A Global Oil Forecasting Model based on Multiple 'Hubbert' curves and Adjusted Oil-industry '2P' Discovery data

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Background

I was born in 1931, one year after the US giant East Texas field was discovered. Flush production from this field led to tumbling oil prices, which in turn led to US' pro-rationing. But later the field was a lifeline for allied oil supply during the Second World War.

In terms of my own career, I studied first mathematics and physics at the Ecole Polytechnique. This was originally a military school created by Napoleon in 1794 to train French military officers and civil servants. Then I took geology at Grenoble University, and finally petroleum studies at the Ecole Nationale du Pétrole in Paris, which is connected with the French Petroleum Institute. I joined Compagnie Française des Pétroles (now Total) in 1955, where I led seismic teams in Algeria and later in Australia, I then became Exploration Manager in Canada before returning to the Paris head-quarters to be in charge of various departments including Negotiations, Basin Studies, and finally Exploration Techniques. (For additional details see Chapter 11 of Campbell (Ed.) (2011), and my CV on the aspofrance web site.)

My interest in oil forecasting arose as follows: When I was in charge of Exploration Techniques at Total, activities included making studies of the geographical distribution of global oil and gas reserves (using Petroconsultants' data), and also monitoring the quantities of global oil and gas being discovered annually. As a consequence, I began to worry about where future oil might be found, and about the decline in the global discovery rates.

Indeed, as a result of this trend of declining discovery of conventional oil, one of my final recommendations at Total was that the company should take a 50% stake in the Gulf farm-out of the Athabasca tar sands Surmount project, which would have required an investment of $10 million for this SAGD pilot, of which half would be subsidized by the Canadian government. This would have let Total get access to 50% of an estimated recoverable oil resource of about 800 Mb. This suggestion was turned down in 1990 by Serge Tchuruk, then Chairman and CEO of Total, because it was seen as too long-term, but was taken up ten years later under Tchuruk's successor, Desmarest.

I was retired by company policy in 1991 when I was sixty, whereas I had wanted to retire at sixty-five. In retirement I became interested in natural distributions in the universe, and found - surprisingly, at least to me - that the size of such diverse phenomena as oil reserves, galaxies, earthquakes, and urban agglomerations all followed the same basic statistical distribution, that of the parabolic fractal (Laherrère, 1996, 1999, 2000a and 2000b; and Laherrère and Sornette, 1998).

I became involved in the sequence of major Petroconsultants' oil and gas supply studies that were produced between 1994 and 1996 because I had written a paper with Alain Perrodon in 1993. Alain was advising Petroconsultants, and I approached the company to suggest that they commission a report on the world undiscovered oil potential, which would be based on the main petroleum systems of the world. I saw this report as being able to draw on Perrodon's knowledge of the Petroleum System (he was the first to use this term), on Demaison's knowledge of quantifying the volumes of hydrocarbon generation by such petroleum systems (he was the first person to do so (Demaison and Huizinga, 1991)) plus his knowledge of English, and on my knowledge of global oil distribution.

Petroconsultants provided the data based on our selection of the areas to cover, and between us we did the work. Petroconsultants paid for the printing and marketing of the final report: *Undiscovered Petroleum Potential* (Laherrère, Perrodon and Demaison, 1994), and we were paid from royalties. Based on this report, I wrote papers for *World Oil*, *American Oil & Gas Reporter*, AFTP, and OPEC.

Subsequently I met Colin Campbell in Total's offices. His involvement, I believe, was because George Leckie, who was in charge of much of the oil discovery data entered into the Petroconsultants' database, had seen the Campbell / NPD book *The Golden Century of Oil: 1950-2050*. For its forecasts this book had used *O&GJ* proved oil reserves, and Leckie suggested the study should be re-done using the Petroconsultants' far better proved-plus-probable oil discovery data. At that time Demaison was back in California so I therefore asked Colin Campbell to join us in the next set of reports. These were: *The World's Oil Supply: 1930-2050* (Campbell and Laherrère, 1995), and *The World's Gas Potential* (Laherrère, Perrodon and Campbell, 1996). We also produced a fourth report, *The World's Non-conventional Oil and Gas* (Perrodon, Laherrère and Campbell, 1998), but Petroconsultants was not keen to publish this, so we published with the *Petroleum Economist*.

The main public outcome of these studies was the article *The End of Cheap Oil* published in Scientific American (Campbell & Laherrère, March 1998).

In 1998 Petroconsultants was bought out by IHS Energy after the death of former's founder, Henry Wassall. It was the end of our association with the company, and most of our contacts in Geneva were fired. IHS kept our three reports in their catalogue until 2010 (Figure 1), and presumably had sales, but never paid us any royalties!

Since working on these Petroconsultants' studies I have continued to model future oil and gas production as new data have become available (see the model described below), to publish widely, and to be an active member of ASPO-France.

2. Data

As all analysts know, any model is only as good as its data, and in the correctness of its methodology to capture enough of reality to be useful. Data for the oil forecast model presented in this paper are discussed in this section, and its methodology in the next.

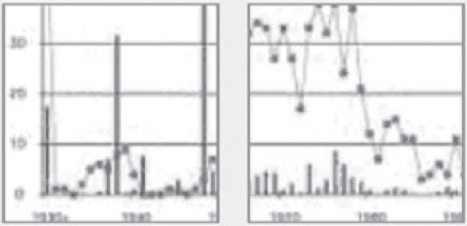
2.1 Data sources

The data used come from a wide variety of sources. For the quantity of oil *discovered*, the oil-industry data used are from several sources, and a number of corrections are then made to adjust the data to what seems to me to be the most-likely '2P' (proved-plus-probable) value, i.e., to be close to the mean value, which is the only value that can be aggregated correctly. It is often over-looked that simply summing the proved reserves

8.1.2 **World's Oil Supply, 1995**

The report has 3 parts; Volume 1 is a comprehensive world evaluation written in non technical language to be readily understood by all disciplines, Volume 2 is a regional evaluation and Volume 3 is a country-by-country analysis.

- *650+ page report.*
- *Illustrated with 650 graphics and 100 datasheets.*



8.1.3 **World's Gas Potential, 1996**

By combining the wealth of data available through the IHS Energy database with penetrative analysis by leading experts, this study forecasts not only the amount of reserves remaining to be found, but the number and size distribution of the fields and the number of wildcats required to discover them. The report assesses in detail seven selected provinces that together hold almost half the world's gas potential, then looks at North America, which has unique reporting practices and traditions, before going on to assemble a global assessment.

