A Bottom-up Model of Future Global Oil Supply

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1. INTRODUCTION

A *bottom-up* model is one which builds up a picture of the whole by summing its smallest practical individual components. When modelling future global oil supply, this usually means estimating the future production of each individual oil field and summing the results. A *top-down* model of oil supply instead forecasts global oil production as a whole, or in just a relatively few large divisions.

Top-down models, for example, may group fields into classes with different behaviours, such as by geological setting, terrain, climate, nationality or political affiliation. Some top-down models require a calculation or estimate of global or regional ultimate recoverable reserves (URR) and/or a rate of production decline after peak production; bottom-up models may derive these parameters from actual field behaviour.

This paper describes in detail one bottom-up model, built and maintained by the author over the past 15 years. It consists of a database of oil production from the world's individual oil-fields since 1992, with production projected out to 2040. Such models are powerful but have both practical and theoretical drawbacks. This paper will be explicit about their failings because they point the way to next-generation models. It also examines this particular model's historical accuracy in a series of annual snapshots over its lifetime.

2. MODEL CONSTRUCTION

2.1 Production and reserve data

The primary data requirement for a bottom-up oil supply model is the past production rate for each oil field or oil project. We define "oil" in this context as mobile crude oil or synthetic crude, excluding condensate and natural gas liquids (NGLs – largely ethane, propane, butane and pentane). For historical reasons we have always included all Venezuelan and Canadian production of extra-heavy oil, bitumen and synthetic crude. These were the only major non-conventional resources in production in 2000 when the model was first created, and their inclusion was both realistic and relatively easy. Light tight oil ("shale oil") is included by default because, in the US, its production rate cannot be easily be deducted from overall US crude production data (which our model records by State rather than by field). Thus this model includes conventional oil, tar sands, Orinoco oil and light tight oil, but excludes NGLs and condensates, oil retorted from kerogen (either above ground or *in-situ*), and also liquids produced from coal or gas, or from biomass (such as biofuel).

In the model the production rate is the annual average of the daily production rate, measured in barrels/day. The data set begins in 1992 which, when the model was first created, allowed for eight years of historical data, sufficient to establish the existing production trend for most fields. Data on remaining reserves are also useful for constraining future production rates, as will be discussed later.

There are various sources for production data but all are neither comprehensive nor entirely accurate. This model was first assembled under the aegis of a major oil company with access to several commercial databases, but none covered every significant oil-field for every year. Even some major fields were entirely omitted, presumably because no data had been released by the field operator. For some other fields the data for certain years were missing. The ultimate source and reliability of the data were usually not indicated, and it was often unclear exactly what liquids were included. These omissions probably reflect reluctance by many national authorities to release what they regard as sensitive or secret data (and also sometimes a lack of awareness or concern for accuracy).

In the model, the minor fields for each country are consolidated into a single group as "others", with net production equal to the difference between total national production and the sum of the major fields. Where field-level data are not obtainable, we use data consolidated by company, geological basin or national state as available.

There are public sources for certain oil production data, all of which are used to compile and update the model:

- The UK Department of Energy and Climate Change (DECC) publishes detailed monthly production data for every UK field[1]. Certain other OECD countries also provide very reliable annual production data by field. The US EIA only provides data consolidated into geographical subdivisions.
- Certain oil companies provide precise field-level production and/or reserves data in their annual reports for countries where the authorities do not do so, for example Lukoil (albeit the data may be of unknown reliability).
- Some agencies provide occasional nuggets of data but not systematic compilations. Examples include the IEA (in their annual World Energy Outlook) and the EIA (in their country analysis briefs or CABs). The original data sources are sometimes not discussed.
- *Oil and Gas Journal* publishes for its subscribers each December a table of many of the world's producing fields, which at its best includes average daily production rate for the previous year, offshore/onshore location, fluid type, operating company, discovery date, depth, number of wells and API gravity. The table has sometimes been prone to typographical and other errors, and there is a growing tendency for production data to be amalgamated by production company, although this may be outside the journal's control. Its US data are amalgamated by State, its Chinese data largely by basin, and its Russian data by producing company.
- The Alberta Oil Sands Industry provides regular quarterly data on all Canadian oil sands projects, although tending to give capacity rather than actual production data[2].
- Company reports and technical presentations containing hard data can sometimes be found on-line. There are also several on-line oil industry news services that provide a daily news digest.

