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Petroleum Analysis Centre

# THE OIL AGE

## Understanding the Past, Exploring the Future

# Background & Objectives

This journal addresses all aspects of the evolving Oil Age, including its physical, economic, social, political, financial and environmental characteristics.

Oil and gas are natural resources formed in the geological past and are subject to depletion. Increasing production during the *First Half* of the Oil Age fuelled rapid economic expansion, with human population rising seven-fold in parallel, with far-reaching economic and social consequences. The *Second Half* of the Oil Age now dawns.

This is seeing significant change in the type of hydrocarbon sources tapped, and will be marked at some point by declining overall supply. A debate rages as to the precise dates of peak oil and gas production by type of source, but what is more significant is the decline of these various hydrocarbons as their production peaks are passed.

In addition, demand for these fuels will be impacted by their price, by consumption trends, by technologies and societal adaptations that reduce or avoid their use, and by government-imposed taxes and other constraints directed at avoiding significant near-term climate change. The transition to the second half of the Oil Age thus threatens to be a time of significant tension, as societies adjust to the changing circumstances.

This journal presents the work of analysts, scientists and institutions addressing these topics. Content includes opinion pieces, peer-reviewed articles, summaries of data and data sources, relevant graphs and charts, book reviews, letters to the Editor, and corrigenda and errata.

If you wish to submit a manuscript, charts or a book review, in the first instance please send a short e-mail outlining the content to the Editor. Letters to the Editor, comments on articles, and corrections are welcome at any time.

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# Editorial

Welcome to the third issue of this journal. As mentioned previously, the main emphasis of these first few issues is on the physical aspects of global oil and gas supply, and in particular on oil and gas forecasting.

In the section of peer-reviewed articles, this time only one oil forecast model is described, that of the bottom-up by-field 'BUEGO' model produced by Christophe McGlade. This is based on the by-field model of Richard Miller described in the previous issue, but where McGlade's model has extensive demand and economic aspects incorporated. Moreover, while Campbell's oil forecast model described in Issue-1 incorporated energy-return factors, McGlade's model includes calculations for - and sets limits on - $CO_2$ emissions.

Also on the topic of global oil supply, this issue contains two articles on ultimate recoverable resource ('URR') estimates for oil. One of these articles is by Steve Andrews and the late Randy Udall, and the other is by myself. The size of the URR is a key controlling factor in how much oil the world can produce.

On wider topics, the 'opinion piece' in this issue is an article by Colin Campbell on the energy future that Ireland faces. It is the intention that this journal will carry further articles on the energy challenges that have been faced, or will likely be faced, by specific countries.

Please note that there is no 'Charts' section in this issue, due to the need to catch up with publishing deadlines; it is the intention that this feature will return in future issues.

*- R.W. Bentley, September 2015.*

# The Oil Age in West Cork

C.J. CAMPBELL

Oil and gas are finite natural resources formed in the geological past, which means that they are subject to depletion. This is a critical subject for the world, and indeed for the survival of *Homo sapiens*. It remains to be seen if he will be as wise as his name implies in addressing the issue to avoid extinction, the fate of many species in the geological past when they exhausted the resources of the niche in which they lived. Every region, including West Cork, needs to prepare for the unfolding situation.

## An Historical Outline

In earlier years, the people of West Cork relied on the energy coming from their muscles and those of their draught animals, supplemented by a little wood and turf from the hills with which to cook and heat their homes. It was not plain sailing as bad weather could damage a harvest, causing hunger. The potato was introduced into Europe from the Americas in the Middle Ages and became a particularly vital crop for the people of Ireland, supporting each community including West Cork. But in the middle of the 19th Century it was struck by *Phytophthora infestans,* a blight that caused a devastating famine. The country's population fell by death and emigration from its maximum of almost 8 million in 1845 to less than 5 million in 1900. Fortunately, it has barely grown since, despite some immigration pressures.

By chance, this famine only slightly preceded the discovery of commercial oilfields, especially in Pennsylvania and on the shores of the Caspian. Oil provided a radical new source of energy ushering in the so-called *Oil Age* that changed the world in remarkable ways. At first, it was used as a fuel for lamps adding an evening to the working day for many people, but then in the 1860s came the *Internal Combustion Engine* when a way was found to inject the fuel directly into the cylinder of an engine, making it much more efficient. The first automobile took to the road in 1882, and the first tractor ploughed a field in 1907. This is not as long ago as it might seem having been witnessed by the father of an old man living today. These developments led to the rapid expansion of manufacturing, transport and trade allowing the world population to grow seven-fold during the *First Half of the Oil Age*. Agriculture became very dependent on this new fuel having been recently described as a process that turns oil into food.

Ireland, then part of the United Kingdom, whose very name implies that it was made up of different factions, lacked sufficient coal deposits to support early industry, and largely remained a country of peasant farmers working land owned by privileged landlords. The famine increased a sense of resentment, especially as food continued to be exported, prompting the people to seek greater independence. These pressures culminated with the establishment of the so-called Free State in 1922, although the province of Ulster, which had been largely settled by immigrants from Scotland in earlier years, was excluded.

The world has enjoyed an epoch of economic growth over the past century, although suffering from two devastating world wars. Germany had previously been made up of small duchies and principalities but the *Industrial Revolution* led to unification and the quest for a trading empire to rival that of Britain.

The growth of trade was accompanied by the rapid development of the financial system, as banks came to lend more than they had on deposit confident that *Tomorrow's Growth* was collateral for *Today's Debt*. The United States emerged after the Second World War as the premier world power. The dollar became the principal currency for world trade which delivered a handsome reward. Previous empires had accepted some responsibility for the territories they controlled but the US concentrated on finance and commerce. Prosperity also came to Ireland, partly encouraged by the tax treatment of foreign companies, and culminated at the end of the last century with the boom of the so-called *Celtic Tiger*.

The *First Half* of the *Oil Age* was an epoch of general prosperity. Even remote villages in West Cork are choked with traffic, while the sky above is cut by vapour trails from airliners crossing the Atlantic, all such transport using oil for fuel. A culture of consumerism developed, with shops selling everything from high-heeled shoes and bow ties to corn flakes. Supermarkets and chain stores took the place of village markets. Although wealth was unevenly distributed, most people assumed that their circumstances would progessively improve in the years to come. While there were many scientific and technological achievements, the underlying driver of this chapter of history was oil-based energy. As even some economists now come to recognise, it is energy not money that drives economic growth.

## The Status of Oil and Gas Depletion

Oil and gas from surface seepages have been known since Biblical times, having been used to caulk boats, but the opening of the first oilfields in the 1860s led to the rapid growth of the oil industry with impressive scientific and technological progress over the past century. The origin of oil came to be understood. In fact, the people of West Cork are well placed to understand the circumstances by viewing Lough Hyne. It is a stagnant pool of water linked by a narrow passage to the sea allowing marine life to enter. In the summer, the surface waters heat up and circulation falls. Anoxic conditions develop at depth such that algae and other organic remains are not oxidized.

The bulk of world supply comes from two epochs of global warming around 90 and 150 million years ago when such stagnant lakes and seas formed where continents moved apart on the back of deep-seated convection currents in the Earth's crust. The compacted organic material, known as *kerogen*, lying on the floor of the lakes and seas was in turn buried below sands and clays washed in from adjoining lands. When buried to depth of about 3000 meters it was heated enough to be converted into oil. Gas was formed in a similar way but from more carbonaceous material as found in the deltas of tropical rivers, and also from the breakdown of oil that was overheated by deep burial. Once formed, the oil and gas migrated upwards to zones of lesser pressure, provided that there were fissures or permeable rocks through which to move. Some oil escaped at the surface, where it was degraded, with the tar sands of Canada being a well known example, but some was trapped in dome-like geological structures provided that they contained a porous and permeable rock, such as sandstone, to act as a reservoir, and were also sealed by a layer of overlying clay or salt.

Much of the world's oil was found by geologists mapping remote areas with technology no more advanced than a hammer and hand lens, but later came geophysics whereby an explosive charge was released and recorders measured the time taken for echoes to return from deeply buried rock surfaces, which could then be mapped in detail allowing smaller and more subtle traps to be identified. Geochemistry too provided new detailed knowledge of the origin of oil, as outlined above.

Once a prospect was identified, it had to be tested by an exploration borehole, known as a *wildcat*. If successful, the new oilfield was developed by closely spaced producing wells and connected by pipeline, all of which involved massive investment. For obvious reasons, the more prospective, accessible and profitable areas were exploited first. As the onshore possibilities dwindled, the industry turned its attention offshore, even into deep water. While oceans cover much of the Planet's surface, relatively few areas beneath them have the right geological conditions to deliver.

A major discovery in 1908 in the foothills of the Zagros Mountains of Iran opened up the area around the Persian Gulf. It proved to be the most profilic oil province, holding almost 40% of the world's conventional oil. In earlier years, the industry was dominated by seven major international oil companies, but national State-owned companies later took dominant positions in most of the principal producing countries.

For Europe, the northern North Sea between the UK and Norway was found in the 1960s to contain a rich belt of effective oil source-rock, laid down around 150 million years ago. The peak of oil discovery in 1974 was followed by a corresponding peak of production in 1999 at 6 Mb/d (million barrels a day) which has since fallen to 2.5 Mb/d, being set to continue to decline at about 5% a year. One barrel contains 36 UK gallons. Ireland is not well endowed, lacking this prime oil source-rock, although a number of small finds, fed by less effective sources, have been made. The Corrib Field, off County Mayo, even contains gas derived from the breakdown of deeply buried coal deposits.

World discovery peaked in 1964 and delivered a corresponding peak of production of *Regular conventional oil* in 2005. This in turn prompted the industry to turn to ever more difficult sources, which have much lower net energy yields. A debate rages as to the precise date of the peak production of all categories of oil, which is imminent, but misses the point when what matters is the vision of the long decline on the other side of it. The difficulties in assessing the position arise because there is no standard classification of the various categories which is a cause of much confusion in public databases. Information on so-called reserves is also unreliable in many countries, especially the OPEC members, due to political and economic pressures. Figure 1 describes the overall position, showing production in billion barrels per year, with gas given in terms of calorific oil equivalent.

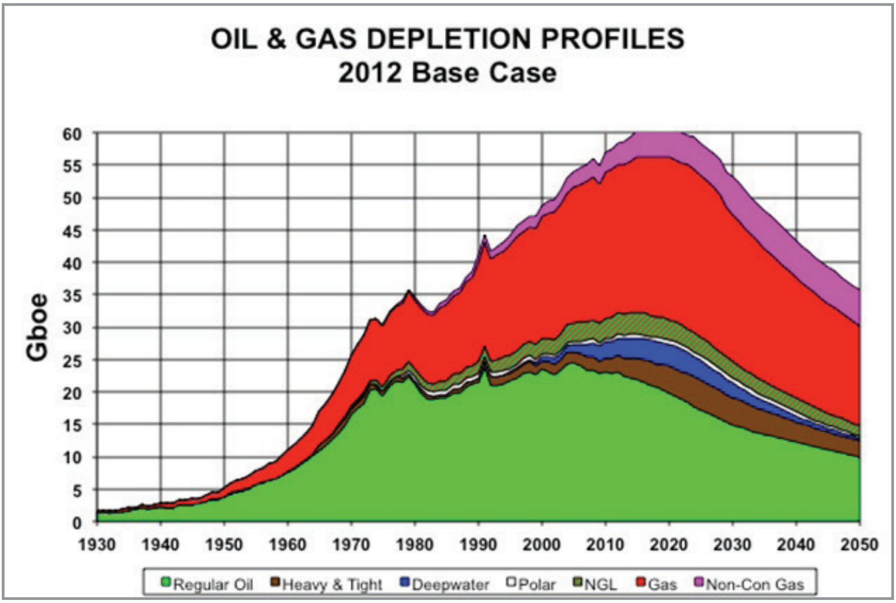


**Figure 1:** Oil & Gas Depletion production in billion barrels per year, with gas given in terms of calorific oil equivalent

## The Second Half of the Oil Age

It is evident from the foregoing that the *Second Half* of the *Oil Age* dawns. The decline in this critical source of energy will clearly have a colossal impact, and the transition threatens to be a time of great tension as indeed already witnessed by demonstrations, riots and revolutions around the world. People facing soaring food prices and unemployment understandably become resentful and blame their governments, not realising that the circumstances are ultimately imposed by Nature.

Oil prices, which had averaged $26 a barrel (quoted in terms of 2014 dollars) over the last century, reached almost $150 in 2008 following the peak of *Regular conventional oil* production three years earlier. This in turn prompted a major economic recession cutting demand. The financial structure of the world was seriously affected with several prominent banks failing. But the fall in demand put pressure on oil prices which have fluctuated widely over the past few years. In the United States, whose conventional production peaked in 1970, the high prices prompted a turn to so-called *fracking* to produce *Tight Oil and Gas.* It involves drilling highly deviated wells to run parallel with oil- and gas-bearing rocks lacking sufficient natural porosity and permeability to be normal reservoirs. Fluids under high pressure are then injected to fracture the rocks adjoining the wellbore. The wells, having a low net energy yield, are expensive and short-lived, with $80 a barrel being widely seen as the minimum oil price to make them viable. The more promising areas, termed *sweet spots,* were naturally tapped first, as soon as they could be identified. The resource in the ground is enormous and unquantifiable, but it is a very different source of energy from that which powered the *First Half* of the *Oil Age.* A recent fall in prices to around $50 a barrel was triggered when Saudi Arabia decided to ignore its OPEC obligations to cut production to support price. Its motives are obscure with a possible factor being the recent death of King Abdullah, who once said that he wished to leave as much oil as possible in the ground for his grandsons. Venezuela and Nigeria, which are also OPEC countries, are suffering a heavy loss of revenue with serious social and political implications. It is too soon to forecast the future price range but the current low level is certainly anomalous and probably short-lived.

It cost Saudi Arabia less than $30 a barrel to produce its oil, so when they sold it for over $100 that was *unearned income* on a massive scale. Much of the surplus was no doubt placed with international banks who in turn lent it out charging interest and creating yet more money out of thin air. It is understandable why usury was condemned as a sin in earlier years by Christian religions. In fact, the low prices make a bad situation worse because they increase demand, accelerating depletion, and also lead to the premature abandonment of aging fields that are no longer profitable, leaving less oil and gas for the future.

It is a large and complex subject that cannot be covered fully here, but there are some indications of positive reactions as people again come to think that they should rely more on whatever their particular region can support. The Transition Town Movement, which was formed in Cork and now has a world following, provides a strategy for localism, including local currencies. Recently, the government of Britain delegated greater financial control to the major cities. Scotland came close to seceding from the country in a recent referendum, and there are similar pressures in Spain and Italy. The European Union may see some of the current members, such as Greece, which is heavily in debt and facing a serious economic recession, withdraw. The people of the Eastern Ukraine, many having strong links with Russia, also wish to go their own way, following a serious economic downturn. The barren lands of North Africa and the Middle East are in turmoil. Immigration becomes a source of tension in these circumstances, and governments are increasingly being forced to restrict it or try to do so.

Ireland is relatively well placed with a population of only 4.6 million and plenty of green fields. It also has considerable scope for tapping renewable energy from hydropower, tides, winds, waves, solar panels, and anaerobic digestion, a process that converts urban and agricultural organic waste into methane that can be used to generate electricity. Indeed, the Shannon Hydroelectric Scheme, which was built in the 1920s to give the newly independent country its own source of power, sets an important precedent.

Ireland was one of the first countries in Europe to face the recent world economic recession, but the worst seems to be over. It would probably be well advised to reintroduce its own currency, to be managed responsibly by a national bank. While its major cities face challenges in adapting to the changing circumstances, the people of West Cork, who have a strong co-operative spirit, are relatively well placed. They can grow much of their own food and catch fish from the adjoining waters. They can even heat their homes with a highly efficient new wood-burning stove, the *EirEco*, which was designed and is marketed in West Cork.

# An introduction to the bottom-up economic and geological oil field production model 'BUEGO'

CHRISTOPHE MCGLADE*

## 1. Introduction and motivations

This paper describes the 'Bottom Up Economic and Geological Oil field production model' ('BUEGO'). BUEGO has a detailed field level, bottom-up representation of the supply side of the oil market and is designed to allow a precise analysis of the characteristics of oil supply. It can, for example, be used to analyse production rates from individual countries, production by onshore and offshore fields including the water depth of offshore fields, production by the dates on which fields were discovered, and production by individual field status (currently producing, undiscovered, fallow etc.).

Few models exist that take account of both supply and demand sides, however an even smaller subset exist that have a detailed field-level representation of oil production that can also take account of economic factors. Two models that do so are produced by the IEA (2012) and the EIA (2011). The IEA, for example, indicates that its 'World Energy Model'

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relies upon a *'detailed field-by-field analysis'* and *'decision mode of the industry in developing new reserves by using the criteria of net present value of future cash flows'* (IEA, 2012).[1]

Jakobsson et al. (2012) also recently proposed a theoretical model that addressed both the geological and economic (or supply and demand) sides of oil production but did not apply this to any real data or produce any scenarios of future global oil production. Given the paucity of other similar models, particularly the absence of other models in the academic literature, BUEGO is therefore well placed to contribute to the debate over future prospects for oil production.

BUEGO generates an oil price in each year to ensure that sufficient new capacity is brought on-line from projects with positive net present value to satisfy oil demand levels provided by the integrated assessment model 'TIAM-UCL'. The TIMES Integrated Assessment Model in UCL is a technology-rich, bottom-up, whole-system model that maximises social welfare under a number of imposed constraints. It models all primary energy sources (oil, gas, coal, nuclear, biomass, and renewables) from resource production through to their conversion, infrastructure requirements, and finally to sectoral end-use. It is a modified version of the ETSAP-TIAM model developed and maintained by the Energy Technology Systems Analysis Programme (ETSAP) (Loulou and Labriet, 2007). Detailed descriptions of TIAM-UCL can be found in McGlade and Ekins (2015) and Anandarajah et al. (2011).

Nevertheless, calculated projections of oil price should from BUEGO not be read as *forecasts* of oil prices over the next 25 years - as explained in detail below they are predicated on a series of assumptions under a range of different scenarios - some of which are very unlikely to hold over this time period. Nevertheless, a key contribution of this model, and an expansion on models such as the IEA's World Energy Model, is its ability to examine changes in production and oil price under different demand scenarios as well as under different geopolitical or institutional events.

This paper is set out as follows: Section 2 first examines the underlying geological model upon which BUEGO is based. Section 3 then explains the new model concept, changes that have been made to the existing model, and new features that have been implemented. Section 4 presents some example results and finally Section 5 concludes.

1 Unfortunately many oil-sector specific modelling assumptions are not set out explicitly by the IEA including, for example, how political constraints are handled.

## 2. Existing model

BUEGO is an extension of a model originally produced by Richard Miller, described in Bentley et al. (2009a) and its annex Bentley et al. (2009b). Miller's bottom up model contains detailed historic field- level production data from 1992 – 2010, and provides estimates of the maximum theoretical production from the most significant oil fields globally within a total of 133 countries from 2010 – 2035. Miller is an ex-geologist from BP and has estimated these maximum flow rates, the years for which peak production can be maintained (i.e. on a plateau), and decline rates for each individual field based on a combination of extrapolated historical production rates, each field's proved and probable (2P) reserves, and his expert judgement. Miller's database is updated annually with the details and results presented here relying upon the 2010 version.

