Vol. 1, No. 1, January 2015 Petroleum Analysis Centre

THE OIL AGE

Understanding the Past, Exploring the Future

Background & Objectives

This journal aims to address 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 six-fold in parallel, with far-reaching economic and social consequences. The *Second Half* of the Oil Age now dawns.

This is seeing significant changes 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 will present the work of analysts, scientists and institutions addressing these topics. Content will include 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.

A subscription form is provided at the back of the journal.

Published by

Petroleum Analysis Centre,
Staball Hill,
Ballydehob,
Co. Cork,
Ireland

ISSN: 2009-812X

Design and printing: Inspire Books, Skibbereen, Co. Cork, Ireland

Table of Contents

Editorial

Welcome to the first issue of this journal. As the objectives state, the journal aims to cover the full range of topics associated with the transition through the 'Oil Age'.

The emphasis in the first few issues will be on physical aspects of the topic, including oil and gas modelling and net-energy, as readers may appreciate these foundations being laid. Future issues will cover wider topics, including the impact of changes in oil & gas supply on agriculture, industry and wealth creation, and on society in general.

Mankind has been fairly poor at understanding its oil-supply situation in the past. For this reason, articles related to the history of the 'Oil Age' are of interest, including problems with past oil and gas forecasting, to help explain 'how we got where we are'. Further still, it is the intention to include articles on the future of energy and other resources, including comprehensive energy/economic systems models; and also on the politics and governance of the 'Oil Age', whether this be 'trust busting', pro-rationing or cartels in the past, or possible transition paths, resilience policies, and scope for international collaboration in the future.

The contents of the current issue are:

Opinion piece:

- *The Oil Age in an Historical Perspective* by Colin Campbell. This article helps set out the reasons for the production of this journal.

Peer-reviewed articles:

- An article, also by Campbell, on his global hydrocarbon forecast model. This is a 'field-aggregate' model, where production across all fields within an oil or gas producing country is modelled as a single unit. Campbell has recently expanded his model to include accounting for oil and gas net-energy.
- An article by Michael Smith of Globalshift Ltd., on the company's global hydrocarbon forecast model. This is a 'bottom-up' by-field model, forecasting production on the basis of individual oil and gas field data where available.
- A short article by myself. This is in the form of a 'student assignment', and shows that surprisingly accurate estimates of oil production can be made using primarily the public-domain data in the BP *Statistical Review of World Energy*.

Charts:

Charts and graphs can be key to understanding any complex topic. This first issue includes:

- Data on oil price and oil supply since 1965 (BP Statistical Review).
- Estimated quantities of recoverable oil by category of oil, vs. production cost. This includes the relatively modest amount available from 'fracking' (IEA: Resources into Reserves).
- Three graphs from Jean Laherrère:
  - Global oil and gas '2P' discovery, and production, 1900 - 2010.
  - Global oil reserves: Comparing 1P with 2P data, 1920 - 2012.
  - Showing how a region's 'creaming' curve can be used to estimate the region's URR.

Discussion:

(i). OPEC & FSU Reserves data

Campbell's model (like that of Laherrère) in assessing future production of conventional oil significantly reduces the size of proved-plus-probable reserves that some industry datasets hold for specific OPEC and Former Soviet Union (FSU) countries.

For OPEC countries, this partly reflects the probable 'quota wars' reserves overstatements that took place mainly in the 1980s; while FSU countries reserves in some industry datasets are treated by both Campbell and Laherrère as closer to proved-plus-probable-plus-possible ('3P') values, rather than proved-plus-probable ('2P').

(ii). Net-energy

As mentioned above, Campbell's hydrocarbon forecast model has recently been expanded to account for net energy. This is an important step, and makes it - at least to my knowledge - the first detailed oil and gas forecast model to include this aspect.

Energy return on energy invested (EROEI; usually EROI in the US) is likely to be a crucial aspect of mankind's energy future, but is almost always overlooked. It is important because nearly all of the 'new' fuels, whether from fossil hydrocarbons (oil from fracking, tar sands, Orinoco heavy, kerogen oil, GTLs, or CTLs; and gas from fracking, other tight gas, CBM, UCG, or methane hydrates), or nuclear or renewables, have - or will probably have when commercial - lower EROEI ratios than most current fuels, and in many cases very much lower. Thus moving to these sources of energy is likely to significantly reduce the amount of useful energy available to mankind.

But virtually all current energy modelling - whether from the IEA, the IIASA GES study, the UK's DECC, or other 'mainstream' modellers, simply does not take falling EROEI ratios into account, and therefore paints almost certainly a far more optimistic picture than reality. It is a reasonable guess that in time all such models will come to include this aspect; and this journal looks forward to reporting on these as they become available.

(iii). Size of the URR for conventional oil.

When comparing oil forecast models (such as, in this case, Campbell's with Globalshift's) observation of many current models indicates that a large part of the difference lies in the assumption made for the size of the ultimately recoverable resource ('URR') of conventional oil. Such an assumption can be explicit; or be implicit by, say, summing the cumulative production of conventional oil to end-2100. This also is an important topic, and will be covered in more detail in future issues of this journal.

(iv). Use of public-domain data.

The background to the 'student assignment' given here is a little curious: For years I have told students that because the oil reserves data in the BP Stats. Review are so poor, no useful forecast of oil production can be generated from these. This is primarily because the proved reserves ('1P') data have not reflected the actual amounts of known reserves of oil, as indicated by the - generally very expensive - oil industry proved-plus-probable ('2P') reserves.

But provided some additional information is used, in fact fairly reasonable approximate oil forecasts can be made with the BP Stats. data. This is potentially quite important, because much of the current lack of comprehension of the oil situation has stemmed from the inability of many analysts to access the 2P data; and, indeed, often from their not knowing of the need to use these data in the first place. But by being able to make approximate forecasts primarily from public-domain 1P data, this lack of comprehension about future oil supply may well be reduced.

I hope that you find these articles useful. By all means contact me should you have corrections, criticisms or comments.

- R.W. Bentley, Jan. 2015.

The Oil Age in an Historical Perspective

C. J. CAMPBELL

1. INTRODUCTION

Geologists study the Earth's long history, spanning billions of years, and identify the sequence of rocks laid down, each having its own characteristics reflecting whatever environmental conditions obtained at the time of its deposition. Some of these rocks contain fossils which have provided a record of evolution that led to the species *Homo sapiens*, about 200,000 years ago. It is therefore natural for geologists to have a long view of history and try to identify the changes that unfolded.

Over the past two centuries, geologists have been employed to identify oil deposits, which led them to understand the conditions under which the resources were formed and preserved. It was far from an exact science, and in earlier years they relied on technology no more advanced than the hammer, hand lens and notebook with which to describe the rocks, using their logic and imagination to interpret circumstances at depth and between isolated outcrops. While they naturally understood that oil and gas were finite resources formed in the geological past, meaning that they were subject to depletion, they were barely conscious of the practical limits. The world was a big place, much of it being unexplored.

Later, came more advanced geophysical techniques whereby an explosive charge was released at the surface, and recorders measured the time taken for the echoes from deeply buried rock surfaces to return to the surface, allowing the geology at depth to be mapped in detail. In addition, geochemical studies began to reveal the precise nature of the rocks in which the oil was formed, allowing them to be identified with more confidence.

These few words provide a background justifying the recognition of an *Oil Age*. It is not only a fleeting epoch in geological terms but also represents no more than a brief span in human history. It lasts only about three hundred years, with significant production spanning no more than about a century.

What could be called *Modern Man* evolved about 12,000 years ago when he took to settled agriculture. For energy, he relied mainly on his own muscles and those of his horses or oxen. Trade in food and other commodities also developed, and money based on gold and silver was increasingly used to facilitate barter. Various communities prospered, leading to growth of kingdoms and empires. However history shows that often an epoch of expansion was followed by one of contraction when the empire exhausted the resources at its disposal. Climate changes also led to bad harvests and sometimes starvation. The transitions were often associated with serious wars and conflicts.

This suggests that the *Oil Age* will wax and wane, as have all other ages in history. The expanding supply of easy energy that oil provided during the *First Half* of the *Oil Age* made it one of the most remarkable chapters of human history, prompting rapid economic growth and trade as well as great technological progress. The human population expanded six-fold in parallel. But logic suggests that the *Second Half*, which now dawns, will be marked by a corresponding contraction of supply, changing the world in radical ways. While this seems so obvious in an historical context, it is very difficult for people living to-day to come to terms with the reality of what unfolds.

The issue of so-called *Peak Oil* has attracted much attention over the past decade or so. A debate rages as to the precise date of peak production, but this misses the point when what really matters is the vision of the long decline in production that comes into sight on the other side of it. Economic theory has it that market forces and technological advances solve all. Indeed this is justified to a degree, insofar as soaring oil prices over the past few years have led to the development of costly *Non-Conventional* sources including so-called *Tight Oil and Gas* which are obtained by artificially fracturing rocks lacking adequate natural porosity and permeability.

2. THE STATUS OF DEPLETION

Before addressing the status of oil and gas depletion it may be useful to briefly cover petroleum geology to explain its occurrence in Nature. There are four main elements: source, reservoir, trap and seal which are briefly described below:

Source: Restricted seas and lakes became stagnant when the surface waters were heated in a warm climate inhibiting circulation. Anoxic conditions developed at depth in these circumstances such that the organic remains from algae and other sources were converted into a chemical known as kerogen. Much of the world's oil comes from just two epochs of global warming, 90 and 150 millions ago. The rocks laid down in such circumstances are dark-coloured clays and claystones, which sometimes smell of oil. When buried to a depth of about 2000 m, the kerogen is heated enough to be converted into oil. Once formed, it migrated upwards through the rocks to zones of lesser pressure provided that fissures or porous and permeable carrier-beds provided pathways. Gas was formed in a similar way from more carbonaceous material as found in the deltas of rivers. Oil overheated by deep burial was also converted into gas.

Reservoir: We are all familiar with a damp sandy beach with the water being held in the pore space between the grains of sand. When buried such beach sands are compressed into sandstones, and some continue to contain sufficient preserved porosity and permeability to form reservoirs for migrating oil, with fractured limestones being another common type. Typically a good reservoir has as much as 25% pore-space, but there is a wide range.

Trap: In some cases, the migrating oil encountered an inclined porous and permeable sandstone carrier bed leading to the surface, in which case it escaped and was degraded, with the tar sands of Canada being a well-known example. But in other cases the rocks were folded by earth-movements into dome-like features known as anticlines, in which the migrating oil and gas collected at the crest of the structure. Other traps were formed by geological faults and where the reservoir thinned and pinched out.

Seal: Oil and gas would have leaked from a reservoir over time from a trap unless it was capped by an effective seal of impermeable rock such as clay or salt.

This summarises some of the geological factors for the entrapment of oil and gas, with relative timing being another important factor. For obvious reasons, the prime prospective tracts were identified first as were the larger fields within them, being too big to miss. But as the prime provinces were depleted, attention has turned to ever smaller and subtle prospects which occasionally deliver a surprise find. As the onshore regions were depleted, the industry explorers turned offshore looking in ever deeper waters, which called more advanced technology. Oceans cover much of the Planet's surface but only a few areas beneath them have the right geological conditions to hold oil or gas, and most of these have now been identified.

It is also important to distinguish the different categories of oil and gas, each having its own costs, characteristics and depletion profile.

Status of Depletion

It is obvious that the production in any oilfield commences after the first well is drilled and the necessary facilities installed. Production then grows as more wells are added, to reach a peak or plateau before declining as the pressures fall and less remains to be extracted. Every effort is made to extract the last drop, where this is helped by higher oil prices and the application of costly specialized technology.

But eventually the field is no longer viable and is abandoned. Norway is one of the countries to publish valid field data, and the graph in Figure 1 shows the depletion of the Draugen Field as a typical example. Production commenced in 1993 and peaked in 1999 when 36% of its oil had been extracted. 90% of its oil has now been extracted, but the tail may drag on for a few more years.

A country's profile is the sum of its fields, being influenced especially by a small number of giant fields, and naturally also moves from growth to decline as illustrated by the production of the United Kingdom as shown in Figure 2. The anomalous fall near peak was due to an accident at the Piper Field that temporarily cut overall production as safety work was carried out across the industry.

It is of course not always as simple as that, because a field may have multiple reservoirs and subsidiary minor traps. This in turn poses difficulties in defining an oil field and the exploration boreholes (known as *New Field Wildcats*) drilled in the search. Many of such boreholes in the

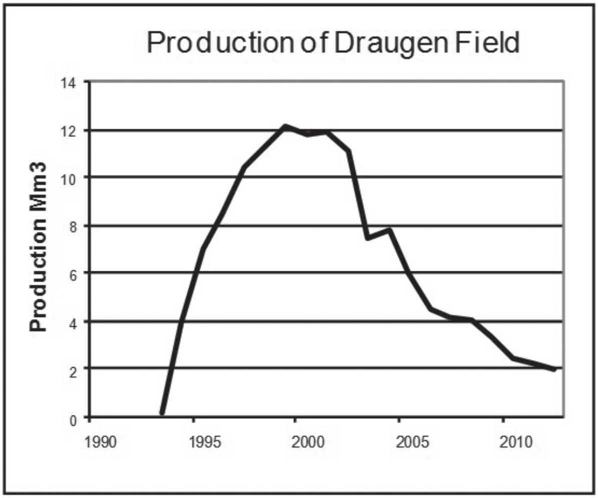


Figure 1: Production of Norwegian Draugen oil field. Source: NPD

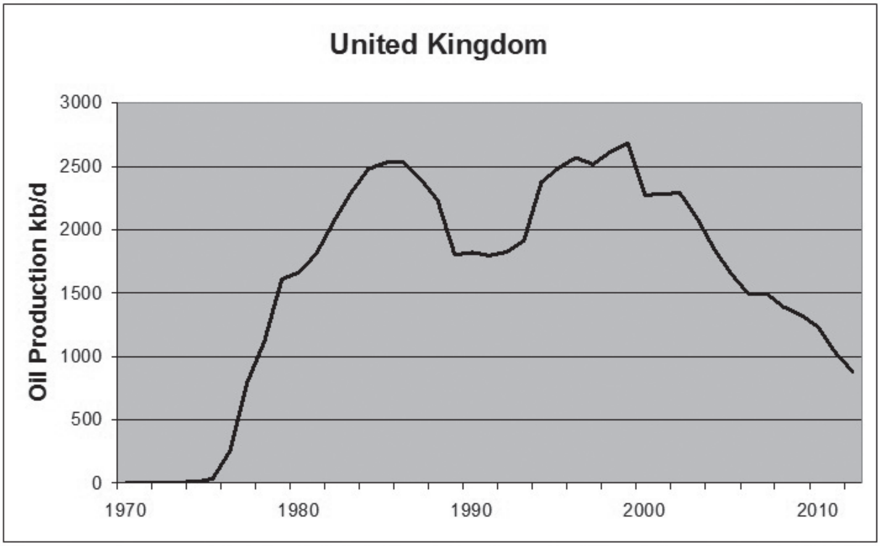


Figure 2: UK Oil Production. Source: DECC.

United States would be better defined as *New Pool Wildcats*, searching for minor outsteps from existing fields.

The depletion profile of a country consists of the sum of its existing fields in production plus provision for new discovery. There are two principal techniques for determining the size of the resource: the so called *creaming curve* on which cumulative exploration boreholes are plotted against cumulative discoveries, and the *parabolic fractal* of field size against rank. Ideally such should be applied to *Petroleum Systems* having common geological characteristics, but they give reasonable results when applied to countries.

Determining the status of depletion is not advanced science, but severe difficulties are faced because the public data are so unreliable, and even the confidential industry databases face increased challenges in tracking the activities of the minor exploration companies that have proliferated in recent years, and in dealing with political distortions imposed on some national statistics, especially those of OPEC countries, where the production quota is in part set by reported reserves.

Figure 1 in the article that follows represents a reasonable representation of the global oil and gas position, although naturally the details evolve over time as more valid information becomes available. *Regular Conventional Oil* peaked in 2005 and that of all categories of oil may do so not too far from now. The peak of all categories of gas may follow around 2020. The decline rates of both oil and gas are at no more than a few percent a year, so unforeseen political and economic factors may well shift the indicated peaks by a few years. That said, the overall profile shown in the Figure is believed to be realistic, suggesting that oil production will have fallen to about half its present level by 2050, and that gas production will be about 20 percent lower by the same date. There will be little left by the end of this century, as the Oil Age draws to a close.

3. ADDRESSING THE CONSEQUENCES

An adage, sometimes attributed to Schopenhauer, may have got it right which said: 'All truth passes through three stages: first it is ridiculed, second it is opposed, and third it is accepted as self-evident.' We may still be in the second stage in relation to addressing Peak Oil.

The transition to the *Second Half* of the *Oil Age* has probably already been characterised by tension, with riots and revolutions breaking out in many countries. It seems these were often triggered by soaring food prices and growing unemployment, which are largely the consequence of soaring oil prices. Agriculture has been described as a process that turns 'oil into food', so dependent has it become on oil and gas for energy. The countries of the Middle East and North Africa seem to have been particularly affected.

In addition, many countries built up massive debts as their economies expanded in the latter parts of the *First Half* of the *Oil Age*, and are now in deep deficit, suggesting perhaps that inflation may prove the only practical method to dispose of this debt.

By contrast, some countries have already recognised the significance of oil-based energy, and more may follow the example of Argentina that has already banned exports. It makes eminent national sense to preserve as much as possible for future national use, although this offends against a principle of globalism, where the resources of any country are deemed to belong to the highest bidder. Al Gore, the former US Presidential candidate, sums up the challenges in coming to terms with what unfolds in his excellent book: (see box)

He also addresses the many adverse environmental impacts of the *Oil Age*, when forests were cut down, and ever more people move to live in urban circumstances, depending on trade and food imports from distant places; with transport making heavy demands for oil. The streets of even remote villages are choked with traffic, while airliners leave vapour trails in the skies above. Manufactured goods contain a large amount of embedded energy, and even the climate may be

> *"We find it hard to imagine, much less predict, a sudden systemic change that moves our world from beneath us and takes us from one equilibrium to a new profoundly different equilibrium, although it can sometimes be anticipated if we can identify a threshold beyond which an obviously different pattern must obtain."*
>
> Gore A., 2007, Earth in the Balance – Forging a new Common Purpose.
> ISBN 978-1-84407-484-6

changing as a consequence, as it has done many times in the geological past.

A moment's reflection of these factors indicates what an exceptional age it has become. The aim of this journal is to raise awareness of the many facets of the *Oil Age*, and to help encourage positive responses to the problems that are not too far away.

Postscript

The foregoing does not cover the recent collapse in oil price. It is a large and complex subject but in brief results from the following factors. The previous high prices prompted a fall in demand and a move in the United States to tap more non-conventional Tight Oil by fracking. The wells are expensive and short-lived, and it is reported that on average they require an oil price of at least $80 a barrel to be viable, but large numbers were drilled causing a glut of oil. This put pressure on OPEC, especially Saudi Arabia, its largest producer, which finally decided to ignore its OPEC obligations to cut production to support price. This led to a collapse in price to around $50 a barrel. It has led to a fall in fracking and prices have recovered to around $60 a barrel. It is too soon to forecast the future trend, but it is likely to be upward.

Modelling Oil And Gas Depletion

C. J. CAMPBELL

1. INTRODUCTION

Oil and gas fuel the modern world, but are finite natural resources subject to depletion. Today more than fifty countries are producing less oil than at some date in their past, with some countries being long into decline. The study of hydrocarbon depletion is thus a critical issue for humankind. But the topic is a good deal less than an exact science, mainly because of the very poor data that are available.

This article summarises the data and methodology used by the author in his current oil and gas forecast model.

2. DATA

As already mentioned, the data for such modelling are generally poor, and there are historical reasons for this.

In the United States much of the onshore mineral rights were held by the landowner, which carried financial implications as an oil discovery became a valuable asset. It led the Stock Exchange to impose strict rules as to what could be reported as reserves. They were designed to prevent fraudulent exaggeration, but under-reporting was smiled on as laudable caution. The international oil companies quoted on the Stock Exchange were subject to the same rules. Reserves were classified as *Proved,* *Probable,* and *Possible* with the meanings the words imply. It was normal to estimate the size of a field on the basis of its *Proved* in full, two-thirds of its *Probable* and one-third of its *Possible*. More recently, probabilistic methods have also been employed, with the *Mean* or *Mode* values being taken as the best estimate.

There are also many commercial and political factors to be taken into account. The oil companies competed with each other, and naturally aimed to maximize their profits. Opening up a new prolific province such as Texas could give a glut of oil, depressing price with far-reaching financial consequences. This prompted moves to restrict production to support the price. In 1928, the major companies met at the Achnacarry Castle in Scotland to sign the *As-Is Agreement*, which set relative production limits; and in 1930 the US Government restricted production to a certain number of days a month in a policy administered by the Texas Railroad Commission.