1 https://www.og.decc.gov.uk/fields/fields_index.htm

2 Most recently, see http://albertacanada.com/files/albertacanada/AOSID_QuarterlyUpdate_Winter2015.pdf

Comprehensive data on reserves are also difficult to acquire. We use the same sources as those above except *Oil and Gas Journal,* which only compiles "estimated proved reserves" data at the country level (these are presumably 1P data, and so suffer problems of under- and over-statement, and non-statement). Problems with reserves data include loose terminology by journalists who do not distinguish between oil originally in place (OOIP), reserves and resources. Some operators and national authorities also do not clearly distinguish between proven, probable and possible reserves; proven, probable and possible, are subjective numbers in any case as different organisations use different definitions and techniques. We always use proved + probable (= 2P, or $\approx P_{50}$) reserves data where available, which from experience are closest to the eventual cumulative production (Bentley *et al*. 2007).

Data are often inconsistent between sources. Differences in field production rates can arise from rounding errors or from the inclusion of condensates or NGLs, but others are not explained. Our model uses data from *Oil and Gas Journal* as the primary but not the sole source for field production data, and as almost the sole source for national total production data, to maximise the model's internal consistency. Once locked into a model, these choices cannot generally be changed without losing its historical insights. The national totals reported by the *Journal* are often significantly lower than those reported by other sources, notably the EIA and the BP Statistical Review, largely because the *Journal* excludes most condensates and NGLs and also because the journal omits numbers for some minor countries.

2.2 Oil Field Production Stages: Growth, Plateau and Decline

Oil fields have a typical production profile comprising a growth phase of several years, a plateau phase of several years, and a long slow decline phase which can last for many decades. The decline is often approximately exponential, i.e. the average production rate each year falls by roughly the same percentage value over the previous year. In general some 60-70% of the initial oil reserves in larger fields are produced during the long decline stage. It follows that, firstly, most of the world's currently operating oil fields are in decline or "post-peak", and secondly, that post-peak fields produce the bulk of global oil supply[3].

3 For this and similar background information used in this paper, the reader is referred throughout to Sorrell et al. (2009).

Our model follows these observations closely. Where a field is in decline, the exponential decline rate is calculated (as the mean of the past three annual rates where the data are available) and is then used to estimate future production rates. Fields on plateau are compared with neighbouring analogues to estimate when decline will commence, and an appropriate decline rate then applied for post-plateau production. Fields still in growth phase usually have a published target plateau rate which can be used.

If reserves data are available, we also compare a field's projected total production out to 2040 with the remaining reserves. Smaller discrepancies can be resolved by adjusting the production decline rate. Larger discrepancies are problematic, and some judgement has to be applied as to whether the estimated decline rate or reported remaining reserve is more likely to be correct.

2.3 Interpolation and Extrapolation of Data

Missing production data have to be interpolated between two known data points or extrapolated into the future from a single datum. Interpolations and extrapolations are clearly distinguished from known data in the data-base, by simple colour coding.

The most unreliable interpolations and extrapolations occur when national production is being depressed for reasons unrelated to simple field operations. For example, most Nigerian individual field data have not been published since 2006, but simple extrapolation since that date is complicated by a wave of increasing sabotage since about 2008, which dramatically reduced total Nigerian output. We do not know which of the hundreds of fields were affected by insurgent activity, or (field by field) by how much. Similar problems have affected Colombia, Libya, Iraq, Kuwait and Iran among others. Production from OPEC states has often been considerably lower than their full capacity, most notably in Saudi Arabia, but in this case for political reasons. Unfortunately we do not know which Saudi fields have been shut-in or are running at reduced output, but we know that current Saudi oil production, which is historically high, may still be significantly less than capacity. The most important field data in bottom-up models are often the least reliable.

2.4 Undeveloped Fields

Discovered but undeveloped fields are incorporated into the model using published or modelled data for dates and rates of future production.

The promoters of fields in development usually announce the expected production rates and anticipated date for coming on-stream, data which can be added very simply to the model. Of more interest are the many discovered but undeveloped fields with no known development plan. Our model assumes that undeveloped fields are always brought on-stream more or less rapidly, according to their location and local practice and regardless of oil demand or price, but some may be undeveloped for good reasons. Recently discovered but currently inactive fields may simply be awaiting their turn for financial sanction, but we have to wonder whether some of those discovered longer ago have deeper underlying problems. For example, some fields may be geologically or technically too complex, or too far from existing infrastructure, to be economic. Some might become economic if the oil price rises, if other adjacent discoveries are made, if technology improves or if new infrastructure is built nearby, but some may prove never to be exploitable. In the worst cases, some fields may have a net energy yield <1 ("EROI", or energy return on energy investment) and never be exploitable at any oil price.