The model includes fields that are currently (as of 2010) in production (a total of 2855 fields), those that have been discovered but are currently undeveloped (a total of 565 fields), and undiscovered fields (a total of 3580 fields). It includes production from all major conventional oil fields, including gas condensate fields, extra-heavy fields (predominantly in Venezuela), natural bitumen projects, both mining and in situ, in Canada, and Arctic fields.

The undiscovered resources present in the original model are based upon Miller's judgement and were derived predominantly through modifying the USGS 2000 World Petroleum Assessment ('WPA') (Ahlbrandt et al., 2000). A total of 225 Gb undiscovered resource (excluding NGL) is included, distributed amongst all 133 countries. A discovery process is specified to simulate a reasonable discovery rate of this resource within each country. This stipulates that 5% of the total resource available in each country is discovered in each of the first six years, 4% is discovered in each of the next six years, followed by 3%, 2%, and 1% in six year intervals. The year in which production can first commence from the first undiscovered field varies by country but ranges from 2012 and 2016. Newly discovered fields are assigned decline rates of either 9% or 5.5% depending on their location and size.

Figure 1 provides the outlook for global oil production from Miller's model in its original form with production grouped by category. A large peak in global production in 2020 can be seen in this figure, and similarly large humps in production are exhibited by all individual countries. This arises because all fields in all countries are brought on-line as soon as they are available and run at maximum production levels for as long as possible regardless of required global demand or the investment necessary to make this happen. The fields brought on-line include many 'fallow' fields, which as defined previously in this work are discovered oil fields that have not been, and are not scheduled to be, brought on-line within ten years of their discovery. In its current form Miller's model can hence be interpreted as assuming a permanently high oil price that is sufficiently large to make all oil fields economic regardless of size, location, type, or demand. This is clearly unrealistic but the model data nevertheless provide an excellent basis for developing a detailed, bottom-up model capable of studying both supply and demand side effects.

## 3. Model concept and explanation

Three key changes that need to be made to Miller's model in order to produce more realistic scenarios of global oil production are that:

(a) a projection of demand must be incorporated;
(b) supply must only be brought on-line to satisfy this required demand; and
(c) only those fields that are economic at a given oil price can be developed or continue to produce.

Figure 2 summarises the algorithm that BUEGO follows in order to incorporate these modifications. The overarching premise of the model is that oil companies can choose whether or not to develop new oil projects depending on their net present values that in turn rely on the project potential, location, and the current oil price. The oil price is determined endogenously depending on required levels of demand and the supply available to meet this. The model base year is 2010 and the time horizon 2035.

The first stage shown in Figure 2 requires the creation of an 'underlying' production matrix (of production versus time for each country and each type of resource). This is the production only from fields currently in production, with each declining in future years at their specific decline rates. This matrix represents what would occur if all capital investment maintaining production at existing fields was to cease immediately and no new fields were to be brought on-line. This is called the 'natural' decline rate.

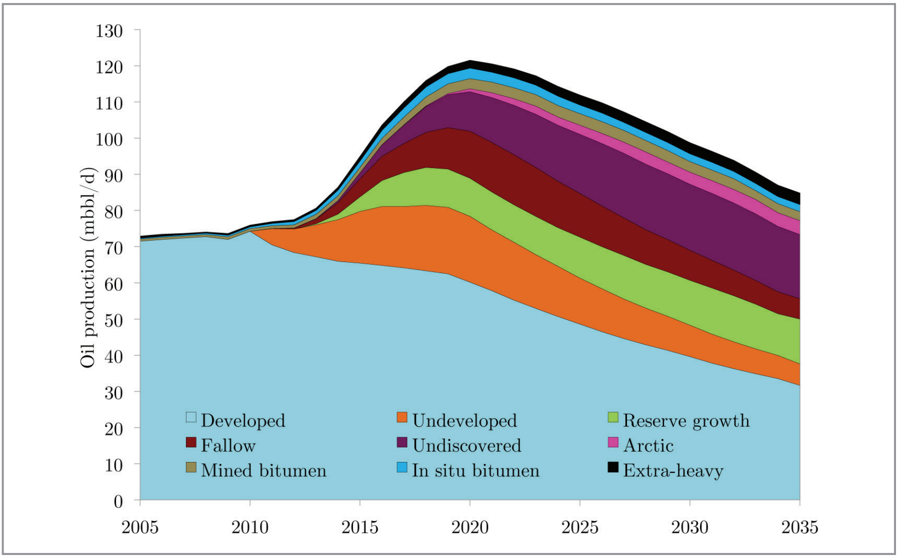



**Figure 1:** Unconstrained oil production from Miller's model grouped by category

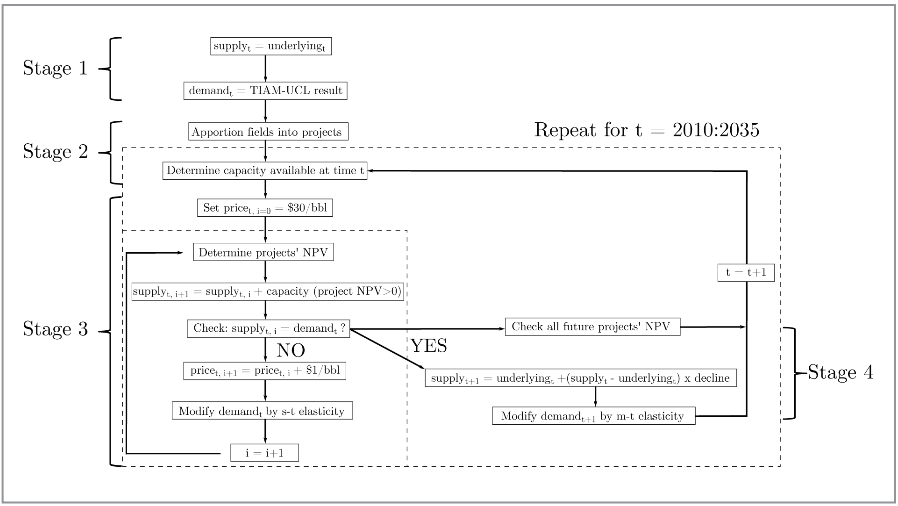



**Figure 2:** Schematic of BUEGO model process

**Notes:** *t* is the year with i the iteration. In each iteration the oil price is increased by a small amount.`s-t' and `m-t' stand for the short-term and medium-term elasticities.

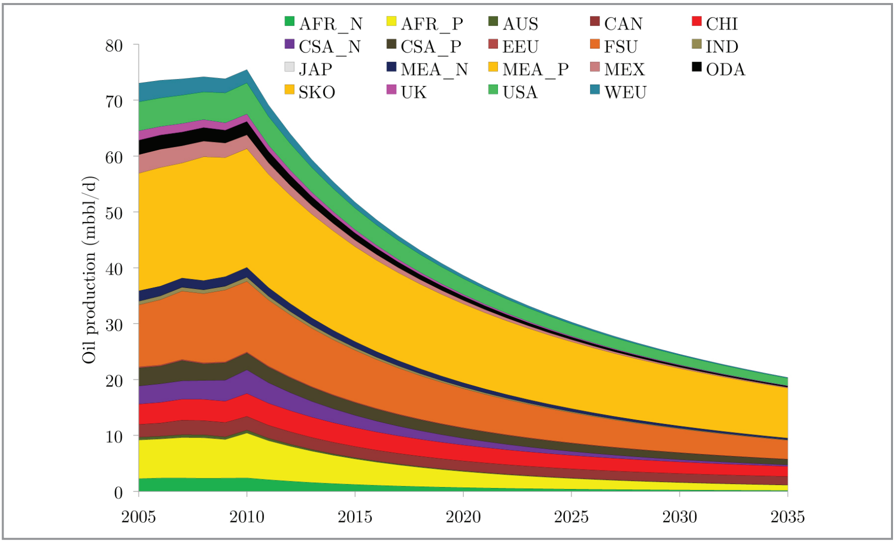



**Figure 3:** Graph of underlying production in BUEGO separated by region

**Notes:** Regions correspond to those used TIAM-UCL. The `N' and `P' subscripts indicate non-OPEC and OPEC countries respectively.

This underlying production matrix is presented in Figure 3 separated by region. The natural decline rate for each individual field is given from data in Miller's original model. The 2010 production weighted global and regional natural decline rates vary from 10.9% in Mexico down to 2.9% in the Middle Eastern OPEC region with a global average 7.3%.[2]

Demand scenarios are produced by TIAM-UCL and introduced into BUEGO as explained in Section 3.3 below. A number of the geological aspects of oil production have been incorporated into the upstream elements of TIAM-UCL through the use of region-specific annual growth and decline constraints. While the aggregated, regional nature of TIAM-UCL means that it will inevitably overlook some important factors that

2 For comparison the IEA (2008) estimated that the global natural decline rate was 9.0%, and that regional decline rates varied from around 18% in the OECD Pacific region to 5% in the Middle East. As well as potentially different decline rate assumptions for individual fields, this difference likely arises from differing aggregation of regions, differing types of average used (it is unclear whether the IEA has used an arithmetic or production weighted average), and differing base years.

affect oil production, its detailed modelling of all end-use sectors and its incorporation of fuel switching and substitution means that it is well placed to generate reasonable projections of oil demand under different scenarios.

Stage two calculates which oil fields and what capacity are available to be developed in the present year. The subtraction of the underlying matrix (from stage one) from the maximum theoretical potential matrix (as shown in Figure 1) yields a matrix of the maximum potential capacity additions available in each year in each field.[3]

Most fields ramp up to maximum production over a number of years. Some fields also require new infrastructure such as pipelines to be constructed, which may take a long period of time to construct, while undiscovered fields will obviously need to be discovered before production can commence. It is therefore necessary to prevent all of the available capacity for a given field coming on-line in a single year. It is assumed that any new capacity additions, no matter how small, must be made through a project, and each project must go though the sequential order specified in the capacity matrix i.e. each project must start at the beginning of its 'development cycle'.

For example, say that the capacity matrix specifies that a new project can add 20 kbbl/d capacity in the first year, 50 kbbl/d in the second year, and 100 kbbl/d in the third year. These three capacity additions over these three years are this project's 'development cycle'. If this project was to remain uneconomic for a number of years but then there was a major price rise making its net present value greater than zero, it is still assumed that only 20 kbbl/d capacity can come on-line in the first year after this rise, 50 kbbl/d in the second year, and 100 kbbl/d in the third year.

At stage three, an initially low oil price is specified. The model tests whether current supply from the underlying matrix is sufficient to meet the demand generated by TIAM-UCL. If it is, then the model moves onto stage four. If not it calculates the net present value ('NPV') of all oil projects available in that year to determine whether they are economic to construct or not i.e. whether an oil company would view the development of each project as profitable given the current oil price. The NPV

3 This process takes account of the fact that new capacity additions also decline over time.

calculation is explained in more detail in Section 3.2, but encompasses the field capital and operational costs, the country-specific tax regime, and the country-specific discount rate (Section 3.2.2).

If the NPV is greater than zero, the project is 'developed', and production commences. The model next tests whether this additional new supply is now sufficient to meet the demand for that year. If not, the oil price is increased by a small iteration (e.g. $1/bbl is shown in Figure 2), demand modified by the short-term elasticity of demand (the base price for which is also generated by TIAM-UCL), and this process repeated until either supply meets demand, or all possible capacity additions have been added. The minimum necessary price required for supply to match demand is set as the 'oil price' for that year.

The final step is to calculate the supply and the new capacity that will be available in the next year so that the above process can be repeated. All projects that have been brought on-line will produce a declining volume each year and so each project's decline rate is equivalent to the field decline rate in which that project is located. Demand in the next year is also modified by the medium-term elasticity of demand.

In parallel, the NPV of all future potential oil projects is determined given the oil price generated in the present year. If a future project's NPV is less than zero, the project cannot move along its development cycle, i.e. the date on which it can begin production is pushed back by a year. This models the behaviour that all future projects require the correct price signals for a suitably long time before development can begin. In the above example, say rather than new capacity being available in 2010, the earliest the first capacity addition (20 kbbl/d) can be added is 2013. If the oil price was low between 2010 − 2012 so that the project's net present value remained less than zero in these years, then even if there is a huge price rise in 2013, the first year in which production from the first capacity addition could come on-line would be 2015.

The model then moves onto the next year, beginning again at stage two, and the process is repeated for each year until 2035.

Some categories of oil are not explicitly included within BUEGO, specifically natural gas liquids ('NGL'), light tight oil, and biofuels. When studying the global supply of all oil, data for these categories are taken from TIAM-UCL and added onto the output of BUEGO.

Finally, apart from production constraints placed upon OPEC as discussed in Section 3.2.3, no other political constraints are placed upon production. This is an important assumption since some countries' production in the future may be hampered by poor government access and domestic pricing policies.

## 3.1 Changes to existing model

### 3.1.1 Undiscovered volumes

As mentioned above, the original field model included 225 Gb of resource distributed amongst the countries in the model. It is important that the data inputs to TIAM-UCL and BUEGO are consistent insofar as possible to prevent major conflicts between their outputs. The existing undiscovered volumes are therefore modified to more closely match those from these sources.

The central estimates of undiscovered oil in each country, which sum to 240 Gb are used in BUEGO replacing the original figures. The discovery process remains the same. This is a slightly smaller volume than the sum of the regional volumes that were input to TIAM-UCL, which total around 280 Gb (excluding NGL). The probability distribution of undiscovered volumes in each country are highly positively skewed and so the sampling procedure tends to increase aggregated estimated volumes. These aggregated volumes are harder to disentangle however and so the volumes for each country are more practical to use even though there is a slight discrepancy between volumes included in the two models.

### 3.1.2 Water depths

Miller's original model contained individual field resource data and decline rates. In order to model some economic factors, water-depth data were added for each field. Fields were also classified according to whether each contains oil or gas condensate as the economics for fields of these differing types can vary significantly. For the 3420 discovered-developed and discovered-undeveloped fields, these water depth data were compiled by an extensive literature review from a wide variety of publicly-available sources.

It is also necessary to estimate the water depths of undiscovered fields. Fields in BUEGO are assigned to one of five groups: onshore, 0 − 500 m water depth, 500 − 1000 m, 1000 − 2000 m and > 2000 m. This process provided estimates for the percentage of undiscovered resource within each water depth range in a total of 102 countries. It was possible to assign percentages for the remaining 31 countries based on analogies with other countries, although the majority of these were landlocked and so would obviously have no offshore resources.

Finally, a random sampling process is employed to allocate fields as they are 'discovered' in the sequential discovery process described above in Section 2. So for example, countries with a larger proportion of deepwater resource are more likely to have the larger fields discovered earlier in the model horizon assigned to be in deepwater.

#### 3.1.3 Reserve growth

Miller's original model contained a small allowance for reserve growth by assuming a 0.2% annual increase in reserves. A new approach is adopted in BUEGO. This relies upon the assumption that the primary mechanism through which reserve growth will occur is the adoption of enhanced oil recovery (EOR). After a project has been in decline for a number of years BUEGO allows EOR to be undertaken resulting in new capacity additions becoming available. This models the behaviour observed in the Weyburn field in Canada as shown in IEA (2008, p. 210) in which EOR techniques increased production after primary production had entered decline

It is assumed that 250 Gb, similar to the figure given by IHS (Stark and Chew, 2009), is available from the adoption of EOR. The assumption of the additional available volume from EOR is unlikely to have too significant an effect on results however since the majority of this resource is not utilised within the model time-frame.

EOR is available at higher (approximately double) capital and operating costs than conventional recovery e.g. EOR in a Saudi Arabian field is about twice the cost of a conventional Saudi field, EOR in fields in the United States twice the cost of a conventional US field etc. For new capacity to come on-line from EOR, it must also go through a development cycle similar to conventional recovery i.e. have positive net present value for a sufficiently long time. While this is obviously a simplified approach to reserve growth, it is expected to represent real world behaviour better than an exogenous annual increase in reserves.

### *3.2 New features of BUEGO*

As discussed in Section 3, a key feature of BUEGO is its calculation of the net present value ('NPV') of all projects at each iteration of the oil price in each year between 2010 and 2035. Equation 1 presents the NPV calculation, which requires data on the capital and operating costs, tax regimes and discount rates. All of these factors vary depending on the project in question.

$$NPV = \sum_{t=0}^{N} \frac{p_t q_t - tax_t(p) - cost_t}{(1+\delta)^t} \quad (1)$$

where $N$ is the lifetime of the project (assumed to be 30 years), $p_t$ is the oil price, $q_t$ is the gross number of barrels produced in that year, $tax_t$ the taxes paid in that year, and $cost_t$ the capital and operational costs, all at time $t$. δ is the project-specific discount rate.

The timings of cashflows for each project are assumed to be identical. Each project has a lifetime of 30 years, first capital expenditure is in year one and first oil is achieved in year three. The capital expenditures are spread out over the first four years in the following proportions: 20% in year one, 30% in year two, 40% in year three (when production starts), and 10% in year four. This follows an example given by Herrmann et al. (2010) who indicate that around 50% of capital is spent before production commences.

Production between years three and thirty declines annually at the field specific decline rate. When calculating the NPV, a project takes the current oil price as constant over its lifetime.

Discount rates (δ) are taken to be similar to a Goldman Sachs report (della Vigna et al., 2012) that uses a rate of 11 − 15% ranging from OECD countries to higher risk non-OECD countries. There is one exception however: the capital intensive mining and in situ projects in Canada are assumed to require a 15% discount rate to provide additional security for the large investment necessary.

### 3.2.1 Cost data

It is important to know what exactly is meant when referring to 'costs', and which factors are included or excluded. For BUEGO, the important costs are exploration, construction of oil platforms or ships (if necessary), drilling development wells, and extraction of the oil from the ground. All but the last of these are included in the capital or 'development costs' in BUEGO with the extraction costs included as variable operating costs. Capital costs are incorporated as the cost of adding one barrel of daily capacity (in $/bbl/d).

The primary sources for field-level capital and operating cost data were Goldman Sachs (della Vigna et al., 2012, 2011), Deutsche Bank (Herrmann et al., 2010, 2009), the IEA (2008), Wood Mackenzie (data taken from Johnston (2011)), CERA (Fagan, 2001), and Quest offshore (2011), while various other news sources provided cost information for specific projects when they were first announced. When development costs were given as a lump sum, these were divided by estimated peak capacity to derive the capital cost per barrel of daily capacity. Peak capacities were either given by the sources themselves, or obtained from data within BUEGO.

Capital cost data were obtained for around 600 fields worldwide compared with a total of 3420 (excluding undiscovered) fields in BUEGO. It was hence necessary to estimate costs for these remaining fields. Babusiaux (2004) indicates that one would expect costs to be similar for fields in similar locations and with similar geology. If this is the case, and if peak capacities are not too dissimilar, he adds that costs can be estimated to vary by the ratio of their capacities raised to the power of 0.6. In practice, this means that a smaller field will have a larger cost per barrel of daily capacity than a larger one geologically and geographically similar.

To generate cost estimates of fields for which cost data were not available, an analogous field was chosen based upon the list of characteristics below. A number of experiments were undertaken to investigate whether this process could reproduce values for some fields for which costs were known. Depending on the number of analogues that could be used to narrow the range, these generally displayed a good match. The characteristics for finding an analogue of a field with unknown costs were (in order of importance):

(a) whether they are oil or gas condensate fields;
(b) whether they are fallow fields;
(c) the proximity of their water depths;
(d) their peak capacities;
(e) their intra-country location;
(f) intra-region location;
(g) resources; and
(h) decline rates.