- *The study shows that the world has produced 2,200 Tcf (62 $T.m^3$) of gas; has reserves of 4,650 Tcf (132 $T.m^3$) and a realistic undiscovered potential of 2,400 Tcf (68 $T.m^3$).*
- *Discussion includes examination of the various ways to assess gas potential, such as field distribution analysis and derivative logistic or Hubbert curves.*
- *The seven areas discussed in detail are the Ahnet Timmoun System in Algeria, Barrow-Dampierre-Rankin, Australia; North of Western Siberia, Russia; Niger Delta, Nigeria; Anglo-Dutch Basin, UK, Netherlands and Germany; Po-Adriatic Gas. System, Italy; Qusaiba-Sudair Gas System, Middle East.*
- *Written in conjunction with three of the world's leading experts on the prediction of the world's resources: Jean LaHerrère, Alain Perrodon and Colin Campbell.*

Figure 1: IHS Energy Publications catalogue, 2009.

We apologise to readers that the text to this Figure, and Figure 2, is not very distinct, but hope that the general ideas conveyed are comprehensible

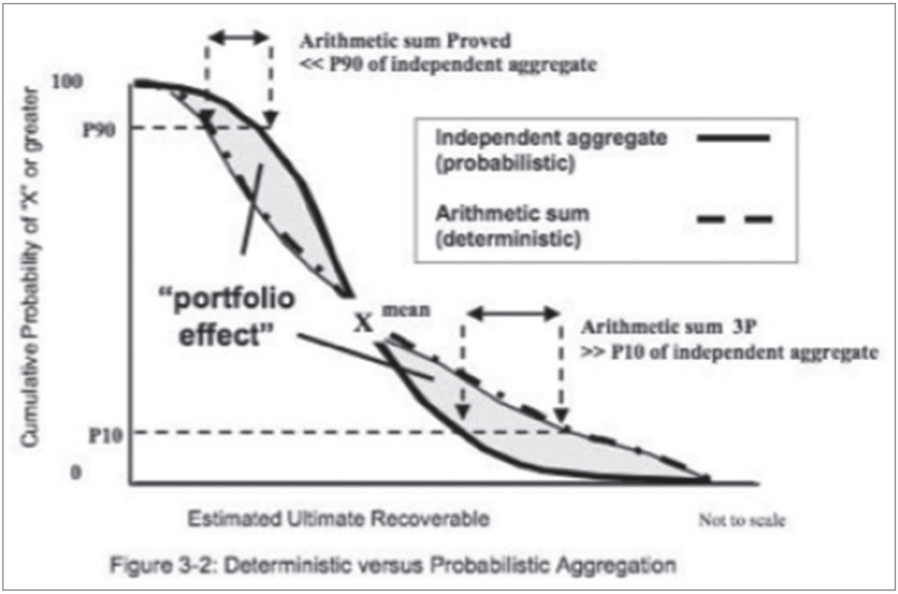


Figure 2: Illustration of the errors introduced when aggregating probabilistic data. Source: Society of Petroleum Engineers.

('1P') of individual fields does *not* give the aggregate 1P reserves of the fields as a group, but an under-estimation (Figure 2.)

For data on oil *production*, there is no consensus on the definition of conventional oil. But, in my view, the most available world source is USDOE/EIA, so I use the EIA definition (that of 'crude+condensate') for 'crude oil'; and then generate data for what might be classed as conventional oil by removing the 'extra-heavies' (XH = heavier than water = <10°API), to generate production data for "crude oil –XH". The latter 'extra-heavies' category applies primarily, in terms of where the data are available, to the two locations of the Athabasca tar sands oil in Canada, and the heavy oil produced from the Orinoco basin in Venezuela. The problem with the definition of 'condensate' is that some countries such as Norway (and as followed by the IEA) define condensate as being crude oil when sold with crude oil, or as natural gas liquids (NGLs) when sold with NGLs. As a result, the IEA global data for NGL production is 2 Mb/d greater than the US' EIA data for natural gas plant liquids (NGPLs).

2.2 Adjustments made to the oil-industry data

Importantly, when we carried out the consultancy studies for Petroconsultants from 1994 to 1996, we trusted their reserves data for OPEC countries. This was because at that time OPEC members were not buying the company's data studies, and also not reporting oil reserves by field.

But a senior employee of IHS Energy (which bought the Petroconsultants' database, as already mentioned) told me that in recent years the company are obliged to accept OPEC field data values, and also the countries' total reserves values. As an example, the current IHS data for Saudi Arabia (Figure 3) gives the country's cumulative discovery of oil as 400 Gb, which is 100 Gb more than the corresponding Petroconsultants' figure in 1998. The number of fields involved has barely changed in the intervening 15 years, and there is no evidence for higher recovery factors or field extensions on such a scale. Further, this 400 Gb is in agreement with the country's declared *proved* reserves as recorded in *OGJ* data, plus cumulative production since 1998. It is as though Saudi Arabia no longer deducts production from its official reserves.

This view of the need to reduce stated OPEC reserves data is supported by remarks made by Sadad Al-Husseini, former VP Aramco, at the 'Oil & Money' conference in London in 2007.

I therefore reduce the current IHS data for cumulative oil discovery as follows:

- By 300 Gb for OPEC discoveries, for the reasons given above.
- By removing 30% (~100 Gb) from FSU discovery data to reflect the fact that these data are ABC1, and are probably closer to 3P than 2P estimates. See Khalimov and Feign (1979), where ABC1 is estimated using the maximum theoretical recovery; and also Khalimov (1993) which indicates that ABC1 data are grossly exaggerated. This view is supported by extrapolation of production decline plots for individual fields (in particular Samotlor, Figure 4), and also by Gazprom audits reported in its annual reports (Figure 5).
- By 200 Gb for Orinoco heavy oil discoveries reported in the period 1936 to 1939.