Miller (2012) showed that 173 Gb of 2P global oil reserves listed in a leading proprietary database (13% of the total) were either in appraisal or awaiting sanction, or were simply listed as "discoveries" without further qualification. 58 Gb of these unqualified "discoveries" had been known for more than a decade, with some dating back before 1960, without apparently moving any further along the development chain. Other fields have seemingly been in appraisal or awaiting sanction for decades, without revision of their status. Miller (2012) concluded that perhaps 105 Gb of reserves worldwide are contained in such *fallow fields*, those long-undeveloped fields which will probably always be uneconomic. Since 2012 we have started removing certain older, smaller, remote and/or complex undeveloped fields completely from the model, where we think these are likely to be permanently beyond economic exploitation.

2.5 Conventional Oil in Undiscovered Fields (Yet-to-find, or YTF)

There is no consensus on exactly how much conventional oil (generally taken as mobile oil that has migrated to distinct fields) remains undiscovered, or where it is, but future discoveries must be incorporated into the model in some way. The *ultimate recoverable reserve* or URR is the sum of (1) the cumulative past production, (2) current reserves, (3) future discoveries and (4) "reserves growth", an increase in oil recovery over time that arises from improvements in knowledge and technology. Future discoveries can be modelled by simple extrapolation from past discovery patterns, or else derived from independent estimates of URR and discoveries to date.

Published estimates of reserves, URR and YTF are difficult to compare because different authors include or exclude certain non-conventional oils, condensate and/or NGLs, and use different assessment methodologies for URR. Estimates of conventional oil already produced as of today are largely consistent at about 1350 Gb, but estimates of the ultimate recoverable conventional oil resource have ranged for some years between about 1900 Gb (for Campbell's 'Regular conventional oil) and 3345 Gb (USGS year-2000 estimate, including NGLs) (Sorrell *et al*, 2009). Two current global reserve estimates are 1688 Gb (BP 2014) and 1647 Gb (*Oil and Gas Journal*, 2014) but both estimates include some 360 Gb of undeveloped Canadian oil sands and Venezuelan Orinoco extra heavy oil. Mainstream estimates of the amount of conventional oil remaining to be found therefore range up to 700 Gb.

We currently assume that some 200 Gb of conventional, economically exploitable crude oil remains to be found, which is allocated country by country. For comparison the USGS mean estimate of undiscovered oil resources fifteen years ago was 649 Gb (Ahlbrandt *et al.* 2000) and subsequent rates of discovery suggest that this was an over-estimate (Klett et al., 2005). Our model uses past estimates by the USGS and others, modified according to subsequent discovery volumes, actual discovery rates and professional opinion. We use a simplistic model of discovery whereby 5% of a nation's YTF is discovered annually for the first 6 years, 4% annually for the next 6 years, then 3%, 2% and 1% for subsequent 6 year tranches. Our estimate of YTF was 376 Gb in 2000 and 235 Gb in 2010; it would have fallen to about 203 Gb in 2010, according to the discovery model, if no revisions had been made in that decade. It is now about 200 Gb.

Newly discovered fields are assumed to be brought on-stream rapidly according to national standards, ranging from perhaps five years for remote off-shore or undeveloped mountain areas, to one year for highly developed basins with good existing infrastructure; but we accept that this is perhaps rather optimistic. Each country's future annual discovery tranches are modelled as a single new field each year, with production that peaks and declines according to one of four simple general models which are based on whether the annual tranche is large or small, and whether it is located largely on- or off-shore.

2.6 Technological Improvements to Oil Production

A criticism sometimes levelled at mechanistic, numerical models such as the model presented here is that they cannot or do not take into account improvements in technology, which can range from new exploration technologies to horizontal drilling and reservoir control additives. In the past our model made a very small specific allowance for such change, by increasing each annual forecast production rate by a factor of 0.2% over the raw estimate. The 0.2% factor is based upon unpublished work by Francis Harper (pers. comm.), who some years ago estimated that global production was rising by 0.15% year-on-year for reasons of technical improvement.

