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The Peak of the Oil Age
- analyzing the world oil production Reference Scenario in World Energy Outlook 2008

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Abstract
The assessment of future global oil production presented in the IEA's World Energy Outlook 2008 (WEO 2008) is divided into 6 fractions; four relate to crude oil, one to non-conventional oil and the final fraction is natural-gas-liquids (NGL). Using the production parameter, depletion-rate-of-recoverable-resources, we have analyzed the four crude oil fractions and found that the 75 Mb/d of crude oil production forecast for the year 2030 appears significantly overstated, and is more likely to be in the region of 55 Mb/d. Moreover, analysis of the other fractions strongly suggests lower than expected production levels. In total, our analysis points to a world oil supply in 2030 of 75 Mb/d, some 26 Mb/d lower than the IEA predicts.

The connection between economic growth and energy use is fundamental in the IEA's present modelling approach. Since our forecast sees little chance of a significant increase in global oil production, our findings suggest that the "*policy makers, investors and end users"* to whom WEO 2008 is addressed should rethink their future plans for economic growth. The fact that global oil production has very probably passed its maximum implies that we have reached the Peak of the Oil Age.

Key words:
Future oil supply, peak oil, world energy outlook 2008

1. Introduction

The International Energy Agency (IEA) is an autonomous body within the framework of the Organisation for Economic Co-operation and Development (OECD). Its purpose is to act as an energy advisor to the 28 member countries of the OECD. Every year the IEA publishes its report "*World Energy Outlook*". And its 2008 edition was released on November 12th (IEA, 2008). On page 51, regarding prospects for oil and gas production the IEA states that "*the results of these analyses are intended to provide policy makers, investors and end users with a rigorous quantitative framework for assessing likely future trends in energy markets*". The consequences of widespread reliance on the WEO prognoses have already been discussed in the press (Monbiot, 2008). Specifically, it is noted that the British government places great faith in the IEA's projections. A similar level of trust in IEA predictions can also be seen within the Swedish Energy Authority when its standpoint on future oil production is examined (Swedish Energy Authority, 2006).

The WEO 2008 study, designed and directed by Dr. Fatih Birol (Chief Economist of the IEA), was advised on the prospects for oil supply by a panel consisting of Guy Caruso, Robert Fryklund, Leo Roodhart, Ramzi Salman, and Adnan Shihab-Eldin (IEA, 2008). In addition, they had support and co-operation from many governmental bodies, international organizations and energy companies worldwide. Many international experts provided their input, commenting on the underlying analytical work, and reviewing early drafts of each chapter. "*Their comments and suggestions were of great value*" states the final document, but the final choice of whether or not to use these comments rested solely with the editors of WEO 2008. It is in the interests of an open debate based upon a complete analysis that this paper is presented and is should be seen as an important adjunct to the WEO 2008.

1.1 Aim of this study

Many people and organizations regard the WEO as an authoritative document and use it as a guideline for developing future energy policy. In this paper the IEA liquid fuels forecast has been broken down into its component parts and analyzed in an effort to verify (and if necessary, challenge) important aspects of their work. The approach is a familiar one to those of us used to the normal peer review process. The importance of the peer review process can be seen by the fact that the Intergovernmental Panel on Climate Change (IPCC) has an explicit policy that contributions should be supported as far as possible by references from within the peer-reviewed and internationally available literature (IPCC, 1999).

The focus of our analysis is on the oil production Reference Scenario that forms the core of WEO 2008 (Figure 1). This is a possible scenario for future oil production that meets projections for future oil demand and is divided among 6 different fractions:

1. Crude oil – currently producing fields,
2. Crude oil – fields yet to be developed ('fallow fields'),
3. Crude oil – fields yet to be found,
4. Crude oil – additional EOR (enhanced oil recovery),
5. Non-conventional oil and
6. Natural gas liquids.

In this analysis, we will discuss the demand scenario and the scenarios for the production of each of the six oil fractions. Our report will also present an alternative future outlook for global oil production based on the same oil categories as those used by the IEA (2008) as well as results and findings from various scholarly studies.

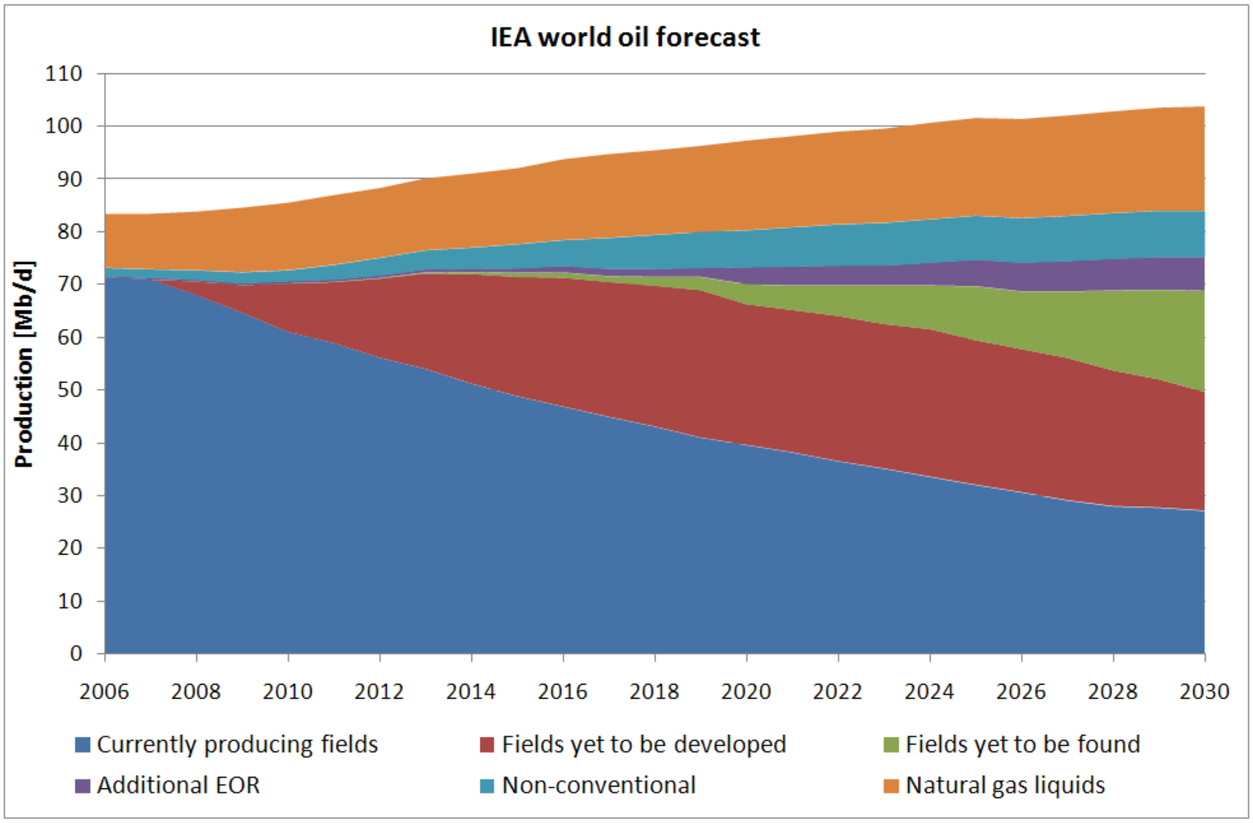

Figure 1: *World oil production by source in the Reference Scenario. Digitized and adapted from Figure 11.1 in WEO 2008.*

1.2 Data gathering

For this analysis it is necessary to access the IEA data in a numerical format. Using a program for the digitization of figures (typical resolution of the digitizing process is estimated at less than 0.1 Mb/d per pixel, excluding human errors), we obtained the numbers shown in Table 1, and in turn this data was used to reconstruct Figure 11.1 from WEO 2008 (Figure 1). From Table 1, annual production, cumulative production up to 2030, the depletion rate of remaining recoverable resources and other useful parameters can all be calculated.

Table 1: *Digitizing of Figure 11.1 from WEO 2008. Numbers indicate Mb/d*

Year	Currently producing	Yet to be developed	Yet to be found	Enhanced oil recovery	Non-conv. oil	Natural gas liquids
2006	71.3	0.0	0.0	0.3	1.6	10.2
2007	70.9	0.0	0.0	0.3	1.7	10.5
2008	68.0	2.5	0.0	0.4	1.8	11.1
2009	64.6	5.2	0.0	0.4	2.1	12.2
2010	61.0	9.1	0.1	0.5	2.1	12.8
2011	58.9	11.5	0.1	0.5	2.8	13.2
2012	56.1	15.0	0.1	0.5	3.4	13.2

2013	54.0	18.1	0.2	0.6	3.7	13.6
2014	51.2	20.8	0.4	0.6	4.1	14.0
2015	48.8	22.6	0.8	0.8	4.6	14.4
2016	46.8	24.4	1.0	1.3	4.9	15.3
2017	44.9	25.6	1.1	1.4	5.9	15.9
2018	43.1	26.7	1.7	1.5	6.5	16.0
2019	41.0	28.0	2.5	1.7	6.9	16.3
2020	39.6	26.7	3.8	3.2	7.0	17.0
2021	38.2	27.0	4.6	3.7	7.4	17.3
2022	36.5	27.5	5.8	3.8	7.9	17.6
2023	35.1	27.4	7.3	3.8	8.1	17.8
2024	33.5	28.0	8.3	4.4	8.3	18.3
2025	32.0	27.4	10.3	5.1	8.4	18.5
2026	30.6	27.1	11.0	5.5	8.5	18.8
2027	29.1	27.0	12.6	5.8	8.6	19.0
2028	27.9	25.7	15.2	6.0	8.7	19.3
2029	27.7	24.3	17.0	6.2	8.8	19.5
2030	27.1	22.5	19.2	6.4	8.8	19.8

2. Future oil needs – the demand scenario

Predictions by the IEA of future oil demand have always been guided by the connection between economic growth and increasing oil consumption. On page 92, WEO 2008 declares that: "*economic activity remains the principal driver of oil demand in all regions. Since 1980, each 1% per year increase in GDP has been accompanied by a 0.3% rise in primary oil demand*".

The IEA's reference scenario assumes continued economic growth of 3% per year until 2015. This requires an increase in oil consumption of 1.3% per year and, for the period following that, they foresee an increase of only 0.8% per year. World oil demand by 2030 would therefore be 106.4 Mb/d based upon these figures. Consequently, production must increase if the gap between the current and projected future demand is to be closed.

It should at this point be noted that WEO 2008 presents a considerable reduction in predicted demand when compared with the 123 Mb/d by 2030 presented in WEO 2004 (IEA, 2004). The previous forecast was based on a correlation of a 3% per year rate of economic growth to a 1.6% per year rise in the rate of oil consumption. In an internet publication from 2004, attention was drawn to this unrealistic level of future oil production (Aleklett, 2004).

Historically, global oil intensity (oil consumption per unit of GDP), is trending downwards and the lower 0.8% per year increase towards the latter part of the scenario period indicates that the IEA assumes that this trend will continue. However, the key question that must be asked of the future demand scenario is whether or not "*business as usual*" (BAU) is a realistic assumption, or whether peak oil (i.e. the arrival of a global maximum oil production) will undermine this presumptive analysis. In other words, the issue is whether future oil production can match the projected demand and sustain continued economic growth rather than the IEA approach of predicting future demand and assuming supply will simply keep pace.

3. The outlook for crude oil production

Crude oil is the dominant contributor to world liquid fuels supply. In WEO 2008, the IEA chose to divide this important source of liquid fuels into four different fractions; currently producing fields, fields yet to be developed, fields yet to be found and additional EOR (enhanced oil recovery).

3.1 Crude oil – currently producing fields

Production of crude oil from those oil fields that were in production in 2007 is reported as 70.2 Mb/d on page 250 of WEO 2008. The question is what will production will be by 2030, 23 years later.

In their Reference Scenario, the IEA distinguishes between production from onshore and offshore fields (IEA, 2008). This distinction is logical, since one can see that the production-weighted declines for these two production types are very different (Höök et al., 2009a, Höök et al., 2009b). In part, this is because it is often easier to maintain and upgrade fields on land than those that are found at sea, implying that the decline rate for the former relative to the latter is lower. However, other key factors - such as the need for high flow rates to recover large initial investments - also play an important role in determining actual decline rates.

The field-by-field analysis of decline rates provided in chapter 10 of WEO 2008 describes results consistent with our own studies of a similar number of giant fields (Höök et al., 2009b). The general trend is that offshore fields decline faster than onshore fields, due to the differences in economic conditions and chosen engineering solutions. The contributors to WEO 2008 have also made separate studies of generic field behaviors and decline rates and similar conclusions (as well as a strong correlation between the depletion rate of remaining recoverable resources and the average decline rate) were found by Höök et al. (2009a).