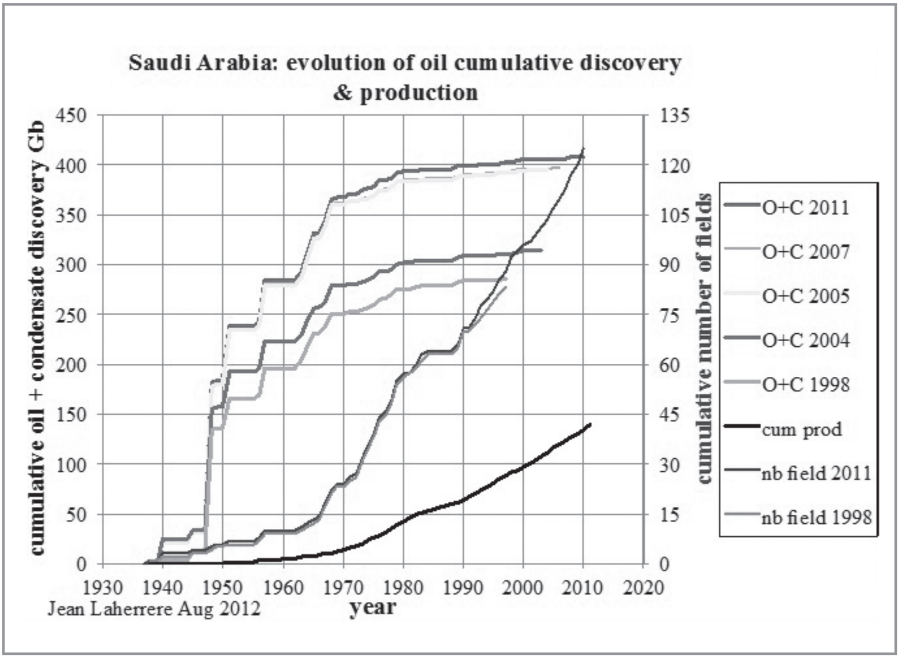


Figure 3: Cumulative plot of Saudi Arabian oil plus condensate 2P discovery and production data 1930 - 2011. Evolution of estimates vs. date.

Notes: O+C year: Oil plus condensate; and year estimate made.
cum prod: Cumulative production.
nb field year: Cumulative number of fields discovered by the year stated.

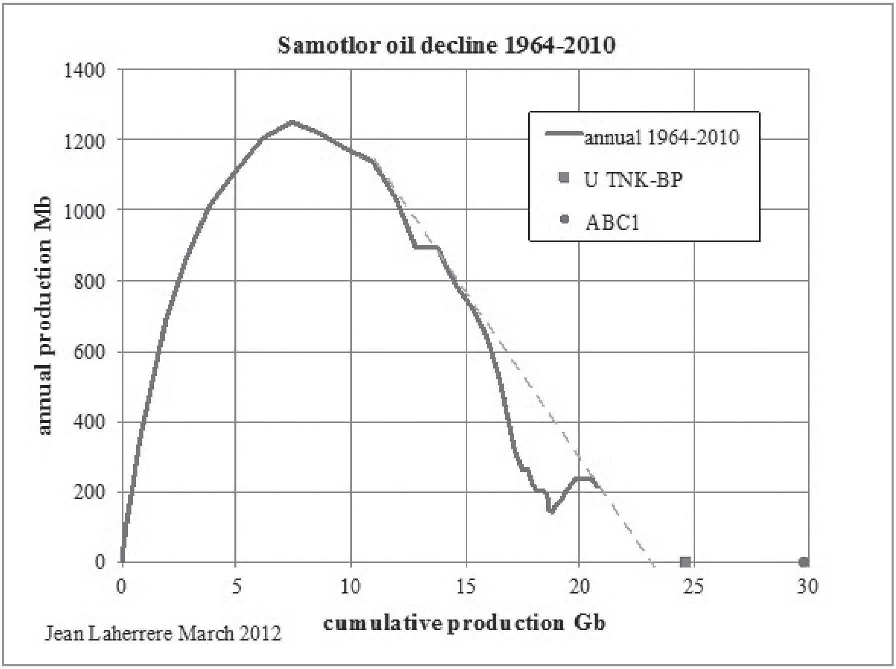


Figure 4: Samotlor field linearised production decline plot (annual prodn. vs. cum prodn.), indicating a possible 'ultimate' of ~23 Gb, in reasonable agreement with the TNK-BP published estimate of ~24.5 Gb; vs. the ABC1 estimate of ~ 30Gb.

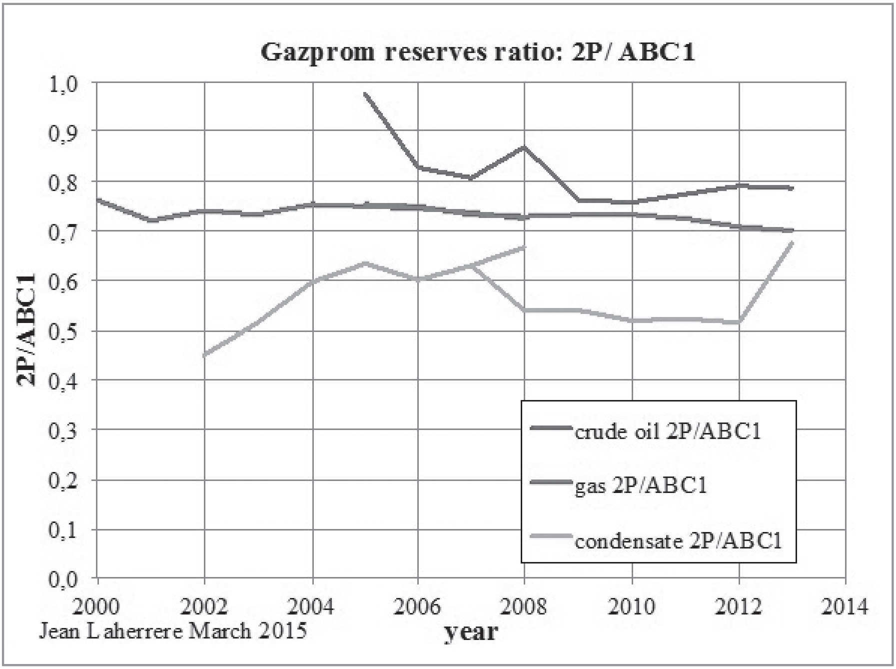


Figure 5: Evolution of ratios of 2P reserves data from Gazprom reports vs. ABC1 data held in industry databases.

3. Methodology

3.1 Determination of URR values

The global ultimate recoverable resource ('ultimate', 'URR') values for the various classes of oil and gas that the models use are found from extrapolation of 'creaming curves' that are modelled with multi-cycles.

A 'creaming curve' is generally a plot of cumulative discovery volume vs. cumulative exploration effort. The latter can be measured in a number of ways, for example, by the number of exploration wells ('new-field wildcats', NFWs) drilled in a region. (Note that the IHS Energy data for NFWs in China are not reliable). A different sort of creaming curve is a plot of cumulative annual discovery volume vs. cumulative annual number of fields discovered. A final type of creaming curve is simply a plot of cumulative discovery volume vs. date of discovery. (But note that this latter plot can be a less reliable indicator of URR, as discovery activity may have been interrupted or lessened for a variety of reasons, and hence an apparent trend of discovery towards asymptote may be misleading.)