However, our model now contains some 20 years of actual historical data. Obviously the technical improvements made during that time are reflected in those data, and we suspect that extrapolating forward in time from those data automatically incorporates further continual, incremental improvement due to better technology and knowledge. Therefore, as of this year, a separate factor for technical improvement in future production rates will not be included in the model.

An exception to this approach would be if the oil price were to be high, ~$100/bbl (or even higher), for long enough for the annual gains in productivity due to the use of enhanced oil recovery (EOR) techniques to be significantly greater than has been the case in the past. While this is conceptually possible, we suspect that such high (or very high) oil prices would instead be more likely to limit the demand for oil.

2.7 Non-conventional oil

As mentioned earlier, the model includes production of some but not all of the non-conventional oils. It includes oil from tar sands, Orinoco oil, and light tight oil currently obtained by fracking of shale and related rock. None of these oils can be modelled in the manner appropriate to production of conventional fields, and in general their production must be forecast by when specific projects for their extraction are likely to be brought on-stream. For these oils, production, reserves and 'yet-to-find' are handled as follows.

Canadian tar sands

The tar sands form reasonably continuous deposits which are divided into numerous project areas. The projects are conceptually relatively simple to model. Project details are declared well in advance of production and published by both company and official sources. Some projects involve strip mining with a constant rate of output until exhaustion. Others are produced *in situ* by various local-scale heating technologies to reduce their viscosity, but because the heating is applied to small blocks within a project area and moved on as each block is exhausted, production levels are likely to prove quite constant until the whole project area has been exploited. Both forms of recovery are thus expected to result in projects which remain on their plateau production levels throughout their life. Reserves data for the smaller projects are not always available.

Venezuelan extra heavy crude

Venezuelan extra heavy crude is quite similar to Canadian tar sand bitumen, but the surface rocks are colder in Canada than in Venezuela because of the climate, so the Venezuelan oil is somewhat less viscous *in situ*. Consequently much extra heavy crude can be produced relatively conventionally, using long horizontal wells, although there is also considerable effort under way to use heating or dilution to improve flow rates and recovery. Project production forecasts are given in public literature.

Although much Venezuelan extra heavy crude will be produced by relatively conventional techniques, the model currently treats the Venezuelan deposits as behaving like tar sands projects, at constant plateau production rates to 2040. There are usually sufficient declared reserves to sustain such a production profile. However, it is likely that these deposits will ultimately decline post-2040 like conventional oil fields with a long slow decline, rather than like tar sand mines with an abrupt end when the deposit is mined out.

Light tight oil

To date, light tight shale oil ('LTO') production is an onshore US phenomenon, occurring within a few large sedimentary basins. LTO production data from the EIA is recorded by basin, but conventional onshore production is generally compiled by State, which are the data used by the model because field-level data are not available. Because the shale basins can extend across several States, it is impossible to know precisely how much production in such States is conventional and how much is not, so LTO production cannot be modelled separately. The problem is compounded because some shale basins also have conventional production from some areas. At present, therefore, the model uses State-level production data which includes both conventional and non-conventional oil. LTO wells are only marginally profitable at current oil prices and have extremely rapid decline rates, typically 50% per year; the future production profile of LTO will therefore be very largely determined by oil price and demand on almost a month-by-month basis, and remains an unresolved modelling problem.

3. MODEL RESULTS

3.1 Current Model

The most recent model for the world as a whole is illustrated by the chart shown in Figure 1, which includes most data to date.[4] Producing countries have been compiled by OPEC or non-OPEC status, and YTF oil has been distinguished. It also shows the factor which reflects future technological improvement on discovery and production (in future this factor will be discontinued as discussed earlier).

The historical data set between 1992 and the first model run in 2000 should of course be identical every year, but it shows a slight increase with time. The two principal reasons are the more recent inclusion of minor oil-producing States for which data was not previously available, and the occasional need to follow subsequent corrections made in the published data.

We have sometimes had to adjust national production data to match field level data. The field level production rates for each country should sum up to the national production rate, but occasionally they apparently exceed the national rates as published by *Oil and Gas Journal*.

The most notable feature in Figure 1 is the forecast decline in the total global production of the classes of oil included in Figure 1 from shortly after about 2020.

A second feature is the 'hump' in future oil production, which commences in 2013 at the start of the projection into the future. This

4 Field level production data from *Oil and Gas Journal* for 2013 were unobtainable until the end of 2014, and are not yet fully incorporated into the model's data.