Russia nationalised its oil industry in 1928, followed by Mexico ten years later, which set examples for Venezuela and several Middle East countries to do so later still. In 1960, the major producing countries formed OPEC to limit production between themselves to support price based on their respective reported reserves, oil revenue having become a critical component of their national budgets.

The commercial oil companies naturally needed to follow what their competitors were doing around the world. This led to the creation of a confidential industry database managed by Petroconsultants in Geneva. It maintained informal contacts with the companies and tracked their operations around the world, collecting information on concessions, the location of exploration wells, the size of discoveries and the level of production. The companies wanted valid information, and hence also gave this in return. But Petroconsultants changed ownership with the death of its owner in 1995, and some of the special relations with the oil companies were lost. Other commercial databases have since been built, but they are costly and subject to strict legal confidentiality, making it difficult for analysts outside the industry to gain access.

The main public-domain sources of oil and gas data are: the BP *Statistical Review*, the *Oil & Gas Journal*, *World Oil*, and the US Energy Information Administration. In addition, various countries publish national statistics, one of the best being that provided by the Norwegian Petroleum Directorate. In earlier times, the industry was dominated by seven major oil companies, but recent years have seen the proliferation of small promotional companies, and this also explains in part why gathering valid data has become more difficult.

It is important also to mention that OPEC official *Proved Reserves* have become extraordinarily unreliable. In 1985, at a time of low oil prices, Kuwait increased its reported reserves from 64 Gb to 90 Gb, although nothing significant had changed in its oilfields. The data suggest that the country may have changed to reporting its *original* rather than *remaining* reserves by not deducting past production; as indeed is normal industry practice when determining the respective ownership of an oilfield that crosses a lease boundary or frontier.

In 1987, Kuwait reported a possibly genuine further small increase in its reserves to 92 Gb, but that seems to have been too much for the other OPEC members. Abu Dhabi matched Kuwait's reserves exactly (up from 31 Gb); Iran went one better, to 93 Gb (up from 49 Gb); and Iraq out-did both at an even 100 Gb (up from 47 Gb). Venezuela for its part increased its declared proved reserves from 25 Gb to 56 Gb, but this included its *Heavy Oil* that had not previously counted for quota purposes. Saudi Arabia could not match Kuwait's move because it was already reporting larger reserves, but in 1990 increased its declared reserves from 170 to 258 Gb.

The oil minister of Kuwait has recently stated that the country's *Proved Reserves* stand at 28 Gb and the *Proved & Probable* at 51 Gb. This sounds reasonable: adding 51 Gb to current cumulative production of 41 Gb does indeed give *original* reserves (i.e., before production started) of 92 Gb. The distortions are important because of the large share of world production coming from the OPEC countries.

Finally, it is worth noting that the recent boom in 'fracking' *Tight Oil and Gas*, though yielding significant additional supplies in the US, partly reflects promotion and speculation by small companies, as actual profits are minimal. This speaks of a radical change in the nature of the oil industry, as no company would follow such an approach if adequate alternative supplies were available.

3. MODELLING DEPLETION

The foregoing has tried to summarise the nature of the oil business, by way of an introduction to the forecast model described below. The steps taken in the analysis for this model are listed, and the final results can be seen in Figure 1, and in detail by country in the recent update of an 'Atlas' of oil and gas depletion' published by the author in 2013 [9].

Ideally the regions modelled should be *Petroleum Systems*, namely areas having common geological conditions, but in general oil forecast modelling is more often done by general geological basin, or by country. The latter approach is easiest as this is how the data are often classified. It is the approach adopted for the model described here, where each of the world's 64 largest oil and gas producing countries is modelled, plus an 'other' category that combines the small producing countries.

Modelling countries separately is particularly helpful in identifying anomalies and uncertainties in the data, particularly once *Depletion Rates* are calculated. Results are summed to give regional and world totals. Calculations run from when production started in each country out to 2100. The spreadsheets perform the calculations annually from 1930 to 2050, and use single-number aggregates for data and calculations prior to 1930, and for the period 2051 to 2100.

Modelling discovery and production to the end of the present century, rather than to some hypothetical date when production stops, has been found expedient for several reasons. It avoids the need to worry about the fairly irrelevant 'tail-end' of production, recognising that the last barrel is unlikely to be found or produced. Also it allows a country's *Total Production to the end of the Century* ('*Total*') to be split into that from *Known Fields* ('reserves'), and that from fields Yet-to-Find. This avoids the many ambiguities surrounding the data and definitions of reserves. Also, by each category being expressed as a percentage of '*Total*', it allows the reasonableness of the past and future discovery to be compared on the basis of what is known about each country's petroleum geology.

Two examples of the spreadsheets used are given in the Appendix. The analysis involves the following steps for each country modelled:

Step 1.

To model future total oil and gas production correctly, it is important to identify and model individually the different categories of oil and gas, as each has its own endowment, production characteristics, cost range, and depletion profile. Unfortunately there is no standard classification for categories of oil and gas, and this is the cause of much confusion in the public-domain oil and gas statistics. The following categories are used in the model:

1. *Regular Conventional Oil and Gas*: Oil from fossil sources, other than from the categories listed below. (A liquid, known as *condensate*, which naturally condenses from gas, is treated together with *Regular Conventional* oil). *Regular Conventional Oil and Gas* make up the majority of all oil and gas currently produced.

2. *Heavy Oils:* Oils with a density greater than 17.5° API, including bitumen. (Degree API is a measure of density). There is no agreed standard cut-off for the definition of *Heavy oil*: Canada, for example, uses 25° API, while Venezuela uses 22° API. The figure chosen for the model, of 17.5° API, is relatively low; but is seen as useful so that all oil that can be produced in more or less normal ways is included as *Regular Conventional.*

3. *Oil Shale*: Oil produced by heating immature source-rocks to retort the kerogen contained therein.

4. *Tight Oil and Gas (*also called *Shale Oil and Gas):* Otherwise conventional light oil, and gas, that is derived from rocks lacking adequate natural porosity and permeability, but which can yield adequate production when artificially fractured. This oil and gas is modelled distinct from *Regular Conventional* because of the large number of wells that need to be drilled, and the rapid declines typical from such wells (and hence also the relatively high energy requirement per average quantity produced).

5. *Deepwater Oil and Gas*: Oil produced from water depths greater than 500m.

6. *Polar Oil and Gas*. Oil and gas produced from fields located above the Arctic Circle. Both *Deepwater* and *Polar* are modelled distinct from *Regular Conventional* because of their generally higher cost, and typically rather different production profiles, than the latter.

7. *Natural Gas Liquids* from gas plants (where production, though included in the oil data, follows gas field discovery and production).

8. *Other Non-Conventional oils* (coal-to-liquids, gas-to-liquids) *and gases* (coalbed methane, gas from underground coal gasification, possible methane hydrates, etc.)

Not modelled are liquid or gas fuels produced from biomass. *Regular Conventional* oil has dominated past production, and will continue to do so for many years to come. The peak of its production in 2005 was therefore a critical turning point in global oil supply.

Step 2.

The next step is to input past production by year. Published production data are reasonably reliable, although war-loss, which is to be regarded as production in this context insofar as it reduces reserves by like amount, is usually not taken into account but is included in the model. The spike in 1992 oil production in Figure 1 reflects Kuwait's war-loss.

It is not always easy to distinguish oil and gas production by the categories given earlier, but an attempt has to be made even if the result is no more than an approximation. This difficulty is however relevant only in those countries having a spread of different categories. In the literature production is normally reported in thousands of barrels a day (kb/d), which in the model is converted into billion barrels a year (Gb/a). These data are then summed by year to give cumulative past production, and this in turn determines the annual percent depleted and the *Depletion Rate* (annual production as a percent of total future production) once Step 3 has been completed.

Step 3.

The modeller must now take a deep breath and try to make reasonable estimates of the *Total quantities to be produced by 2100*, for each oil and gas category.

For *Regular Conventional* oil and gas, the following three statistical methods can be used: a) the *Creaming Curve* which plots cumulative discovery against cumulative exploration wells ('new-field wildcats') and extrapolates the trend to asymptote; b) the *Parabolic Fractal* which plots individual field size against rank on a log-log scale; and c) the *Derivative Logistic* which plots annual/cumulative production against cumulative production, and extrapolates any indicated trend. The first two methods need access to industry proved-plus-probable ('2P') data. The third approach works with public-domain data, but sometimes is not very useful, especially if a country's production is still some way before its peak. All three approaches are used where possible, and the results compared. Deriving the *Totals to be produced by 2100* is an iterative process, and is subject to examination of other relationships. For example, if the indicated current *Depletion Rate* for a country should exceed about 7% it suggests that the *Total produced to 2100* has been under-estimated.

Particular care is needed with former Soviet Union ('FSU') countries, as here the industry data on discoveries are probably closer to proved-plus-probable-plus-possible ('3P') than 2P, and need to be reduced. An estimate of the reduction ratio to use can be obtained by examination of plots of individual field production vs. cumulative production. Such plots, once a field is in decline, linearise exponential decline, and hence allow an estimate to be generated for the field's ultimately recoverable resource ('URR').

Significant efforts must also be made to arrive at sensible data for the OPEC countries. As explained in the section above on data, the public-domain reserves data for these countries are dubious, with in the past the declared proved (1P) reserves often, against logic, *exceeding* the data held in the industry databases for the countries' 2P reserves. Moreover, in recent years, in some industry databases and for some OPEC countries, the 2P data have grown to be closer to the public-domain 1P data. One approach employed in the model to address these uncertainties is to reduce an OPEC country's public-domain reserves by its cumulative production over the period that these reserves have remained static. Other approaches are also used. Overall, considerable judgement is needed to come up with consistent, justifiable data for the OPEC countries.

For oil and gas other than *Regular Conventional*, different approaches are needed, see Step 8.

Step 4.

Subtract *Past Production* from the *Total to 2100* to deliver *Future Production* and then estimate the percentage of *Future* coming from *Known* fields, namely '*Reserves',* based on published and available confidential numbers which commonly show a range, sometimes a wide one. Subtracting the *Known* from the *Future* delivers the *Yet-to-Find*.

There is a difficulty with so-called *fallow fields*, which are discoveries that have not been developed for whatever reason and are not therefore counted as having *Reserves*. Their holdings, to the extent they enter the database, can best be treated as *Yet-to-Find*. It is another iterative process to try to come up with a reasonable working hypothesis, recognising that it is subject to revision as better information becomes available.

Step 5.

Input reported discovery by year, again from industry '2P' data, distinguishing that in giant fields (>500 Mb), and then apply a small *growth* factor so that the total matches the sum of the assessed *Past Production* and the *Known Future*. The sum gives the total discovered to-date which is a useful statistic. Then, input past exploration drilling in so-called *New Field Wildcats* by year and estimate the future rate, assuming, say, a ten percent annual decline in a mature country. *New Field Wildcats* need to be distinguished from *New Pool Wildcats*, referring to additions to existing fields, and any reserve revisions have to be backdated to the date of the original discovery.

Step 6.

Take another deep breath and estimate the future production *profile* by year based on several considerations. If the country has passed its midpoint of depletion and is in decline, it may be assumed that the decline continues at the current *Depletion Rate*. Naturally there will be departures from the indicated downward trend for all sorts of above-ground reasons, but the model self-adjusts, so that if less than the amount estimated is produced in a particular year, more is left for the future and vice versa. If the country has not yet reached its midpoint, as is the case with most OPEC countries, the production to midpoint has to be assessed in the light of local circumstances, it being normal to assume a plateau. Today, some fifty countries are past their midpoint of *Regular Conventional* oil, many being long into decline.

The analysis for gas production is similar to that described above for oil, but the model assumes that gas production normally reaches a plateau, set by infrastructure limits, including pipeline capacity, lasting from when a country is 30% to 70% depleted, after which production declines steeply at the then-current depletion rate. For gas it is also necessary to take into account the amounts flared, and that re-injected to maintain pressure in oilfields.

Step 7.

Into the spreadsheets insert oil and gas consumption, and also other parameters of interest such as population, the country's area, population density, and trade; and summarise the various relationships involved, including the time-lag between the actual date of peak production and the indicated date of the indicated midpoint of depletion. It is a lengthy iterative process to use the various relationships to try to spot and correct any anomalous situations.

One statistic *not* to use is the *Reserve to Production Ratio* quoted in years, as reported for example in the BP *Statistical Review*. A recent Prime Minister of Britain was almost certainly being advised by this ratio when he declared that there could be 'no oil supply problem for 40 years', even though it is absurd to assume that current production can stay flat for a given number of years and then stop dead overnight, when in practice all oilfields decline slowly to final exhaustion.

Step 8.

The *Non-Conventional* resources of oil and gas have also to be evaluated, each having its own production characteristics. It is a much more difficult task, but fortunately carries less weight, given that world production is dominated by *Regular Conventional* oil, and that this will continue to be the case for many years to come. A variety of sources need to be used, including industry Associations for the type of resource considered, and realistic estimates made of likely production into the future, taking into account resource production costs and projected industrial capacity.

Step 9.

Finally, the data generated by the model can be presented in a variety of tables and graphs by country and by region, as well as for the World as a whole. The graphs include:

Graph 1: Production of Oil and Gas by Year 1930-2050 (area graph).

Graph 2: Status of Oil Depletion showing: a). initial endowment b). production c). remaining reserves (area graphs).

Graph 3: Cumulative discovery vs. Cumulative new-field wildcats (line graph).

Graph 4: Derivative logistic – 'Hubbert linearisation': Annual/Cumulative production vs. Cumulative production (line graph); with an arrow extrapolating the indicated trend. A clear trend is apparent in some countries, but not in all.

Graph 5: Production with a superimposed Hubbert Curve (Logistic).

Graph 6: Discovery (bars) versus production (line).

Figure 1 is an example a 'Type-1' graph, showing the model's forecast for all fossil oil (i.e., excluding biofuels), and all fossil gas (excluding biogas), out to 2050. There are many caveats on such a projection as examination of the methodology set out above will have made clear, but

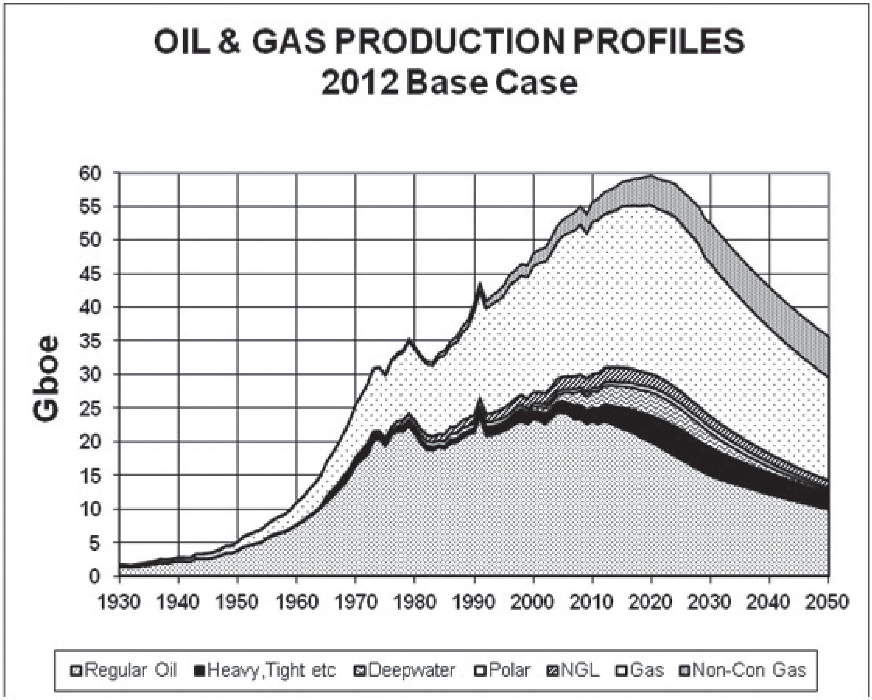


Figure 1: Current model forecast, as of 2014, reflecting an updated '2012 Base Case' model.

This gives total global production of all fossil oil and gas (and hence excludes production of oil and gas from biomass). Production of coal and gas to liquids, and of oil reported from kerogen, are not modelled explicitly but are assumed small throughout this forecast period. For definitions of the various categories of oil and gas shown see those in 'Step 1' above. (NB: The spike in production in 1992 reflects war loss in Kuwait, when some 2 billion barrels of oil went up in smoke.)

The Figure shows that the production of Regular Conventional oil peaked in 2005; while the production of all categories of oil is expected to peak in 2015; and all categories of gas in 2024. In this model, the global production of all fossil hydrocarbons reaches its peak about 2020.

Given the uncertainty of the underlying data, the importance of this Figure is not in the precise dates given, but in the decline indicated once the various peaks are past.

what is also clear is the nature of the hydrocarbon supply challenge that Mankind almost certainly faces in the relatively near future.

4. MIDPOINT PEAK

As mentioned, the study of oil and gas depletion is far from an exact science, principally because the data (and especially the public-domain data) on production, reserves and discovery are unreliable, and also because there is no standard classification of the different categories of oil and gas. Jean Laherrère has recently given a full review of these problems [31].

But, oil being a finite resource, it is evident that there is such a thing as an *Oil Age* in an historical context. In a general sense, it is reasonable to assume that the economic expansion of the *First Half* of the *Oil Age* will be followed by contraction during the *Second Half*, and that the turning point will come approximately at the midpoint of depletion. That said, there are departures in individual countries for all manner of reasons, including political incentives and constraints on both exploration and production.

5. NET-ENERGY

A new feature of the model, not yet included in the 'Atlas' [9], is accounting for *Net-Energy*. This topic has been studied for some years, especially by Professor Charles Hall and his group at the State University of New York at Syracuse. It is a critical issue, and also has an important impact on the range of uncertainty regarding future production forecasts of the different categories of oil and gas. It is the focus of a recent book by Tim Morgan, *Life After Growth* [53] which states that it is energy, not money, that drives economies.

The data in Figure 1 can be modified to reflect not the *total* barrels of oil (and barrels of oil equivalent, for gas) produced, but the '*net-energy*' contributed to society by these barrels after the energy required for their production is subtracted off.

There are many difficulties in determining net energy, and indeed in defining what should be covered in such calculations. The assessment could simply refer to exploration activity, or to the wellsite operations themselves, or ideally should also cover the energy consumed in pipelines, tankers, refineries and filling stations before it reaches the final consumer.

Calculating the actual energy consumed is thus a difficult task, but in a sense a comparison between the price of crude oil and marketed product gives an indication, although naturally distorted all by sorts of financial elements, including taxation, oil company profit and administrative charges.

In the initial model reported here the data for net energy are very approximate, and open to criticism and revision. So this calculation should be seen mainly as just a 'first pass' to understand the general nature of the issue. The assumptions used are:

An average oilfield of *Regular Conventional* oil will yield 20 times the total energy consumed in its exploration, production, refining and delivery over its lifetime; its 'energy return on energy invested' ('EROEI') of these activities. Put another way, for every 100 barrels of oil produced by the field, its yields 95 useful barrels of energy to society. So the 'net-energy' variant of the model multiplies the barrels of *Regular Conventional* oil in Figure 1 by 0.95 to yield an estimate of the useful 'net-energy' barrels.

Net energy yield varies over the life of a field. An aging North Sea field requires more maintenance than when at its prime, and improved recovery technology also makes heavy demands on energy. There are also close links to the field's profitability, which is ultimately based in part on the net energy the field delivers, so more detailed modelling would vary the EROEI ratio assumed across a field's life.

Deepwater oil and oil from *Polar regions* might be expected to have somewhat lower EROEI ratios. Here an EROEI of five is assumed for both types of oil, resulting in net-energy factors of 0.80.

Further down the energy scale, so-called *Tight Oil*, obtained by artificially fracturing productive rocks lacking sufficient porosity and permeability to form a normal reservoir, is assumed in the model to yield only four times the amount consumed in all the steps to produce; so barrels of *Tight Oil* in Figure 1 are multiplied by 0.75 to yield net barrels.

At possibly the bottom of the current energy scale is oil from *Tar Sands*, where EROEIs of 3 have been quoted in the literature (and even as low as 1.5), but where for simplicity the model assumes the same EROEI (and hence 'net-energy' factor) as for *Tight Oil*. (A similar low EROEI may well apply in future to oil produced by retorting kerogen from oil shales.)

NGLs (produced from gas) are modelled on their energy content, so total barrels produced are multiplied by 0.80 to give the net-energy barrels.

Regular conventional gas is assumed – on very limited data – to have perhaps the same EROEI of 20 as regular conventional oil; while Non-conventional gas (which can come from a wide variety of sources) is assumed to have an approximate EROEI of 6.7 (giving a net-energy factor of 0.85).

Putting these data together yields Figure 2, which should be compared to Figure 1.

Note: As the text mentions, there are significant uncertainties in the data used here, and in the calculation, that await resolution.