Capital costs more than doubled between 2000 and 2011 (CERA, 2011). To obtain a consistent basis by which to measure capital costs, the IHS CERA upstream capital cost index, was employed to convert costs provided on the date on which the development costs were announced, or subsequently adjusted, to 2010 capital costs.

Despite these processes, field-level cost data are notoriously inaccurate and imprecise. Babusiaux (2004) for example indicates that initial cost estimates are usually only within a plus or minus 30% range of the final estimated cost, with detailed conceptual studies only reducing this range marginally. Cost overruns are also common, meaning that cost estimation and reporting can have an even larger uncertainty range. It was found, for example, that for one development, the Agbami field in Nigeria, for which five sources reported capital cost data, the highest and lowest cost estimates were around 85% higher and 35% lower than the mean respectively. For many other fields, only one source was available and indeed, as noted above, for the majority there was none. Field-level cost data evidently carry a wide range of uncertainty.

The development of gas condensate fields will more likely be driven by gas prices rather than oil prices. Since gas prices are not calculated internally by BUEGO, energy equivalence is assumed to convert from oil to gas prices i.e. the gas price is around one sixth of the oil price. The cost/bbl/d capacity for gas condensate fields is thus calculated by taking the total development costs and dividing by the sum of peak gas capacity (in barrels of oil equivalent) and peak condensate capacity.

Foss (2011) indicates that the ratio of oil (West Texas Intermediate) to gas prices (Henry Hub) in the United States has varied significantly over the past 20 years but has nearly always been greater than energy parity. Simply assuming energy parity in BUEGO will therefore tend to give gas fields a lower relative cost/bbl/d capacity than oil fields. This assumption will have a minimal effect however, since there are only 431 gas condensate fields in BUEGO compared with 6569 oil fields.

Operating costs were obtained from a variety of sources but particularly Herrmann et al. (2009), who provide costs in a number of countries, the ranges of operating costs in others, and some specific field costs. Operating costs were also modified on the basis of water depth, with Speight (2011) for example indicating that operating costs for deepwater rigs are around 3 – 4.5 times more than operating costs for shallow water rigs.

Finally for undiscovered fields, water depth and region were used as the primary factors driving capital costs. After assigning fields to specific water depth ranges as explained in Section 3.1.2, a number of fields within each region were used to act as analogues for each undiscovered field. A total of 58 analogues were selected (in 19 regions corresponding to the TIAM-UCL regions and five water depths but with some regions not having any fields in certain brackets) that were judged to match best the undiscovered fields in the specific region. An additional cost was added to the costs of these 58 analogues to represent the likelihood that there will be some wasted exploration costs looking for these fields.

### 3.2.2 Taxes

The remaining component of the NPV calculation in Equation 1 is the tax charged by each country. Countries' tax regimes can be broadly classified into one of three categories: concession regimes, production sharing contracts ('PSC'), and service contracts.

Fiscal terms (royalties, taxes, and profit oil[4]) vary significantly between these three categories and between individual countries. Terms also depend upon certain project milestones being achieved or exceeded. Such 'trigger points' include levels of gross annual production, internal rates of return, or the 'r-factor' (generally defined as the ratio of cumulative receipts by a company to its cumulative expenditure). In general, as a project becomes more profitable, the host country will increase taxes, royalties, or its share of profit oil (or all three).

The exact fiscal terms (e.g. the tax rate) were individually specified for all 133 countries[5] within BUEGO. Six classifications were constructed that aided specification and identification of similar models of taxation.

4 In production sharing contracts the gross volume of oil produced is usually split into 'royalty oil', 'cost oil', and 'profit oil'. 'Royalty oil' is the percentage of gross production oil taken by the host government before the subtraction of any other factors; 'cost oil' is the volume of oil allocated to an oil company to cover its capital and operating expenditure, generally allowed up to a maximum of gross revenues, and intended to allow for the swift repayment of the costs associated with the project; and 'profit oil' the volume remaining after royalty and cost oil have been subtracted. 'Profit oil' is split between the company and host country generally on a sliding scale, and is then usually taxed.

5 Some countries have no history of hydrocarbon production and so no special hydrocarbon fiscal regime. In these cases, nearby countries which have such a history were used as analogues. The number of countries this affected was small and their relative contribution to global oil production minimal.

These are: concession terms that change with differing production levels, concession terms that change with differing r-factors, PSC terms that vary with production levels, PSC terms that vary with the r-factor, PSC terms that vary with the internal rate of return, and service contracts. Obviously a country could also have tax terms that are static i.e. do not vary by production, r-factor etc. In these cases they are simply assigned to the relevant 'production' classification but with terms kept constant.

Twelve unique countries were also identified that impose specific or unique taxes or vary their share of profit oil in a manner unlike any other country and so do not fit neatly into these six classifications. Russia, for example, imposes an export tax, China applies an extra tax called the 'Petroleum Special Revenue Charge', Libya requires the oil company to undertake 50% of the capital expenditure but receive a maximum 15% of the production (with this percentage varying on a unique combination of annual production and the r-factor), while Mexico has two fiscal regimes, one for the state-owned company PEMEX, and one for foreign investors.

Data for the fiscal regimes for each country were obtained from a number of sources including Ernst and Young (2011), Portillo and Kapadia (2011), Agalliu (2011), Zahidi (2010), Zakharova and Goldsworthy (2010), Johnston et al. (2008), Wood (2008), Putrohari et al. (2007), and Sunley et al. (2003). Company presentations or individual countries' departments of energy or resources often also provided information for certain countries.

One way of examining differences in countries' fiscal regimes is through the 'government tax take' for a model oil field. This is generally defined as the ratio of the sum of a host government's (discounted) tax takes to the (discounted) sum of gross revenues minus all capital and operations costs over a given time-frame. This is shown in Equation 2. If the discount rate is not equal to zero it is possible to have a tax take greater than 100% although in this case the NPV would be less than zero.

$$\text{Government tax take} = \frac{\displaystyle\sum_{t=0}^{N} \frac{tax_t(p)}{(1+\delta)^t}}{\displaystyle\sum_{t=0}^{N} \frac{p_t q_t - cost_t}{(1+\delta)^t}} \times 100 \qquad (2)$$

All tax takes and hence projects' NPVs are calculated dynamically in BUEGO so that the tax take will vary on the particular characteristics of the oil project, the host country and the current oil price. A new tax take is thus calculated for each project at each iteration of the oil price.

The need to do this is demonstrated by the examples shown in Figure 4. In these a model oil development is taken with the following characteristics: a capacity addition of 50 kbbl/d, capital costs of $40000 per bbl daily capacity, a decline rate of 5%, and a discount rate of 10%. The upper portion demonstrates the effect of varying the oil price from $70-$110/bbl while the lower half shows the variation in tax take as capital costs increase from $30000−$50000 per bbl daily capacity with an oil price of $90/bbl. The twelve countries imposing unique taxation terms have been allocated to the classification that most closely matches their fiscal regime.

The arrows in Figure 4 indicate the direction of change in tax take in each country as price or capital costs increase. Figure 4 therefore demonstrates that there is a very wide range in the tax takes by different countries, and that an increase in oil price or project capital costs can have markedly different effects in different countries, lowering it in some cases and raising it in others. For example, China's tax take increases by over 15 percentage points as the oil price increases by $40/bbl, while India's tax take for example decreases by 6 percentage points as the project's capital costs increase.

Similar graphs can be produced for examining changes in all of the other characteristics of the project and these exhibit a similarly wide variation in tax take. This demonstrates the necessity of not imposing a single average government take for all fields within a country for all oil prices.

Figure 4 also indicates that Mexico's fiscal regime for foreign investors is the most stringent regime globally.[6] It is therefore anticipated that few foreign oil companies will choose to invest in Mexican oil fields and so within BUEGO it is assumed that Mexican fields are subject only to the taxation regime levied on PEMEX.

6 Mexico follows a service based fiscal regime but imposes a cap on the annual amount claimable. This 'Available Cash Flow' is extremely low meaning that capital costs cannot be reclaimed until a long period after production commences. When costs are discounted this therefore often pushes the government take above 100%

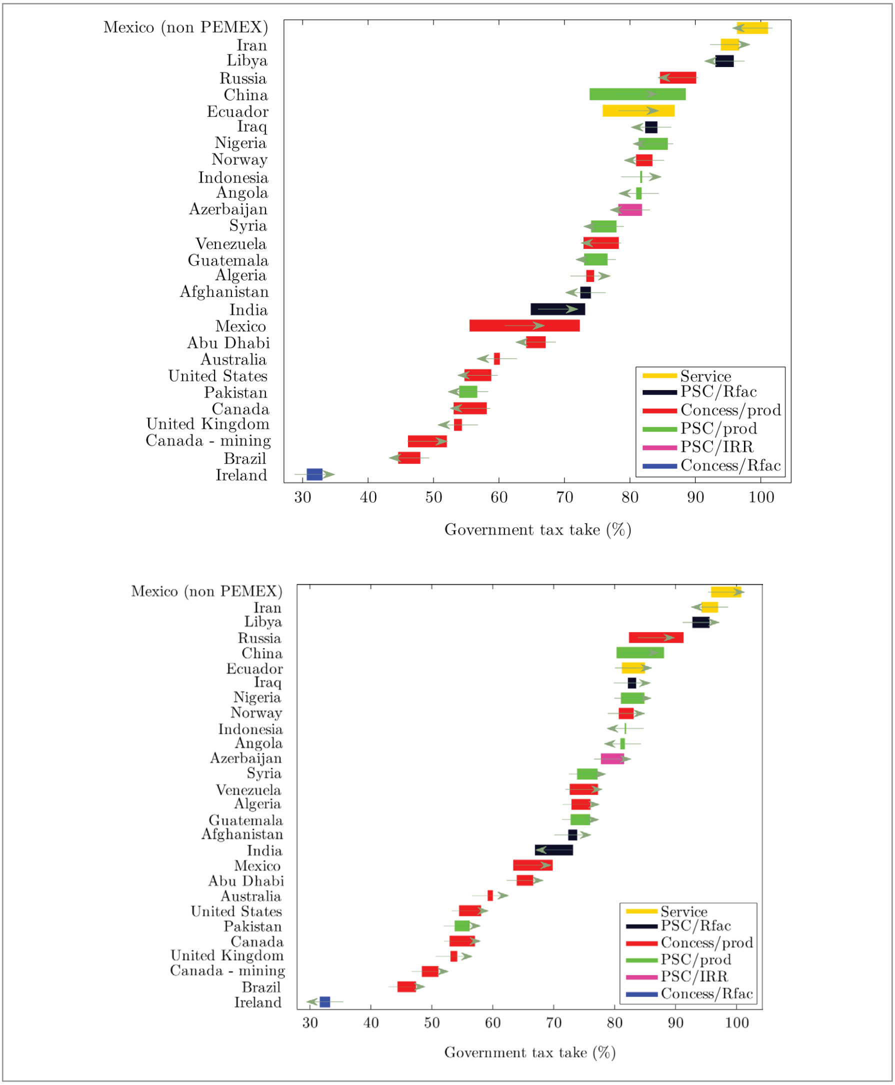



**Figure 4:** Government tax take for a model oil field development

**Notes:** Arrows indicate the direction of change as the oil price increases from \$70–\$110/bbl (upper half) and capacity costs increase from \$30000–\$50000 per bbl of daily capacity (lower half), with bars representing the magnitude of the change. The six categories correspond to the groups identified in the main text and 'Canada-mining' is the tax regime for mined natural bitumen in Canada.

**Table 1:** Daily production capacity constraints imposed on OPEC countries in BUEGO

| Country | Maximum daily production rate (mbbl/d) |
|---|---|
| Algeria | 1:7 |
| Angola | 2:0 |
| Libya | 1:7 |
| Nigeria | 3:0 |
| Ecuador | 0:55 |
| Venezuela | 3:1 |
| Kuwait[1] | 2:6 |
| Iran | 4:0 |
| Iraq[2] | 5 — 10 |
| Qatar | 1:0 |
| Saudi Arabia1 | 9:5 |
| UAE | 2:85 |
| **Total** | **37 — 42** |

1 Production from the Neutral Zone is split equally between Kuwait and Saudi Arabia.

2 Iraq is subject to a 5 mbbl/d cap up to 2015 and a 10 mbbl/d cap from 2020.

### 3.2.3 OPEC

An additional critical factor in any model producing scenarios of oil production is the modelling of OPEC behaviour. Many members of OPEC contain large potential capacity additions available at low costs. In order to model real world situations it is therefore necessary to incorporate some behaviour amongst the OPEC members to prevent this capacity from immediately coming on-stream.

Al-Qahtani et al. (2008) identified a number of possible options for modelling OPEC behaviour including: as a single profit maximising cartel; as a split group with some elements maximising price and others profit; split into three groups, with some elements choosing to maximise profit, some price and some quantity; with Saudi Arabia or a core group maximising profit and others acting as a competitive fringe; targeting a certain price, capacity, or revenue. Each of these options was reviewed by Al-Qahtani et al. (2008) and it was found that none was particularly satisfactory at reproducing historical changes in OPEC production volumes and price.

As a result a simple and transparent method of restricting production of various OPEC members is used in BUEGO. Caps are imposed on annual production, which are set at the maximum historical annual production levels within each country that have been seen since 2000 (taken from the original model database). These are shown in Table 1. These values essentially assume the continuation of any currently existing geopolitical factors that restrict production; principally either countries obeying OPEC quotas, or because of sanctions placed upon Iran. Other events, such as the failure of Iraqi production to materialise because of civil war or the lifting or strengthening of Iranian sanctions for example, are not included but can be modelled as separate scenarios. It is important to note that these constraints may never necessarily become binding in the model.

Iraq is an important exception given that it is not currently subject to any OPEC quota and the geopolitical constraints on production over the past decade are now no longer as relevant. It is also unclear when or if Iraq will become subject to a new quota on its production. A simple slowly increasing cap between 2015 – 2020 is therefore imposed on Iraqi production; this is obviously a relatively weak assumption.

## 3.3 Linkage with TIAM-UCL and demand-side modelling

BUEGO relies on TIAM-UCL for a number of input factors. The process and relationship between the two models for each scenario generated is summarised in Figure 5.

Outlooks generated by TIAM-UCL rely upon a range of factors including macro-economic assump- tions, fossil fuel costs and availabilities (including of substitutes to oil), and $CO_2$ mitigation levels.

These outlooks are for all oil. As mentioned in Section 2, this global demand is therefore split into two parts, one for the categories modelled within BUEGO, and one for those that are not (NGL, biofuels, and light tight oil). The former of these is the level of demand which BUEGO seeks to satisfy in each year, while the latter is simply added onto the top of the outlooks produced by BUEGO. Kerogen oil and the other Fischer-Tropsch liquids are also not included in BUEGO. While they are included in TIAM-UCL, they are expected only to play a minor role prior to 2035 and so are not included in the results below.

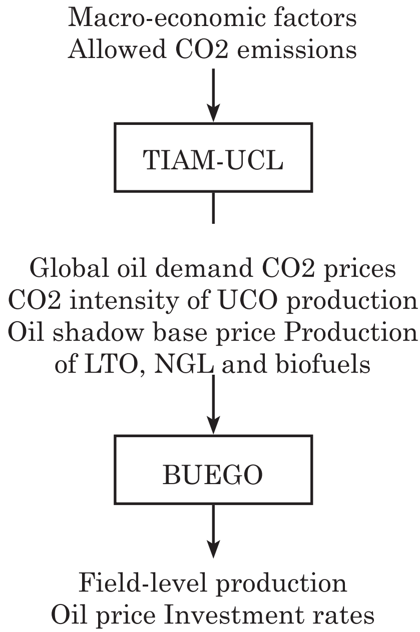



**Figure 5:** Schematic of relationship between inputs and outputs of TIAM-UCL and BUEGO

**Note:** `UCO' is unconventional oil, `LTO' light tight oil, and `NGL' natural gas liquids.

TIAM-UCL also generates $CO_2$ prices and the $CO_2$ intensity of unconventional oil production. These are also input to BUEGO. The product of these two factors is used to generate an additional cost mark- up to unconventional oil production to model the effects of the $CO_2$ emission reductions requirements on its production. Although other sources of conventional production can also have a high $CO_2$ intensity (e.g. because of flaring), no equivalent $CO_2$ mark-up is included, since it is assumed that these countries will stop flaring in the presence of a $CO_2$ tax.

Finally, short and medium-term price elasticities of demand are used in BUEGO and so base prices are needed from which demand can react. The shadow price for oil generated by TIAM-UCL is therefore also fed into BUEGO. The TIAM-UCL shadow prices incorporate the costs of oil production, choices of substitutes, constraints that are imposed, and (importantly here) long-term energy-service demand elasticities.[7] Long, medium and short-term elasticities are therefore incorporated into the results of BUEGO.

For the actual short and medium-term price elasticities of demand to use, Hamilton (2009) indicates that such figures are very difficult to estimate with confidence but comments that they should be small and negative. Fattouh (2007) indicated that the literature suggested ranges of around 0 to −0.11 and −0.08 to −0.64 for the short and long-term elasticities respectively. A short-term elasticity in the median of this range of −0.05 is assumed and a medium-term elasticity of −0.15 taken: towards the lower end of the long-term elasticity.

## 4. Example results

The combination of production data from BUEGO and TIAM-UCL gives total production in 2010 and 2011 of 83.2 and 84.1 mbbl/d respectively. This compares with 82.5 mbbl/d and 83.6 mbbl/d as reported by BP (2012).

Figures 6 – 7 present global oil production in a modelled 'new policies demand scenario' (NPS) with historic data from 2005 to 2010 and the results from BUEGO and TIAM-UCL from 2010 to 2035. This scenario includes some modest greenhouse gas emissions (GHG) reductions requirements but leads to a long-term temperature rise of around 3.5oC.

Results are split by region (corresponding to the regions within TIAM-UCL), by water depth, by the dates on which the fields were discovered, and by field type. The types identified are: fields in production in 2010, fields discovered but undeveloped in 2010, fallow fields, undiscovered fields, bitumen recovered by either mining or in situ production, extra-heavy oil, and from TIAM-UCL, NGL, biofuels, and light tight oil production.

In the NPS demand case it can be seen that oil production does not peak within the model hori- zon although it does reach something of a plateau from 2030 onwards at 97 mbbl/d. Underlying this conventional oil grows to just over 90 mbbl/d, staying on a plateau from 2025 onwards, with growth in unconventional oil thus accounting for most of the rise in production in later periods. Fallow fields play very little role until

7 The energy-service demands within TIAM-UCL are the level of demand for personal cars, aviation etc. These elasticities therefore differ from those in BUEGO, which are the overall price elasticity of oil.

after 2025, which as will be shown below, occurs only when there is a relatively rapid increase in oil prices, while in the late 2020s there is also an increasing contribution from Arctic fields, growing to around 2.5 mbbl/d by 2035.