On page 255 of WEO 2008, the IEA (2008) states that the mean decline rate for fields on land is 3.2% per year and the corresponding offshore value is 6.3% with both remaining constant during the 23 years to 2030. The IEA fail to show how they arrive at these decline rates and the production-weighted average decline rates that they give for fields in decline are higher than these particular figures of 3.2% and 6.5%. Production is made up of fields that are in decline, fields in plateau production, and fields that are currently under development and hence where production is still rising. A production-weighted average decline rate of 3.2% for all fields currently in production (rather than just the fields already in decline) is therefore plausible, and we assume that the 3.2% value is just such a number. If we extrapolate the values that we have previously calculated for giant fields to cover the size range of the fields analyzed in WEO 2008 then we obtain a value similar in size to that of the IEA (Höök et al., 2009b). In the same way, we can say that the decline rate of 6.3% for offshore fields is also plausible for all offshore fields and not just those already in decline.

The IEA's assumption about constant mean decline rates is a somewhat ambivalent statement as the IEA also writes that "*the expected shift in the sources of crude oil, in terms of region, location and field size, means that the average production-weighted observed post-peak decline rate tends to rise*". Currently, the world is seeing a tendency towards increasing decline rates but this is not discussed by IEA in any detail, despite the fact that this increase may result in a difference in oil production rate as great as 7 Mb/d by 2030 (Höök et al., 2009b).

At the sixth meeting of the Global Roundtable on Climate Change on February 2009 at Columbia University in New York, IEA Chief Economist Fatih Birol discussed three strategic challenges for the future and one was the gap caused by decline in existing production. Birol

(2009) noted that: "*even if oil demand was to remain flat to 2030, 45 Mb/d of gross capacity – roughly four times the capacity of Saudi Arabia – would be needed just to offset decline from existing fields.*"

In conclusion, this part of WEO 2008 is sound and is in overall agreement with the findings of other investigations (Höök et al., 2009b). Consequently, we find no substantial differences and nothing to object to in the IEA's outlook for crude oil from currently producing fields. We can only conclude that significant new capacity additions will be required to offset decline in existing production, and the immense scale of this challenge seems to be adequately understood by the IEA.

3.2 Fields yet to be developed

Using the digitization program, we extracted production data for fields yet to be developed from Figure 11.6 in WEO 2008 (Table 2). This new production is divided into four classes of field: OPEC onshore, OPEC offshore, non-OPEC onshore, and non-OPEC offshore. Page 257 in WEO 2008 states that the total oil reserves to be developed are 257 Gb in 1874 fields, with 133 Gb in OPEC fields and 124 Gb in non-OPEC fields. The onshore percentages for OPEC and non-OPEC fields are 65% and 38% respectively.

If we calculate the cumulative production of yet to be developed fields, we find to our surprise that we get a total production for the period 2008–2030 of roughly 185 Gb, in disagreement with the 257 Gb stated on page 257 of WEO 2008. This error will not affect the rest of our analysis and is likely the result of a typographical error or numeric mix-up in WEO 2008. Table 3 shows the current reserves in each field class, the volumes to be produced by 2015 and 2030 and the reserves remaining in 2030 as stated in WEO 2008.

In determining whether or not the WEO 2008 reference scenario for new field developments is realistic (Figure 2), we chose to utilize depletion rate analysis. Höök et al. (2009a) as well as Jakobsson et al. (2009) and Höök (2009) have shown that only certain depletion rates are reasonable for real production. Our approach here is to compare the depletion rate behaviour in the IEA outlooks with historical experience and see if they agree with realistic values.

Table 2: *Digitization of Figure 11.6 in WEO 2008. Numbers indicate Mb/d*

	OPEC Onshore	**OPEC Offshore**	**Non-OPEC onshore**	**Non-OPEC Offshore**	**Total**
2008	0.72	0.27	0.77	0.92	2.68
2009	1.64	0.62	0.96	1.92	5.14
2010	2.60	1.69	1.23	3.54	9.06
2011	3.71	2.35	1.73	4.23	12.02
2012	4.82	3.12	2.08	5.38	15.40
2013	5.40	3.92	2.42	6.38	18.13
2014	5.86	4.54	3.15	7.08	20.63
2015	6.78	4.65	3.31	7.85	22.58
2016	7.58	4.38	3.54	8.54	24.04
2017	7.96	4.42	3.15	9.54	25.08
2018	9.19	4.00	3.42	9.69	26.31
2019	9.42	3.77	4.00	10.23	27.42
2020	10.18	3.50	4.38	10.73	28.80
2021	10.45	3.27	4.50	10.85	29.07
2022	10.76	2.92	5.08	10.58	29.33
2023	10.52	2.77	5.54	10.08	28.91
2024	10.40	2.77	6.12	9.50	28.79
2025	10.28	2.42	6.27	8.65	27.63
2026	10.32	2.58	6.31	7.54	26.74
2027	10.51	2.50	6.65	6.92	26.59
2028	10.31	2.62	6.08	6.15	25.16
2029	9.66	2.42	5.81	5.96	23.85
2030	9.15	2.12	5.73	5.54	22.54

Table 3: *Reserves yet to be developed in Gb, divided into different field classes. Based on Figure 11.6 in WEO 2008*

	Reserves not yet developed	Volume produced by 2015	Volume produced by 2030	Reserves at the end of 2030
OPEC onshore	86.5	11.5	65.1	21.4
OPEC offshore	46.5	7.7	24.7	21.8
Non-OPEC onshore	47.1	5.7	33.7	13.4
Non-OPEC offshore	76.9	18.6	61.3	15.6
Sum of all classes	257	43.5	184.8	72.2

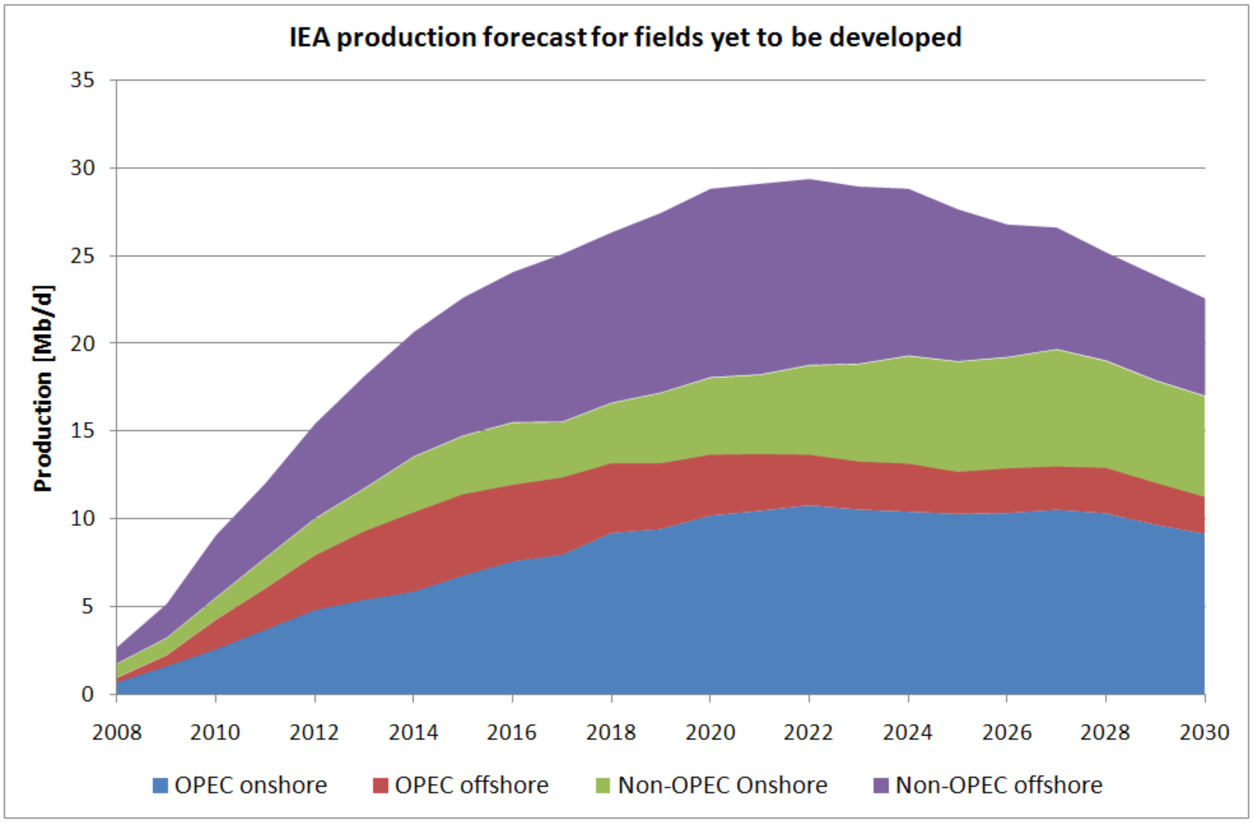

Figure 2: *Crude oil production from yet-to-be-developed fields in OPEC and non-OPEC regions by location in the WEO 2008 Reference Scenario*

The *depletion rate of remaining recoverable resources*, $d_{\delta t}$, is as important for understanding the build-up and plateau production phases of an oilfield as for understanding the decline rate and tail-end production of a field. This parameter has been studied in a field-by-field study of giant fields, where a narrow band of reasonable values for $d_{\delta t}$ is observed as well as a strong correlation between $d_{\delta t}$ at peak and the average decline rate (Höök et al., 2009a; Höök, 2009). Its definition is given in Equation 1,

$$d_{\delta t} = \frac{q_t}{R_t} = \frac{q_t}{R_0 - Q_t} \tag{1}$$

where
$d_{\delta t}$ = depletion rate of remaining recoverable resources,
R_0 = initially present reserves or ultimate recoverable resources,
R_t = remaining recoverable resources at time t,
q_t = production at time t,
Q_t = Cumulative production up to time t.

If we have an arbitrary oilfield which follows exponential decline curve behaviour, we can apply a typical production profile (Figure 3). The plateau normally ends before half of the ultimately recoverable resources (URR) have been produced, typically around 40-45% and production peaks within a narrow interval of depletion rates (Höök et al., 2009a). It is interesting to note that $d_{\delta t}$ increases until the end of the plateau production phase and reaches a maximum at this point in the general hyperbolic case (Höök, 2009). The exponential decline curve is a special case of the general hyperbolic case, and is significantly easier to work with. It can be analytically shown that $d_{\delta t}$ prior to the onset of decline will equal the average decline rate (Jakobsson et al., 2009), thus $d_{\delta t}$ will be constant once the maximum value has been reached. A more complete description of depletion rate modelling as well as mathematical derivations for field behaviour can be found in Höök (2009).