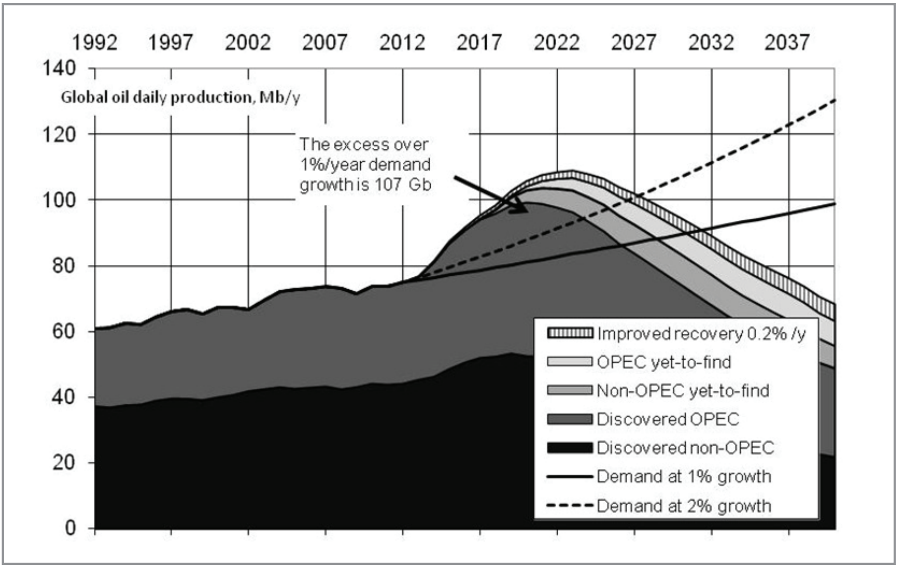

Figure 1: Output of the Global oil forecast model, updated to today. Oil production includes conventional oil (oil in fields), tar sands and Orinoco oil, and 'light-tight' oil from fracking. It excludes production of NGLs and condensate, oil retorted from kerogen, GTLs and CTLS, and oil from biomass (including biofuels).

hump reflects an excess of some 107 Gb over the projected oil demand, should the latter increase at 1% p.a., which is a typical current estimate of demand growth. The hump is primarily generated by known but undeveloped fields which are modelled to come on-stream over the next five years. As discussed earlier, we have some doubts about 105 Gb of oil reserves contained within "fallow fields" ever being commercially exploitable. Other such reserves are certainly real, developed and ready to go on-stream but are simply not required yet, such as some smaller Saudi Arabian fields.

If much of this 105 Gb of oil currently in 'fallow fields' does not come on-stream as shown in Figure 1, total global production of the classes of oil included in the Figure is likely instead to exhibit a 'bumpy production plateau' at around 80 Mb/d or so, from roughly about now. However, if such a plateau occurs, decline after this plateau may be less steep than the rate of decline shown in the Figure of ~3% per year.

3.2 Historical Model Accuracy

Every year since 2000 the author has taken snapshots of the model to be able to examine, analyse and improve its long-term accuracy, and its shortcomings. The summary of future global oil production forecasts is shown in Figure 2. Note the production hump that starts at the end of each model period. This hump has been a feature of the model since its first inception, probably because it contains many of the same group of undeveloped discoveries every year. As the model has been continually updated and improved, the hump gradually achieved a largely consistent size and shape in about 2005. The projected peak of conventional oil production is consistently some eight to nine years ahead of the model date, ever since the first model run in 2000. The last model run in Figure 2 is from end-2012, and its peak is 2021. This behaviour is what might reasonably be expected if the hump represents a block of fields which are either undevelopable or placed on hold for many years for political reasons: each hump will always have the same general size and shape.

4. STRENGTHS AND WEAKNESSES OF BOTTOM-UP MODELS

We do not think our model differs materially in its concepts from most other current bottom-up models, so we may consider the properties of the model type as a whole, based on our experience of this example.

4.1 Strengths of Bottom-Up Models

The first great strength of the bottom-up model is that it makes the fewest assumptions:

(i) Top-down models must assume, explicitly or implicitly, a value for global (or regional) reserves, where bottom-up models use field-by-field reserves. These should be the same but are not, because field data throw up many cases where actual production data do not support the stated reserve data, which can be too low or too high (stated reserves which are far higher than required to support a declining production are not impossible but are often unreasonable). The global reserves data will also probably include certain fallow fields which on balance are unlikely to be developed, and Middle East OPEC official reserves which are often regarded as suspect. These problems can be addressed individually in the bottom-up approach.

