabouts

SAGD plant operating conditions

Figure 3 hereabouts

The constants for the in-situ model will be simplified by assuming that the proportionality constants for the number of SAGD/CSS plants, and the number of wells in the SAGD/CSS plant are constant for all basins ($k_S^{Ib} = k_S$, $k_{wl}^{Ib} = k_w$) and all SAGD/CSS plants are the same size ($URR_l^{Ib} = URR_l^I$) for all basins and SAGD/CSS plants. In Figure 3 we have actual production data for the JACOS SAGD plant, by observing production for the first 2 wells, we see that production took 6 months to reach a maximum before beginning to decline. We see that initial production for the two wells was slightly less than 1Mb/y hence the initial production of a well (p_0) was set at 0.0005 Gb/y. Figure 3 indicates that, there was a total of 15 wells brought on-line and the URR for the 15 wells was estimated at 0.025 Gb (best fit to the data) and the rate constant for the number of wells k_w was set at 10 (best fit to the number of wells data, R^2=0.93). The total number of wells for each SAGD/CSS plant for a given basin b was determined by scaling the numbers used to model the JACOS plant so, $N_{wl}^{Ib} = (15/0.025)URR_l^I = 600URR_l^I$. All SAGD/CSS plants are assumed to have the same operating parameters (maximum production $p_M = 72$kb/d, 40 year lifespan) as the recent Nexen Long Lake plant Long Lake (2009). The rate constant for the number of SAGD/CSS operations k_S was determined to be 7 by fitting the model to the Canadian In-situ production (R^2=0.98). Figure 4 shows the comparison between the model and the data for In-situ Canadian production. The constants for the in-situ model for all basins are shown in Tables 4 and 5.

Figure 4 and Tables 4 and 5 hereabouts

Mine operating conditions

The mining rate constant k_m^{Mb} for Canada, was found to be equal to 10 by fitting the model to the Canadian data. The same value was assumed for all other countries where production has not yet commenced. An approximate maximum production of each mine for Canadian production was assumed to be 0.01 Gb/y

(~0.03 Mb/d). During the period when Suncor was the only mine in Canada (1967-1978) production was more like 0.02 Gb/y (~0.05 Mb/d), but because of the ceiling function, after 1 year the model produces 2 mines, which remain for approximately 10 years, so, the maximum production for Canadian mines was set at 0.01 Gb/y (~0.03 Mb/d). The mines used in the Canadian oil sands industry are amongst the biggest mines in the world, for this reason a long mine life was assumed essential and was set at 80 years. The mining rate constant k_m^{Mb} for Canada, was found to be equal to 10 by fitting the model to the Canadian data. Figure 4 shows the fit between the model and the data for the Canadian tar sands mining ($R^2 = 0.96$ for pessimistic and best guess cases, and 0.93 for optimistic case). The same rate constant $k_m^{Mb} = 10$ was assumed for all other countries where production has not yet commenced. The maximum production of a mine and the life of the mine was determined directly from the ultimately recoverable reserves of the basin, as indicated in Equations 13 and 14.

$$M_p^{Mb} = \begin{cases} 0.01 \text{ Gb/y (27 kb/d), if } URR^{Mb} \geq 10 \\ 0.005 \text{ Gb/y (14 kb/d), if } 1 < URR^{Mb} < 10 \\ 0.001 \text{ Gb/y (3 kb/d), if } URR^{Mb} \leq 1 \end{cases} \tag{13}$$

$$M_L^{Mb} = \begin{cases} 80 \text{ y, if } URR^{Mb} \geq 10 \\ 60 \text{ y, if } 1 < URR^{Mb} < 10 \\ 40 \text{ y, if } URR^{Mb} \leq 1 \end{cases} \tag{14}$$

In the US Green River deposit production will be limited due to a lack of water availability. The pessimistic case limits production to 0.3 Gb/y (0.7 Mb/d), the best guess case to 2 Gb/y (5.7 Mb/d) and the optimistic case is restricted to 4 Gb/y (10.7 Mb/d). For more information on how these numbers were determined see Appendix. The constants for the mining model for all basins are shown in Tables 6 and 7.

Tables 6 and 7 hereabouts

Results and Discussion

The in-situ model was used to model in-situ natural bitumen production and extra heavy oil production. The mining model was used to predict production from mined natural bitumen and shale oil production. Currently shale oil is extracted via mining and retorting techniques; in the future, production particularly in the Green River and Devonian basins could be from in-situ techniques, however extraction methods are still in the research and development phase. Due to the lack of in-situ techniques currently available, it is assumed that shale oil production is via mining methods only.

Unconventional oil production for the three different scenarios are shown in Figure 5. The unconventional oil has been split into the different types of unconventional oil production, namely natural bitumen, extra heavy oil and shale oil. Unconventional oil production is anticipated to peak between 18 Gb/y (49 Mb/d) in 2076 and 32 Gb/y (88 Mb/d) in 2084, with the best guess scenario of 22 Gb/y (60 Mb/d) in 2077.general shale oil has the biggest potential production, with shale oil peaking at 10 Gb/y (27 Mb/d) in 2108 for the pessimistic case, 12.9 Gb/y (35.3 Mb/d) in 2105 for the best guess scenario and 19 Gb/y (52 Mb/d) in 2123 for the optimistic case. Although oil shale has the greatest potential, it also has the greatest uncertainty surrounding its extraction methods and economic viability. Extraction methods in the past have been via mining; however Shell is developing an in-situ method of recovery (Shell, 2007). In terms of economics, Shell have argued that shale oil is potentially economical at ∼\$25 a barrel (Fletcher, 2005b), however Australia oil shale production ceased in 2004 stating that production was uneconomic Francu et al. (2007).

Figure 6 shows the unconventional oil production by countries for the three different scenarios. Unconventional oil is found in three main countries: natural bitumen in Canada, extra heavy oil in Venezuela, and shale oil in USA. Figure 6 shows that these three countries are the biggest producers of unconventional oil. Along with these nations, the Former Soviet Union countries will also have considerable unconventional oil production with all scenarios indicating FSU unconventional oil production to be greater than 8 Mb/d by 2100.

Literature and our estimate for Canadian natural bitumen is shown in Figure 7. The literature scenarios and our estimates are shown up to 2030, with our estimates ranging from 4.5 to 5.8 Mb/d in 2030. In 2030 both Greene et al. (2006) and the U.S. Department of Energy (2008) high price scenario are significantly higher than our forecasts, with Greene et al. (2006) estimating 12.6 Mb/d and U.S. Department of Energy (2008) high price scenario indicating 8.7 Mb/d. The U.S. Department of Energy (2008) low price and low growth scenarios are both considerably below our estimate with projections of 1.4 and 1.7 Mb/d respectfully. The bulk of literature projections U.S. Department of Energy (2008) reference and high growth cases, Zittel and Schindler (2007), Caruso (2005), along with all three of Söderbergh (2005) have a range of 3.4 Mb/d to 6.9 Mb/d in 2030, which is close to our projection of 4.5 to 5.8 Mb/d. Our projections of Canadian natural bitumen agree with the bulk of the literature estimates.

