UK ENERGY RESEARCH CENTRE

Annex 1: Models of Global Oil Supply for the Period 2008-2030

UK Energy Research Centre UKERC/WP/TPA/2009/023

Introduction

The models that have been reviewed for this study are described below. As far as possible, the same format has been used to describe each model, to facilitate comparison. Each description commences with a list of the more common basic input and output parameters, assumptions, definitions, components and data sources, and a statement of the type of model. Where appropriate, a brief comment on the model is included at this stage.

This is followed by a more detailed description of the modelling methodology and of the relevant assumptions and components. Each model description then concludes with a summary. In general we have offered no detailed criticisms in writing these descriptions, although we do include occasional comments concerning assertions, assumptions, missing arguments or possible internal contradictions. Detailed comments on each model are given in Section 4: Comparison of Models, set out above.

The original data for the model descriptions have come from a range of sources, including personal communication, printed publications and internet-sourced documents. For most of the models there has been discussion with the model creator as to the correctness of what we have written, although the degree of this co-operation varies between models, and is set out in each case.

In addition to model descriptions, where appropriate, modellers were asked for, and sometimes provided, their current forecasts of oil production out to 2030 for the world, and for four countries (the UK, the US, Brazil and Saudi Arabia) to enable their forecasts to be compared. These four countries were chosen because:

- The UK possesses an excellent public data set, so all modellers should have the same input data
- The US is the world's largest oil consumer, and has good summary data, although onshore field detail is only accessible through proprietary databases
- Brazil is an active frontier exploration area with partially accessible data
- Saudi Arabia is the world's greatest oil supplier and possesses the greatest reserves of conventional oil, but has notoriously contentious reserves data. Where such data were provided, they are shown together.

Data in the model descriptions have been entered in the following format:

Author:	Name of the model creator or owner.
Description approved?	Has our description been approved by the model's author?
Date of model:	Year of the model being described.
Study reference:	The main data source(s) on which this description is based.
Coverage:	The geographical coverage of the model (e.g. Global), and the types of liquids included (e.g. Oil - see definitions).

Basis: Short description of the main methodology used.

Global oil production data source: The source the modeller uses for historical production data.

2007 global daily rate: Global production rate given by the model for the year 2007 or the most recently available year. Different models include different liquids components, and so will show different 2007 production data. This number is used for re-basing some models to assist graphical comparison.

Data sources: Sources the modeller uses for key input parameters, such as production, reserves and URR values.

Definition of liquids:

- By location/setting: Whether oil classes are defined by geographical location (Campbell's model in particular uses this approach)
- Types of liquids included in the model. The possible components are: condensate & NGLs, medium/light crude, heavy crude (10-26° API) and/or extra-heavy oil, oil/tar sands, shale oil, GTL, CTL and biomass.

Peak Date: The date of any *resource-limited* global production peak forecast by the model, either for a specific oil category or for all the liquids covered by the model.

Peak daily rate: The annual rate of production of the liquids covered by the model at the date of the forecast *resource-limited* peak.

Reserves definition: Any specific reserves definition quoted by the modeller.

URR: Any URR assumed or used by the modeller, specifying where possible to what categories of liquids this applies. Sometimes we note the implicit URR where this can be deduced but is not made explicit.

IEA Oil Supply Model

Author: International Energy Agency

Description approved? This description is based largely on the references listed below. Dr. Fatih Birol of the IEA was visited by two of us (Miller & Bentley) in October 2008, and kindly gave some key insights into their 2008 study prior to its release. Dr Birol subsequently suggested minor changes to this description but has not specifically approved it.

Date of model: 2008

Study references: World Energy Outlook 2008 (WEO 2008); Medium-Term Oil Market *Report*, July 2008 (*MOMR 2008*) [1]

Coverage: Global, Liquids

Basis: Bottom-up production modelling of current fields/projects, modelling of future demand, and calculation of required investment for incremental demand

Global oil production data source: Proprietary IEA databases

2007 global daily rate: 85 million b/d

Data sources: USGS; *Oil & Gas Journal, World Oil;* national government bodies; IHS Inc.; ENI; National Energy Board, Canada (for oil sands information); World Energy Council

Definition of oil:

- By location/setting: No
- Condensate & NGLs: Yes
- Medium/light: Yes
- Heavy (10-26° API) Yes
- Oil sands & shale oil Yes
- GTL: Yes
- CTL: Yes
- Biomass: Yes, but treated separately

Peak Date: Conventional oil production "levels off" towards 2030, non-conventional oil keeps rising.

Peak daily rate: Not reached, 103.8 million b/d by 2030

[1] *International Energy Agency (IEA), 9 Rue de la Federation, 75739 Paris Cedex 15, France*

	Demand reaches 106 million b/d, the difference being refinery gains
Reserves definition:	2P. IEA follows Petroleum Resources Management System
URR:	Conventional + NGLs: 3577 Gb (2P reserves, reserves growth and YTF) *(WEO 2008* Table 9.1)
	Non-conventional oil sands and extra-heavy oil: 1000 - 2000 Gb
	All potentially recoverable oil resources: 6500 Gb
	All resources including CTL and GTL: 9000 Gb
Global YTF:	805 Gb (*WEO 2008* Table 9.1)
Reserves growth:	402 Gb (*WEO 2008* Table 9.1)

Comment: *WEO 2008* is a significant departure from *WEO 2007*, particularly in its detailed look at field decline rates and its bottom-up modelling of potential supply from known fields. The modelling is very granular. *WEO 2008* is also an excellent source book for understanding the issues affecting the future of the oil industry. We have found some lack of clarity in the definition of some data and parameters.

Description of Model

Scale and Definitions

The scale is global; and covers all conventional and non-conventional oil (including NGLs) and synfuels. Biofuels are considered separately.

Demand modelling

The IEA uses forecasts of population and GDP growth to forecast oil demand. World total energy use increases steadily in the Reference Scenario, at an average of 1.6% p.a.. The average energy intensity (energy demand per unit of GDP) is expected to decline by 1.7% annually, reflecting an increasing service economy and higher energy efficiency. Energy demand for transport is expected to grow at 1.5% p.a. to 2030. The IEA does not expect a significant penetration by electric or hydrogen fuel-cell cars before 2030.

Oil demand (excluding biofuels) in the Reference Scenario rises by an average 1.3% p.a. to 2015, and an average 0.8% p.a. between 2015 and 2030, an overall average growth of 1% p.a.. Annual consumption rises from 85 million b/d[2] in 2007 to 94 million b/d in 2015 and 106 million b/d in 2030, which is 10 million b/d less than last year's forecast.

Supply Modelling

[2] Production in 2007 cited in *WEO 2008* as 82.3 million b/d, reflecting refinery gains

The IEA model determines the investment required to meet oil demand. This analysis is based upon recent and current spend in the industry and its results in production terms. Upstream costs rose by 70% between 2000 and 2007 but the rate of growth is expected to level off. The oil and gas industry plans to invest $600 billion/year by 2012, a rise of over 50% in five years. The IEA estimates that a total of $6.3 trillion is required in upstream investment between 2007 and 2030 (in 2007 dollars). This represents an average annual capital investment which is significantly less than current levels, but this money needs to be invested where the oil is – the Middle East.

7 million b/d of new projects will need to be sanctioned within the next two years to avoid a projected shortfall in 2015. However, political or economic constraints may retard investment in the right places, while there is an increasing shortage of skilled labour. The IEA concludes that there are “compelling” mutual benefits to accrue from partnerships between the NOCs and IOCs, the former being rich in opportunity and the latter rich in capital and staff.

The bottom-up production modelling has been carried out field by field, using discovered fields, 2P reserves, and the USGS’ country-by-country estimates of URR. Standard production profiles are applied to existing and YTF fields. The exploration and development model assumes that investment is a function of past production, oil price and known policies, and that all developments are profitable. Profitability is assessed by standard economic theory, including projected oil price, costs, tax and cash-flow re-investment rates. For countries closed to international investment, more subjective development criteria are used, based upon announced plans and policies, and the feasibility of investment.

World oil production, including non-conventional oil, CTL and GTL, but excluding processing gains and biofuels, is forecast to rise from 82.3 million b/d in 2007 to 103.8 million b/d in 2030. The output of crude oil from existing fields falls from 70 million b/d in 2007 to 27 million b/d in 2030. The production of conventional crude and condensate is forecast to increase by only 5 million b/d and to level out by 2030.

The bulk of the net increase in production comes from NGLs and non-conventional sources. The primary source of these increases is the Middle East, Canada, Caspian countries and Brazil. Most other countries will see output fall. Non-conventional oil, including extra-heavy oil outside Venezuela, oil sands and CTL and GTL, is expected to rise from 1.7 million b/d in 2007 to 8.8 million b/d in 2030. The Canadian oil sands are expected to contribute 5.9 million b/d by 2030, by which time the IEA expects that all the surface mineable Canadian oil sands will be developed. The growth of GTL and CTL is sensitive to capital costs, operation/feedstock costs and, for CTL, the cost of carbon sequestration.

Known projects

WEO 2008 identifies some 180 current non-OPEC offshore projects which are expected to develop 65 Gb of 2P reserves within 5 or 6 years, with a further 150 fields holding 20 Gb to be developed longer term. Non-OPEC onshore projects are rare outside Russia. OPEC is estimated to have 101 new projects in hand. By volume, one third of these relate to EOR, the remaining additions being from the development of known but undeveloped fields (“fallow fields”).

Undeveloped Discoveries and Reserves

257 Gb of conventional oil 2P reserves exist in known but undeveloped fields[3], distributed roughly evenly between OPEC and non-OPEC countries. The IEA expects 220 Gb of this oil to have been produced by the end of 2030. Undeveloped fields will produce more than YTF fields, every year up to 2030, although they peak between 2020 and 2025. By 2030, they produce 23 million b/d, while YTF fields contribute 19 million b/d.

The undeveloped fields form part of the current conventional 2P reserves, which are estimated at 1200-1300 Gb, including 200 Gb of Canadian oil sands. 79% of the remaining conventional 2P reserves are contained in fields already being exploited.

YTF

Slightly modifying the USGS estimate, the IEA believes that 805 Gb of conventional oil and NGLs remains to be discovered as of end-2007. The discovery of YTF is modelled by a creaming curve which correlates the total number of exploration wells drilled with the total amount of oil discovered. Total final discoveries are assumed to equal the URR noted above. Conventional oil production from YTF fields will reach 19 million b/d in 2030, by which time 114 Gb worldwide will have been discovered (i.e., averaging 5.2 Gb/year over the period).

New discoveries since 1990 have averaged 13-17 Gb/year, compared to production of 26-33 Gb/year. The IEA ascribes the fall in discoveries to falling exploration in the countries with the best prospects, and a fall in the average size of new discoveries.

Technical Improvements

Reserves growth is given as 402 Gb in Table 9.1, and EOR as 300 Gb on p 260.

Reserves growth depends largely upon increasing the global recovery factor, but better delineation of reservoirs, and changes in the economic, logistical and regulatory/tax environment, can also result in reserves growth. The IEA estimates that current production ascribable to various EOR technologies is 2.5 million b/d, and that such EOR-dependent production will rise by 6.4 million b/d by 2030. The cumulative EOR-dependent production from 2007 to 2030 is 24 Gb.

Peak

Peak is not reached in the IEA model. However, they note, (1) that demand growth may exceed supply growth sometime after 2010 if sufficient investment is not committed to new projects in the next two years; and (2) conventional oil production will have levelled off by 2030.

URR

Despite their conclusion of a sufficiency of recoverable conventional oil reserves, the IEA acknowledges that the rate at which they can be produced is far from certain.

[3] IEA analysis of IHS data

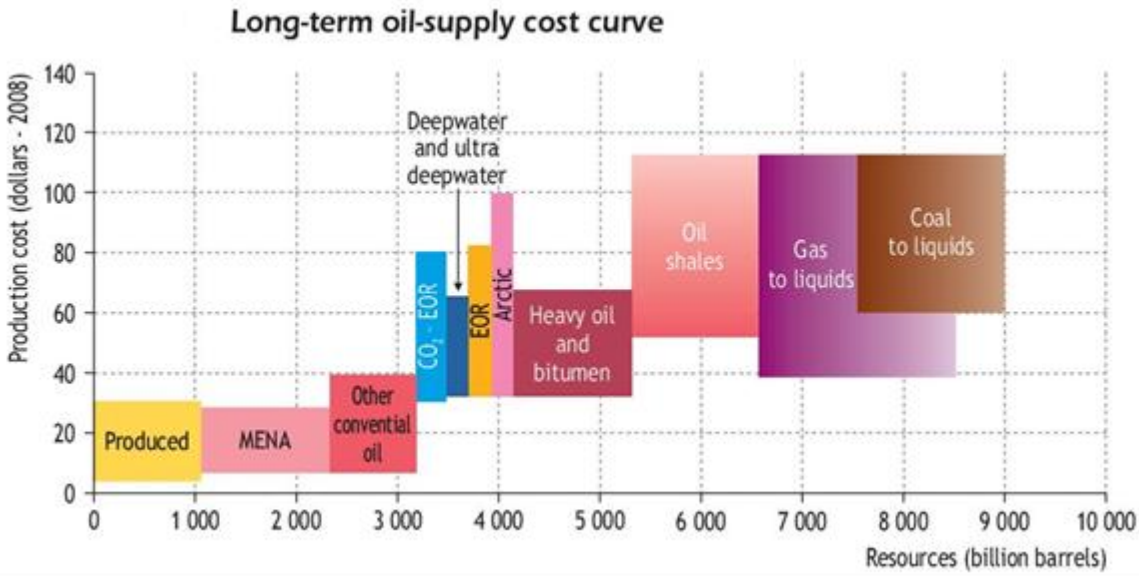
IEA primarily follows the USGS in assessing the URR. Their current estimates of ultimately recoverable conventional oil and NGLs are (Table 9.1):

- Cumulative discoveries of 2369 Gb, of which 1128 Gb have been produced and 1241 Gb remain
- Future reserves growth 402 Gb
- YTF 805 Gb.

This means that the conventional URR is 3577 Gb and remaining recoverable resources are 2449 Gb. A further 90 Gb may exist in Arctic basins.

The IEA suggests that non-conventional resources of oil sands and extra-heavy oil total 6000 Gb, of which 1000 Gb - 2000 Gb may be economically recoverable. Oil shales may have potential, but the cost and impact is uncertain. The IEA includes the chart below, which is their view of the volume and cost of exploiting the various conventional and non-conventional oil resources.

Figure i: IEA estimate of cost and volume of conventional and non-conventional oil. MENA = Middle East/North Africa. Source: World Energy Outlook 2008



Decline Rates

The IEA has made a detailed study of decline rates, including external factors such as the effects of war and production quotas, and the effect of added investment in stemming decline. They distinguish between the post-peak plateau and the post-plateau decline.

The IEA finds that larger fields, with a lower peak relative to reserves, have a lower decline rate. Onshore fields have lower decline rates than offshore, and younger fields decline faster than older fields, which reflects their generally smaller size and frequently off-shore location.

The IEA assumes an exponential decline in its calculations. The average field post-peak decline rate for 580 of the largest fields, which currently produce 58% of global crude oil supply, weighted by total past production, is 5.1%, ranging from 3.4% for super-giant fields, to 6.5% for giant fields, to 10.4% for large fields. Fields which are not just post-peak but also post-plateau are declining at 5.8%.

This result has been extrapolated to cover all oil fields, which are generally smaller and thus declining faster. The estimated post-peak managed decline for all fields is 6.7%, compared to the estimated natural decline rate of 9%. A 6.7% annual decline, if applied to all current fields, would equate today to an annual loss of 4.7 million b/d of production, although not all current fields are in decline. The natural global decline rate is expected to reach 10.5% by 2030, as average field size decreases and more production occurs offshore. The natural decline rates for regions outside the Middle East range from about 6% in Eastern Europe/Eurasia, to 12.5% in the OECD Pacific countries.

Using a third party study by Goldman Sachs, the IEA also shows that the average natural decline rates for fields operated by 15 major oil companies may have risen, from 10.6% to 13%, in the 5 years to 2006. Extrapolated world-wide, this represents a further loss of 700 kb/d of production in 5 years.

The alternative scenarios explored in WEO 2008 raise or lower the annual decline rate of current fields by 1%, all other variables (including new field decline rates) being held constant. The resulting cumulative investment required up to 2030 varies by about 20% up or down.

Model Summary

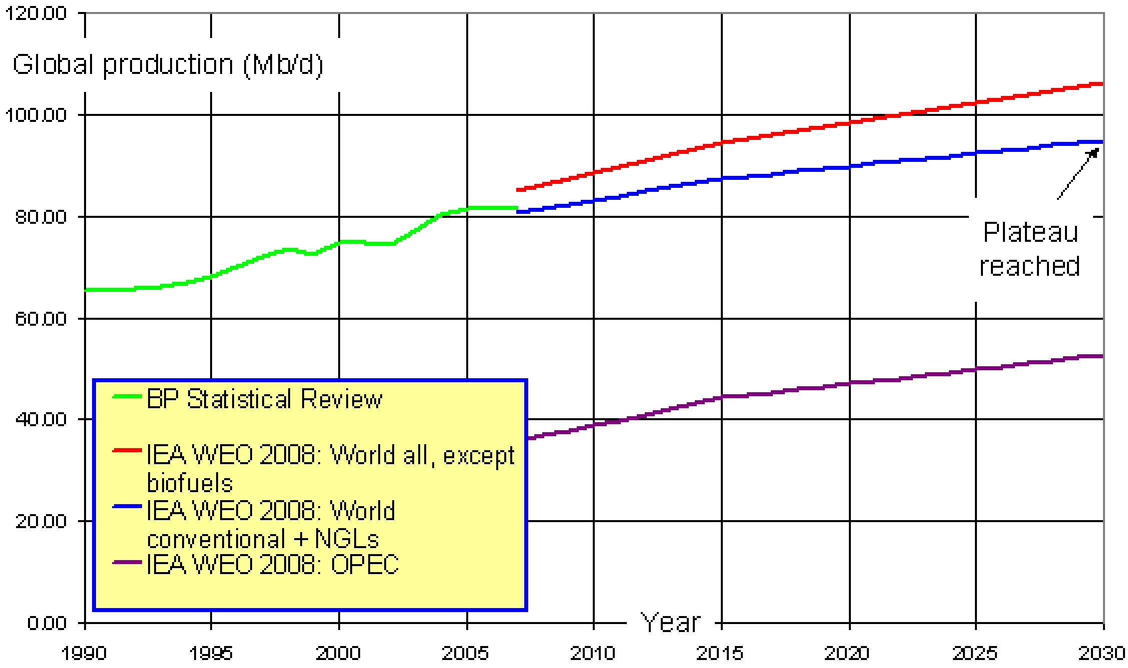
WEO 2008 is considerably more downbeat than *WEO 2007*, with the forecast 2030 oil demand and supply 10 million b/d lower than before. *WEO 2008* has a Reference Scenario, and alternative High Decline Rate and Low Decline Rate scenarios.

The model involves several parts. The first is a bottom-up model of production from existing fields and sanctioned projects. The second is an assessment of future demand. The gap between production and demand is filled by undeveloped discoveries, non-conventional oil supply and new discoveries, again modelled bottom-up. The requirement up to 2030 is assessed as achievable, but the necessary investment of $6.3 trillion[4] (2007 dollars) is described as “daunting”. Conventional oil production will level off by 2030.

There is a risk of a medium term supply crunch after 2010 unless some 7 million b/d of new projects, over and above those already sanctioned, are brought on-stream by 2015. These will need to be sanctioned in the next two years. The scale of investment required leads the IEA to question whether this will occur.

[4] WEO 2008 p. 89

Figure ii: IEA estimate of liquids production (WEO 2008)



OPEC Oil Supply Model

Author: Organisation of the Petroleum Exporting Countries

Description approved? OPEC was visited by two of us (Miller & Bentley) in November 2008 for very helpful discussions with Dr Nimat B. Abu Al-Soof, Garry Brennand and colleagues. However, OPEC has not formally approved the model description provided here.

Date of model: 2008, updated annually

Study reference: World Oil Outlook 2008 (WOO 2008) –

http://www.opec.org/library/World%20Oil%20Outlook/pdf/WOO2008.pdf

Coverage: Global, all liquids

Basis: Explicitly assumes sufficient oil, given the investment, for supply to meet demand. Future demand is calculated from forecasts of economic growth.

Global oil production data source: Implicitly generated internally from own data sources

2006 global daily rate: 84.7 million b/d

Data sources: USGS World Petroleum Assessment 2000 (URR and reserves growth); US EIA's IEO 2008 and IEA's WEO 2007 (for comparisons); UN (for population forecasts); the BP Statistical Review of World Energy; the IMF; Cambridge Energy Research Associates (CERA), IHS Energy and Wood Mackenzie.

Definition of oil:

- By location/setting: No
- Condensate & NGLs: Yes
- Medium/light: Yes
- Heavy (10-26° API) Yes
- Oil sands & shale oil: Yes
- GTL: Yes
- CTL: Yes
- Biomass: Yes

Peak Date: Not by 2030

Peak daily rate: No peak, reaching 113.6 million b/d in 2030 (reference case), range 99-121 million mmb/d

Reserves definition: Not stated but WOO 2008 follows USGS usage

URR: 3,345 Gb (USGS[5] data)

Global YTF: Not given, but implicitly follows USGS

Reserves growth: Tacitly accepts the USGS growth model

Comments: Little explicit consideration of production limitations or field decline.

Description of Model

Coverage and definitions

OPEC's model is global and covers all primary energy, but focuses on hydrocarbons. "Liquids" includes conventional oil (crude, condensate and especially NGLs, which are emphasized), non-conventional oil (including shales) and other liquids (biofuels, CTL and GTL). OPEC describe their models as referring to "feasibility", not absolute forecasts.

Demand modelling

In the reference case, total energy demand rises by 1.7% p.a., and liquids demand rises from 84.7 million b/d in 2006, to 92.3 million b/d in 2012 (the medium term) and 113.3 million b/d in 2030 (the longer term).

WOO 2008 lists these as its main assumptions in its demand forecast:

- A crude price for ORB (OPEC Reference Basket of crudes) of $70-90 in nominal terms until 2030
- A global population increasing by 1% p.a. to 2030 (UN data), with further assumptions on the urban vs. rural division
- A world economic growth rate averaging 3.5% p.a.. to 2030.
- No significant change in national policies

OPEC's assumption of a $70-90 crude price is based on two observations: (1) Economic growth and oil demand have been unexpectedly resilient to the near five-fold price rise since 2003; (2) OPEC believes that the marginal cost of producing alternative fuels, from either oil sands or GTL and CTL, is probably >$70/bbl.

WOO 2008 contains forecasts of the upstream investment cost per b/d for conventional oil, which we assume is equivalent to F&D (Finding & Development) cost. These are compared with 2006 figures. The figures are (US$1,000, 2007 dollars):

[5] United States Geological Survey (USGS) (2000), *World Petroleum Assessment 2000*

Table i: OPEC estimates of F&D costs

	2006	2020	2030
North America	22.5	22.5	22.5
Western Europe	23.0	26.5	29.0
Other Europe	20.0	20.0	20.0
OECD Pacific	16.0	20.6	23.9
Developing countries	18.0	19.8	21.0
OPEC	13.0	13.0	13.0
Russia & Caspian	19.0	20.5	22.0
China	18.0	19.0	18.0

Table i shows OPEC's forecasts that costs will rise by no more than 50% by 2030. This contrasts with another observation in WOO 2008*: "The tremendous increase in upstream costs over the past few years is clearly a major issue, as reflected in the IHS/CERA Upstream Capital Cost Index, which has costs in this industry segment doubling over the period from 2003 to mid-2008."* OPEC presently believes that costs are cyclical, and are effectively at the top of the cycle today.

Supply Modelling

OPEC describe their modelling as "demand steered", with OPEC continuing its role as a swing producer. The model is based on filling the projected demand. Non-conventional oil, synthetic liquids and forecast non-OPEC production by region are counted first, with the balance being the call upon OPEC.

OPEC's *medium-term* assessment (to 2012) is based on known, committed upstream projects, offset by the net decline in existing fields. The *long-term* assessment of supply growth is underpinned by the "rather conservative" USGS[6] forecast of remaining URR, which OPEC notes has risen from 1,700 Gb in the early 1980s to over 3,300 Gb. This "…can comfortably support future world demand for the foreseeable future", especially when the resource of non-conventional oil and the increasing supply of NGLs are considered too. WOO 2008 acknowledges the subsequent review by the USGS in 2007[7] which revealed lower discovery rates than

[6] United States Geological Survey (USGS) (2000), *World Petroleum Assessment 2000*, USGS, Washington, D.C. http://pubs.usgs.gov/dds/dds-060/
[7] T. R. Klett, Donald L. Gautier, and Thomas S. Ahlbrandt, 2005, "An evaluation of the U.S.Geological Survey World Petroleum Assessment 2000": AAPG Bulletin, v. 89, pp. 1033–1042

would be anticipated on the basis of the forecast YTF. OPEC ascribes this in part to low oil prices and minimal exploration activity, rather than to less YTF than forecast.

WOO 2008 states that the situation is further improved because certain countries now actively producing oil, or scheduled to do so, were thought by the USGS in 2000 to have no resources[8]. We note that under-estimates might be statistically offset by over-estimates.

New discoveries, new technology and reserves growth are also used to support expanded resource and supply. OPEC sees the primary challenge as how to develop, produce, transport, refine and deliver this oil. A wide range of variables is considered in this regard, from the development of cellulose-based biofuel, to the retirement of the baby-boom generation and the consequent implications for skilled labour. Variant scenarios from the reference case have been modelled to explore effects such as improved vehicle efficiencies, economic growth variability, biofuels and climate change policies.

Production by 2030 is forecast to comprise:

- Non-OPEC crude 38.1 million b/d
- Non-OPEC non-conventionals 10.9 million b/d[9]
- Non-OPEC NGLs 8.4 million b/d
- OPEC crude 43.6 million b/d
- OPEC non-conventional + NGLs 9.8 million b/d
- Processing gains 2.9 million b/d

TOTAL: 113.6 million b/d[10]

Supply capacity is forecast to reach 113.6 million b/d in 2030. Conventional crude excluding NGLs makes up about 82 million b/d of this total. Global CTL and GTL is forecast to reach 3.7 million b/d by 2030, and biofuels 3.5 million b/d.

Non-OPEC liquids supply, including biofuels and non-conventional oil, is expected to grow by nearly 6 million b/d between 2007 and 2012. In the medium term, WOO 2008 forecasts that the non-OPEC liquids supply will increase slightly faster than global demand, leading to a reducing call on OPEC and a growth in spare capacity. After 2012, the supply of non-OPEC liquids of all types increases a further 5 million b/d by 2030, reaching 60.3 million b/d. OPEC maintains its proportional market share of crude.

WOO 2008 models several alternative demand scenarios for the longer-term forecast. The greatest single effect comes from the economic growth assumption rather than from any technical changes, producing a demand range of 99-121 million b/d.