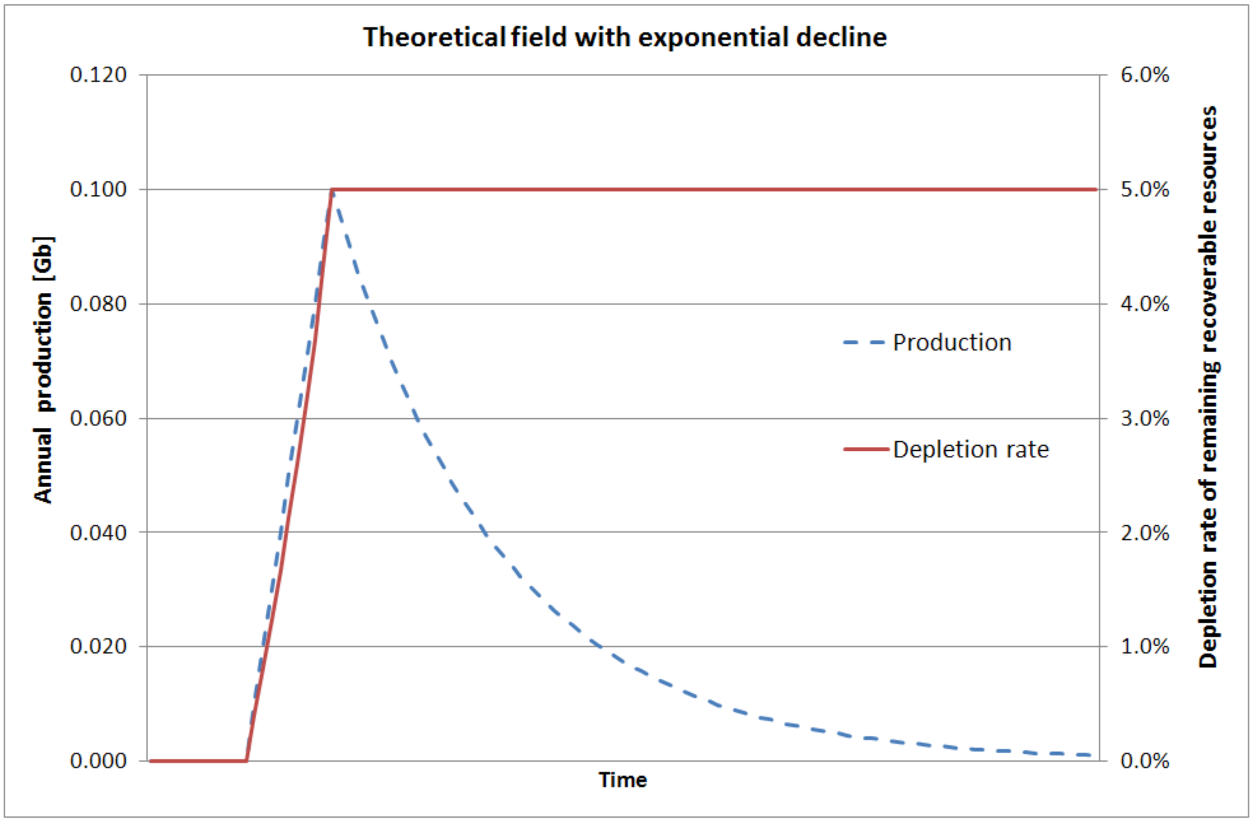

Figure 3: *Theoretical production curve of a 2.5 Gb field following an exponential decline curve with a decline rate of 5%. Based on Höök (2009)*

Normally, in a region with several fields, $d_{\delta t}$ stays at a relatively constant value after the regional production peak. We have also observed that $d_{\delta t}$ for a region always tends to be lower than for the individual fields that constitute the region. This is explained by the fact that a region consists of fields in decline as well as fields in a build-up or plateau phase or even dormant/undiscovered/undeveloped fields and will have the effect of moderating the aggregate $d_{\delta t}$.

The North Sea is a region with an estimated URR of around 75 Gb (Table 4), with 35 Gb in Norway, 35 Gb in the UK, and remainder located in the Netherlands, Denmark and Germany. The first North Sea oil was produced in the mid-1970s and its production peak occurred in 2000. Figure 4 shows the depletion rate behaviour of the North Sea. In Table 4 a comparison of the North Sea with other regions finds that no other region in the world has shown more rapid deletion of remaining recoverable resources than the North Sea region. This is consistent with the aggressive development of its offshore production capacity. Typical $d_{\delta t}$-values for regions are below 7% and are usually even lower for larger regions.

However, we must stress that 7% should not be regarded as an absolute or theoretical maximum. Rather, it is only an empirical upper value that has been observed in historical time series. No one can provide definitive predictions of what depletion rates might be achievable under very high oil prices in regions with much of the necessary infrastructure already in place and producers keen on extracting the oil rapidly. However, there is little doubt that depletion rates equal to or surpassing the most extreme rates seen historically are possible given sufficient availability of investment and its correct application. The depletion rate constraint is dependent on the size distribution of fields, life times of fields, decline rates, infrastructure needs and many other factors that require further and more comprehensive studies to be better understood, but this is work for future studies. Empirical data at the field level (Höök et al., 2009a) and the regional/global level (Jakobsson et al., 2009) shows the existence of a depletion rate limitation and that this is useful in forecasting.

In contrast to the maximum depletion rates that might be possible, we see that slow rates of investment, the fact that some producers are unlikely to deplete their oil at extremely high rates (this particularly applies to OPEC), accessibility issues, environmental concerns that call for reduced oil consumption as well as other limiting factors support a 7% depletion rate as a reasonable assumption for the future. The IEA and other authors who assume depletion rates higher than anything previously seen must justify their higher rates.

Table 4: *Depletion rate of remaining recoverable resources at peak for selected countries, along with the peak years, peak production levels and estimated URRs used for calculations. For comparison we give the $d_{\delta t}$ numbers for 332 giant oil fields and where these fields can be seen as a region. URR estimates taken from BERR (2008), Höök and Aleklett (2008), Campbell (2009), Höök et al (2009b) and Norwegian Petroleum Directorate (2009)*

Country	**Peak Year**	**Peak Prod. [Mb/d]**	**Depletion rate of remaining recoverable resources at peak**	**Estimated URR [Gb]**
USA	1970	9.6	2.6%	230
Giant fields	1979	44.5	1.8%	1136
Russia	1987	11.5	2.4%	250
Indonesia	1991	1.7	3.0%	35
UK	1999	2.9	6.9%	35
North Sea	2000	6.4	5.6%	75
Norway	2001	3.4	6.1%	35
Mexico	2004	5.5	5.5%	60

Two key projects for future OPEC capacity are Khurais and Manifa. Correspondingly, closer investigations of these two projects are useful to better understand OPEC's yet to be developed capacity. The Saudi Arabian Khurais project, including the Abu Jifan and Mazalij fields, is estimated to hold a total of 27 Gb (Worth, 2008). Massive water injection systems are planned from the start, a measure that is normally used after a field has been producing for several years (Landers, 2008). Saudi Aramco expects that Khurais and its satellite fields should produce around 1.2 Mb/d or 0.44 Gb/y of high quality Arabian Light Crude (Latta, 2009). Reasonable depletion rates are around 2% and it is reasonable to assume that the same production rate will be maintained beyond 2030 in line with Saudi Aramco’s production strategy. Calculating the $d_{\delta t}$-value, we get 1.6% at the start and around 2.5% by 2030, which is relatively low compared to non-OPEC fields but well in line with the behaviour of other Saudi fields.

The Manifa field development is the second mammoth project under way in Saudi Arabia, revived after a long period of being mothballed due to the heaviness of its crude oil (Saudi Aramco, 2008). This offshore field is expected to produce 0.9 Mb/d, or 0.33 Gb/y once it reaches plateau production (Latta, 2009). The field is estimated to contain 11-23 Gb (Robelius, 2007) and IEA (2005) places Manifa's URR at 22.8 Gb. In comparison, Saudi Aramco (2008) writes that Manifa only has an estimated crude reserve of 10 Gb, but this may refer to only a part of the field. Manifa was originally due to come on stream in 2011, but due to the financial crisis, we now expect that it will be delayed for some years and that 2015 may be a more realistic production start date. At start, we calculate $d_{\delta t}$ will be around 1.4%, and that it will reach 1.8% in 2030.

From Table 3, we can then calculate the $d_{\delta t}$ for the data points given in Figure 11.6 of WEO 2008 (Figure 5). The $d_{\delta t}$-numbers for OPEC offshore fractions increase to ~4% and then remain constant. During the 20 years it took to reach the maximum rate of production in the North Sea, the depletion rate increased by around 0.3% per year. The build up phase for the OPEC-offshore field class is faster (Figure 5), but we can accept this because it may be assumed that a large fraction of the build up comes from Manifa. Half of the OPEC offshore field class (22.8 Gb out of 46.6 Gb) has a $d_{\delta t}$-value of 1.8 % by the end of the period. If the rest of the projects in this class reach 6%, it is acceptable to have a $d_{\delta t}$-parameter of around 4%, which we see in 2017. However, OPEC has never developed fields with $d_{\delta t}$-numbers of 6%. The depletion rate for remaining recoverable resources, $d_{\delta t}$, for the other three field classes (OPEC onshore, non-OPEC onshore and non-OPEC offshore) reach numbers that have never been previously seen even in the most prominent offshore region, i.e. the North Sea.

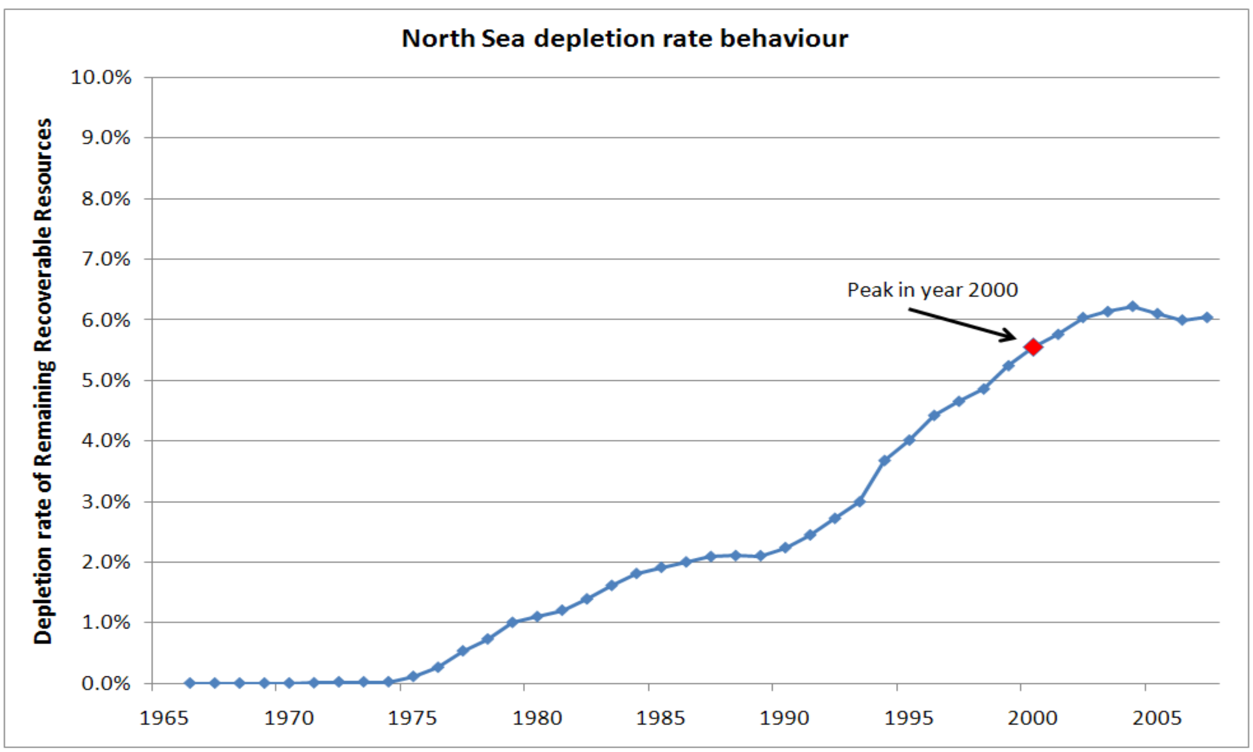

Figure 4: *Development of the $d_{\delta t}$-parameter for the total North Sea region. The depletion rate increased by 0.2-0.3% per year until it levelled off at the maximum depletion rate of remaining recoverable resources.*

The non-OPEC onshore class is said to be dominated by fields in Russia. Russia's total production today has a $d_{\delta t}$-value around 3% (Mäkivierikko, 2007). There are indications that Russian oil production has reached a second peak and will decline in the future (Hoyos and Blas, 2008; Upstream, 2008; Gronholt-Pedersen, 2009). No other onshore region of comparable size has reached $d_{\delta t}$-values higher than around 3-4% (Table 4), implying that much higher $d_{\delta t}$-values than are currently observed are unreasonable. Since Russia dominates the non-OPEC onshore class, we can limit the depletion rate for this class to roughly 3% in our future prognoses (Figure 6). The non-OPEC offshore class can be expected to develop quickly and to behave in a similar manner to the North Sea. We regard this as an optimistic stance given the favourable economic conditions that pertained during the development of the North Sea (Figure 6) and this may be a less realistic outlook going forward.

In contrast to the non-OPEC offshore class, we assume that production from the OPEC onshore and OPEC offshore classes will be developed in line with historical strategies. Thus, emphasis will be placed on low depletion rates and production longevity as opposed to the rapid development assumptions used by the IEA (2008). It is hardly reasonable to assume that OPEC will develop all their fields prior to 2030, as their strategy is to maintain stable production. In conclusion, we expect low depletion rates from OPEC and limit these to only 2-2.5%, in line with Saudi Aramco's production goals (Figure 6).