Literature and our estimate of Venezuelan extra heavy oil production is shown in Figure 8. Our projections up to 2030 indicate that extra heavy oil production will yield ∼1 Mb/d in 2012, and 3.7 to 4.0 Mb/d in 2030. Shorter term projections from Moritis (2005) and Smith (2007) indicate production in 2012 will be 1.2 to 1.9 Mb/d notably higher than our estimate for the time period of 1 Mb/d. The U.S. Department of Energy (2008) estimates in 2030 are between 1.1 and 2.1 Mb/d which is lower than our estimate of 3.7 to 4.0 Mb/d in 2030. However Greene et al. (2006) indicates the production will be around 6 Mb/d in 2030 considerably higher than our estimate. There is considerable range of estimates for Venezuelan extra heavy oil production, however our production estimate is within literature estimates if on the optimistic side.

Figure 9 shows literature and our projections of world unconventional oil production up to 2030. Our projection of unconventional oil reaches 10.7 to 10.9 Mb/d in 2030. Edwards (1997) projects unconventional oil far lower than our estimates with 0.9 Mb/d in 2030. The U.S. Department of Energy (2008) high price case has production higher than our projections at 11.2 Mb/d in 2030. However the other U.S. Department of Energy (2008) projections which range from 2.5 to 6.6 Mb/d are lower than our estimates at 2030. Koppelaar (2007) is slightly higher than our projection with 10.7 to 12.1 Mb/d in 2030. Greene et al. (2006) is significantly higher than our estimates in the future with 27.8 Mb/d in 2030. Our total unconventional oil production projections can be thought of as on the high end of the literature estimates.

Figure 10 shows the unconventional growth rates up to 2050. The growth rates for unconventional oil in our models are between 7-11% up to 2025, and thereafter decline slowly to 4-5% by 2050. Greene et al. (2006); De Castro et al. (2009) indicate that very high growth rates in unconventional oil production are needed for the future. Greene et al. (2006) indicates that a growth rate of around 7-9 % is needed if non Middle-East oil production is near peak production, whereas, De Castro et al. (2009) shows that unconventional oil growth rates in excess of 10% are needed to mitigate conventional peak oil. Based only on growth rate assumptions from literature, it might be possible for unconventional oil to mitigate conventional oil declines.

Figure 11 shows combined conventional and unconventional oil production. The conventional oil production includes three projections and is from Mohr and Evans (2008). The combined total oil production in Figure 11 shows that the pessimistic oil production scenario peaks in 2010 at 31 Gb/y (84 Mb/d). The total oil production best guess scenario is projected to peak in 2014 at 32 Gb/y (87 Mb/d). In the optimistic scenario conventional oil peaks in 2025 and total oil production predicted to peak around 2050 (2052 at 39 Gb/y or 106 Mb/d).

Although the optimistic scenario peaks in the long term future, demand for oil in 2030 is projected to be 40 Gb/y (109 Mb/d)[2] U.S. Department of Energy (2008), whereas even in the Optimistic scenario production is only 36 Gb/d (99 Mb/d), so even with optimistic scenarios there will be insufficient oil supplies by 2030. Combining conventional and unconventional oil production indicates that only in a very optimistic scenario can oil production peak after the next 5 years.

The scenarios presented in this article ought to be considered optimistic given the lack of economic constraints and EROEI constraints (e.g. shale oil extraction is currently expensive and energy intensive). Despite the optimistic nature of the assumptions in these scenarios, total oil production is forecasted to decline within 5 years for both the pessimistic and best guess scenarios. Only in the optimistic scenario does total oil production not peak in the near future. The analysis of unconventional oil indicates that at the absolute best it can only delay the peaking of world oil production by about 25 years.

Figures 5-11 hereabouts

Conclusion

A model has been developed to predict unconventional oil production for the next 200 years. Three scenarios (Pessimistic, Best Guess, and Optimistic) where chosen with URR's ranging from 2000 Gb to 3750 Gb. The developed model projected unconventional oil production oil production to peak between 18 Gb/y (49 Mb/d) in 2076 to 32 Gb/y (88 Mb/d) in 2084. The Best Guess scenario assumed a URR of 2500 Gb and peaked in 2077 at 22 Gb/y (60 Mb/d). When combined with literature projections of conventional oil production, total oil production in both the pessimistic and best guess scenarios peaked within the next 5 years, with only the optimistic scenario having unconventional oil partially mitigating conventional oil peaking. The optimistic scenario of total oil production peaks around 2050.

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[2] 4 Mb/d of Coal to Liquid, Gas to Liquid and Biofuels have been removed from the U.S. Department of Energy (2008) projection to make the definitions of oil as similar as possible

Nomenclature

Functions

$C^{Ibo}(t)$ The Cumulative production of oil in the b-th basin (Gb)

$C_l^{Ibo}(t)$ The Cumulative production for the l^{th} SAGD/CSS plant in the b-th basin as a function of time (Gb)

$C_{li}^{Ibo}(t)$ The Cumulative production of oil for the i-th well in the l-th SAGD/CSS plant, in the b-th basin (Gb)

$C_{li}^{Ibw}(t)$ The Cumulative production of water for the i-th well in the l-th SAGD/CSS plant, in the b-th basin (Gb)

$C_l^{Mb}(t)$ The Cumulative production of oil, from the l-th mine in the b-th basin (Gb)

$f_{li}^{Ibo}(t)$ The fraction of oil, in the i-th well of the l-th SAGD/CSS plant in the b-th basin (-)

$n_S^{Ib}(t)$ The number of SAGD/CSS plants in the b-th basin as a function of time (-)

$n_{wl}^{Ib}(t)$ The number of well pairs in operation for the l^{th} SAGD/CSS plant in the b-th basin as a function of time (-)

$n^{Mb}(t)$ The number of mines on-line in the b-th basin as a function of time (-)

$P^{Ib}(t)$ The production from the b-th basin from the in-situ model

$P_{li}^{Ib}(t)$ The production of oil from the i-th well in the l-th SAGD/CSS plant in the b-th basin (Gb/y)

$P^{Mb}(t)$ The mining production from the b-th basin

$P_l^{Mb}(t)$ The production from the l-th mine in the b-th basin

R^2 The coefficient of determination (-)