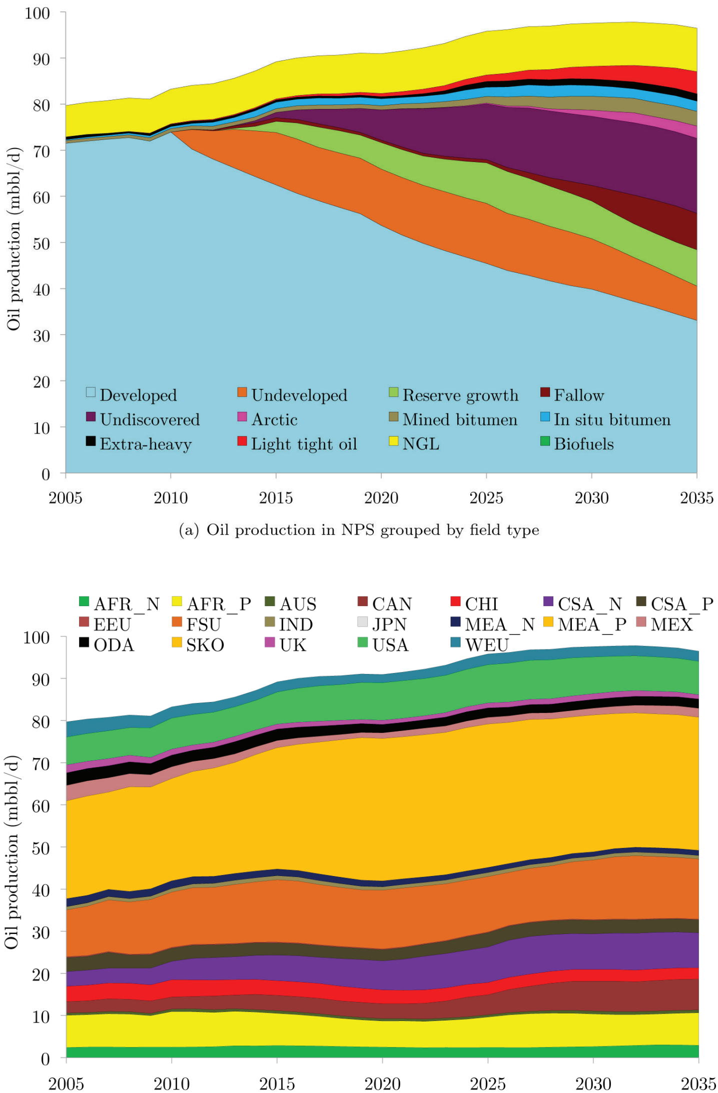
Light tight oil does not grow nearly as rapidly as projected by some sources, indeed in 2012 production is less than 0.2 mbbl/d and only surpasses 1 mbbl/d after 2020 - this is significantly less than the approximately 2 mbbl/d production that actually occurred in 2012. As noted above, the projection of light tight oil included here relies upon results from TIAM-UCL, which has a baseline of 2005. Since production of light tight oil has been much more rapid than was anticipated in 2005 (indeed there was no anticipation that it would occur at all at that time), TIAM-UCL is unable to increase production rapidly to the levels actually seen. It would therefore be desirable to incorporate light tight oil into BUEGO at the shale play level so that its production can be modelled more realistically. This is beyond the scope of this work but would form an interesting area for future research.

Figure 6 also separates fields by region. Production by members of OPEC grows initially from around 36 mbbl/d in 2010 to a maximum level of 45 mbbl/d in 2025 but this subsequently declines to 42 mbbl/d by 2035. As a result OPEC's share of total production peaks at 47%, up marginally from 43% in 2010, but returning to almost exactly the same level by 2035. Most of the growth in production occurs in Iraq, with extra-heavy oil from Venezuela also helping to offset falls in other countries (particularly African members). Canada is the region that grows its market share to the largest degree, managing to double its contribution to global production by 2035, while the United Kingdom's and China's shares almost halve.

Figure 7 displays production separated by field age and water depth. The continuing importance of fields discovered before 1960 is evident. Production from these fields remains above 27 mbbl/d between 2010 – 2035. In contrast production from fields discovered between 1970 and 2000 almost halves over the same time-frame. The bottom half of Figure 7 shows that while onshore fields retain by far the largest share of production, from fields classified as 'deepwater' (fields at water depths greater than 500 m) steadily increases from 6.5 mbbl/d in 2010 to over 10 mbbl/d by 2035. The rise of production from ultra deepwater (> 2000m) fields is more rapid, from an initial level of less than 0.2 mbbl/d in 2010, it reaches 2 mbbl/d in 2020, and 3 mbbl/d just after 2025. This occurs predominantly through the development of Brazil's ultra deep pre-salt oil fields, which come on-stream throughout the 2010s, and through new discoveries in Angola, Nigeria, Brazil and the United States.

The NPS demand scenario that was fed into BUEGO reaches 115 mbbl/d in 2035, almost 20% greater than the level shown here. This difference arises because TIAM-UCL does not incorporate the short or medium-term elasticity used in BUEGO: demand of over 15 mbbl/d is thus destroyed because of increases in the oil price. The oil price generated endogenously within the model reaches very high levels particularly after 2030. In later periods, despite the fact that overall production does not fall, the model struggles to meet the required level of demand through the addition of new capacity.

Figure 8 demonstrates the outlook for production in a 'low carbon scenario' (LCS) demand case, which has much more stringent GHG emissions reduction requirements, leading to a long-term temperature rise of 2°C. Production exhibits much more of an undulating or bumpy plateau than was seen in NPS: two maxima at around 88 mbbl/d are seen in both 2015 and 2025. With increasing light tight oil and biofuel production, total oil production does start to rise again after 2035 and so the peak in 2025 is not necessarily the final peak seen in all production in this scenario. Conventional oil also follows this bumpy plateau between 2015 – 2025, reaching 85 mbbl/d on these occasions but then declines at 1.2%/year. There is additional conventional capacity that could come on-line to ameliorate this decline but this is only available at higher prices. Without this the conventional sources not modelled within BUEGO (NGL and light tight oil) would need to increase by an additional average of 1 mbbl/d every year to offset this decline.




(a) Oil production in NPS grouped by field type



(b) Oil production in NPS grouped by region

**Figure 6:** Global oil production in NPS grouped by field type and region

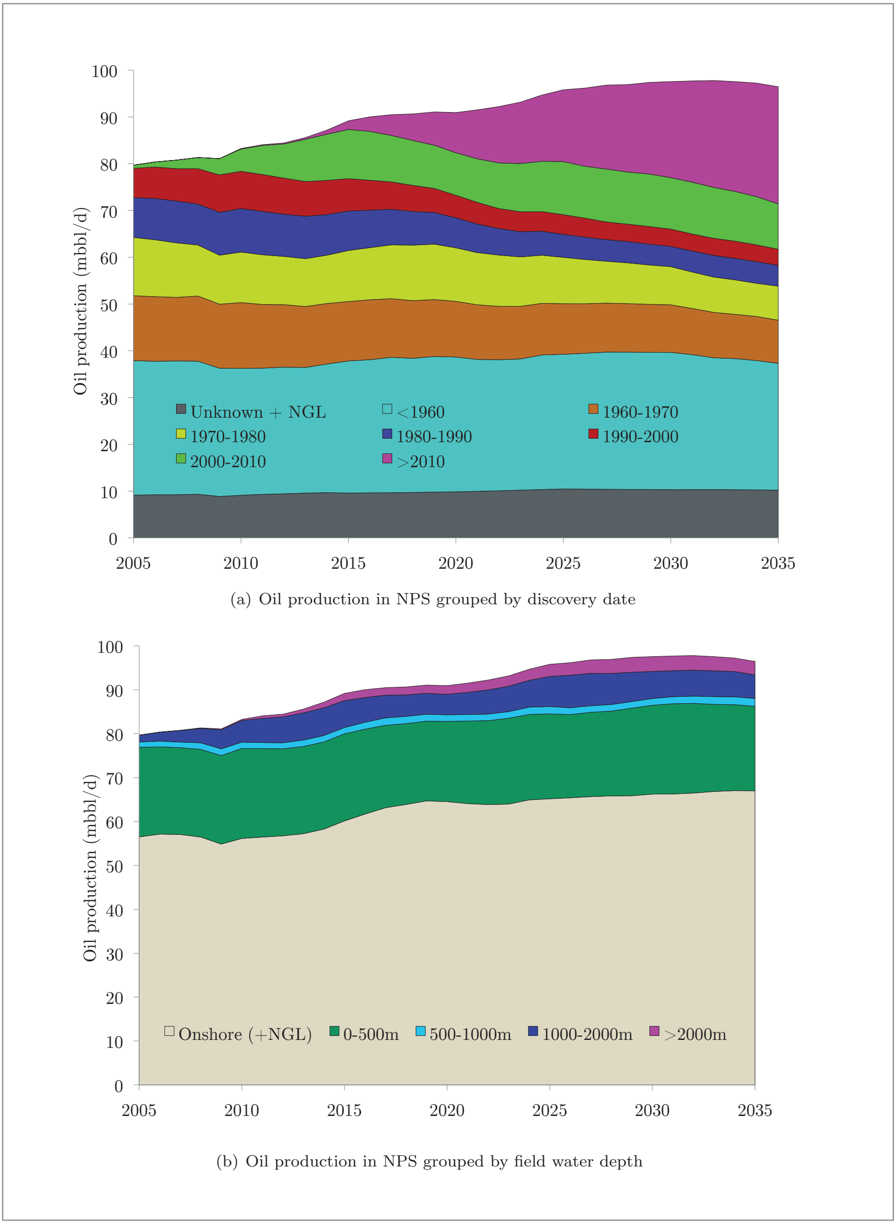



**Figure 7:** Global oil production in NPS grouped by discovery date and water depth

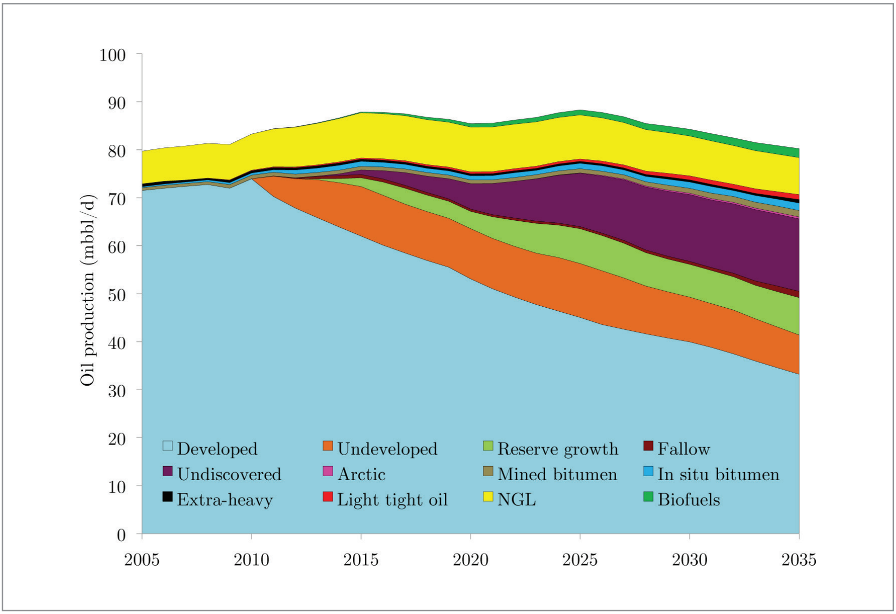


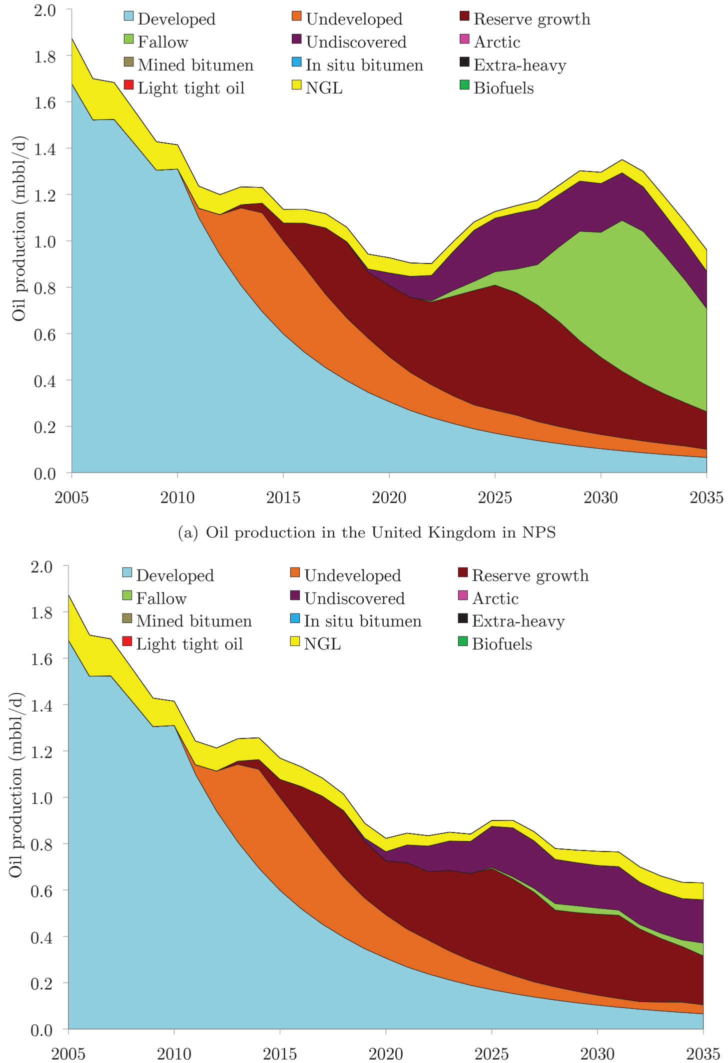

**Figure 8:** Global oil production in LCS grouped by field type

## *4.1 Outlook for the United Kingdom*

In the United Kingdom in both demand scenarios the decline in total production that can be seen to have been occurring from 2005 (indeed which has been occurring since UK production peaked in 1999), is temporarily moderated between 2012 – 2014 (Figure 9). Thereafter until 2020 both scenarios follow relatively similar paths, with production declining at an average of 6%/year.

With an increased differential in prices in the 2020s there is, however, a divergence between the two scenarios. In NPS reserve growth first plays an increasingly important role, production from which peaks at just over 0.5 mbbl/d in 2025. Subsequently production also rises from fallow fields, which peaks at 0.65 mbbl/d in 2031. Consequently between 2022 – 2031 UK production rises to a new peak at over mbbl/d. This is only possible, however, with a major increase in oil prices.

This rise in the mid to late 2020s does not occur in LCS. While reserve growth contributes an increasingly large share of total production, there




(a) Oil production in the United Kingdom in NPS



(b) Oil production in the United Kingdom in LCS

**Figure 9:** Production of oil in the United Kingdom in NPS (top) and LCS (bottom)

is little development of fallow fields. Nevertheless production remains approximately stable throughout the 2020s at an average of just over 0.8 mbbl/d although with a slight peak in 2025. Thereafter production declines at an average of 6%/year in the 2030s.

The ongoing exploration efforts in the North Sea and Atlantic Margin mean it is also of interest to examine the undiscovered volumes of oil that are brought into production. In the United Kingdom, fields at water depths greater than 1000 m are found only in the West of Shetland area and so it is possible to determine the approximate location of the undiscovered fields developed by examining their water depths.

In LCS only one undiscovered field with 2P reserves of 93 mbbl is developed in the West of Shetland region, which occurs 15 years after it is discovered. Although around 250 mbbl of other resources are discovered in this region, these are not brought into production. This relatively low utilisation therefore calls into question the rationale for a large portion of the ongoing exploration into deepwater resources, much of which could not be burned (consistent with a low-carbon energy system) even if they were discovered.

## 5 Conclusions and potential model extensions

This chapter explains the methodology and assumptions of a new bottom-up medium-term model called BUEGO that incorporates the major economic and geological factors affecting oil production. BUEGO models the behaviour of oil production companies choosing to develop projects on the basis of required demand and projects' net present values.

The model consists of a data-rich representation of 7000 producing, undiscovered, and discovered but undeveloped oil fields. Field specific decline rates, 2P reserves, and potential capacity increases were based upon a dataset developed and maintained by Dr. Richard Miller. This work incorporated a number of additional features including new data on water depths, field capital and operating costs, countries' fiscal policies, and demand, and enhanced the representation of reserve growth and OPEC production restrictions to allow more realistic outlooks of global oil production to be developed.

Demand levels for BUEGO are taken from the integrated assessment model TIAM-UCL. The oil price in each year is increased iteratively to ensure there is sufficient new capacity coming on-line from projects with positive net present value to satisfy these demand levels. The minimum oil price necessary to bring on the marginal project to meet global demand in a given year is taken to be the average oil price for that year.

A project's net present value is calculated by taking into account project-specific details including costs, additional capacity made available and decline rates, and country specific details such as tax regimes and discount rates. Government tax takes were demonstrated to vary widely between different fiscal regimes, between different countries, between different price levels, and between different assumed capital costs. A similar variation in tax take is found when other project-specific characteristics change. When calculating the net present value of a given project, BUEGO therefore individually generates the tax take of each project within each country at each price iteration in each year.

It is important to highlight that a field-by-field bottom model itself carries significant uncertainties. Many of the assumed parameters could vary, for example tax rates (actual versus theoretical), and how they could change over time would be an interesting study themselves.

BUEGO is designed to examine short-term, small-scale, or oil-sector specific uncertainties and to allow a detailed examination of the characteristics of supply. A number of scenarios were developed to elucidate this. Two demand levels were examined - a low-carbon scenario (LCS) and a 'new-policies scenario' (NPS). Three specific scenarios were also modelled looking at the influence of: disruption to production from a major oil exporter (Libya), OPEC quotas no longer being maintained, and an institutional reluctance to invest in new projects.

A number of possible extensions to BUEGO that could assist in its representation of global oil production. These include:

- the inclusion of additional oil types, including biofuels and kerogen oil, but most importantly light-tight oil;
- a better characterisation of reserve growth, so that only suitable fields can utilise enhanced oil recovery and a better representation of EOR costs;
- the inclusion of oil densities, so that a discount can be applied to the production of heavy oil, and to allow investigation of changes in the average density of a crude oil barrel on a disaggregated basis;
- additional and more precise modelling of elastic demand response,

Huntington (2010) for example finds that demand responses differ depending on whether oil prices achieve historic highs or move at prices below previous peaks and also that demand responses can be asymmetric; and

- the incorporation of reinvestment of profits by companies or countries into exploration so that the discovery of new fields is endogenised.

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# Oil Prophets: Looking at World Oil Studies Over Time

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Note: This article was originally presented at the ASPO 2003 conference in Paris. The version here incorporates minor corrections.

*All great truths begin as blasphemies. (George Bernard Shaw)*

*Trust everyone, but always cut the cards. (Mark Twain)*

*It wasn't raining when Noah built the ark. (Howard Ruff)*

Broad world oil assessments generally tackle one of two different but related questions: how much oil will eventually be produced (Estimated Ultimately Recoverable oil, EUR), and when might daily world oil production peak? Geologists and oil research groups wrestle with the former question through detailed assessment of petroleum fields worldwide. A growing number of individuals and forecasting entities have addressed the latter. Some engage both questions.

Those seeking best-estimate answers to these two questions are hamstrung by lack of access to essential geological data. In particular, uncertainties about the size of Middle East reserves and resources abound. Most recent EUR estimates fall between 2000 and 3000 billion barrels of petroleum liquids.

When addressing the second question - when production will peak - the process becomes much more complex. In addition to geologic limits, numerous political, economic, financial, social, and technological factors play very substantial roles in oil production and consumption, in the past, today and in the future. Commentators who disregard the import of these factors to focus on apparent geological constraints do so at their peril. The depletion of existing fields will play a key role, but since the bulk of remaining oil is in a dozen nations, investment constraints could be paramount in the timing of peak oil production. A brief listing of projected maximum daily production is attached; it falls well short of assumptions by the U.S. Energy Information Agency and the International Energy Agency.