Current fields

[8] OPEC notes that Vietnam, Philippines, Papua New Guinea, Thailand, Chad, Sudan, South Africa, Mauritania and Uganda all now have "discovered reserves" exceeding their USGS-estimated URR.
[9] 7.5 million b/d non-conventional oil, primarily from Canadian oil-sands, and 3.5 million b/d biofuels
[10] Rounding error

The forecast to 2012 is based primarily on current activities and projects, including current production volumes and recent rates of decline in output from producing fields.

Known projects

OPEC maintains a database of >250 upstream projects expected to mature by 2012, including 120 in OPEC states.

Undeveloped discoveries and reserves

Specific, known investment projects are integral to OPEC's model, and all other undeveloped discoveries are therefore simply a component of the basic oil resource.

Yet-to-Find

Yet-to-Find is taken from the USGS World Petroleum Assessment 2000, modified for individual countries or regions where subsequent exploration and production has already exceeded the previously forecast URR.

Technical Improvements

The effect is mentioned but not quantified.

Peak

Global peaking is dismissed "*for the foreseeable future*", although peaking in certain countries is mentioned. WOO 2008 notes that all past predictions of peak oil have passed without being realized.

URR

OPEC accepts the USGS assessment of the global conventional oil URR as 3,345 Gb, with modifications for specific countries & regions, as mentioned above.

Decline Rate

Average decline rates are asserted to be at lower levels than previously thought. OPEC states, *"Decline rates vary from country-to-country and field-to-field. However, a global average decline rate is estimated in the range of 4–5%"* (and much lower in OPEC countries). While slightly ambiguous, this estimate appears to refer to natural field decline.

Summary

OPEC makes global forecasts out to 2030, using a reference case and a number of variant scenarios. The forecast is primarily a demand forecast, making the explicit assumption that there is sufficient oil resource to meet supply if sufficient investment is made in time. Therefore, the volume of oil required is calculated from the demand, after subtraction of other liquid fuels. The variables considered include future vehicle efficiency, national policy and economic growth. The forecasts include conventional oil (crude, condensate and NGLs), non-conventional oil (extra-heavy and oil sands) and other liquids (biofuels, CTL and GTL).

OPEC’s reference case assumes an OPEC Reference Basket (ORB) crude price of \$70–90/bbl in nominal terms throughout the projection period, and upstream costs which do not grow by more than 50% by 2030.

Figure iii: OPEC's global oil production forecast (WOO 2008):

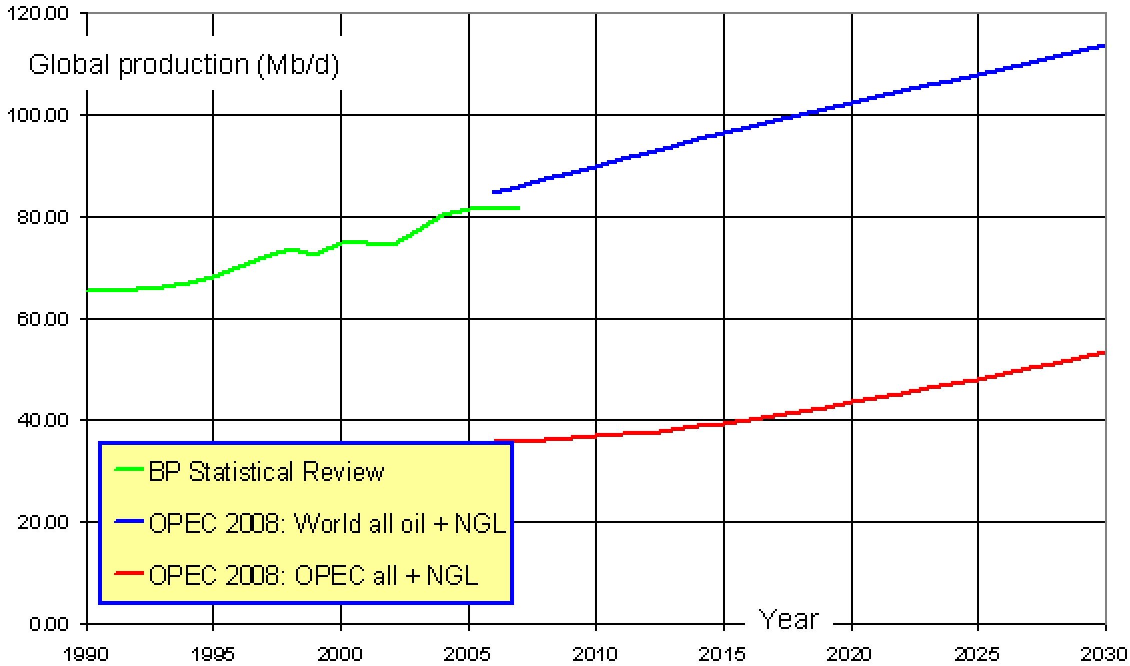


Figure iv: OPEC oil production forecast for OPEC and non-OPEC states (WOO 2008)

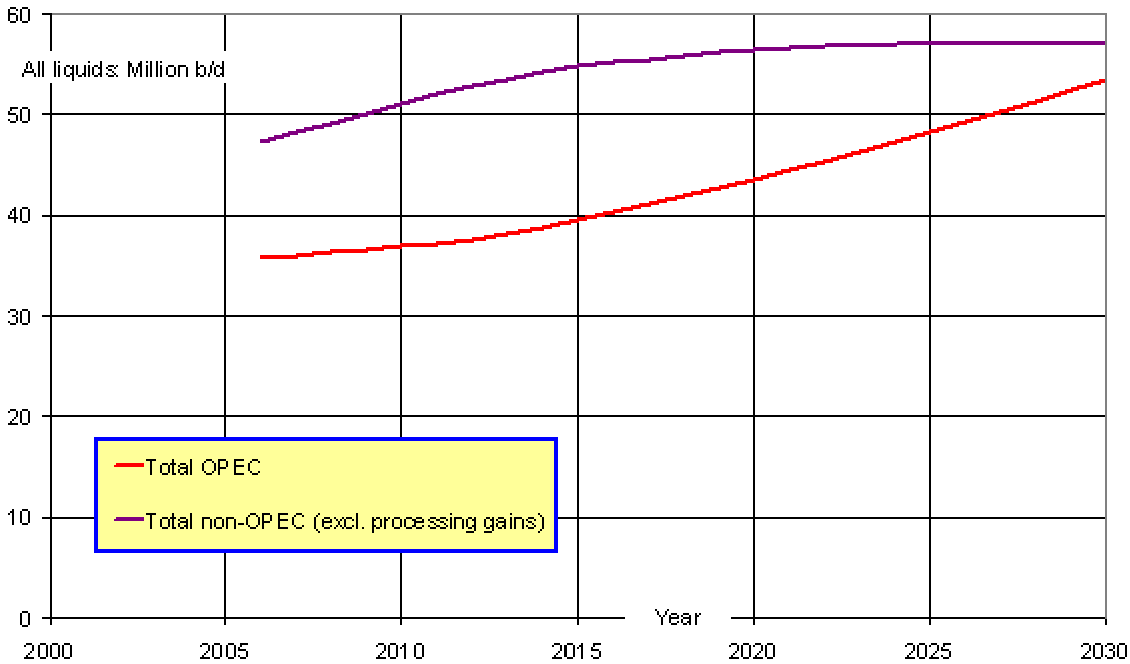
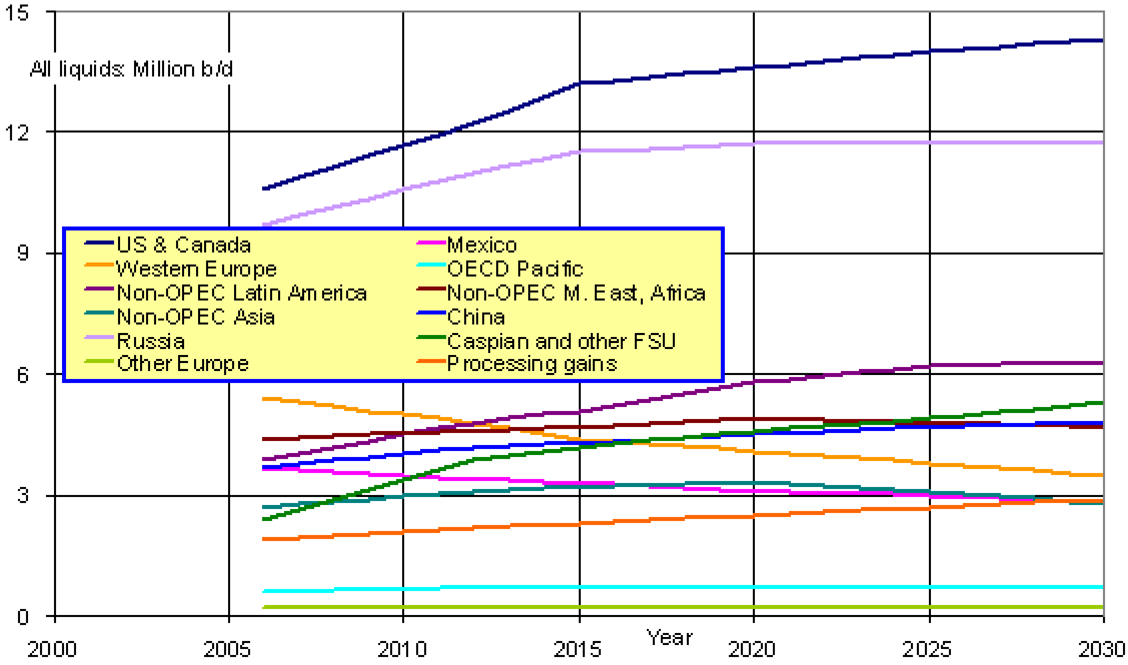


Figure v: Regional oil production forecast (WOO 2008)



US EIA Oil Supply Model

Author: US Energy Information Administration

Description approved? This description has been approved by John Staub of the US EIA.

Date of model: 2008; updated annually

Study references[11]: International Energy Outlook 2007 (IEO 2007) – http://www.eia.doe.gov/oiaf/archive/ieo07/index.html

International Energy Outlook 2008 (IEO 2008) (highlights only) - http://www.eia.doe.gov/oiaf/ieo/highlights.html

Coverage: Global, all energy

Basis: Future demand is calculated from forecasts of economic growth, population growth, and technology improvements. Implicitly there is sufficient oil, given the investment, to meet demand.

Global oil production data source: Own databases; IEA Monthly Oil Data Service

2005 global daily rate: All liquids 84.3 million b/d

Data sources: BP Statistical Review, Oil & Gas Journal, World Oil, Energy Intelligence, PIRA, PFC Energy, F.O. Licht, Cambridge Energy Research Associates (CERA), IHS Inc., Nehring Associates, Wood Mackenzie, others; Global Insight, Inc. (for global economic growth modelling)

Definition of oil:

- By location/setting: No
- Condensate & NGLs: Yes
- Medium/light: Yes, including refinery gain/loss
- Heavy (10-26° API) Yes, also <10 API extra heavy
- Oil sands & shale oil: Yes
- GTL: Yes
- CTL: Yes
- Biomass: Yes

[11] Although published in 2003, the article *"World conventional oil supply expected to peak in 21st century"* by Wood, Long and Morehouse (Offshore" magazine, vol. 63 no 4, April 2003) is a concise statement of EIA views on some of the issues.
http://www.offshore-mag.com/display_article/173967/9/ARCHI/none/none/1/World-conventional-oil-supply-expected-to-peak-in-21st-century/

Peak Date:	Not by 2030
Peak daily rate:	No peak, reaching 112.5 million b/d in 2030
Reserves definition:	"Proved reserves of crude oil are the estimated quantities that geological and engineering data demonstrate with reasonable certainty can be recovered in future years from known reservoirs, assuming existing economic and operating conditions."
URR:	Not given
Global YTF:	Not given
Reserves growth:	Briefly mentioned
Comment:	Little description of production limitations or field decline

Description of Model

Coverage and definitions

The US EIA model is global. "Non-conventional liquids" include oil sands, oil shales, ultra-heavy crude, biofuels and synfuels. Conventional liquids include heavy crude, NGLs and condensate.

Demand modelling

The forecast methodology estimates future primary energy demand, according to projections of population and GDP growth for various regions. The link between GDP growth and oil consumption ("Energy Intensity") is described qualitatively but not quantified. The forecast for future GDP in all scenarios is provided by Global Insight, Inc., "World Overview".

Three scenarios are developed In the reference case, oil prices are forecast to decline to around $70 per barrel in 2015, then to rise to $113 per barrel in 2030 ($70 per barrel in inflation-adjusted US$ 2006). In the high price case, to which the US EIA currently inclines, oil prices in 2030 reach $186 per barrel in nominal terms (which we calculate to be $115 in US$ 2006).

Production Modelling

The US EIA model does not consider any production disruptions due to war, terrorism, weather or politics. The reference case assumes that OPEC producers will maintain their current 42-43%[12] share of the world liquids supply, and will invest accordingly in additional production capacity. Global liquids production in 2005 was 84.3 Mb/d, and in the reference case, global production of all liquids is forecast to be 95.7 Mb/d in 2015, and 112.5 Mb/d in 2030, an average growth rate of 1.16% p.a..[13]

[12] Lauren Mayne, USGS, pers. comm. 2008
[13] This forecast from IEO 2008, compared to IEO 2007, has been reduced by 5.5 Mb/d (4.7%) in a year, illustrating perhaps the sensitivity of the model to oil prices.

The final mix in 2030 comprises 102.8 Mb/d of conventional liquids and 9.7 Mb/d of non-conventional (from 2.5 Mb/d in 2005). By 2030, conventional liquids supply from OPEC members grows by 12.4 Mb/d, and conventional liquids supply from non-OPEC countries grows by 8.6 Mb/d. Individual country forecasts are published[14].

The high price case assumes that OPEC members will maintain their production at around current levels, sacrificing market share, while non-OPEC resources are less accessible and/or more expensive. Global liquids production reaches 99.3 Mb/d in 2030, a growth rate of 0.66% p.a.. The high price scenario makes non-conventional liquids more competitive, and they account for 20% of total supply in 2030, compared to 9% in the reference case. Conventional supplies actually decline over the projection period, by 1.5 Mb/d, compared to an increase of 21.0 Mb/d in the reference case, because the high price encourages an increase in non non-conventional supplies to 19 Mb/d. The US EIA presently sees this case as closer to reality than the reference case.

In a typical model run, oil demand is modelled at the regional level and aggregated to a world total. Next a supply scenario is developed to meet that demand level. The supply scenario is tied to oil prices and producer behaviour assumptions, and constrained by estimates of maximum production expansion rates and resources. The high and low price scenarios reflect the impact of different resource and producer behaviour assumptions on prices, which in turn impact demand and production decisions. The goal of the modelling is to balance supply and demand of all fuels and create a range of internally consistent scenarios.

Current fields

The forecast to 2015 is based primarily on current activities, including current production volumes, recent rates of decline in output from producing fields, and planned EOR projects.

Known projects

The US EIA asserts that it conducted an extensive review of anticipated investment in exploration and production up to 2015, which should cover reported projects.

Undeveloped discoveries and reserves

The US EIA estimates national proved reserves from data reported to the SEC, from foreign government reports, and from international geologic assessments. It notes that some countries explore only to maintain a level of proved reserves, leading to extended periods of steady reserves with occasional sudden jumps. (This view we discuss elsewhere.)

The US EIA asserts, *"It is generally acknowledged that OPEC members with large reserves and relatively low costs for expanding production capacity can accommodate sizable increases in the world's petroleum consumption. In the IEO 2007 reference case, the production call on OPEC suppliers grows at an annual rate of 2.0 percent through 2030….In the reference case, Saudi Arabia's production is projected to be 9.4 million barrels per day in 2015 and 16.4 million barrels per day in*

[14] http://www.eia.doe.gov/oiaf/ieo/excel/ieopol.xls

2030." The questions about the true size of OPEC's reserves, and whether they can be put into production, are not discussed.

Among many individual forecasts, Iraq's oil production is projected to reach 3.3 million barrels per day in 2015 and 5.3 million barrels per day in 2030. Oil production in Iran is projected to increase from 4.1 million barrels per day in 2004 to 4.3 million barrels per day in 2015, and to reach 5.0 million barrels per day in 2030. Venezuela is expected to see some increase in production after 2015. The field-by-field detail of the production is not given.

Yet-to-Find

The forecast to 2015 includes planned exploration and development projects. In the reference case, non-OPEC production is forecast to increase steadily up to 2030, as high prices attract investment to previously uneconomic areas. *"After 2015, the reference case assumes that production decisions are made primarily on economic grounds, based on assessments of the resource base, with less weight placed on current political conditions."* We deduce that the US EIA assumes that YTF and investment are both sufficient to meet the demand profile.

The US EIA analyses some specific countries, with their general prospects and specific forecasts for production in 2030. In general, the US EIA *"... anticipates considerable new production, both conventional and unconventional, from sources including Azerbaijan, Brazil, Canada, Kazakhstan, and the United States. However, markets are expected to remain tight."*

Technical Improvements

The effect is not quantified. US EIA notes that new technologies, aggressive cost-reduction programs, and the emergence of non-conventional resources, all contribute to the outlook for continued growth in non-OPEC liquids production.

Peak

The global peak is not discussed, although peaking in some individual countries is mentioned.

URR

The global ultimate recoverable resource is not discussed.

Decline Rate

Decline rates are stated to be incorporated in the medium-term forecast to 2015, but no analysis is published.

Summary

The US EIA makes global forecasts out to 2030. The forecasts include conventional oil and condensate, NGLs, refinery gain, non-conventional oil (extra-heavy, and oil sands, shale oil) synthetic liquids (CTL and GTL) and biofuels.

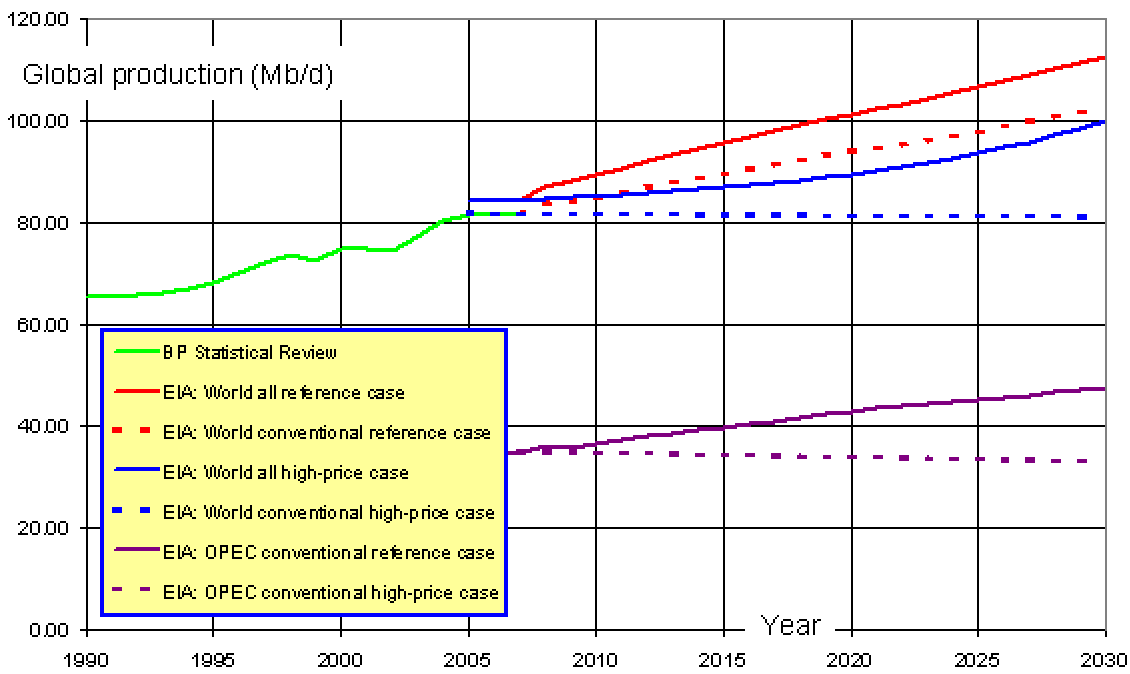
The forecast methodology assesses future primary energy demand from projections of population and GDP growth for various regions. The algorithm which links oil demand to these data is not explicit.

In the reference case, current laws and policies remain unchanged. The reference case forecasts an average global liquids demand growth of 1.16% p.a. to 2030. Implicitly there is sufficient oil to meet this forecast. GDP growth forecasts are considered for high- and low-price scenarios. These diverge significantly by 2014, but by 2030 are little different from the reference case as economies adjust.

In the reference case, the oil price declines to around \$70 per barrel by 2015, then rises to \$113 per barrel in 2030 (\$70 per barrel in inflation-adjusted 2006 dollars). OPEC producers maintain a steady 40% market share of world liquids supply, and invest accordingly in additional production capacity. IEO 2007 analysed both high- and low-price alternative cases for oil. IEO 2008 includes an alternative high price case, where OPEC members maintain their production at around current levels, sacrificing market share.

Ongoing US EIA analysis of field and country level initial-oil-in-place estimated volumes and recovery factors seeks to understand long run supply potential from all petroleum sources. Preliminary findings were presented at the April 2008 US EIA conference[15]. IEO 2007 noted that actual oil production and the increase of declared reserves during 2006 implies 54 billion bbl of oil discoveries and reserves growth. There is considerable detail about current production and reserves, and generalised prospects for various countries, but rather less detail about future modelling.

Figure vi: US EIA forecast of global liquids production



[15] http://www.eia.doe.gov/eia_conference_2008.html, see specifically http://www.eia.doe.gov/conf_pdfs/Monday/Sweetnam_eia.pdf

Figure vii: US EIA forecast of United Kingdom conventional oil production (no data points between 1990 and 2006; data table G2, International Energy Outlook 2008).

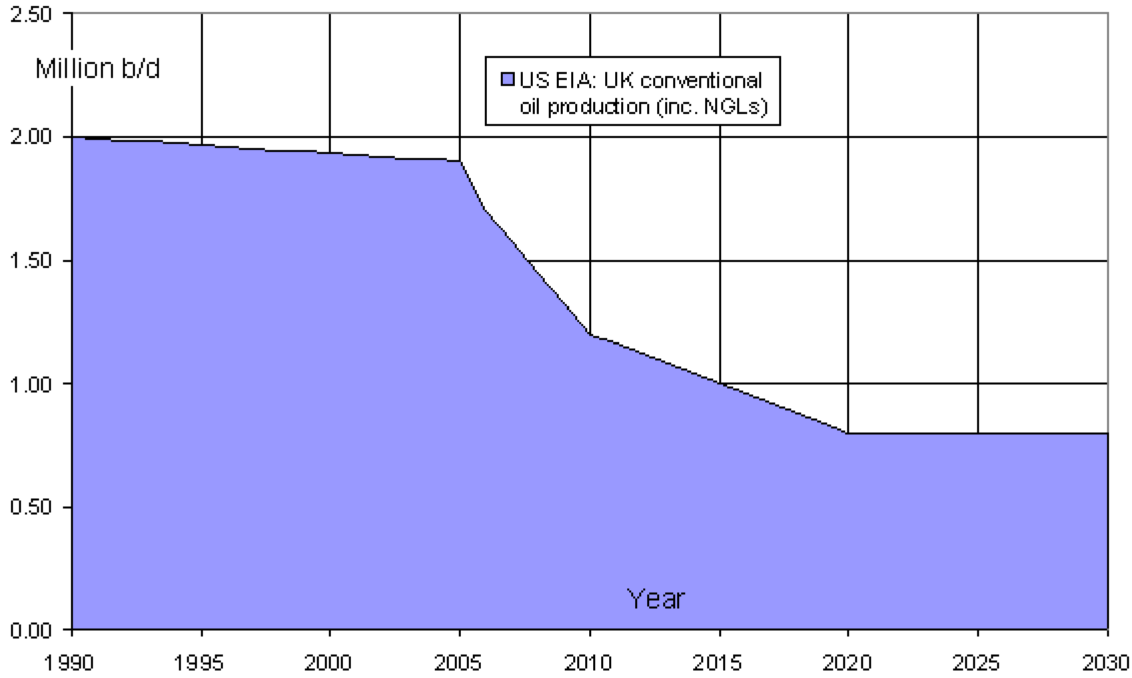


Figure viii: US EIA forecast of United States oil production (no data points between 1990 and 2006; data table G2, International Energy Outlook 2008).

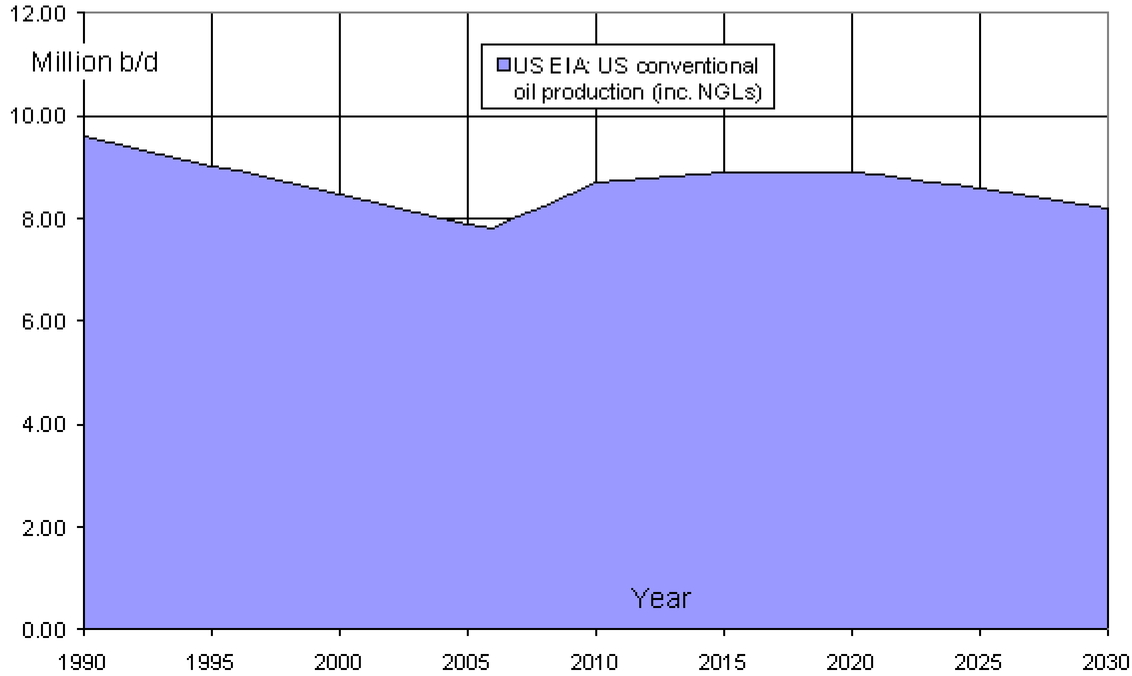


Figure ix: US EIA forecast of Saudi Arabia oil production (no data points between 1990 and 2006; data table G2, International Energy Outlook 2008).