Variables

K_{li}^{Ib} Constant linking production to pressure in the i-th well of the l-the SAGD/CSS plant in the b-th basin (Gb/Pa)

k_S^{Ib} The proportionality constant for the number of SAGD/CSS plants in the b-th basin (-)

k_{wl}^{Ib} The proportionality constant for the number of well pairs built in the l-th SAGD/CSS plant, in the b-th basin (-)

k^{Mb} The proportionality constant for the number of mines in the b-th basin (-)

k^M The proportionality constant for the number of mines (-)

k_S The proportionality constant for the number of SAGD/CSS plants (-)

k_w The proportionality constant for the number of well pairs (-)

M_{lL}^{Mb} The mine life of the l-th mine in the b-th basin (y)

M_L^{Mb} The mine life of the mines in the b-th basin (Gb/y)

M_{lp}^{Mb} The maximum production of the l-th mine in the b-th basin (Gb/y)

M_p^{Mb} The maximum production of the mines in the b-th basin (Gb/y)

N_S^{Ib} The total number of SAGD/CSS plants in the b-th basin (-)

N_{wl}^{Ib} The total number of SAGD well pairs in operation in the l^{th} SAGD/CSS plant in the b-th basin (-)

N^{Mb} The total number of mines in the b-th basin (-)

p_0 The initial production of the wells in the SAGD/CSS plants (Gb/y)

p_M The maximum production from an in-situ plant

Pr_{li}^{Ib} The pressure of the i-th well in the l-th SAGD/CSS plant in the b-th basin (Pa)

t time (y)

t_l^{Ib} The year the l-th SAGD/CSS plant in the b-th basin comes on-line (y)

t_{li}^{Ib} The year the i-th well in the l-th SAGD/CSS plant in the b-th basin comes on-line (y)

t^{Mb} The year the b-th mining basin comes on-line (y)

URR^{Ib} The in-situ Ultimately Recoverable Resources in the b-th basin (Gb)

URR_l^{Ib} The in-situ Ultimately Recoverable Resources for the l^{th} SAGD/CSS plant in the b-th basin, (Gb)

URR_l^{I} The in-situ Ultimately Recoverable Resources for the l^{th} SAGD/CSS plants, (Gb)

URR_{li}^{Ib} The in-situ Ultimately Recoverable Resources of the i-th well in the l-th SAGD/CSS plant in the b-th basin (Gb)

URR^{Mb} The mining Ultimately Recoverable Resources in the b-th basin (Gb)

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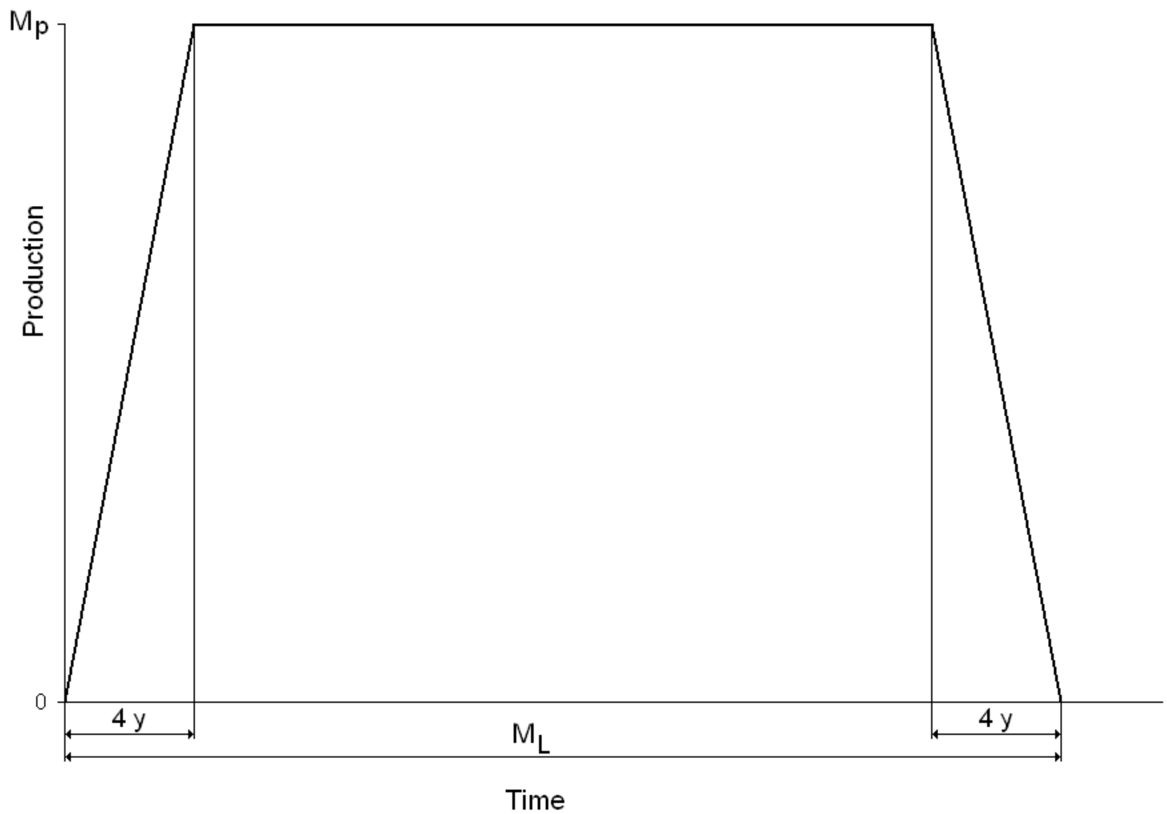