As can be seen the main overall effect to reduce the total barrels of oil equivalent produced (down from a peak of 60 Gboe/yr. to 55 Gboe/yr. when measured in net-energy terms); and in particular to reduce the contributions to world supply that come from the various *'Non Regular Conventional'* hydrocarbons.

Moreover, net energy carries another implication in relation to the resource assessment of the different categories of oil and gas, and their future production profiles. If, for example, estimates of future production

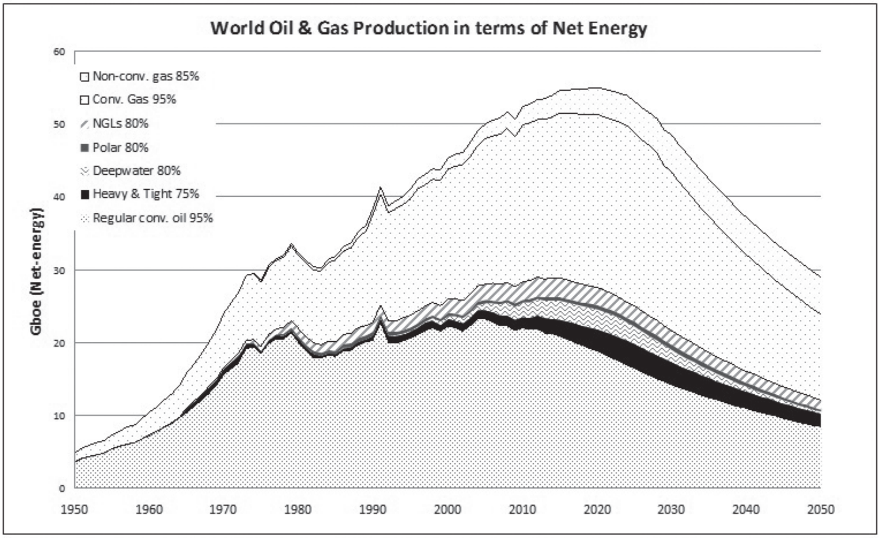


Figure 2: The same data as Figure 1, but now expressed in terms of 'net-energy barrels of oil equivalent' (i.e., barrels of useful energy delivered to society), once the energy used in the production of the oil and gas is subtracted off.

from a field of *Regular Conventional Oil* range from 100 Mb to 150 Mb, this gives a range of uncertainty of 50 Mb. If this oil has a net energy yield factor of 0.95, the corresponding uncertainty in terms of net energy is 47.5 Mb. If, on the other hand, a field of *Tar Sands* or *Tight Oil* with the same volume range has a net energy factor of 0.75, the uncertainty is less, at only 37.5 Mb.

This is an important result because it means that *Regular Conventional* oil and gas will continue to dominate world supply in *net-energy* terms, and the uncertainties relating to the amount coming from the *Non-conventional* oil and gas sources with lower net-energy yields are less significant.

6. CONCLUSIONS

It is recognised that this study does not perhaps comply with strict scientific standards, as the input data are far from reliable, and there are many places where estimates - and even guesses - of the numbers to use are needed. In particular, as mentioned, official reported oil and gas reserve estimates are subject to many commercial and political pressures.

Moreover, it is accepted that earlier versions of this model placed the global 'all-oils' peak around 2008, not then giving sufficient attention to the growth of costly *Non-conventional* oils (such as *Light-Tight*), made possible by the dramatic rise in oil prices.

Nevertheless the model is believed to deliver a valid overall picture of the situation, which is of critical world importance given the overwhelmingly dominant role of energy from oil and gas for society. The main values of the study are to highlight the coming post-peak decline, and to identify the need for better information with which to improve the model.

Despite these caveats, there is however increasing recognition that the peak of *Regular Conventional* oil was indeed passed in 2005 as indicated by the model (and where, incidentally, this peak came one year after the reported peak of oil production from the six major oil companies).

This peak of *Regular Conventional* oil prompted the oil price to surge to almost \$150/bbl in mid-2008, compared with an average of \$25/bbl over the previous century (2011 dollars; BP *Statistical Review*), and to stay in the \$80/bbl to \$100/bbl range for the majority of the period since. The high oil price has, in turn, contributed to the current global economic and financial problems, said to rival those of the Great Depression of 1930.

Turning to the various *Non-Conventional* sources, claims are made that these, especially *Light-Tight* oil, will yield significantly higher quantities than indicated here. But if the *net-energy* yield is taken into account, the impact of such increases is likely to be relatively small for the reasons explained above.

Overall, based on this model, it is fairly clear that the *First Half* of the *Oil Age* is about over. Society and governments are likely to have difficulty in coming to terms with what unfolds, as the *Second Half* of the *Oil Age*, with the supply of energy from oil and gas declining from natural depletion, is likely to see radical changes in the way we have to manage our affairs. Moreover, debt, which played a central role in the modern world as bankers lent more than they had on deposit confident of future economic growth, may no longer be so useful a construct as these critical energy supplies decline.

This is not necessarily a doomsday message. Once people come to understand that the depletion of these two critical fossil energy supplies is imposed by Nature, they may react in positive and constructive ways. Renewable energy can increasingly be tapped from wind, wave, tide, geothermal and solar sources; and energy-saving measures, for which there is plenty of scope, become more widely adopted. There may also be a reversion to localism, as people again come to rely on whatever their particular region can support.

It is a fascinating and important subject to observe, and to try to understand. It is hoped that the model presented here can help, in some measure, support the latter objective.

7. BIBLIOGRAPHY & REFERENCES

1. Aleklett K.,2012, *Peaking at Peek.* ISBN 978-1-4614-3423-8
2. Bardi U.,2011, *The Limits to Growth Revisited*. ISBN 978-1-4419-9415-8
3. Bentley, R.W., S.A. Mannan, and S.J. Wheeler, 2007, *Assessing the date of the global oil peak: The need to use 2P reserves.* Energy Policy, vol. 35, pp 6364-6382, Elsevier, 2007.
4. British Petroleum Co., *BP Statistical Review of World Energy*. Published annually by BP, London.
5. Brown L.R., 2012, *Full Planet, Empty Plates.* ISBN 978-0-393-34415-8

6. Campbell C.J., and J.H.Laherrère, 1998, *The end of cheap oil*. Scientific American March 80-86
7. Campbell C.J., 2005, *Oil Crisis*; Multi-Science Publishing. ISBN 0906522-39-0
8. Campbell C.J., 2011, *Peak Oil Personalities*. ISBN 978-1-908378-06-4
9. Campbell C.J., 2013, *Campbell's Atlas of Oil and Gas Depletion*. Springer. ISBN 978-1-4614-3575-4
10. Campbell C.J., 2013, *The Oil Age in Perspective* ; Energy Exploration & Exploitation. vol. 21-2 148-164
11. Clugston C.O., 2012, *Scarcity – Humanity's Final Chapter*. ISBN 978-1-62141-250-2
12. Deffeyes K.S., 2001, *Hubbert's peak - the impending world oil shortage*. Princeton University Press 208pp
13. Deffeyes K.S., 2005, *Beyond Oil – The View from Hubbert's Peak*. Hill & Wang, N. York 202p
14. Dittmar M., 2009, *The Future of Nuclear Energy : Facts and Fiction*. www.theoildrum.com Aug 5- Nov 10. Also a 2011 update
15. Duncan, R.C. & Youngquist, W., 1999, *Encircling the peak of world oil production*. Natural Resources Research, Vo. 8, No. 3
16. Energy Information Administration – annual reports.
17. Fleming D., 2011, *Lean Logic*. ISBN 978-0-955-0849-6-6
18. Gore A., 2000, *Earth in Balance*. ISBN 978-1844-074846
19. Gore A., 2009, *Our Choice – A Plan to Solve the Climate Crisis*. ISBN 978-0-7475-9098-9
20. Hall D.C., 2004. *External Costs of Energy.* Encyclopaedia of Energy 651-667 2.
21. Heinberg R., 2003, *The Party's Over*;.New Society Publishers 274p
22. Heinberg R., 2006, *The Oil Depletion Protocol*. ISBN 10-0-86571-563-7
23. Heinberg R., 2013, *Snake Oil : How Fracking's False Promise of Plenty Imperils our Future*. ISBN 978-0-9767510-9-0
24. Hirsch R.L., R.H.Bezdek & E.M.Wendling, 2010, *The Impending World Energy Mess*. ISBN 9-781926-837116
25. Hughes J.D., 2013 *Drill, Baby, Drill – can unconventional fuels usher in a new era of energy abundance?* Post Carbon Institute ISBN 978-1-482555233

26. International Energy Association, *World Energy Outlook* (published annually)
27. International Monetary Fund, 2012. *The Future of Oil: Geology versus Technology.* IMF Working Paper WP/12/109
28. Klare M.T., 2008, *Rising Powers – Shrinking Planet – The New Geopolitics of Energy*. ISBN 978-0-8050-8064-3
29. Laherrère J.H. 2003, *Will the natural gas supply meet the demand in North America?* International Journal of Global Energy Issues 19 n°1 2003
30. Laherrère J.H., 2013. *Very short world oil and gas production forecasts 1900-2100.* http://www.theoildrum.com/node/10009
31. Laherrère J.H., 2014. *Oil and gas perspectives in the 21st Century*. ESCP Europe London Campus
32. Leggett J., 2005, *Half Gone*. 312p, ISBN 1-84627-004-9
33. Leggett J., 2013, *The Energy of Nations: Risk Blindness and the Road to Renaissance.* ISBN 978-0-415-85782-6
34. Leonard, R., 2013, *The New Oil World : the Game has changed, but how ? Africa is becoming a Major New Player in the new World Hydrocarbon Order*. American Foreign Policy Interests 35:352-359
35. Longwell H.,2002, *The future of the oil and gas industry: past approaches, new challenges*. World Energy 5/3 2002
36. Norwegian Petroleum Directorate. *Facts* (published annually)
37. Perrodon A., J.H.Laherrere and C.J.Campbell, 1998, *The world's non-conventional oil and gas*. Pet. Economist
38. Peters, S., 2004, *Coercive western energy security strategies: Resource wars as a new threat to global security*. Geopolitics, Vo. 9 No 1, 2004
39. Powers L.W., 2012, *The World Energy Dilemma*. ISBN 978-1-59370-271-7
40. Reynolds D.B., 2011, *Energy Civilization – The Zenith of Man.* ISBN 978-0-615-52155-8
41. Rubin J. 2012, *The Big Flat Line: Oil and the No Growth Economy.* ISBN 978-0-230-34218-7
42. Simmons M.R., 2005, *Twilight in the Desert*. ISBN 0-471-73876-X
43. Skipper K., 2001, *Petroleum Resources of Canada in the Twenty-First Century* (AAPG Memoir 74, Chapter 8). ISBN 0-89181-355-1

44. Skrebowski, C., 2004, *Oil field mega-projects 2004.* Petroleum Review Jan. 2004
45. Stanton W., 2003, *The Rapid Growth of Human Populations 1750-2000.* ISBN 0-906522-21-8
46. Tolub L and M.A. Erb 2010, *Oil price band for the next decade : Utopia versus Reality.* Swiss Derivatives Review, Issue 43, Summer 2010.
47. Yergin D.,1991, *The Prize: the epic quest for oil, money and power.* ISBN 0-671-50248-4
48. Youngquist W., 1997, *Geodestinies: the inevitable control of earth resources over nations and individuals*. ISBN 0-89420-299-5
49. Ziegler, W.H., C.J.Campbell & J.J.Zagar, 2009, *Peak Oil and Gas*; Swiss Bulletin for Applied Geology 14/1-2
50. Zittel W., J. Zerhausen & M.Zerta., 2013, *Fossil and Nuclear Fuels – the Supply Outlook*. Energy Watch Group. www.energywatchgroup.org
51. Hall C. et al., 2003, *Hydrocarbons and the evolution of human culture*: Nature v. 4626.
52. Morgan T., 2014, *Life after Growth – How the Global Economy really Works and why 200 Years of Growth are Over*. ISBN 978-0857-193391

APPENDIX: EXAMPLE SPREADSHEETS OF THE OIL & GAS FORECAST MODEL

A1. Example Spreadsheet for Mexico

Below is part of the spreadsheet for *Regular Conventional* oil (as defined in Step 1 of the main text, above) for Mexico. The full range of individual year rows covers 1930 to 2050. Columns are listed alphabetically (A to O) from left to right, and the rows are numbered consecutively downwards. There is a corresponding spreadsheet for Mexico for *Conventional* gas.

Other categories of oil and gas (for countries that do, or will, produce these) are modelled in small additional spreadsheets (not shown here, but given in [9]); and results are accumulated to yield global production forecasts of ‘all fossil oil’, and ‘all fossil gas’.

COUNTRY		Mexico						REGION		L. America		Revised	26/4/14	2013
PRODUCTION		Gb	%	**MIDPOINT**			**TRADE**	**PEAK**		**RESERVES**			**WILDCATS**	
Current		0.94		Gb		28.00		Date	2004	O&GJ	10.26	Av	Past	1574
PAST		41.84	75%	Date		2000		Depleted	58%	BGR	11.39	13.37	Future	119
FUTURE		14.16	25%	Lag		4		Disc	1977	BP	11.40	SD	Av Disc	34.68
Known	90%	12.75	23%	**GIANTS**				Lag Disc	27	ENI	10.16	0.64	**DEP RATE**	
To be found		1.42	3%	Total		30.17	**Post**	Wildcat	2003	EIA	10.26	19.452	MP	3.6%
Discovered		54.58	97%	%		55%	**2012**	Static Yr	0	Static	0.00	Growth	Current	6.2%
TOTAL		56.00		Last		1999	DR	5yr Trnd	-1%	Other		91%	Final	
Consume kb/d		2082	**Per Cap**	6	**Pop.**	117.6	3%	**Area**	1.966	**Density**		60	**Trade**	480
DATE	**PRODUCTION**					**Cons**		**DEP.**	**DISCOVERY**				**WILDCATS**	
	kb/d	Gb/a	Cum	Y-t-P	Dep	**-ume**		**RATE**	Giant	All	Grth	Cum		Cum
Pre 1930			1.56	54.44					2.22	3.72	3.39	3.39		64
1930	108	0.040	1.60	54.40	3%	213	-104			0.00	0.00	3.39	3	67
1931	91	0.033	1.63	54.37	3%	215	-124	0.06%		0.20	0.18	3.57	11	78
1932	90	0.033	1.67	54.33	3%	217	-127	0.06%		0.00	0.00	3.57	3	81
1933	93	0.034	1.70	54.30	3%	219	-126	0.06%		0.00	0.00	3.57	4	85
1934	105	0.038	1.74	54.26	3%	221	-117	0.07%		0.00	0.00	3.57	5	90
1935	110	0.040	1.78	54.22	3%	223	-113	0.07%		0.16	0.15	3.72	6	96

Cell Descriptions

Cell A1 – Country (only significant producers are covered, with the minor producers being lumped together in the World assessment)

Cell C2 – The values are quoted in barrels (42 US gallons)

Cell C3 – Current production for the assessment year

Cell C4 – Past Production, being total produced to the assessment year

Cell C5 – Future Production, being Total (C9) less Past (C4)

Cell C6 – Known Future, being the assessed percentage of Future coming from Known Fields: in other words *Proved & Probable Reserves*. It is a critical step in the assessment, based on the numbers quoted in public databases (Cells K&L 3-7) and in available industry sources. It is an iterative process to try to come up with a plausible, albeit uncertain, value. Additions coming from enhanced recovery and/or fields not yet in production are treated as To-be-Found (C7).

Cell C7 – To be Found: this is the Future (C4) less the Known (C6).

Cell C8 – Discovered: this is the sum of Past Production and Known Future (C4+C6)

Cell C9 - TOTAL: this is an assessment of the total to be produced by the end of the century. It is the most difficult step in the assessment, and takes into account the status of depletion and the current Depletion Rate. If, for example, a country has a Depletion Rate in excess of about 6% in would be reason to increase the TOTAL.

Cell C10 – Consumption. Note that the EIA, which is the principal source, evidently includes the consumption in refineries and ships' bunkers, with some small islands and countries have anomalously high consumption per capita.

Cells D4-8 – List of the values as a percentage of the Total (C9)

Cell E10 – Consumption per capita (measured in kb/d).

Cell G3 - The amount produced at the Midpoint of Depletion when half the Total has been produced (C9/2).

Cell G4 - The date of Midpoint.

Cell G5 - The time lag between the date of the actual Peak of production and the Midpoint (J3-G4).

Cell G7 – The total amount of oil found in giant fields (>500 Mb). They are important, usually containing a large proportion of the country's total and are found early, being too big to miss.

Cell G8 – The percentage discovered in Giant Fields.

Cell G9 – The date of the last giant discovery.

Cell G10 – Population of the country.

Cell H10 - The assumed future decline rate of consumption.

Cell J3 – The date of peak production.

Cell J4 – The percentage produced at the date of peak production.

Cell J5 – The date of the peak of discovery.

Cell J6 - The time-lag between peak discovery and peak production in years.

Cell J7 - The date of the peak in the drilling of exploration wells ("wildcats").

Cell J8 - The EIA is taken as the prime source of production and reserve data by country, but in many cases it shows a country having the same reserves year or year, despite it being utterly implausible that new discovery would exactly match production except on very rare occasions. In practice, it probably means that the EIA have simply not received new information to update their reserves data. The reserves should naturally fall to match production unless new discoveries are made. This cell lists the number of years of unchanged reports.

Cell J9 – The production trend over the past five years.

Cell J10 – The area of the country including its offshore.

Cells L3-7 - List the reported reserves by the main public sources

Cell L8 - The amount of production during the period of unchanged reserves as reported by the EIA.

Cell L9 – The amount of reserves not classed as Regular Conventional.

Cell M4 – The average of the publicly reported reserve estimates.

Cell M6 – The Standard Deviation of the reported reserve estimates as an indication of the level of uncertainty.

Cell M9 - This is a so-called "Growth Factor" to adjust proportionately the indicted discovery by years in Col. K. so that it matches the assessment made here.

Cell M10 – Population density by area

Cell N1 – Date of revision

Cell O1 – Year of assessment.

Cell O3 – Total number of exploration wells ("*wildcats*") drilled to date.

In principle, they should be exploration wells that if successful find a new field, but in some countries, especially the USA, some wells drilled to find an extension of an existing field are treated as wildcats, and should be deducted.

Cell O4 – Estimated number of future wildcats to be drilled, normally assuming a 10% annual decline in mature countries as fewer and fewer valid prospects of ever decreasing size can be identified and considered capable of delivering a viable find if successful.

Cell O5 - The average past discovery per wildcat.

Cell O7 – The Depletion Rate (Annual as a percentage of estimated Future production at Midpoint (when half the Total has been produced).

Cell O8 – The current Depletion Rate.

Cell O9 – The final Depletion Rate in countries, not yet at midpoint, whose production is assumed to plateau or rise to midpoint and then decline.

Cell O10 – Trade, with export being positive values when production exceeds consumption and vice versa.

Line 13 – Sums any pre-1930 production, discovery and wildcat drilling.

Column Descriptions

Column A – Lists the years from 1930 to 2030 (It is planned in future to change this period to 1950 to 2050, to give more meaningful results.) If a country has passed its midpoint, as have more than fifty, it is assumed that its future production declines at the current Depletion Rate. In the case of countries not yet at midpoint (mainly in the Middle East) it is assumed that production plateaus to midpoint and thereafter declines as the then depletion rate. Political events as for example in Syria or Libya are taken into account showing reduction in production over the near term, before recovering to the indicated available amount.

Column B – Lists annual production in kb/d (thousand barrels a day) by year.

Column C - Converts kb/d in Gb/a (billion barrels a year).

Column D – Lists cumulative production by year.

Column E – Lists the indicated amount of production to be produced in the future by year in Gb.

Column F – Lists the percentage depleted by year.

Column G - Lists consumption by year.

Column H – Lists Trade, namely production less consumption giving exports when positive and vice versa.

Column I – Lists Depletion Rate by year.

Column J – Lists discovery in Giant Fields (>500 Mb) by year.

Column K – Lists all discovery as reported (mainly in confidential databases) with future discovery being estimated on the basis of the average indicated discovery per wildcat.

Column L – Application of a Growth Factor (see Cell M9) so that the reported discoveries are adjusted to match the total discovered as calculated in the model (C8).

Column M – Cumulative discovery per year.

Column N – Number of wildcats drilled per year with the future rate normally being assumed to decline at 10 per cent a year (subject to reassessment).

Column O – Cumulative number of wildcats per year.

Sheet Descriptions

The following regions, made up of the principal producing countries, are recognised:

AFRICA – Algeria, Angola, Cameroon, Chad, Congo(B), Egypt, Gabon, Libya, Nigeria Sudan, Tunisia, Uganda

ASIA-PACIFIC – Australia, Brunei, India, Indonesia, Malaysia, Pakistan, Papua-New Guinea, Thailand, Vietnam

EURASIA (former Communist world) – Albania, Azerbaijan, China, Croatia, Hungary, Kazakhstan, Romania, Russia, Turkmenistan, Ukraine, Uzbekistan.