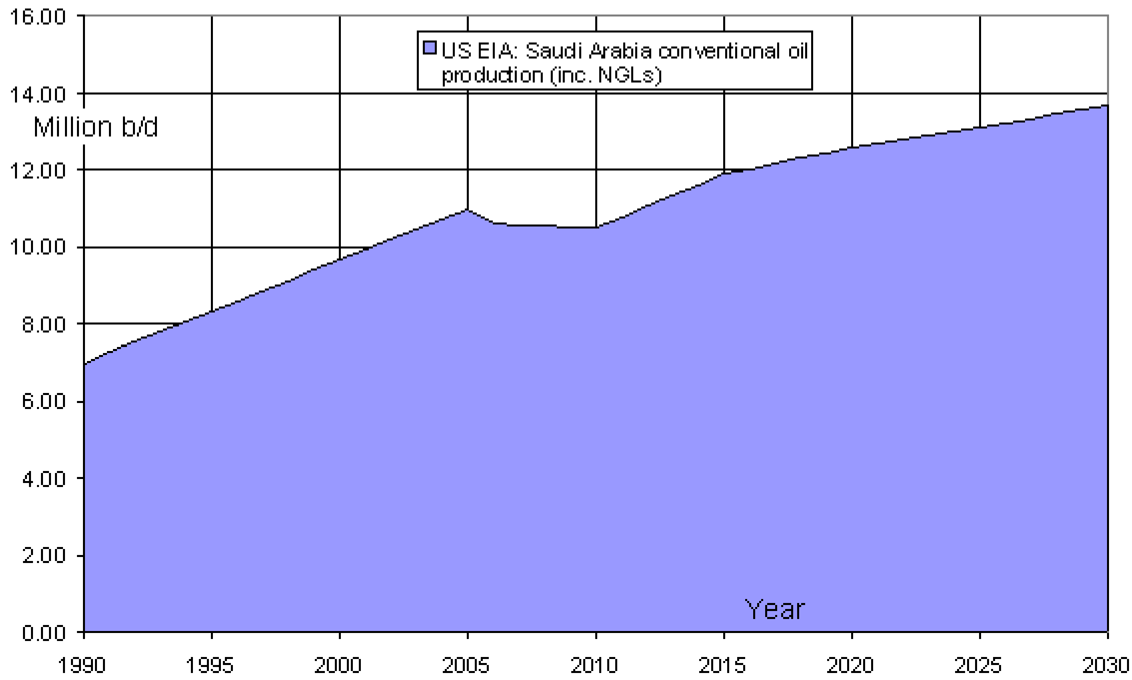
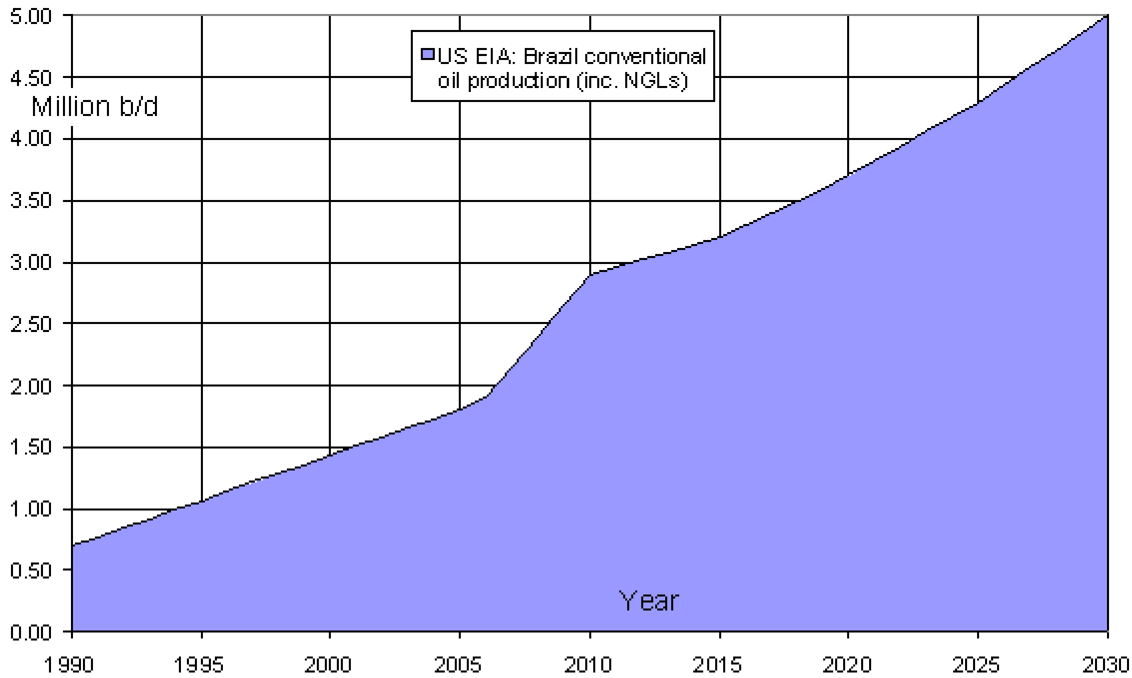


Figure x: US EIA forecast of Brazil oil production (no data points between 1990 and 2006; data table G2, International Energy Outlook 2008).



German Federal Institute for Geosciences & Natural Resources (BGR) Oil Supply Model (2006) and View (2008)

Author: BGR (Bundesanstalt für Geowissenschaften und Rohstoffe)

Description approved? Germany's BGR produced a simple global oil supply model in 2006 based on their detailed oil assessment studies, described below. The BGR is the only national government body in recent times to project oil peaking. In response to a request for information for this study, the BGR kindly sent the short commentary included below ("Addendum").

We understand that the BGR will be looking at global oil supply in detail in the first half of 2009.

Date of Model: 2006; assessments updated annually (2007 update now available)

Study reference: Reserves, Resources and Availability of Energy Resources 2006
http://www.bgr.bund.de/cln_101/nn_336024/EN/Themen/Energie/Produkte/energiestudie__kurzf__2006__en,templateId=raw,property=publicationFile.pdf/energiestudie_kurzf_2006_en.pdf

Coverage: Global. The 2006 model covers conventional oil. BGR assessments cover all hydrocarbons, and also coal and nuclear resources

Basis: The BGR used a "mid-point peaking" model in 2006, calculating that half of their estimated URR of conventional crude oil will have been consumed by around 2020, and asserted that thereafter production of crude oil will decline.

Global oil production data source: Not stated

2006 global daily rate: About 81.6 million b/d (3.918 Gt/year)

Data sources: Oil & Gas Journal; BP Statistical Review; OPEC; national authorities; in-house estimates; IEA, US EIA

Definition of oil:

- By location/setting: No
- Condensate & NGLs: Yes
- Medium/light: Yes
- Heavy (10-26° API) Yes
- Oil sands & shale oil: No – non-conventional oil is dealt with separately
- GTL: No
- CTL: No

- Biomass: No

Peak Date: Around 2020

Peak daily rate: Not specifically stated

Reserves definition: BGR uses what they assess to be mainly 1P (proved). In some cases (Western Europe, CIS) they use 2P (proved plus probable).

URR: 2979 Gb (392 Gt)

Global YTF: Global crude oil "resource" (non-reserve) is 623 Gb (82 Gt)

Reserves growth: Acknowledged but not quantified

Comment: The 2006 model is comparatively simple. There is no detailed modelling or listing of the basic parameters for calculation. The assumption that the crude oil peak will occur when half of the URR has been produced is not defended. The reserves data appear to be taken at face value from official sources.

Description of Model

Coverage and Definitions

The coverage of the 2006 model is global, and projects conventional oil production. The resources covered in the BGR's assessment include oil, gas, coal and nuclear energy.

Demand modelling

There is no modelling of demand, although BGR notes that a moderate increase in the rate of production can be sustained until the peak.

Supply Modelling

No specific modelling is described, but there is a series of assumptions and conclusions. BGR expects that a moderate increase in oil consumption can be sustained until the "depletion midpoint" is reached, that is, when half of the global URR of crude oil has been produced. The BGR estimates that this will occur around 2020.

The BGR notes that non-conventional resources are very large, but adds that the largest of these, oil shales, are subject to high costs and environmental constraints that make their contribution negligible (we take the relevant forecast period to be from now until peak). Oil sands and extra-heavy oil projects are more viable but "*…these projects will reach only a fraction of the production capacity of conventional oil within the foreseeable future, although they may gain regional significance*." By 2020, non-conventional oil (which we take to be shale oil, bitumen and extra-heavy oil) will comprise 5-10% of total oil production.

The chief sensitivities noted are: (1) that OPEC reserves could be less than claimed; (2) that other reserves could be greater, because reported reserves often exclude the probable and possible categories; (3) the uncertain degree of reserves growth.

Known projects

There is no consideration of short- and medium-term production which would require a specific consideration of current projects.

Undeveloped Discoveries and Reserves

The BGR distinguishes between reserves and ‘resources’. The resources category appears to include both yet-to-find and yet-to-develop, but excludes reserves (i.e. the sum of reserves and BGR ‘resources’ gives what is termed remaining potential in this report). The sources of data are not stated.

Reserves of crude oil are given as 1239 Gb (163 Gt) as of 2006. Reserves of non-conventional oil are 502 Gb (66 Gt). The recent annual rises in global crude oil reserves are ascribed mainly to re-evaluations of known fields rather than new discoveries.

Resources of crude oil are 623 Gb (82 Gt). Resources of non-conventional oil are 1900 Gb (250 Gt).

YTF

As noted, the YTF appears to be included in the category termed “resources”, which may include yet-to-develop. The global crude oil resource is estimated to be 623 Gb, based on the USGS 2000 assessment and the BGR’s own estimates.

Technical Improvements

BGR notes the phenomenon of reserves growth, which it ascribes to better reservoir performance and enhanced production methods.

Peak

The estimate of the peak is based upon the assumption that production rates will fall after 50% of the URR has been produced.

URR

The URR estimate explicitly consists of cumulative production, reserves and resources, as the BGR uses these terms. A value of 392 Gt (2979 Gb) is noted as BGR’s own estimate as of the end of 2006.

Decline Rates

There is no discussion of decline rates.

Summary of the 2006 Model

The BGR model is straightforward but not very explicit. At its heart is the assumption that the global peak will occur at the mid-point of production of the global URR. The methods used, and the sources of data, for estimating when mid-point will be reached are not stated.

Addendum, 2008

In response to a request for information for this study, in August 2008 the BGR sent us the following statement (here translated from the German), which suggests that they are moving towards a changed view, and recognise the problems of a simple numerical analysis. We understand that they are scheduled to produce a new report in spring 2009.

"The BGR collates data on the current levels of world production of conventional crude oil in a yearly Energy Study. The study takes into account the extraction, reserves, resources and total production potential as well as consumption, both on a worldwide and country-by-country basis. The definitions used are based on international standards.

A major element in the work of collecting data from individual sources is to make these compatible with one another, and to conduct more thorough studies where differences are found. Non-conventional sources of Crude Oil have previously only been marginally discussed, and now their increasing importance is being reflected in the work on the BGR. The main task is to discuss trends and issues in politics and the economy in terms of the basis for decision making.

In the course of our work, we have come to the decision that due to the complex connection between crude oil and the world economy, accurate forecasts are impossible. While oversimplified numerical models give the illusion of precision, they have little to do with reality. They explain neither the non-linear jumps of the past, nor give a valid picture of future developments.

Nevertheless, there are some regularities relating to the finite nature of the oil: its extraction, its potential for partial replacement, use of non-conventional oils, effects of its use in terms of pollution, political trends etc. These relationships and trends are also discussed, but not included in a final model."

Shell Energy Scenario Models

Author: Shell International BV

Description approved: Yes (David Freedman)

Date of model: 2008

Study reference: David Freedman (Shell EP Think Tank), meeting 8/9/2008

Shell energy scenarios to 2050

http://www.shell.com/home/content/aboutshell/our_strategy/shell_global_scenarios/dir_global_scenarios_07112006.html

Coverage: Global; All energy

Basis: Modelling of the global energy outlook includes both demand and supply-side analyses. The supply model for oil is bottom-up. Two published scenarios, *Scramble* and *Blueprints*, use these models and reflect different socio-political developments at a global level and consequently different policy decisions.

Global production data source: Generated internally from a range of published sources

2000 global daily rate: 70 million b/d (given as 147 EJ/y)

Data sources: World Bank WDI, Oxford Economics, UN Population Division, Energy Balances of OECD Countries 2006, Energy Balances of Non-OECD Countries 2006; IHS, Wood Mackenzie and other commercial databases; US EIA, IEA and independent analysts

Definition of oil/liquids:

- By location/setting: No
- Condensate & NGLs: Yes
- Medium/light: Yes
- Heavy (10-26° API) Yes
- Oil sands & shale oil: Yes
- GTL: Yes
- CTL: Yes
- Biomass: Yes

Peak Date: "*By 2015, growth in the production of easily accessible oil and gas will not match the projected rate of demand growth*."

Shell has not articulated a view of "peak oil" *per se:* the two scenarios show outlooks where liquids supply is affected by a

	much broader range of concerns than mere geology. Both scenarios indicate a *de facto* peak in oil supply around or before 2030, but peak liquids occurs after 2030 (in fact after 2050) due to biofuels and possibly synfuels.
Peak daily rate:	The peak for all-oil is around 91.4 million b/d (192 EJ/year) in 2030 in the *Blueprints* scenario, and around 89 million b/d in 2020 in the *Scramble* scenario. The scenarios are not explicit about the date or height of the peak for all-liquids.
Reserves definition:	Unstated in the scenarios, but careful attention is paid to different reserve categorisations in supply modelling.
URR:	Modelled internally, not published
Global YTF:	Modelled internally, not published, but liquids estimates are "generally below" the USGS mean forecast[16] of some 730 Gb.
Reserves growth:	Modelled internally, not published.
Comment:	The degree of blending of demand and supply forecasts is not clear, and this work cannot be independently duplicated. Nevertheless the scenarios embody clear and (currently) reasonable choices, and this appears to be a logical, rounded forecast methodology.

Model Description

Coverage and Definitions

The liquids supply model is global in scope. It covers all liquids, both natural and manufactured, including NGLs, biofuels and synfuels.

Demand modelling

Demand modelling is an integral part of the Scenarios. Shell uses UN data for expected population growth, but issues such as where developing nations will "plateau" in terms of their per capita energy consumption are modelled internally.

Production: Modelling and Sources

Field and country production data are taken from IHS, Wood Mackenzie, IEA and US EIA databases.

Shell has worked to estimate the highest production rates that the world could achieve by considering the maturation of resources. For example, they estimate how rapidly the YTF can be discovered ("*How far can the tail of future discoveries be compressed?*") and how rapidly discoveries can be matured and produced.

[16] United States Geological Survey (USGS) (2000), *World Petroleum Assessment 2000*, revised

Shell has also considered the investment required to maintain or grow oil production and how this might act as a constraint on supply growth.

Known projects

The scenarios do not specifically comment, but Shell's underlying supply model takes account of all known development projects under way.

Undeveloped Discoveries and Reserves

The supply model takes account of known but undeveloped discoveries, with the IHS database as a primary data source. The modelling recognises the possibility that many of these small fields will never be economically developed at any oil price.

Shell uses its own internal analysis to assess both existing reserves and the capacity for reserves growth. They are confident that their data are supported by their experience and their view of future technological change.

YTF

The estimates for YTF are derived using a proprietary methodology applied to data from IHS, with whom Shell has worked closely. The USGS YTF estimates are not used.

Technical Improvements

The scenarios assume that the eventual ultimate recovery factor which will be reached for the world is significantly greater than the current global average.

Peak

Shell estimates that by 2015, growth in the production of easily accessible oil will not match the projected rate of demand growth, a state which is close to but not identical to peak production.

The Scramble scenario forecasts peak oil production around 2020, at about 186 exajoules/y (89 million b/d, compared to some 144 Ej/y or 69 million b/d in 2000). Peak liquids production is after 2030, which includes biofuels (some 4.8 million b/d in 2020 and 13.5 million b/d in 2030) and CTL and GTL liquids (these are unquantifiable from Shell's published data, being included within the total consumption data for coal and for gas).

The Blueprints scenario forecasts peak oil production around 2030, at about 91.4 million b/d (191 Ej/y). A peak for all liquids, which includes biofuels and synthetic liquids as above, cannot be deduced from the published data.

The socially chaotic and highly competitive Scramble scenario results in an earlier and lower peak than the more structured Blueprints, which might be counter-intuitive. It is envisaged that under Scramble, OPEC is able to reduce output to maintain higher prices, which results in more rapid replacement of conventional oil. This leads to rapid growth of non-conventional oil supplies in the medium-term, but longer-term inefficiencies are expected. In Blueprints, OPEC raises production to defer the development of more costly alternatives, and development of non-conventional sources is more planned, structured, co-ordinated and efficient.

URR

URR is broken down by Shell into four components, namely already produced, current reserves, YTF, and future improvements in recovery. They take a view on all these, but these views are not published. The detail is described as being very granular, with approximately 85 countries and 280 basins analysed individually.

Decline Rates

Shell has an internal model of decline rates, which is granular and recognises the variations between different types of fields and basins. Specifically Shell models the "natural" decline rate, which is the decline in production without any further development activity.

Shell has also considered the empirical relationship between the R/P (Reserves to Production) ratio and the rate of production growth/decline, and concludes that production growth becomes more difficult to achieve as R/P ratios decline.

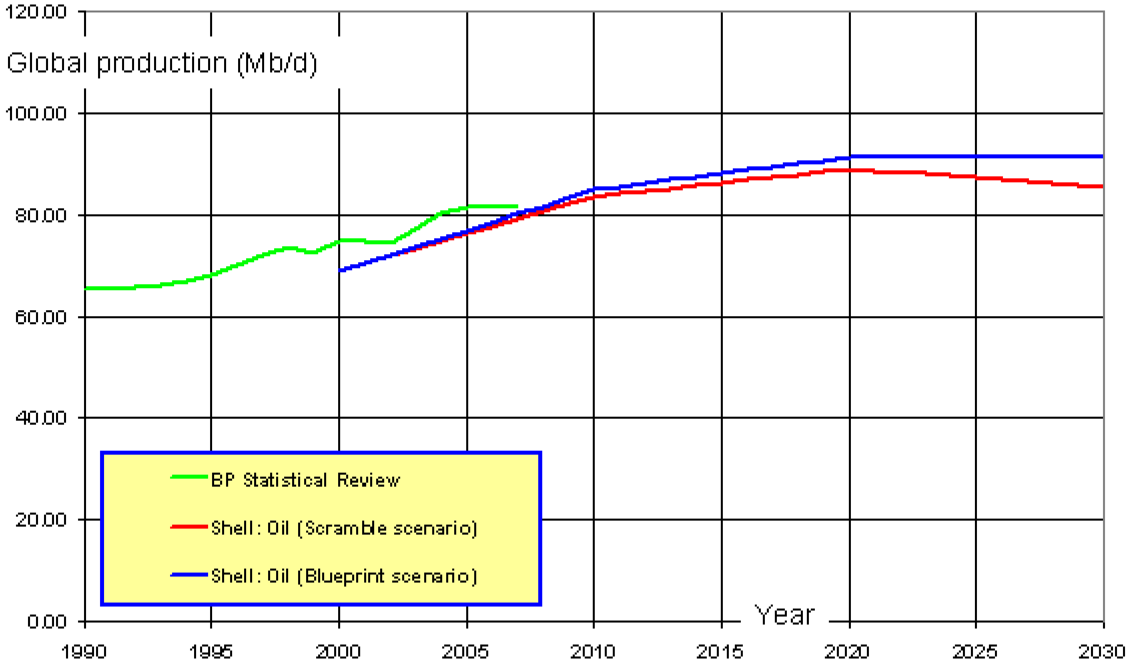
Summary

The above model description merges the published information in Shell's Scenarios and privileged information from conversations with David Freedman, of Shell's Think Tank.

Shell starts with the observation that by 2015, growth in the production of easily accessible oil will not match the projected rate of demand growth. This is derived from Shell's internal modelling of the near term future. However, the inclusion of other forecast liquids (CTL, GTL, biofuels and non-conventional oils) shows that total liquids supply growth is expected to match projected demand growth.

Shell then considers two socio-political scenarios. *Scramble* is dominated by national energy security interests rather than energy efficiency or climate change considerations; *Blueprints* is dominated by the development of coalitions concerned about supply, the environment and entrepreneurial opportunities. The coalitions include cities, regions and companies. The consequent scenarios include both supply-side and demand-led modelling, taking into account such variables as substitution and alternatives, environment and geopolitics. The supply side modelling is described as granular and bottom-up, using and aggregating field, basin or country data as appropriate. Only primary energy supply is shown in the scenarios publication (i.e., the global consumption of oil, biomass, coal and gas), and the liquids derived from biomass, coal and gas conversion are not explicitly shown, although they are modelled. Shell has also modelled the development of electric transportation which is relevant as a potential substitute for liquids.

Figure xi: Shell scenario models of oil production. (Original data are in units of thermal energy (EJ/y) which do not have a direct conversion factor to volumes of oil. Here we use 1 EJ = 174 Mb oil).



Meling (StatoilHydro) Oil Supply Model

Author: Leif Magne Meling. The model is sanctioned for publication by StatoilHydro, but does not necessarily reflect their view

Description approved? Meling has approved this review.

Date of model: 2006, but still viewed as current

Study references: The Origin Of Challenge – Oil Supply And Demand (Part 1/2), *Middle East Economic Survey, VOL*. XLIX, No 24, 12-Jun-2006

The Origin Of Challenge – Oil Supply And Demand (Part 2/2), *Middle East Economic Survey*, VOL. XLIX, No 25, 19-Jun-2006

Coverage: Global, Oil

Basis: Bottom-up compilation of data at country level, consolidated into OPEC and non-OPEC. Demand growth is exponential extrapolation, but tabular data or other functions can be used.

Global oil production data source: Unstated

2005 global daily rate: 80 million b/d

Detailed data sources: IHS data base; BP Statistical Review of World Energy

Definition of oil:

- By location/setting: No
- Condensate & NGLs: Yes
- Medium/light: Yes
- Heavy (10-26° API) Yes
- Oil sands & shale oil: Yes, included separately
- GTL: No by implication
- CTL: No by implication
- Biomass: No by implication

Peak Date: Base case peak is 2028, but supply fails to match demand by 2011

Peak daily rate: 95 million b/d

Reserves definition: Follows IHS usage of proved + probable

URR: 3149 billion barrels, including condensate and 200 Gb of Canadian mined oil sands.

Global YTF: 309 Gb conventional oil

Reserves growth: 520 Gb

Comment: Unusual in forecasting supply as the "out-take" ratio, i.e. the percentage of reserves produced each year. Meling finds a production peak and also identifies when the modelled supply fails to match the assumed demand growth. Some of the detailed modelling is not shown, so that conclusions appear as assertions. There is no discussion of decline rates.

Model Description

Coverage and Definitions

Meling models global conventional oil supply, including Canadian oil sands.

Demand modelling

Meling does not forecast future prices or population, but extrapolates GDP growth, and correlates this with oil demand growth. He has found no convincing documentation showing that oil price affects exploration success, development activity, reservoir growth or oil production growth. Drilling activity is affected by the oil price, but the outcome is masked by the declining size of discoveries.

As an example, Meling considers Chinese GDP growth and its consequent oil demand growth, concluding that Chinese demand for oil will reach 25 million b/d by 2020. By analogy, India and other developing states will also increase demand. He estimates a global GDP growth of 4% p.a. would lead to an oil demand growth of 2.5% p.a., but assumes oil demand growth of 1.6% p.a. in the model, similar to the average over the last 25 years.

Reserves Position

Meling uses the IHS estimate that about 2.3 trillion barrels of conventional oil have been discovered, 1 trillion produced, 1.2 trillion barrels remain as (developed) reserves, and 200 billion are undeveloped (note rounding errors).

New discoveries are not replacing consumption, and Meling ascribes this to a decrease in the size of discoveries, not to a reduction in exploratory activity, although the question of whether OPEC states are exploring as fast as other countries is not addressed.

The industry develops about 10% of undeveloped reserves each year. Further investment in such reserves can provide a short-term production increase, but only significant new discoveries can change that situation.

Meling discusses the USGS study of reserves growth[17]. He believes that the US experience on reserves growth is a product of US business regulation (SEC rules that constrain the estimates of reserves), and so it cannot be used in countries with

[17] http://pubs.usgs.gov/fs/fs119-00/fs119-00.pdf

different practices for booking reserves. Meling instead evaluates the possible global contribution from improved and enhanced recovery (EOR), finding a total of some 520 Gb of reserves growth. The seventy largest fields that contain 60% of all oil reserves contribute 70% of this growth, and OPEC will be the greatest contributor. The evaluation method is discussed in a separate paper[18].

YTF

Meling uses an extrapolation of discovery trends to estimate that global YTF is some 309 Gb of conventional oil.

Production: Modelling and Sources

Meling discusses production as "out-take", which is the proportion of remaining developed reserves produced each year (it is the inverse of the R/P ratio, but based here on 2P reserves rather than the 1P often quoted by commentators). It is equivalent to the depletion rate used by other authors. Raising the out-take requires investment in extra engineering (pressure support, drilling more wells, artificial lift and new handling capacity).

From analysing out-take since 1900, Meling estimates a future maximum out-take rate of 9% (currently 7%) for non-OPEC states and 7% for OPEC (currently <2%). Out-take has risen since 1990. Meling expects non-OPEC countries to see reduced production growth from operational fields by 2010, as their out-take ceases to grow. OPEC faces the challenge of both raising their out-take and developing more reserves if they are to meet the future demand.

Meling has analysed the sensitivity of future supply potential to 6 variables. These, with their base case values, are demand growth (1.6% p.a.), exploration potential (309 Gb), OPEC reserves (850 Gb), OPEC outtake growth (4% p.a.), reserves growth (520 Gb) and yearly development of reserves (10%). A standard deviation of +/- 30% is used for each variable compared to the base case, to show the resulting effect on the supply-demand balance. The greatest variance is seen with OPEC out-take, which changes the point of supply-demand balance by over 10 years, while demand growth shows a change of 9 years. Exploration potential shows the least change (<3 years). This makes the point that increased reserves affect the tail of future production, rather than the timing of peak production.

All major producing countries are evaluated and compiled into the global production model. In the base case, including Canadian oil sands production, supply is insufficient to meet the assumed demand from around 2011, although this is not peak production. By 2020, supply is some 10 million b/d below the extrapolated demand. Peak supply occurs about 2028-2029 at some 95 million b/d, of which Canadian oil sands contribute some 7.5 million b/d.