To determine a region's URR, the creaming curves used are modelled as hyperbolas with several cycles, and where the number of these cycles is dictated by the data, and by knowledge of the region's exploration history. The URR is then determined by reasonable extrapolation, for example to about double the current number of NFWs, or alternatively double the current number of fields, to estimate the 'ultimate' of the final discovery cycle. Geological knowledge is also used to indicate if significant future discovery cycles are to be expected for the region considered.

Figure 6 gives the creaming curves of global cumulative discovery vs. date for conventional oil, and for gas; and also the corresponding cumulative production data curves. The oil curve is for 'conventional oil' (i.e. crude plus condensate, and excluding the extra-heavies), and where the discovery data shown are after reducing the industry 2P values for OPEC, FSU & Orinoco data as outlined above. The gas curves (discovery, and production) are both for 'all-gas', i.e., including tight gas that requires fracking for extraction.

For both 'conventional' oil and for gas three distinct main cycles of discovery are identified, and lead to corresponding estimates for URR when extrapolated, in this case, to the year 2100. For conventional oil, the discovery cycles correspond roughly to those of surface exploration alone; then with seismic; and finally including the recent deepwater discoveries.

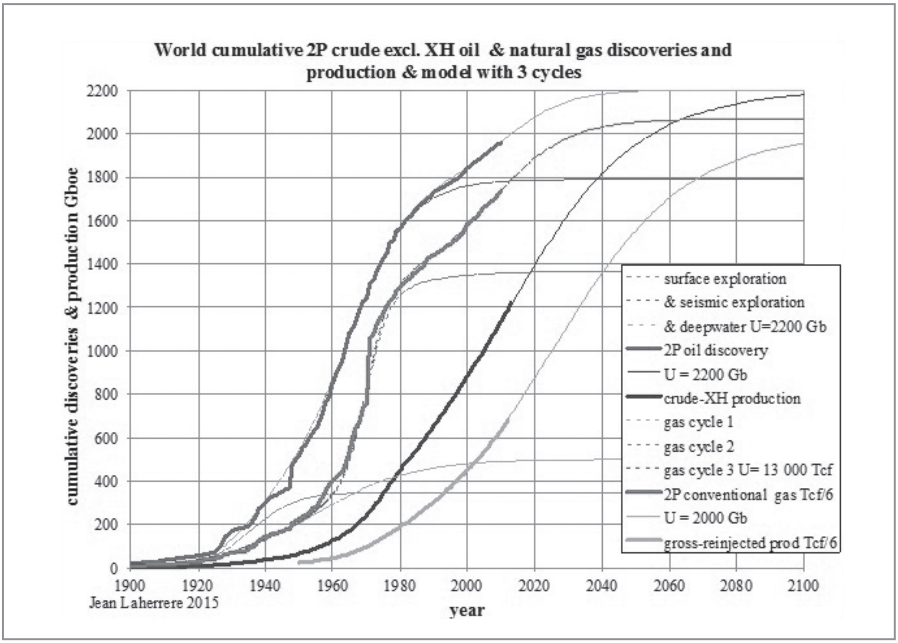


Figure 6: Oil & gas cumulative 2P Discovery & Production.

Solid lines:

Left: Judgement of the 'most probable' adjusted global backdated 2P cumulative global discovery data for 'conventional' oil (crude oil plus condensate, less the extra-heavy oils; the latter mainly tar sands and Orinoco oil; and not including NGPLs).

Next left: Corresponding data for 'all-gas', calculated as Tcf/6.

Next leftmost: Cumulative global production of 'conventional' oil, as defined above.

Rightmost: Cumulative global production of 'all-gas', Tcf/6.

Faint / dotted lines:

Indicate approximate cycles of discovery, three in each case, for oil and gas.

Notes:

The 2P oil discovery data are based on a number of industry sources, but reduced by: 300 Gb to allow for probable overstatement of OPEC Middle East original reserves data; by 30% of the FSU data (~100 Gb) to allow for datasets holding probably closer to 3P than 2P data; and by 200 Gb to allow for early Orinoco 2P discoveries reflecting non-conventional oil.

The three discovery cycles for conventional oil correspond to roughly pre-seismic, post-seismic and deepwater discoveries. The three discovery cycles for gas correspond to roughly pre- and post the giant Middle East gas discoveries, and to the wide variety of gas discoveries since, including most recently, tight gas deposits that requiring fracking for their extraction.

Extrapolation of the final discovery cycles shown, out to the year 2100 indicate likely URR values for 'conventional' oil and 'conventional' gas as 2200 Gb and 2000 Gboe, respectively.

For all-gas, the discovery cycles correspond roughly to discoveries prior to the major Middle-East gas discoveries; then with these discoveries (in particular the North field / South Pars field, which can be clearly seen on the plot); and finally with the wide range of more recent gas discoveries, where the latest data also includes tight gas projects (*projects*, as opposed to fields, since tight gas that requires fracking for its extraction is often extensive in nature, and its general location frequently long well known).

The total extrapolated discovery curves yield (see Figure 6) ~2200 Gb for 'conventional' oil (crude-plus-condensate less the extra heavies) and ~13000 Tcf (~2200 Gboe) for 'all-gas'.

The URR values then used in the oil & gas models are taken as 2200 Gb for 'conventional' oil, and 2000 Gboe for conventional gas (i.e., taking off something like 200 Gboe to allow for the tight gas from fracking that may be produced over the medium-term.)

3.2 General methodology

The global oil forecasting model described below in this paper combines a general 'multiple Hubbert-curves' approach with my judgement, discussed above, of what is necessary in the way of adjustments to both the industry (roughly) 'proved-plus-probable' oil discovery data, and to the production data. The model correlates global *discovery* of a class of oil to *production* of the same class of oil using multi-cycles.

Thus several peaks of production are modelled on the different cycles of discovery, and where the forecast for each class of oil must agree with past production in this cycle, and where the forecast slopes of the cycles must agree with the ultimates assumed. More detail on the approach is given in Laherrère (2000c, 2001 and 2002).