EUROPE - Austria, Denmark, France, Germany, Italy, Netherlands, Norway, UK.

LATIN AMERICA – Argentina, Bolivia, Brasil, Chile, Colombia, Ecuador, Mexico, Peru, Trinidad, Venezuela.

MIDDLE EAST GULF – Iran, Iraq, Kuwait, Neutral Zone, UAE, Saudi Arabia.

MIDDLE EAST MINOR – Bahrain, Oman, Qatar, Syria, Turkey, Yemen.

NORTH AMERICA – Canada, USA,

MINOR – the other minor producing countries are lumped together.

ROUNDING – A rounding sheet provides a total of 23 Gb.

WORLD – The above sheets are summed to provide a WORLD assessment. The Rounded sheet provides enough to provide a rounded total of 2050 Gb

(Note: There might be a case for reorganising the regions. The former Communist bloc is recognised as Eurasia because of its special past environment and reporting practices.)

A2. Example Spreadsheet for Britain

Britain started the depletion of its oil cautiously, even having a national oil company; but a change of government led to rapid development with capitalistic verve and every technological help. As a result, Britain exported oil for ten years from 1981 at a time of low oil prices, but now finds itself importing 55% of its needs at very high prices.

The calculation in the spreadsheet suggests that the actual peak of production in 1999 came two years after the midpoint of depletion. One of the reasons was the Piper Field accident that affected production over all UK North Sea fields for a period while systemic safety work was implemented.

COUNTRY	United Kingdom				REGION		Europe		Date	9/5/13	2012
PRODUCTION	Gb	%	MIDPOINT		PEAK		RESERVES			WILDCATS	
Current	0.32		Gb	16.00	Date	1999	O&GJ	3.12	Av	Past	3385
PAST	25.40	79%	Date	1997	Depleted	55%	BGR	5.79	4.42	Future	172
FUTURE	6.60	21%	Lag	2	Disc	1974	BP	3.1	SD	Av Disc	9.26
Known 90%	5.94	19%	GIANTS		Lag Disc	25	ENI	2.83	1.27	DEP RATE	
To be found	0.66	2%	Total	12.87	Wildcat	1990	EIA	2.83	7.392	MP	5.3%
Discovered	31.34	98%	%	41%	Static Yr	0	Static	0.00	Growth	Current	4.6%
TOTAL	32.00		Last	1993	5yr Trnd	-7%	Other		95%	Final	
Consume kb/d	1519	Per Cap	9	Pop.	64.1	Area	0.246	Pop.Density	261	Trade	-638

DATE	PRODUCTION					Cons	DEP.	DISCOVERY				WILDCATS	
	kb/d	Gb/a	Cum	Y-t-P	Dep	-ume	RATE	Giant	All	Grth	Cum		Cum
Pre 1930			0.00	32.00					3E-04		0.00		16
1930	0	0.000	0.00	32.00	0%				0.00	0.00	0.00	0	16
1931	0	0.000	0.00	32.00	0%		0.00%		0.00	0.00	0.00	1	17
1932	0	0.000	0.00	32.00	0%		0.00%		0.00	0.00	0.00	1	18
1933	0	0.000	0.00	32.00	0%		0.00%		0.00	0.00	0.00	0	18
1934	0	0.000	0.00	32.00	0%		0.00%		0.00	0.00	0.00	0	18
1935	0	0.000	0.00	32.00	0%		0.00%		0.00	0.00	0.00	0	18
1936	0	0.000	0.00	32.00	0%		0.00%		0.00	0.00	0.00	3	21
1937	0	0.000	0.00	32.00	0%		0.00%		0.00	0.00	0.00	5	26
1938	0	0.000	0.00	32.00	0%		0.00%		0.00	0.00	0.00	15	41
1939	0	0.000	0.00	32.00	0%		0.00%		0.02	0.02	0.02	27	68
1940	0	0.000	0.00	32.00	0%		0.00%		0.00	0.00	0.02	6	74
1941	1	0.000	0.00	32.00	0%		0.00%		0.00	0.00	0.02	6	80
1942	2	0.001	0.00	32.00	0%		0.00%		0.00	0.00	0.02	3	83
1943	2	0.001	0.00	32.00	0%		0.00%		0.00	0.00	0.02	23	106
1944	2	0.001	0.00	32.00	0%		0.00%		0.00	0.00	0.02	12	118
1945	1	0.001	0.00	32.00	0%		0.00%		0.00	0.00	0.02	18	136
1946	1	0.000	0.00	32.00	0%		0.00%		0.00	0.00	0.02	6	142
1947	1	0.000	0.00	32.00	0%		0.00%		0.00	0.00	0.02	5	147
1948	1	0.000	0.00	32.00	0%		0.00%		0.00	0.00	0.02	12	159
1949	1	0.000	0.00	32.00	0%		0.00%		0.00	0.00	0.02	2	161
1950	1	0.000	0.00	32.00	0%		0.00%		0.00	0.00	0.02	3	164
1951	1	0.000	0.01	31.99	0%		0.00%		0.00	0.00	0.02	1	165
1952	1	0.000	0.01	31.99	0%		0.00%		0.00	0.00	0.02	1	166
1953	1	0.000	0.01	31.99	0%		0.00%		0.00	0.00	0.02	5	171
1954	1	0.000	0.01	31.99	0%		0.00%		0.00	0.00	0.02	8	179
1955	1	0.000	0.01	31.99	0%		0.00%		0.00	0.00	0.02	13	192
1956	1	0.000	0.01	31.99	0%		0.00%		0.00	0.00	0.02	6	198
1957	2	0.001	0.01	31.99	0%		0.00%		0.00	0.00	0.02	4	202
1958	2	0.001	0.01	31.99	0%		0.00%		0.00	0.00	0.03	17	219
1959	2	0.001	0.01	31.99	0%		0.00%		0.02	0.02	0.05	12	231
1960	2	0.001	0.01	31.99	0%		0.00%		0.00	0.00	0.05	13	244
1961	2	0.001	0.01	31.99	0%		0.00%		0.00	0.00	0.05	10	254
1962	2	0.001	0.01	31.99	0%		0.00%		0.00	0.00	0.05	6	260
1963	3	0.001	0.01	31.99	0%		0.00%		0.00	0.00	0.05	7	267
1964	3	0.001	0.01	31.99	0%		0.00%		0.01	0.01	0.05	8	275
1965	2	0.001	0.01	31.99	0%	1486	0.00%		0.01	0.01	0.06	28	303
1966	2	0.001	0.01	31.99	0%	1595	0.00%		0.04	0.04	0.10	31	334
1967	2	0.001	0.02	31.98	0%	1718	0.00%		0.00	0.00	0.10	42	376
1968	2	0.001	0.02	31.98	0%	1824	0.00%		0.00	0.00	0.11	41	417
1969	2	0.001	0.02	31.98	0%	1967	0.00%		0.19	0.18	0.29	54	471
1970	4	0.001	0.02	31.98	0%	2081	0.00%	2.60	2.80	2.65	2.94	30	501
1971	5	0.002	0.02	31.98	0%	2090	0.01%	1.90	2.82	2.67	5.61	34	535
1972	8	0.003	0.02	31.98	0%	2211	0.01%	2.12	1.66	1.57	7.17	35	570
1973	9	0.003	0.03	31.97	0%	2280	0.01%	1.00	2.85	2.70	9.87	68	638
1974	10	0.004	0.03	31.97	0%	2120	0.01%	3.21	5.05	4.78	14.65	75	713
1975	34	0.012	0.04	31.96	0%	1860	0.04%	1.04	3.00	2.84	17.49	82	795
1976	253	0.092	0.13	31.87	0%	1848	0.29%		1.00	0.94	18.43	73	868
1977	792	0.289	0.42	31.58	1%	1870	0.91%		1.08	1.02	19.45	80	948
1978	1119	0.408	0.83	31.17	3%	1930	1.29%		0.19	0.18	19.63	37	985
1979	1611	0.588	1.42	30.58	4%	1947	1.89%		0.28	0.27	19.89	41	1026
1980	1663	0.607	2.03	29.97	6%	1725	1.99%		0.21	0.20	20.10	41	1067
1981	1811	0.661	2.69	29.31	8%	1590	2.21%		0.46	0.43	20.53	69	1136
1982	2065	0.754	3.44	28.56	11%	1590	2.57%		0.52	0.49	21.02	92	1228
1983	2291	0.836	4.28	27.72	13%	1531	2.93%		0.49	0.46	21.48	96	1324
1984	2480	0.905	5.18	26.82	16%	1825	3.27%	0.50	1.30	1.23	22.71	149	1473
1985	2530	0.923	6.11	25.89	19%	1617	3.44%		0.56	0.53	23.24	135	1608
1986	2539	0.927	7.03	24.97	22%	1637	3.58%		0.42	0.40	23.64	149	1757
1987	2406	0.878	7.91	24.09	25%	1611	3.52%		0.38	0.36	23.99	94	1851
1988	2232	0.815	8.73	23.27	27%	1692	3.38%		0.97	0.91	24.91	115	1966
1989	1802	0.658	9.38	22.62	29%	1731	2.83%		0.59	0.56	25.47	117	2083
1990	1820	0.664	10.05	21.95	31%	1776	2.94%		1.10	1.04	26.50	168	2251
1991	1797	0.656	10.70	21.30	33%	1803	2.99%		0.47	0.44	26.95	148	2399
1992	1825	0.666	11.37	20.63	36%	1815	3.13%		0.31	0.30	27.25	110	2509
1993	1915	0.699	12.07	19.93	38%	1829	3.39%	0.50	0.65	0.61	27.86	60	2569
1994	2375	0.867	12.94	19.06	40%	1833	4.35%		0.10	0.10	27.95	70	2639
1995	2489	0.909	13.84	18.16	43%	1816	4.77%		0.18	0.17	28.12	63	2702
1996	2568	0.937	14.78	17.22	46%	1852	5.16%		0.40	0.38	28.50	81	2783
1997	2518	0.919	15.70	16.30	49%	1804	5.34%		0.29	0.28	28.78	76	2859
1998	2616	0.955	16.65	15.35	52%	1792	5.86%		0.10	0.10	28.88	56	2915
1999	2684	0.980	17.63	14.37	55%	1797	6.38%		0.11	0.10	28.98	24	2939
2000	2275	0.830	18.46	13.54	58%	1759	5.78%		0.09	0.09	29.06	31	2970

Forecasting Oil & Gas Supply And Activity

Michael R. Smith
Globalshift Limited

ABSTRACT

This article discusses why comprehensive forecasts of oil and gas supply and activity are essential for the oil and gas industry - especially the service sector - to plan future investment. It describes the approach used by Globalshift Limited to achieve a quantitative analysis of past and future oil and gas production, drilled well numbers and associated activities. The discussion emphasises the importance of including and defining all types of hydrocarbon supply and demand in the analysis, along with drilled and active well numbers, to measure and project local and global industry activity. It also stresses the value of transparency in the methods of data collection and forecasting.

Globalshift publishes histories, and forecasts to 2050, of production volumes of hydrocarbon types by country and sedimentary basin, along with numbers of drilled and active wells by country. The forecasts are predicated on the behaviour of producing reservoirs in a finite hydrocarbon system, such as an oil field or a sedimentary basin. In such an environment extraction rates go up and then go down over an extended period. The shapes of the ensuing production and well number profiles always vary due to differences in the geology. In turn they are modified according to rates of investment in down-hole and surface facilities. This has been demonstrated many thousands of times in wells and fields and also in sedimentary basins and countries.

The production forecasts use a bottom-up method - by-field where the data are available - backed up by experiential analysis to discriminate reality from hearsay and cognitive bias. Regional historic and forecast drilling activities, in addition to past production and a range of subjective criteria, are used to provide estimates of potential future output and activity in the short and medium term.

Historic data are drawn from a very wide variety of open-file industry sources. These are inspected and scrutinised for reliability, missing values, ambiguity and reporting bias. Production rates and well numbers are forecast forwards in a variety of profiles dependent on location, data availability, hydrocarbon type, size of resource, history matching, and estimated local and global activity and demand levels.

1. INTRODUCTION

Although oil was used to seal boats in the Middle East at least 5,000 years ago, the first true oil well was drilled in 1859 in Pennsylvania. The subsequent oil boom supplied kerosene for artificial light at prices near US$450 a barrel in today's terms. Diesel and gasoline were just waste products but were eventually adopted into the transport industry for use in internal combustion engines which developed through the 1880s.

After 50 years of slow growth the demand for oil products began to rise rapidly in the 1930s as the transport industry expanded. Most ended up burnt in trains, planes and automobiles and oil was recognized as an important but scarce commodity. The practice of predicting energy supply and demand became important for governments to make strategic decisions over sourcing the means to power and build the economy of a nation and its armies. But it was within the now influential oil and gas industry that forecasts of supply were especially needed.

Although the oil industry had always tried to predict output from individual wells and fields in order to plan future purchases of equipment and services, it was during the 1950s when the importance of basin, country and global forecasts began to be realised. Operations were spreading internationally and the use of expensive and specialized technologies was rapidly expanding. In 1956 a future peak in supplies from the USA was predicted within two decades. Soon after a new wave of resource nationalism ensured that industry forecasts of oil supply became valuable in more than just the local environment.

However, it was not until the 1990s that more robust global forecasting techniques were established when computing power became widely available and when the internet began to improve the ability of individuals with modest budgets to acquire data. Scientists began to recognise once again how vulnerable the world was to repeated oil shocks.

At the time many global forecasts appeared pessimistic to professionals who had seen only growth in their lifetime. The established industry and financial sector were quick to decry concerns about oil supply for the early part of the 21st Century; an establishment now silent about how prescient some of those forecasts actually were. Oil prices surged with energy prices becoming exceptionally volatile. Technologically challenging and more expensive supplies were failing to add sufficient oil to replace depletion in older areas to meet the full needs of the market. A permanent price jump was the result.

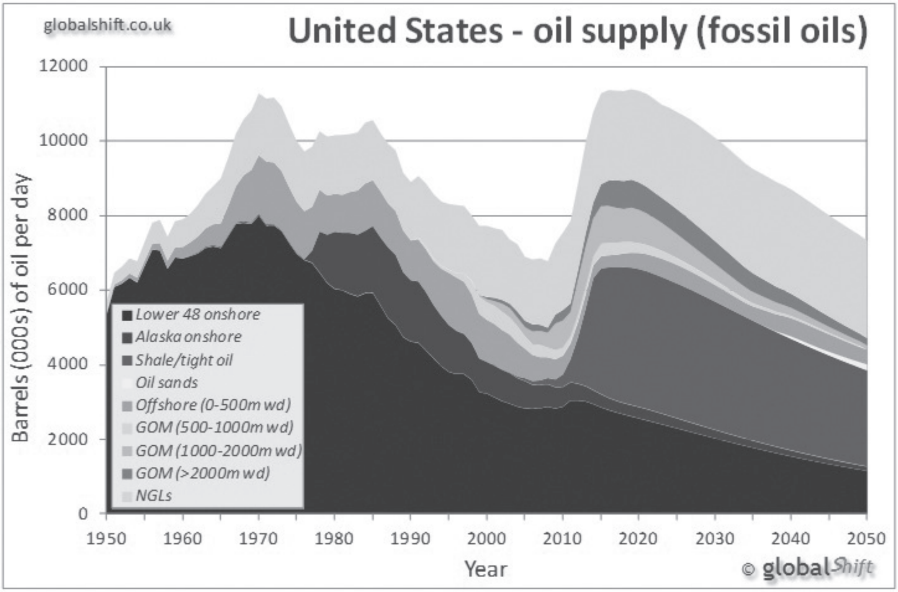


Figure 1: Historical data, and forecast, of all fossil oil production in the USA, 1950 – 2050 (includes shale/tight oil, oil sands and NGLs; excludes GTLs, CTLs & biofuels). For this oil, the USA will have 3 peaks: 1st driven by conventional onshore oil in 1970; 2nd driven by new Alaskan output in 1985; 3rd through a combination of shale oil, deep-water oil and NGLs around 2020

For example the forecasts of Energyfiles (the author's former company) repeatedly warned about a series of signals of tight supply foretelling rapidly rising oil prices, global recession and the need for technologies (and price levels) to access alternative hydrocarbon sources. The advent of higher oil prices did indeed facilitate large-scale exploitation of new sources using more costly methods and technologies, especially applied to deep waters and to fracturing oil and gas-rich shale beds.

The changing scene in the critically important USA market over the last 3 or 4 years was driven by the tight supply situation identified in those forecasts over a decade ago, and this may have been recognized by some of the first companies who became expert in the practice of fracturing tight oil reservoirs . Figure 1 gives Globalshift's current forecast of US all-fossil-oil production to 2050, including NGLs.

2. THE PURPOSE OF FORECASTS

The modern oil and gas industry is a long term one. Except on a small scale gone are the days when an oil well will be drilled, oil found and sufficient volumes of production sent to market in a timeframe that could have a rapid effect on supply and price. Oil from most fields of any size takes years to appraise, develop, produce, transport and sell to market. Even drilling for oil trapped in shale reservoirs requires a large number of wells before total volumes begin to have an impact on the global market. Output from the larger, more predictable fields is in relative decline and a huge industry has developed to service the more complex reservoirs and remote regions, especially offshore. The service industry employs technologies that often require large front-end investments.

Thus comprehensive, transparent forecasts have become increasingly valuable to direct such investment. Do you invest in new drilling rigs, platforms, ships, pipelines, service personnel, specialized subsea equipment and where do you put them if you do? Oil companies and their associated service industries have to make decisions on building and purchasing equipment that may not turn a profit for a decade.

For example a new deep water drilling rig can take three or four years to build and will cost over half a billion dollars. It must have some contractual certainty over the long term to justify the investment. Without believable forecasts of output of all the different hydrocarbons requiring all the different equipment it is hard for companies to raise the capital for such ventures.

3. GLOBALSHIFT FORECASTS

Oil field engineers know that when a successful well is completed and produced it usually delivers oil and/or gas at a rate that rises rapidly to a brief plateau. It then declines over a period of time - due to pressure decline in the reservoir along with water and/or gas encroachment - until it is abandoned. Growth, then decline has happened since the first well was drilled.

When a collection of wells is completed in a discrete accumulation - called a field - production rises and falls in the same fashion. When a collection of fields is developed in a sedimentary basin, with generally the biggest and best found and developed first, total production must rise and fall too. Of course the same is true for collections of basins in a country; countries in a region; and, ultimately, all regions in the world.

A comprehensive data-driven supply forecast has been developed by Globalshift to help define the timing and magnitude of this growth and decline, for fields, basins, countries, regions and the world. The forecasts are founded on empirical observations combined with technical analysis, insights into the historic hydrocarbon flow behaviour of oil and gas wells and of fields, and examination of the historic numbers of wells and items of associated equipment required to explore for, and to exploit, this oil and gas.

All forecasts made by Globalshift assume oil production activity will only be constrained by the macro effects of the global economy, including (occasionally) OPEC members' and other exporters' attempts to support oil prices when demand flags. Meanwhile petroleum technology is assumed to continue to improve in terms of better imaging of the subsurface, engineering advances in accessing new output and containment of costs in increasingly challenging areas.

Making technical forecasts for leaders, governments and economists - groups that prefer forecasts based on trends rather than science - is a thankless task. Even if the complex forecasts are understood there is a tendency to cherry-pick numbers that suit a current agenda. No one wants to run with a bold forecast that is out of line with the pack. And when forecasts do not meet shareholders or voters needs, 'chicken-and-egg' arguments are preferred, citing the importance of demand over supply or vice versa. Globalshift forecasts are thus aimed at the sharp end of the industry; the technical specialists that endeavour to find and exploit oil.

They focus on helping the oil and gas industry make the most effective decisions to maximize the potential returns on investment capital.

4. VARIABLES

Forecasts are made for every country and sedimentary basin for the following (*inter alia*):

- Oil production – onshore and offshore (0-500m, 500m-1000m, 1000m-2000m, >2000m water depth intervals) with separate analysis of field oils, natural gas liquids, shale/tight oils, heavy oils, extra-heavy oils and bitumens, retorted shale oil, gas-to-liquids, coal-to-liquids and biofuels; as well as speculative undeveloped and speculative undiscovered production profiles; and cumulative produced and cumulative remaining unproduced volumes by year.
- Sales Gas production – onshore and offshore (0-500m, 500m-1000m, 1000m-2000m, >2000m water depth intervals) with separate analysis of all field sales gases, shale/tight reservoirs and coal bed and coal mine methane; as well as speculative undeveloped and speculative undiscovered production profiles; and cumulative produced and cumulative remaining unproduced volumes by year.
- Drilled Wells - onshore and offshore (0-100m, 100-500m,500-1000m, 1000m-2000m, >2000m water depth intervals) with separate analysis of exploration, appraisal, and development wells. For offshore the latter are divided into surface-completed and subsea-completed wells.
- Active Wells - onshore & offshore (0-500m, >500m water depth intervals). For offshore these are divided into surface-completed and subsea-completed wells.