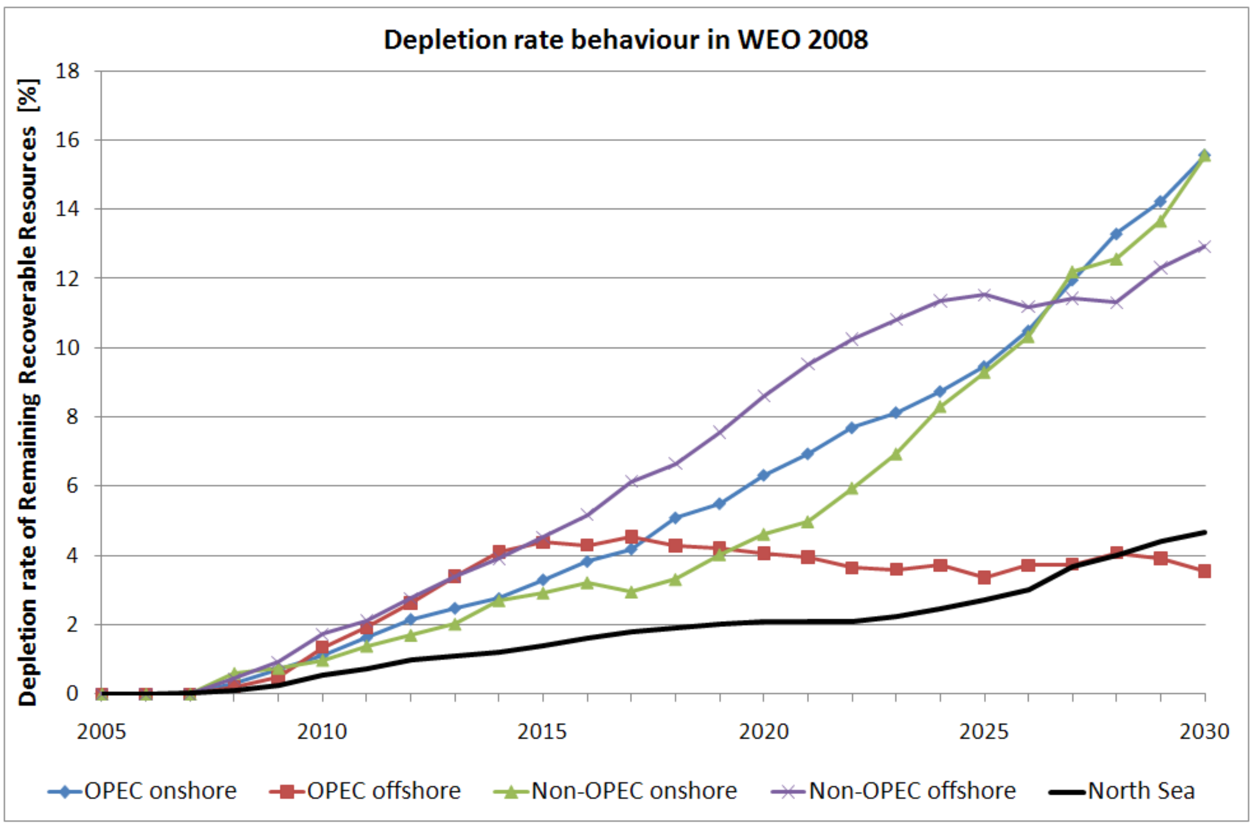

Figure 5: *Depletion rates for remaining recoverable resources for OPEC onshore and offshore and non-OPEC onshore and offshore production used by the IEA in World Energy Outlook 2008. For comparison, the depletion rate development of the North Sea is also shown, shifted to start in the same year.*

The unrealistic forecast given in WEO 2008 for production from fields yet to be developed gives a maximum for all field classes combined of 29.3 Mb/d just after 2020 subsequently falling back to 22.5 Mb/d in 2030. This is only possible with unreasonably high depletion rates. We cannot regard the assumption that OPEC will develop their reserves much faster than the North Sea as reasonable. We obtain a very different future outlook for fields yet to be developed when we apply depletion behaviour consistent with historical experience and production policies (Figure 7).

A difference of 9 Mb/d in 2030 is seen for production from fields yet to be developed in the IEA Reference Scenario (with a production of 22.5 Mb/d), compared to our scenario (with a production of 13.5 Mb/d). Even though our projection is much lower than that of the IEA, we must still regard our outlook as optimistic. The yet-to-be-developed reserves of 257 Gb in WEO 2008 are located in 1874 fields that should come into production during the next 20 years. That is something like 8 fields per month coming on stream during that period, with a significant proportion of these fields being developed at a pace equal to that of the North Sea. Even if the oil exists, it is questionable whether the necessary investment needed to produce such a rapid pace of development can be achieved in timely fashion.

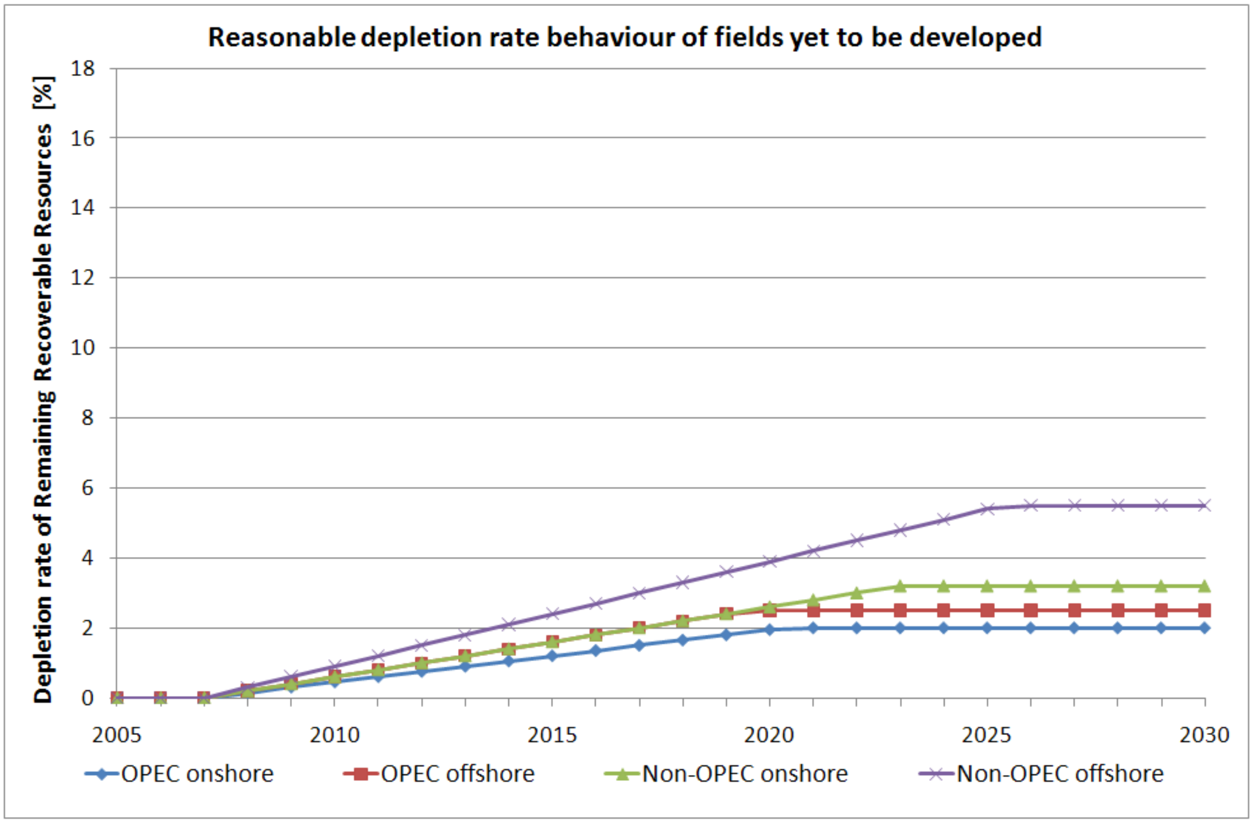

Figure 6: *Reasonable depletion rate behaviours of the different field classes. Non-OPEC offshore is assumed to be developed equally fast as the North Sea, while other classes are developed less aggressively and have lower $d_{\delta t}$-values, consistent with production policy and historical data.*

In summary, we find the production outlook made by the IEA to be problematic in the light of historical experience and production patterns. The IEA is expecting the oil to be extracted at a pace never previously seen without any justification for this assumption. In theory, it would be possible to achieve such a rapid depletion if proper investments were made along with sufficient access to the fields, but this must be seen as an extreme case. Instead, the production policies of OPEC as well as recent financial challenges indicate that one can expect lower depletion rates in the future. Later in this study, we will consider both faster and slower development rates of the fields yet to be developed in order to provide more comprehensive outlooks into future world oil production.

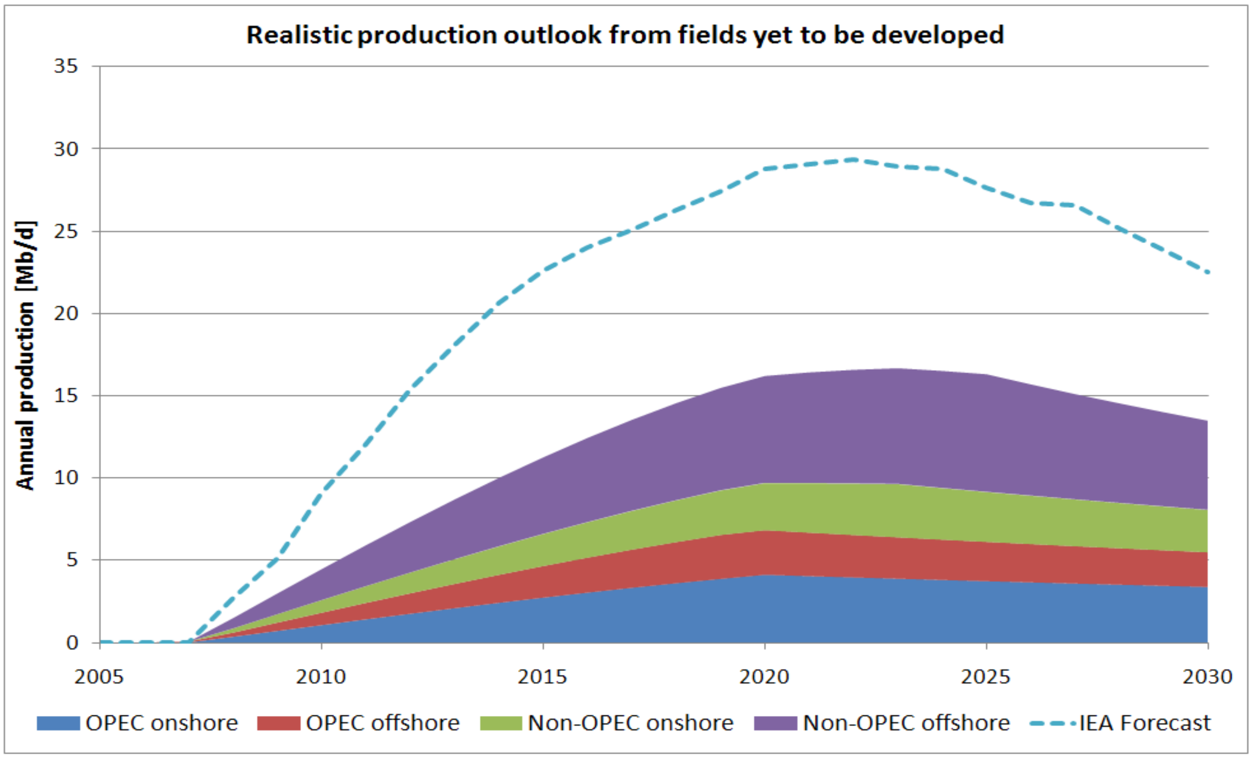

Figure 7: *A realistic production outlook the fields yet to be developed fraction in WEO 2008, based on realistic and historical depletion rate behaviour. The IEA forecast is also shown for comparison.*

3.3 Fields yet to be found

In the WEO 2008 Reference Scenario, oil production is predicted to be 104 Mb/d by 2030, 25% of this is to come from fields with declining production, 22% from known fields yet to be developed and 18% (19 Mb/d) from oilfields yet to be found. To justify the 25% contribution from currently producing fields the IEA uses an entire chapter and yet justifies the 22% contribution from known fields yet to be developed in just three pages. However, in defending the 18% from oilfields yet to be found the IEA uses only the following sentences, combined with Figure 8:

"Conventional oil production from yet-to-be-found fields is projected to reach 19 Mb/d in 2030, based on the projected discovery of 114 billion barrels of reserves worldwide over the projection period. Almost 11 Mb/d comes from offshore fields. Onshore production comes mostly from OPEC countries – 8 Mb/d out of a total of 8.7 Mb/d in 2030 – as most undiscovered

resources in the Middle East are onshore. By contrast, the bulk of production from yet-to-be-found offshore fields comes from non-OPEC countries: they produce 7.9 Mb/d out of a total of 10.7 Mb/d in 2030. Non-OPEC offshore yet-to-be-found fields are about equally divided between Russia and other Eurasian countries, Africa and OECD North America."