Note that this approach is different from that used by Colin Campbell, as described for example in *The Oil Age*, vol. 1, no. 1. Campbell models production of 'Regular conventional' oil by country, using the peak at 'mid-point' approach; and then adds on the production of the other classes of oil, such as deepwater, polar, NGLs, light-tight and the heavies (<17.5°API, but there is no consensus on definition of heavy and no world production data), etc. However the overall results for the global production of 'all-oil' from my model and that of Campbell are fairly close. This is probably in large part because both models take a more conservative view than most of the likely realistic URR for conventional oil, at least as this URR affects near and medium-term production, where the estimate of URR is driven in the main by extrapolation of 2P conventional oil discovery data. Likewise, both our models take a rather more conservative view than most 'mainstream' models on the rates that the various classes of non-conventional oil will be able to come on-stream.

The methodology of my model is now discussed by category of oil.

3.3 Modelling by category of oil:

(i). Conventional oil

Conventional oil generally refers to light oil that has migrated from its source rock to a reservoir from which it can be extracted without modification of either the oil itself, or the surrounding sand or rock, by own-pressure, pumping, or gas- or water-drive. As made clear above, 'conventional oil' as modelled here covers (primarily because of data availability) crude oil plus condensate, and excludes extra-heavy oil and also NGPLs. As mentioned, the data used for conventional oil discovery are 2P data from a wide variety of sources including IHS Energy, and where these values are reduced to reflect judgement of probable overstatements, as listed earlier.

When modelled with several cycles of discovery (and hence production), the mid-points of the URR values assumed *do not* exactly correspond to the production peaks, but such mid-points are usually not too far from the peak dates for many countries; except for the OPEC countries which are difficult to deal with because of variations in production due to quotas, and sometimes war.

(ii). Fallow fields

A fallow field is one that has been discovered, but which for some reason has not yet been scheduled for production. Some analysts (for example, see Miller in this issue) suggest that a significant quantity of the oil already discovered is in fields which are unlikely to go into production, at least in the near or medium term.

My view is that while the total *number* of such fields might be quite high, the total reserves that they hold are probably relatively small. For example, in Europe at end-2011, out of 5175 oil discoveries made (with total original oil reserves, URR, estimated at 84.2 Gb), 22% of these (some 1142 discoveries) were still on 'discovery' status (but containing only 2% of the region's original oil reserves), 9% were on appraisal (6% of original reserves), 1% were classed as awaiting development (1% of reserves), 2% as developing (1% of reserves), 41% as producing (85% of reserves), 4% shut in (2% of reserves), 20% abandoned (3% of reserves) and 1% had no data (0% of original oil reserves).

In the North Sea the majority (in numerical terms) of all discoveries are still in 'discovery' status, with probably most of these being far from current oil producing platforms, and hence uneconomic to produce (and even more uneconomic as and when the platforms are removed, even if the oil price goes high in the future). Thus my view is that while the number of such fallow fields is important, the volume of their reserves is not, being less than the uncertainty on the current value of the North Sea's total remaining reserves.

(iii). EOR, & Scope for 'reserves growth'

On the scope for enhanced oil recovery (EOR) to increase production, and hence for 'reserves growth', my view is as follows: Most of the IHS field original reserves data are estimates by geologists; and specifically by geologists who do not care about technology but who assume that producers will do the best to extract the oil that the geologists estimate as extractable.

Specifically, most of the reserve growth claimed by the USGS on their year-2000 Assessment study came from Petroconsultants 1996 data, where about 2000 fields were missing up to 1996, compared to present data. In my view, much of apparent 'reserve growth' is due to either poor practices in estimating the reserves, or in reporting the data. In the US, for example, the annual volume of oil production from EOR has been varying between about 0.6 and 0.8 Mb/d since 1986; and where the volume of EOR-produced oil in 2014 was about the same as that back in 1992, despite the large increase in oil price since then.

(iv). Heavy and Extra-heavy oils

a). Heavy oil needing thermal stimulation

Much heavy oil needs thermal stimulation if it is to be produced. One of the best examples is that of the Midway-Sunset field in California which was discovered in 1894, but which reached peak production only a century later; and where production increased with the number of wells drilled, and since the application of steam injection from the 1960s (Figure 7).

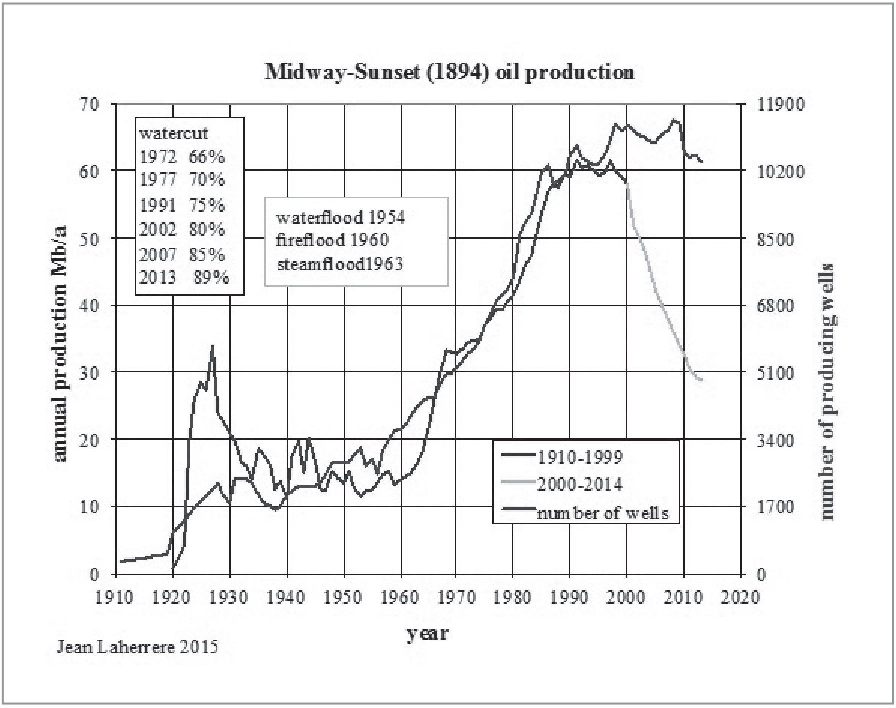


Figure 7: Production of Midway-Sunset heavy oil field, illustrating the increase in the number of producing wells, and the application of different oil extraction techniques.

b). Tar sands

The tar sands of Athabasca in Canada have been known since around 1750 when the area was opened up by the Hudson's Bay Company. Production of this oil started in 1956 (at 0.1 Mb/d), and reached 1 Mb/d by 2004, and 1.9 Mb/d by 2013.