The forecasts primarily address the upstream (from prospect to pipeline) and midstream (processing, gathering and transporting) parts of the industry. However, manufactured oils are also estimated, delivered from the downstream (refining and petrochemical) sector. Histories are from 1900 with published forecasts running to 2050 (although the models run further).

At *www.globalshift.co.uk* summaries and news can be accessed for every country in the world for those interested in the overall picture of future output in specific areas or globally. For people or companies needing to make costly decisions on investment, Excel files can be purchased comprising historical and forecast numbers for production and wells; arranged into categories (a selected dataset for every country/region), or into individual countries and regions (giving all categories).

These files are presented in worksheets; historic from the year 1950, and forecast to the year 2050, and allow energy companies, oil companies, service companies, associated industries and governments to create presentations, evaluate assets and develop strategies and policies.

5. ASSUMPTIONS

The difference between a forecast and a projection is in the nature of the assumptions. In a forecast, the assumptions represent expectations of actual future events. A projection is a 'what if' scenario where the input assumptions are not necessarily the most likely.

Globalshift prepares forecasts based on geoscientific and engineering principles of field discovery, field exploitation and field depletion under commercial constraints combined with inspection of historic relationships between production and activity. Forecasts depend on three fundamental, empirical, observations:

- Supply from an oil and/or gas well grows to a maximum, has a short plateau, relative to the life of that well, and then declines. This is the basis on which engineers in the oil and gas industry forecast output from individual wells and, for a collection of wells, from fields.
- In general larger and cheaper (and easier to find and exploit) accumulations are found and developed first followed by progressively more difficult, more cost-intensive projects in concert with technological advancement.
- Real-world production and activity profiles can be heavily influenced by non-technical (economic, commercial and geographic) effects and these are accounted for by history matching and general expert evaluation of areas, regions, countries and country groups.

The forecasts try to account for 'below-ground' geological and engineering factors as well as 'above-ground' commercial, political and environmental (e.g. hurricanes in the Gulf of Mexico) factors, which are much more volatile. The most important of the 'above-ground' influences remains demand for oil. This is especially volatile when new supplies become more costly to access whilst political, financial and catastrophic one-off events act to restrict maximum potential output in individual countries.

Each individual country supply forecast in Globalshift is thus modified with qualitative assumptions related to most-likely government policies, oil prices and oil demand. The most significant of these are:

- Oil demand will be driven by price. Despite encouraging words it is judged that there will be little political will to subsidise new fuel substitution, even within the European Union.

- Non-OPEC governments will allow investing companies to find and produce oil as fast as possible using the technologies available for profitable sale at the prevailing oil price.

- OPEC governments will eventually act, if they deem necessary, to support price by restricting output when the price level falls. However, the decision by OPEC to do this is dependent on which approach maximizes income, and different members have different needs.

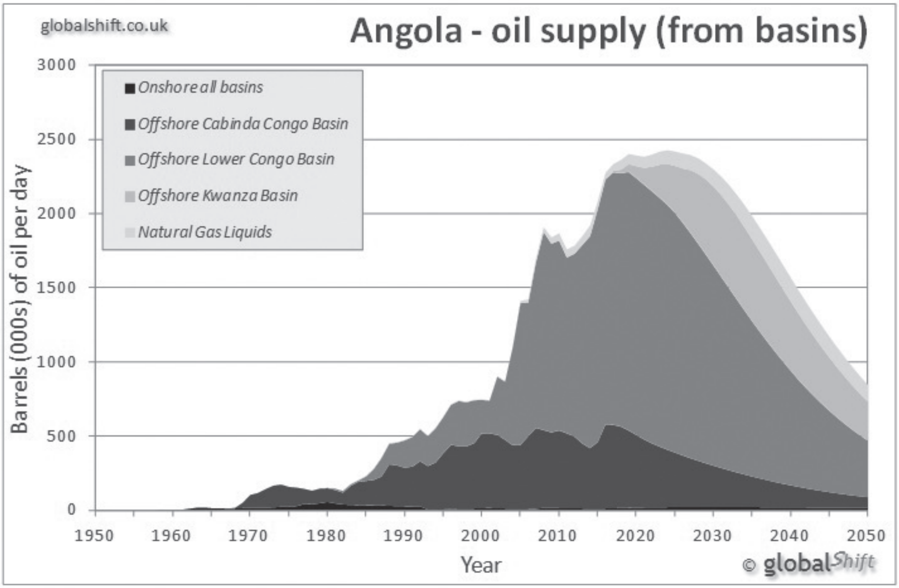


Figure 2: Historical data, and forecast, of oil supply in Angola, 1950 - 2050, by basin (including NGLs). The development of technologies to exploit deep water oil and more recently to image sub-salt has dramatically improved Angola's potential, such that all its offshore basins are now being explored and/or exploited.

In reference to the last of these the current forecasts assume that, up to the mid 2020s there will be a number of countries where output growth will proceed sufficiently fast to offset declines elsewhere; particularly Brazil; the OPEC countries of Iraq, Angola and Nigeria; NGLs from Qatar; heavy oils from Colombia and Venezuela; syncrude from Canada; oil from shales in the USA and elsewhere; and, later, potential pre-salt developments off West Africa such as in Angola (see Figure 2).

During this period it is assumed that higher cost oil developments will be curbed, and/or Saudi Arabia (and to a lesser extent other OPEC countries) will eventually restrict output into existing infrastructure to try to prop up oil prices and maintain global supply at a level that could meet 2% to 3% per year demand growth. Negotiations to do the latter, as always, will be protracted as individual members argue for quota. Even if some output reductions are met by unplanned cuts, for example those that occurred during rebellion in Libya and other North African countries, oil prices will always be volatile when supplies can meet demand.

By the mid 2020s the model indicates that no country will be left with spare capacity. Demand, driven by uncomfortably high oil prices in a supply-constrained environment, will have to decline, creating the conditions necessary for an energy transition. Whether such a transition is smooth or not depends on the response today to the production and activity forecasts presented by organisations such as Globalshift.

6. PROCESS

Stand-alone datafiles have been created for every country in the world within which individual production and activity spreadsheets have been formulated for onshore regions and offshore regions at a range of water depths. The sheets list, wherever possible, historic oil and/or gas output split into component types (light, heavy, extra-heavy, from shale/tight reservoirs etc.) for every year that oil and/or gas has been produced for every oil and/or gas field that has produced in that year, as well as by name for every field that has been discovered but, as yet, has not been developed.

Along with the production profile for each field the name, operator, license, sedimentary basin, year of discovery, year onstream (if applicable) and hydrocarbon type and reported volume are included (if available).

The files also list numbers of exploration, appraisal and development wells drilled for onshore and offshore regions at a range of water depths for every year that drilling has been conducted from 1930, and for cumulative wells drilled prior to 1930 (see Figure 3).

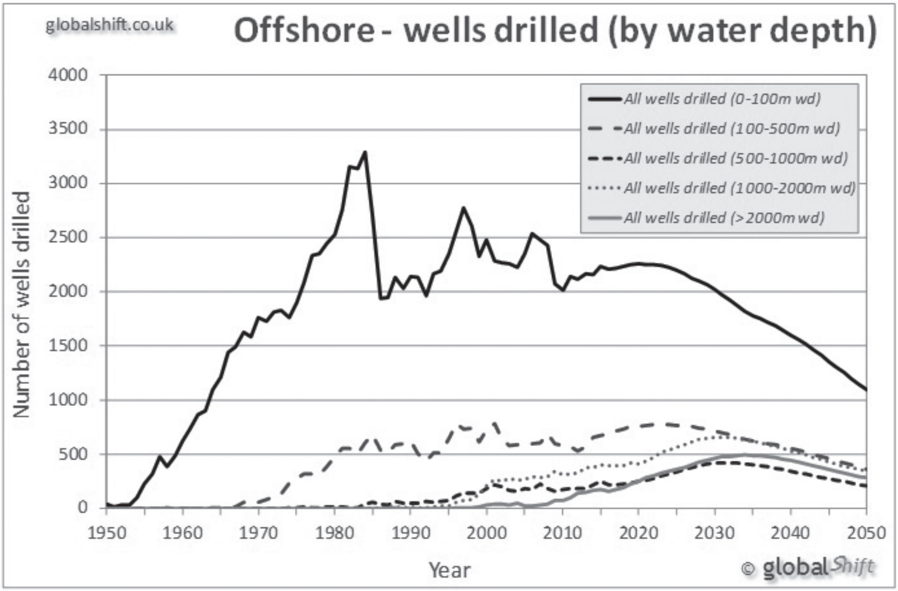


Figure 3: Historical data, and forecast, of global offshore drilling 1950 - 2050 by water depth. Drilling totals are dominated by shallow wells (drilled with jackups). Relative future growth is expected in ultra-deep waters (drilled with high-specification mobile rigs).

A forecast for each field is made based on history matching past performance - or typical performance in a reservoir or sedimentary basin where there is no history match. Future field total outputs are constrained by reported reserves and/or resources of each field (if numbers are available) after investigating the validity of such reports - a validity that depends on their provenance.

Inevitably there are many data gaps. Spreadsheet yearly totals are constrained by considering sums that match reported total country yearly production using estimates defined as 'balancing volumes.' These correspond to fields, field complexes or sedimentary basins that have no individual data reported but require balancing volumes to make up the difference. Where only limited information is available or full data sets have not yet been analysed, estimates are made by interpolation or extrapolation in as much detail as possible using the data that can be obtained.

Also included in the spreadsheets, as far as possible, are all field discoveries which have not yet entered production but will be developed. These are called 'speculative undeveloped'. Many of these fields will have published estimates of volumes and future profiles. Otherwise volume and maximum output numbers are estimated based on analogy with neighbouring fields and by examining the exploration history and general geological potential of each area. The 'speculative undeveloped' component is added to the production forecast (using a model such as shown in Figure 4).

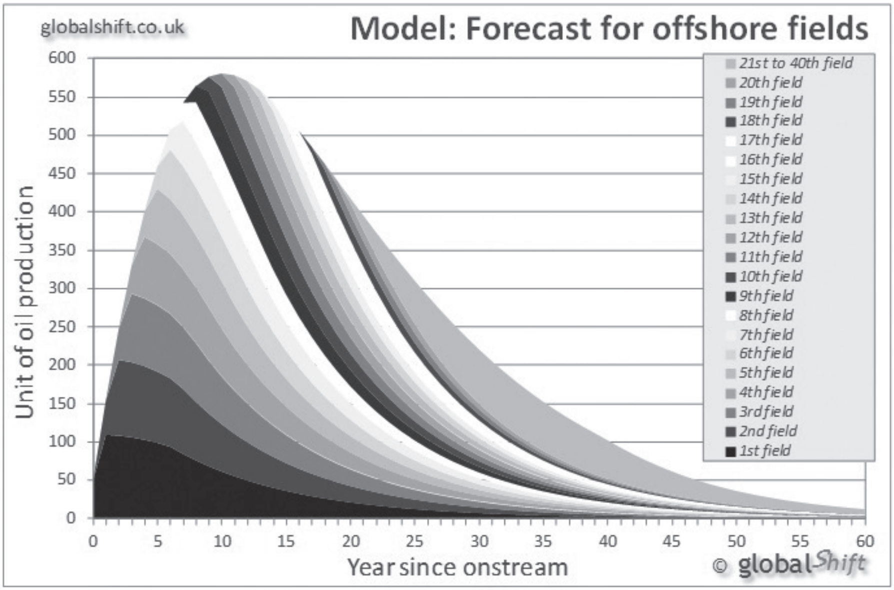


Figure 4: Model demonstrating summed field production profiles creating a right skewed distribution in a sedimentary basin. This model assumes no 'above ground' influences on activity. Most basins will only roughly follow this path, and countries rarely do.

Also included are all potential field discoveries (yet-to-find). These are called 'speculative undiscovered'. The volumes and maximum output of 'speculative undiscovered' are determined through subjective evaluation of how much exploration acreage remains to be explored in an area, how successful exploration has been in the past, how new technology is allowing access to new resources and how the history of exploration in a given area has panned out.

Of course there are many uncertainties in determining 'speculative undeveloped and undiscovered' profiles. Besides volume uncertainties, regional production curves only occasionally form a simple right-skewed bell shape as in Figure 4 (unlike individual field profiles). Regions are influenced by other factors beyond statistical, geological and engineering principles and these are considered accordingly. In particular a country usually comprises a collection of individual profiles delimited by the location of overlapping sedimentary plays or basins which sum together to create a full country profile. Unstable economics, investment, politics and other unpredictable events in a country or region are also disruptive. For example:

- Oil price fluctuations (determined by politics and economics as well as supply and demand) influence the amount of investment in a non-linear fashion
- Countries do not have borders coincident with sedimentary basins, so different areas may be developed at different speeds e.g. Alaska in the USA
- Offshore areas require different technologies and have usually (but not always) been developed later than onshore areas
- Deep waters, with their challenging technological requirements, have been developed independently from shallow waters
- Shale oils have been developed last of all, relying on high oil prices and rapid advances in horizontal drilling that occurred in the latter part of the 20th century
- Environmental influences and disasters, such as hurricanes in the Gulf of Mexico and accidents on platforms, e.g. the Piper Alpha disaster in the North Sea, can disrupt output in an unpredictable way
- Political events can have an effect on investment levels, e.g. changes of government (such as the demise of communism in the Soviet Union)

and sanctions (such as in Iraq whilst Saddam Hussein was leader), severely disrupt country output curves

- Artificial constraints on output conserve oil for the future; especially repeated attempts since the 1980s by OPEC to prop up prices through production quotas.

Different oils are considered in different ways, but always volumetrically (note they may have different energy densities). For example the future output of natural gas liquids is estimated based on past volumes as a constant ratio to total gas production forecasts. Oil sands output is project-based whilst shale oil output is determined through forecasting potential well numbers that could be drilled each year constrained by available volumes, acreage and logistics, as shown globally in Figure 5.

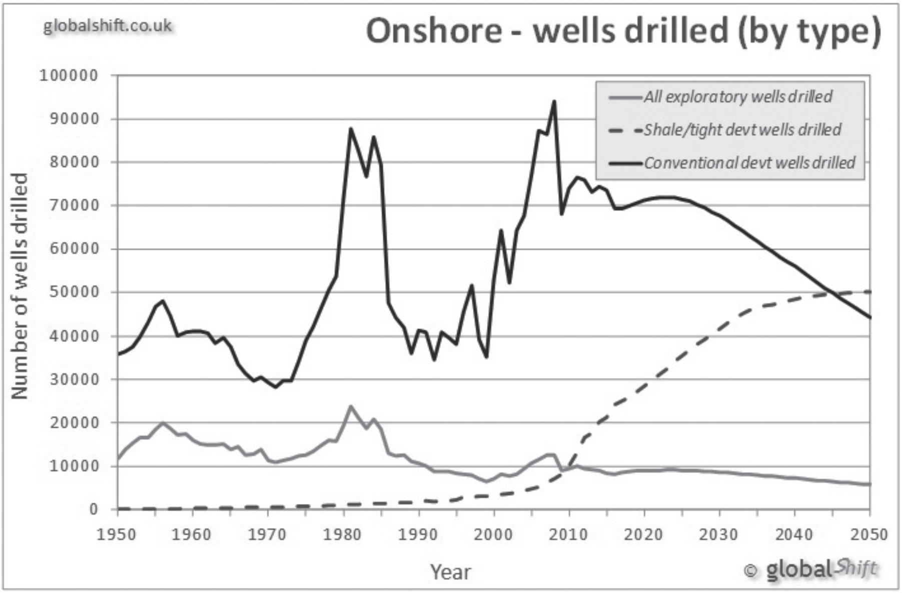


Figure 5: Historical data, and forecast, of onshore drilling, 1950 - 2050. Development wells have shown an erratic path (dominated by the USA), matched by exploratory wells prior to 2000. Drilling for shale reservoirs is now surging, and other types will decline.

Updates are carried out whenever new information appears (which may be daily). Full reviews, to ensure that global interpretations are consistent and match the economic circumstances of the time, are carried out in January and July each year.

All spreadsheets are collated into a single folder, and compared graphically with actual consumption figures to ensure future global supply and demand match. The model is supply-driven with demand (and oil prices) moving to match available supply, which may be constrained by all or any of OPEC, geology, engineering, investment, varied political and economic events and, of course, energy prices that are themselves dependent on all or any of these.

7. DEFINITIONS

Clear-cut and consistent definitions are important to allow comparison between forecasts and to evaluate and criticise past forecasts, otherwise any comparison can be misleading. Complex models require transparent definitions. Selected ones applied to oil are as follows:

- *"Fossil Oils"* are volumes of fossil liquid hydrocarbons produced from a buried reservoir through wells (or rarely by mining) to the surface. Here they can exist as a liquid at surface temperatures and pressures without processing. They can be transported, before or after refining, in liquid form and are used, before or after refining, as fuels or in the chemical industry. The hydrocarbons include all oils and condensates from oil, oil and gas, and gas fields and dispersed reservoirs, all natural gas liquids, all drilled shale oils from shale reservoirs as well as extra-heavy oils (including bitumens) used for energy before or after conversion to syncrude.
- *"Field Oils"* are fossil hydrocarbon liquids extracted through wells from a field with a porous and permeable reservoir that can exist naturally as a liquid at the wellhead. They may also be called conventional oils.
- *"Drilled Shale/Tight Oils"* are fossil hydrocarbon liquids extracted through wells from tight (shale, sandstone or carbonate), non-field, dispersed reservoirs usually after fracturing the reservoirs underground.
- *"Oils from Oil Sands"* are extra-heavy oils extracted from shallow

sands (also known as tar sands) through wells (usually with steam), or by mining. They are often converted to syncrude by chemical processes, making them more convenient to transport and burn.

- *"Natural Gas Liquids (NGLs)"* are light oils recovered from associated/free gas in a processing plant, stable at normal temperatures. Liquefied Petroleum Gases (LPGs) are NGLs which comprise synthesised propanes and butanes that need pressurised containers for storage.
- *"Manufactured Oils"* are manufactured synthetic liquid hydrocarbons (not including syncrude made from oils from oil sands), with similar characteristics and used for the same purpose as fossil liquid hydrocarbons. They are oils created through chemical conversion processes from gas, from coal, from shale rock, and from biomass (bioethanol and biodiesel).
- *"Gas-To-Liquids (GTLs)"* are created in a refinery by converting natural gas or other gaseous hydrocarbons into longer-chain gasoline or diesel fuel either via direct conversion or via syngas as an intermediate. The Fischer-Tropsch and Mobil processes are the most commonly used methods.
- *"Coal-To-Liquids (CTLs)"* are created by coal liquefaction mainly using the Fischer-Tropsch process. Coal is gasified to make syngas and Fischer-Tropsch catalysts are used to convert the syngas into light hydrocarbons which are further processed into gasoline and diesel.
- *"Mined Shale Oils (retorted)"* also called kerogen oils, are created by heating and processing mined shale rock in a plant.
- *"Biomass-To-Liquids (BTLs)"* are liquid hydrocarbons made from plant material rather than petroleum products. They do not include biomass solids (crops and residue, wood, animal waste, aquatic plants and organic components of waste). Biodiesel is created when plant oils are combined with alcohol in the presence of a catalyst to form ethyl or methyl ester. Ethanol BTLs are formed during sugar fermentation of plants, including cellusosic ethanol created from woody biomass.
- *"Gains (Refinery)"* are liquid hydrocarbons, with the same characteristics and used for the same purpose as fossil liquid hydrocarbons. They represent the increase in volume of refined products compared to an input volume of crude. The processing of oil

and the associated chemical changes increase the volume by a few percent, depending on input and output characteristics.

- *"Production"* is defined as oils and gases produced and sold to refineries or other users and measured as a volume per time period. Production includes from 'currently producing fields and those in development' (all oil from existing fields and from fields that have operator-announced plans for their development), from 'discovered fields which will be developed' (all oil from potentially commercial drilled fields) and from 'yet-to-find (undiscovered) fields which will be developed' (all oil from potentially commercial undrilled areas).
- *"Production profiles"* are the shape of the production curve between two times. Profiles are created based on past production histories and output models for onshore and offshore areas.

Onshore and offshore hydrocarbons must be treated differently owing to their different development methods. Onshore fields are usually (but not always) developed early and sequentially, and offshore fields are usually (but not always) developed within a single development plan.

- *"Onshore production"* comes from onshore wells including wells drilled within lakes and swamps; regardless of their subsurface location, even when such wells are drilled from piers and/or deviated to locations beneath the sea.
- *"Offshore production"* comes from offshore wells; including those drilled from fixed platforms in shallow waters and from artificial islands unconnected to the mainland (not including wells located in freshwater inland areas). For fields overlapping on and offshore areas and water depth intervals the allocation is estimated. It is assumed that the location of the well completions define water depth.
- *"Very Shallow waters"* are defined as areas of oil and/or gas output from reservoirs beneath marine water depths ranging from greater than 0 meters down to 100 meters.
- *"Medium Shallow waters"* are defined correspondingly for water depths ranging from greater than 100 meters down to 500 meters, and likewise:
- *"Medium Deep waters"*: >500 meters to 1000 meters.
- *"Very Deep waters"*: >1000 meters to 2000 meters.
- *"Ultra Deep waters"*: >2000 meters.