In the "optimistic" liberal-market scenario, Meling assumes demand growth of 2% p.a., and OPEC out-take growth of 6% p.a.. Supply can meet demand until about 2020, and global production peaks at 115 million b/d around 2030. In the

[18] Meling, L.M., "How and for how long it is possible to secure a sustainable growth of oil supply." World Petroleum Congress 2nd Regional Meeting, Doha, 8-11 December 2003. Middle East Economic Survey (MEES), vol. XLVI, No 51/52, 22-29 December 2003

"pessimistic" scenario, demand grows by 1.4% p.a. and OPEC increases its out-take by 4% p.a., but the Middle East OPEC states of Saudi Arabia, Iraq, Iran, Kuwait and Abu Dhabi limit production to a ceiling of 35 million b/d. Demand outstrips supply at around 2015, which is also the peak of production at 90 million b/d.

Decline Rates

By definition, decline rates are identical to the out-take rate if no measures are made to increase the out-take rate and no further development occurs. The base case indicates an aggregate global production decline rate of some 2.6% p.a.[19].

Known projects

Known projects are not distinguished in Meling's model.

Undeveloped discoveries

Meling estimates that 200 Gb of oil are discovered but undeveloped, from IHS data. These are assumed to be developed and produced at a global rate of 10% p.a. as part of the general reserve.

Technical Improvements

Meling finds that any relationship between new technology and additional conventional oil discovery or production is hard to quantify. Horizontal drilling has made a significant production contribution in non-OPEC countries. Deepwater technology has opened up the deep and ultra deep continental shelf. There is no evidence that 3D seismic has improved wild-cat success rates, which have remained at around 25% since the 1970s, although arguably it prevented a declining success rate. Technological advances may have a larger impact on the production of unconventional oil and other liquid fuels.

Peak

Meling notes that peak is not the only critical point in future oil supplies; just as significant is the date when supply cannot match the assumed demand, which suggests the risk of serious economic disruption. The peak date ranges from 2015 to 2030, at levels of 90 to 115 million b/d.

URR

The global URR is not specifically estimated. However, Meling considers that 2300 Gb have been discovered (following IHS), with 540 Gb of reserves growth and 309 Gb of YTF, which totals 3149 Gb.

Summary

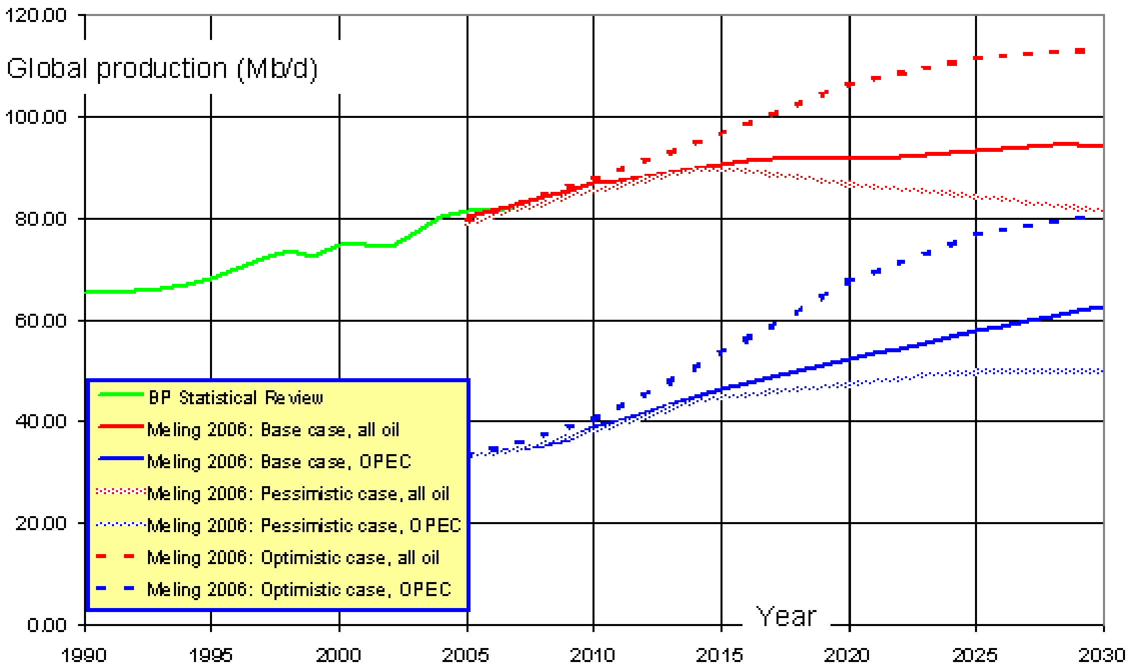
Meling's model has been presented and published with his employer Statoil's permission, but it does not necessarily reflect Statoil's views.

[19] This is based upon URR = 3149 Gb, production to end-2007 = 1150 Gb, production 2008-2029 = 729 Gb, leaving 1270 Gb to produce from a peak of 95 million b/d.

The model is a global model of production of conventional oil, divided into Middle East OPEC, rest of OPEC and non-OPEC classes, which is compared to extrapolated global demand. All major producing countries are separately evaluated and included in these classes. The model estimates the date when supply fails to match the anticipated demand – the point of supply/demand balance – as well as the subsequent peak of maximum production. Demand is extrapolated from the present by a global, exponential growth factor, although tabular data or other functions can be used. Since demand is not modelled explicitly, feedbacks between supply and demand are not captured.

Production is measured as "out-take", which is the percentage of reserves produced each year. Future production is divided into 6 classes: current fields at natural decline rates, increase in the out-take, reserves growth, new field development (we understand this to be development of fallow fields), new discoveries and Canadian oil sand output. Various models of demand, and of how the OPEC and non-OPEC "out-take" might change with time, generate model variations from a base case. Meling uses IHS data for reserves and his own estimates of YTF and reserves growth (comprising improved and enhanced oil recovery).

Figure xii: Meling global oil production forecast



Total Oil Supply Model

Author: Total Exploration & Production

Description approved?: This summary was reviewed and approved by Laurent Maurel, VP Business Strategy

Date of model: 2008

Study reference: Proprietary document: "TOTAL methodology to estimate future supply of liquid fossil hydrocarbons - December 2008".

Coverage: Global, Oil

Basis: Bottom-up modelling by field and basin

Global oil production data source: Unspecified, probably generated internally

2007 global daily rate: 83.7 million b/d

Data sources: Wood Mackenzie, IHS, Society of Petroleum Engineers (SPE)

Definition of oil:

- By location/setting: In part; fields are typed by reservoir lithology (clastic or carbonate)
- Condensate & NGLs: Yes, considered separately
- Medium/light: Yes
- Heavy (10-26° API) Yes, included in conventional crude
- Oil sands & shale oil: Yes, included in the extra-heavy oil category
- GTL: No
- CTL: No
- Biomass: No

Peak Date: 2020

Peak daily rate: 95 million b/d

Reserves definition: Not specified or required by the model methodology; actual "technical" (ultimate) reserves are an output of the process

URR: Not stated

Global YTF: 200-370 billion barrels recoverable

Reserves growth: EOR could raise the global recovery rate of original oil in place by 5%.

Description of Model

Coverage and Definitions

The model is global, and covers all conventional and non- unconventional oil (including NGLs and oil sands).

Demand modelling

Demand is not explicitly modelled by Total and is simply assumed to grow at 1.4% p.a.

Supply Modelling

Total's approach analyses production at every scale, using plots of the *draw-down rate* (the percentage of original oil in place, or OOIP, produced each year) against the *recovery rate* (the percentage of the OOIP which has been or will be recovered).

The analysis commences with detailed production data from representative fields. They find two main types of behaviour, linked primarily to a reservoir's geological properties and its type, namely carbonate or clastic[20]. Within a basin, this is sufficient for evaluating future production from fields that are either known, in production, identified for production or yet to be discovered.

Analysis of the production rate of both oil and water against (a) time and (b) recovery rate shows the following characteristics:

- Fields with carbonate reservoirs (such as the Middle East) are characterized by low annual drawdown rates[21], from 1% to 3%, with rapid water inflow within three to four years of being brought on stream. The ultimate recovery factor rarely reaches 50%, although this can be exceeded with EOR techniques. Oil production declines steadily once the recovery factor reaches 30%, i.e. when 60% of the recoverable oil has been produced.
- Fields with clastic reservoirs (such as the North Sea) are characterized by high annual draw-down rates, between 5% and 10%, with significant water inflow around five years after they are brought on stream. Ultimate recovery factors in the most efficient fields are generally about 60%, but may exceed 70% in some cases. Output declines once the recovery rate reaches 30%, i.e. when about 50% of the recoverable oil has been produced. Water inflow becomes noticeable roughly when oil production begins to decline. Total liquid output of oil + water remains virtually constant, and depends on surface production capacity.

Total's point of "production decline" for a field refers to the end of plateau production, rather than to the exact peak. In Total's examples, the exact peak occurs when recovery reaches a range of between 4% and 32% of total oil in place. Variations in the plot of annual draw-down rate vs. recovery rate allow Total to define

[20] "Carbonate" sediments are primarily limestones and dolomites, ultimately produced by organisms which precipitate calcium carbonate from seawater, as shells or other skeletal elements. "Clastic" sediments, such as sandstones, are those composed primarily of grains of various silicates ultimately eroded from older igneous or metamorphic rock.
[21] The percentage of reserves produced each year

a field's technical reserves, and to verify the estimated production profile for a basin, country or the world.

Starting with production charts for each field, Total establishes the ultimate recovery rate for each field. The next step is to plot the daily production rate against cumulative production. The often almost straight-line decline can give a good estimate of the reserves in known oil plays within a given geological basin or country. New plays are taken into account in analyzing the yet-to-find.

Total observes that the United Kingdom's original "technical reserves" are estimated at 30 billion barrels of liquids, of which 7 billion are still to be produced. The end of the UK plateau occurred when production reached 59% of the estimated ultimate recoverable resources.

Total also describes the example of Russia, where it is unclear if peak has yet occurred. Two possible solutions are described. In a model prepared by a consulting firm, Russian production rises to a peak of 13 million b/d and begins to decline when output reaches 70% of the original oil in place. Under this scenario, the ultimate recoverable reserves are 350 billion barrels, of which around 200 billion are yet to be produced. An alternative interpretation is that production will decline when output reaches 60% of the original oil in place. In this scenario, production would peak at just above 10 million barrels per day, declining by 2014, and the ultimate recoverable reserves would total 300 billion barrels (of which some 150 billion are yet to be produced). The Russian case illustrates the uncertainty involved in estimating ultimate resources.

Production and reserves are evaluated for given fields, basins and countries, and the countries are then compiled into a profile of global production. Total then adds estimates of future extra production, which include increases in recovery rates through growth and technology, natural gas liquids and condensate, and future discoveries. Some 8 million b/d of natural gas liquids and condensate are currently produced with natural gas. Total estimates from the characteristics of the fields involved that this production will peak at 10 million b/d. These liquids represent around 100 billion barrels of reserves.

Known projects

Total does not analyse current projects as a separate entity.

Undeveloped Discoveries and Reserves

Total is almost unique in using considerable original source material from the Society of Petroleum Engineers to assess current reserves, in addition to the more usual range of databases and publications. Reserves are calculated using standard techniques for each field, based on the pore volume of the reservoir(s) and on various in-well or laboratory measurements. They are extrapolated using 2D, 3D and 4D seismic data, borehole pressure readings taken at different stages of field life, and geological models.

YTF

Total uses both geological appraisal and a more analytical analysis to estimate the YTF.

The geological approach looks at the efficiency of petroleum systems in sedimentary basins. This is determined by comparing the volume of oil in the fields to the volume of oil generated by the source rocks identified within the sedimentary basin. The theoretical yield is estimated from the yield in basins considered to be fully or almost fully explored ("mature" basins).

Petroleum system efficiency is directly related to the type of sedimentary basin, or to certain petroleum system parameters such as tectonic history and hydrocarbon migration pathways and distances. When the typology and geometry of a basin is known, its maximum potential can be assessed, and the YTF in under-explored or unexplored areas can then be estimated by comparison with fully explored analogues.

Total has a database of more than 50 mature sedimentary basins which have been used as analogues for more than 200 others, some of them under-explored or unexplored. Unexplored basins with few geological data are assigned a large margin of uncertainty. The YTF calculated in this way is a maximum of 1 trillion barrels of oil in place.

The second, more analytical approach involves quantifying the recognized prospects in each basin. To this are added potential oil plays and prospects that could exist by analogy with similar basins that have already been explored. Given that the average size of fields discovered over the last 20 years or so is quite small, around 50 million barrels, the result obtained is undoubtedly at the low end of the range of estimates for residual worldwide exploration potential. Total calculates that YTF calculated this way is in a range of 550 to 1000 billion barrels of oil in place.

Based on these two approaches, Total suggests that YTF oil resources in the 200 sedimentary basins under consideration are between 200 and 370 billion barrels recoverable. Production from these resources has been added to each country's profile, taking into account the assumed development schedules.

Technical Improvements

Total's model estimates in detail how widely EOR techniques might be used, rather than simply applying a single factor to all fields world-wide. Total estimates that EOR methods could be used on a quarter of global reserves, and could increase the fields' recovery rate by 20%. This would raise the ultimate recovery rate of global original oil in place by 5%.

Peak

The estimate is for a peak for all conventional and non-conventional oil in 2020, at 95 million b/d.

URR

Total estimates that the original conventional oil in place is some 6500 Gb, including 1000 Gb yet to be discovered. They estimate a further 2.8 to 3.6 trillion barrels of extra-heavy oil in place. They do not forecast the proportion which will eventually be recovered.

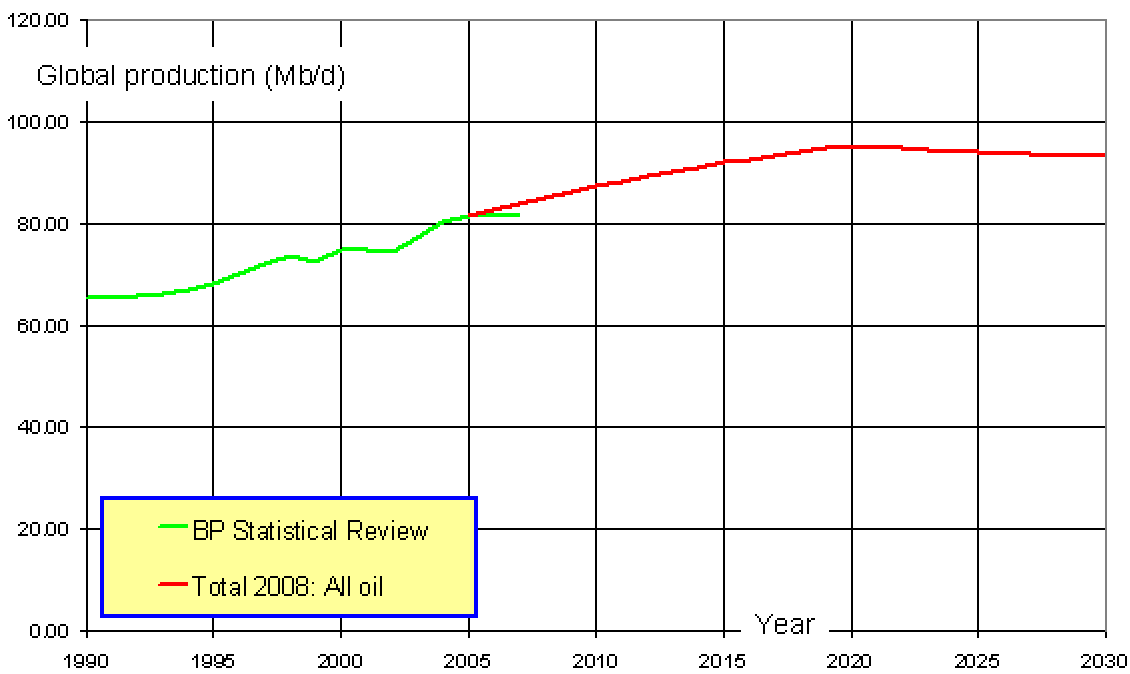
Decline Rates

Total does not estimate average natural, managed or observed field decline rates or aggregate production decline rates.

Summary

Total's is a detailed bottom-up production model, with field and basin estimates consolidated into a global model. It includes geological information and techniques that are not used by other models reviewed in this report. Future production is estimated from historical depletion rates, and estimates of URR for each field or region based on production curves. YTF is estimated primarily by geological analogies rather than extrapolation of historical discovery rates.

Figure xiii: Total's estimate of global oil production



ExxonMobil (XOM) Oil Supply Model

Author: ExxonMobil

Approved by author? Exxon was contacted with a request for information, and subsequently with a copy of this review for comment, but did not respond.

Date: 2008, developed annually

Reference: "The Outlook for Energy – a View to 2030" (2008)

http://www.exxonmobil.com/Corporate/energy_outlook.aspx

"Energy Outlook for 2007", also titled "The Outlook for Energy – a View to 2030"[22]

Scale: Global, all liquids

Basis: Explicitly there is sufficient oil, given the investment, for supply to meet demand. Future demand is calculated from forecasts of economic growth.

Global oil production data source: Implicitly generated internally from own data sources

2005 global daily rate: 84 mmb/d for all liquids

Detailed data sources: USGS

Definition of oil:

- By location/setting: No
- Condensate and NGLs: Yes
- Medium/light: Yes
- Heavy (10-26° API) Not mentioned but implicitly included
- Oil sands: Yes
- GTL: Yes
- CTL: Yes
- Biomass: Yes

Peak Date: Not by 2030

Peak daily rate: Peak not reached, 108 million b/d of all liquids by 2030 (105 million b/d of liquids excluding biofuels)

Reserves definition: Not stated

[22] The Energy Outlook for 2007 is no longer available on-line

URR: Not stated but implicitly follows USGS (3345 Gb)

Global YTF: Not stated

Reserves growth: Not stated

Comment: Too little information is supplied for a close comparison with other models. There is no analysis of the capability of industry to exploit the resource at a sufficient rate.

Model Description

Scale and definitions

XOM's model is global and covers all primary energy. "Liquids" includes conventional oil (crude, condensate and NGLs), oil sands, synfuels and biofuels. There are no data on the minor liquid components in the current *Energy Outlook*, although some data were given in the *Energy Outlook for 2007*.

Demand modelling

"Outlook for Energy" describes expected future population growth (<1% p.a. from 2005 to 2030), global GDP growth (3% p.a. from 2005 to 2030) and total energy demand growth (1.2% p.a. from 2005 to 2030). Energy intensity is expected to improve *"…at a 70% faster pace."* Demand modeling does not involve any price assumptions.

Transport is one of four categories of energy demand (the others being power, industry and residential/commercial), and is the category that ExxonMobil describes in greatest detail. Future fuel demand is analysed by forecasting the size and increasing efficiency of the future transport fleet, sub-divided by vehicle type and by OECD/non-OECD location.

Transport usage is divided between light duty vehicles, heavy duty vehicles, aviation, marine and rail. Global transport in 2005 consumed nearly 44 Mb/d of oil equivalent, of which 98% was oil (the remainder was gas and biofuel; this analysis excludes electrical rail and vehicle transport). ExxonMobil forecasts consumption by transport to grow by 1.4% p.a. between 2005 and 2030, reaching 62 Mb/d of oil equivalent, of which 94% will be oil and 5% biofuel. The growth is subvided by transportation type and by geographic region. The fuel efficiency of new US vehicles is forecast to improve by nearly 3% p.a. to 2030.

Other global oil usage in the power generation, global industry and residential/commercial sectors is analysed in a similar way.

Supply Modelling

The global demand for all liquids, which was 84 Mb/d in 2005 and 86 Mb/d in 2008, is expected to reach 108 Mb/d in 2030, a rise of 30% since 2005 [this equates to a growth rate of 1.0% p.a.]. This is 8 Mb/d lower than ExxonMobil's previous forecast in 2007.

Non-OPEC oil production is expected to remain relatively stable. Declines in, for example, the US and the North Sea are expected to be off-set by growth in countries such as Brazil and Kazakhstan. Canadian oil sand production is forecast to reach 4 Mb/d by 2030, NGLs and condensate production will grow as gas production increases, and biofuels will reach 2.8 Mb/d by 2030. These non-OPEC supply contributions are unchanged since ExxonMobil's previous forecast. Consequently, the expected call on OPEC crude oil in 2030, which last year was expected to reach 45-50 Mb/d, has been reduced to 38 Mb/d.

The global supply in 2030 relative to 2005 therefore includes:

- Non-OPEC crude and condensate 44 Mb/d (from 42 Mb/d in 2010)
- Oil sands 4 Mb/d
- All NGLs and OPEC condensate 20 Mb/d (from 15 Mb/d in 2010)
- GTL 1 Mb/d (cited in "*Energy Outlook for 2007"*)
- CTL - a small component from demonstration plants (cited in "*Energy Outlook for 2007"*)
- Biofuels (primarily ethanol) 2.8 Mb/d
- OPEC crude 38 Mb/d (from 28 Mb/d in 2010)

ExxonMobil states, "Through research and development of technology over the years, we've significantly increased efficiency in all of the four sectors of energy usage. In the U.S. alone, these improvements helped to reduce U.S. energy demand by close to 75 percent over what it would have been otherwise, and the results are similar in other countries."

Current fields, Known projects, Undeveloped discoveries and reserves, Yet-to-Find

There is no separate discussion of these subjects.

Technical Improvements

There is no discussion of technical improvements which increase the oil supply, such as reserves growth or EOR. However, improvements in end-use efficiency and consequent demand reductions are included in the liquid fuels forecast.

Peak

There is no discussion of global peaking, and the graphs show no foreseeable peak

URR

There is no discussion of URR, but ExxonMobil cites the USGS 2000 view of the recoverable, conventional resource base (3345 Gb), and asserts, *"Only one third of the total recoverable resource [of conventional crude and condensate] has been produced to date."* This implies that conventional oil URR is about 3350-3450 Gb (see section 4.2.2.4).

ExxonMobil recognises that non-conventional oils are significant in volume, but notes the technological and political challenges to accessing both conventional and non-conventional resources.

Decline Rate

There is no discussion of decline rates.

Summary

ExxonMobil's Energy Outlook is a web-published report on global primary energy. XOM's forecast asserts, "*We must meet the ever-growing need for reliable and affordable energy – energy that is necessary to sustain economic and social progress – while minimising the effects of this increased usage on the environment*." The model energy forecasts demand and then assesses how this might be met. The liquid fuels demand is based on estimates of the size and increasing efficiency of the future transport fleet. ExxonMobil places great emphasis on both energy efficiency and increasing the energy supply from all economic energy sources, including oil.

The *Energy Outlook for 2007* explicitly stated that there was sufficient oil, given the required investment, for supply to meet demand. This assertion is now only implicit. ExxonMobil expects energy demand to grow at about 1.2% p.a. until 2030.

Figure xiv: Exxon forecast of global liquid supply and global oil supply to 2030

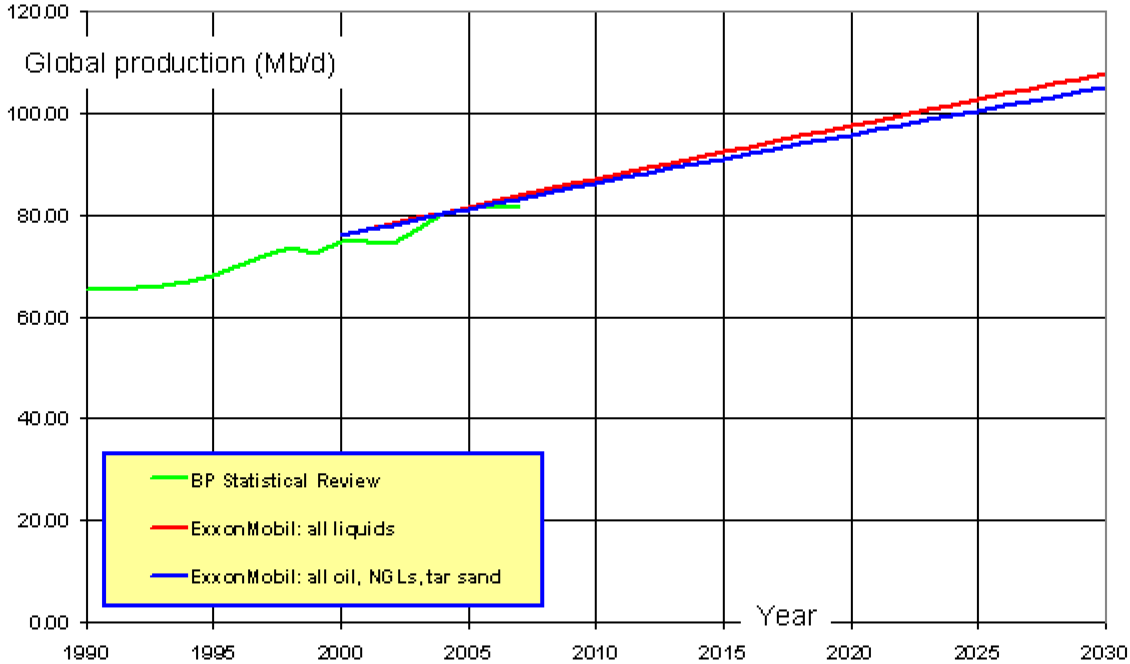
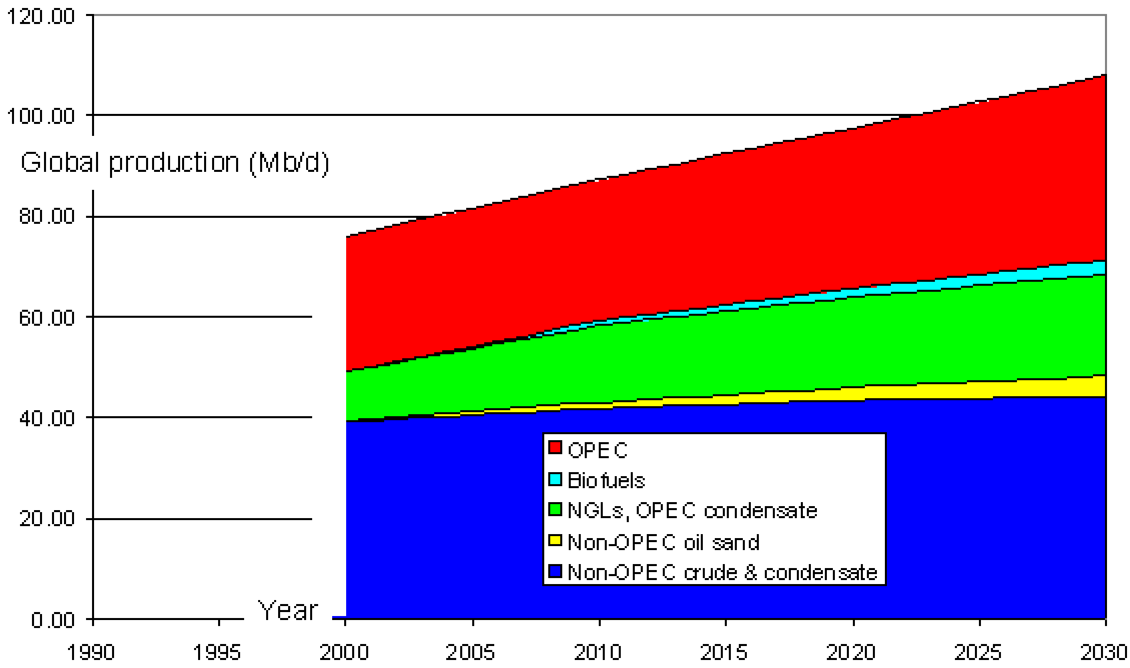


Figure xv: ExxonMobil forecast of the composition of global liquid fuel supply



ENI View

Author: ENI S.p.A

Description approved?: ENI has not responded to our enquiries for this report.