About half of the oil produced is from open-pit mining, with the other half from *in situ* processing using steam injection (steam-assisted gravity drainage, SAGD). As of June 2014, the Canadian Association of Petroleum Producers (CAPP) forecasts Canadian tar sands oil production to be 2.3 Mb/d in 2015, 3.2 Mb/d in 2020 and 4.8 Mb/d in 2030. Note that this oil must be upgraded to reduce its viscosity before it can be run through a pipeline.

Constraints to current production are above-ground, i.e., economic constraints (the global oil price vs. tar sands cost to produce), pollution, authorization for pipelines, etc. The ultimate reserves (URR) of the Athabasca tar sands are about 250 Gb, but in terms of forecasting global oil production, as with some of the other non-conventional oils, the size of the non-conventional reserves does not matter so much as the size of the tap!

c). Orinoco oil

Orinoco extra-heavy oil is similar in gravity to Athabasca tar sands oil, but the former lies in reservoirs at a temperature of 55°C, against 5°C for Athabasca oil, giving the latter a high viscosity with no flow, and hence its classification of 'bitumen'. By contrast, Orinoco oil is fluid, and can be produced with cold production (for example, by a progressive-cavity pump, giving typically at start 1000 b/d per well), but with a much lower recovery (25%) than with steam injection.

The main problem of extracting the Orinoco oil is political. Chavez nationalised the efficient foreign companies such as Exxon and Total, and as a result production, which started in 1979 (and was sold as Orimulsion), rose from 0.1 Mb/d in 2000 to 0.8 Mb/d by 2008, but then has stayed below this level ever since. Note that the ultimate (URR) for Orinoco oil is about the same (in very round figures) as that for Athabasca oil.

d). Hence, total heavy oil

My rounded guess for the total URR of extra-heavy oil is 500 Gb, and with production modelled as peaking around 2060 at about 16 Mb/d. But note that the shape of the production profile of this oil, and hence the date of peak, and peak volume, is something of a wild guess.

(v). 'Light-tight' oil from fracking ('shale oil'), and oil retorted from kerogen

a). 'Light-tight' oil ('LTO') produced by fracking ('shale oil')

Our 1994 Petroconsultants report *Undiscovered Petroleum Potential* (with Perrodon & Demaison) was, as far as I know, the first to study the world's main petroleum systems, and hence to quantify the total generation of hydrocarbons, and also to derive an estimate for the ultimate of conventional oil.

Importantly, the report suggested that only about 1% or less of the total hydrocarbons ever generated will be produced, leaving 99% either in the original sediments, or lost at the surface. It is in part a reflection of this 99% figure that allows so many to now claim a huge potential for the shale oil plays, but where this confuses the up to 99% left as resources in the source rock with the *reserves* of this oil, accumulated mainly in fractures within the tight formations.

The US burst in production of LTO since 2009 was due to high price, and not to technology as horizontal drilling and hydraulic fracturing have been known for 50 years.

(Incidentally, US shale gas was produced in 1821 at Fredonia (New York State) for lighting to compete with whale oil costing about 1000 $2015/bbl. In recent times the production of shale gas was dropped when cheap oil occurs, and came back again with Barnett production when the gas price was high.)

b). Oil from kerogen ('oil shale' oil)

In contrast with light oil produced by fracking, this is the oil derived from the oil pre-cursor, kerogen, either by mining the rock in which it is held, followed by retorting; or by an *in situ* process.

Oil was produced from shale rock well over a century ago. For example, France produced oil from the Schistes d'Autun from 1831 to 1969, with a first peak in production at 250 b/d in 1866, a second peak at 250 b/d around 1900, and a last peak at 500 b/d in 1950. (Indeed, in 1859 France was producing ten time more oil than API records indicate was the case for the US!) China's oil shale production started in 1920 and peaked in 1960 at 16 000 b/d; while Estonia also started production in 1920 and reached 11 000 b/d in 1965.

In general the production of shale oil declined as the easier-to-extract oil from fields became available. Following the 1970s oil price shocks however, interest in shale oil returned, and in 1981 a potential 400 000 b/d project was reported by AAPG for the Piceance basin in the US. With the collapse of the oil price in the mid-1980s this project did not go ahead, but interest in shale oil never disappeared entirely, and a number of companies have pursued pilot projects over many years. Shell, for example, ran its US Mahogany project for over 25 years (using electric heaters in boreholes surrounded by frozen sediments) before it was closed in 2013 despite the return to high oil prices (an associated project continues in Jordan). An Australian oil shale project ran from 2000-2004.

The primary problem with shale oil is the economics, in part reflecting the technology's generally low return of energy to that invested (EROI). For example, in 2006 Shell reported that a full-scale plant using its then-current technology would return, over its full life cycle, about three to four units of energy for every unit of energy consumed.

c). Hence, total light-tight oil and oil from kerogen

In terms of data for the oil forecast model, I conclude that the world tight oil potential (both from fracking for 'light-tight' oil, and from retorting kerogen) is:

- small compared to the corrections needed for the 2P conventional oil reserves (for example, of fallow fields, and possible over-estimation of deepwater);
- already discovered; which is why I do not change the estimate of the 'crude less extra-heavy' ultimate;
- but where data on tight oil is indeed now included, in the sense that for example oil from the Bakken formation in Canada is included in conventional reserves.

(vi). GLTs, CTLs. Synthetic oil

For all these classes of oil (GLTs, CTLs and synthetic oil) I assume that, for reasons of production cost, production will be too small, at least over the near and medium term, to be included in the model.

(vii). Biofuels

Some have commented that agriculture is the process of 'transforming oil into food' thanks to fertilizer, tractors, irrigation, etc. Currently there is no clear agreement on the EROI ratio for corn ethanol, but it is likely to be close to or below 1; and only ethanol from sugar cane has a clear EROI ratio above 1. Nevertheless, in the model biofuels production is included, and is assumed to reach an asymptote of 3 Mb/d. (Note, I have reduced this figure; a few years ago my assumed biofuels asymptote was 6 Mb/d).

4. Model results

4.1 Global oil forecast results

Figure 8 shows the results from the oil forecast model described above for global 'all-liquids' production out to the year 2200, together with the corresponding forecasts for the various oil and other liquids components that sum to this 'all-liquids' total. As the figure shows, the model predicts that the peak of global 'all-liquids' production to be roughly about now, at around ~95 Mb/d or so.

Also shown in the figure, for comparison purposes, are 'all-liquids' forecasts from a variety of 'mainstream' institutions. As can be seen, the model presented here gives sharply different results to most of these other forecasts, as they show (except for the IEA's 450 ppm scenario) increasing 'business-as-usual' production curves, in contrast to the near-term peak of the model presented here.