The terms reserves and resources are often misunderstood and misused in the oil and gas industry and media. They may have multiple meanings. Here:

- *"Reserves"* are considered as 'Cumulative Production' plus 'Remaining Production'. Proved, probable and possible reserves (P+P+P) are not used in Globalshift in this context. These represent the concept of 90% (proved reserves are subject to a 0.9 success risk), 50% (probable reserves are subject to a 0.5 success risk) and 10% (possible reserves are subject to a 0.1 success risk). Note that Globalshift 'remaining production', by definition, should be more than proved reserves for a field, basin or the world, and could roughly be equated to P+P (2P) reserves.

- *"Cumulative Production"* Is the total volume of oil and/or sales gas up to a given year that has been produced (in Globalshift this is to the current year minus one).

- *"Remaining Production"* equates to most likely remaining recoverable resources of oil or sales gas that have not yet been produced but will be recovered under economic conditions that could exist in the future. This assumes the world remains a stable, comfortable place to live with a price regime that satisfies demand whilst demand changes in manageable steps, and fossil fuels retain market share. They are summed output values over a future period (in Globalshift this is to the year 2100). Remaining production volumes are not statistically derived and are best thought of as one interpretation of 'most likely' numbers.

- *"Speculative Undeveloped (also known as potential additional resources)"* is that part of Remaining Production that represents all current field discoveries that have not yet entered production but will be developed. It is a speculative estimate based on subjective (but educated) examination of the relevant area. The term 'Reserves Growth' (not used by Globalshift) has often been used to define these volumes. 'Reserves growth' is a confused term with multiple definitions, including undeveloped fields (or fallow fields) and the use of improved technology to access hitherto un-producible volumes.

- *"Speculative Undiscovered (also known as yet-to-find)"* is that part of Remaining Production that represents all potential field discoveries which have not yet been discovered but will be found and developed. It is a speculative estimate based on subjective (but educated) examination of the relevant area.

- *"Ultimate Production"* volumes are the sum of 'Cumulative Production' (volume of oil and/or gas up to a given year that has been produced) and 'Remaining Production' (the volume of oil and/or gas up to a given year that will be produced).
- *"Resources"* are all the oils or gases that exist in the earth from any source, including developed, undeveloped and undiscovered that, if produced (extracted from the subsurface), could be used for fuel or in the chemical industry.

Resources are not critical to forecast production profiles in Globalshift since a substantial portion of estimated resources will either be produced far in the future, when the world must no longer be dependent on fossil fuels, or will never be produced due to unfavourable economic and/or technological circumstances.

Full definitions of all other terms used in the database are available at *www.globalshift.co.uk/definitions.html*

8. SOURCES AND UNCERTAINTIES

All numbers in the database are either historical estimates or forecasts. There is no guarantee that such estimates are accurate, or that the forecasts will prove accurate.

Extrapolation, interpolation and judgement are used to complete spreadsheets where a full data stream is required or desirable. No one source is treated as perfect. Numbers are sense-checked and adapted.

Data are acquired from a wide variety of government websites, company websites, press releases, annual reports and personal written and verbal sources.

9. VOLUMES

The forecasts are about production and drilling profiles but volume estimates are also created. As defined above, cumulative and remaining, including speculative undeveloped and speculative undiscovered elements, individually make up the ultimate volumes in an area through summing each profile over a time period. When volumes are considered in terms of these profiles three aspects become evident:

- Are the volumes there?
- Can we access them?
- Is it worth it?

Total production volumes of all-oils (excluding 'manufactured' oils) in current Globalshift production profiles are given in Table 1.

GLOBAL REGION	Cumulative Production *(bn bbls to 2013)*	Remaining Production *(bn bbls to 2100)*	Ultimate Production *(bn bbls to 2100)*
North America	286	356	642
Latin America	165	213	378
Europe	242	227	469
Africa	123	187	310
Middle East	372	629	1001
Asia-Pacific	140	217	357
GLOBAL	**1328**	**1829**	**3157**

Table 1: Production volumes of all-oils (not including "manufactured oils", defined above).

10. MAXIMUM OUTPUT

In the decades after the oil shocks of the 1970s the industry changed. In the 1980s the focus had been technology, especially offshore. New frontiers of science and geography were optimistically targeted, unfettered by global resource or environmental fears. But in the mid 1990s, the focus moved to availability of oil supplies with recognition of the twin threats of fewer lower cost reservoirs and environmental change.

By the turn of the millennium an impending supply gap had been identified with the realisation that unconventional oils, including oils from shales and oil sands, could not, in the long term, fully offset declining conventional oils. The relative importance of geographic and technological frontiers (such as the Arctic) once again became central to analysis of future supply. Forecast drilling and spending levels were crucial for identifying investment strategies to meet these challenges.

After a deep recession, the world now appears resigned to higher and, more especially, volatile oil prices. Demand has been hit, and a future of sharp and rapid price rises and falls, and scarcity of low cost oil resources, is expected - with resources shared amongst growing, affluent populations living under the dual threat of resource wars and environmental disaster.

Although there are many complications attendant on selecting a year for a global maximum in production, the data show a peak in output of all oil supplies (fossil oils plus other oils) will occur in the mid 2020s unless a huge new oil source is identified (Figure 6). Deep waters and shale oil are unlikely to ever meet more than around 20% of global supply.

However, the sharp end of the oil industry, engaged in exploring for, developing, and producing energy supplies, have little interest in discussions of global peak. The subject adds little to investment attitudes except to encourage companies to explore. It rarely influences

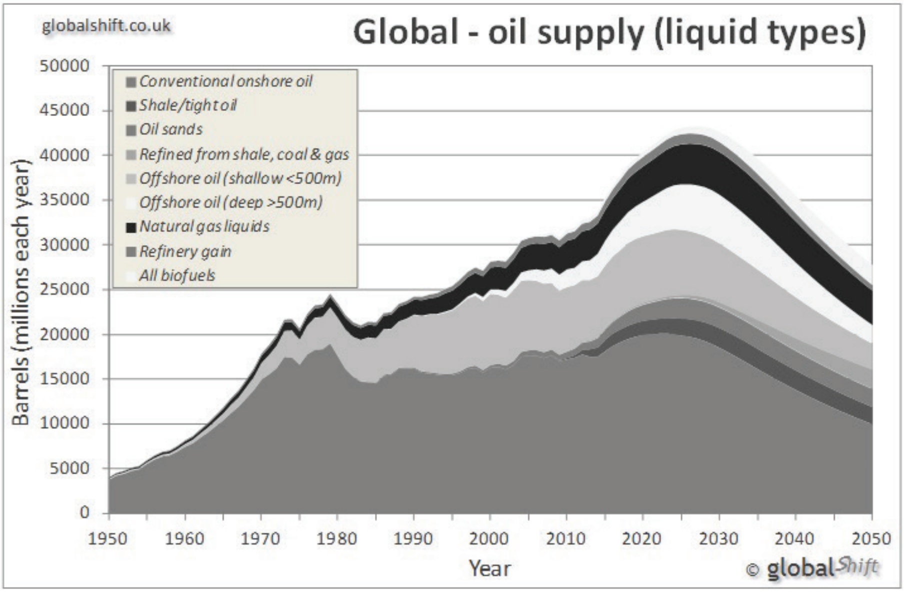


Figure 6: Historical data, and forecast, of all liquid types through to 2050. Shale/tight oil, oil sands and refined liquids act to maintain onshore output to the end of the 2020s, whilst new production from progressively deeper waters sustains offshore output.

government policy, especially since many economists and academics who engage in advising managers and governments have never worked in the oil exploration or production business.

Furthermore published material about growth and decline of energy supplies is affected by cognitive bias. The effects of social and emotional factors on economic decisions and the consequences for market prices and returns are bound to cause bias. Studies fall back on language such as; "production capacity" (to sit on the fence); "reserve growth" (to conjure up new volumes without examining the origin); and "years remaining" (to give comfort whilst ignoring the engineering issues). The term '*argumentum ad consequentiam'* applies: 'your theory is false because I do not like its consequences'.

The forecasts of Globalshift are not alone in showing that in the early 2020s, when the surge in output from the present-day growing countries ends, all countries will ramp up supply as fast as they can whilst the oil price escalates naturally and demand declines. There will then be room and economic pressure for more biofuels; CTLs; GTLs; even expensive oil extracted thermally from mined shales; as well as determined fuel substitution and ultimately conservation policies.

The true shape of the global all-liquids production curve during this period of plateau and peak will depend on demand volatility influenced by the fluctuating state of a global economy in periods of spiking oil prices, and on whether large-scale fuel substitution can be successful. The on-going balance of these issues will make the production curve more uneven than depicted by a simple supply model, since the period of plateau production must affect activity. Drilling activity in the relevant areas will follow a pattern consistent with production and price.

Many countries have already passed their oil production maximum. Libya (1970), Iran (1974) and Indonesia (1977), for example, had early peaks due to restriction of output in periods when production could have been greater. Although these countries may have growth potential they are unlikely to regain 1970s volumes. The USA (1970) has been rejuvenated by shale oil production, deep waters and NGLs just sufficient for it to regain the 1970 peak, but not in terms of energy return on investment.

Russia (1982) suffered a drop in output due to lack of investment as communism collapsed. Russia has grown almost back to former levels, but volumes and investment rates will probably be insufficient to return it to its 1980 maximum. The UK (1999) was the first of the major offshore producers to reach maximum, closely followed by Australia (2000), Norway (2001), Mexico (2004) and Denmark (2004). Growing NGLs production in Australia will almost lead to recovery in Australia, whilst many other countries are being supported by new gas developments with associated oils.

Many peaks in oil production will occur in the 2020s. A higher oil price from the late 2000s drove comprehensive investment in most remaining remote and difficult areas. By 2025 there will be few opportunities in deep waters (even in Brazil), or in shale oil that are significant enough to delay a global maximum. OPEC countries that had growth potential will now be producing at capacity. Kuwait, Saudi Arabia, the United Arab Emirates, Angola and even Iraq are all expected to reach a peak in the 2020s. By the 2030s there will be few countries remaining with any unexplored or significant unexploited acreage.

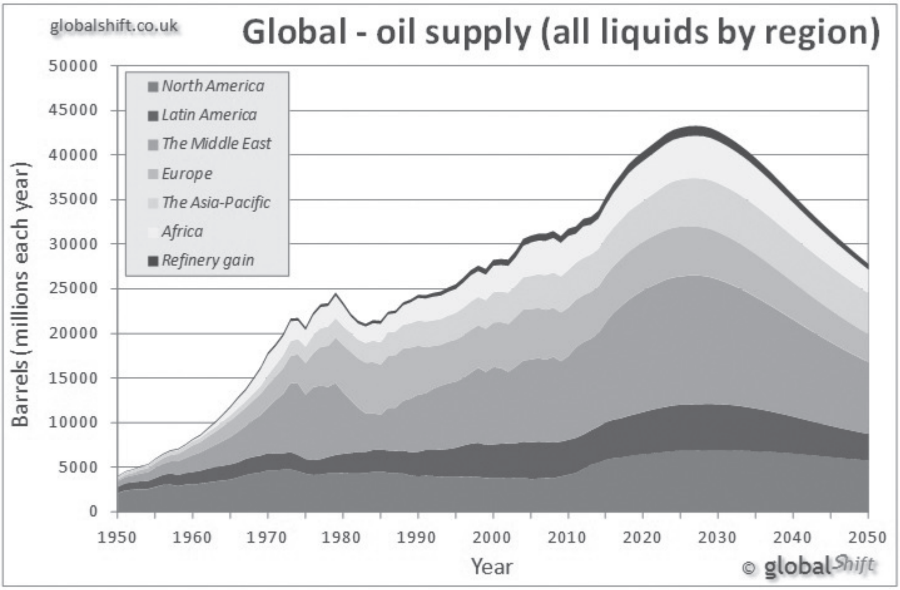


Figure 7: Historical data and forecast by region of all-liquids production, 1950 to 2050. North American oil supply has recently recovered due to shale oil from artificially fractured reservoirs and conventional oil from deep waters. The Middle East continues to grow as a percentage of the total, contributing a third of total oil to world supply by 2050.

These maxima are not signals of the end of exploration and discovery of oil. New oil is found every year. However, there will not be enough new discovery to fully offset decline in output from older finds. Most countries will never 'run out of oil.' Instead production will cease to rise. It will plateau for a period and then begin a slow and erratic decline (Figure 7) with occasional surges - such as the surge in output and consequent decline in oil prices (allied to weaker demand) in late 2014.

11. CONCLUSIONS

Oil companies, service companies and consumers have become increasingly reliant on oil that is hard to find and exploit because of:

- Geology; with new reserves trapped in complex, tight and restricted reservoirs
- Chemistry; with oils of inferior quality, requiring special technology to extract and process with lower energy content
- Geography; with new oil now buried under deep waters, in extreme climates and far from infrastructure
- Politics; with the low-cost, high return opportunities restricted to countries that are unstable and not keen to be exploited

Oil companies are spending more to maintain production rates and to increase them. Rising costs are mostly a result of aging fields and reduced opportunity. Many fields have produced for longer than expected as higher oil prices delay abandonment. These fields need maintenance. As the most profitable fields deplete companies are drilling smaller fields or more testing reservoirs in more difficult locations. Every so often new opportunities appear. These are driven by higher prices, such as shale oil, but each one is often more expensive than the last.

The service industry thrives as oil gets harder and more costly to find, but it is a volatile business. The service industry was in an upward cycle from 2009 which led to high inflation across most sectors. Consequently oil companies reported reduced earnings even though oil prices were stable. As costs went up, budgets fluctuated and oil companies became more selective in their choice of project. For example a glut in older deep-water rigs has materialised after a surge in new builds over the last three years. Oil companies are reining in expenditure growth, but increased volumes of higher specification equipment are coming into the market.

Low margin product lines must be sold or scrapped.

Service companies, more than ever, must rely on forecasts to plan effective investment strategies, appreciating both below-ground and above-ground issues. These forecasts should help companies, in an unbiased way, plan investment strategies for equipment such as drilling rigs and point them to regions where these will be required to cost-effectively take advantage of change.

Of course there is nowhere a complete or accurate database of oil production and reserves. Below-ground forecasts of supply will never be founded only on data and, in any case, above-ground events are erratic and can be catastrophic. No forecasts are always going to be right, but comprehensive forecasts based on real data with transparent methodology and definitions, avoiding simple extrapolation of trends, and aimed at investment decisions are, at least, founded in reality. Forecasts will always be relevant to the oil and gas industry for as long as it exists.

Forecasting Oil Production using Data in the BP *Statistical Review of World Energy*

R. W. Bentley
Visiting Research Fellow, Dept. Cybernetics,
University of Reading, UK.

1. CLASS ASSIGNMENT FOR STUDENTS

This assignment involves the estimation of future oil production by country and globally.

The data source you will use is the BP *Statistical Review of World Energy*. With only these data it is *not possible* to make a useful study of future global oil supply. This is unfortunate, as many analysts have relied on these data for just this purpose.

However, by combining the data with additional knowledge, and some simplifying assumptions, useful predictions of future oil supply can be made. In particular, estimates can be made for the dates when specific countries will reach their maximum production peaks of *conventional* oil, after which their production of this class of oil will decline. With the same technique, the date of the global peak in conventional oil production can also be estimated. In addition, an estimate can be made of the date of the global production peak of *'all-oil'*, though admittedly here several caveats apply.

These notes explain some of the problems with the data and the implied methodologies in the BP *Statistical Review*, and also set out how useful oil predictions can be made. The following are suggested steps, but other approaches are also valid.

Step 1: ***Use data from the BP*** *Statistical Review of World Energy.*

Do this by downloading the long-run (since 1965) spreadsheet data in the file: 'Statistical Review 2014 workbook' (these data are in MS Excel '.xlsx' format, and the file is 1.6MB in size), from the site:

www.bp.com/statisticalreview, and look for 'downloads'

(or via the full address: *http://www.bp.com/en/global/corporate/about-bp/energy-economics/statistical-review-of-world-energy/statistical-review-downloads.html*)

The workbook download you need is obtained by clicking the middle 'download rectangle' in the top row, of the six 'download rectangles' given on this web page.

Step 2: ***Use the oil classification of the BP*** *Stats. Review.*

For simplicity, initially follow the oil classification used in the BP *Stats. Review* data, which lumps together as 'oil' all the main types of fossil oil produced today. [1]

Step 3: ***Do not use R/P ratios.***

Do not use reserves-to-production ratios ('R/P' ratios) to give an indication of future security of supply, despite the fact that this is done in the *Statistical Review* itself (pages 6 and 7), and by many analysts.

This is because a region (or the world) may have a quite secure-looking R/P ratio, but be close to – or already past – its physical maximum in oil production; its 'oil peak'.

Take the example of Norway. Here the 2013 proved reserves (as given by *Stats. Review*, page 6) are 8.7 thousand million barrels, (i.e., billion barrels, Gb).

Its production in 2013 (page 8) was 1837 thousand barrels a day. This has to be multiplied by 365 (the days/year) and divided by a million to give Norway's annual oil production in billion barrels; which is thus 0.67 Gb/yr.

Thus Norway's R/P ratio is 8.7 / 0.67 = 12.9 (page 6, final column); i.e., Norway's current proved reserves are sufficient to give the country 12.9 years' of supply at the current rate of production. This would seem to be a fairly comfortable number, especially as new oil fields are still being found, and also the country is improving extraction rates from its existing oil fields.

But the problem is that Norway is already *past its peak* of conventional oil production, and its production has been in terminal decline since the year 2001 (see the *Stats. Review* spreadsheet production data). The reason for Norway's oil peak is simple: not enough new oil fields of adequate size have been found in Norway's waters for many years.

(And note that back in 2001, the year of Norway's peak, there was little in the BP *Stats.* data to indicate that the peak was at hand. In that year, despite a small hiccough in 1998 and 1999, Norwegian oil production had been on a steadily rising trend for many years; proved reserves stood near their all-time high; and - as today - new fields were being discovered and recovery rates improving.)

And what about the R/P ratio of the world? BP *Stats. Review*, page 6, shows that today's global proved reserves today are sufficient to provide 53.3 years' of global production at the current rate. This reassuring 'over 50 years of secure production' is often quoted to prove that any potential global oil supply constraint must be very distant. And - as in the case of Norway - not only does the world have substantial *proved* reserves, but large volumes of oil are still being discovered annually around the world, and significant improvements being made in global oil recovery rates. [2]

But as we know from Norway's case, the question to ask is *not* 'How many years' of proved reserves remain?', but 'How close is the world to its physical peak in production?' You will answer this question for conventional oil in Step 8; and - if you have time, and wish to do so - carry out the calculation for 'all-liquids' in Step 12.

Step 4: *Changes in proved reserves are a very poor indicator of oil discovery.*

Do not use changes in proved reserves data as being indicative of the history of oil discovery in a region. However, this also is often done; e.g. in past issues of the BP *Stats. Review*, or in the *Oil & Gas Journal*, or by chairmen of oil companies (who ought to know better), declaring reassuringly that: 'Global proved oil reserves have increased yet-again this year.'

The problems here are a little complex, but briefly:

i. Proved reserves (so-called '1P') data for a specific oil field, or for a region, have historically been very conservative numbers, and usually significantly lower than the more likely 'proved-plus-probable' ('2P') reserves estimates. Over time, as more knowledge about fields accumulates - and in the case of large fields, as these are drilled more extensively - the oil in the proved reserves estimates grows toward the larger 2P values. Thus growth of proved reserves in a region from one year to the next *may mean* that more oil has been discovered, but may often *also mean* simply that the 1P values are now closer to the more realistic 2P ones. [3]

ii. An important anomaly arises with OPEC proved reserves data. Here, against logic, for many years the 1P (proved reserves) have been *larger* than the 2P (proved-plus-probable) values. This has often been due to manoeuvring by OPEC countries to obtain better oil production quotas under OPEC rules. For this reason OPEC proved reserves data must be handled with a great deal of caution.

iii. The proved reserves data in the BP *Stats*. reflect different categories of oil (not just conventional oil), so - as the data for Canada and Venezuela show - large increases in a country's proved reserves can result from the inclusion of new classes of oil. There is nothing intrinsically wrong with this approach, but if one is trying to find out when *conventional* oil production in a region will peak, these other classes of oil must be stripped out.

Step 5: *What to do.*

If we cannot use R/P ratios (Step 3), nor rely on *changes* in proved reserves (Step 4), what do we do?

The answer is to use the 'mid-point peaking' rule-of-thumb. This says that production of *conventional* oil in a region typically peaks (i.e., reaches a maximum and then declines) – due primarily to physical processes – when about half of the region's original amount of conventional recoverable oil has been produced.