In the face of these considerable analytical challenges, a growing list of indomitable individuals has studied these related questions. A work-in-progress list of nearly 100 estimates is attached. It expands on similar previously published lists (Bentley, Edwards, Nehring, McKenzie). The majority project a peaking between 2010 and 2020. The author invites additions, either recent or historic.

In the process of assembling this list, over a dozen listed US-based individuals not attending the ASPO 2003 conference were contacted for their then-current observations about world oil resource and oil peaking estimates. A selection of their comments is included.

## I. EUR Assessments

The earliest identified global EUR oil assessment dates back to 1942, with the initial wartime effort conducted by Wallace Pratt and Lewis Weeks (Standard Oil Co. of New Jersey). In the intervening 60 years, the number of studies projecting EUR oil has reached over 75, perhaps as high as 100. Additional searching, including contributions from attendees at this conference, should lengthen the attached list.

How have their estimates fared? Given general agreement that we haven't yet reached the halfway point in eventual production, it's too early to offer definitive judgment. And as Colin Campbell acknowledged in one of his early publications, in what he termed an addition to Murphy's Laws:

> "ALL FIGURES ARE WRONG … without reliable statistics, there can be no real experts anyway, and the door is open for informed speculation by whoever cares to address the problem. We can at least try to understand the patterns and trends, and above

all, to study carefully the implications of successive revisions." *(Campbell: Golden Century of Oil)*

In line with that admonishment, several factors stand out from a review of the EUR assessment list.

### *Learning curve*

Once the initial 1942 EUR assessment was published, before 2-D and 3-D seismic exploration had been developed, it took just 16 years for projections to emerge that are in line with lower-end projections of more recent studies.

At first glance, it appears the learning curve leads to a grouping of assessment at the 2000 billion barrel level. However, there were always more optimistic assessments. Weeks' 1959 assessment showed an upper end possibility for 3500 billion barrels of oil - in line with a number of studies reported over time. In recent times, the assessments generally fall between 2000 and 3000 billion barrels - still a very substantial differential. That differential tends to narrow when studies use the same reporting framework (discussed below).

### *Multiple studies leads to higher assessments*

For those individuals and groups who conducted multiple studies, subsequent EUR numbers generally trend higher.

From Weeks' initial assessment in 1942 through his seventh projection in 1978, he steadily increased his projections - from 650 billion to 3600 billion EUR. Over a 10-year interval (1970 – 1979), Moody's six EUR estimates grew more gradually from 1750 to 2150 billion. Campbell's EUR figures increased from an initial 1650 billion to his present 2700 billion, though the latter figure represents a substantially different metric: "all liquids" in the latter vs. conventional oil (excluding heavy oil and unconventional enhanced recovery oil) in the former. Nehring's first and last estimates, calculated in 1978 and 1982, were relatively the same. Odell was an exception; between 1973 and 1983 his EUR estimates decreased from 4000 to 3000 billion barrels.

USGS estimates varied substantially over time in a non-linear fashion. During the mid-1970s, Grossling's figures reached a substantial new high for the USGS - as much as 5600 using one method. Earlier estimates by Hendricks during the 1960s were higher than EURs projected by Masters during the 1980s, though in line with the latter's last publication in 1994.

### Common definitional framework: missing

The list of EUR estimates lacks a common definitional framework. Without a common measuring scale, any list won't be very useful.

A paper at last year's ASPO conference made the following reference: "There is a wide range of estimates for the world's original endowment of conventional oil (i.e., recoverable oil excluding the tar sands, etc.)" It is the "etc." that causes problems. The devil is in the details. Does "conventional oil" include lease condensate? Natural gas liquids? Polar and deepwater oil? Does "all liquids" include heavy oil and tar sands production?

The US Dept. of Energy's historic production tables include "crude oil, natural gas plant liquids, and other liquids" (EIA). BP's annual oil production tables in their Statistical Review of World Energy "includes crude oil, shale oil, oil sands, and natural gas liquids." However, the oil reserve figures in BP's tables historically exclude those resources. But the Oil & Gas Journal's annual assessment in December 2003 added 175 billion barrels of tar sands to Canada's "conventional oil reserves." Will BP follow suit?

When it comes to assessing peak oil, ASPO's Newsletter reported an "all liquids" figure. This acknowledges the fact that end-users have no way of differentiating most liquid fuels by origin.

### Access to data: a significant weakness

While the ability to locate, evaluate and extract oil in the field has drastically improved over time, analysts continue to be hampered by lack of access to definitive data.

Limited Middle East data is the pivotal issue. We know that Prudhoe Bay peaked in 1987, but how many of the 40 giant fields in the Persian Gulf have also peaked? Such information is not in the public domain. Without solid numbers, EUR forecasting becomes like "Blind Man's Bluff." By most accounts, the Middle East holds about two-thirds of the world's remaining conventional oil. Thus the related data uncertainties tied to a single region in the world make the process quite difficult and related projections open to question.

### Assessment methodology arguments

The methodology used by the USGS' world energy assessment team in 2000 has received harsh criticism, especially from Jean Laherrère (Laherrère). He argues that selecting a mean EUR oil figure, between oil for which there is a 95% discovery possibility and oil that has a 5% chance of being found, leads to an unrealistically high assessment (3000 billion barrels of conventional oil). Off East Greenland, USGS says there's a 95% chance of at least 1 barrel, a 5% chance of nearly 100 billion, and thus a mean of around 50 billion. Campbell retorts, "you might as well say there's a 5% chance of my being a frog." The USGS cites support for their methodology from the AAPG Resources Assessment Committee, the National Academy of Sciences, and others.

Campbell and others argue that, seven years into the USGS study period, new discoveries should already be tracking higher if we are ever to meet the USGS' mean 3000 billion barrel EUR oil projection. Supporters counterpoint that producers, especially in the Middle East and other OPEC nations, don't have incentive in the current world-oil environment to explore for new oil they don't need immediately.

## II. Peaking Estimates

Striving to determine how many petroleum liquids we have left and will ultimately produce is a useful exercise, but primarily as a means to help determine when daily worldwide production is likely to peak.

This effort, exercised judiciously, should help long-term planners make better decisions. Yet it is fraught with pitfalls.

### *Not all resources are created equal*

Many of the larger new fields are located in harsh and remote regions, in politically unstable environments, or require larger energy inputs during extraction. There may indeed be 50 billion barrels of oil offshore Greenland - but will it ever be produced? Since demand is somewhat fickle, identifying a year or range of years when liquids production will peak qualifies as part art, part science. That said, the paper lists a wide range of estimates for a peak in petroleum liquids production. They range from 1992 to 2030.

Oil bears or pessimists argue that if oil is in relatively limitless supply, then why are we going to the ends of the earth, in harsh physical and political environments, to develop more expensive and riskier resources? Responding that the Middle East is off limits to increased production by international oil companies is an incomplete answer. Everywhere but the Middle East, and perhaps there too, the big easy pools of oil are draining fast.

## *The large role of non-geologic factors*

Consider the world events of 1979-1983. Crude oil consumption declined 15% during that short span and didn't exceed the 1979 consumption level until 1996. The fall was primarily due to political, technological and economic drivers: a mix of wars, revolutions and production cuts driving up prices; a concerted effort by OECD nations to improve efficiency by consumers; substantial fuel-switching away from oil in power generation; and more.

On a smaller scale, consider the impact of the former Soviet Union's massive transformation during the early 1990s. Geologic constraints played a role in the precipitous 43% decline in oil production between 1988 and 1996. But the social, political and economic impacts of the break-up coincided with and partially triggered the steepest decline. From 1996-2001, during the era following the initial turmoil, nations of the former Soviet Union added nearly as much new net production than the rest of the non-OPEC world combined (BP).

Today, the range of non-geologic factors that can negatively impact the supply and demand situation is long and growing. Table 1 includes samples of each.

**Table 1:** Short sample of factors other than geology that can constrain world oil demand and supply.

| Key demand-side variables | Key supply-side variables |
|---|---|
| World-wide economic health. Example: so-called "Asian flu" of 1997-1999; business and individual responses to world violence - less leisure and business travel. | Violence: war, revolution, guerillas blowing up pipelines, terrorist activities. |
| Extreme price volatility impacts business investment decisions and some personal purchase decisions - "demand destruction". | Financial support from the markets for exploration and drilling. |
| Unusually hot or cold weather. | Natural disasters: hurricanes, typhoons, earthquakes. |

| Key demand-side variables | Key supply-side variables |
|---|---|
| Political initiatives aimed at reducing demand: gasoline taxes, requirements or incentives to produce more efficient energy-consuming devices. | Environmentally-focused political initiatives (e.g., Alaska National Wildlife Refuge off limits to drilling; oil tanker off Spanish coast). |
| Political instability holding back economic development, slowing demand growth. | Strikes and other social/political unrest: Venezuela and Nigeria. |
| Market responses to higher energy prices: more efficient homes, cars; fuel switching; technology breakthroughs in hybrid-electric cars. | Corporate merger activity. |
| Social initiatives: groups lobbying individuals to “do the right thing.” | Legislative road-blocks to participation by international oil companies. |
| Educational efforts, through schools, universities, the trades | Political initiatives aimed at diversifying supply. E.g.: more biofuels and wind energy. |
| Regional or world health problems. For example, SARS’ impact on jet fuel demand | Financial investment in upstream infrastructure: pipelines, tankers, etc. |
| *The Big Surprise* | *The Big Surprise* |

### *The "common framework" issue*

With all the variables impacting rates of oil production, analysts trying to assess world oil peaking would benefit from a common framework. In our view, it makes most sense to use an "all liquids" template for future forecasts.

### *How have their estimates fared?*

Projections for an early peaking of production, during the early-1990s through today, have not proven out. This provides critics with ammunition. Yet we're steadily approaching the time - 2010 to 2020 - when the largest grouping of analysts projects that daily petroleum liquids production will peak.

The scientific method is typically an iterative process: pose a hypothesis, test the hypothesis, study the results, adjust the hypothesis, retest, etc. Until the Wright brothers' plane actually lifted off the ground and flew for 12 seconds 100 years ago, all the previous hypotheses ended as "in-progress experiments." Peaking, no matter the ultimate shape of the curve, is a matter of "when," not "if."

The "grandfather of oil prophets" was M. King Hubbert, a former employee of Shell and the U.S. Geological Survey. First in 1948 and later in 1956, Hubbert projected an EUR oil figure for the US that led to him to predict a peaking of US production by 1970, plus or minus a year. By 1961, the USGS countered with an EUR figure nearly three times as large as Hubbert's, implying that his near-term peaking projection would not be a problem. Yet daily crude oil production from the US peaked in 1970, as Hubbert projected, at close to 10 Mb/day. Since then, it has declined to under 6 Mb/day.

### *The "if-then" approach*

While Hubbert studied US oil in detail and issued a number of predictions, he was very reluctant to make firm projections at the world level, according to collaborator Ivanhoe. Instead, he offered up contingent estimates: if our EUR for world oil ends up at 2000 billion barrels, then world oil production should peak around 1995 – 2000. If the EUR figure ends up higher, the peak will be later.

Al Bartlett, a physics professor emeritus at the University of Colorado (Boulder, CO), takes a similar route (Bartlett). He adjusts his peaking projection based on the amount of EUR oil. During each of the 1,491 public presentations (as of May 12, 2003) he has made of his talk, "Arithmetic, Population and Energy," he states the peak could occur in 2004 with 2000 billion barrels of EUR oil, 2019 if there are 3000 billion barrels, and so on. He assumes each additional billion barrels of oil production pushes the peak back 5.5 days.

A Douglas-Westwood world oil study, reported August 12, 2002 (Oil & Gas Journal Online), makes a similar distinction, but with respect to varying rates of demand growth. "A 1% annual growth in world demand for oil would cause global crude production to peak at 83 million b/d in 2016. A 2% growth in demand would trigger a production peak of 87 million b/d by 2011, while 3% growth would move that production peak to as early as 2006."

### *Production system limits*

During the process of identifying projections as to when world oil production might peak, a number of individuals offered the level at which they felt daily oil production system might be constrained, for all the reasons cited above and more. A short list of such estimates follows, See Table 2. Note the IEA and EIA estimates are much larger than those offered by most other commentators. Expanding this list should help identify the "when" of world oil production.

**Table 2:** Comparison of estimates of the level at which the daily oil production system might be constrained.

| *Individual* | *Association* | *When estimate offered* | *Level at which daily world oil production will be limited (million barrels/day)* |
|---|---|---|---|
| Sir John Browne | BP | Nov 2000 | About 90 million b/day |
| Colin Campbell | ASPO | July 2002 | About 87 million b/day (in 2010) |

| *Individual* | *Association* | *When estimate offered* | *Level at which daily world oil production will be limited (million barrels/day)* |
|---|---|---|---|
| Tom Ahlbrandt | USGS | May 2003 | "I wouldn't venture a rate; ask Richard Nehring" |
| Richard Nehring | NRG & Associates | May 2003 | Into the mid-80 Mb/day range; "probably can't reach 90." |
| Pete Stark | IHS Energy | 2003 | About 92 Mb/day |
| *Agencies* | *Publication* | | |
| International Energy Agency | World Energy Outlook 2000 | 2000 | Production might reach 115 Mb/day by 2020 |
| US Energy Information Agency | International Energy Outlook 2003 | 2003 | Production might reach 119 Mb/day by 2025 |

## III. Broad observations by US individuals on both EUR and "peak"

Over the course of the last few weeks, these writers met with, interviewed by phone or corresponded by e-mail with people who either; work in the oil industry, retired from the oil industry, or have been closely following it at some professional level. Most of those individuals live in the US and are not attending the 2003 ASPO conference in Paris. Most have conducted world oil studies. Each was asked a range of questions about their earlier efforts, any updated studies, how their studies varied over time, key lessons learned, how large the EUR oil figure might eventually grow, and when they thought daily world oil production might peak.

The comments below are excerpted from those communications. Comments were selected that express the wide diversity of opinions on

EUR and world oil peaking. Yet there are also areas of broad agreement; those are summarized at the end of this section.

> *Tom Ahlbrandt,* Ph.D. petroleum geologist, head of USGS World Oil Study Group (Denver, CO), on 5/14/03: "New world oil is all about Russia and the South Atlantic, not just the Middle East and certainly not about Europe … Field growth is just coming into its own in the world …We're optimists everywhere in the world except North America … I don't believe in the idea of a peak *per se,* I'm a plateau guy; I wouldn't venture a rate for the plateau; if you need a figure Richard Nehring is pretty reliable … Gas hydrates should be economically viable in 5 years [from MacKenzie Delta]."
>
> *Rich Duncan,* Ph.D. electrical engineer (Seattle, WA), worked in Saudi Arabia energy sector; annual world oil analysis since 1996, on 5/21/03: "The world oil production peak can be reckoned by historical data alone [from the peaking rate of the world's top-producing nations] … The oil industry itself appears ready to accept that the peak is near … It's time to put the peak behind us and focus on the post-peak production decline rate and what to do about it."
>
> *L.F. "Buzz"* Ivanhoe, retired petroleum geologist (Ojai, CA), creator of Hubbert Center Newsletter, on 5/18/03: "I'm not one to argue with data. Yet interpretation of data depends on your philosophy … There are not enough excellent plays out there to make the money people drool … Remember that during the peak decade of worldwide discoveries - the 1960s - we found all that oil with single full seismic, not the fancy new tools."
>
> *Michael Lynch,* president of Strategic Energy and Economic Research, Inc. (Springfield, MA), on 5/20/03: "It's hard to compare different EUR estimated because of definitional problems, but those by single authors do tend to increase over time ... We have seen recent estimates much higher than the 2000 billion that was common in the 1970s/1980s, reflecting improved technology, better infrastructure, etc. … I don't see any peak for 20-30 years, unless it is demand driven."
>
> *Charlie Matthews,* energy investment analyst, Weeden & Co (Greenwich, CN), on 2/11/02: "[The optimists are] in the grip of a view that comes from the concept: 'decide what you believe first, then

assemble the evidence to support it.' … [The pessimists] have hurt their case in the past by calling for an early peak. Then when it did not happen in 2000, and won't in 2006, they are unfortunately discredited … I hold that we can see the non-OPEC peak quite clearly in the three-year period 2007 – 2009; that is the big one."

*Jim MacKenzie,* Ph.D., World Resources Institute (Washington, DC), authored world oil issues analysis in 1996, on 5/12/03: "It is a total enigma trying to understand resources in the Middle East … European and Japanese car makers plus Shell and BP are behaving in ways that suggest they know the problem is real … This is not a long way off … Fundamentally this isn't a resource problem, it's a matter of will power; or we can sit and play Russian roulette with our resources and the climate."

*Richard Nehring,* president NRG & Associates, a US petroleum database firm (Colorado Springs, CO), on 5/15/03: "An EUR range between 2500 and 3000 billion, including liquids from unconventionals, is reasonable; 3500 billion would be aggressive … I underestimated Iraq. It's been under-drilled and under-developed. It could end up with between 200 and 300 billion EUR … Since 1990, only 15 discoveries in the onshore Lower 48 have been over 5 million barrels … On worldwide production, we can get into the low 80s [crude oil, million b/d]. We'll probably never reach 90 million b/d; infrastructure systems will be stressed to get into the high 80s."

*Joe Riva,* petroleum geologist, researcher and author (Great Falls, VA), authored world oil study in 1995, retired from the Congressional Research Service and Library of Congress, on 5/18/03: "In science, we make a hypothesis, check it, change it as needed, then check it again. Saying about the pessimists, 'you guys were wrong before so you will be wrong again' is a dangerous mindset … I don't trust a lot of the numbers. I don't know how you verify them … It's simple: our big fields are old and our new fields are smaller … For any oil off Greenland and the Falkland Islands, the economics will be very tough."

*Matt Simmons,* president Simmons & Co. Intl (Houston, TX), frequent industry presenter and volunteer energy advisor to the Bush Administration, on 5/9/03: "I would not even try to put a date to the year when global oil (and probably natural gas not far behind) will peak. Too many people do not appreciate that the peak does not mean 'out' … At a [Dept. of Defense] Energy Workshop, [I said] we all need to begin assuming Saudi is close to peaking …"

*Pete Stark,* IHS Energy, V.P. Industry Relations, Ph.D. (Denver, CO), on 5/15/03: "We have way too much oil coming to the market for the balance of the decade. By 2007, based on past discoveries that are allowing projects to come on stream, we could see adding a net [including depletion] 10.2 million barrels a day of new oil on the market. We don't think demand will be that high, so we expect lower supply and some project slow-downs … Reserve growth is significant … OPEC will lose share … We are showing Middle East reserves cresting."

*Walter Youngquist,* retired Ph.D. petroleum geologist, author of Geodestinies (Eugene, OR), in May 2003: "I rather doubt we can reach 90 million barrels a day of production. Two years ago, when I asked a member of the Saudi oil ministry how high their production would reach, he said '12 million barrels a day.' In my opinion we'll peak in 10 years or less. The tail [back side of production] will drop very slowly, extended by Canadian heavy oil."

## *Bottom line disagreement*

With respect to the personal observations listed above, disagreements between two camps over EUR oil and a projected peaking date rage on. Current arguments between the Optimists and Pessimists, or Bulls and Bears, date back over 15 years. The USGS' 2000 world energy assessment, with its 3000 billion barrel EUR (mean figure for conventional oil), raised the argument's profile. This 700 Gb difference (compared to the 1994 assessment of 2300 Gb) is significant: depending on your viewpoint, almost half the world's conventional oil is gone - or two-thirds of it remains. At the end of the day, any policy makers investigating the broad energy picture can't escape the argument. The Bulls see substantially more oil to be produced than the Bears. While there are many other points of disagreements, this lies at the heart of the fray.