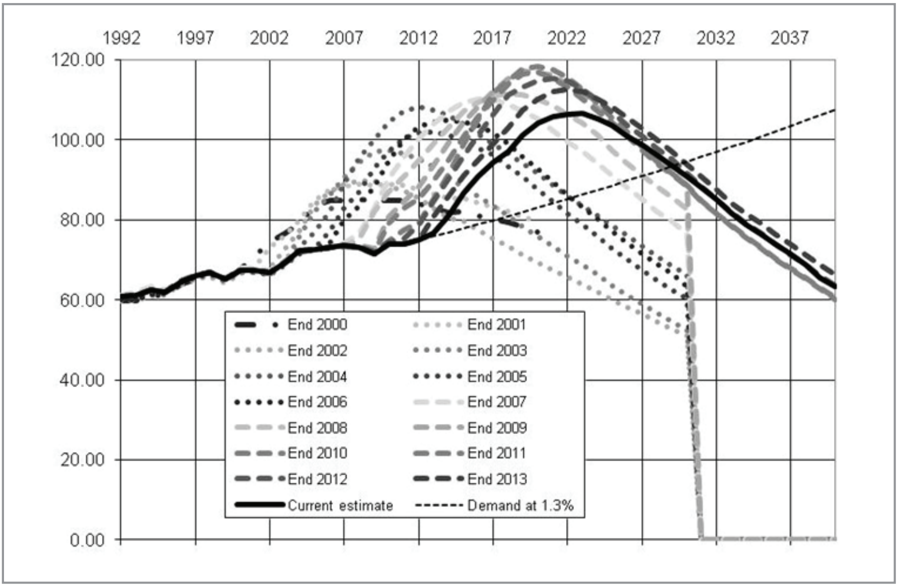

Figure 2: Historical actual global oil production, and forecasts of future production. The forecasts were made annually from end 2000, and extend to the interim forecast for end-2014. (For classes of oil included in the forecasts shown here, see notes for Figure 1.)

(ii) Both model types must make similar assumptions about YTF, although bottom-up models will likely be able to include greater granularity – by basin rather than by country for example.

(iii) Both model types require post-peak decline rates. These are often made explicit in the bottom-up model, which has numerous individual post-peak fields to act as templates, where the top-down has to use a single average for all fields, derived from observed decline rates. When a bottom-up model finds individual field decline rates which do not match expectations from reserves, they can be adjusted or examined further to find any external, above-ground effects biasing the data. Further, when considering a simple historical country production profile, we cannot distinguish between a situation of high field decline rates offset by a high rate of new field development, and a situation of low field decline rates with low rates of new field development. The past profiles will look similar, but their future profiles will differ as new discovery rates and developments fall away. Bottom-up models measure and must honour actual field behaviour.

The second great strength is a greater understanding of actual field behaviour which can be applied when projecting into the future. It has become clear to us, for example, that EOR generally increases the amount of oil recovered, by slightly reducing the field decline rate and extending its productive life; however, in some fields, EOR seems to increase the rate at which the reservoir is drained without greatly increasing the eventual total recovery. We can also see directly in the model how offshore fields are exploited faster than onshore fields, and smaller fields are evidently engineered for faster decline rates than larger fields.

4.2 Weaknesses of Bottom-Up Models

The failings of bottom-up models must be acknowledged, and these are largely the effects of poor data and/or external influences. The greatest of the latter are financial, political and geological.

Bottom-up models suffer from incomplete data. For the more significant fields without production data, estimates must be made. Smaller fields, as noted previously, are conveniently amalgamated into one group with an output fixed by the difference between larger fields and national total production, but this fails when the larger fields alone apparently produce more than the whole country (where different data sources are used for fields and for the country as a whole). By contrast, top-down models frequently use national total production data, which are usually officially published by national authorities and are in that sense complete. Governments have reason to provide reasonably accurate summary data for reasons of taxation, investment attractiveness, national and party political prestige, production quotas etc. Of course different countries include or exclude different liquids such as condensates or NGLs, or liquids consumed as fuels during the production process, causing some inconsistency between different sources for some data. There is also the chance of an approximate crude external audit, because oil exports and imports and refinery runs cannot be realistically hidden, and domestic consumption can be estimated.