A number of explanations for this difference between the model presented here and the other forecasts shown will be apparent from the discussions on the data used in this model, and its methodological approach, as set out in Sections 2 and 3 above. (I am given to understand that further exploration for the underlying differences in the various oil forecast results shown here, and also in comparison to a number of other current oil forecasts, will be covered in future issues of this journal.)

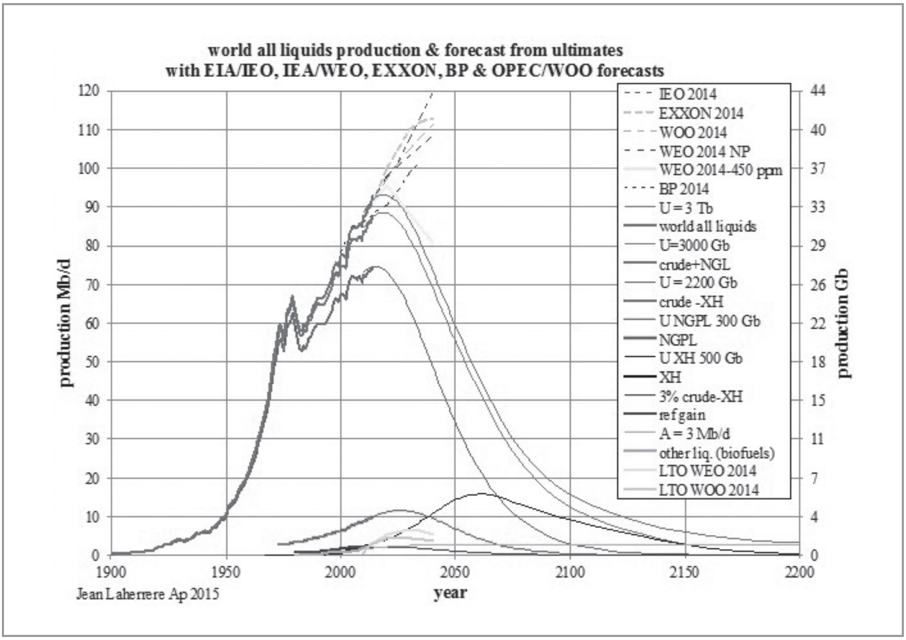


Figure 8: Production of global all-liquids supply, and forecast to 2200.

- Production of global all-liquids, 1900 - 2014.
- Forecast of global all-liquids supply 2015 - 2200, generated by the model presented in this paper, and based on URR values by category of liquid.
- Components of this forecast.
- Global all-liquids production forecasts generated by the US EIA, Exxon, OPEC, IEA and BP; and also IEA and OPEC forecasts for the production of 'light-tight' ('shale') oil.

Legend:

- IEO 2014: US EIA *International Energy Outlook* all-liquids forecast, 2014.
- EXXON 2014: Exxon all-liquids forecast, 2014.
- WOO 2014: OPEC *World Oil Outlook* all-liquids forecast, 2014.
- WEO 2014 NP: IEA *World Energy Outlook*, New Policies scenario all-liquids forecast, 2014
- WEO 2014-450ppm: IEA *World Energy Outlook,* Scenario to meet 450 ppm CO2, all-liquids forecast, 2014.
- BP 2014: BP *Energy Outlook* all-liquids forecast, 2014.

- U = 3 Tb: 'Hubbert curve' (logistic derivative curve) for a URR of 3 Tb *plus* addition of refinery gain plus production of 'other liquids' (modelled here as primarily biofuels, but conceptually including small amounts of oil from kerogen, GTLs and CTLs). This curve is drawn so that its upside roughly matches past actual all-liquids production, and its total area = 3 Tb *plus* the addition of refinery gain (increase in volume but not in energy) and other liquids. The figure of 3Tb itself results from summing a URR of 2200 Gb for 'conventional' oil (crude oil production including condensate but less the extra-heavies, and less NGPLs); plus a URR of 300 Gb for NGPLs; plus a URR of 500 Gb for the extra-heavy oils (primarily tar sands and Orinoco oil).
- world all liquids: World all-liquids actual production.
- U=3000Gb: 'Hubbert curve' for a URR of 3000 Gb (= 3 Tb) drawn so that its upside roughly matches past actual all-liquids production excluding refinery gain and 'other liquids', and its total area = 3 Tb.
- crude+NGL: Actual production of global all crude oil (comprising conventional oil, , heavy oils, tar sands and Orinoco oil and 'light-tight' oil), plus all NGLs.
- U NPGL 300 Gb: 'Hubbert curve' for a URR of 300 Gb drawn so that it matches past actual natural gas plant liquids (NPGL) production data, and its total area = 300 Gb.
- NGPL: Actual production of NPGLs.
- U XH 500 Gb: 'Hubbert curve' for a URR of 500 Gb drawn so that it roughly matches past actual extra-heavy oil production data (primarily tar sands and Orinoco oils), and its total area = 500 Gb.
- 3% crude – XH: A simulacrum of refinery gain, calculated as 3% of total crude production less the extra-heavies production.
- ref gain: Actual refinery gain data.
- A = 3 Mb/d: Modelled production of 'other liquids', i.e. liquids for fuels not included in the categories modelled above, and consisting primarily of biofuels, but also of assumed small contributions from GTLs, CTLs, synthetic oils, and oil retorted from kerogen either at the surface or in situ. Production is modelled as a curve reaching 3 Mb/d by ~2030, and holding constant thereafter.
- other liq. (biofuels): Actual production data for 'other liquids', primarily biofuels.
- LTO WEO 2014: The IEA World Energy Outlook 2014 forecast for production of 'light-tight' ('shale') oil.
- LTO WOO 2014: The OPEC World Oil Outlook 2014 forecast for production of 'light-tight' oil.

In summary, the global all-liquids forecast to 2200 shown in Figure 8 that results from the model described in this paper is derived from summing predicted production data based on ultimates ('URRs') for the different categories of oil, where the latter are estimated from extrapolation of adjusted industry 2P cumulative discovery data (creaming curves) where appropriate, and otherwise from extrapolation of cumulative production.

Specifically, the ultimates assumed are as follows:

- Crude oil (+condensate) less extra heavy oils: 2200 Gb, giving a production peak in 2010.
- Extra-heavy oils: 500 Gb, giving a peak in 2070.
- Natural gas plant liquids (NGPLs): 300 Gb, giving a peak in 2025.
- Refinery gain, calculated as 3% of crude production less the extra heavies production: 70 Gb.