After reviewing WEO 2008, we must question the reality behind these numbers. On page 257, WEO 2008 states that discovered fields include fields discovered in 2007. The production in 2030 is based on projected worldwide new discoveries of 114 bb, but they give no details of how much will be discovered in the different regions. Historical discoveries of crude oil during the time period 1945 to 2005 are presented in, for example, Robelius (2007) or Campbell (2009). The rate of discoveries peaked in the mid-1960s and has decreased ever since. Extrapolating the historical trend observed over nearly half a century, we estimate that around 149 Gb can be discovered during 2008-2030.

The typical lead time between discovery and first production is about 5 years for giant oil fields, with the current trend being towards longer delays (Höök et al., 2009a). Fields expected to be in production in 2030 must in most cases be discovered by 2024 or so, in order to be developed and on stream. Consequently, we use the summed discoveries from 2008 to 2024 as reserves to be developed, which can be estimated at 121 Gb. Thus, the 114 Gb that the IEA uses, is a realistic value according to our analysis.

Digitizing Figure 11.9 in WEO 2008 (Figure 8 and Table 1), gives an estimated cumulative production until 2030 from fields yet to be found of 46 Gb. From the information provided in WEO 2008, we cannot calculate the depletion rates for individual regions. For global production, the depletion rate in production from fields yet to be found can be calculated and the numbers are given in Figure 9. In WEO 2008, the first oil from fields yet to be found is expected to be produced in 2010 and that appears much too early for discoveries made in 2008. The estimated start-up years are probably not unrealistic for all fields, but most significant new discoveries will most likely need more than the two years implicit in the forecast by the IEA.

As a comparison, we present the depletion rate for the North Sea from 1975-1995, the region that, so far, has had the world's most rapid increase in depletion rate (Figure 9). We compare this with the IEA outlook for undiscovered fields and find large discrepancies with historical experience of depletion rate behavior.

Prior to 2019, the IEA (2008) gives a reasonable outlook for the development of future discoveries. These are assumed to be developed less rapidly than the North Sea. However, around 2019 this reasonable trend is replaced by a phase of much more rapid development (and depletion), in fact an unprecedented rate of development. Therefore, as a more realistic projection, we chose to restrict the rate of development after 2019 to that previously observed for the North Sea (Figure 9). Calculating equivalent production, we get 8.7 Mb/d from fields yet to be found by 2030. By way of comparison, a discovered volume of 114 Gb is on the order of one and a half North Sea regions. It took around 25 years to get North Sea production to a maximum of 6 Mb/d. Therefore, a production level of roughly 9 Mb/d is realistic, if 114 Gb is discovered and developed as rapidly as the North Sea region. We would like to emphasize that the North Sea region was developed especially rapidly and showed a high rate of depletion. Therefore, using it as a model for the development of the fields-yet-to-be-found fraction as a whole should be seen as relatively optimistic.

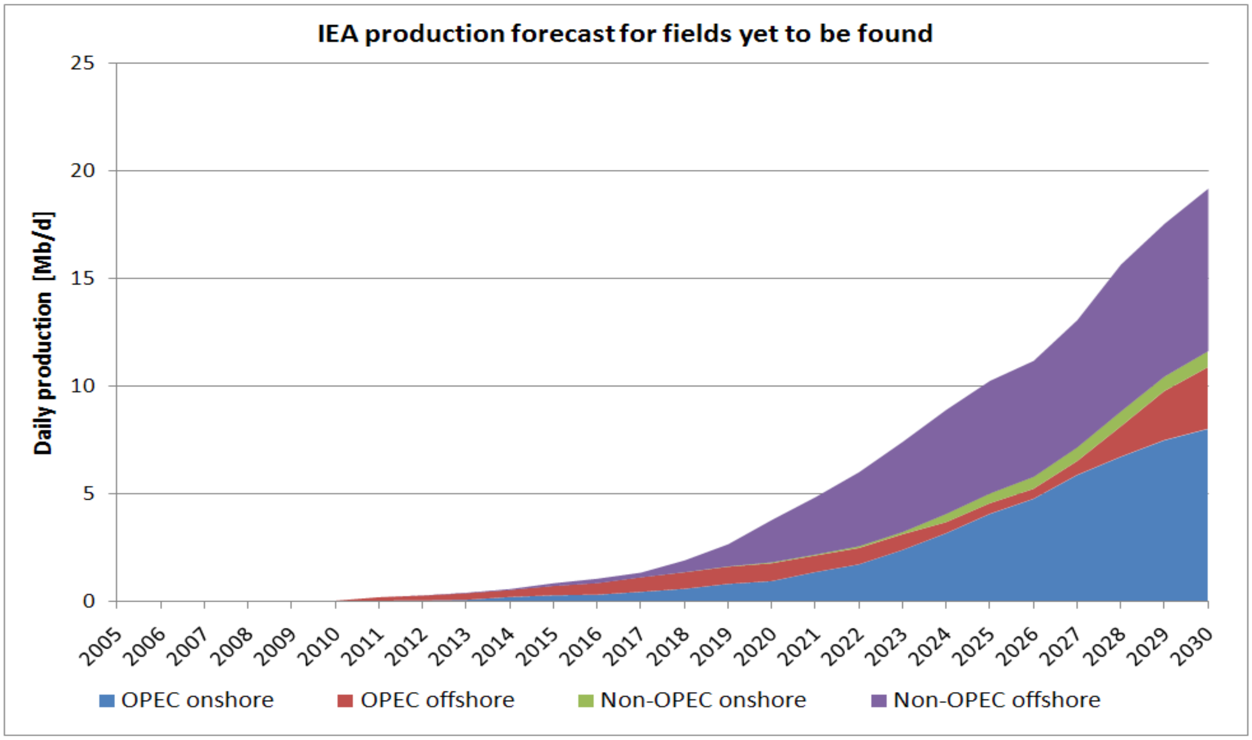

Figure 8: *World crude oil production of yet-to-be-found oilfields in OPEC and non-OPEC countries by location in the Reference Scenario. Digitized and adapted from Figure 11.9 in WEO 2008*

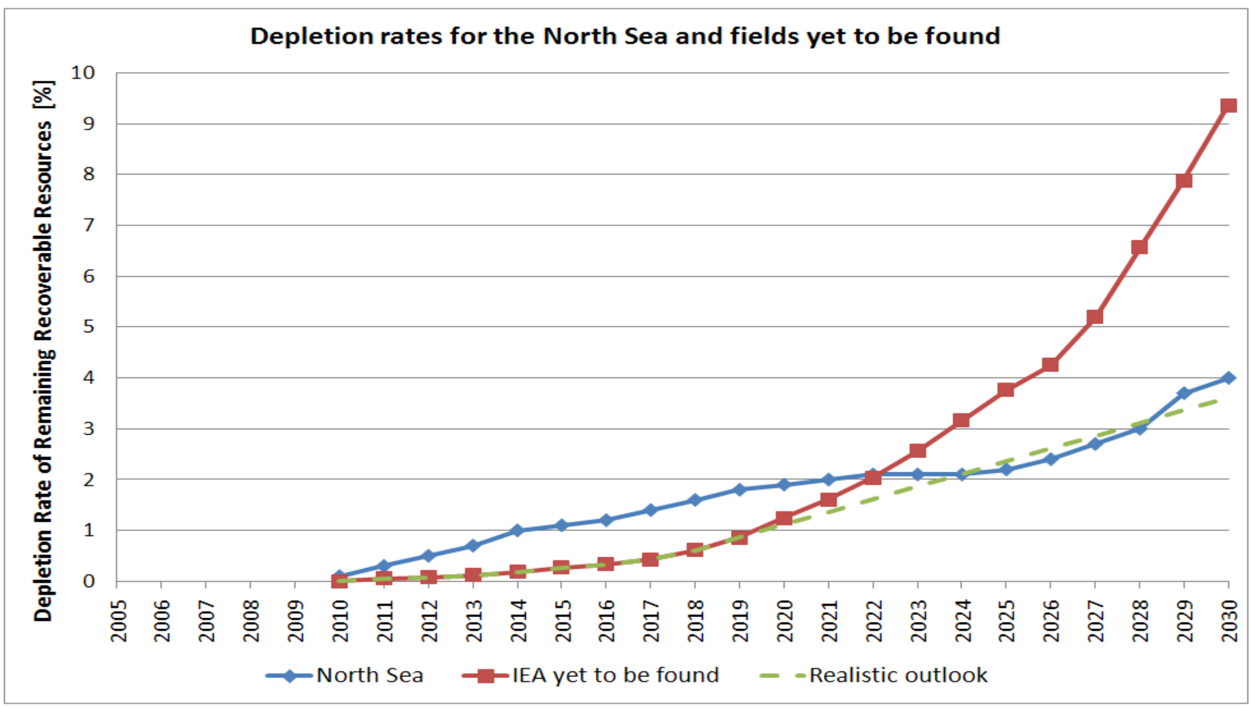

Figure 9: *Depletion rate of remaining recoverable resources for the North Sea region and the yet-to-find fraction from WEO 2008. The realistic outlooks follow the IEA case up to 2019, before following a similar growth trend as the North Sea.*

In conclusion, an assumed production of 19 Mb/d in 2030 from fields yet to be found is based on an unrealistically high depletion rate never before seen in history. Depletion is a major factor for reservoir flows (Satter et al, 2009), and flows will naturally decrease as reservoirs are depleted. Certainly, these factors can be influenced by technology to a limited extent, but this requires increasing work input and investments to counter depletion-driven decline. We already see the North Sea example as an optimistic outlook for the future, while the IEA is even more extreme in their expectation from undiscovered fields without providing any justification for this dramatic deviation from historical behavior.

3.4 Additional EOR

In WEO 2004, additional enhanced oil recovery was estimated to be in the order of 25 Mb/d by the year 2030 (IEA, 2004). In WEO 2008, this number has been reduced to 6.4 Mb/d (IEA, 2008). IEA (2008) attributes great importance to CO2 injection. We believe that the oil industry will use any and all means available to increase oil production from old oilfields because the decline in production from existing fields will be severe (Höök et al., 2009b). Currently, only a small fraction of the world's oil fields are using EOR (IHS, 2007). The projected production volume from EOR in 2030 may be reasonable, if use of CO2 injection is implemented along with massive investments and developments. In summary, we can regard the future outlook for this fraction as acceptable.

3.5. Crude oil – total in the future

By adding crude oil from fields in production, fields yet to be developed, fields yet to be found and additional EOR we get a projection of future crude oil production indicating that the peak of world oil production is probably occurring now. In WEO 2008, the IEA obtains a very different picture using the same data. Can we explain this difference in outlook? We have shown that the IEA's estimates for future production from fields currently in production are acceptable. We have also accepted their estimates for the volumes of oil in fields yet to be developed and yet to be discovered. Finally, we accept their estimate for additions from EOR as being realistic. The difference thus lies in one parameter only and that is the depletion rates of remaining recoverable resources ($d_{\delta t}$). The future production that IEA proposes assumes unrealistically high $d_{\delta t}$-values.

Discovered fields are tending to decrease in size and this fact affects future production dramatically. The history of oil production in Norway follows a pattern that reflects this (Figure 10). The importance of this has been addressed previously in Aleklett (2004). Detailed study of the data displayed in Figure 10 shows that whenever production increased in Norway, this was due to the addition of new oilfields. Ultimately, the new fields were too small to offset the decline in the larger fields (Höök and Aleklett, 2008) and so peak oil in Norway became a reality.