Figure 1: Schematic production profile of a mine

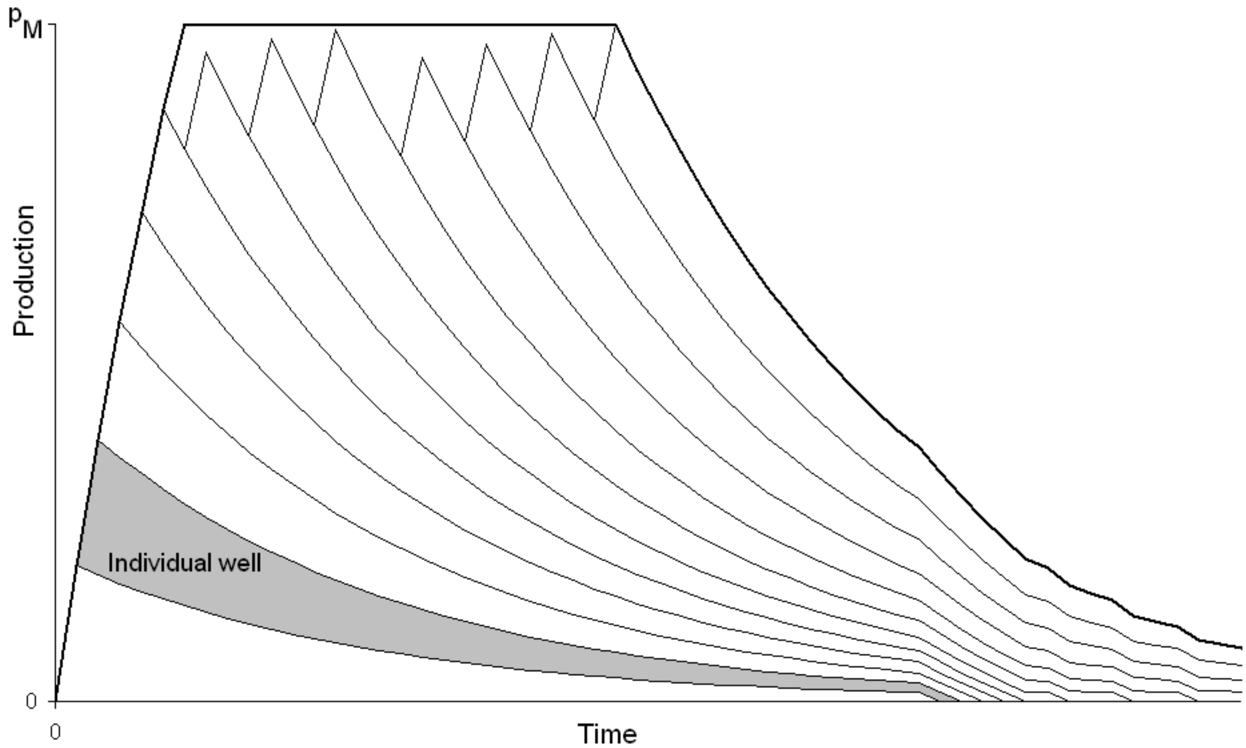

Figure 2: Schematic production profile of a SAGD/CSS plant

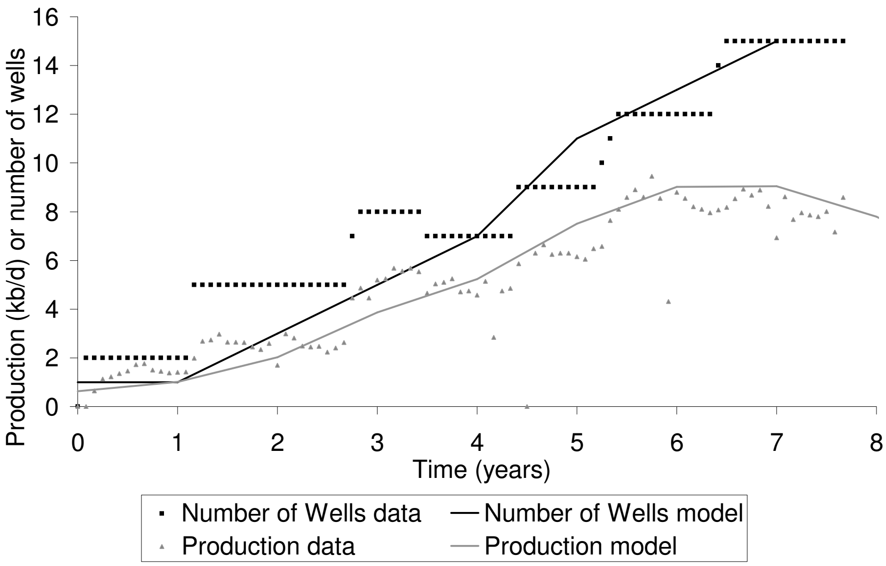

Figure 3: Reported JACOS (2007) versus predicted unconventional oil production and number of wells a SAGD Canadian bitumen plant

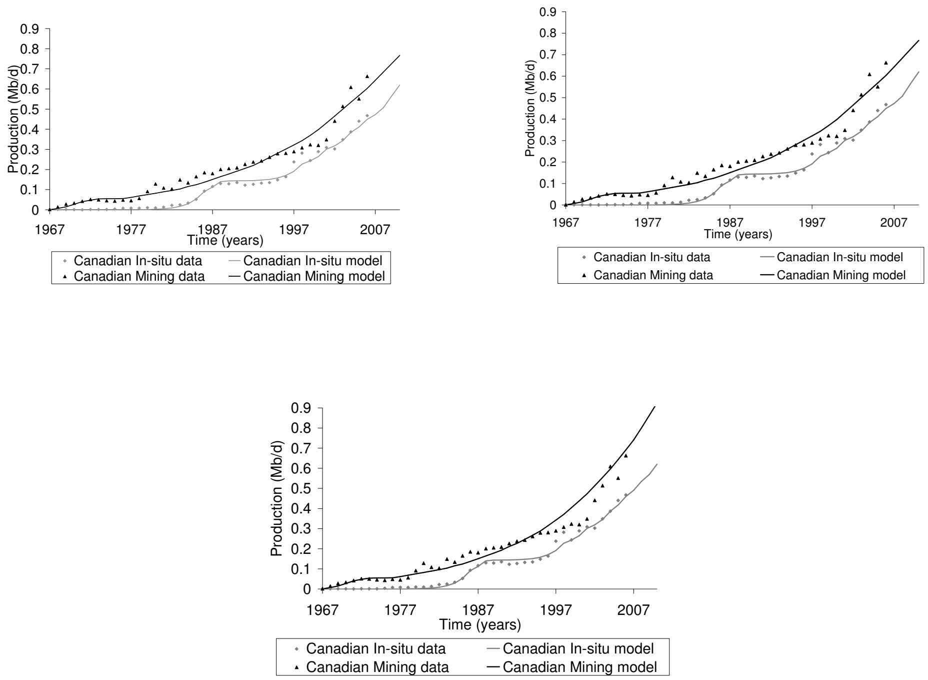

Figure 4: Unconventional oil model applied to Canadian Tar sands production, A) Pessimistic Case B) Best Guess Case C) Optimistic Case