## *Yet … areas of broad agreement*

1. World oil is a finite resource.
2. There is further room for daily world oil production to grow.
3. Russia, the deep Gulf of Mexico and the South Atlantic show

further promise.

4. Most of the world's oil is located in OPEC's hands.
5. More big oil will likely be found in under-developed structures in Iraq.
6. Limited access to OPEC data clouds our vision.
7. Some new oil could be developed in currently off-limits sections of non-OPEC.
8. Demand is a key variable in assessing any peaking timeframe.
9. Economic, financial, political, social and technology factors not related to geological limits are likely to constrain production over the next 10-15 years.
10. For purposes of analysis and planning, the most useful production figure is an "all-liquids" number.
11. The backside of the oil production curve is likely to be shallower than the front side, thanks to increased liquids production from heavy oil, tar sands and other unconventional sources.

While there was definitely not consensus on when daily world oil production might peak, the majority of those interviewed expect that peak will occur between 2010 and 2020.

## IV. Personal observations

*You can't be a good egg all your life. Sooner or later,*
*you have to hatch or rot. (C.S. Lewis)*

The Bulls and Bears can't both be right. There are some very convincing points as well as serious holes in arguments put forth by both sides. But at the end of the day, we lean towards the "harsh realists" as being closer to the mark.

We note that only people concerned with world oil peaking tend to make predictions. If bullish analysts had to project a range of dates for peaking, there might be as many wrong guesses on the far side of the peak as on the near side. Bullish agencies such as the US EIA show scenarios for decline curves that defy reality. By 2040, their oil decline curves could well look as farfetched as most of their energy price and natural gas supply prognostications over just the last five years. In due course, the much maligned "wrong early predictions" likely will be counterbalanced by overly optimistic ones.

Efforts to educate policy makers about world oil peaking should not leave consumers out of the mix. Most policy makers become very tentative when they get too far in front of their constituents. The educated consumer should be viewed as the foundation for the development of policies that reflect the visible long-term petroleum production problems. But to be effective, we believe the consumer education process may need some thinking outside the box.

The eleven broad areas of agreement listed above point towards world oil production constraints during the 2010 - 2020 timeframe. On an informed hunch, plus a dartboard, we pick a peaking date of 2013. But baring a sharp and sustained surge in demand, the "peak" is more likely to look like a bump on a long ridge than the classic bell-shaped curve. The speculation here is that it won't be in the Middle East nations' longer-term interests to invest in sufficient new production capacity to let a sharp production peak occur.

Price and production scenarios after the peak are not givens. There are still opportunities to change. But for long-term planning purposes, 2010 - 2015 is just around the corner, while 2020 would give very useful breathing room.

Think back to 1998, just five years ago. Oil prices crashed to a 10-year low, the UK hadn't yet experienced peak production, and natural gas in the US was available in the $2 range. Today, the UK is slipping down the back side of their oil production curve and the future of domestic natural gas has lost its shine. In the US, we import nearly 60% of our petroleum products. Our natural gas prices on the spot market have tripled with little likelihood that price pressures will recede substantially over the next three years.

The window of opportunity for substantial change feels like it's closing. Given the long lead times it takes to diversify energy systems and realign infrastructure investments, time could be extremely short. Without deliberate change, a business-as-usual scenario leaves us vulnerable to chaotic change.

To increase the chances for serious dialogue on this subject in the US and perhaps elsewhere, proponents of change will have to improve their message. Consider Harry Truman's observation about a major new factor in peoples' lives: "The release of atomic energy constitutes a new force too revolutionary to consider in the framework of old ideas." Replace "release of atomic energy" with "peaking of world oil" and the statement is equally valid.

### *One final note*

During the early 1970s, history validated Hubbert's oil peaking prediction, though he missed badly with his estimates of natural gas EUR - a fact which he readily admitted. History also showed the USGS of that day to be wishful thinkers. There is a worrisome parallel between the Hubbert-USGS debate of the 1960s and the current disagreements: between those who project a world oil peaking by or well before 2020, and those who embrace the less worrisome EUR figures in the USGS's year 2000 World Energy Study. (The USGS does not project a peaking date for world liquids production.)

## V. Summary comment

See Appendix 1 for a list of individuals and organizations that have studied world oil for its EUR potential and potential production peak. A simple majority pick some year or years during 2010 - 2020 as the time frame when daily world oil production is most likely to peak and thereafter slowly decline. A minority expects to see world oil peak within this decade. An even smaller number don't anticipate a peak until after 2020.

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# Appendix 1

***World Oil EUR Studies; and World Oil Production Peaking Projection***

(Bold type indicates multiple estimates from a given author.)

Steve Andrews May 29, 2003 May 26-27, 2003

Updated for Paris ASPO Conference

| Year of study or projection | Year of projected peak | Name | Group or organization | EUR (Gb) published* (if studied) | Notes |
|---|---|---|---|---|---|
| 1942 | | Pratt, **Weeks** | | 650 | |
| 1946 | | Duce | | 400 | |
| 1946 | | Pouge | | 555 | |
| 1948 | | **Weeks** | | 650 | |
| 1949 | | Levorsen | | 1500 | |
| 1949 | | **Weeks** | | 1000 | |
| 1953 | | MacNaughton | | 1000 | |
| 1956 | 2000 | **Hubbert** | | 1250 | |
| 1958 | | **Weeks** | | 1500 / 3000 | |
| 1959 | | **Weeks** | | 2000 / 3500 | |
| 1965 | | Hendricks | USGS | 2000 / 2500 | |
| 1967 | | Ryman | ESSO | 2150 | |
| 1968 | | Shell | | 1750 | |
| 1968 | | **Weeks** | | 2200 / 3350 | |
| 1969 | 2000 | **Hubbert** | | 1350 / 2100 | |
| 1970 | | **Moody** | Mobil | 1750 | |
| 1972 | 2000 | | ESSO | 2100 | "Oil increasingly scarce by 2000" |
| 1972 | | Warman | BP | 1200 / 2000 | |
| 1972 | | **Moody**/ Emmerich | Mobil | 1800 | |
| 1972 | | Bauquis et al | IFP | 1900 | |
| 1972 | | **Moody** | | 1800 | |
| 1972 | 2000 | Ward and Dubois | report for UN | n/a | assumed 2500 billion barrels |
| 1973 | | Schweinfurth | USGS | 2950 | |
| 1973 | | Linden | Inst.Gas Tech. | 2850 | |
| 1973 | | **Odell** | Erasmus | 4000 | |
| 1974 | | Bonillas | SOCAL | 2000 | |
| 1974 | | Howitt | BP | 1750 | |
| 1975 | | **Moody & Esser** | Mobil | 2000 | 1300 / 2000 / 3250 |

| Year of study or projection | Year of projected peak | Name | Group or organization | EUR (Gb) published* (if studied) | Notes |
|---|---|---|---|---|---|
| 1975 | | **Moody** | independent | 2050 | 1700 / 2050 / 2500 |
| 1975 | | Adams & Kirby | | 1600 / 2000 | |
| 1976 | about 2000 | Marshall | UK Energy Dept | n/a | research paper |
| 1976 | | Folinsbee | | 1800 | |
| 1976 | | | Am.Petr.Inst. | 2050 | |
| 1976 | | Grossling | USGS | 1950 / 5600 | Method 1 (note from Nehring) |
| | | | | 2200 / 3000 | Method 2 (note from Nehring) |
| 1976 | | **Klemme** | | 1600 | |
| 1977 | | | W.E.Conf. | 2250 | |
| 1977 | | Nelson | SOCAL | 2000 | |
| 1977 | | Delphi | IFP | multiple means | 1250 / 1800 / 2100 / 3050 |
| 1977 | 1996 | Hubbert | | | Used Nehring's 2000 EUR figure |
| 1977 | 2000 | Erlich, Erlich,Holden | book | | assumed 1900 EUR |
| 1978 | | **Weeks** | | 3600 | |
| 1978 | | DeBruyne | Shell | 1600 | |
| 1978 | | **Nehring** | Rand Corp. | 1700 / 2300 | |
| 1978 | | **Klemme** | | 1750 | |
| 1978 | | Styrikovich | | 6000 | conventional liquids (11000 total liquids) |
| 1979 | | **Halbouty & Moody** | | 2150 | 1400 / 2150 / 3550 |
| 1979 | | **Nehring** | Rand Corp. | 1600 / 2000 | |
| 1979 | | Roorda | Shell | 2400 | |
| 1979 | | Meyerhoff | | 2200 | |
| 1980 | | | W.E.Conf. | 2600 | |
| 1981 | | Strickland | Conoco | 2100 | |
| 1981 | | Colitti | AGIP | 2100 | |
| 1981 | | **Halbouty** | | 2250 | |
| 1981 | 2000 | **Hubbert/Root** | | 2000 | reviewed estimates by others |
| 1981 | around 2000 | | World Bank | n/a | assumed 1900 EUR |
| 1982 | | **Nehring** | Rand Corp. | 2350 | conventional petroleum liquids |
| 1983 | 2025 | **Odell**/Rosing | | 3000 | |
| 1983 | | **Masters/Root** | USGS | 1700 | and Dietzman (EIA) |

| Year of study or projection | Year of projected peak | Name | Group or organization | EUR (Gb) published* (if studied) | Notes |
|---|---|---|---|---|---|
| 1984 | | Martin | BP | 1700 | |
| 1984 | | **Ivanhoe** | | 1700 | |
| 1987 | | **Masters** | USGS | 1750 | |
| 1987 | | Jenkins | BP | 1700 | |
| 1989 | 2010 | Bookout | Shell | 2000 | |
| 1991 | 1992-1997 | **Campbell** | | 1650 | Excl. tar sands, heavy oil |
| 1991 | | **Masters** | | 2200 | |
| 1992 | | Montadert/ Alazard | | 2200 | |
| 1993 | | | OPEC | 2150 | |
| 1993 | 2000 | **Laherrère** | | 1700 | |
| 1993 | 2010 | Townes | | 3000 | |
| 1994 | | **Masters** | USGS | 2300 | 2100 to 2800 range |
| 1995 | | Mabro | | 1800 | |
| 1995 | 2025 | Jennings | Shell | n/a | |
| 1995 | 2000 | **Laherrère** | | 1750 | |
| 1995 | 2005 | Bernabe | ENI SpA | n/a | |
| 1995 | 2005 | **Campbell/ Laherrère** | Petro consultants | 1800 | World's Supply of Oil: 1930-2050 |
| 1995 | | Riva | | 2300 | CRS Report to Congress in 1995 |
| 1996 | 2014 | MacKenzie | World Res. In. | n/a | Scenarios: 2007 - 2019 peaks |
| 1996 | 2010 | **Ivanhoe** | | 2000 | |
| 1996 | 2010 | Appleby | BP | n/a | Oil & Gas Journal column |
| 1996 | 2030 | Romm & Curtis | 94 Shell data | n/a | |
| 1996 | 2005 | **Duncan** | | | Peak production to be 29.0 Gb/yr |
| 1997 | 1998 - 2008 | **Campbell** | | 1800 | Narrow def. of "conventional" |
| 1997 | 2020 | Edwards | | 2850 | retired from Shell |
| 1997 | 2007 | **Duncan**/ Youngquist | | | Peak production to be 30.6 Gb/yr |
| 1998 | 2013 | Udall/ Andrews | | n/a | Early SWAG; probably 2010-2020 |
| 1998 | | Perrodon/ **Laherrère** | | 2750 | all liquids: 2300 - 4000 |
| 1998 | 2014 | | IEA | 2300 | Used latest USGS reference case |
| 1998 | 2020 | Schollnberger | BP | | |

| Year of study or projection | Year of projected peak | Name | Group or organization | EUR (Gb) published* (if studied) | Notes |
|---|---|---|---|---|---|
| 1998 | 2006 | **Duncan** | | | Peak production to be 31.6 Gb/yr |
| 1999 | 2005 | **Duncan** | | | Peak production to be 31.1 Gb/yr |
| 2000 | 2007 | **Duncan** | | | Peak production to be 30.9 Gb/yr |
| 2000 | | Alhbrandt et al. | USGS | 3000 | 2250 / 3000 / 3850 |
| 2000 | 2005? | Magoon | USGS chart | n/a | Large chart displays peak |
| 2000 | 2010 | Browne | BP | n/a | |
| 2000 | 2016 - 2037 | | US EIA | 3000 | Used latest USGS reference case |
| 2001 | 2004-08 | Deffeyes | book | | |
| 2001 | 2010 2015 | Matthews | Weeden & Co | n/a | long-time financial analyst |
| 2001 | 2006 | **Duncan** | | | Peak production to be 28.8 Gb/yr |
| 2002 | 2008 | **Duncan** | | | Peak production to be 28.3 Gb/yr |
| 2002 | 2015 | **Laherrère** | at ASPO | | All liquids |
| 2002 | by 2020 | Leonard | at ASPO | | with YUKOS |
| 2002 | by 2020 | Bauquis | at ASPO | | with TotalElfFina (but personal est.) |
| 2002 | 2011 - 2016 | Smith | Energyfiles | n/a | Used 2200 EUR; 2% and 1% growth |
| 2003 | 2020-2040 | Nehring | personal est. | 2500 - 3000 | all liquids; 3500 "aggressive" |
| 2003 | by 2013 | Youngquist | personal est. | n/a | "within the next decade" |
| 2003 | 2006 | Bahktiari | | | Uses Campbell figure of 1900 bb EUR |
| 2003 | 2010 - 2020 | Ivanhoe | personal est. | n/a | |
| 2003 | 2003 - 2016 | **Duncan** | | | Oil & Gas Journal feature |
| 2003 | 2010 | **C.J. Campbell** | ASPO | 2700 | All liquids, through 2075 |

* EUR = Estimated Ultimately Recoverable, rounded to nearest 50 billion barrels (equivalent to Texas)

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- update by Andrews in May 2003

# A Review of some Estimates for the Global Ultimately Recoverable Resource ('URR') of Conventional Oil, as an Explanation for the Differences between Oil Forecasts – Part 1

R.W. BENTLEY

## 1. Introduction

This is the first part of a two-part article looking at the link between the estimated size of the global ultimately recoverable resource ('URR') of conventional oil and forecasts which have used this value. The second part will be published in the next issue of this journal.

Those studying the future of global oil supply have the problem that current oil forecasts from different individuals and organisations give significantly different predictions. Only a few years' back the difference between such forecasts was very large: one set of forecasts saw global production of 'all-oil' as reaching a resource-limited peak in the near or medium-term, followed by a steady decline, while other forecasts predicted that production of this oil would be able to keep rising in a normal 'business-as-usual' manner out to the end of the forecast time horizons.

This first set of forecasts included those by Campbell, Laherrère, Miller, Deffeyes, Energyfiles, Germany's BGR, LBST and the University of Uppsala, while the latter were mainly those from the 'mainstream' oil forecasting organisations, such as the IEA, US' EIA, OPEC, an EU study, some of the oil consultancies, and most of the oil majors. It was clearly very unsatisfactory to have such a wide divergence of forecasts, given the importance of the topic to the global economy and to society as whole.

To understand the differences between forecasts at that time, and hence see which was most likely, the UK Energy Research Centre (UKERC) undertook a major study, summarised in the *Global Oil Depletion* report (Sorrell *et al.,* 2009). This included a detailed comparison of a range of then-current forecasts, with the results being given in the study's Technical Report 7 (Bentley et al., 2009). The study as a whole looked primarily at the future global production of only conventional oil, and concluded:

> "*On the basis of the current evidence we suggest that a peak of conventional oil production before 2030 appears likely and there is a significant risk of a peak before 2020.*"

However, the study did also report on a number of forecasts that covered the global production of 'all-liquids'.

More recently there have been two significant developments in global oil forecasting. Firstly, most of the 'mainstream' forecasting organisations listed above have now begun to recognise the likely existence of a near-term peak (or at least a plateau) in the global production of *conventional* oil, see the charts in *The Oil Age* Vol. 1 No. 2. Secondly, partly in response to the 'light-tight' oil now being produced by hydraulic fracturing in the US, there is greater attention on forecasts of 'all-liquids' production, and on the components of this (again, see the charts mentioned).

Even so, despite these recent developments, there still exists today an uncomfortably large gap between the forecasts which see a near or medium-term peak in global 'all-liquids' production, and those which see this supply, though admittedly now somewhat constrained, as still able to increase to meet expected demand out to the end of the forecast horizons (typically now to 2035 or 2040). So there is still a need to understand why such significant differences in oil forecasts can exist, and to judge which set of forecasts is the more likely.

## 1.1 Differences between Forecasts in the Size of Global Conventional Oil URR

There are of course a number of reasons for such differences. But one of the main reasons, already identified at the time of the UKERC study, is the difference between the sizes assumed for the ultimately recoverable resource ('URR') of global *conventional oil*. This subject is the main focus of this paper. To discuss it, we need to be clear on the various categories of oil considered, and also on what is generally meant by 'ultimately recoverable resource'. This is covered in the next two sections.

## 1.2 Definitions

There are many types of hydrocarbon liquids, and there is no fully standard way to classify them. Here we define:

**Conventional oil:** Taken as referring to *flowable oil in fields*, i.e., oil that has migrated to a trap, and from which, under a 'standard' drive mechanism such as own-pressure, mechanical lift, or gas- or water-drive, it is able to flow to a production well. The bulk of all oil produced currently, and by far the largest part of that historically, has been of conventional oil.

**Non-conventional oils:** These tend to be found in geographically extensive regions (within which there may be 'sweet spots'), and where flow to a production well is not possible without significantly changing the nature of the oil (for example, by heating, or treating with a solvent), or that of the surrounding material (for example, by hydraulic fracturing ('fracking') of the rock, or by mining the sand, in which the oil resides). These non-conventional oils include:

- Light-tight ('shale') oil: light oil trapped in very low permeability rock, and which requires fracking of the rock, and these fractures to be kept open by proppants, for its production.
- Very heavy oils that require thermal stimulation to be produced (though these are sometimes classed within conventional oil).
- Oil produced from tar sands, either by mining the sand and then separating and upgrading, or produced thermally *in-situ*.
- Heavy oil from the Orinoco basin.

Liquids from gas, either in the same field as oil, or from a separate condensate or gas field. Sometimes these liquids are included in oil production data: They are:

- Condensate, liquids which condense out of the gas at surface temperature and pressure.
- Other natural gas liquids (NGLs), including those produced in a processing plant (NGPLs).

'Other liquids'. These do not come from either oil or gas fields. They include:

- Oil produced from the oil pre-cursor kerogen (giving 'oil-shale' oil), either by mining the rock and retorting, or by retorting in situ.
- Liquids produced by chemically altering natural gas ('gas to liquids', GTLs).
- Liquids produced by chemically altering coal ('coal to liquids', CTLs).
- Oil from biomass (including directly from oil seeds; or from alcohol produced from corn, sugar-cane or other biomass; or produced from biomass by some other process).

In addition, in forecasting total liquids production, account must be taken of refinery gain.

Thus we get the three main categories of oil liquids:

- **Conventional oil:** Crude oil plus condensate, but excluding the non-conventional oils ('light-tight' oil, extra-heavy oil, oil from tar sands, and Orinoco oil), and also excluding oil from kerogen. Some sources, such as the UKERC report, include NGLs in their definition of 'conventional oil', but here - in order to be able to compare to URR estimates made back in the 1960s to 1980s - we do not. (NGLs are therefore in 'all-oil', see the next category.)
- **All-oil:** Conventional oil, plus: non-conventional oils, NGLs, and oil from kerogen.
- **All-liquids:** All-oil, plus: CTLs, GTLs and biofuels.