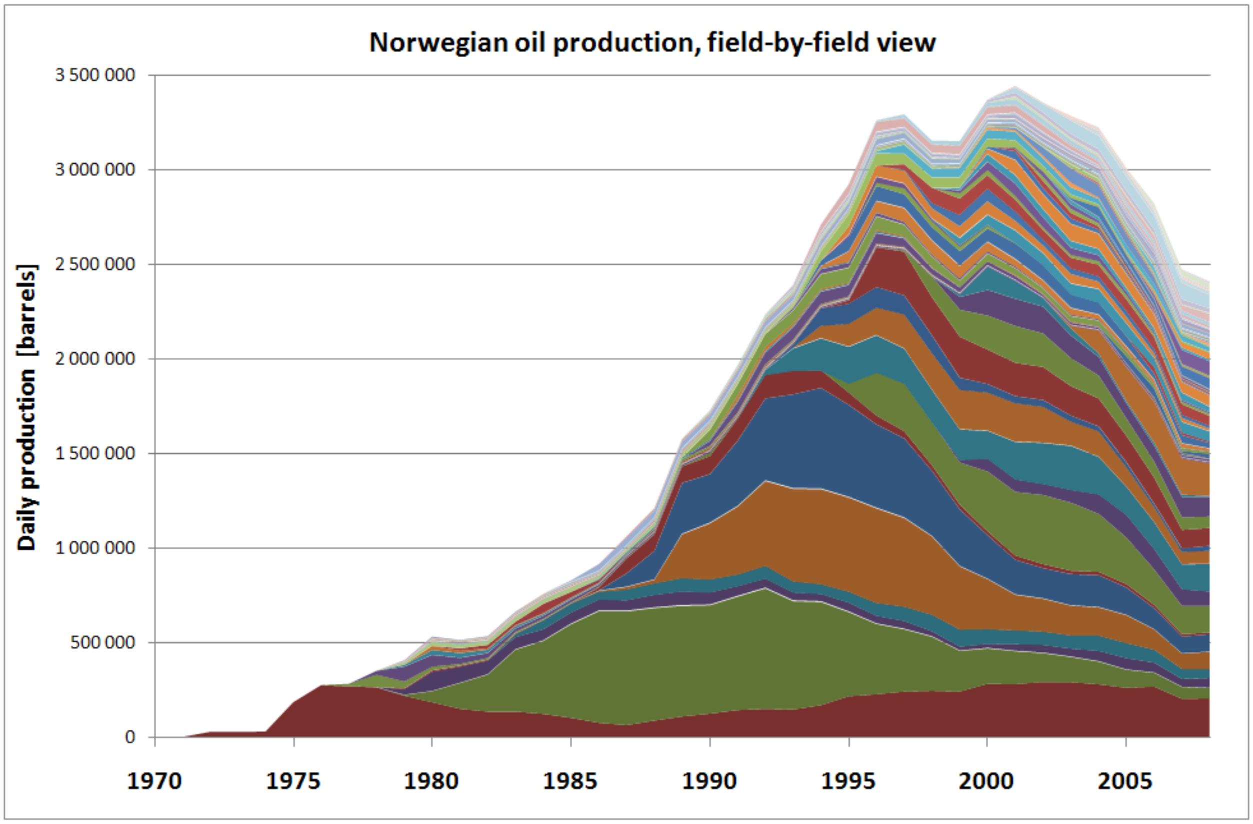

Figure 10: *A field-by-field plot of Norwegian oil production, showing both the volume and temporal distribution of production for each field. Most of the giant fields peaked prior to 2000. Initially, their decline was offset by a massive expansion of development of smaller fields before the overall decline became unstoppable.*

We can also discuss these findings from a strictly theoretical standpoint. It can be shown that the maximum depletion rate of remaining recoverable resources is the same as the decline rate (Jakobsson et al, 2009, Höök, 2009). Empirical studies of actual production data have confirmed this and have shown a strong correlation between $d_{\delta t}$ and average decline rate (Höök et al., 2009a).

By adopting a theoretical model based on the maximum depletion rate and an assumed production level dependent only on URR (Figure 11), we can study the effect of the decreasing size of discovered fields. Theoretically, a field can be developed and the production expanded to the maximum $d_{\delta t}$. However, it is common that large fields are kept at a lower plateau production level than our theoretical field. Despite this, at the end of the plateau production phase the maximum $d_{\delta t}$ is reached (Figure 3). Assuming that each year's discoveries can be approximated by a single giant oil field and developed in line with Figure 11, we can aggregate production behaviour, thus creating a possible profile for undiscovered fields (Figure 12). While this is a purely theoretical model, it is in agreement with the Norwegian experience. It gives a somewhat higher rate of production than the 9 Mb/d obtained using the North Sea as a model, and so should be seen as quite optimistic. Nevertheless, this method still predicts a production rate below the IEA's expected contribution from undiscovered fields.

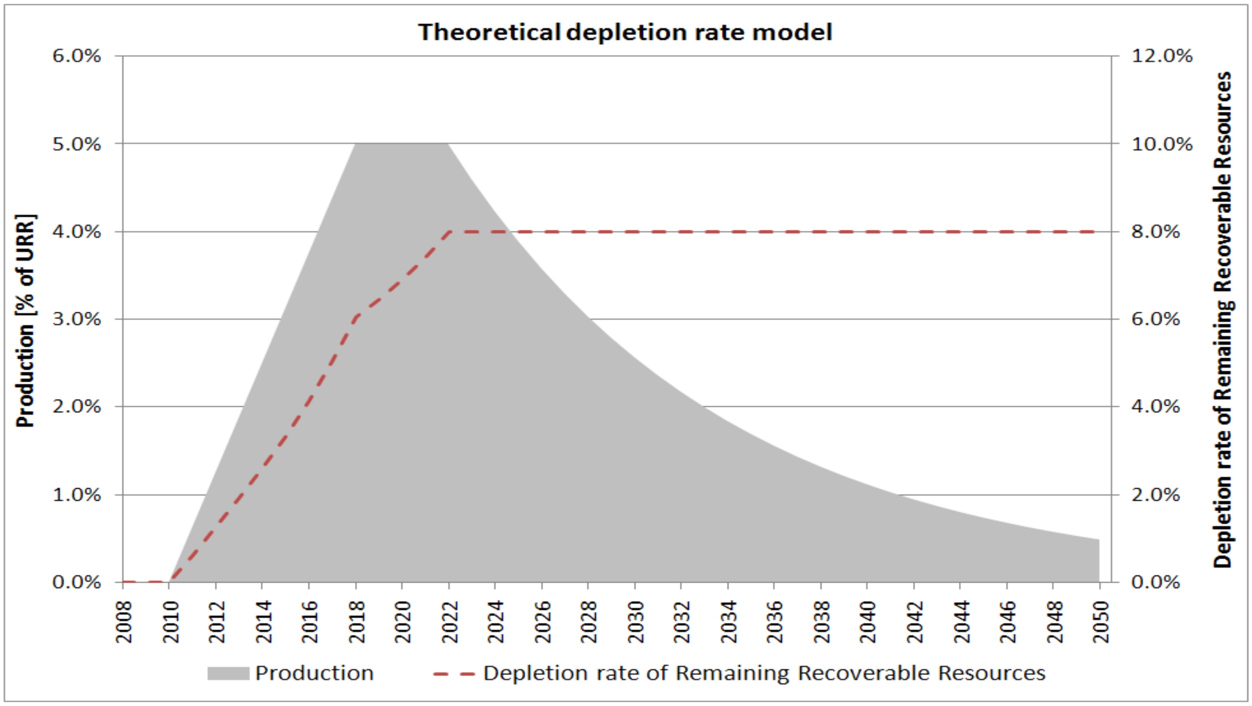

Figure 11: *Theoretical production profile based on a maximum depletion rate model.*

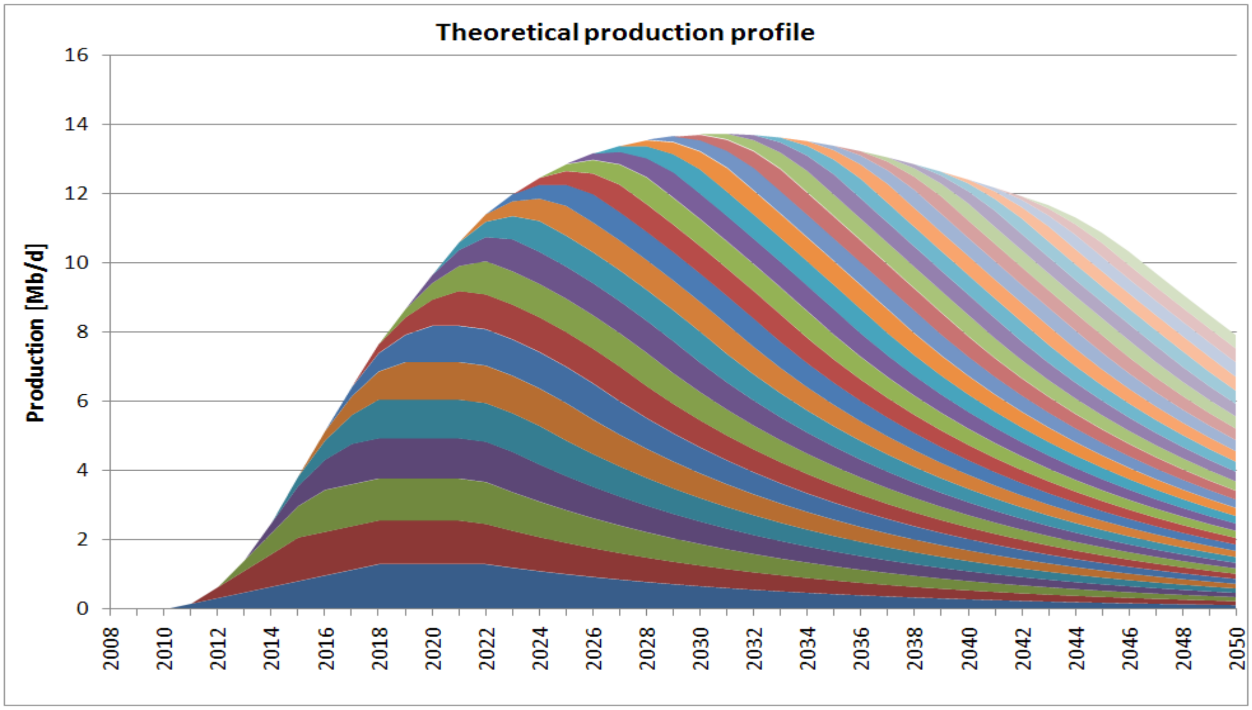

Figure 12: *Theoretical production profile for fields yet to be found based on the maximum depletion rate model shown in Figure 11. In total, 182 Gb of new discoveries are developed from 2008 to 2040. The annual discovery rate starts at 9.5 Gb in 2008 and drops gradually to 3 Gb by 2040. Each year's discoveries will be developed in the same way, but shifted in time. The decreasing size of new discoveries, all other things being equal, will unconditionally lead to a peak in production when new projects are unable to offset decline in existing fields.*

4. Non-conventional oil

The IEA defines non-conventional oil as oil sands, extra-heavy oil, gas-to-liquids, coal-to-liquids, and chemical additives. In WEO 2008, non-conventional oil is anticipated to increase from the 1.7 Mb/d of 2007 to 8.8 Mb/d by 2030. With an annual average growth rate of 8%, this is a spectacular rate of development comparable to the oil boom following the Second World War. However, de Castro et al. (2009) showed that the attenuation in supply due to the peak oil decline, even with the most optimistic assumptions, requires a sustained growth of more than 10% for non-conventional oil production over the next two decades.

From a resource perspective, non-conventional oil appears to have huge potential, but the industrial processes required to convert these resources into fluids useful for transportation are very different from the production of gasoline, aviation fuel, diesel and bunker oil from crude oil. The lowest production costs for extraction of any of these resources is much higher than the lowest production cost for crude oil. These high costs will definitely be a limiting factor in production.

4.1. Oil sand

In a report to the US Department of Energy, "*Peaking of World Oil Production: Impacts, Mitigation and Risk Management*", Hirsch et al. (2005) concluded that peak oil will happen and "*that worldwide large-scale mitigation efforts are necessary to avoid its possible devastating effects for the world economy*". These efforts include accelerated production, (referred to as crash program production), from Canada's oil sands.

WEO 2008 predicts that the level of production from oil sands will be 5.9 Mb/d split between 1.4 Mb/d from mining and 4.5 Mb/d from in situ. In 2007, the project-by-project study "*A Crash Program Scenario for the Canadian Oil Sands Industry*" was published (Söderbergh et al., 2007). In this analysis all planned projects were assumed to become reality (Figure 13). The Crash Program Scenario (Söderbergh et al., 2007) presents a possible scenario in which the contribution from mining reaches a level of 2.0 Mb/d and the in situ contribution attains 2.5 Mb/d by 2030.

In comparison, the Canadian Association of Petroleum Producers (2008) forecasts future oil sand production at 3.8-4.5 Mb/d by 2020 (largely dependent on infrastructure developments and investments) and Cambridge Energy Research Associates (2009) place two of their oil sands outlooks at 3 Mb/d or less by 2030, whilst their most optimistic scenario attains 5.5 Mb/d.

For the mining contribution we readily accept 1.4 Mb/d by 2030 as proposed by the IEA (2008), which is roughly 70% of our crash course scenario and seems reasonable since the IEA do not consider a crash course development. For the future contribution from in-situ recovery, we chose to use the crash program scenario outlook as an upper limit, since the IEA projections seem to lack this 'crash program' perspective.