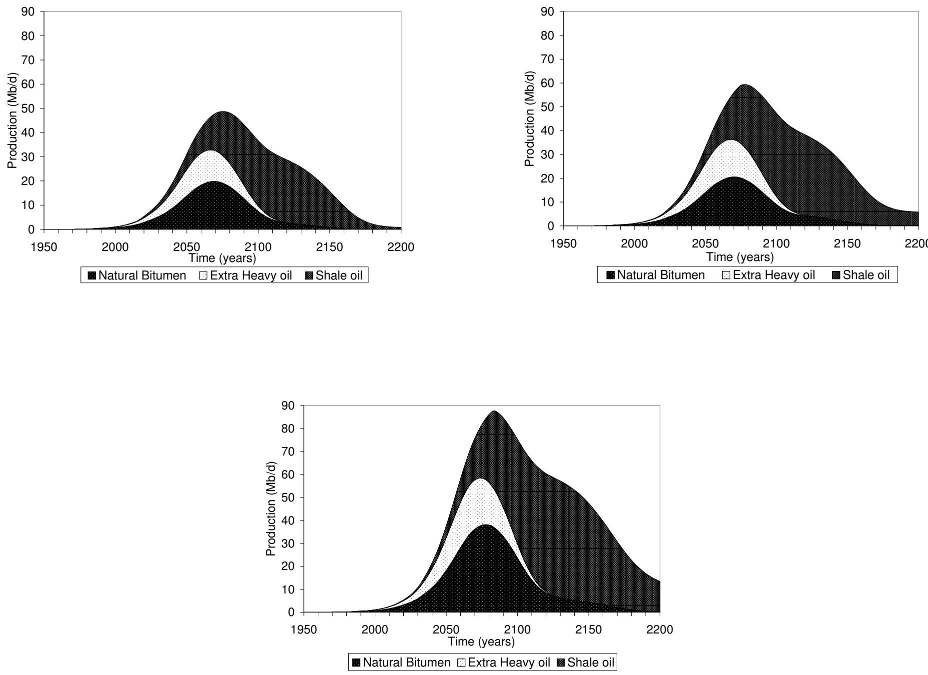

Figure 5: Unconventional oil production predictions 1950–2200 A) Pessimistic case B) Best Guess Case C) Optimistic Case

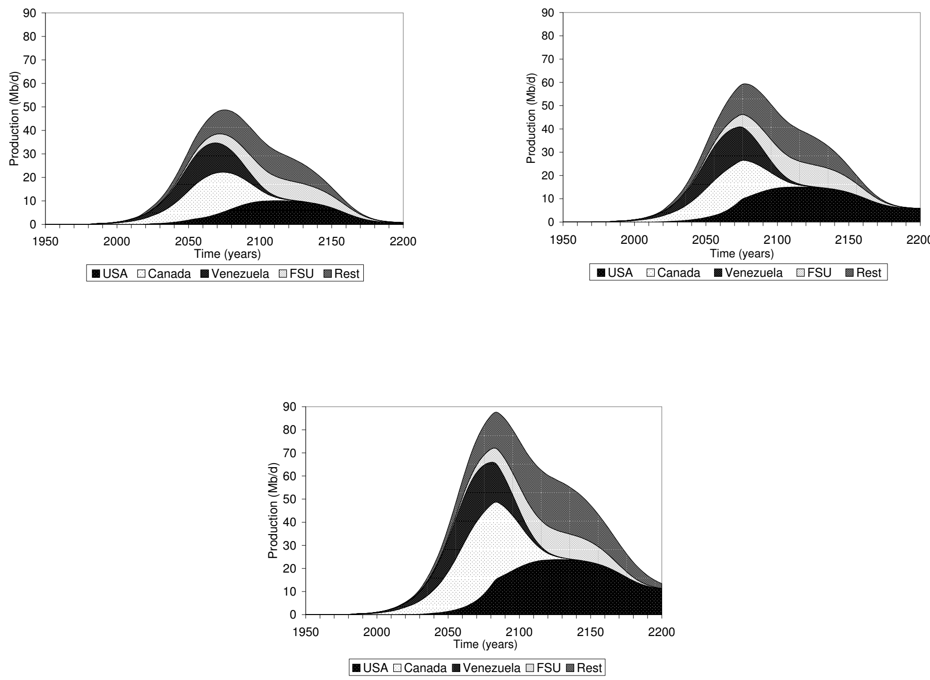

Figure 6: Unconventional oil production predictions 1950–2200 A) Pessimistic Case B) Best Guess case C) Optimistic Case

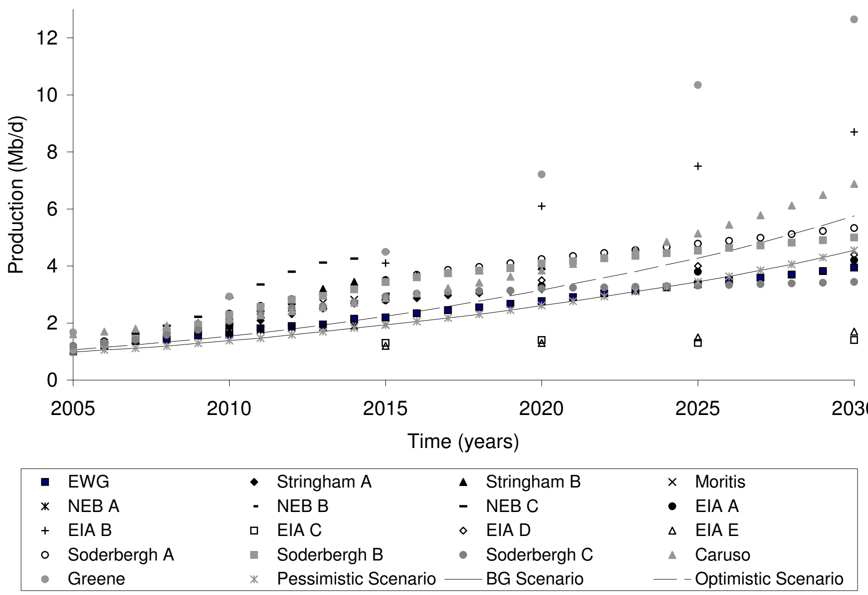

Figure 7: Canadian natural bitumen production predictions[3] 2005–2030

[3]Zittel and Schindler (2007); Stringham (2006); Moritis (2006); NEB (2006); U.S. Department of Energy (2008); Söderbergh (2005); Caruso (2005); Greene et al. (2006), EIA A = EIA Reference Case, EIA B = EIA High Price Case, EIA C = EIA Low Price Case, EIA D = High Economic Growth Case, EIA E = Low Economic Growth Case