The reason for differentiating conventional oil from the non-conventional oils (and other liquids) is that conventional oil is generally *intrinsically* cheaper, and has a better energy return ratio, than these other liquids; see the discussion in Bentley & Bentley (2015).

### 1.3 Meaning of ultimately recoverable resource (URR)

Now we consider what is meant by a field's, a region's, or the global 'ultimately recoverable resource' (URR) of a class of liquids.

The *reserves* of an oil field give the amount of recoverable oil remaining in the field at a given point of time. The *resource* of the field, by contrast, refers to the total amount of oil in-place, and thus includes the oil that is recoverable and unrecoverable. (Note that for reserves there is a strong need to distinguish proved ('1P') reserves from proved-plus-probable ('2P') reserves, see Bentley & Bentley, 2015.)

For a region comprising a number of fields, there are also fields yet to find. Here the term 'reserves' refers only to oil that has been discovered. The resource for a region, by contrast, includes the oil yet to be discovered. Thus at a given point in time, a region's ultimately recoverable resource (URR) is given by:

*URR = cumulative production to-date + proved-plus-probable reserves + recoverable oil yet-to-find*

Note that this estimate of URR can be expected to change with the recovery technology used, and the price of oil.

So if the URR can change with technology or oil price, what is meant by 'ultimately' in this context? Most modellers today do not think in terms of a true ultimate 'ultimate' (who knows what oil extraction technology might be economic in 100 years?), but in more pragmatic terms of how much their models expect to see produced of a given class of oil out to some rather distant date, for example to 2070 or 2100.

In addition, some forecasters take optimistic views of how much extra *conventional* oil new technology or a higher price can bring on-stream. With the current global volume-weighted average recovery factor of oil in fields at perhaps only 40%, there is a great deal of *theoretically* potential oil that can be gotten from these fields. But other forecasters point to calculations by reservoir engineers, and to the fact that two near-decade-long periods of high oil prices (above $60/bbl in current real terms) did not bring on much extra oil. Because of this difference of views, this 'scope for true 2P reserves growth' question remains an important research topic.

## 2. The UKERC Study, 2009

Now we return to the UKERC *Global Oil Depletion* study mentioned above, as this developed a useful approach for examining the differences between oil forecasts. This approach was developed by Dr. Richard Miller (one of the report's authors), and looked explicitly at the link between the assumed (or imputed) global URR for conventional oil used in the forecast, the date of peak production of this oil (if peak occurred within the forecast horizon), and the predicted or imputed rate of post-peak decline in the production of this oil.

Figure 1 shows the predictions for global oil production out to 2030 made by the different forecasts examined in the UKERC report.

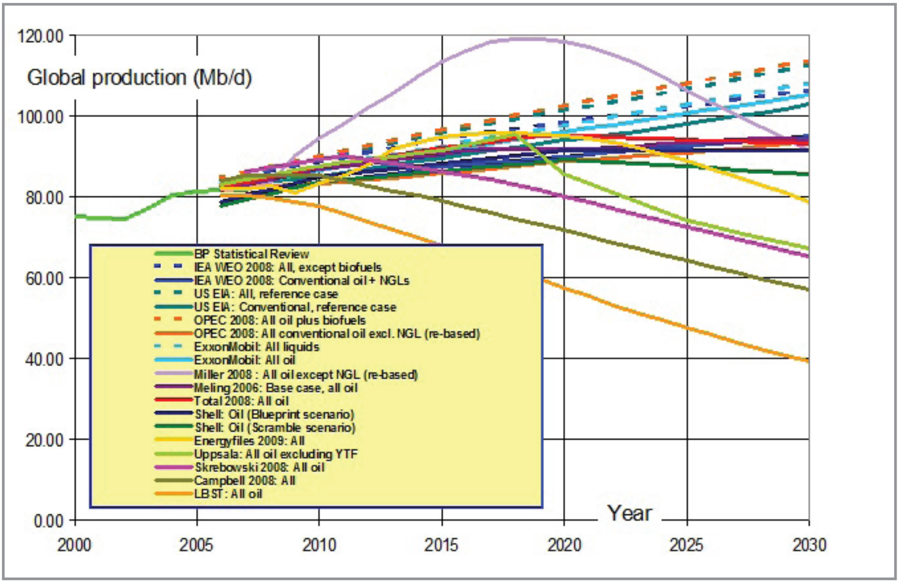


**Figure 1:** Forecast global oil production (covering various categories of oil) vs. date.

Legend (from top) is:
BP Statistical Review (historical data)
IEA WEO 2008: All oil, except biofuels
Ditto: Conventional oil + NGLs
US EIA: All-oil, reference case
Ditto: Conventional oil, reference case
OPEC 2008: All-oil plus biofuels
Ditto: All conventional oil excl.
NGL (re-based)
ExxonMobil: All liquids; All-oil
Miller 2008: All-oil except NGL (re-based)
Meling 2006: Base case, all-oil
Total 2008: All oil
Shell: Oil (Blueprint scenario)
Ditto: (Scramble scenario)
Energyfiles 2009: All-oil
Uppsala University: All oil except yet-to-find
Skrebowski 2008: All-oil
Campbell 2008: All-oil
Ludwig-Bölkow-Systemtechnik GmbH (LBST): All-oil

*Source: UKERC Global Oil Depletion report (2009).*

As figure 1 shows, at that date there were three distinct classes of forecast:

- Forecasts that showed global oil production peaking before 2030. These were mainly from the 'independent' forecasters: Energyfiles, LBST, University of Uppsala, Miller, Campbell and Skrebowski.
- Forecasts that saw production increasing out to 2030, but flattening out. These were either from the 'mainstream' forecasters but for conventional oil, or were for 'all-oil' from the other oil companies reviewed: Shell, Total and StatoilHydro (where the latter was a private forecast from a senior employee).
- Forecasts for a roughly linear increasing trajectory for global oil production out to 2030 (the end of the forecast period). These forecasts were mainly for all-oil from the 'mainstream' forecasters: the IEA, US EIA, OPEC, and ExxonMobil.

The difference between these forecasts was not explained simply by the categories of oil they covered. For example, the US EIA forecast had a roughly linear plot for global conventional oil production, with this reaching ~103 Mb/d by 2030, whereas at the other end of the spectrum LBST forecast 'all-oil' production to fall to only 40 Mb/d by the same date. The main difference between the forecasts was that between the 'mainstream' oil forecasters and the others. (And note that only a few years earlier these 'mainstream' forecasts had been for global supply to grow much faster still, to reach around 120 Mb/d by 2020.)

To examine the assumptions - not always explicit - in the above forecasts for conventional oil, and to see how likely were these assumptions, Miller's analysis is given in Figure 2.

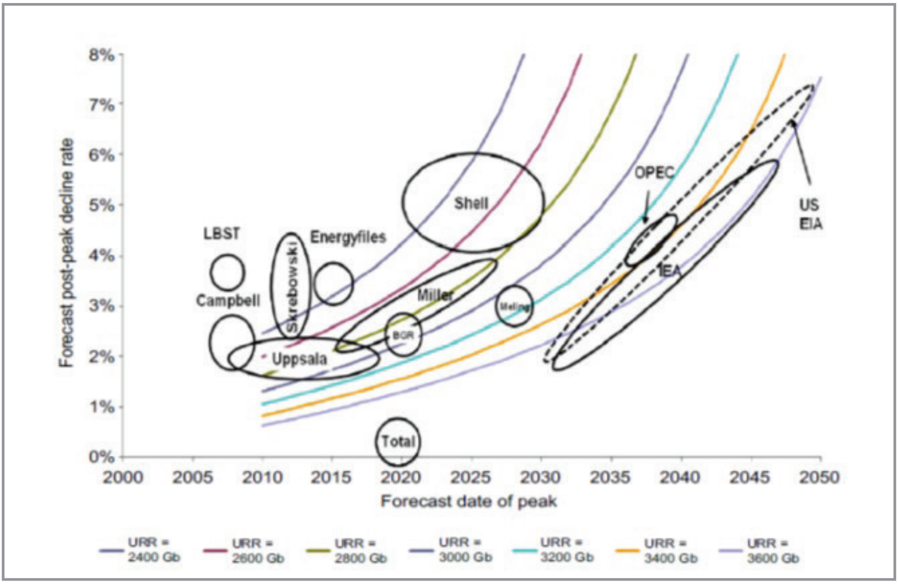


**Figure 2:** Date of peak vs. post-peak decline rate and size and ultimately recoverable resource (URR) for conventional oil.

Graph developed by Dr. Richard Miller to examine the differences between the forecasts for (primarily) conventional oil. Iso-lines represent the assumed or implied global URR of conventional oil. Rate of production increase prior to the peak was set to 1.3%/year. Mapping of individual forecasts onto the graph involved some judgment. Conventional oil here includes crude oil, condensate and NGLs, but in some cases also included production from currently operating and planned oil sands production as this was difficult to separate out. Excluded was oil from oil sands plants not yet planned, oil from kerogen shale, and other liquids (GTLs, CTLs and biofuels). Note that the forecast from Total included extra-heavy oil in its model.

*Source: UKERC Global Oil Depletion report (2009).*

On such a plot, forecasts that showed global production of conventional oil as peaking before 2030 are to the left, while the 'quasi-linear' forecasts are to the right. As the plot shows, most forecasts which had the date of peak as 2020 or before (LBST, Campbell, Skrebowski, Energyfiles, Uppsala University, BGR and Miller) typically had fairly low URR's for conventional oil, and also 'medium' post-peak decline rates (from 2 to 4% p.a.); while the 'mainstream' forecasts of OPEC, US EIA and the IEA were constrained to have high URRs for conventional oil (from ~3,250 to ~3,800 Gb); and also post-peak decline rates that were quite high (~ >5% p.a.) if the date for peak was assumed to be after 2040.

Thus - in broad terms - the large difference between the forecasts in Figure 1 for global 'all-oil' oil production could be explained mainly by differences in the URRs assumed or implied for conventional oil; and in the post-peak decline rates assumed or implied.

Next we look at more current forecasts.

## 3. Current Forecasts

As mentioned earlier, current oil forecasts still give very different predictions, now generally for 'all-liquids' production. In broad terms, the current forecasts can be classified as:

- Forecasts that see the global production of all-liquids as probably peaking within less than a decade from the date of assessment; see e.g., Campbell (2015), Laherrère (2015).
- Forecasts that have global all-liquids as peaking, but not until perhaps 2025 to 2035; see e.g., Smith (2015), Miller (2015).
- Forecast that see no-peak in all-liquids production out to the end of their forecast horizons of 2035 to 2040. (See e.g., the charts mentioned earlier for IEA, BP and ExxonMobil given in *The Oil Age*, Vol. 1, No. 2).

As in the explanation given above for the UKERC study, it would seem that a significant part of the differences between current forecasts still lies in the URR values they assume for conventional oil, though now also – and to a lesser extent - in the rates of production assumed for the non-conventional oils and other liquids.

It is for this reason that this paper presents data on some of the estimates for the size of the global conventional oil URR made at different dates, and by different sources. These data illustrate two things:

- Firstly - and perhaps surprisingly - that in the view of the 'near-peak' oil forecasters, the size of this URR has not changed by much over the years, despite increasing knowledge and technological progress.
- Secondly, the large current disagreement between the 'near-peak' and the 'far-peak' (or, indeed, 'no-peak') forecasters over what is realistic to assume for this URR, and hence difference in their resulting forecasts.

It is intended that the information below will be updated in future issues of this journal, and also be subjected to a more detailed analysis. In this sense, this paper is only preliminary in terms of examining this important topic relating to the future production of oil.

In terms of the information provided here, see also the excellent broader summary of, and commentary on, global URR values given by Andrews and Udall in this issue.

## 4. URR Data: Conventional oil; and Also for other categories of oil and liquids

This section gives a selection of estimates of global URR values for conventional oil, and for other categories of oil and liquids, from a variety of sources and over a range of dates. The URR values are selected as having a bearing on the various oil forecasts discussed here, and also on the general problem of the disagreement between forecasts mentioned above. The selection starts with some early estimates for the global URR of conventional oil used, or listed, between 1956 and 1981.

### *4.1 Relatively early estimates for the global URR of conventional oil, from 1956 - 1981*

Table 1 shows some relatively early estimates for the global URR of conventional oil and (in most cases) the corresponding predicted dates of the production peak of this category of oil. (As mentioned, for a more exhaustive list of URR estimates, see Andrews and Udall in this issue.)

**Table 1.** Estimates from 1956 - 1981 of Global URR for conventional oil (almost certainly ex-NGLs), and Corresponding predicted dates for peak or plateau of global production of this category of oil.

| Date | Author | Hydrocarbon | Ultimate Gb | Date of global peak |
|---|---|---|---|---|
| 1956 | Hubbert | Cv. Oil | 1250 | "about the year 2000" [at 35 Mb/d] |
| 1969 | Hubbert | Cv. Oil | 1350<br>2100 | 1990 [at 65 Mb/d]<br>2000 [at 100 Mb/d] |
| 1972 | ESSO | Pr. Cv. Oil | 2100 | "oil increasingly scarce from ~2000." |
| 1972 | Report: UN Confr. | Ditto. | 2500 | "likely peak by 2000." |
| 1974 | SPRU, UK | Ditto. | 1800-2480 | no prediction |
| 1976 | UK DoE | Ditto. | n/a | "about 2000" |
| 1977 | Hubbert | Cv. Oil | 2000 | 1996 if unconstrained logistic; plateau to 2035 if production flat. |
| 1977 | Ehrlich et al. | Ditto. | 1900 | 2000 |
| 1978 | WEC / IFP | Pr. Cv. Oil | 1803 | no prediction |
| 1979 | Shell | Ditto. | n/a | "plateau within the next 25 years." |
| 1979 | BP | Ditto. | n/a | Peak (non-communist world): 1985 |
| 1981 | World Bank | Ditto | 1900 | "plateau at ~ turn of the century." |

**Notes:** Cv.: Conventional. Pr.: Probably. Gb: billion barrels.
'Ultimate': Ultimately recoverable resource (URR); this is equal to the recoverable portion of the original total in-place oil resource.
This table is not complete; one notable omission is the WAES study from the late 70s / early 80s; there are probably other forecasts omitted also.
Methodologies:

- 1956 Hubbert: Used a global ultimate from Weeks (but modified); and predicted production via a hand-drawn curve constrained to fit this URR, past production, and judged realistic future production.
- 1969 Hubbert: Used symmetric logistic curves.
- 1972 Ward & Dubois, a report to the UN.
- 1977 Hubbert: Used a global ultimate from Nehring; and assumed two cases: an unconstrained logistic curve, this generated a 1996 peak; and flat demand flat from 1974, which generated a production plateau lasting to 2035. (Actual global oil demand post-1974 was between these two cases.)
- 1979 BP: Ultimate for conventional oil for the non-communist world, ex NGLs. With unconstrained demand this gave a peak at 1985. This prediction was later used (e.g., variously by Odell, Mitchell and Smil) to dismiss all such 'fixed-resource' predictions. In fact the size of the URR assumed was about right for the oil covered (non-communist conventional oil, ex-NGLs), but global demand fell sharply post the 1978 price shock, rather than rising as assumed in the BP forecast.

*Source: Bentley & Boyle (2008); Detail on sources is given in the Annex.*

At these dates, it is almost certain that the URR estimates in Table 1 referred only to conventional oil (i.e., essentially, oil in fields), and did not include NGLs. Also at these dates the existence of light oil trapped in rock (but not its extraction process), of the extensive quantities of oil in tar sands, and very large quantities of oil potentially producible from kerogen were well known, see for example the estimates quoted by Hubbert (1949) for tar sands and kerogen oil, but these are not included in the URR estimates given above, which relate to conventional oil only.

The conclusion to be drawn from Table 1 is that at that time the URR estimates for global conventional oil (ex-NGLs) ranged typically from 1,800 to 2,500 Gb, with the resulting dates for the corresponding global peak or plateau in production (predicted prior to the large global fall in oil demand triggered by the 1978 price shock) mostly lying around the year 2000.

The next section examines some somewhat later URR estimates, up to the year 2005; where these cover a range of categories of liquids.

### *4.2 Somewhat later estimates of the global URR for conventional oil, and also non-conventional oil and other liquids, 1992 to 2005.*

These later data are given in Tables 2 and 3. Table 2 gives URR estimates mostly associated with a prediction for date of peak, and are data mostly from non-'mainstream' forecasts, except for the significant 1998 IEA forecast (that has been written about by several authors in Campbell, Ed., 2011); and the 2002 BGR forecast. Table 3 gives forecasts from a range of the 'mainstream' forecasters, none of which saw oil production as reaching peak or plateau within their forecast horizons; and where for some of these URR estimates were given.

**Table 2.** Later estimates for the global URR of conventional oil, and also non-conventional oil and other liquids, 1992 to 2005.

| Date | Author | Hydrocarbon | Ultimate Gb | Date of global peak |
|---|---|---|---|---|
| 1992 | D. Meadows *et al.* | Pr. Cv. Oil | 1800-2500 | no prediction |
| 1995 | Petroconsultants, '95. | Cv. oil (xN) | 1800 | About 2005 |
| 1996 | Ivanhoe | Cv. Oil | ~2000 | About 2010 [Prodn. mirrors Disc.] |
| 1997 | Edwards | Pr. Cv. Oil | 2836 | 2020. |
| 1997 | Laherrère | All liquids | 2700 | no prediction |
| 1998 | IEA: *WEO 1998* | Cv. Oil | 2300 ref.case | 2014 |
| 1999 | Magoon of the USGS | Pr. Cv. Oil | ~2000 | Peak ~ 2010. |
| 2000 | Bartlett | Ditto. | 2000 & 3000 | 2004 & 2019, respectively. |
| 2002 | BGR (Germany) | Cv.&Ncv. Oil | Cv.: 2670 | Combined peak in 2017. |
| 2003 | Deffeyes | Cv. oil* | | ~2005 [Hubbert linearisation.] |
| 2003 | P-R Bauquis | All liquids. | 3000 | Combined peak in 2020. |
| 2003 | Campbell-Uppsala | All h'carbons | | Combined peak ~2015 [Includes gas infrastructure constraints.] |
| 2003 | Laherrère | All liquids | 3000 | See notes. |
| 2003 | Energyfiles Ltd. | All liquids | Cv: 2338 | 2016 (if 1% demand growth). |
| 2003 | Energyfiles Ltd. | All h'carbons | | Combined peak ~ 2020 [Includes gas infrastructure constraints.]. |

| Date | Author | Hydrocarbon | Ultimate Gb | Date of global peak |
|---|---|---|---|---|
| 2003 | Bahktiari model. | Pr. Cv. Oil | | 2006 - 7 |
| 2004 | Miller, BP- own model | Cv.&Ncv. Oil | | 2025: All poss. OPEC prodn. used. |
| 2004 | PFC Energy | Cv.&Ncv. Oil | | 2018 - Base case. |
| 2005 | Deffeyes | Cv. oil* | | 2005 [Hubbert linearisation.] |

**Notes:** Cv.: Conventional. Pr.: Probably. xN: ex-NGLs. +N: incl. NGLs. All liquids: Conv. and Non-conv. oil plus NGLs. All h'drocabons: Conv. and Non-conv. oil and gas. Gb: billion barrels.
* = and probably all-oil.
'Ultimate': ultimately recoverable resource (URR); equal to the recoverable portion of the original total in-place resource.
Laherrère: Laherrère, probably as much as anyone, knows how uncertain are the oil data, particularly as far as which of the possible non-conventional oils, and oil substitutes, are likely to yield useful volumes on a world scale. At this date (2003) he was reluctant therefore to break this 3 Tb estimate into components; but a reasonable guess (personal communication) was: 2.0 Tb for conventional oil, 0.3 Tb for NGLs, 0.3 Tb for tar sands, 0.3 Tb for Orinoco and other very heavy oils, and 0.1 Tb for refinery gains and GTLs etc.
*Source: Bentley & Boyle (2008); Detail on sources is given in the Annex.*

The conclusions from Table 2 are:

- This later range of URR estimates and production forecasts explicitly sometimes included allowance for the production of non-conventional oils, and other liquids,
- As these forecasts were made well after the 1970s price shocks, allowance was now included for the fall in demand that had resulted from the period of oil high prices.
- Within this period, two 'mainstream' forecasts did predict a peak in oil production; that of the IEA 1998 forecast, and the Germany BGR forecast in 2002.
- URR estimates for *conventional* oil were mostly still in the range 1,800 to 2,500 Gb; (Bartlett's 2,000 and 3,000 Gb data were more of a 'let's see when peak is, if the URR has these values').
- URR estimates including non-conventional oil, or all-liquids, increased the URR up to ~3,000 Gb.