Date of view: Annual statements reflect ENI's views, but provide no supporting model

Study references: "World Oil and Gas Review 2007"

"World Oil and Gas Review 2008"

http://www.eni.it/wogr_2008/default_en.htm

Coverage: Global, Oil and Gas

Basis: No model

Global oil production data source: Unspecified, probably generated internally

2007 global daily rate: 83.1 million b/d

Data sources: Arab Oil & Gas Directory, Cedigaz, Enerdata, Eni, International Energy Agency, Italian Ministry for Economic Development, Oil & Gas Journal, Parpinelli-TECNON[23], Petroleum Intelligence Weekly, Platts and other official sources

Definition of oil:

- By location/setting: No
- Condensate & NGLs: Yes
- Medium/light: Yes
- Heavy (10-26° API) Yes
- Oil sands & shale oil: Yes
- GTL: No
- CTL: No
- Biofuels: Yes, treated separately

Peak Date: n/a

Peak daily rate: n/a

Reserves: n/a

URR: n/a

[23] Parpinelli-TECNON are consultants based in Milan and Houston

Global YTF: n/a

Reserves growth: n/a

Comment: Although there is no model, we deduce that ENI takes the view that reserves are plentiful, and can therefore underpin the supply required to meet demand.

Summary

ENI make the following comments in their annual review:

Oil consumption has constantly increased over time, yet reserves have increased and not decreased. This means that every year more oil has been discovered than was consumed.

Given that just over 30 Gb of oil are consumed every year, oil reserves are still abundant. Therefore, it is difficult to say that we are slowly coming to "the end of oil". Also, oil reserves are dynamic and uncertain, not stable and known. Reserves can increase, due to new discoveries, and to the decision to develop oilfields which in the past were considered technologically difficult or non-economic.

In 2007 the global R/P ratio rose to 39 years from 38 in 2006. Logic would suggest that this ratio – also called "residual life of reserves" – decreases over time, but this is not the case. This index has remained fairly stable (varying between 37-39 years) from 1996 until now, despite the fact that oil production has increased by 17% during this period. Its stability over time shows that not only has it been possible to replace the reserves used every year, but that new reserves have been added such as to keep the R/P ratio unchanged, in spite of increasing production levels. [R/P ratios and their significance are considered in Section 2.2.5].

These statements indicate that ENI takes the view that reserves are sufficient to meet supply for the foreseeable future. ENI's Chief Economist, Leonardo Maugeri, has written widely in support of this view[24], but his arguments have been challenged by Meng and Bentley[25].

[24] e.g. "*Oil: Never Cry Wolf – Why the Petroleum Age is far from over"* (Science, 2004, vol. 304, pp. 1114-1115).

[25] Q.Y. Meng & R.W. Bentley (2008): "*Response to L. Maugeri: Why the world should not count on abundant supplies of oil"*(*Energy*, 2008, vol. 8, pp 1179-1184).

BP View

Author: BP plc

Description approved? BP has declined to discuss their views, for commercial reasons (Dr. Christof Ruehl, BP Group Chief Economist, pers. comm. 25 July 2008)

Date of view: Press releases and speeches in 2008 reflect BP's views, but provide no supporting model

Study references: Press releases, speeches, and meetings: 1995 to 2008.

Coverage: n/a

Basis: Explicitly there is sufficient oil, given the investment, for supply to meet demand. Future demand forecasts are not specifically published

Global oil production data source: BP Statistical Review of World Energy, June 2008

2007 global daily rate: 81.5 million b/d

Detailed data sources: Primary official sources; OPEC secretariat; World Oil; Oil and Gas Journal; public domain data (Russia);

Definition of oil:

- By location/setting: No
- Condensate and NGLs: Yes
- Medium/light: Yes
- Heavy (10-26° API) Yes - not mentioned but implicitly included
- Oil sands & shale oil: Yes
- GTL: No
- CTL: No
- Biomass: No

Peak Date: Not given. An eventual peak is acknowledged

Peak daily rate: 95-105 million b/d

Reserves definition: Proved reserves are "*…taken to be those quantities that… with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating conditions*"[26]

URR: BP does not publish its view of URR

[26] BP Statistical Review of World Energy, June 2008

Global YTF:	At least 300-400 Gb (20 billion b/y discovery rate for 15-20 years)
Reserves growth:	Up to 700 Gb
Comments:	BP asserts a number of reasons for a large global resource of oil. It does not publicly analyse the rate of supply than can be delivered, but suggests that 95-105 million b/d is both achievable and sustainable.

Description of Model

Coverage and definitions

BP's published oil data are global in scale, and include conventional and unconventional oil, condensate and NGLs. Biofuels and synthetic fuels are excluded, for consideration elsewhere. We do not know which liquids are included in BP's view of future global production, but assume that it covers all liquids.

Demand modelling

BP does not publish any forecasts of oil demand, but has suggested that another price spike could occur when the global economy improves, due to delayed upstream investment in the current economic climate.

Supply Modelling

BP does not publish a model of supply from reserves and resources. Our understanding is that they run no such model.

Current fields

BP does not publish an analysis of currently operating fields.

Known projects

BP does not publish an analysis of current projects.

Undeveloped discoveries and reserves

There is no discussion of undeveloped discoveries and reserves.

Yet-to-Find

There is no discussion of Yet-to-Find

Technical Improvements

BP frequently cites two specific technical improvements as being a major factor for foreseeing no peak in future oil production, namely better definition of fields (e.g. by better seismic definition), and higher recovery factors from EOR operations. BP notes that a 5% "increase of oil-in-place" (we believe this means a 5% increase in URR) would add 170 Gb to reserves, and BP goes on to suggest that EOR could "…add 15-20% to recovery rates", which appears to mean an increase of 510-680 Gb of reserves.

Peak

While more recently acknowledging that a peak will come, BP does not appear to see this as happening within a relevant time frame.

URR

BP does not disclose any estimate of URR.

Decline Rate

BP quotes CERA's estimate of a global decline rate in the existing base of productive fields of 4.5% p.a.

Summary

BP states that its purpose is to ensure the efficient development of hydrocarbons in order to meet consumer demand. BP makes internal assessments of global and regional oil supply, using a variety of public and internal sources of information, but these are not made public. Their in-house view of the future is understood to be provided by their Economics Department.

Two speeches in 2007 make BP's view of future oil supply fairly clear[27],[28]. BP is unclear when the oil-supply peak will occur, suggesting instead that the "current hype" around peak oil is only a metaphor for anxiety about western energy security, not based on fundamental geological limits. The fear of peak oil is described as irrational. Supply only failed to match demand in 2008 because of inadequate investment.

In 2007, BP noted that the world contains very large oil resources in unexplored basins, unconventional oil accumulations (estimated to contain 7 trillion barrels), currently uneconomic fields and small pools, which could be economically accessed at higher oil prices. BP suggested that 10 billion b/y seemed a sustainable rate of new discoveries for 15 to 20 years, but added that this could be doubled if there was open access to regions such as the Middle East, Mexico and Arctic Russia. Reserves growth was cited as another enhancement to oil supply, stemming from better definition of fields and higher average recovery rates, which could conceivably be pushed to 65% or even 80%. A 10% increase in recovery from the known resource base would add some 700 Gb of supply. An oil production rate of 95-105 million b/d was said to be achievable, and sustainable for some time. Nevertheless, BP added that the world does

[27] Dr Tony Hayward, BP Group Chief Executive, 11 June 2007
http://www.bp.com/genericarticle.do?categoryId=98&contentId=7033952

[28] Dr. Michael Daly, BP Group Vice President Exploration, 10 September 2007
http://www.bp.com/genericarticle.do?categoryId=98&contentId=7037773

need to prepare for the eventual decline, with substitution by other fuels and increased efficiency.

In 2008, BP noted that non-OPEC production had consistently fallen below expectations and was not responding to market signals[29], and the world would come up against a mid-term supply constraint. Also in 2008, BP's then recently-retired Chief Economist, Peter Davies, explained at a meeting of the UK All Party Parliamentary Group On Peak Oil (APPGOPO) that, in his view, any near or medium term peak in oil production was unlikely because the world still had a secure 40 years' worth of proved reserves, and technology was continually accessing more oil.

[29] Reuters, 3 November 2008 http://www.guardian.co.uk/business/feedarticle/7978573

Energyfiles Ltd. Oil Supply Model

Author: Energyfiles (Dr Michael R. Smith)

Description approved? The author kindly submitted a detailed description of his model and its results in response to a request by this study. This summary is compiled from that submission and has been approved by the author.

Date of model: July 2008 but the model is updated daily

Study references: Submission to UKERC, July 2008

Coverage: Global (all producing countries), oil

Basis: Detailed bottom-up summation of current and projected production from fields (where available), operators, projects and basins

Global oil production data source: Own data, gathered from a wide range of public sources

2007 global daily rate: 82 million b/d

Data sources: BP Statistical Review; OPEC, EIA and IEA publications; proprietary Energyfiles data; government websites; Oil and Gas Journal and World Oil magazine and other magazines; oil company websites and annual reports; many small private and internet sources of individual field data

Definition of oil:

- By location/setting: The model deals separately with onshore and offshore fields, and divides offshore into four water-depth categories[30]
- Condensate & NGLs: Yes
- Medium/light: Yes
- Heavy (10-22° API) Yes (note Energyfiles definition differs from others)
- Oil sands & shale oil: Yes (shale oil assumed negligible)
- GTL: No
- CTL: No
- Biomass: No

Peak Date: 2017, assuming an average business as usual growth in demand

Peak daily rate: 94 million b/d

[30] Water depth ranges are 0-399 m, 400-1000 m, 1001-2000 m and >2000 m.

Reserves definition:	Assumed "most likely" volume, which is not necessarily equivalent to 2P, and implicitly includes reserves growth
URR:	2685 Gb
Global YTF:	250 Gb
Reserves growth:	Incorporated
Comment:	A detailed bottom-up model. Energyfiles note: "*Assumptions: investment proceeds rapidly, based on historic rates and driven by oil price; the world remains a stable place to work. Uncertainties: plateau and decline data on old giant OPEC fields; YTF volume and discovery rate in frontier basins; data from developing and secretive countries*."

Description of Model

Coverage and definitions

The model is global in scale. It covers all oil (and gas) that can exist without conversion as a liquid at the surface. This includes, for example, NGL and LPG; but excludes refinery gains, LNG, GTL (included in Energyfiles' gas model), CTL and biofuels (included in Energyfiles' all-energy model).

Demand modelling

Energyfiles evaluates demand based on supply availability and price influences, but this is not linked to the supply modelling.

Supply Modelling

Future supply is modelled by extrapolation of past performance, including the behaviour of existing fields, new fields coming on-stream, discovery rates, and recovery improvement. The production profiles are constrained by adopting views on the most likely URR for fields, basins and regions.

Current fields

Detailed profiles of cumulative production to date are created at field and/or basin, or country level, according to data availability. These are extrapolated, balancing the constraints of past decline rates, regional decline rates and most likely remaining reserves. NGL production is estimated directly from similar profiles of future gas production.

Known projects

Known projects are treated as any other field.

Undeveloped discoveries and reserves

Energyfiles uses published reserves data as little as possible, pointing to the uncertainties created by ambiguous definitions of reserves and of oil, variable definitions between jurisdictions, accounting conservatism and political influences. Instead, they estimate the 'most likely remaining reserves', defined as the area under the full-life production profile to the year 2140. Most estimates are obtained by extrapolating the decline rates of producing fields. For undeveloped fields the estimates are based upon announced expected plateau levels, decline curves and most likely volumes. Energyfiles observes that: "*This also has the important benefit of making the false concept of reserves/production ratio redundant.*"

Regional total reserves in the Energyfiles model may systematically under-estimate by omission. This potential under-estimate is accounted for in YTF and yet-to-develop data and profiles.

Reserves included through "reserves growth" are included within the "most likely remaining reserves" in Energyfiles production profiles. Most reserves growth, other than growth by discovery of new prospects, should be booked to the original field discovery date, not to the year announced.

Yet-to-Find

The Energyfiles evaluation of YTF is based on geological analysis of basins and plays where possible. Offshore and onshore discoveries are modelled separately. Successive discoveries are progressively smaller, and typical production profiles are applied (rapid rise to a peak or plateau, then decline). The estimated YTF of 250 Gb is around one third of the USGS mean estimate. In the view of Energyfiles, some resources, such as any as yet undrilled areas lying within the Arctic Circle, are unlikely to contribute to global supply for at least the next two decades.

In countries past or near their peak, YTF is stated to be of little global consequence, being probably smaller, or having poorer reservoirs. These resources may only serve to reduce the rate of decline somewhat and should have little influence on the date of the global peak.

Technical Improvements

Reserves growth, as already discussed, is one form of technical improvement, which is incorporated directly into the estimates of 'most likely remaining reserves'. Energyfiles takes the view that improved technology often helps to cut the costs, which may increase the production rate, and also the total recovery but not to a substantial degree. New technology may also speed up the conversion of YTF into active production. But, all in all, the influence of future new technology is thought to be much as it was in the past; past peaks and decline rates guide future peaks and decline rates.

Peak

The global oil production peak is around 2017 at around 95 million b/d for an assumed business-as-usual growth in demand of 1.8%, albeit highly volatile as peak nears and prices oscillate.

URR

The URR is currently estimated at 2685 Gb of oil.

Decline Rate

Energyfiles finds that output from wells declines at around 15% p.a.. Offshore fields made up of several wells decline by around 10% p.a., due to work-overs of existing wells, and secondary and tertiary recovery efforts, but small offshore fields can decline at up to 30% p.a.. Onshore fields, and basins, decline by around 5% p.a., due to infill drilling and small satellite field exploitation. Countries and regions comprising several basins may have smaller decline rates if basins are developed at different times and rates. Giant onshore fields also decline more slowly than small ones, as development expands slowly over a large area. The aggregate decline in post-peak, global oil production is estimated by Energyfiles to be 2.0% p.a. by 2022 and 3.0% by 2030.

Summary

The Energyfiles model is a commercial product for providing production forecasts at the regional and global level. These are based on technical data, rather than just on forecast demand.

Energyfiles uses historic discovery and production data for oil and gas, derived from various public domain sources, to determine a future production profile for a field, basin or country. Yet-to-find resources are independently determined, based on geoscience, engineering principles, exploration experience and contacts with oil companies and governments.

Oil production modelling is individually carried out for all actual and potential oil producing countries in the world. Future production capacity estimates are based on judgemental basin-by-basin analysis offshore and onshore, using individual growth and decline curves that meet exploration, engineering and economic constraints. The curves inherently calculate total reserves and resources ("ultimates"), and make no assumptions about a simple "mid-point peak". The global summary for oil in the Energyfiles reports is the sum of compiled country profiles, giving a view of the limits to global oil production and the viability of alternatives that may be developed over coming years.

Figure xvi: Energyfiles forecast of global oil production

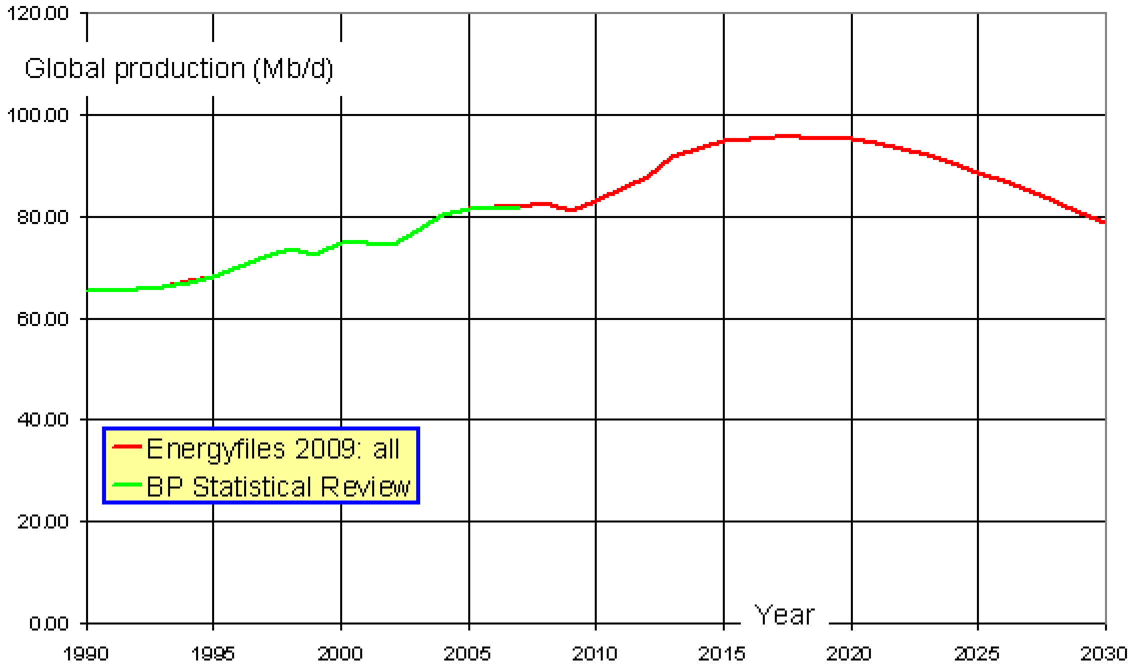


Figure xvii: Energyfiles history, components and forecast of global oil production 1945-2025