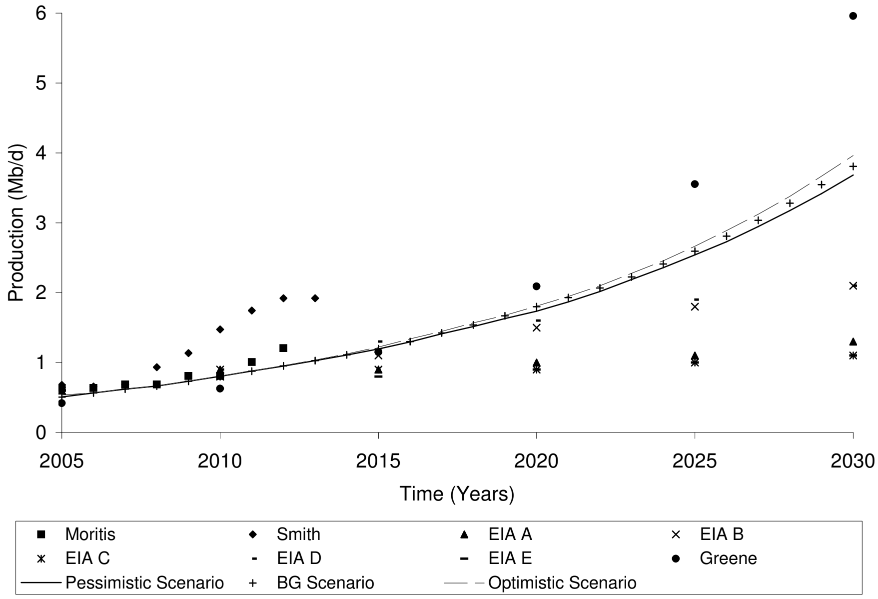

Figure 8: Venezuelan extra heavy oil production predictions[4] 2005–2030

[4]Moritis (2005); Smith (2007); U.S. Department of Energy (2008); Greene et al. (2006), EIA A = EIA Reference Case, EIA B = EIA High Price Case, EIA C = EIA Low Price Case, EIA D = High Economic Growth Case, EIA E = Low Economic Growth Case

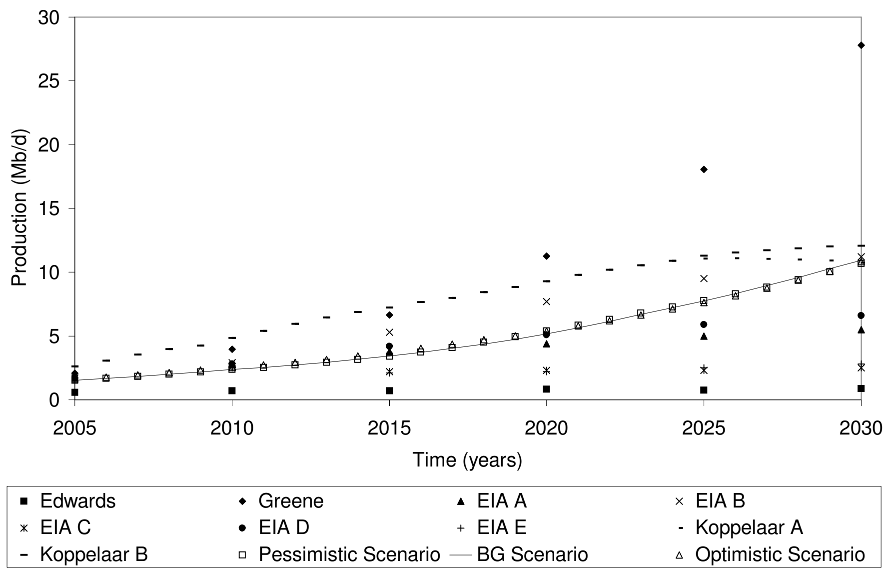

Figure 9: World unconventional oil production predictions[5] 2005–2030

[5]Edwards (1997); Greene et al. (2006); U.S. Department of Energy (2008); Koppelaar (2007), EIA A = EIA Reference Case, EIA B = EIA High Price Case, EIA C = EIA Low Price Case, EIA D = High Economic Growth Case, EIA E = Low Economic Growth Case

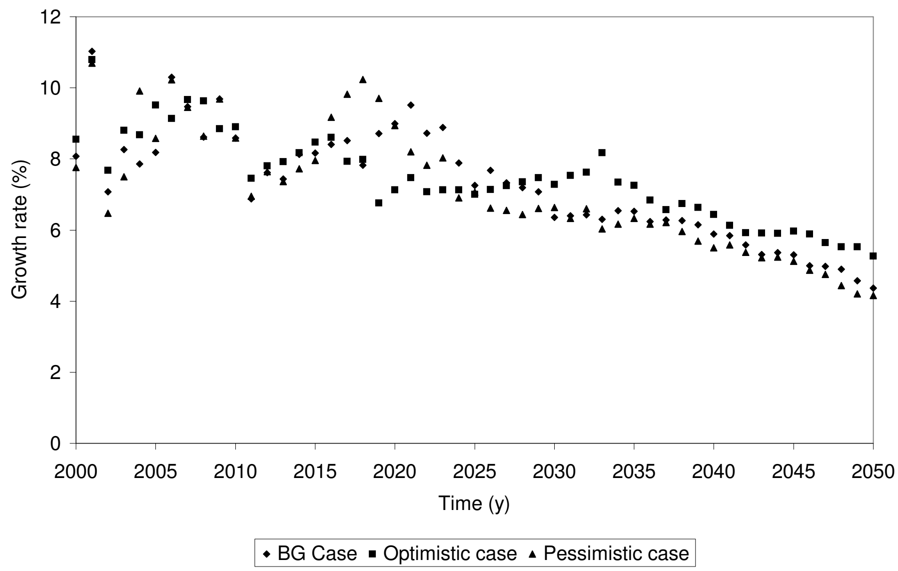

Figure 10: Unconventional oil growth rate prediction

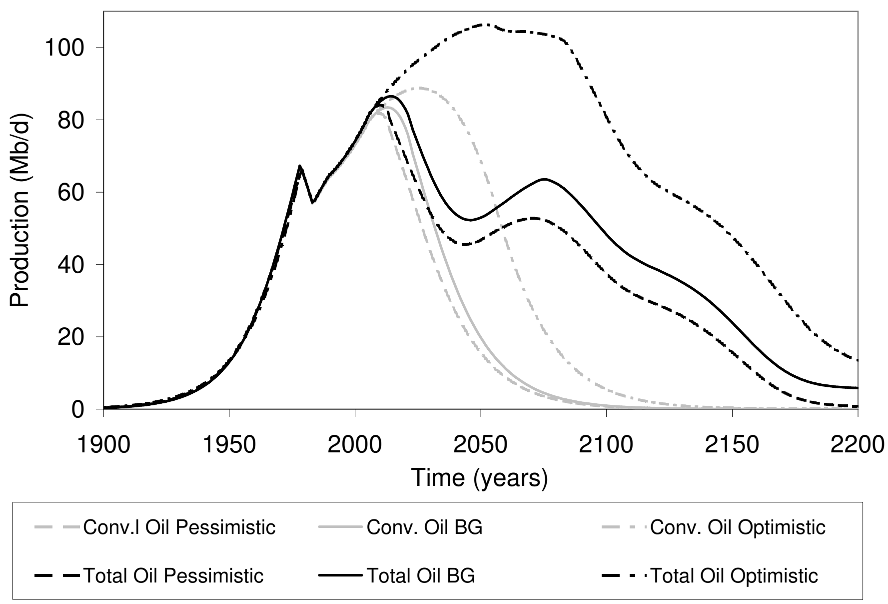

Figure 11: Combined conventional and unconventional oil production predictions[6]