The total original amount of conventional oil in a region (i.e., before production started) is called its conventional oil 'ultimately recoverable resource' ('URR').

Once production in a region has been underway for some period, this conventional oil URR is thus composed of:

- *the* total conventional oil produced to-date from the region,
- *plus*: the region's current conventional oil 2P reserves (i.e., the oil that has been discovered, but not yet produced),

- *plus*: the conventional oil in fields not yet discovered, i.e., the region's yet-to-find.

Thus: URR of a region = oil produced to-date + current 2P reserves + yet-to-find.

And thus, in turn, the 'mid-point' rule says that production of conventional oil in a region typically reaches its physical maximum ('peak') when about 50% of this URR has been produced.

But how can this rule be applied to estimate the date of peak conventional oil production in a region (such as a specific country) when we have only the BP *Stats.* data to hand?

This can be done; but there are several problems, and we will deal with them in turn.

(i). Categories of oil.

As we know, BP *Stats.* data account for 'all-oil', not just conventional oil for which the 'mid-point' rule holds. But the oil produced in these other categories of oil is – except for Canada and Venezuela – not much, so initially just use the BP *Stats.* data without adjustment.

(ii). Finding total oil production to-date if production started before 1965.

Total oil production to-date in some regions, such as Norway or the UK, can be found easily enough by simply summing the data in the BP *Stats.* spreadsheet you have downloaded (recalling of course to multiply the production data given in '000 bbl/day by 365 and dividing by a million to give total production to-date in Gb).

But what to do if production in the country started before 1965, the start-date in BP *Stats.*? This applies to quite a number of countries, including the major producers such as the US, Russia and Middle East countries.

In this case use three simple approximations:

(a). Guess (or look up on the web) the start date of oil production in the country concerned.

(b). Then assume oil production grew from zero in the start year in a simple straight-line fashion to the volume per day given by the 1965. Make a simple calculation of the total oil volume that would have been produced up to end-1964. (It is a triangle, use: half base * height).

(c). Multiply this total by 0.7 to roughly allow for the fact that production typically increases exponentially, rather than linearly.

Take the case of the U.S. Though production here started in the 1860s, assume little was produced to 1900, and take this as the US start date. Since US production was 3.29 Gb/yr. in 1965, cumulative 'straight-line' production from 1900 to 1964 would be: 0.5 * 64 yrs * 3.29 Gb/yr. = 105.3 Gb; and roughly cumulative 'exponential' production of about (0.7 * 105.3 =) 73.7 Gb. This is a pretty good approximation, at least for the US.

Adding on cumulative production from 1965 to to-date gives total US cumulative oil production to-date as 237.0 Gb.

(iii). Can we use proved reserves data, if these data are so poor?

This is an important question, and the crux of this assignment. In the past *proved* reserves ('1P') data have been of no use at all for oil forecasting purposes because such data were very conservative numbers. But in recent years, for most countries, these proved reserves have grown to be at least reasonably close to the more accurate 'proved-plus-probable' ('2P') reserves data held in the oil industry datasets. So initially in this assignment assume that all current proved reserves data as given in the BP *Stats. Review* are good enough to use in the equation for URR given above.

(iv). How to estimate a country's yet-to-find?

The 'mid-point' peaking rule requires that an estimate to be made of the region's oil not yet discovered (its 'yet-to-find').

For analysts with access to proper oil industry proved-plus-probable (2P) data, this is not as difficult as it might appear, and there are many ways of making such an estimate, such as looking at the past oil 2P discovery history in the region, and extrapolating this forward.

But because the BP *Stats.* data do not give the oil discovery history in terms of 2P data, you must make some assumption about the yet-to-find if you are to use the 'mid-point' peaking rule to determine the date when peak production in a region is likely to occur (or has occurred if this peak was in the past, as is the case for conventional oil for many countries).

Here external experience is of help. While the amount of conventional oil yet-to-find is quite variable between counties, examination the historical 2P oil discovery data has told analysts that the total amount of conventional oil yet-to-find globally is probably not large. So initially in your calculations assume the yet-to-find in each country you examine adds just 15% to the total of: (cumulative production to-date plus reserves).

Step 6: *Two examples of applying the 'Mid-Point' rule.*

So now you are in a position to use the BP *Stats*. data to apply this 'mid-point' peak rule to a specific country to see when to expect its peak in production of conventional oil:

First pick the UK.

Look at the spreadsheet. A very small amount of oil production in the UK came from on-shore fields before 1965, but oil production in any volume (from off-shore) only started in 1976. So add up the total UK oil production from 1965 to to-date in the spreadsheet.

Remember that the oil production is in thousands of barrels per day, so has to be multiplied by 365 (i.e., days/yr.), then divided by a million to give billion barrels in a year. Summing the data gives UK total oil production to-date (ignoring the very small amount *before* 1965) as: 27.8 billion barrels (i.e., 27.8 Gb).

Next you need the BP *Stats*. data for reserves, where the proved reserves can be read from the BP *Stats. Review* page 6. These are: 3.0 thousand million barrels (i.e., 3.0 Gb).

So UK total oil discovered to-date = total oil produced to-date + reserves = 27.8 + 3.0 = 30.8 Gb

Adding the crude approximation of 15% for yet-to-find gives the UK's URR for conventional oil as 35.4 Gb, and where the 'mid-point' rule expects the production peak to occur at half of this, i.e., at 17.7 Gb.

Going back to the spreadsheet, examination of the production data shows that a total of 17.7 Gb of oil had been produced in the UK by 1998. Since the actual date of the UK production peak was 1999, as examination (or better, plotting) of the spreadsheet data of UK production will show, this indicates the usefulness of this technique, as least in this example.[4]

Take one more example, that of the US.

As you have already seen, US cumulative production to-date is 237.0 Gb. Adding on proved reserves of 44.2 Gb gives the US total discovered to-date of 281.2 Gb; and adding on an additional 15% for yet-to-find gives the US URR as 323 Gb. The US peak would be expected when half of this, 161.5 Gb, had been produced. From the spreadsheet, we can see that this quantity of cumulative production was reached in 1987.

In fact the US peak was quite a bit earlier, in 1971. The explanation for this discrepancy is several-fold: experience shows that many regions in fact see their peak of production some way *before* half of their URR is reached; in the US the largest field (Prudhoe Bay, in Alaska) was only discovered in 1968, so it did not impact the date of peak, but did significantly slow the post-peak decline; the current US proved reserves have grown in recent times due to exploitation of non-conventional oil (here, shale 'light-tight' oil); and 15% is a generous quantity to allow for the yet-to-find of conventional oil in a country so well explored.

But despite this discrepancy between the predicted date of peak of 1987 and the actual peak in 1971, again the value of the 'mid-point' technique is clear: it gives a useful indication of the production peak - and hence of the subsequent decline - of conventional oil in a region, and avoids being misled by the size of proved reserves, R/P ratios, or production trends etc.

Step 7: *Determine the date of Conventional Oil peak in other countries of interest.*

Now apply the method just outlined to your choice of any three other countries of interest (such as, for example, Russia, Canada, Saudi Arabia, Iraq, Iran, Mexico, China, India, Indonesia, Nigeria; or your own country if it is an oil producer and listed in the BP *Stats.* data); to see when to expect their peaks in conventional oil production.

If a country you have chosen is *not yet past* its peak (unlike the UK and US examples given above), you must project that country's oil production forward (making a reasonable assumption on how fast this production will grow each year) until the 'mid-point' rule says that the country's conventional oil production peak will have been reached. This applies, for example, to Middle East OPEC countries, Nigeria, and a number of other countries. (And to carry out this calculation, make the over-simplifying assumption that the country's proved reserves do not change over this projected future period.)

List the key data you use in each country's calculation, as given above in Step 6 for the UK and US.

Step 8: *The Global conventional oil peak*

Apply the same 'mid-point' method to roughly estimate the date of peak of *global* conventional oil production.

Step 9: *Compare your results to Globalshift's (and Campbell's if possible).*

Compare your results for *conventional* oil production with the graphs of past and predicted future *'all-oil'* production on the Globalshift website: *www.globalshift.co.uk* (Go to the home page, then select a region of the world from the banner near the top, and then a country from those in the subsequent list.)

(And if you have access to *Campbell's Atlas of Oil & Gas Depletion* (Springer), compare your results to the data for '*Regular Conventional*' oil.)

Step 10: *Advice to Governments*

On the basis of your findings in Step 7, state briefly how you would advise the governments of the three countries you selected.

Now look at the global picture. Once global conventional oil production approaches its peak, and can no longer increase sufficiently to meet rising demand, the additional oil required must come from the non-conventional sources of oil. Often these are more expensive to produce than conventional oil, in part because of the additional energy required for their production. And in terms of the world price for oil, in an open market it is the price of the marginal barrel (i.e., the most expensive of these 'extra' barrels of oil required to meet demand) that sets the overall price of oil.

Using this information, and your finding from Step 8 of the likely timing of the global peak in conventional oil production, state briefly how you might advise an international body such as the UN.

2. CONCLUSIONS

In this assignment you have investigated a simple way to estimate the date of the peak of production of *conventional* oil in regions (such as specific countries), and in the world as a whole, using the BP *Stats. Review* data combined with external knowledge and assumptions.

And also as a result you have found out how not to be misled by R/P ratios, current trends in production, apparent increases in proved reserves, or high 'ultimates' as apparent proof that there can be no supply-side constraints to global oil supply for many years to come.

3. POSSIBLE ADDITIONAL WORK

If desired, and if time is available.

Step 11: *Special handling of OPEC countries' reserves; also Canada & Venezuela oil types.*

The above analysis can be extended and refined; for example:

a). Recall the remark above that proved '1P' reserves as reported in the BP *Stats. Review* in some OPEC countries are probably *larger* than the more likely '2P' reserves. So reduce proved reserves in these countries by some amount (such as by their cumulative production during the total time their 1P reserves remained static), and re-calculate their expected dates of conventional oil peak.

b). Treat Canada and Venezuela differently because of their tar sand, and Orinoco oils, respectively; making guesses (or assumptions, based on web data) for the production of these oils and subtract off to give estimated production of conventional only; and for reserves likewise subtract off the tar sands and Orinoco Belt proved reserves shown at the bottom of page 6. Then use these revised data in a 'mid-point' calculation to arrive at the two countries' dates of expected peaks in their production of *conventional* oil.

Hence modify your earlier calculation of the expected date of the global peak to more closely reflect the date of global peak as it applies to conventional oil only.

Step 12: *Forecasting the Global production of 'All-Liquids'*

Move beyond the peak of *conventional* oil, and see what is likely globally from the production of non-conventional oils. Recall that these include 'light-tight' oil (shale oil); tar sands and Orinoco oils; oil from shale rock ('kerogen oil'); oil produced by processing coal, and gas - but remembering in the latter case the approaching production peak of *conventional* gas); and oil from biofuels. Use the two reserves figures you have just used (for tar sands and Orinoco oils), plus other data from the web.

Couple these findings with the global peak you have above for conventional oil, to allow a picture to be built up of the possible future global supply of 'all-liquids' (i.e., all types of oil, including biofuels and oil produced chemically from coal & gas), to see what sort of oil future the world faces. For forecasting purposes, assume for simplicity that global conventional oil production in a region, *once it is past its conventional* *oil production peak*, declines at 3% a year (where this corresponds to a decline of ~5% p.a. from the fields in the region that themselves are past their production peak, offset by an increase of ~2% p.a. from newer fields in the region that are coming on-stream, including - in time - fields still yet-to-find).

There are, of course, significant caveats to such an 'all-liquids' forecast. These include:

(i). Higher prices can help find more oil, and also make more of the non-conventional oils (including probably even 'kerogen' oil) economic to produce.

(ii). A high oil cost is ultimately self-limiting, as it leads to oil 'demand destruction', and damages overall economic activity;

(iii). Production of significant quantities of non-conventional oil may be restricted under forthcoming climate change agreements: if we burn all the oil we know about, including all of the non-conventionals, the global 2 °C limit is far exceeded.

Step 13: *Other approaches for predicting the date of peak production of conventional oil in a region using the BP Stats. Review data.*

In addition to the 'mid-point' rule used above, there are two other simple approaches that can be used to estimate the date of peak conventional oil production in a region.

(i). PFC Energy's '60%' rule.

The 'PFC Energy' rule-of-thumb is that production of conventional oil in a region typically reaches its peak when about 60% of the total conventional oil that has been discovered in the region to-date has been produced.

That is, for a region, for conventional oil:

Total oil discovered to-date = oil produced to-date + current 2P reserves

with the 'PFC Energy' rule saying that production of conventional oil in a region typically reaches its peak for primarily physical reasons when about 60% of this 'total oil discovered to-date' has been produced.

This rule is thus simpler than the 'mid-point' rule, in that no estimate is required of the region's yet-to find. But the rule does rely on the reserves data being proved-plus-probable (2P) reserves, not proved reserves, and so can be rather unreliable when using BP *Stats.* data.

(ii). Hubbert Linearisation

An even simpler rule assumes that cumulative production of oil in a region follows a 'logistic' curve (the derivative of which, for oil, is known as the 'Hubbert curve'). In this case a clever linearisation of this curve (by plotting production data in a region against suitable axes, see below) gives not only the quantity of oil that will have been produced by the peak data (and hence allows the peak date to be determined - either historically if in the past; or by extrapolation if in the future), but also the region's URR.

The approach, for a given region, is to plot on a graph's ordinate (vertical) axis for each year: the region's (annual production divided by its cumulative production); and on the abscissa (horizontal axis) for the same year the region's (cumulative production).

Such a graph indicates the region's URR by the value indicated by extrapolating the (notionally) straight line produced to the abscissa; with the region's production peak occurring when cumulative production reaches half this value. (This technique works because a logistic curve is symmetrical, and peak in such a curve occurs at exactly half of URR).

This approach is simpler than either the 'mid-point' approach or the PFC '60%' rule, as it requires only the region's annual production data, which are usually fairly well known. But because it assumes production is following a logistic curve fairly accurately, it is often only reliable later in a region's life, once the peak date is near or past.

If you have the interest and time, by all means try either or both of these techniques on one or more of the countries that you have already investigated for date of peak under the 'mid-point' rule, and see how each of the three the techniques compares for ease of use and accuracy.

Step 14: *Net energy*

Of considerable interest going forward is how the generally lower energy-return-on-energy-invested (EROEI) ratios of nearly all new sources of energy (such as non-conventional oil and gas, as well as the renewables) will impact mankind's ability to access energy. Some analysis suggests that the impact will be large.

To investigate the oil aspect of this question, take your global 'all-liquids' forecast and modify the production quantities of the various categories of oil you assume (such as conventional oil, 'light-tight', tar sands, biofuels etc.) by the EROEI ratios listed below (converting EROEI numbers to 'net-yield' numbers, and making estimates where needed) to change your forecast from 'total barrels of liquids' to a forecast of 'useful net-energy' barrels of liquids; and hence compare the two forecasts and determine the implications for mankind.

Table: Estimates of Energy-return-on-energy-invested (EROEI, or EROI) ratios for different types of oil.

	Approx. EROEI range
Conventional oil: 1930 / 1970 / today	30 / 40 / 14
Shale oil ('light-tight' oil)	8?
Tar sands / Orinoco oil	1.5 - 8
Oil from kerogen ('oil shale')	5?
GTLs, CTLs	10?
Biodiesel, gasohol	~3

(Sources: Various; incl. C. Hall & J. Day, *American Scientist*, 97, 230-237, 2009.)

Note: If you search on the web for EROEI data, be aware of whether or not the 'internal' energy of the source material is included in the calculation of EROEI. For example, in determining the EROEI for 'kerogen' oil, a great deal of the heat need for retorting the kerogen can come from burning the kerogen itself. Including this energy leads to a low EROEI value. If only the energy purchased by the plant (the 'external' energy) is included, a higher EROEI value results.

4. ENDNOTES

1. Thus the main oil data in the BP *Stats. Review* include the following categories of oil:

- Conventional oil (i.e., normal 'flow-able' oil located in distinct oil fields, and which makes up the majority of all oil produced globally);
- Light-tight oil (also called 'shale oil': i.e., light oil locked in the rock pores, and which must be extracted by hydraulic fracturing - 'fracking' - of the rock);
- Oil extracted and upgraded from oil ('tar') sands (today, mostly in Canada);

- Orinoco oil (the heavy oil from the Orinoco Belt in Venezuela);
- Oil produced from oil shale (by retorting the oil pre-cursor, kerogen, in the shale rock; either on the surface following mining of the rock, or by *in-situ* methods). Very little of this type of oil is currently produced, though it is likely to become important in future.
- Condensate (oil that condenses naturally from gas streams, from either an oil well's gas cap, or a separate gas field, when this gas reaches the surface).
- NGLs (the oil-like 'natural gas liquids' that are produced by physical processes from gas in gas fields, and which constitute about 10% of total global oil supply. These are composed mostly of ethane to pentane, being either liquid at normal temperatures and pressures, or can be turned into a liquid by moderate pressure).

Note that three types of oil are excluded from the main BP *Stats. Review* oil data. These are: oil produced by chemical processes from coal or natural gas (coal- and gas-to-liquids, 'CTLs' & 'GTLs', respectively), and oil from biomass (biofuels). Production of these last three classes of oil is currently fairly small, and they are excluded from the main BP *Stats.* oil data because they are produced from very different sources, and by very different processes, than 'normal' oil.

Note also that while the BP *Stats.* includes oil from the Canadian oil sands and from the Venezuelan Orinoco Belt in the main oil data for reserves and production, for reserves these two classes of oil are included in the data, but also broken out separately at the bottom of the table. This is very useful when analysing the likely dates of the Canadian and Venezuelan production peaks of *conventional* oil, and also for estimating the possible future contributions from these two classes of oil.

2. Note that there is plenty of scope - at least in theory - for knowledge and technology to increase the recovery of oil from existing fields. Production of *conventional* oil typically recovers – on a global average – only about 40% of oil in fields, leaving behind 60% that cannot be produced by normal means. Thus the original *oil-in-place* in fields is - on average - usually more than twice the amount of oil considered *recoverable*. However, in your analysis deal only with the oil that is considered recoverable, as given by the BP *Stats.* reserves data; do not consider the oil in fields that is currently considered difficult or impossible to recover.

3. In collaboration with two students from a course possibly rather like yours, an academic paper was published in 2007 on the need to use such '2P' data:

Bentley, R.W., Mannan, S.A., and Wheeler, S.J. (2007). *Assessing the date of the global oil peak: The need to use 2P reserves*. Energy Policy, vol. 35, pp 6364–6382, Elsevier.

This paper drew on one of the oil industry's main datasets of '2P' data, that of IHS Energy Ltd. This was the company's 'PEPS' Exploration & Production dataset, purchased by the Oil Depletion Analysis Centre, London. The data that were published in the paper were with the permission of IHS Energy.

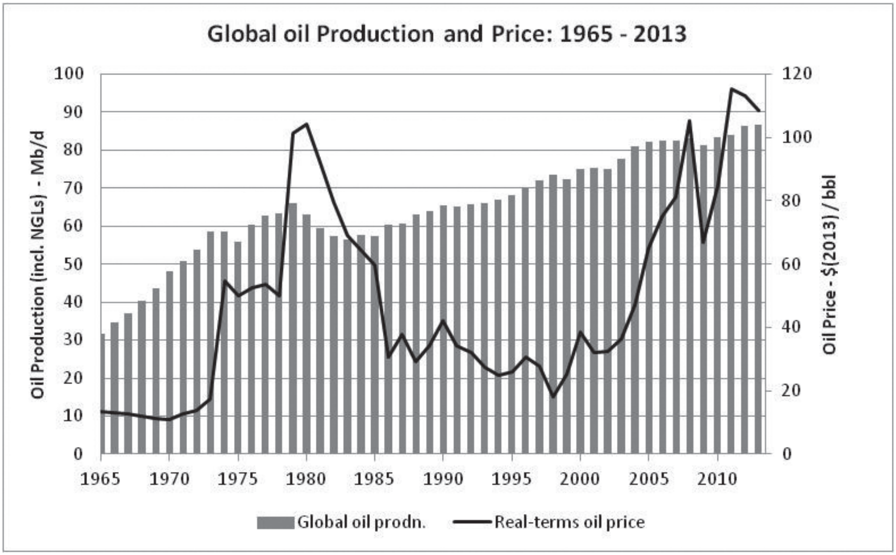
4. This precision in estimating the date of the UK peak from using a rough rule-of-thumb is something of a lucky fluke. The explanation is partly that BP *Stats.* 1P reserves for the UK underestimates the 2P reserves by a factor of two (an unusually large ratio compared to many other countries); coupled with the fact that the UK peaked later than expected due to its 'double-hump' production profile, itself partly an outcome of safety work carried out across all oil fields following the Piper-Alpha tragedy.