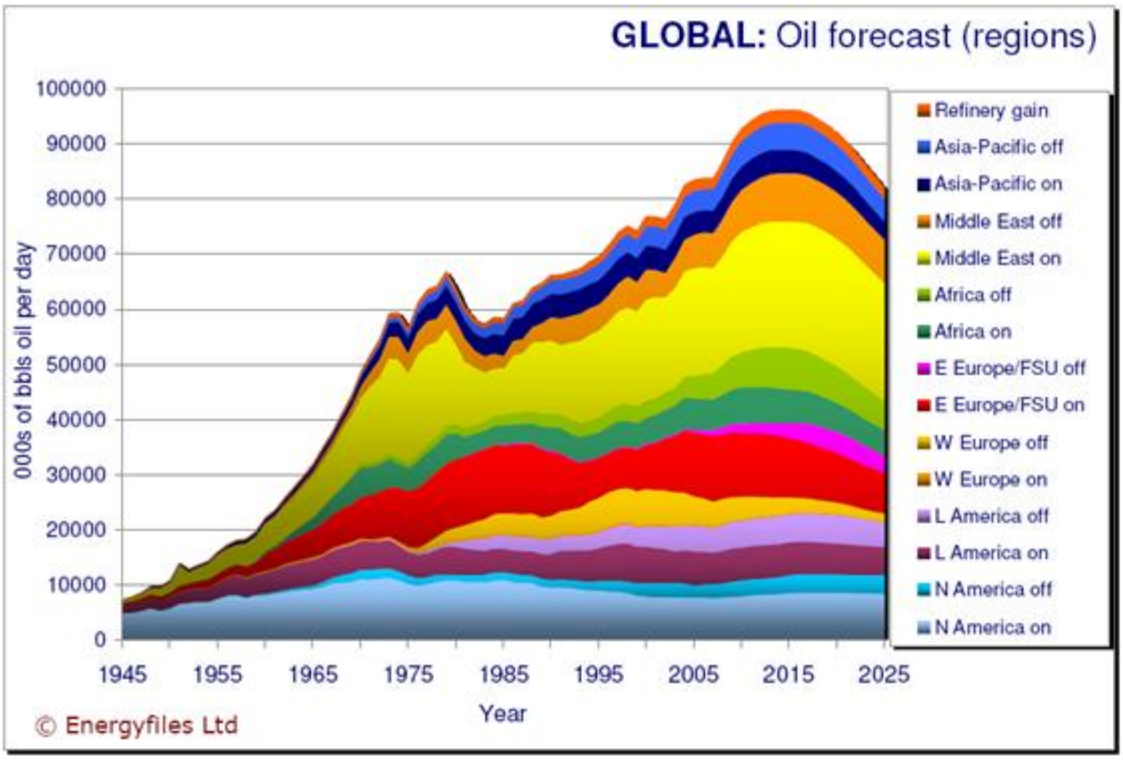


Figure xviii: Energyfiles forecast of United Kingdom oil production

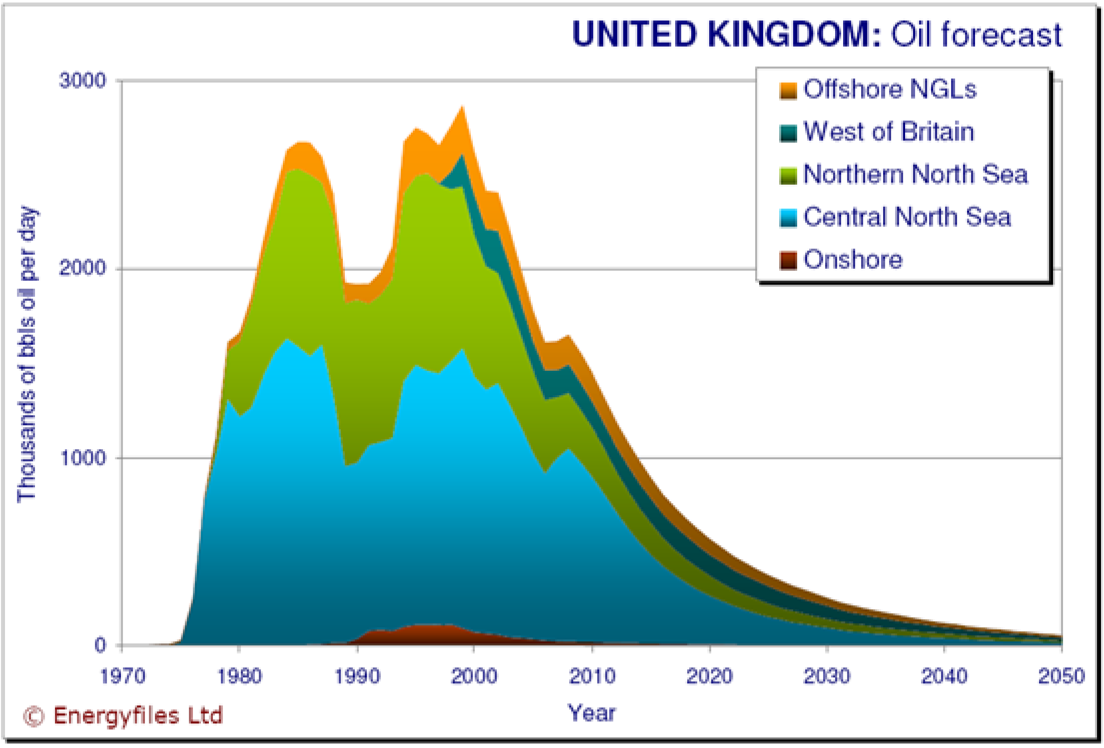


Figure xix: Energyfiles forecast of United States oil production

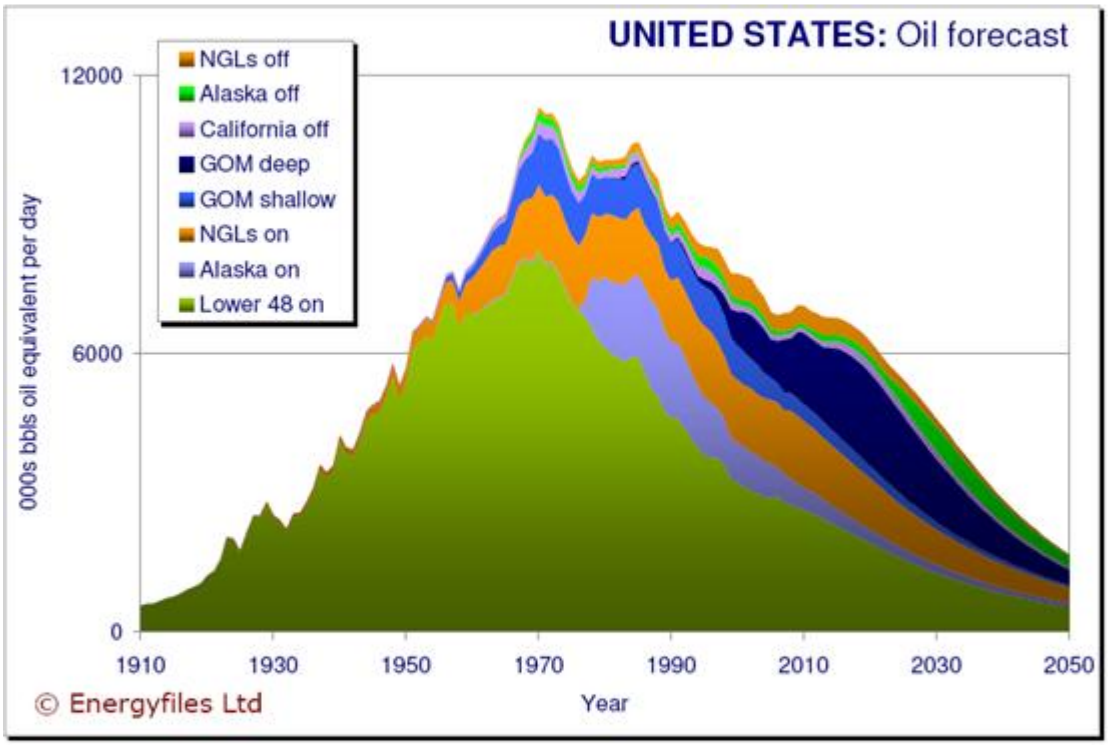


Figure xx: Energyfiles forecast of Saudi Arabia oil production

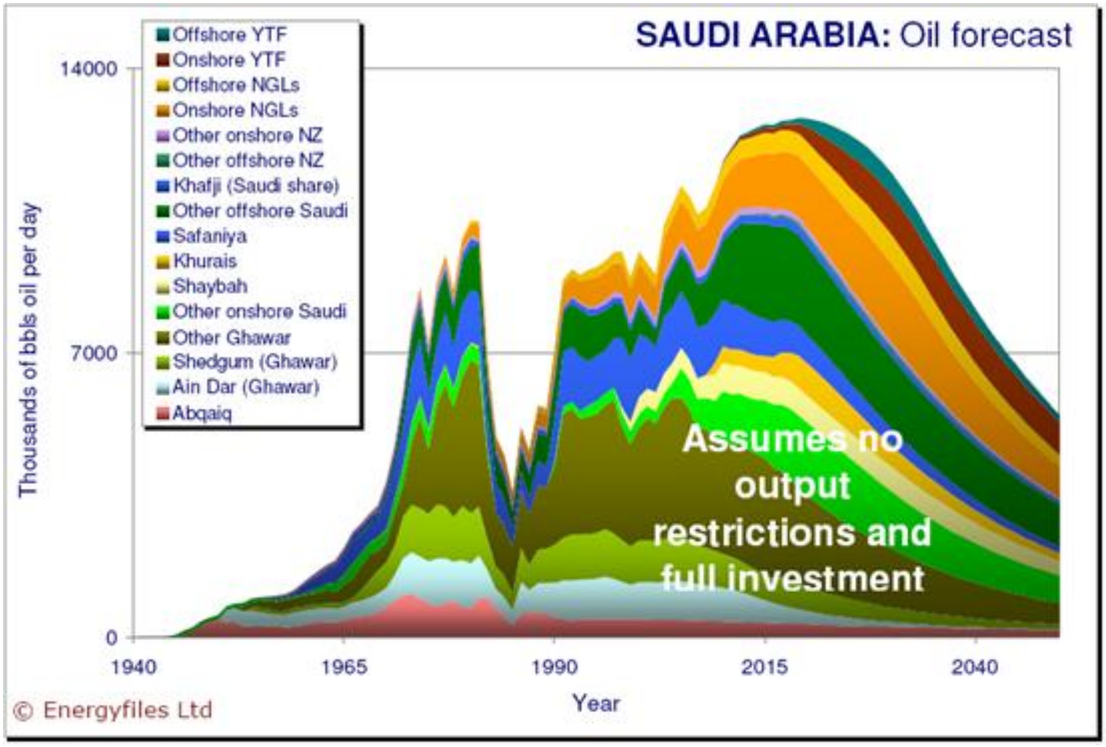
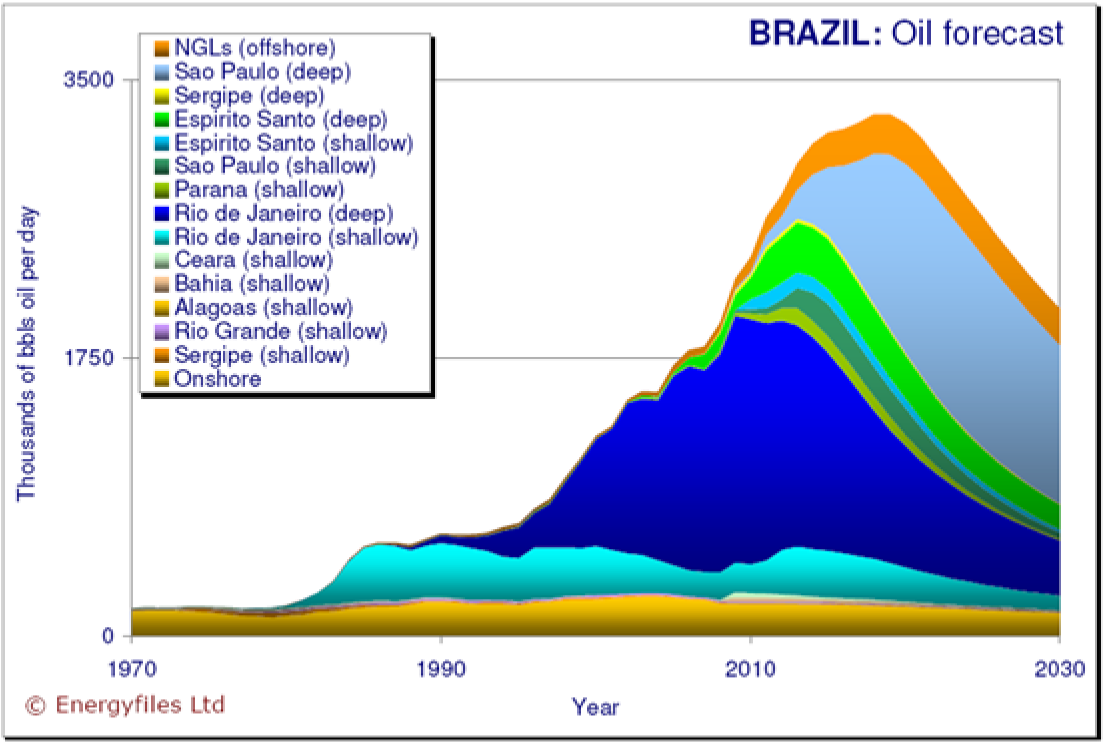


Figure xxi: Energyfiles forecast of Brazil oil production



LBST Consultancy oil supply model ("Energy Watch Group")

Author: Ludwig-Bölkow-Systemtechnik GmbH (LBST) (Dr. Jörg Schindler, Dr. Werner Zittel)

Description approved? The authors submitted a detailed description of this model and its results. This summary from that submission is approved by Dr. Zittel.

Date of model: 2007

Study references: "Crude Oil: The Supply Outlook" – background paper EWG-Series No.3/2007, October 2007

Description: August 2008, & subsequent communications.

Coverage: Global, oil

Basis: A bottom-up production model, made by compiling individual region or field production profiles. Decline rates and estimates of remaining reserves are obtained from plots of annual production vs. cumulative production. The methodology does not rely primarily upon reserves data, for reasons of reliability.

Global oil production data source: Not stated

2007 global daily rate: 81 Mb/d

Detailed data sources: IHS Energy; government statistics (USA, Canada, UK, Denmark, Norway, Australia [ABARE]); company data (Saudi Arabia, Mexico, Brazil); Not stated, but include industry data and data from the US Minerals Management Service (MMS)quarterly reports from BP, ExxonMobil, Shell, ChevronTexaco, ConnocoPhillips, Total, Eni, Repsol; www.economagic.com

Definition of oil: "Conventional oil" includes condensate, NGLs, shale oil and bitumen.

- By location/setting: Offshore and onshore treated separately
- Condensate & NGLs Yes
- Medium/light: Yes
- Heavy (10-26° API) Yes
- Oil sands & oil shale: Yes
- GTL: No
- CTL: No
- Biomass: No

Peak Date:	2006
Peak daily rate:	81 Mb/d
Reserves definition:	Although the problem of reserves definition is discussed in detail, the definition used is not stated.
URR:	1840 Gb
Global YTF:	Not stated
Reserves growth:	Implicitly included in the extrapolation method used.
Comments:	The LBST model uses the smallest current value of the global oil URR. Energy Watch Group is extremely critical of official reserves data.

Description of Model

Coverage and definitions

The scale is global and confined to oil.

Demand modelling

This is not modelled.

Supply Modelling

Supply is modelled by simple profiles of future production, constrained by estimates of remaining reserves. The profiles are first compiled by country on a field by field basis, or on a basin-wide basis. These country profiles are then merged into the ten global regions used by the IEA, to facilitate comparisons.

The constraining data are historical discovery and production, remaining reserves, and known future projects. For regions or fields already in decline, future production profiles are estimated from the linear extrapolation of plots of annual production vs cumulative production. For regions with poor data, production profiles are estimated by assuming a Hubbert-style, logistic production curve for the largest known fields. Canadian tar sand production is forecast from industry announcements and the projections of the Alberta NEB (National Energy Board).

EWG notes that, outside OPEC and Russia, the only significant current producers not yet past peak are Angola, Brazil, Chad, China, Equatorial Guinea, Sudan, Thailand and Vietnam. EWG believes that geological limits are now more significant than economic or political factors, which only serve to further constrain what is geologically possible.

Current fields

For regions where data is available, future production is calculated by extrapolating detailed production data, field by field, to 2030. For fields which have passed their peak, this uses a linear extrapolation of the annual versus cumulative production plot, which corresponds to an exponential decline in production. These extrapolations are cross-checked with the remaining reserves. Examples of this method include the UK, the Gulf of Mexico, Alaska, offshore Brazil and the largest fields in the US Lower 48.

Known projects

These are not treated as a separate category, but included within each country profile. Future production profiles are estimated from announced plans, with the addition of hypothetical or model fields to accommodate the estimated YTF.

Undeveloped discoveries and reserves

The yet-to-produce (YTF + reserves) for regions or individual fields which are in decline are estimated from a plot of annual production vs. cumulative production, which is extrapolated to zero production to provide an estimate.[31] These estimated resources are cross-checked with the explicit data on reserves in individual fields from other sources, e.g. IHS, or the US Minerals Management Service [MMS] for the Gulf of Mexico fields. For pre-peak fields, the peak production rate is estimated either from published company plans or, when no further information are available, from the estimated reserves. Yet-to-produce resources in undeveloped fields can be assessed by subtracting the remaining reserves in active fields from total regional reserves.

As an example: in Brazil, offshore discoveries listed by industry sources total about 28 Gb at end 2005. Extrapolation of discovery trends (see below) suggests total discoveries would reach about 35 Gb by 2050. 35 Gb, in turn, results in a production profile which reaches a maximum of 3 million b/d in 2019 and declines to zero in 2050.

Yet-to-Find

This is calculated for each country, and separately for on-shore and off-shore areas, by extrapolating a plot of cumulative oil discoveries vs. new field wildcats (a "creaming curve") to its asymptotic value to yield the URR. The YTF is then estimated by subtracting known reserves.

Technical Improvements

EOR is discussed, but LBST is cautious, noting firstly that EOR technologies have already been applied for 30 years, so no great changes should be expected in future; and secondly, EOR, which is generally applied after peak production, cannot reverse decline for any great period of time. LBST also asserts that EOR usually increases (temporarily) the rate of production, but does not significantly increase recovery.

Peak

LBST estimates that the peak of oil production, including NGLs and oil sands, occurred in 2006, at 81 million b/d.

[31] This technique is commonly used within the oil industry for individual fields, but is likely to be less appropriate for oil-producing regions.

URR

LBST discusses past estimates of URR, and believes that the USGS estimate is very optimistic. The total URR is estimated at 1840 Gb, which includes all oil. In regions where the decline rate determines the production profile, the URR is determined empirically by the extrapolation of production rate against cumulative production. In regions at or before peak, the maximum reserves are based on IHS historical discovery patterns and their asymptotic extrapolation. For the Gulf of Mexico, Minerals Management Service (MMS) data are used. For Middle East countries and Venezuela, the official national estimates are used, after adjustment on the assumption that the reserve growth which occurred at the end of the 1980s was spurious and purely political.

Decline Rate

Field decline rates for post-peak fields are essentially defined by historic data, and other fields are assigned production profiles "in line" with these. Decline rates are obtained from plots of annual production vs. cumulative production for post-peak fields and regions. LBST estimates an aggregate post-peak global production decline rate of 3% p.a.. From their data, we calculate the post-peak aggregate decline rate to be between 3.5% and 4% p.a..

Summary

LBST "Energy Watch" uses a bottom-up production model which does not include demand modelling. Linear extrapolation of plots of annual vs. cumulative production is used to determine the reserves remaining in fields or whole basins. These reserves estimates are used to constrain profiles of future production.

Figure xxii: LBST forecast of global oil production

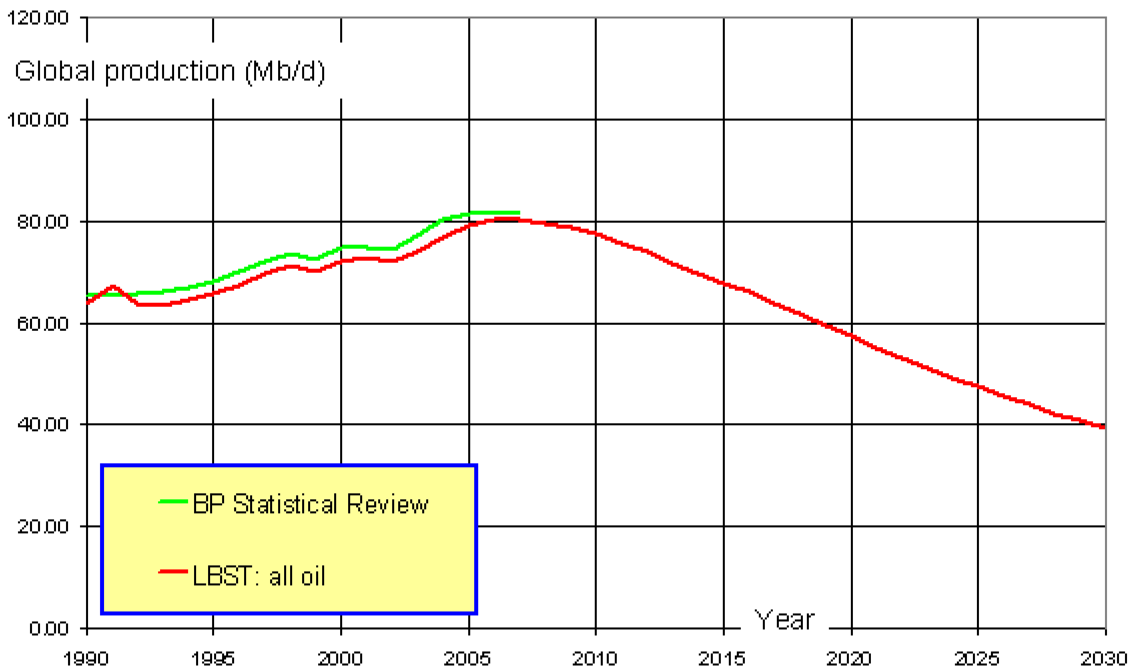


Figure xxiii: LBST history, forecast and components of global oil production

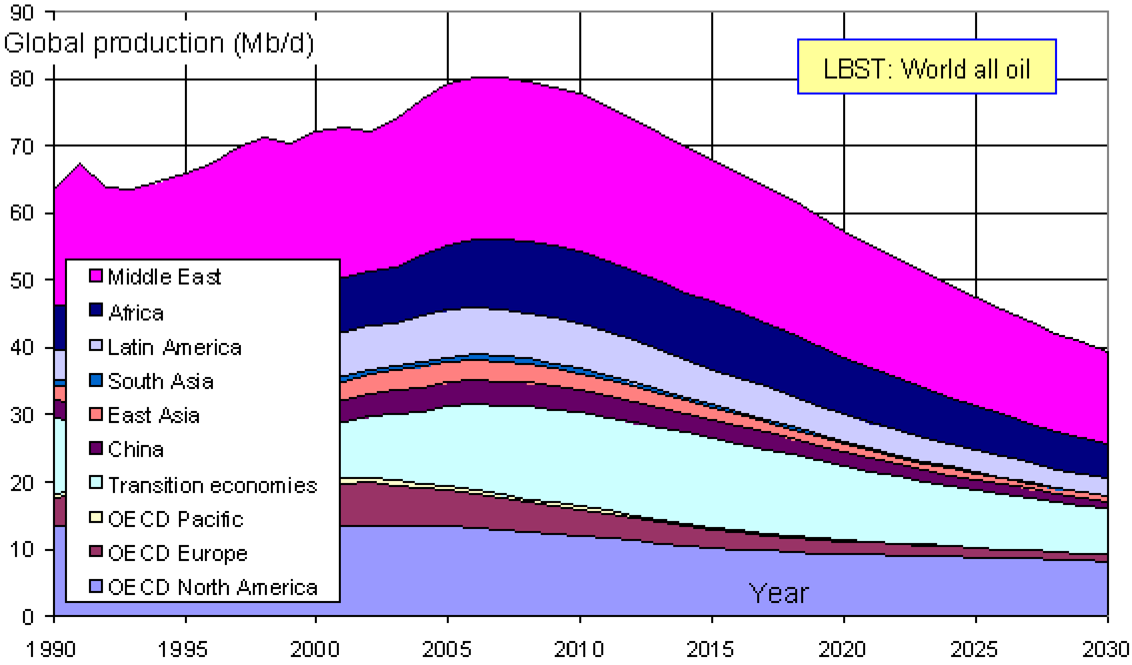


Figure xxiv: LBST forecast and components of United States oil production (excluding NGLs)

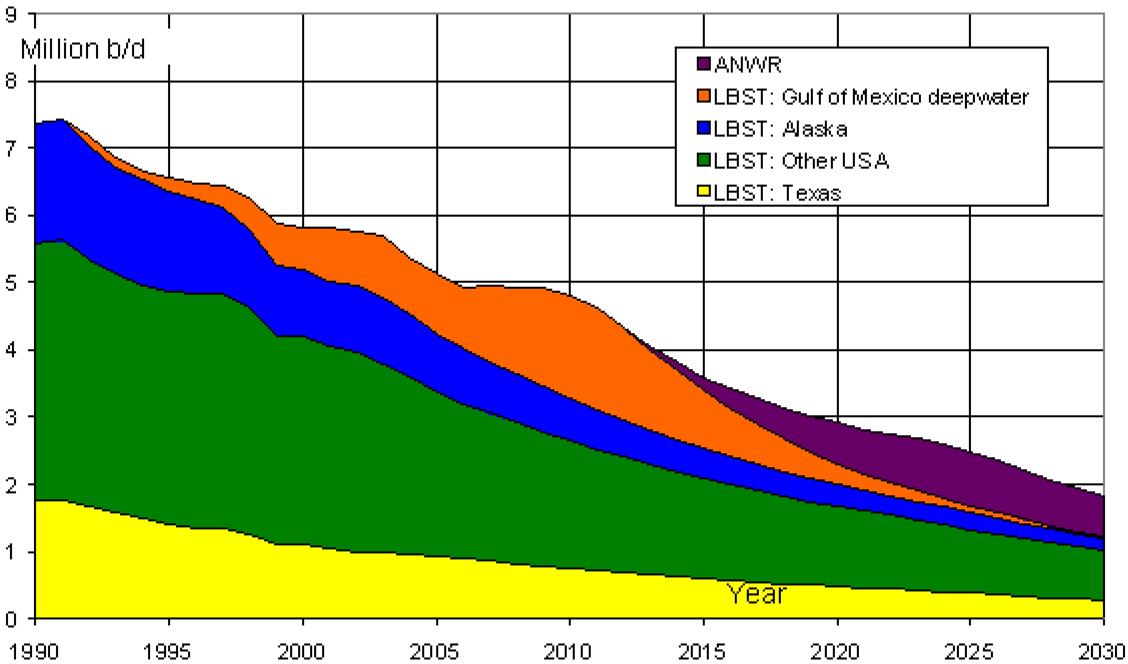
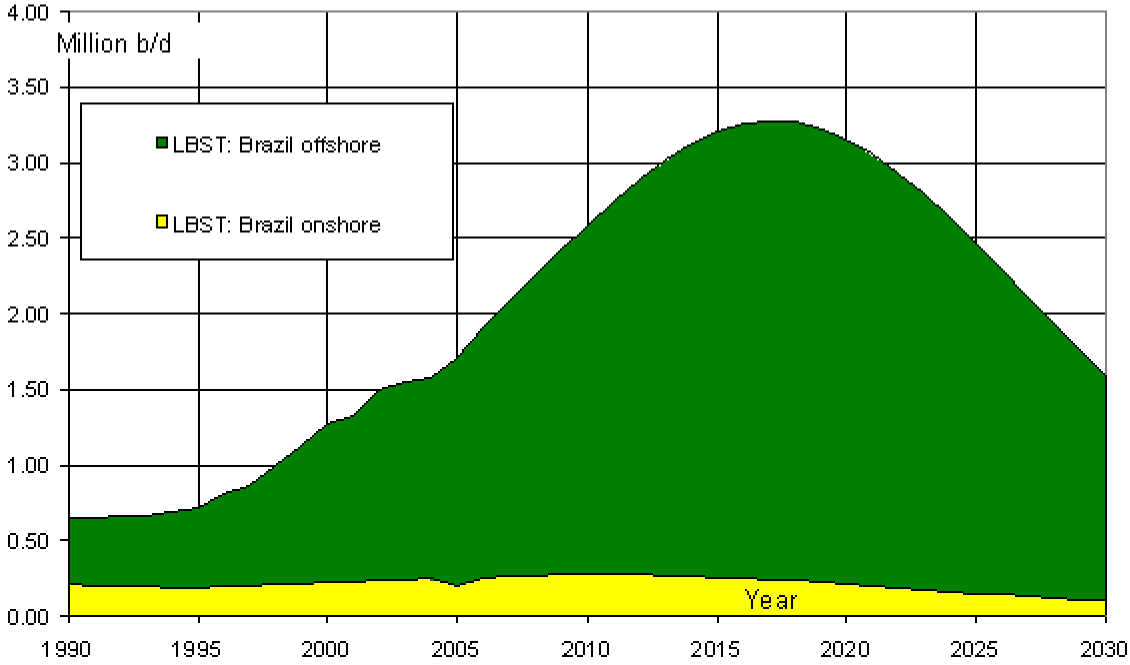


Figure xxv: LBST forecast of Brazil oil production



Peak Consulting (Skrebowski) Oil Supply Model

Author: Chris Skrebowski (Peak Oil Consulting)

Description approved? The author kindly submitted a detailed description of his model and its results in response to a request by this study. This summary is compiled from that submission and has been approved by the author.

Date of model: 2008; the model is updated continually

Study references: Submission to UKERC October 2008 and personal communication

"The Oil Crunch" p.9-15 http://www.peakoiltaskforce.net/ [32]

Coverage: Global, all oil

Basis: A "flows-based" model, which reconciles new production with loss of production by depletion, to give net annual production increments. It is thus a short to medium-term supply calculation, based upon current production, global decline rate, the future contribution from "Megaprojects" (committed, large developments of >40,000 b/d), and an estimate of new small projects (<40,000 b/d).

Global oil production data source: US EIA

2005 global daily rate: 84.6 million b/d (from IEA data)

Detailed data sources: US EIA, IEA; own proprietary database of public information

Definition of oil:

- By location/setting: To some extent within the Megaprojects database
- Condensate & NGLs: Yes
- Medium/light: Yes
- Heavy (10-26° API) Yes
- Oil sands & shale oil: Yes (shale oil is irrelevant over the timescale concerned)
- GTL: Yes
- CTL: No
- Biomass: Yes, but not specifically identified

Peak Date: 2011-2013

[32] "The Oil Crunch" is the first report of the UK Industry Taskforce on Peak Oil and Energy Security, published privately late October 2008

Peak daily rate: 92-94 million b/d

Reserves definition: Not stated

URR: Not estimated

Global YTF: Not estimated

Reserves growth: Not considered as a separate matter, but implicitly included in the extrapolated production from current fields.

Comment: The model is straightforward, and easy to test for sensitivity.

Description of Model

Coverage and definitions

The model is global and covers all oil, condensate, NGLs, oil sands and biofuels.

Demand Modelling

Modelling of oil demand is not a component of this model.

Supply Modelling

Skrebowski's proprietary Megaprojects database lists 258 known oil development projects and undeveloped oil discoveries which are intended to come on stream by December 2016, and which each have a potential future production of >40,000 b/d. Future production from these new sources is summed to give the gross yearly increment to global annual production, taking into account start up dates and production build up profiles. The gross data are adjusted by two factors. The first is a delay factor, to take account of the normal slippage that projects experience. The second is a reduction factor to take account of normal production stoppages, due to operational constraints and maintenance.

The incremental supply from one year to the next is the gross new capacity from the Megaprojects, plus the gross new capacity from small projects, minus the loss of capacity due to the depletion of existing production. The volume of small projects (<40 kb/d) is estimated by backcasting. This uses historical records to determine the contribution of small projects, and then extrapolates this forward, on a gentle decline to take account of the reducing volume of resources remaining to be found.

Skrebowski finds that the industry average lead time between a major discovery and first oil production is 6.5 - 7.0 years. This means that future incremental additions are highly predictable out to 2015/2016. By 2020-2025, Skrebowski expects that the existing stock of known discoveries will all have been brought into production. The world will then be limited to developing only immediate discoveries, or rather those of 7 years earlier. Current discovery (new fields) averages arround 10 Gb/y, which can support new production of about 2.5 million b/d each year.

Skrebowski's estimates of future additions to conventional oil supply as at October 2008 are tabulated below:

Table ii: Peak Oil (Skrebowski) estimate of future oil supply projects, October 2008

Year	Number of OPEC projects	Number of Non-OPEC projects	Gross new capacity (million b/d)
2008	33	38	5.2
2009	20	20	7.2
2010	18	20	4.4
2011	10	17	3.8
2012	20	24	4.7
2013	6	18	4.5
2014	2	3	2.3
2015	2	5	1.1
2016	1	1	0.8

There is clearly a steep decline in the new production expected to become available after 2013.

Reserves growth is not handled as a separate issue in this model. Future production from current fields is estimated by a single exponential decline value, which therefore accounts for past reserves growth and effectively extrapolates this into the future.

Current fields

Production from current fields is treated as a single global quantity in this model, using US EIA data.

Known projects

This model compiles all known development projects. These are held in a proprietary database[33].

Undeveloped discoveries and reserves

Undeveloped discoveries and reserves are not treated as a single entity; they are tabulated in an appendix to the Megaprojects database. Large fallow fields will at

[33] The Megaproject database as of February 2007 can be found at: http://docs.globalpublicmedia.com/bulletin/documents/MegaProjects_Feb2007.pdf

some point become declared development projects, and then they will enter the main Megaprojects database. Skrebowski asserts that the stock of undeveloped discoveries is now small, and that these will mostly have entered production by 2020-2025. Small fallow fields may never have commercial potential.

Yet-to-Find

The YTF is not given a value in this model, but it is expected to provide some 10 Gb of new discoveries per year. How this value may fall with time is unclear.

Technical Improvements

Technical advances are not considered in this model.

Peak

Skrebowski finds that new annual production fails to exceed annual decline by 2013 at best, which is therefore the peak of production.

URR

The URR is not estimated.

Decline Rate

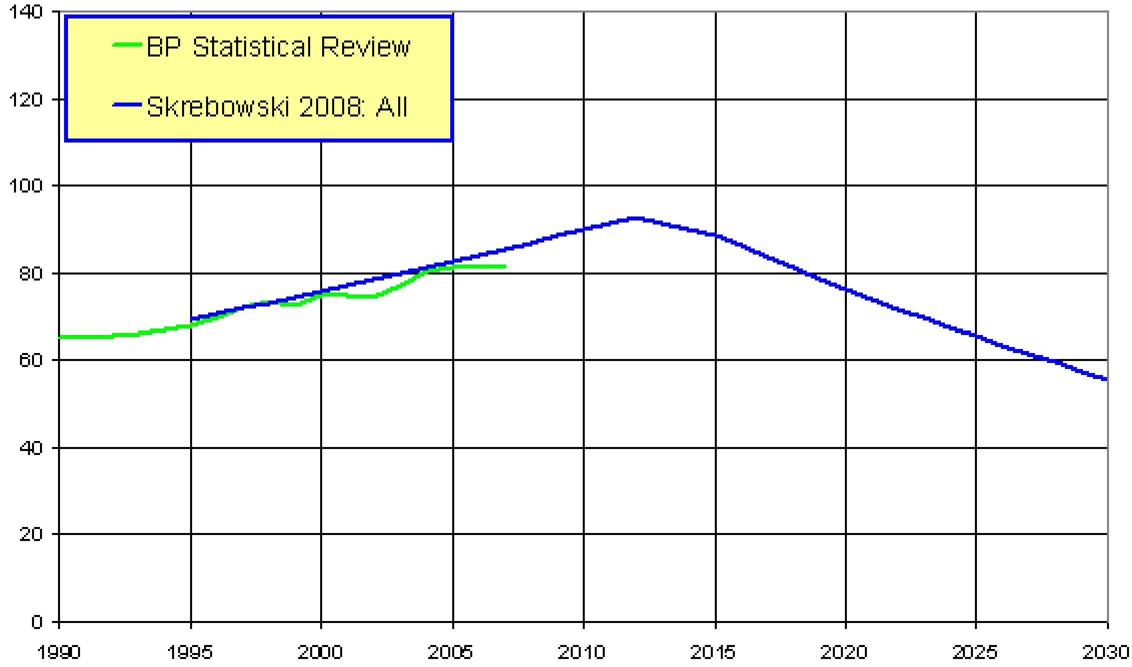
The loss of global production from depletion at current fields is assessed at 3.5 - 3.9 million b/d per year (about 4.5% p.a.). The effective aggregate decline rate of total global oil production is 2% p.a. by 2025 and 2.3% p.a. by 2030.