[6]conventional oil projection from Mohr and Evans (2008)

Table 1: Natural Bitumen Resource and URR Estimates

Country	Resources (Gb) [a]	URR Gb			Comments
		P	BG	O	
Angola	5	0.7	0.7	0.7	P, BG and O assume 15% recovery
Canada	2400	350	350	700	P and BG from WEC (2007) O from White (2006)
China	2	0.2	0.2	0.2	P, BG and O assume 15% recovery
Indonesia	5	0.7	0.7	0.7	P, BG and O assume 15% recovery
Italy	2	0.3	0.3	0.3	P, BG and O assume 15% recovery
Kazakhstan	420	63	63	63	P, BG and O assume 15% recovery
Madagascar	2 – 21[b]	1	3	9.8	P from Jeans and Meerbeke (N. D.) BG from 15% of 20 Gb O from Madagascar Oil (N. D.)
Nigeria	30 – 43 [c]	4.5	6.5	6.5	P from 15% of 30 Gb BG and O from 15% of 43 Gb.
Russia[d]	62 – 800 [e]	10	53	100	P assumes 62 Gb resource and 15% recovery BG assumes 350 Gb resource and 15% recovery O assumes 700 Gb resource and 15% recovery
USA	54 – 80[f]	8	11	12	P assumes 54 Gb resources and 15% recovery BG uses 11 Gb recovery from U.S. Department of Energy (2006) O assumes 80 Gb resources and 15% recovery
Rest	1	–	–	–	insignificant
World	2983 – 3779	438	488	893	

[a] WEC (2007) unless stated otherwise

[b] WEC (2007); Madagascar Oil (N. D.); Rusk et al. (N. D.); Jeans and Meerbeke (N. D.)

[c] WEC (2007); M.S.M.D. (2006); Adewusi (1992)

[d] bitumen has low saturation Meyer and Freeman (2006); Meyerhoff and Meyer (1987)

[e] Resources range from Meyer and Freeman (2006)

[f] Resources from U.S. Department of Energy (2006); U.S. Geological Survey (2006)

Table 2: Extra Heavy Oil Resources and URR Estimates

Country	Resources (Gb) WEC (2007)	URR Gb			Comments
		P	BG	O	
China	8.9	1.3	1.3	1.3	P, BG and O assume 15% recovery
UK	12[a]	1	1.5	2	P assumes 1 Gb produced (WEC, 2007) BG average of P and O. O assumes no oil produced
Venezuela	1200−2450[b]	250	300	400	P is approx of historic estimate [c] BG is the high end of historic estimates[c] O 20% recovery[d] of 2000 Gb resources
Rest	17.6	–	–	–	insignificant
World	1239–2489	252	303	403	

[a]Lies in developed Piper field and second undeveloped basin WEC (2007).

[b]Williams (2003); Hobbs (1995); NCEP (2004); Moritis (2005); James (2000); Paez et al. (2000); Fletcher (2005a); WEC (2007)

[c]NCEP (2004); James (2000); Hobbs (1995); Paez et al. (2000); Fletcher (2005a); Wertheim (2007)

[d]recovery factor PDVSA believes is possible Moritis (2005)

Table 3: Shale Oil Resource and URR Estimates

Country	Resources (Gb) [b]	Grade [a] L/t	URR Gb P	URR Gb BG	URR Gb O	Comments
Australia	$32-2030$[c]		24	34	224	
Toolebuc	$0-2000$	37-45[c]	0	10	200	Resource limited to 315 Gb Dyni (2003) P assumes no prod. (grade too low) BG guess, water believed issue O assumes 64% recovery of 315 Gb.
Rest	32	$65-105$[d]	24	24	24	P, BG & O from WEC (2007)
Brazil	82	$70-125$[d]	53	53	53	P, BG & O assumed 64% recovery
Burma	2	$125-188$	1	1	1	P, BG & O assumed 64% recovery
Canada	$3-15$		3	3	11	
Collingwood	$0-12$	< 30[e]	0	0	8	P & BG: grade too low O: 64% recovery assumed
Rest	3	$20-140$[e]	3	3	3	P, BG & O assumed 64% recovery
China	~ 330[f]	$\sim 70-80$[f]	220	220	220	P, BG & O assumed 64% recovery
Egypt	6	$79-188$	0	3.8	3.8	P, resource not exploited BG & O assumed 64% recovery
Estonia	16	> 183	10	10	10	P, BG & O assumed 64% recovery
France	7	$70-100$	4.5	4.5	4.5	P, BG & O assumed 64% recovery
FSU ex. Estonia	278	> 92[g]	178	178	178	P, BG & O assumed 64% recovery
Germany	2	?	1	1	1	P, BG & O assumed 64% recovery
Israel	4	$60-71$[d]	3	3	3	P, BG & O assumed 64% recovery
Italy	$14-180$		2	9	115	
Sicily	$4-170$[h]	$8-125$[i]	2	2	108	P, BG: assumed 64% recovery of 4 Gb O: 64% recovery of 170 Gb
Rest	10[j]	?	0	7	7	P, assumed not exploited BG & O assumed 64% recovery
Jordan	34	$75-100$[d]	22	22	22	P, BG & O assumed 64% recovery
Morocco	$37-53$[k]	$50-70$	24	34	34	P assumed 64% recovery of 37 Gb BG & O assumed 64% recovery of 53 Gb
Sweden	6		0	0	0	assumed to be Uranium source rock
Thailand	6	$37-168$	4	4	4	P, BG & O assumed 64% recovery
Turkey	2	~ 60[l]	1	1	1	P, BG & O assumed 64% recovery
UK	4	119	3	3	3	P, BG & O assumed 64% recovery
USA	2250–2420		786	1086	1496	
Green River	$1500-1800$[m]	115	500	800	1100	P, BG, O (Bartis et al., 2005)
E. Devonian	189	50	121	121	121	P, BG &, O assumed 64% recovery
Phosphoria	250	83	160	160	160	P, BG & O assumed 64% recovery
Heath	$7-180$[n]	48	5	5	115	P & BG assumed 64% of 7 Gb O assumed 64% of 180 Gb
Elko	0.2	?	0	0	0	Too small
Zaire	100	183?	0	64	64	P assumed not exploited BG & O assumed 64%
Rest	< 3		0	0	0	
World	2900–5580		1340	1730	2450	

[a] Russell (1990) unless stated otherwise
[b] Dyni (2003) unless stated otherwise
[c] Dyni (2003); Cane (1979)
[d] Dyni (2003)
[e] Dyni (2003); Russell (1990)
[f] Liu et al. (2007)
[g] data for part of resource
[h] Russell (1990); Broquet et al. (1984)
[i] Dyni (1988)
[j] Russell (1990)
[k] Dyni (2003); Bekri (1992)
[l] Sener et al. (1995)
[m] Bartis et al. (2005)
[n] Dyni (2003); Derkey et al. (1985)