How WEO 2008 can have such high expectation of in-situ recovery, without greater justification, is difficult to understand. Consequently, we would like to see more detail on the underlying assumptions upon which the in-situ outlook relies, and we must therefore regard the IEA production figure as somewhat dubious until it is explained more fully. In summary, we expect future oil sand production to be 3.9 Mb/d by 2030, split between 1.4 Mb/d from mining and 2.5 Mb/d from in situ recovery.

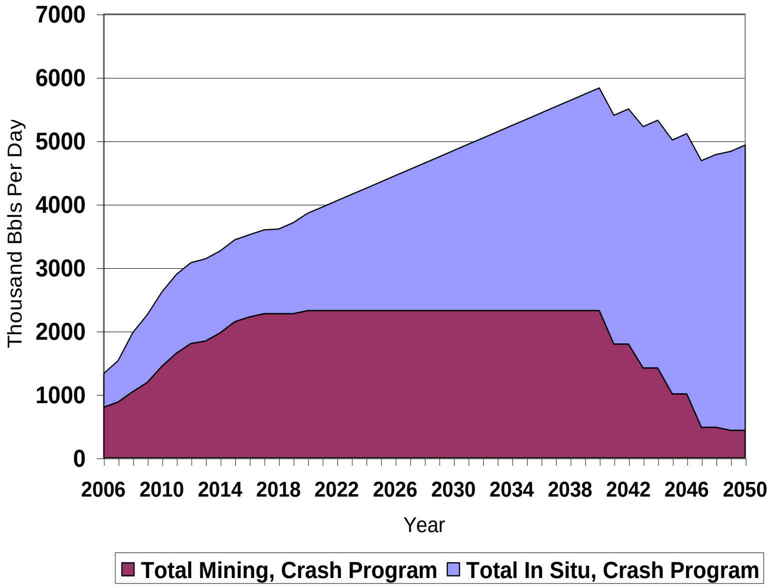

Figure 13: *Future production outlook for Canadian oil sands in a crash program. Adapted from Söderbergh et al. (2007)*

4.2 Extra-heavy oil

Production from the extra heavy oil in Venezuela is usually treated as non-conventional oil, but the IEA now classify this as conventional oil. Somewhat surprisingly, its production is not discussed in great detail.

The remainder of extra-heavy oil production that is not Venuzuelan is primarily planned production predominantly in Kuwait, but also from a few isolated projects in Brazil, Vietnam and Italy. Therefore, the 0.7 Mb/d predicted is reasonable. However, Kuwait has recently revised their development plans for heavy oil and is now aiming for 0.45 Mb/d by 2020, instead of the original goal of 0.7 Mb/d (MacDonald, 2009). If the economy recovers and oil prices rise, it is reasonable that 0.7 Mb/d may still be reached. In essence, we cannot regard the IEA's expectations on extra-heavy oil as unrealistic.

4.3 Gas-to-liquids (GTL)

The IEA (2008) provides estimated production costs of US$40-90 per barrel, largely depending on feedstock gas price. Furthermore, WEO 2008 claims that planned projects will bring total world GTL capacity to above 0.2 Mb/d in 2012. In total, it is expected that world GTL production will reach 0.65 Mb/d by 2030.

High production costs, and the fact that natural gas will probably be needed as gas in the future (Bentley, 2002), indicate that future production levels will be less than 0.65 Mb/d and closer to 0.2 Mb/d in 2030. However, we cannot dismiss the IEA prediction as unreasonable on this point and, since the contribution of GTL to total world oil production is minor, we will not pursue discussion of it further.

4.4 Coal-to-liquids (CTL)

Historically, coal-to-liquids have only been developed in a few countries during special circumstances. South Africa is one such example and began using this method when they were subject to sanctions, and Sasol has maintained production at roughly 0.15 Mb/d ever since. A new Chinese CTL-plant was recently completed, but the government has now suspended any further CTL development with the exception of just two projects (Tingting, 2009).

During the last oil crisis Perry (1980) pointed out that the construction of a synthetic fuels industry would be very costly and provide only a minor increase in oil independence. Currently the situation has not changed, and replacing only 10% of US transport fuel consumption with CTL would require over US$70 billion in capital investments and an increase of about 250 Mt in annual coal production according to research by the IEA Clean Coal Centre (Couch, 2008). Furthermore, Milici (2009) states that only very modest amounts of liquid fuels can be produced from CTL without depleting available US coal reserves prematurely.

In WEO 2008, it is proposed that CTL will increase to 1 Mb/d by 2030. Typical CTL liquid yields are roughly 1-2 barrels/ton coal (Sasol, 2005; National Petroleum Council, 2007; Couch, 2008; Milici, 2009), implying that volumes corresponding to around 5% of world coal production in 2007 would be liquefied annually for a quite insignificant contribution to global liquids supply. We conclude that the CTL expectation in WEO 2008 is optimistic and only vaguely justified, but not unachievable if proper investments and developments are pursued. However, we believe that CTL production will be less than IEA (2008) estimates in a realistic future.

4.5 Chemical additives

This category is barely mentioned in WEO 2008 and not discussed in that report. As we do not see the same increase in oil production as in WEO 2008, we do not expect an increase in this volume. The contribution of chemical additives will remain at 0.2 Mb/d, but we are prepared to accept the figures in IEA (2008) as reasonable. However, we feel that this category is described in vague terms in WEO 2008, and we would like to see more details in future editions of WEO.

4.6 Summary of non-conventional oil

With extra heavy oil from Venezuela discounted we can assume the following volumes; 3.9 Mb/d from oil sands, 0.7 Mb/d from extra-heavy oil, 0.65 Mb/d from gas-to-liquids, 1 Mb/d from coal-to-liquids and finally 0.2 Mb/d from chemical additives. The sum of these gives a total of 6.5 Mb/d. This is 2.3 Mb/d less than the figure predicted in WEO 2008.

The German Federal Institute of Geosciences and Natural Resources states the following: "*After peak oil, the non-conventional oil production will rather modify the decline in oil supply than close the gap between demand and supply*" (BGR, 2008). Similarly, IEA (2008) does not foresee any significant contribution from non-conventional oil compared to conventional oil and neither do we.

5. Natural gas liquids (NGL)

The Reference Scenario for future oil supplies shown in Figure 11.1 in WEO 2008, places a significant role on the contribution from NGL. The chosen unit of measurement in this case is barrels per day following the convention used for oil. This, however, is slightly misleading in the case of NGL. It is energy that is vital to the economy, and so these scenario results should, in reality, be shown in energy units. The energy content of the five major NGL fractions; ethane, propane, butane, isobutane and pentanes plus range from 3.25-4.56 GJ/barrel (Energy Information Administration, 2009), significantly less than the energy content of a standard barrel of oil (6.1 GJ). In summary, one barrel of NGL can only replace 0.7 barrels of oil in terms of energy. Thus the Reference Scenario, if re-stated in energy terms, would be some ~ 6 Mboe/d lower.

We also note that the IEA (2008) claims that NGL production was 10.5 Mb/d in 2007. This contrasts with the estimate given by EIA (2008) of 7.92 Mb/d. The ratio between these two numbers is 0.75, approximately the same value as the energy ratio between a barrel of NGL and a barrel of crude oil. The conclusion is that the EIA is describing NGL production in equivalent volumes of oil, which appears to be a more appropriate method. For some unclear reason, the IEA (2008) does not appear to follow this methodology. Volumetric or energy units make significant differences when it comes to NGL.

In Chapter 11 of WEO 2008, the IEA (2008) uses the following justification for a roughly 100% increase of NGL volume by 2030: "*Output of natural gas liquids – light hydrocarbons that exist in liquid form underground and that are produced together with natural gas and recovered in separation facilities or processing plants – is expected to grow rapidly over the Outlook period. Global NGL production is projected to almost double, from 10.5 Mb/d to just under 20 Mb/d in 2030. This increase is driven by the steady rise in natural gas output. The bulk of the increase comes from OPEC countries, where gas production (to supply local markets and new LNG projects) is projected to expand quickest. OPEC NGL production almost triples, from 4.7 Mb/d in 2007 to over 13 Mb/d in 2030. The Middle East accounts for four-fifths of this increase. Non-OPEC NGL production increases by about 1 Mb/d, to close to 7 Mb/d in 2030. These projections assume that the average NGL content of gas production is constant over the projection period*."

First we wish to investigate whether the "*average NGL content of gas production is constant over the projection period*". Studying global NGL and natural gas production (Figure 14), it can be found that the NGL fraction has been more or less constant at 15% compared to global dry gas production over the past 40 years. Furthermore, the correlation between NGL and gas production is 0.99, which is extremely high. This supports the assumption of constant NGL content in future natural gas production and is in agreement with statements from WEO 2008. Accordingly, doubling the global NGL production would then require a similar increase of world natural gas production.

However, the IEA (2008) projects world gas production to be 4434 billion cubic meters (bcm) by 2030 in the reference case, a 47% increase in the production level of roughly 3000 bcm in 2007. At the same time, NGL production is expected to increase by 90%. This cannot be consistent with the assumption of a constant NGL content over the projection period. Either, NGL production will only increase by 47% to 15.5 Mb/d by 2030 or the NGL content of natural gas must double to fulfil the NGL scenario. Given the empirical data (Figure 14) and the IEA's explicit assumption, we regard it more likely that NGL content will stay constant and thus NGL production volume will only increase to 15.5 Mb/d by 2030 if the two sets of numbers (NGL production increase and gas production increase) are to be brought into accordance.

In summary, the NGL fraction is misleadingly expressed in volume units instead of energy units. Converting to energy units, a 25-30% reduction of NGL production volumes is found when obtaining oil equivalent units. Based on a constant NGL content of natural gas and the assumption that the IEA (2008) Reference Scenario for global gas production is accurate, we find that global NGL production by 2030 only equals 15.5 Mb/d, or 11.5 Mboe/d. In essence, much of the seemingly massive NGL contribution disappears upon closer inspection.

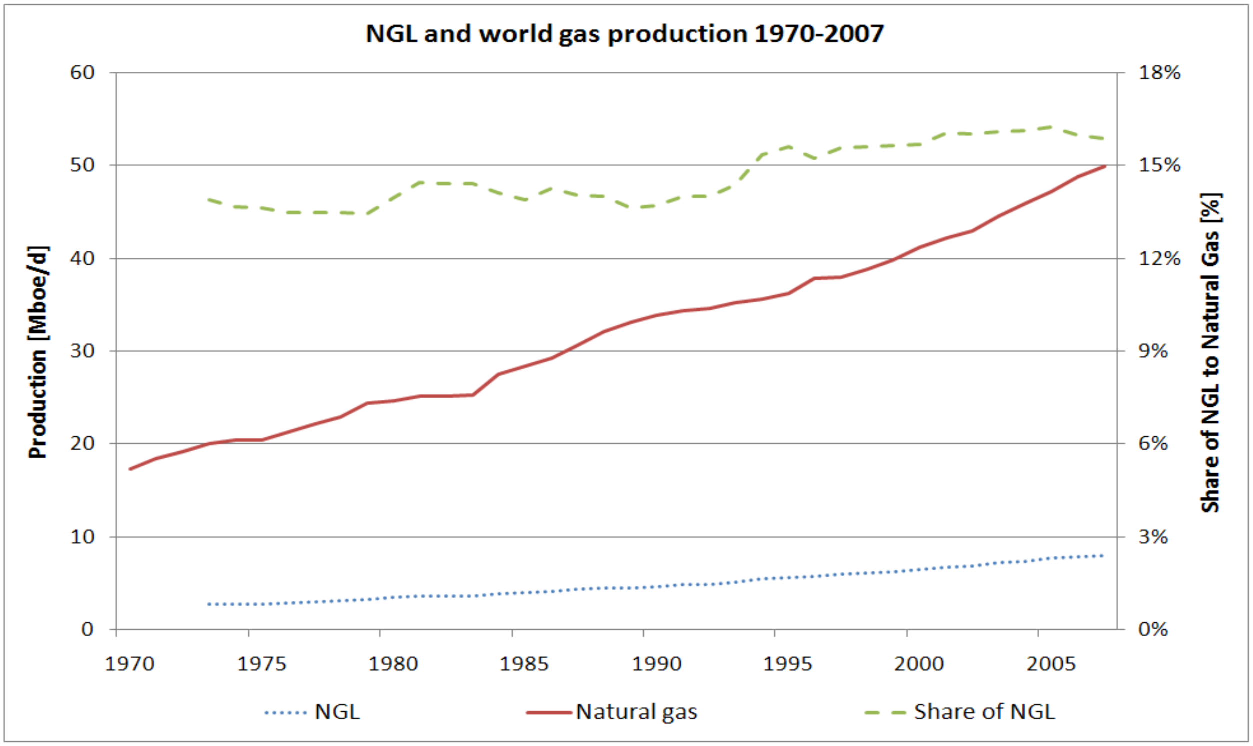

Figure 14: *World NGL and natural gas production 1970-2007. The fraction of NGL compared to natural gas has been 14-16%, following a slowly increasing trend. Data taken from Energy Information Administration (2008) and BP (2008)*

6. Conclusions

The world oil supply, including processing gains, was reported to be 84.3 Mb/d in 2007 and this is an increase of 10% when compared with production in 2000. In the same period the world witnessed a large increase in GDP growth and this increase is linked to the increase in the use of oil according to the IEA. When looking into the future, the IEA maintains this link between future increase in GDP and increasing oil production. On this basis, a possible conclusion may be that any decline in future oil production would produce a similar decline in GDP, as oil, despite the availability of other energy sources, could no longer help drive future GDP growth. This has also been discussed by Hirsch (2008), who found an approximately 1:1 correlation between decline in world oil supply and the percentage decline in GDP.