Summary

Skrebowski analyses the supply of new oil and liquids into the global system from all major development projects. This, off-set by the decline in production from existing fields, largely determines the potential annual increments to annual production rates. Skrebowski has compiled a comprehensive database of all the world's current, committed, planned or likely oil development projects above 40,000 b/d, the so-called Megaprojects.

The model does not use reserves data, and focuses on production data instead, which are both more accurate and easier to find. New projects usually have handling facilities of a known capacity, so that when reserves prove to be larger or smaller than declared, they will result in a longer or shorter field life rather than a markedly different annual production rate.

Figure xxvi: Peak Consulting forecast of global oil production



Campbell Oil Supply Model

Author: C.J. Campbell

Description approved? This description is compiled from various sources and personal communications. Campbell has approved this description.

Date of model: 2008; updated annually

Study references: Campbell, C.J. and Heapes, S. *An Atlas of Oil and Gas Depletion*. Jeremy Mills Publishing, Huddersfield, UK, 2008.

Aleklett, K. and Campbell, C.J., "The Peak and Decline of World Oil and Gas Production"; Minerals and Energy 2003, v. 18, 5-20

Personal communications

Coverage: Global, all oil and gas

Basis: Forward modelling from estimates of URR by country, divided into oil categories ("regular" and others), assuming depletion after production half of the estimated URR. Forecast production rates post-peak are set by the depletion rate at peak (i.e. annual production as a percentage of estimated yet-to-produce).

Global oil production data source: Oil & Gas Journal; US EIA

2006 global daily rate: 80.8 million b/d (all liquids)

Data sources: Industry datasets, BP Statistical Review; Oil and Gas Journal; World Oil. Preferred estimates are selected from these and other sources, having removed historical and other anomalies and incorperated various judgemental adjustments.

Definition of oil:

- By location/setting: Yes, divided into Regular, Heavy, Deep-water (>500 m), Polar and also NGL and non-conventional
- Condensate & NGLs: Yes. NGLs treated separately; condensate treated as oil.
- Medium/light: Yes
- Heavy (17.5-26° API) Yes, treated separately (note the cut-off at 17.5° API)
- Oil sands & shale oil: Yes, treated separately, as non-conventional
- GTL: No
- CTL: No
- Biomass: No

Peak Date: 2008

Peak daily rate:	81.0 million b/d (all liquids)
Reserves definition:	2P, but adjusted in some cases (see “Description of Model”, below)
URR:	2425 Gb up to the year 2100
Global YTF:	114 Gb
Reserves growth:	Not stated. The estimates of future production from known fields implicitly include “reserve growth”.
Comment:	An updated version of the 1989 “mid-point” model that helped bring global oil peaking back to the world’s attention.

Description of Model

Coverage and Definitions

The coverage is global.

Campbell follows Hubbert in backdating any revisions to the cumulative discovery estimates for a field to the original date of the field’s discovery.

The depletion rate is the annual production expressed as a percentage of the estimated yet-to-produce.

In recent years Campbell has divided conventional oil according to its likely rate and profile of production. Thus “regular” oil accounts for most conventional oil, with the remainder divided into heavy (<17.5° API), deep-water (>500m), polar and NGLs (which are expected to grow and decline in parallel with gas production). He also models non-conventional oil (largely tar sands, but taken for practical purposes to be all liquids sources other than those covered above).

Demand modelling

Demand is not modelled specifically. For non-Middle East, pre-peak countries, production is taken as rising at a modest rate, depending on local circumstances.

Supply Modelling

Campbell’s model is a bottom-up model by country for the 58 largest producers, plus a catch-all region to account for current minor producers. A separate category models oil from countries that future discoveries will make producers. Details of the modelling are set out in *An Atlas of Oil and Gas Depletion*.

Production is plotted from 1930 to the current year, with any pre-1930 production being summed[34]. Estimates of URR by country are then assessed using a variety of methods. These include the ‘creaming curve’ , the ‘linearised logistic’, and the parabolic fractal - see YTF below. Campbell notes, “*This is an iterative process to*

[34] Data sources: back issues of Oil & Gas Journal; post-1980 data are taken from the EIA

evaluate the maturity of exploration; the reported reserves; and the resulting depletion rates, and eventually divine a reasonable [URR] *estimate."*

Subtraction of cumulative production from the estimated URR then determines whether the country has passed its volumetric mid-point of production. An estimate of the future production from known fields yields the remaining reserves at those fields, and hence the YTF.

Campbell then calculates cumulative production by year, the yet-to-produce by year, the percentage depleted and the annual depletion rate. "Non-regular" oil categories are assessed separately.

Future production is then forecast by country. Past mid-point countries are assumed to continue production at their current depletion rates, i.e. at a fixed annual percentage of their yet-to-produce. Countries not past mid-point, with the exception of Middle East OPEC states, are typically assumed to produce at a fixed growth rate until mid-point is reached. Production of the five critical Middle East OPEC countries is modelled under several hypotheses, "*…the preferred one being that production will remain approximately flat until the depletion rate rises to about 3%, heralding the onset of terminal decline.*"

In addition, Campbell collates oil discovery data from numerous public and industry sources, and separates these into giant fields and all fields. Various adjusting factors may be applied to make these data, and the expected future annual discovery rate, reach the YTF already calculated.

Forecast country production data are summed into appropriate continents, regions and political affiliations for plotting.

<u>Known projects</u>

Known projects are not treated separately.

<u>Undeveloped Discoveries and Reserves</u>

Campbell (and Laherrère) extensively use the 2P reserves data held in the industry databases, but are perhaps more willing than most current modellers to question these data, and adjust - often downwards - as suggested by experience or analysis. In particular, Campbell reduces some of the Middle East reserves data below their reported 2P values: *"These countries, led by Kuwait, announced massive increases in the 1980s. OPEC production quota was based in part on reported reserves, and countries had motives to increase production at a time of low oil prices to maintain national revenues. The numbers suggest that they may have changed to reporting "original" rather than "remaining" reserves, by not deducting production."* Campbell likewise reduces some FSU reserves, believing these to be 3P in some cases.

<u>YTF</u>

Campbell (like a number of other groups) challenges the assessment of yet-to-find for conventional oil made by the USGS[35] in 2000. He uses the following methods to assess YTF values by country:

- The 'derivative logistic': a graph showing annual/cumulative vs. cumulative production. Extrapolation of this graph to zero yields an estimate for URR, from which cumulative production plus reserves can be subtracted to yield an estimate of the YTF. Campbell notes that this "linearised logistic" approach "*works well in some countries, but not in others …*"
- The creaming curve, which plots cumulative 2P discovery data against time or effort (e.g. exploration wells), producing a hyperbola which can be extrapolated to an asymptote to give an estimate for URR
- The parabolic fractal approach of Laherrère (1996)[36] , which plots field size against rank on a log-log scale, describing a parabola which can be extrapolated to the smallest field. Since a complete segment of a distribution in a natural domain mimics the whole, the size distribution of the larger fields found earlier can indicate the total.
- Subjective judgement and experience

A global YTF value of 105 Gb for regular oil is given in *An Atlas of Oil and Gas Depletion*, and a figure of 114 Gb, also for regular oil, is published in the ASPO newsletter for November 2008[37].

Technical Improvements

Campbell questions the reserves growth model used by the USGS in 2000 (op. cit.). While Laherrère argues for the need to include an allowance for reserves growth in the modelling, Campbell, by contrast, has generally taken the industry dataset 2P reserve values as correctly allowing for realistic reserves growth; arguing that these data typically were provided by independent sources within the industry as estimates of each field's likely production at end-of-life. Campbell does not dismiss the longer-term importance of technically-driven reserves growth, but holds it unlikely to be a major factor in determining the date of peak.

Peak

The global peak of all oil production in Campbell's latest update is 2008.

URR

The URR is calculated on a country basis (see above). Campbell's URR for "regular" oil is 1900 Gb, and a global total of 2450 Gb production of all-oil up to 2100 is cited in the ASPO monthly newsletter for November 2008 (op. cit.). Campbell notes that the current linearised-logistic plot of annual/cumulative production vs. cumulative production also yields 1900 Gb as the URR for regular oil.

[35] "*World Petroleum Assessment*", United States Geological Survey http://pubs.usgs.gov/dds/dds-060/
[36] Laherrère, J.H., 1996; "*Distributions de type 'fractal parabolique' dans la Nature*". C.R. Acad. Sci. Paris, p. 322-
[37] http://www.aspo-ireland.org/contentFiles/newsletterPDFs/newsletter95_200811.pdf

Decline Rates

Depletion rates are used rather than decline rates, although mathematically they are similar. In Campbell's model, depletion rates are calculated as the percentage of the yet-to-produce produced each year, and are used to estimate future production based solely upon remaining oil. The effective aggregate post-peak global production decline shown by Campbell's data is approximately 2.1% p.a.

Summary

Campbell (together with Laherrère) is one of the best-known, long-term proponents of a relatively imminent peak in global oil production.

Campbell came to the topic several decades ago when, as a senior exploration geologist, he was asked by his employer to make a *tour d'horizon* of global oil prospects. He was surprised by the extent to which prospects had already been identified and exploited globally. In 1988 he initiated a study funded by the Norwegian Petroleum Directorate to investigate the situation, which resulted in the book, "*The Golden Century of Oil: 1950 – 2050*"[38]. This relied largely on publicly-available proved reserves data, which Campbell did not then realise was a definition substantially subject to stock exchange regulations. George Leckie read Campbell's book, and encouraged Petroconsultants (now IHS Energy) to carry out a ground-breaking study on the global endowment of oil and gas, using its comprehensive database. The consequent report, *"The world's oil supply, 1930-2050"* by Campbell and Laherrère, was subsequently suppressed under pressure from an oil company.

In Campbell's current model, conventional oil is divided into five classes, namely regular, heavy, deep-water, polar and NGLs. Production from each of these classes is forecast individually by country. Conventional oil production in a country is assumed to peak when half the estimated URR has been produced.

Countries are forecast in three groups:

- Countries which have yet to reach mid-point. These are assumed to produce at a modest growth rate until mid-point is reached, then to continue producing at their depletion rate as of that date. This assumption is stated to be insensitive, because these countries are mostly close to their mid-point.
- Countries past mid-point are assumed to continue production at their current depletion rate (the percentage of the remaining URR that is produced each year).
- Production from the five Middle East OPEC countries of Abu Dhabi, Iraq, Iran, Kuwait and Saudi Arabia is modelled under a number of scenarios, one of which is that production remains flat until the depletion rate rises to about 3%, heralding the onset of terminal decline.

Overall, Campbell's model is fairly simple, with the hard work going into estimation of the two variables - reserves and URR values - which will define the peak. "Mid-point peaking" is a well established technique, but considered by some to be optimistic as regards peak date. For example, most of the current 60 or so countries

[38] "The Golden Century of Oil 1950-2050", C.J.Campbell, 1991, Springer, 368 p.

which have passed their peak appear to have done so before 50% of their estimated URR had been produced, some considerably before. On the other hand, by reducing certain Middle East reserves to below the industry 2P values, and by assuming an effectively zero value for reserves growth (in terms, that is, of affecting the date of peak), Campbell's model can be seen as being on the conservative end of the spectrum. The model's general approach is supported by the many countries that have subsequently passed their peak.

Figure xxvii: Campbell's forecast of global oil production

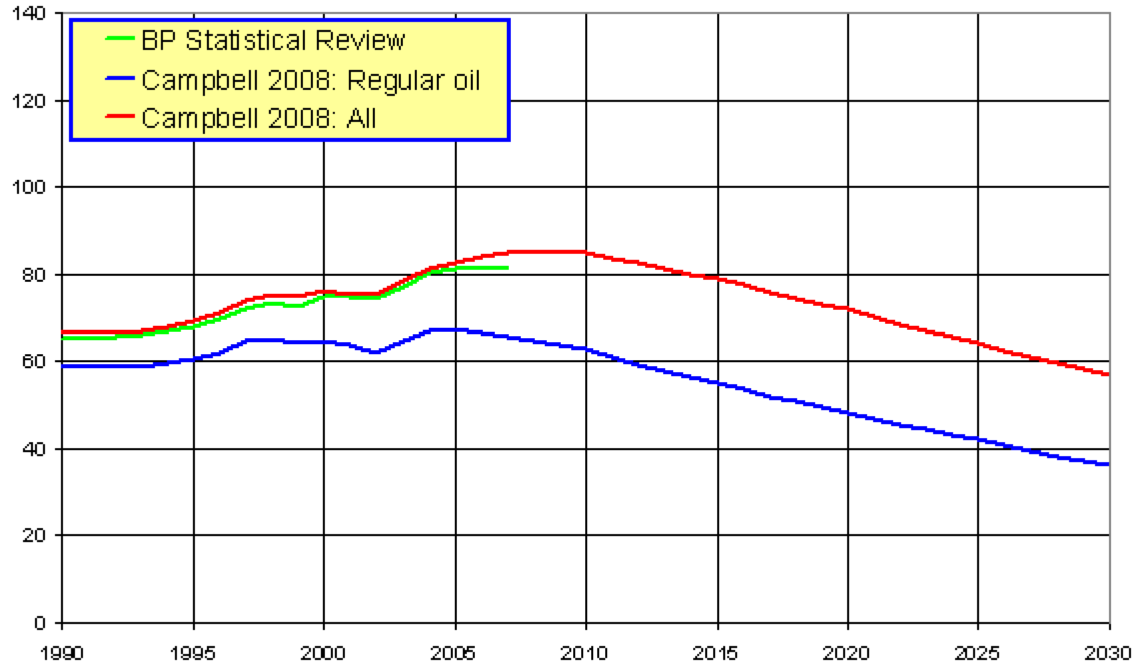


Figure xxviii: Campbell's forecast of United Kingdom oil production

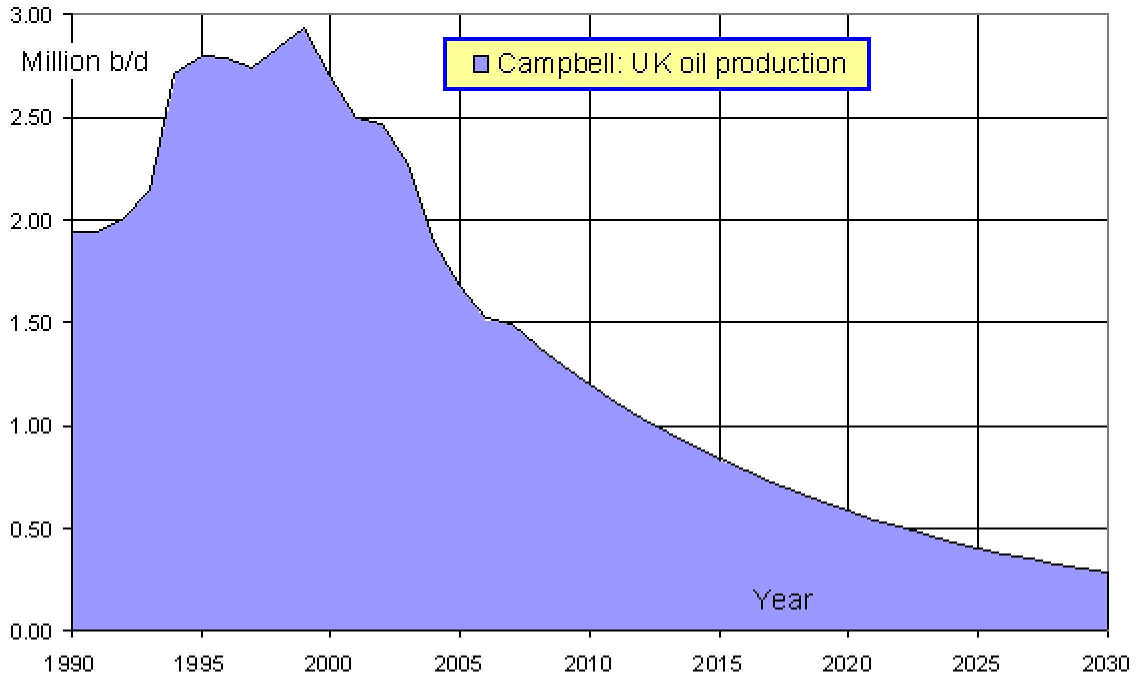


Figure xxix: Campbell's forecast of United States oil production

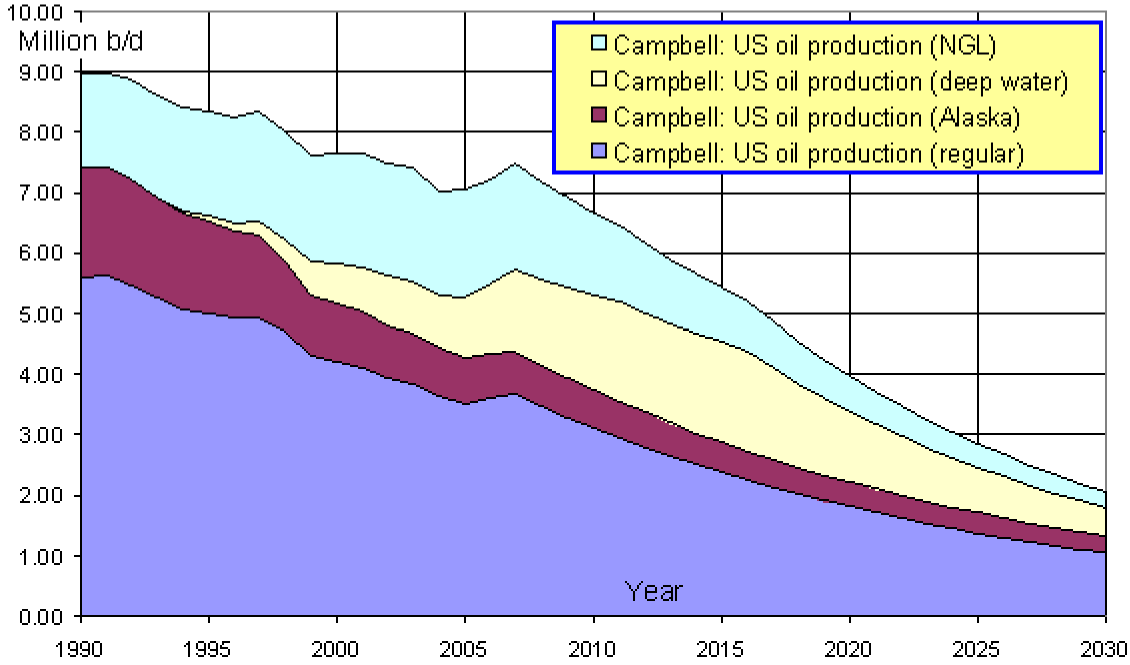


Figure xxx: Campbell's forecast of Brazil oil production

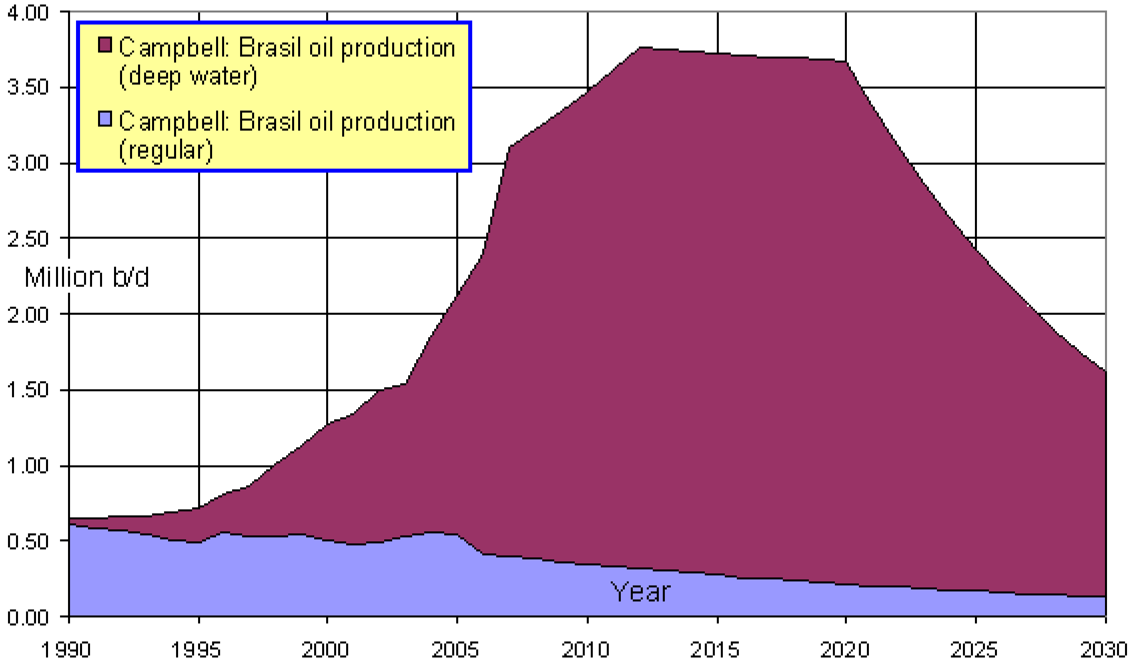
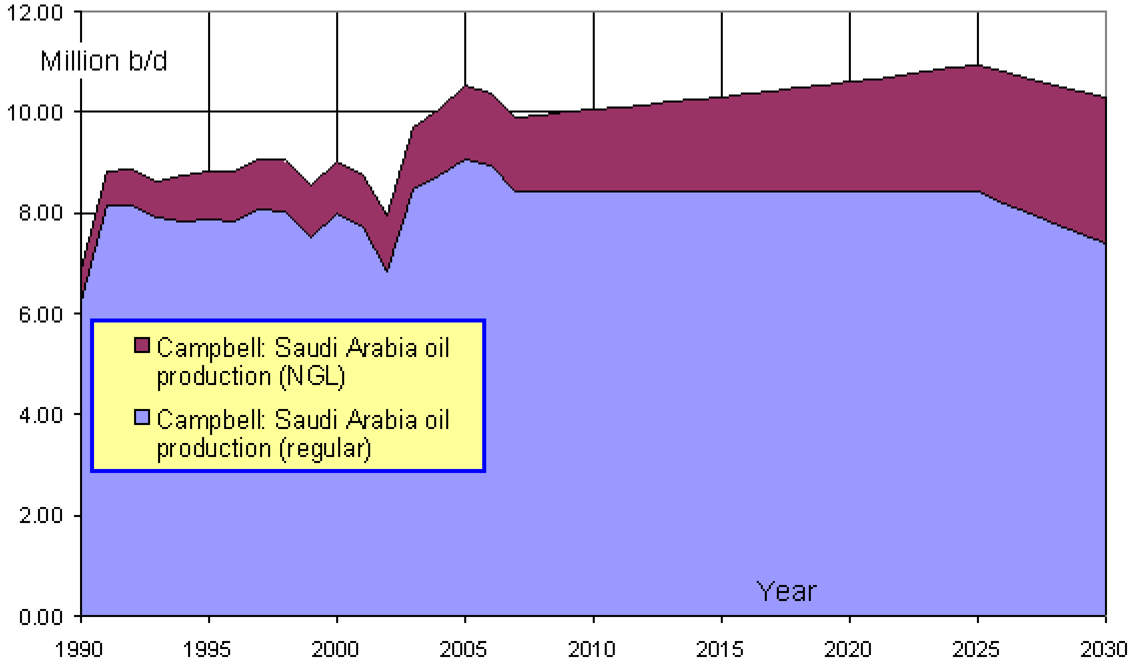


Figure xxxi: Campbell's forecast of Saudi Arabia oil production



University of Uppsala Supply Models

Authors: Fredrik Robelius, Kjell Aleklett, *et al.*

Description approved? This description is compiled from a number of sources (see "Study references"). It has been amended and approved by Aleklett.

Date of models: Giant Oil Fields model: 2007; All-oil model: 2007

Study references: The model was presented in 2007 in the thesis of Fredrik Robelius. It is still under development, with recent publications making detailed studies of depletion and decline.

Robelius, F. (2007), "Giant Oil Fields - The Highway to Oil: Giant Oil Fields and their Importance for Future Oil Production". Acta UniversitatisUpsaliensis 69 (2007); see abstract at http://urn.kb.se/resolve?urn=urn:nbn:se:uu:diva-7625

Aleklett, K., 2007, "Peak-Oil and the Evolving Strategies of Oil Importing and Oil Exporting Countries"; presented at OECD Round Table, Paris, 15-16 November 2007

Aleklett, K. and Campbell, C.J., "The Peak and Decline of World Oil and Gas Production"; Minerals and Energy 18, 5-20

Personal communications

Coverage: Global, Oil (Giant fields model; All-oil model)

Basis: Forward modelling of giant oil fields on a range of decline assumptions; separate modelling for other conventional oil, deepwater, tar sands, heavy oil, and NGLs. Excludes synfuels (GTLs, CTLs) and biofuels.

Global oil production data source: Various, mainly *Oil & Gas Journal*, AAPG, BP.

2005 global daily rate: 82.1 million b/d

Data sources: A very wide variety of data sources, mostly public, but results informed from analyses using industry datasets.

Definition of oil:

- By location/setting: Yes, divided into giant fields, other conventional, deepwater, tar sands, Orinoco, and NGLs.
- Condensate & NGLs: Yes, NGLs treated separately
- Medium/light: Yes
- Heavy (10-26° API) Yes, Orinoco treated separately

- Oil sands & shale oil: Yes, tar sands treated separately, shale oil assumed not significant over the forecast period
- GTL: No
- CTL: No
- Biomass: No

Peak Date:	2008 - 2018, depending on scenarios and demand growth. This estimate is under review, downwards.
Peak daily rate:	Between ~ 85 Mb/d and 95 Mb/d, depending on assumptions.
Reserves definition:	2P (proved plus probable), to the extent possible.
URR:	Not stated (though included in the modelling)
Global YTF:	Not stated (though included in the modelling)
Reserves growth:	Not stated (though included in the modelling)
Comment:	A detailed model drawing on a very wide variety of sources. Sets out to run optimistic and pessimistic cases for giant field URR's, but may be conservative on new discoveries and reserves growth. Excludes synfuels and biofuels.