Table 4: Natural Bitumen (In-Situ model) – URR and Start Years

Country	URR Gb			Start year		
	P	BG	O	P	BG	O
Canada	300	300	600	1978	1978	1978
Nigeria	2	3	3	2012	2015	2025
USA	4	5	6	2015	2013	2025

Table 5: Extra Heavy Oil (In-Situ model) – URR, and Start Years

Country	URR Gb			Start year		
	P	BG	O	P	BG	O
China	1.3	1.3	1.3	2010	2013	2025
UK	1	1.5	2	2015	2018	2030
Venezuela	250	300	400	1975	1975	1975

Table 6: Natural Bitumen (Mining model) – URR, Start Years, Max Production and Mine Life

Country	URR (Gb)			Start year			Max Production (Gb/y)			Mine Life (y)		
	P	BG	O	P	BG	O	P	BG	O	P	BG	O
Angola	0.7	0.7	0.7	2020	2023	2035	0.001	0.001	0.001	40	40	40
Canada	50	50	100	1967	1967	1967	0.010	0.01	0.01	80	80	80
China	0.2	0.2	0.2	2010	2013	2025	0.001	0.001	0.001	40	40	40
Indonesia	0.7	0.7	0.7	1990	1990	1990	0.001	0.001	0.001	40	40	40
Italy	0.3	0.3	0.3	2017	2020	2030	0.001	0.001	0.001	40	40	40
Kazakhstan	63	63	63	2015	2018	2030	0.010	0.01	0.01	80	80	80
Madagascar	1	3	9.8	2013	2013	2015	0.001	0.005	0.005	40	60	80
Nigeria	2.5	3.5	3.5	2012	2015	2025	0.005	0.005	0.005	60	60	60
Russia	10	53	100	2025	2025	2035	0.010	0.01	0.01	80	80	80
USA	4	6	6	2015	2013	2025	0.005	0.005	0.005	60	60	60

Table 7: Shale Oil (Mining model) – URR, Start Years, Max Production and Mine Life

Country		URR (Gb)			Start year			Max Production (Gb/y)			Mine Life (y)		
		P	BG	O	P	BG	O	P	BG	O	P	BG	O
Australia		24	34	224									
	Toolebuc	0	10	200		2050	2050		0.01	0.01		80	80
	Rest	24	24	24	2015	2013	2025	0.01	0.01	0.01	80	80	80
Brazil		53	53	53	2004	2004	2004	0.01	0.01	0.01	80	80	80
Burma		1	1	1	2020	2023	2035	0.001	0.001	0.001	40	40	40
Canada		3	3	11									
	Collingwood	0	0	8			2030			0.005			60
	Rest	3	3	3	2015	2018	2030	0.005	0.005	0.005	60	60	60
China		220	220	220	2004	2004	2004	0.01	0.01	0.01	80	80	80
Egypt		0	4	4		2018	2030		0.005	0.005		60	60
Estonia		10	10	10	2004	2004	2004	0.01	0.01	0.01	80	80	80
France		5	5	5	2015	2023	2030	0.005	0.005	0.005	60	60	60
FSU ex. Estonia		178	178	178	2020	2020	2030	0.01	0.01	0.01	80	80	80
Germany		1	1	1	2015	2018	2030	0.001	0.001	0.001	40	40	40
Israel		3	3	3	2015	2018	2030	0.005	0.005	0.005	60	60	60
Italy		2	9	115									
	Sicily	2	2	108	2020	2023	2035	0.005	0.005	0.01	60	60	80
	Rest	0	7	7		2023	2035		0.005	0.005		60	60
Jordan		22	22	22	2015	2018	2030	0.01	0.01	0.01	80	80	80
Morocco		24	34	34	2015	2018	2030	0.01	0.01	0.01	80	80	80
Thailand		4	4	4	2015	2018	2030	0.005	0.005	0.005	60	60	60
Turkey		1	1	1	2015	2018	2030	0.001	0.001	0.001	40	40	40
UK		3	3	3	2015	2018	2030	0.005	0.005	0.005	60	60	60
USA		786	1086	1496									
	Green River	500	800	1100	2015	2012	2012	0.01	0.01	0.01	80	80	80
	Devonian	121	121	121	2020	2023	2035	0.01	0.01	0.01	80	80	80
	Phosphoria	160	160	160	2020	2023	2035	0.01	0.01	0.01	80	80	80
	Heath	5	5	115	2020	2023	2035	0.005	0.01	0.005	60	60	80
Zaire		0	64	64		2023	2035		0.01	0.01		80	80

A. Maximum production for Green River deposit

By analyzing the long term allocations for Upper Colorado basin states from U.S. Department of the Interior (2005) it is concluded that if upper Colorado basin states allocations are at 6 Maf/y (million acre-feet per year), then, by 2050, there will be essentially no free water available for oil shale processes. If water flow rates return to higher levels then the Upper Colorado Basin states allocation will rise, alternatively legal action may occur to ensure that water allocations for the Upper and Lower Colorado basins are once again equalized. Further water could be pumped to the Upper Colorado basin from other basins. The Pessimist case will assume that upper Colorado allocations are at approximately 6 Maf/y and little water is sourced from other basins, hence a water usage of 0.1 Maf/y will be assumed. The Best Guess will assume that 0.8 Maf/y of water is available, through a water allocation of more than 6 Maf/y and pipelines from other basins. The Optimists case will assume that 1.5 Maf/y of water is available. To provide perspective on the very optimistic assumption assumed for the Optimists case, Edmonton in Canada has a population of around 900,000 people and consumes 0.1 Maf/y (Griffiths et al., 2006).

In all cases it is assumed that 2 barrels of water are needed to provide 1 barrel of oil (which includes the amount of water necessary for the significantly increased population). Also uncertain is the amount of water necessary for the Shell in-situ process, and to a lesser degree surface mining. It is assumed that in-situ processes dominate, as in-situ processes are assumed to consume significantly less water than mining methods. Given the Shell in-situ method generates 1/3 gas (Shell, 2007) and Bartis et al. (2005) indicates that roughly all of the gas is needed to generate the electricity for the process. It is concluded that the Pessimist case will have a maximum production of 0.3 Gb/y (0.7 Mb/d) the Best Guess has a max production of 2 Gb/y (5.7 Mb/d) and the Optimist case has 4 Gb/y (10.7 Mb/d). It should be stated that water supplies in the Upper Colorado Basin are far from certain, and it is likely that even without an oil shale industry a lack of water will be a major issue for these states.