Using the data provided by the IEA in WEO 2008 and in peer reviewed publications, we have, in Sections 3-5, analyzed the same fraction of world oil supply as has the IEA. In essence, we use virtually the same input data and classifications as the IEA for our analysis, but different methodologies. Summing the different fractions, we find that the world oil supply by 2030 will only be 75.8 Mb/d (Table 8).

Table 5: *Summery of reported production numbers in World Energy Outlook 2008 and results from the analysis in this work. All numbers in Mb/d*

Fractions defined by IEA in World Energy Outlook 2008	**Production in 2030** World Energy Outlook 2008	**Production in 2030** This study
Crude oil – currently producing fields	27.1	27.1
Crude oil – to be developed	22.5	13.6
Crude oil – new discoveries	19.2	8.7
Crude oil – Enhanced oil recovery	6.4	6.4
Crude oil - total	**75.2**	**55.1**
Non-conventional oil	8.8	6.5
Natural Gas Liquids (NGL)	14.9*	11.5
Sum of all fractions	98.9	73.2
Processing gains	2.6	2.6
World oil supply	**101.5**	**75.8**

**) 19.8 Mb/d NGL has been converted to 14.9 Mb/d oil equivalents*

The driving fraction in the past has been crude oil production and about 80% of the difference between our numbers and the IEA's comes from the difference in the figures for future crude oil production. In our analysis, we have introduced the depletion rate of remaining recoverable resources ($d_{\delta t}$). This parameter has been studied in separate publications (Höök et al., 2009a; Jakobsson et al., 2009, Höök, 2009) and reasonable limits for $d_{\delta t}$ can be defined for real production. In WEO 2008, the IEA has not considered the $d_{\delta t}$-factor, and for the fractions where this is important the IEA has obtained what appear to be unrealistic production scenarios. In analyses where $d_{\delta t}$-numbers are unimportant, the IEA forecasts in WEO 2008 generally agree with our evaluation. In general, any analysis that assumes higher $d_{\delta t}$-rates than anything seen before in history must explain what factors and conditions will be responsible for accomplishing such deviations from historical patterns.

Based on studies of the world's giant oil fields (the backbone of global oil production) it can be concluded that new fractions are largely unable to compensate for the decline in existing production. It is unlikely that future world crude oil production will ever return to the levels seen in 2008. Increasing trends for average decline rates (Höök et al., 2009b) complicate and worsen the situation further. The collapse of the oil price since mid-2008, and the delays in investment this has induced, will make this situation even more challenging, especially considering that the actual economic impact is hard to quantify at the present time. Therefore, our outlook for new field developments and yet to find fractions are optimistic, since lack of investment will generally dampen future developments severely.

The difference in non-conventional oil production comes mainly from different estimates of future oil production from the oil sand in Canada. We agree on the volume of the mining fraction, but disagree when it comes to the in-situ fraction where, instead, we use production numbers found credible in a crash management analysis (Söderbergh et al., 2007).

The IEA reports the NGL fraction to be 19.8 Mb/d and this fraction is subsequently converted to 14.9 Mb/d of oil equivalents following best practice. To produce this amount of

NGL we need a 90% increase in natural gas production, but the WEO 2008 gas outlook only predicts an increase of only 47%. Making the additional correction discussed in section 5, we arrive at a future NGL contribution of only 11.5 Mboe/d.

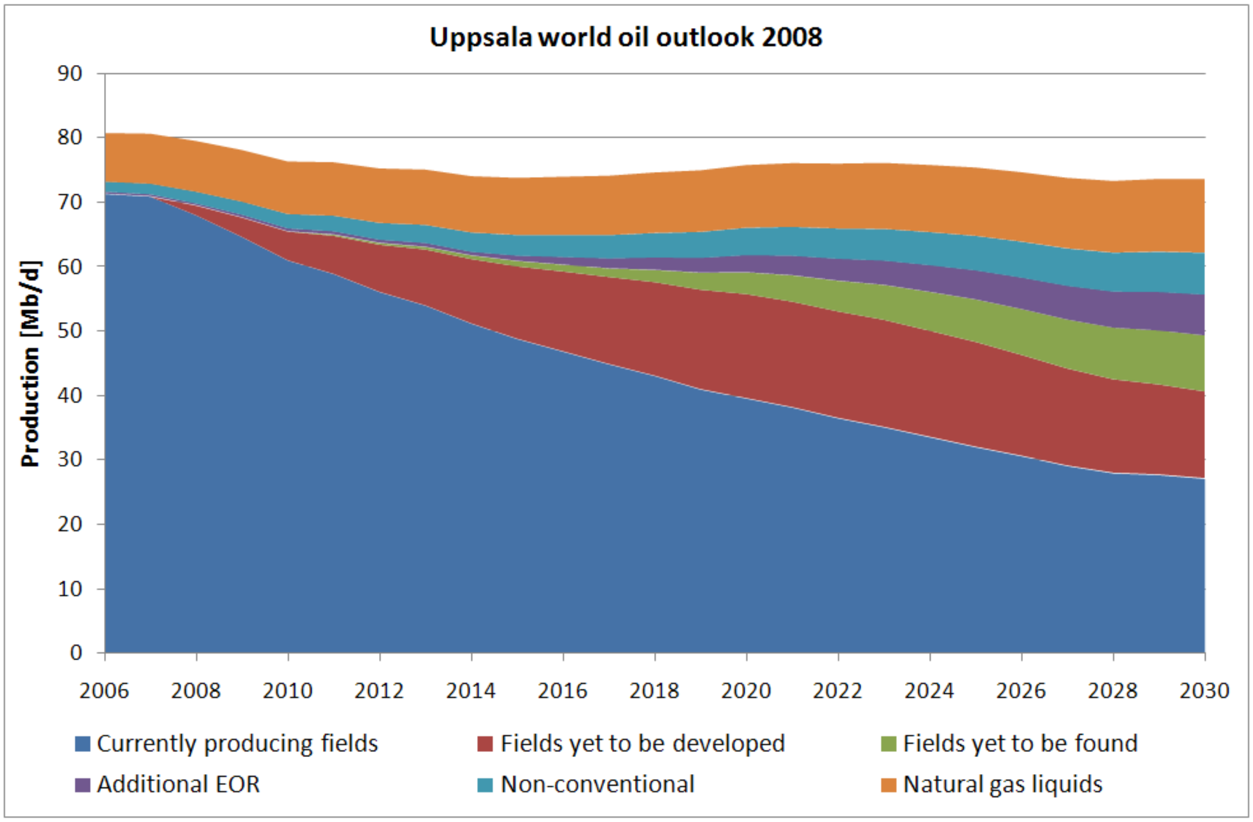

Figure 15: *Total oil production based on IEA data, but using realistic depletion rates of remaining recoverable resources, minor adjustments for non-conventional oil and recalculation of NGL to oil equivalents. The production volumes from fields yet to be developed or found should be regarded as optimistic.*

The sum of all fractions is given in Figure 15, and this may be seen as our future reference case – '*the Uppsala world oil outlook 2008'* – which yields a undulating and gentle descent to a production level of around 75 Mb/d by 2030. However, future oil production is very dependent on the fields yet to be developed and in order to provide some alternative outlooks both faster and slower development rates than depicted in Figure 6 have been considered (Figure 16). The fast development means that the maximum depletion rates will be reached twice as fast, while the slow development scenario implies that it takes twice as long to reach the maximum depletion rate as in Figure 6. The fast development scenario may be seen as a future where the economy recovers rapidly and the fields yet to be developed are brought on stream quickly. Even in this scenario, the peak is only pushed forward a few years before a descent begins. The slow development scenario assumes slow development where new fields are brought on stream gradually and further into the future. This actually leads to a descent followed by a partial recovery after 2020. All our projections imply that the world oil production by 2030 will be lower than today.

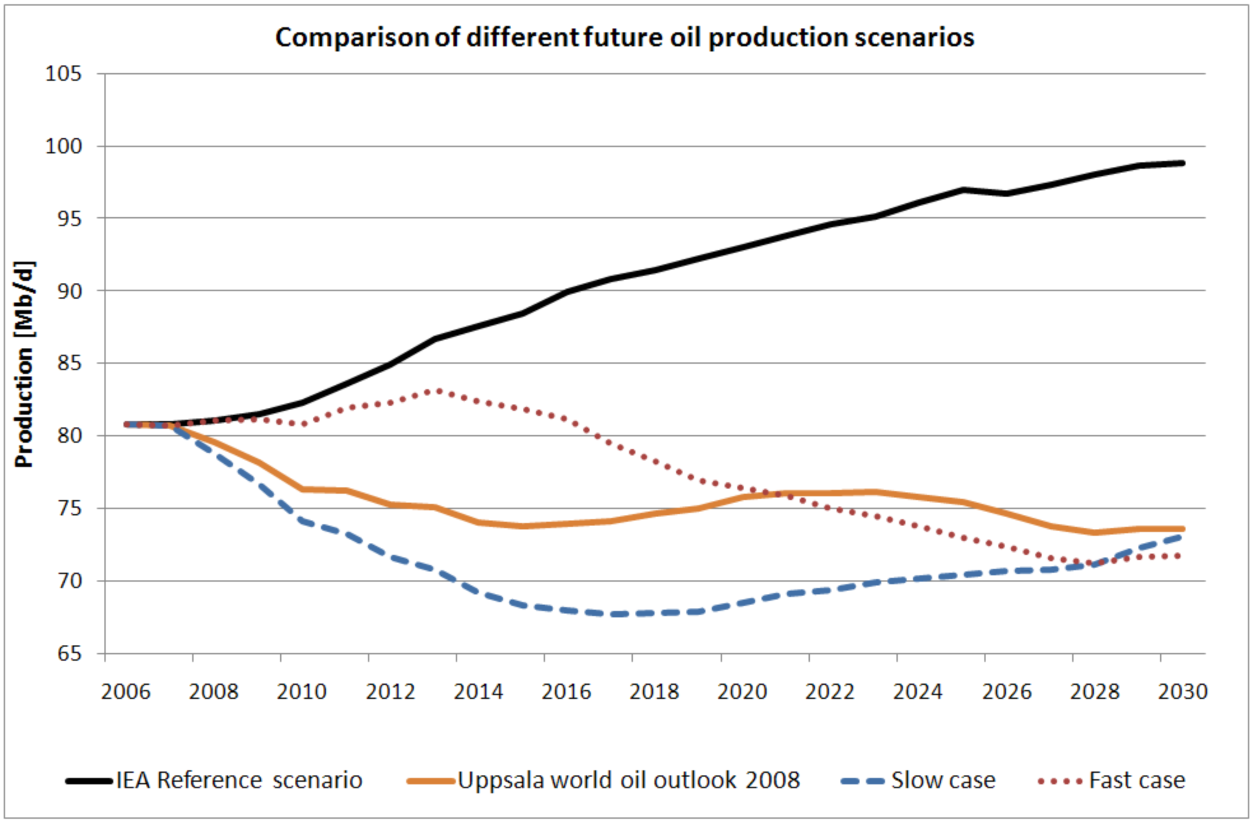

Figure 16: *Comparison of different future oil production scenarios. The Uppsala world oil outlook is the same projection as in Figure 16, while the slow and fast cases features alternative development speeds for the fields yet to be developed with all other things being equal.*

The link between GDP growth and growth in the consumption of oil is usually called "*business as usual*", and we can now conclude that future growth in GDP must be dependent upon fuels other than oil if it is to continue as expected. This, in turn, defines the beginning of the end of the '*Oil Age*', and society will have to seek other driving forces for future GDP growth. In all our projections, future oil production by 2030 will have decreased from present levels. The world appears most likely to have passed the peak of global oil production and to have entered the descent phase. If this is the case, then the world has reached the '*Peak of the Oil Age'*.

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