Description of Model

Coverage and Definitions

The coverage is global. The model focuses on some 330 giant fields, but covers all types of oil, except for CTL, GTL and biofuel.

Demand modelling

Demand is not modelled. The IEA 2006 assumption of demand growth of 1.4% p.a. is assumed in comparing the model's forecast "unfettered production" peaks, under various scenarios, with expected demand growth.

Supply Modelling

The "Uppsala Giant Field" model (Robelius 2007) is a detailed bottom-up model by field for some 330 giant fields, and bottom-up by field for some other categories such as new offshore and Orinoco heavy oil, and (by project) the Canadian tar sands. Giant fields are defined here as either giant fields *sensu stricto* (URR > 0.5 Gb) or those which have produced over 100,000 b/d for at least one year during their production history. For the other categories of oil, more generalised assumptions are made.

Detailed data on giant fields were assembled from a variety of sources. The study worked with three databases: Giant fields (GF), for which the main source was the AAPG; Giant field production (GFP), for which the main source was *Oil and Gas Journal* and the AAPG, although DTI, NPD, NNPC and Pemex also contributed; and

Oilfield News for existing fields and especially for new projects expected to come on stream (main source Schlumberger). A wide range of data sources was consulted, mostly public but also proprietary, with the data being collated and compared to yield the final datasets used. Missing data for field production were estimated by interpolation and judgement.

Modelling differs by category. Giant fields were modelled individually, driven by the published URR for each field. Managed field exponential decline was modelled for three rates, of 16%, 10% and 6% p.a.. Production was assumed to fall until reaching a low, economic threshold rate, below which production ceased. The remaining potential production was then put into a "potential reserves growth" category. Each giant field was modelled as either on plateau or already in decline, depending on its accumulated production to date, its URR, and the chosen decline rate.

Other categories of oil that may fill the foreseen gap between current fields and future demand (i.e. new supply not from giant fields) were modelled separately. Categories include deepwater oil production for all field projects (by field), all oil sands projects in Canada (by project), current and probable projects developing Orinoco heavy oil, future production from Saudi Arabia, and other known future major oil field developments. There is no detailed modelling of YTF, NGLs (assumed to plateau at 10 Mb/d) and the possible contribution from technology (for details see the model author's report). The potential impact of oil price on future exploration and production was examined, but considered to make only a minor contribution to the date of peak, based on the recent reported experience of some of the major IOCs.

The model was run for four scenarios (Best case; Standard, high and low; Worst case), and with and without a constraint set by the assumed demand growth rate. The findings (p.136 of Robelius) were: "*The worst case scenario shows a peak in 2008, while the best case peaks in 2013 although at a higher production level. The production in the best case scenario increases more rapidly than a future demand growth of 1.4 per cent. Therefore the production can be adjusted to follow the demand growth, resulting in postponed peak oil to 2018. Thus, global peak oil will occur in the ten year span between 2008 and 2018.*"

<u>Known projects</u>

Known projects are listed specifically.

<u>Undeveloped Discoveries and Reserves</u>

It is assumed that such fallow fields are not modelled explicitly.

<u>YTF</u>

YTF is not modelled explicitly. Because the model finds the peak date to be close, only identified projects are modelled. This may be seen as a criticism of the model.

<u>Technical Improvements</u>

Reserves growth is included as a factor for big fields, but Robelius points to the long-term trend of falling discovery rates (by volume), and the consequent dominance of giant fields in setting the data of peak production, to support the view that technology gain will contribute little to setting the date of global peak.

Peak

The global peak of all-oil production (excluding synfuels and biofuels) is calculated as between 2008 and 2018.

URR

Not given explicitly, but a URR is implicit in the model.

Decline Rates

Based on examining plots of production vs. cumulative production for big fields, on a log basis, three field managed decline rates are modelled, namely 16%, 10% and 6%[39].

Summary

The Uppsala (Robelius) model is a detailed model, driven by large fields but including all oil. The authors justify their focus on big fields by their observation that the world's 500 or so largest fields (out of a total of ~50,000) contribute 60% of current production, and 65% of estimated URR.

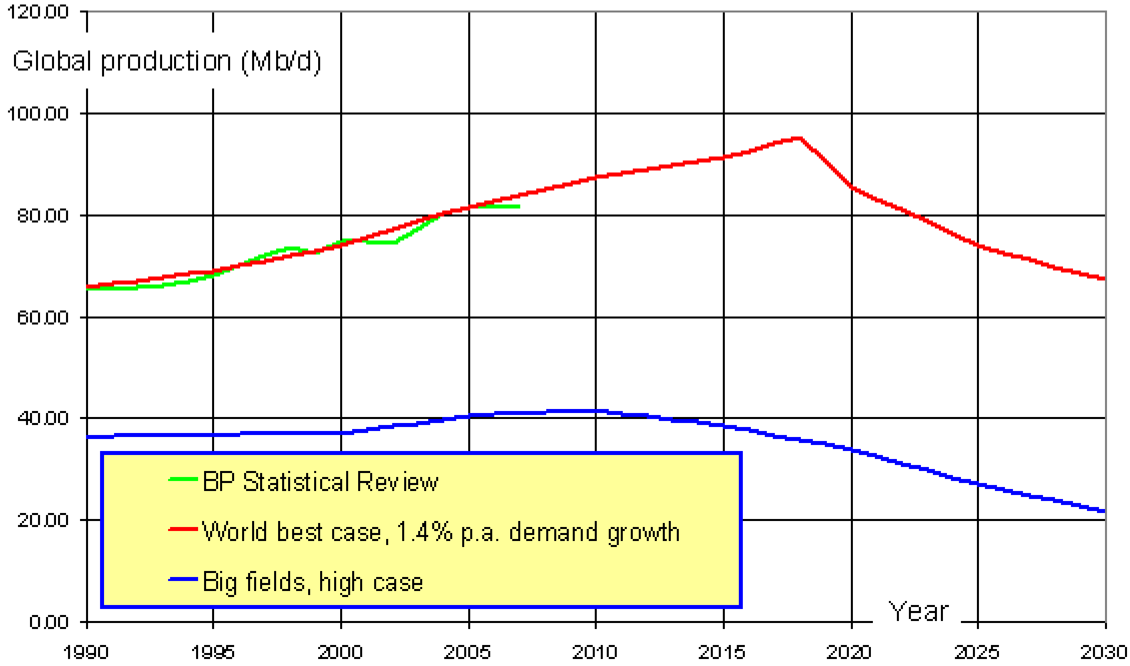
The model does not cover synfuels or biofuel. Concern may also be expressed that it takes a conservative view of both YTF and reserves growth. However, the authors argue that with the forecast global peak so close, these factors, though probably important in the longer term, are unlikely to impact the date of peak significantly. The model uses both optimistic and pessimistic URR values for individual big fields where there is a range.

We highlight here a question over the completeness of past annual production data for some of OPEC's Middle East fields, which are among the world's largest (Simmons likewise has said it is hard to get these data). We understand that industry data sets have gaps in these data, which may indicate either no production or no data. We are unclear how appropriate it is in such cases just to interpolate, or smoothly decline, the production data for these fields, given the production quotas that have been applied to some of these fields at certain periods. However, the Uppsala authors feel that this issue is subsumed by modelling both the highest and lowest values for URR in these fields.

[39] The University of Uppsala has subsequently published a detailed study of forecast Canadian oil sands production, and several studies on giant oil field behaviour:
Höök, M., Söderbergh, B., Jakobsson, K. and Aleklett, K. The evolution of giant oil field production behaviour. Accepted for Natural Resources Research.
Höök, M., Hirsch, R. and Aleklett, K. Giant oil field decline rates and their influence on world oil production. Accepted by Energy Policy.
Höök, M. & Aleklett, K, 2008: "A decline rate study of Norwegian oil production". Energy Policy 36, 4262-4271.

On global URR, Robelius used some data from the model of Anders Sievertsson, who in turn worked closely with Campbell's model, so there may be a degree of data alignment here.

Figure xxxii: Uppsala model of global oil production



Miller Oil Supply Model

Author: Richard G. Miller

Description approved? Yes. Miller is principal author of this report

Date of model: 2008, updated annually since 2001

Study references: Not published but pre-print available[40]

Coverage: Global, Oil

Basis: A pure bottom-up model, extrapolating and compiling future production field by field. To this are added contributions from known projects, known but undeveloped discoveries, modelled YTF and modelled technical improvement (cf. reservoir growth)

Global production data source: *Oil & Gas Journal*

2007 global daily rate: 73.3 million b/d[41]

Data sources: IHS global field level database; Oil & Gas Journal annual production data; IEA; US EIA; other published data and information sources

Definition of oil:

- By location/setting: No
- Condensate and NGLs: Some condensate (following *Oil & Gas Journal* standard); no NGLs
- Medium/light: Yes
- Heavy (10-26° API) Yes
- Oil sands: Yes, Canada only
- GTL: No
- CTL: No
- Biomass: No

Peak Date: 2019 (unlimited investment); 2013-2017 in practice

Peak daily rate: 110 million b/d (unlimited investment); 84-90 million b/d in practice[42]

[40] "Global Oil Supply to 2030", accepted by Marine and Petroleum Geology October 2004 when the author worked for BP Exploration, subsequently withdrawn by author
[41] Uniquely low because Miller uses *Oil and Gas Journal* data which exclude NGLs and some condensates
[42] Low for reasons noted in footnote above

Reserves definition: Proved + Probable

URR: 2800 Gb

Global YTF: 227 Gb conventional oil

Reserve growth: Yes – modelled annual production increment

Comment: Miller's model does not take economic limitations into account, and indicates the supposed maximum theoretical production that could be reached with unlimited investment. The actual achievable peak height and date are subjective estimates based on this theoretical curve.

Description of Model

Coverage and definitions

The model is global in scope, and includes Canadian oil sands and all oil that can flow naturally. The inclusion of condensates is difficult because *Oil and Gas Journal*, which is used as the guide for country totals, includes some but not others; decisions on its inclusion are therefore taken on a field-by-field basis. Miller has taken an annual "snap-shot" of his forecasts to show how well they matched reality.

Demand modelling

Miller's model does not use forecasts of price or population-based demand growth. Future demand is modelled as simple 1% and 2% p.a. exponential increases, but only to examine how this affects the date when the assumed demand exceeds supply. The demand starting point is 72.9 million b/d in 2006[43]. A 2% long-term growth in demand is thought to be more appropriate because of the long and rapid demand growth expected primarily in China and India.

Supply Modelling

Miller extrapolates the future production for the most significant fields and all declared future projects in each country, out to 2030. The definition of what constitutes a significant field depends upon the country, but in total some 3,300 fields are modelled individually. The future production profile of each field is constrained by its P50 reserves (where known) and the historical decline rate. These significant fields are summed by country, and the sum is then raised to the national total declared annually by *Oil and Gas Journal*[44] by ascribing the difference to small fields ("other"). Miller finds that the total of the significant fields alone sometimes exceeds the *Oil and Gas Journal* total national estimate, and the model's global total for 2007 is therefore about 1 million b/d more than the OGJ total.

[43] Based on Oil and Gas Journal production data which are some 10 million b/d or more below most others.
[44] Oil and Gas Journal was the most comprehensive public source available for field data when the model was first built

For certain countries, notably China and onshore USA and Canada, the production data and reserves for individual fields are often not freely available, and they are therefore consolidated into basin, state or province units.

Current fields

Future field production forecasts are constrained by both estimates of the remaining 2P reserves and the historical decline rate, but these numbers may not be consistent. Some fields, if extrapolated at past decline rates, will never produce all their apparent reserves, while others apparently have insufficient reserves to support their production profile[45]. Each case is resolved individually according to the available information. The bias is to produce all the notional reserves even when the observed rate of decline has to be reduced to achieve this.

The model does not assume any redevelopment of an abandoned field with remaining reserves, except where this has actually happened.

Known projects

The modelling of future output from active development projects is straightforward. Forecast average output is reduced slightly from the announced maximum, to account for normal maintenance down time, accidents, bad weather and other interruptions.

Undeveloped discoveries and reserves

The possible production from all significantly-sized fallow fields is modelled and included, phasing the possible development of a country's fallow fields over a period of some years. Miller notes that many of these fields will probably never be developed, due to their size, remoteness or geological complexity, but exactly which fields will remain undeveloped cannot presently be identified. The potential production from all these dormant fields world-wide produces a sharp short-term rise in Miller's model that history shows is never realised.

Yet-to-Find

Miller originally estimated YTF for every country as of the year 2000, using a subjectively modified view of the USGS estimates. The original model assumed that 5% of this will be discovered each year for the first 6 years, 4% per year for the next 6 years, then 3%, 2% and 1% annually for successive 6 year intervals. The remaining YTF today is estimated at 227 Gb. The YTF estimates have subsequently been more objectively revised whenever a country's general rate of average annual discovery is significantly greater or less than the forecast, so that the modelled discovery rate is in line with actual discovery.

The speed at which new discoveries are expected to come on stream (the lead time) depends upon their size, location and country. Offshore fields take a minimum of 4 years in countries such as Angola or Brazil, but it can be as little as 1-2 years in on-shore areas, or where there is a dense existing infrastructure and discoveries are generally small.

[45] One cause of apparent over-production when compared to declared reserves is the aggregation of production data from several adjacent fields.

New discovery fields are classed as small onshore, large onshore, small offshore and large offshore, with global average annual decline rates of 5%, 3.7%, 8% and 4.6% respectively. In light of recent reports[46] these values will be adjusted upwards in the next annual model.

This YTF model assumes that all discoveries are brought into very early production. Even in countries where no exploration is taking place, the YTF is decreased annually.

Technical Improvements

A 0.2% global production increment is added annually (i.e. 0.2% in year 1, 0.4% in year 2 etc.) to account for technical improvements. This figure is based upon unpublished information studies by Francis Harper, who calculated a figure of approximately 0.15%. The increment is effectively an empirical combination of improved recovery and reserves growth.

Peak

The model shows a potential production peak in 2019 at 110.4 mmb/d. This would be some 10 million b/d higher if the model used the current global production estimates from BP or World Oil rather than Oil and Gas Journal, and this is shown as the "re-based" curve on the plot below. A theoretical excess of production over demand could extend from 2009 to 2024, and totals 85 Gb.

The excess potential production can be interpreted in two ways. First, Miller believes that all of this, and a little more beside, is based on discoveries which will always be uneconomic to develop, and this excess can in fact never be realised. This would bring the peak forward. Second, if any of this excess potential *can* be realised, it will be delayed until it is required, which would defer the peak. Miller concludes, from a review of previous annual forecasts, that the production peak is most likely well within 5-10 years, at little more than current production levels.

Comparisons of the previous annual forecasts show that the potential peak has moved ahead by a year each year. However, the peak height has been relatively stable over the past four forecasts, as has the volume under the curve (the URR), and the post-peak aggregate decline has consequently steepened. Miller regards this as evidence that the model is relatively stable, that the URR is about right, and that post-peak production decline will finally be somewhat steeper than presently indicated.

URR

The model does not directly require a URR estimate.. By simple extrapolation and using published historical production data, total production by 2100 will have been 2655 Gb, and the production rate will be 2.9 billion b/y (7.95 million b/d), so a URR of around 2800 Gb is appropriate.

Decline rate

[46] Recent CERA and IEA estimates of decline, and Miller's own recent estimates

Modern non-OPEC fields are typically engineered to reach the highest possible plateau very quickly, and subsequently decline very quickly, which provides the best return on investment. Annual decline rates of up to 20% p.a. are now quite common in small offshore fields, compared to large old fields where decline is only a few per cent. Decline rates are estimated for new fields from typical regional values. The forecast aggregate global decline in post-peak oil production from 2025 is 3.3% p.a.. This estimate has been slowly increasing with each annual run of the model.

Summary

Miller's model does not forecast actual future oil production, but the maximum possible future production if all fallow fields and future discoveries were to be developed as briskly as technically possible, regardless of cost. It therefore exceeds the demand forecasts for over a decade.

This model was initially created in 2001 for internal reference within BP, but does not represent BP's view. It is continually updated, and a snapshot kept every year to analyse secular changes. Uniquely among the models, Miller uses *Oil and Gas Journal* historical global production data, which are some 10 million b/d lower than the BP Statistical Review, EIA or US IEA estimates (see Table 2.1). It is re-based here to align it with BP's historical data.

This is a "bottom up" model. It extrapolates individually the future annual production of significant current oil fields to the year 2030. Smaller fields are compiled into a single group by country for extrapolation. Canadian oil sands are included. Forecasting for each field is constrained by its 2P reserves and/or historical decline rate, where these are known. It includes future production from declared development projects, and importantly all significant dormant discoveries (fallow fields). After the fields are summed by country, the model adds the expected production from future discoveries (the YTF), and a small annual increment to production ascribed to technical improvements.

By keeping past forecasts and noting their discrepancy from what has subsequently occurred, Miller has subjectively assessed the effect of reserves which appear to remain continually undeveloped, to reach a view on the likely timing and height of maximum global production.

Figure xxxiii: Miller's forecast of global potential oil production, re-based

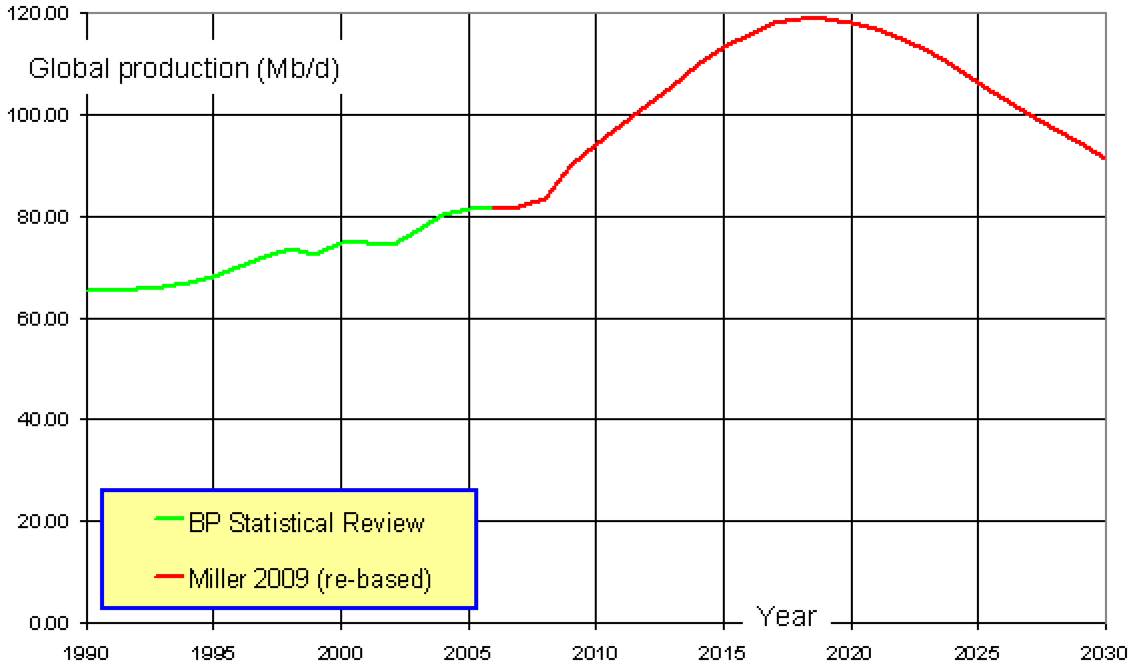


Figure xxxiv: Miller's forecast of United Kingdom potential oil production

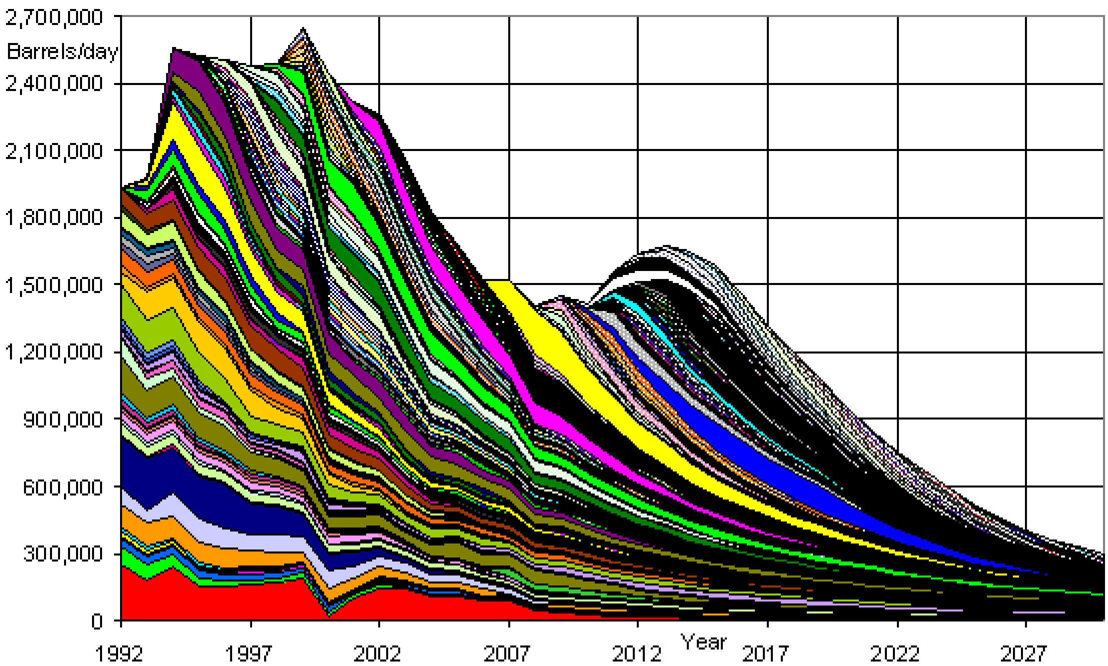


Figure xxxv: Miller's forecast of Unites States potential oil production

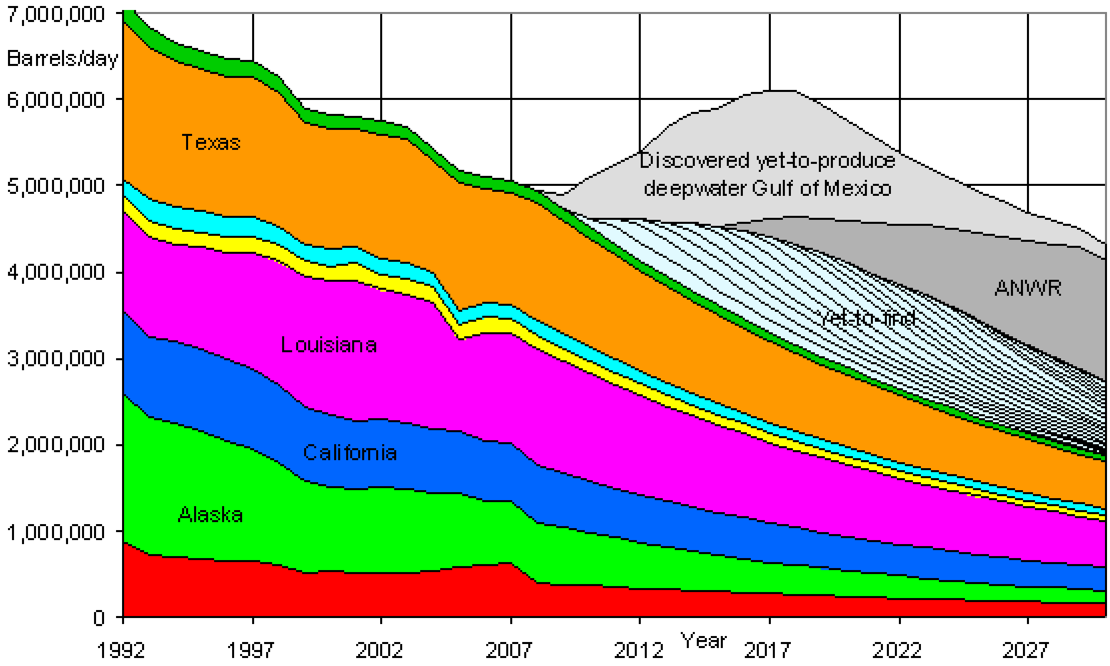


Figure xxxvi: Miller's forecast of Brazil potential oil production

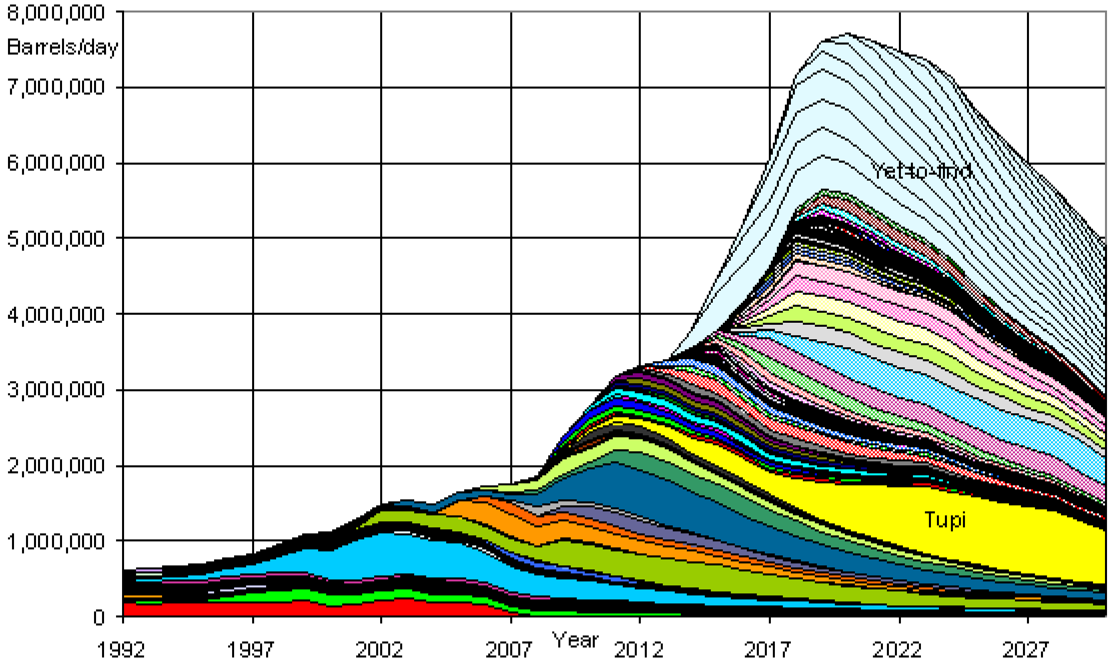


Figure xxxvii: Miller's forecast of Saudi Arabia potential oil production