Within this period, we can also examine a number of the more typical 'mainstream' forecasts; these are given in Table 3.

**Table 3.** Data on a number of 'mainstream', mostly non-peak forecasts, 1998 - 2005.

| Date | Author | Hydrocarbon | Ultimate (Gb) | F'cast date of peak (by study end-date) | World prod. Mb/d 2020 2030 |
|---|---|---|---|---|---|
| 1998 | WEC/IIASA-A2 | Cv. Oil | | No peak | 90 100 |
| 2000 | IEA: *WEO 2000* | Cv. oil (+N) | 3345 | No peak | 103 - |
| 2001 | US DoE EIA | Cv. Oil | 3303 | 2016 / 2037*** | Various |
| 2002 | US DoE | Ditto | | No peak | 109 - |
| 2002 | Shell Scenario | Cv.& Ncv. Oil | ~4000* | Plateau: 2025 – 2040 | 100 105 |
| 2003 | 'WETO' study | Ditto | 4500** | No peak | 102 120 |
| 2004 | ExxonMobil | Ditto | | No peak | 114 118 |
| 2005 | IEA: *WEO 2005* | | | | |
| | Reference Sc. | Ditto | | No peak | 105 115 |
| | Deferred Invest. | Ditto | | No peak | 100 105 |

**Notes:** Mb/d: Million barrels per day. Cv.: Conventional. Ncv: Non-conventional. (+N): Plus NGLs.

*Shell's ultimate of 4,000 Gb was composed of: ~2,300 Gb of conventional oil (incl. NGLs); plus ~600 Gb of 'scope for further recovery' ('SFR') oil; plus 1,000 Gb of non-conventional oil.

**WETO's ultimate of 4,500 Gb is for conventional oil only; it started with a USGS figure of 2,800 Gb, then grew this by assuming large and rapid recovery factor gains to 2030.

***These are results from an EIA paper that assumed a global URR of 3,303 Gb and then applied various R/P ratios (and hence post-peak decline rates). An R/P ratio of 10, giving the peak at 2037, matched US experience (for 100 years!), but based on 1P reserves data. This gave a very sharp post-peak rate of production decline. Only the post-peak decline rate corresponding to the peak date of 2016 (for this URR of 3,303 Gb) was realistic in terms of typical regional oil production behaviour; the EIA paper did not seem to recognise this.

The conclusions from Table 3 are;

- Over this period, the bulk of 'mainstream' forecasts predicted no peak in oil production out to 2020, or 2030.
- Use was now being made of the USGS year-2000 Assessment data (the 3,303 and 3,345 Gb estimates), see the next section on USGS estimates.
- Shell's values for the size of the components of the 'all-oil' URR were sensible, as is the plateau for 'all-oil' from 2025. But there was possibly no recognition that the earlier peak of conventional

oil production would lead to historically high oil prices (and hence global recession, and subsequent reduced economic activity) that the world has experienced since 2008.

- The WETO study URR of 4,500 Gb for conventional oil only was an outlier. (A technically polite way of saying 'very unlikely', in terms of ability of this oil to impact medium-term oil production, given the quantity of oil discovered to-date, and the declining long-term trend in oil discovery in new fields.)

Next we look at estimates for global URR generated by the United States Geological Survey (USGS) from 1991 to 2012.

## 4.3 USGS Assessments, 1991 to 2012

Over many years now the USGS has been unique in the world as a public institution in carrying out high quality detailed basin-based assessments of global undiscovered oil, for which they are much to be thanked. (Other institutions also carry out various important fossil fuel assessments, including Germany's BGR, France's IFP, the British Geological Survey and the World Energy Council, but the USGS assessments of undiscovered oil and gas are by far the most extensive.)

In assessments carried out prior to the year-2000, the USGS had formally decided to exclude reserves growth in these calculations, recognising that while such growth appeared large in the US, this was fundamentally an issue with US data, and it would be inappropriate to apply reserves growth factors to 2P data for regions outside the US (see comments at the time by C. Masters).

This changed with the Year-2000 Assessment, where a reserves growth factor was applied by globally (and possibly also by region, though not by country). Reserves growth refers to the change over time (usually growth, though sometimes reduction, especially for smaller later fields) in the estimated size of the total recoverable oil that will be produced by a field over its lifetime (and hence also in a region, if field data are aggregated). Reserves growth is a wonderfully complex topic, see for example the discussion in Bentley (accepted for publication).

Some earlier, and the Year-2000, USGS global assessments are tabulated in Table 4.

**Table 4.** Summary of USGS Global Oil Assessment Data, 1991 to 2000.

| Date of Assessmt. | (Date of data used) | Category of oil included | URR | | | |
|---|---|---|---|---|---|---|
| | | | F95% | Mode | Mean | F5% |
| 1991 | (1990) | Cv., no RG, ex-NGLs | | 2200 | | |
| 1994 | (1993) | Cv., no RG, ex-NGLs | 2100 | 2300 | 2400 | 2800 |
| 2000 | (1996) | Cv., no RG, ex-NGLs | 2000 | 2300 | 2300 | 2800 |
| | | RG | 200 | 700 | 700 | 1100 |
| | | Cv. + RG; ex-NGLs | 2200 | 2900 | 3000 | 3900 |
| | | *NGLs + own RG* | *200* | *300* | *400* | *500* |
| | | **Cv.+RG+NGLs+RG** | **2400** | **3200** | **3300** | **4500** |

**Notes:** Data have been rounded to make comparisons easier.

All data need re-checking; they are probably correct but please do not quote these data without checking back to the original sources; and please bring any errors to my attention.

Data in Gb (billion barrels). Cv. Conventional oil. RG: Reserves growth. NGLs: Natural gas liquids. F95%, mode, Mean, F5%: Probabilities.

URR: Ultimately recoverable oil resource. Here given by:

*URR = Cumulative produced + ['2P'] Reserves + Yet-to-find*

and, where stated, includes allowance for 'reserves growth', and NGLs, including the latter's own allowance for reserves growth.

USGS Assessments primarily look only at the question of the quantities of undiscovered oil, and only in specific basins outside of the US. Hence some basins, generally assumed less productive, are not included in these data. Moreover, the US data included in the above global totals come from other assessments, or from non-USGS sources (but are included in USGS' own summary tables). Likewise, the cumulative production and '2P' reserves data used to generate the above URR totals are not USGS data, but are drawn from other sources; in the case of the Year-2000 Assessment, from Petroconsultants' data.

*Sources: USGS Assessments, as of dates specified.*

The conclusions from Table 4 are:

- If we look at the 'mode' values for global URR (which in turn, are close to the 'mean' values), we can see that if only conventional oil is considered (i.e., excluding allowance for reserves growth or NGLs), then these changed little between assessments. They also sat comfortably within the URR range of 1,800 to 2,500 Gb that had been common for a long time (Tables 1 and 2).
- If reserves growth and NGLs (and the latter's own scope for reserves growth) are added, then the potential global URR can be

quite a bit larger, up to the mean value of 3,345 Gb generated by the Year-2000 Assessment.

[Perhaps the readers will excuse an anecdote here; to use a term first heard from my PhD supervisor Professor Peter Dunn, I have reached my anecdotage:

At the time the Year-2000 USGS Assessment was being prepared, I was working as the employee of the Oil Depletion Analysis Centre (ODAC) in London. I knew that the USGS was working on the Assessment, and would regularly 'phone their competent and amiable Ron Charpentier, who was in charge of pulling the final data together, to ask what the new global URR number was likely to be.

When told it was to be a big jump from previous assessments, as it now included reserves growth, I said that there was a danger that this new number would become 'carved in stone', and mislead the mainstream analysts. Ron saw this point of view, but pointed out that the Assessment methodology, including how reserves growth was calculated and why it was applied, would all be clearly stated, and it was up to analysts who used the data to make their own judgement on the issues. Both of us were right: the data, methods and reasoning were there for all to see; but also the new URR number of 3,345 Gb did indeed get 'carved in stone', and used without caveat in subsequent IEA and other 'mainstream' forecasts; see Table 3.]

The caveat that needed to be applied was to compare such a relatively high URR estimate with the amount of conventional oil that had been discovered to-date. No-one suggested that 3,345 Gb was too high *in principle*, but the questions centred on how fast the yet-to-find contained in this quantity would be found, given the much lower amount that had been found at that date, and the declining discovery rate of oil in new fields; and under what technical conditions and oil price, and how quickly, could the reserves growth also assumed in the URR estimate come on-stream. To some analysts the 3,345 Gb URR (incl. NGLs) seemed to require rather heroic assumptions, compared to lower range for the global URR for conventional oil that had seemed reasonable since about 1970, of 1,800 - 2,500 Gb (ex-NGLs).

We now turn to the updated more recent 2012 USGS assessment data. First we re-present the USGS Year-2000 data of Table 4 in a way to facilitate comparison with the 2012 data; this is done in Table 5.

**Table 5.** USGS Year-2000 Assessment: World conventional oil, including NGLs.

| Report Date | Date of data (1 Jan) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 2000 | 1996 | Cum. Prod | Reserves | --------Y-t-F-------- | | | -----Ultimate----- | | |
| | | | | F95 | Mean | F5 | F95 | Mean | F5 |
| Total ex-RG | | 717 | 959 | 495 | 939 | 1589 | 2171 | 2615 | 3265 |
| RG | | | | | | | 265 | 730 | 1197 |
| **Total+RG** | | | | | | | **2436** | **3345** | **4462** |

**Notes:** All data in Gb. Cum. Prod.: Cumulative production. Reserves: 2P reserves; data from Petroconsultants S.A. Y-t-F: Yet to find (i.e., 'undiscovered') Ultimate: Ultimately recoverable resource ('URR'). F95, Mean, F5: Probabilities. RG: Reserves growth in the 2P data.

*Source: USGS (2000).*

Unlike Table 4 which just shows the URR totals, this table shows the components of this, broken out as cumulative production, 2P reserves, and yet-to-find. As can be seen (and Table 4 showed, rounded), a mean global allowance of 730 Gb was made for reserves growth, resulting in the total mean global URR for conventional oil of 3,345 Gb, if both NGLs and reserves growth were included.

Now we turn to the 2012 data. The USGS team in 2000 had accepted that their methodology for reserves growth was in part preliminary, based largely on US experience, so in work leading up to the 2012 Assessment a new approach was adopted. For the 2012 report they write: "Unlike past assessments of reserve growth that relied on statistical extrapolations of growth trends, this [new] methodology includes detailed analysis of geology and engineering practices observed in developed fields." But they add: "Because of the paucity of data for many fields outside the United States, data acquired from U.S. fields undergoing reserve growth were used as analogs in this study." The resulting Year-2012 data, comparable to Table 5, are shown in Table 6.

**Table 6.** USGS Year-2012 Assessment: World conventional oil, including NGLs.

| Report Date | Date of data | | | | |
|---|---|---|---|---|---|
| 2012 | 2009-11 | Cum. Prod | Reserves | Y-t-F | Ultimate |
| | | | | Mean | Mean |
| Total ex RG | | 1250 [1] | 1110 [2] | 780 [3] | ~3150 |
| RG | | | | | 723 |
| Total+RG | | | | | ~3850 |

**Notes:** All data in Gb. RG: Reserves growth.

- Though Year 2012 data are given by probability, this time these values have not been summed statistically as was the case in year-2000, so the 2012 totals are given only for the mean values (shown here).
- As far as I am aware, the USGS year-2012 Assessment did not give data for global cumulative production or 2P reserves, nor for yet-to-find in the US. Hence the following approximations have been made in compiling this table, with data not from the USGS year-2012 reports shown in the Table in italics:

1 Cum. Prod.: Based on the 2011 IHS Energy 'Liquids' value given in the text of Miller and Sorrell (2014), of 1,248 Gb. Then a guessed 100 Gb subtracted to take off the non-conventional oil component in the IHS 'Liquids' category; and a further guessed 100 Gb added back on for production 2012 to 2015 inclusive.

2 Reserves: 2P reserves. Likewise, based on the 2011 IHS Energy 'Liquids' value given in the text of Miller and Sorrell (2014) for cumulative discovery of 2,486 Gb, and with 1,248 Gb subtracted off to give 2P reserves. Then reduced to a guessed 1,100 Gb to reflect only conventional oil.

3 Y-t-F: Yet to find. The USGS Year-2012 Assessment gives an estimate for the global mean undiscovered, excluding U.S. Including NGLs this is 732 Gb. Adding on a guessed 50 Gb for the U.S. (reduced from the specified 83 Gb for the U.S. Y-t-F in the Year-2000 Assessment) gives an approximate total for global yet-to-find, including the U.S. and NGLs, of ~780 Gb.

*Note that all three of these estimates (Cum. Prod., Reserves, and Y-t-F), while certainly approximate, would probably agree with data the USGS would produce for these categories for conventional oil plus NGLs to perhaps +/- 50 Gb or so.*

*USGS Sources:*

- An Estimate of Undiscovered Conventional Oil and Gas Resources of the World, 2012. USGS Fact Sheet: 2012-3028, March 2012.
- Assessment of Potential Additions to Conventional Oil and Gas Resources of the World (Outside the United States) from Reserve Growth, 2012. USGS Fact Sheet: 2012-3052, April 2012.
- Assessment of Potential Additions to Conventional Oil and Gas Resources in Discovered Fields of the United States from Reserve Growth, 2012. USGS Fact Sheet: 2012-3108, August 2012.

As can be seen from Table 6, the Year-2012 Assessment puts global reserves growth of conventional oil (plus NGLs) as ~ 720 Gb, i.e., essentially unchanged from the Year-2000 value.

By contrast, given the passage of time, and hence the amount of oil that has been produced from 1996 to about 2010 or so, and the revised view of the quantity of oil yet to be discovered, the Year-2012 Assessment puts the global conventional oil URR (including NGLs), if based on the approximations made here, at ~3,850 Gb; i.e., about 500 Gb higher than the figure estimated in the Year-2000 Assessment.

So the key question is: How does this new estimate for the global URR of conventional oil agree with the amount of conventional oil that has been discovered to-date? This will be addressed in the second part of this paper, which will cover information from:

- IHS Energy, 2011
- The US EIA, 2013
- IEA *Resources to Reserves* report, 2013
- The oil models described in this journal to-date (Campbell, Smith, Laherrère, Miller and McGlade).
- The 'mainstream' forecasts for which charts were given in Issue-2 of this journal (IEA, BP and ExxonMobil).

It is the intention that a summary table of 'all-liquids' URR estimates from different authorities will be generated, including the components of this, to allow useful comparisons to be made.

## 5. CONCLUSIONS

The main conclusions to be drawn from the first part of this paper are:

1. Only a few years back, the difference between oil forecasts was very large; some seeing the peak production of conventional oil as being soon, others seeing no peak of this oil out to the end of their forecast horizons. Recently this gap has closed somewhat, with most forecasts now recognising the importance of modelling the various components of 'all-liquids' production, and where the global production of conventional oil (essentially, oil in fields) is expected to reach a peak (or at least a plateau) in the near to medium term.

2. Perhaps surprisingly, in the view of the 'near-peak' group of oil forecasters, the estimated size of the global URR for conventional oil (ex-NGLs) has not changed by much over the years, despite increasing knowledge and technological progress, still taking a value in the range 1,800 - 2,500 Gb.
3. There is, however, still wide disagreement over what is the most realistic value to assume for this URR; a disagreement that feeds directly into how near or far forecasters see the peak of global conventional oil production. This topic will be examined in detail in the second part of this paper.

## Annex: Data Sources for Tables 1 to 3

### *A. General background and early sources*

In the 1970s and early 1980s a variety of groups forecast the date of global oil peak, probably in some (or even most) cases using either Hubbert's own findings, or his general methodology. These forecasts included:

- ESSO used an ultimate of 2,100 Gb to expect: "oil to become increasingly scarce from about the year 2000", (The Ecologist, 1972, pp 18 and 130).
- B. Ward and R. Dubois, in a landmark environmental report to the United Nations, said: "One of the most quoted estimates for usable reserves [of oil] is some 2,500 billion barrels. This sounds very large, but the increase in demand foreseen over the next three decades makes it likely that peak production will have been reached by the year 2000. Thereafter it will decline", (Ward and Dubois, 1972, p184).
- The UK Department of Energy, in commenting on the expected date of the UK peak, noted that the world peak would not be far behind, at: "about [the year] 2000." (UK Dept. of Energy, 1976, p12).
- P. Ehrlich et al. calculated the global oil peak date at the year 2000 based on their 'high-estimate' for conventional oil endowment of 10,900 trillion MJ (~ 1,900 Gb), (P. Ehrlich et al., 1977, pp 400-404).
- Shell in 1979 expected oil production to: "plateau within the next 25 years." However, they did not specify the data behind this forecast. (Shell, 1979, p 1)

- The World Bank, on the back of an ultimate of 1,900 Gb, expected oil to "plateau around the turn of the century." (World Bank, 1981, p 37, 46).

A number of other authorities at about this time also gave estimates for size of the global oil ultimate but did not carry these through to predictions for the date of peak. These included:

- The Science Policy Research Unit (SPRU) at Sussex University, which gave a range for the world oil ultimate as 1,800 – 2,480 Gb, (Cole et al., Eds., 1974).
- The World Energy Conference (WEC, now the World Energy Council), whose Commission report included a Petroleum Resources and Production study by the Institut Français du Pétrol. This estimated the world oil ultimate as 1,803 Gb. In commenting on this WEC/IFP study, J. Keily noted presciently: "The world can have the energy it needs for the rest of the 20th century. But … with a false sense of security, many will not look over the horizon to the early part of the 21st century. … It is only by looking beyond the early 2000s that we can see how fast the change will come." (J. Keily, 1980, pp 26 - 32.)
- D. Meadows et al. in Beyond the Limits (sequel to Limits to Growth) quoted the range for the world's oil ultimate as 1,800 – 2,500 Gb (D. Meadows et al., 1992). No forecast for date of peak was given; the group perhaps not aware of the serious implications of combining these data with a 'decline from the mid-point' model.

## *B. The above sources, and others for Tables 1 to 3*

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