Charts

As mentioned in the Editorial, it is the intention to include in each issue of this journal a small number of charts - usually from already-published sources - chosen as being particularly informative. In this issue five charts are included. These depict:

- Recent global oil production, and real-terms price;
- Global oil potentially available, by category and production cost;
- Global oil discovery and production;
- Hence reserves; comparing 1P to 2P data;
- Use of a ‘creaming’ curve to estimate a region’s URR.

Chart 1. Global Oil Production and Real-terms Price, 1965 – 2013.



Notes:

- Global 'all-oils' production: vertical bars, left scale.
- Real-terms oil price ($2013): line, right scale.
- Production data include all fossil oils plus NGLs; but exclude GTLs, CTLs and biofuels.

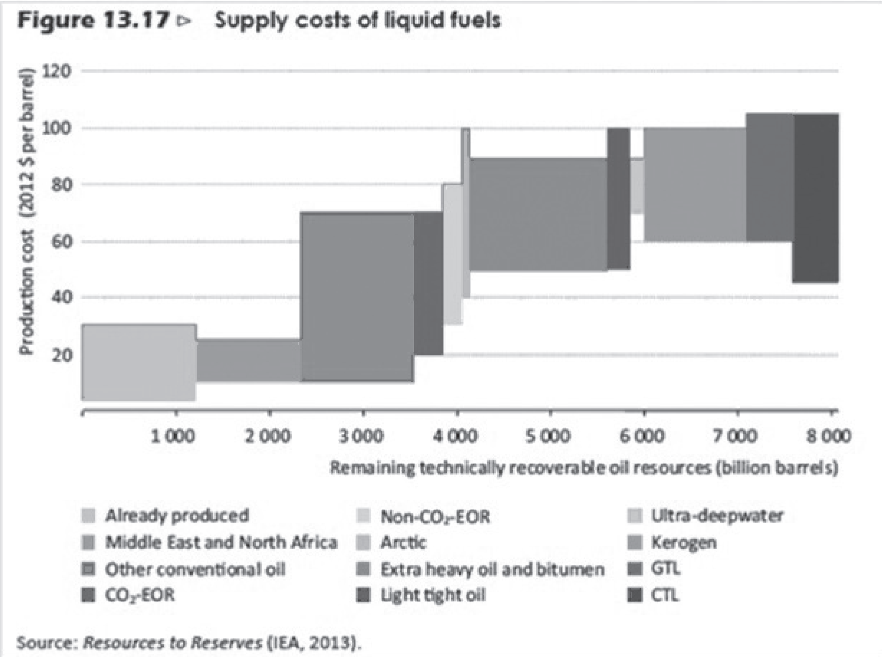
Comments:

- Production has shown weak growth since 2005.
- Over the last six years the average real-terms price of oil has been roughly that of the 1978 'oil shock', and approximately twice that of the 1973 shock.
- BP *Statistical Review* data show that for over four decades *prior* to 1973, the real-terms oil price averaged about $15/bbl; and global production grew rapidly, at up to ~8% a year.

- Once the shocks of the 1970s were passed, the oil price collapsed, but only down to about twice the pre-1973 level; averaging a real-terms ~$30/bbl over the following 15 years or so (1985 to 2000). This was because now the marginal barrels to meet demand were the more expensive oils from the North Sea, Alaska, offshore Africa, etc. As a result of this doubling in real-terms price, growth in oil production was considerably less, averaging somewhat under 2% a year.
- More recently, with the oil price between $50/bbl and $100/bbl, production growth (of all-liquids) has been lower still, below 1% a year, and where now the marginal barrels are the additional conventional oil itself brought on by the high price, plus increasing production of the generally expensive non-conventional oils.
- Note that the current high price cannot be driven *fundamentally* by growth in demand alone as is often claimed (citing e.g., rapidly rising demand in China & India). This is because in the over a century from 1861 to 1973, the average price of oil *fell* while global oil demand for oil grew rapidly. Today's high price thus needs an explanatory factor in addition to demand. This factor is the declining availability of conventional oil, as the papers in this issue have explained.

Source: BP *Statistical Review of World Energy,* 2014 edn.; graph based on an original by E. Mearns.

Chart 2. Quantities of Oil available by Category vs. Production cost:



International Energy Agency (IEA) plot of Global remaining technically recoverable volumes of oil available, by category (in Gb) vs. Production cost ($2012/bbl).

Notes:

- EOR: Enhanced oil recovery. MENA: Middle East and North Africa. GTL: Gas to liquids. CTL: Coal to liquids.
- Volumes of oil potentially available are shown along the x-axis, *not by the area* indicated.
- The first six categories of oil (up to 'Arctic'), plus also 'Ultra-deepwater', refer to mainly conventional oil.
- The other five categories are usually classed as either non-conventional oils (Extra heavy, Light tight and Kerogen) or as 'other liquids' (GTLs & CTLs). The plot does not include biofuels.

Comments:

- In terms of the current 'peak oil is dead' debate, note that the IEA's assessed global quantity of recoverable shale ('light-tight') oil is rather small, at ~250 Gb; i.e. about 8 years' of global supply, giving - *very roughly*, and if only this oil were used - about 4 years' to its peak.
- The wrong way to read a chart like this was that of the UK's Dept. of Trade and Industry which said, based on an earlier version of the chart, that "There is more than enough oil available to meet foreseeable demand". And this view might seem natural enough: after all there *is* ~ 7 000 Gb of recoverable oil of all types remaining, with a century-and-a-half of global production only having produced ~1 250 Gb.
- But this view is naïve. The correct way to read the chart is as follows:

  (a). Understand the 'mid-point' peak of *conventional* oil production, so on these data expect the global peak of conventional oil when ~1 875 Gb has been produced (i.e., half of the ~3 750 Gb URR resulting from summing 'already produced,' MENA, other conventional, Arctic, plus ultra deepwater; and excluding EOR, as this usually comes on only late in a region's life). At the current production rate of ~30 Gb/yr., and with 1 250 Gb already produced, the global conventional oil 'mid-point' peak is then expected roughly 20 years from now, depending on the rate of demand growth.

  (b). But then recognise that production of much of the MENA oil will not increase significantly due to resource-national reasons.

  (c) So look instead for the 'mid-point' of *total non-MENA* conventional oil. On these data this occurs at 1 325 Gb produced (half of ~2 650 Gb), i.e. in about 5 years' time.

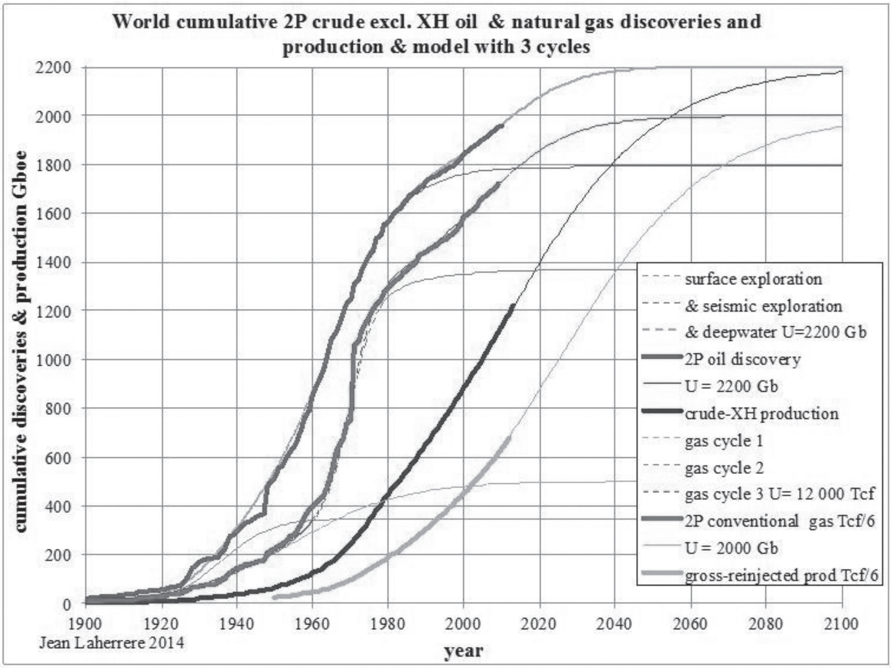
  (d). Recall also, from the papers in this issue of the journal (and data elsewhere), that a global URR of 3 750 Gb for conventional oil (incl. NGLs) is judged by some analysts as being on the high side, at least as far as derived from extrapolated discovery, and hence in terms of driving the date of peak. These analysts estimate the total production of conventional oil (inc. NGLs) to 2100 (roughly equivalent to the URR) as being between 500 Gb and 1 000 Gb lower than the IEA 3 750 Gb number.

  (e). Hence conclude, correctly, that the steep rise in the oil price over recent years has been because of the restricted increase in global conventional oil production resulting from proximity to this peak, which in turn has forced the world to obtain its marginal barrels of oil, to meet the growing demand, from the expensive oils shown to the right of the chart.

(f). And recognise that these ‘other oils’ tend to have poor energy-return-on-energy-invested (‘EROEI’) ratios (indeed, a major factor in why they are costly to produce); and face other constraints on their production, such as permitting, water requirement, CO_2 emissions, and volume of waste if produced by mining.

Source: IEA *Resources into Reserves*, 2013.

Chart 3. Plot by J. Laherrère: Global Oil & Gas 2P Discovery and Production, historical data & forecast, 1900 - 2100.



Notes:

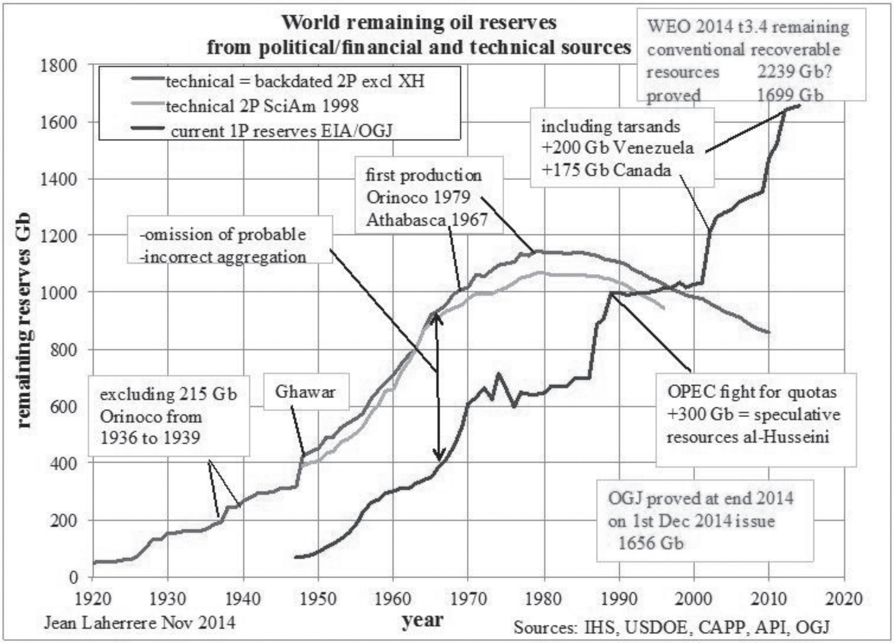
- Leftmost line: Laherrère's judgement of 'most probable' *backdated 2P cumulative global discovery* data for crude oil less extra heavy oil (the latter mainly Athabasca tar sands and Orinoco oil), and does not include NGPLs.
- Next left line: Corresponding data for gas, calculated as Tcf/6.
- Next left line: Cumulative global production of crude oil less extra heavy oil. (EIA data includes condensate).
- Rightmost line: Cumulative global production of gas, Tcf/6.

Comments:

- The 2P discovery data reflect data from industry scout sources, but reduced by: 300 Gb to allow for Laherrère's view of overstatement of the OPEC Middle East original reserves data (as confirmed by Sadad Al-Husseini, former VP Aramco, at the 2007 'Oil & Money conference', London); by 30% of the FSU data (~100 Gb) to allow for the datasets ABC1 holding probably closer to 3P than 2P data (as indicated by field decline plots and by Gazprom audits in annual reports); and by 200 Gb to allow for Orinoco 2P discovery data reflecting non-conventional oil.

- As the chart indicates, Laherrère's view of the likely extrapolation of the backdated cumulative 2P discovery curve indicates a 'medium-term' global URR for 'conventional' crude oil (including condensate) less extra heavy of 2 200 Gb. On this basis, and using the 'peak at ~mid-point' rule, the 'expected' date of peak would be about the year 2010, having a cumulative production of 1 100 Gb; in reasonable agreement with the apparent actual date of this peak.
- Alternatively, one can use the 'PFC Energy '60%' rule, and estimate the global peak date, for conventional oil ex NGLs. On the basis of the data shown here, 60% of current 2P discovery (at 2,000 Gb) is 1,200 Gb, which estimates the date of this peak slightly later, but still in the past, at about the year 2012.

Chart 4. Plot by Jean Laherrère: World Remaining Oil Reserves: Comparison of 2P with 1P data, 1920 – 2014.



Notes:

- Laherrère's view, from sources listed, of the difference between *global backdated proved-plus-probable* ('2P') oil reserves, estimated from oil industry scout data, and *current-basis proved* ('1P') global oil reserves as given by public-domain data.
- Leftmost line (exhibiting a peak in 1980 at ~1,150 Gb): Laherrère's estimate of global 2P backdated oil reserves, 1920 to 2010, excluding extra-heavy oils (tar sands and Orinoco oil). Data are from industry scout databases as listed, but adjusted by removing 300 Gb from Middle East reserves, and 30% of FSU reserves, for the reasons given in Chart 3, above.
- Next leftmost line: The same data, but as reported in the article: *The End of Cheap Oil* by Campbell & Laherrère, *Scientific American*,

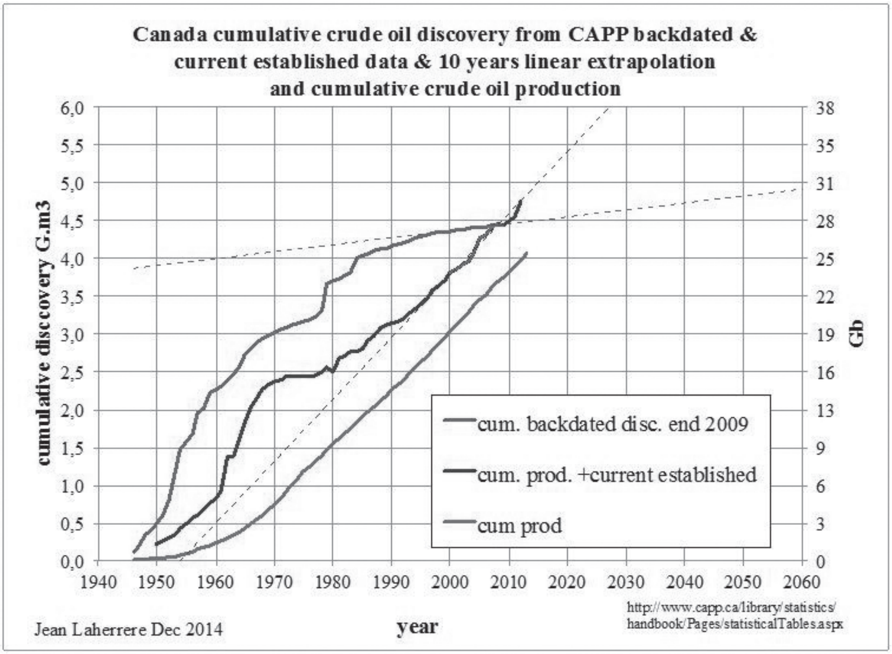
March 1998.

- Rightmost line: Data from US EIA and *Oil and Gas Journal* (OGJ) of public-domain current-basis global 1P oil reserves, 1947 to 2014, *including* extra-heavy oil.

Comments:

- The estimated backdated 2P global oil reserves, excluding extra-heavy oil, peaked in 1980.
- The global 1P oil reserves, also excluding extra-heavy oil, rose consistently to ~1997, to roughly match the 2P data (implying OPEC 1P overstatements roughly matched the industry global probable reserves); and increased subsequently, in part due to adding in Canada and Venezuela extra-heavies.
- On the public-domain 1P reserves data Laherrère notes that: 'The most recent figure available is that of 1 656 Gb, posted on internet on Nov 24 2014, of the OGJ issue dated 1st December 2014, and relating to reserves as the 1st of January 2015. These data are not measurements but guesses, and in fact political statements, because technical estimates cannot be delivered before March 2015. The OGJ data report 106 countries, of which 66 countries showed no change in their proved reserves from the previous year. (Within Eastern Europe and FSU, this was 19 countries out of 20). Hence only 40 countries showed any change in their 1P data. The countries that showed no change include those where assembly of technical estimates of proved reserves had not yet been carried out, as the year 2014 was not then completed. Note that in countries like Iran, Iraq, Qatar, Saudi Arabia & UAE the proved reserves data are used as a basis in quotas negotiations.'
- [For comparison of the 2P reserves data shown here with IHS Energy's 'all-oil' 2P reserves data, go to Miller and Sorrell (*The future of oil supply*. Phil. Trans. R. Soc. A **372**: 20130179, 2014) and subtract the graphed data for cumulative production from the corresponding graphed data for cumulative 2P discovery.]

Chart 5. Plot by Jean Laherrère: Creaming curve for Canadian conventional oil; Extrapolation to an estimated URR; and Comparison of backdated discovery vs. non-backdated discovery data.



Notes:

- Leftmost line: Backdated industry proved-plus-probable data for conventional oil discovery in Canada, to end-2009.
- Next leftmost line: The corresponding public-domain non-backdated discovery data to end 2013, generated by adding 'current established' (remaining) reserves to cumulative production.
- Rightmost line: Cumulative production.
- Data sources: As listed on the chart.

Comments:

- Estimating the total amount recoverable of conventional oil or gas that will have been produced by the end of production for a region, known as the region's ultimately recoverable resource ('URR'), can be done in a number of ways. One of these is the 'creaming' curve method, which plots cumulative discovery against the cumulative number of New Field Wildcats (NFWs). The latter are exploration boreholes which are looking for new fields, contrary to exploration appraisal wells. The trend-line produced is known as the *Creaming Curve* for that region, and this can be extrapolated, sometimes using several cycles to reflect distinct phases of discovery, to give an estimate of the region's URR.

- A similar curve (often also called the creaming curve) can be produced by plotting cumulative discovery vs. date. This is usually less useful than vs. NFWs, as discovery effort may change with time, for example when the oil price is low, or political restrictions are imposed on exploration, and the discovery trend is less clear. Nevertheless, where discovery data vs. NFW drilling are not available, a 'creaming curve' vs. date can still give a good indication of URR (subject always to geological information being included of the chance of new plays in a region and their likely prospectivity).
- Here the creaming curve vs. date for Canada is shown. As this indicates, in the case of Canada's conventional oil, there have been two main cycles of discovery, reflecting discovery in the Western Canadian Basin and in the Eastern Offshore. As also shown, the trend of the line for backdated industry proved-and-probable ('2P') discovery data points to a total URR for Canadian conventional oil of around 32 Gb (billion barrels).
- By contrast, if public-domain non-backdated ('current') data are used, a picture of ever-advancing discovery emerges. Not only is this very misleading, but also no useful estimate of the region's URR can be derived.
- Laherrère notes: 'It is impossible to update this graph because CAPP has stopped reporting backdated reserves beyond 2009, and the same for New Field Wildcats. This is a shame: [perhaps] they do not want to show disappointing real data. Note that the graph of discovery versus date has a crooked section since 2010 because of tight oil.'

SUBSCRIPTION FORM FOR "THE OIL AGE"

NAME:____

POSTAL ADDRESS:________________________________

____

EMAIL ADDRESS:__________________________________

**Please note – Your details will not be shared with third parties.

IRELAND

Issue 1 (January 2015) only Post & Packaging **TOTAL**	€15.00 €1.65 **€16.65**	☐ Please check here
Annual Subscription 2015 (4 issues) Post & Packaging **TOTAL**	€50.00 €6.60 **€56.60**	☐ Please check here

REST OF WORLD

Issue 1 (January 2015) only Post & Packaging **TOTAL**	€15.00 €3.50 **€18.50**	☐ Please check here
Annual Subscription 2015 (4 issues) Post & Packaging **TOTAL**	€50.00 €14.00 **€64.00**	☐ Please check here

see next page for payment details

PAYMENT DETAILS

By Cheque:

Please send a cheque (in Euro) for total checked above to: "ASPO Ireland"

Postal Address:
Petroleum Analysis Centre,
Staball Hill,
Ballydehob,
Co. Cork,
Ireland

By Bank transfer:

Please transfer amount for total checked above to Allied Irish Bank:
"ASPO Ireland"
IBAN IE14 AIBK 9340 4617 1950 13
BIC AIBKIE2D

By PayPal:

Please transfer amount for total checked above to: **"theoilage@gmail.com"**
(please note there is an extra charge to use this service)

Queries should be addressed via email to Noreen Dalton: theoilage@gmail.com/ Telephone +353 85 160 7001