The financial weaknesses of simple bottom-up models are clear. Our model assumes by default that all known undeveloped discoveries will be brought on-stream within a few years, for want of a better model. This generates a production hump in the near future in every annual projection, a surge which has never yet materialised. The model takes no account of the external financial environment, the effects of which include (1) the ranking and financial viability and future development (or not) of undeveloped discoveries, (2) the rate of exploration effort and the discovery of new reserves, and (3) the ranking and rate of investment in sanctioned projects, which can be postponed or speeded up. To give an example, in the first half of 2014, with a sustained high oil price, exploration budgets were comparatively high, and a string of postponements made since 2008 in some developing Canadian oil sand projects had been reversed. Such projects should have the effect of ensuring a higher oil supply capacity some years in the future, because they have lead times of a few years to perhaps a decade. Today, with the oil price now halved, exploration budgets have been dramatically cut and new oil sands projects are again being subjected to delays, and this in turn indicates that in the *further* future there may be a dearth of new supply capacity. The oil industry, with its long lead times for new supply capacity, has always displayed a well-known cyclicity in this regard. This cyclicity cannot be accounted for in simple bottom-up models; it requires the imposition of a set of price/cost/demand scenarios.

A second financial effect is that oil production must vary according to demand, and demand in turn is subject to effects such as price, economic growth or recession, efficiency gains in oil use, and regulation requirements as climate change moves up the political action agenda. The size and influence of future demand is missing from the bottom-up model, which treats it as a known and predictable parameter.

Political effects can include for example sanctions, OPEC output quotas and insurgent activity. Bottom-up models cannot easily take quotas into account; we rarely know which fields may be throttled back if quotas are cut, nor with any accuracy how much extra capacity might be brought on-stream if quotas are raised, nor when such a change in quotas may next arise.

Geological influences are another aspect of the financial influence. A recent manifestation has been the development of light tight oil in the US. Although the existence of such oil was well known geologically, few foresaw that a combination of high oil prices, specific US regulatory conditions and improved drilling technology would result in development of this resource, let alone such rapid development. Light tight oil was not a feature foreseen in our model, and is exceedingly difficult to incorporate now.

The financial problems of the old generation of bottom-up models such as this are acute, and it is pleasing to see the development of a new generation capable of adding an economic dimension, such as that by McGlade (McGlade, 2012). These still require a detailed field-by-field and project database, but incorporate scenarios for the investment requirements, the price consequences and the subsequent effect on demand and economic growth.

5. CONCLUSIONS

The simple bottom-up model, in our view, has certain advantages over the top-down model, despite the difficulty of acquiring sufficient and accurate data. It certainly gives the user a deeper understanding of how oil fields behave. Nevertheless we feel that such simple models, which take no account of price and demand implications, have largely run their course, insofar as they cannot materially improve in their current form. The new generation of bottom-up models which include an integrated analysis of financial and economic constraints and considerations should prove more effective and reliable. Such models take a view on likely global economic paths of growth or decline, with their effects on oil price and investment in the production industry. Global demand is modelled, from the likely future price of oil adjusted for investment in new supply, and global economic trends. Because demand, supply and price are all interdependent, the new model iterations and assumptions will be formidable.

In tandem with the broader economic picture, a better model needs considerable granularity in deciding where the available capital should be invested, between countries and between different projects in those countries. The projects will include exploration, primary production and enhanced oil recovery techniques, and will need to be ranked by economic return as well as output capacity. It will be a severe challenge, and one which may perhaps be overtaken by the game-changing effects of the incipient peak in conventional oil supply, the rapid technical improvement of renewable energy generation, and the recognition of the regulatory challenge to all fossil fuel production which may be imposed by climate change.

Author Details

The author writes: "I worked in BP from 1985 to 2008 as a geochemist, geologist and records manager, but also tended to be given exploration problems/projects which fell outside the company's normal business expertise. From 2000 to 2008 I wrote a short internal annual report on future oil supply for the company. Since retirement in 2008 I've still been looking at future global oil supply, with some interests in non-conventional liquids as a consequence. I was a co-author of the UKERC report of 2009 on Global Oil Depletion (Sorrell *et al.*, 2009), and Invited Editor of the recent *Royal Society Phil. Trans.* issue on '*The Future of Oil Supply*' (Miller and Sorrell, 2014)."

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