A fifth and final contribution to all-liquids production is the 'other liquids', where here the main contribution is from biofuels. In this case the use of an 'ultimate' is not appropriate, being a renewable resource, and instead an asymptote of 3 Mb/d is assumed.

Taken together, these assumptions generate a global all-liquids production peak about now, and at a production level of roughly 95 Mb/d.

4.2 Oil forecast results by country

Currently, the model forecast is global. Though data are derived ultimately by field (or by project in the case of non-conventional oils), and hence also can in principle be split by country, currently no specific by-country forecast is generated.

4.3 Model uncertainty

The model described here gives a single-value prediction for what is intrinsically a very uncertain forecasting exercise, in part due to the poor quality of data currently available. This is true even within industry 2P databases, where for example as explained above, data on OPEC Middle East and FSU reserves are surprisingly uncertain.

In addition there is scope for considerable uncertainty on the rate that currently fallow fields may come into production; on the extra oil that EOR techniques will yield at a high oil price; on the likely rate that the various non-conventional oils will be brought on-stream; and on the effects of possible government-imposed limits on the production of the

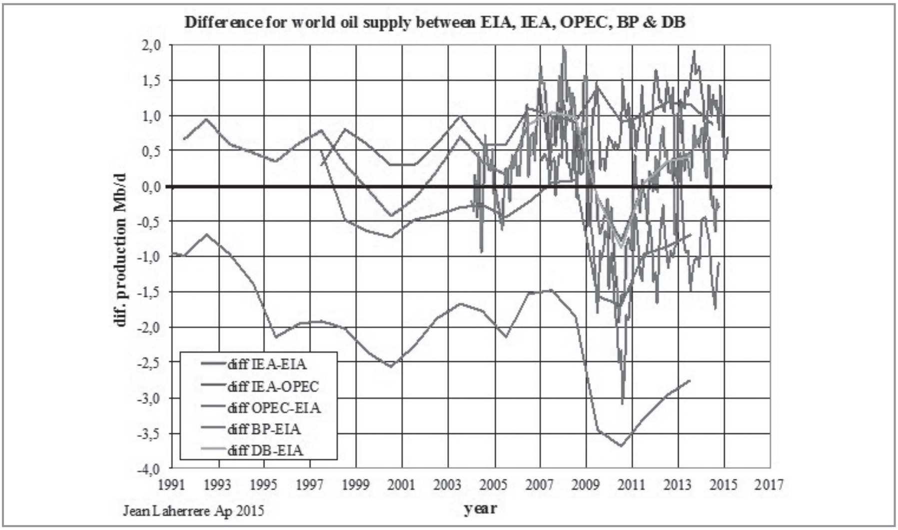


Figure 9: Differences in global oil production data from different sources.
We apologise to readers that the text of this Figure is not very distinct, though it does indicate the typical magnitudes of differences, in Mb/d, between the datasets. A clearer copy of this Figure will be provided in a future issue of this journal.

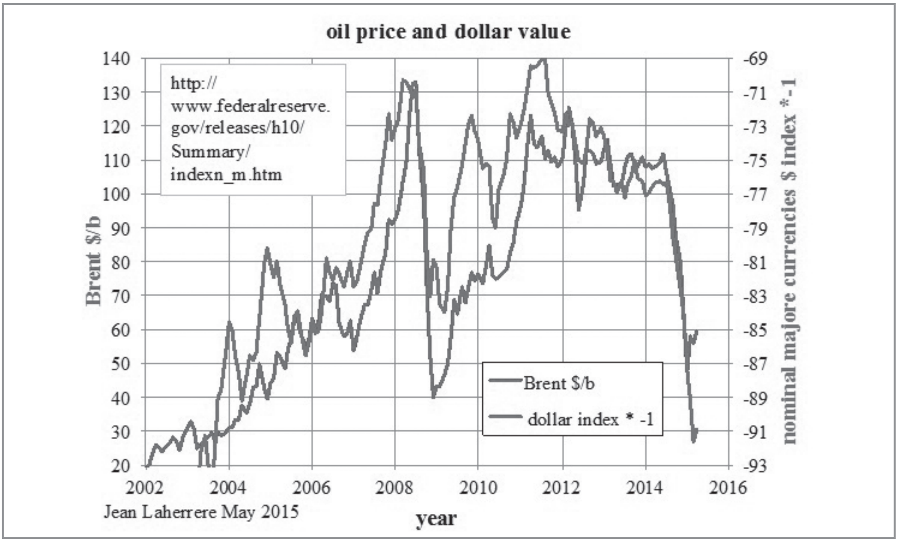


Figure 10: Correlation between Oil price and Inverse of US dollar index vs. other major currencies. Data source: see chart. Line starting at 2002: Brent price. Line reaching -69 in 2011: Inverse of dollar index.

non-conventional oils due to CO_2 concerns. Given these factors, I judge that the overall uncertainty on future oil production is probably of the order of 10 Mb/d.

Incidentally, the uncertainty on current oil production data, as derived from different sources, is not small at over 2 Mb/d, see Figure 9.

4.4 Demand

It is recognised that some analysts are not concerned about future oil supply on the assumption that global demand for oil will be less than the supply available. They see demand as rising less quickly than increasing supply, and falling in the near to medium term, due to increased vehicle efficiency, switching to alternative transport fuels (such as CNG or electricity), and to direct falls in demand resulting from a high oil prices, or from government fiat based on CO_2 concerns. Clearly such demand factors are in operation, or seem likely, but where the oil forecasting model described in this paper indicates that supply will be the near-term limiting issue.

5. Conclusions

This paper describes a global oil forecasting model based on multiple 'Hubbert' curves, and which uses adjusted oil-industry '2P' discovery data. The results indicate that a maximum ('peak') in the global production of 'all-liquids' is likely to be fairly close.

This peak is due primarily to 'below-ground' resource constraints. A high oil price can certainly encourage the discovery and production of additional oil, and also limit demand. It is also recognised that there is uncertainty in both the data, and the use of this relatively simple model.

The recent sharp decline of oil price is due to the weak demand, the strong LTO production and mainly the strong dollar value (see Figure 10 on the fairly good correlation since 2004 on oil price and dollar value). It is hard to forecast the value of any currency (and of the dollar in particular) in the long term.

But the general robustness of these data, and the reliability of this model in capturing past experience of the production of oil (and also other resources) in basins and regions, suggests that future global 'all-liquids' production is unlikely to be very different from that which the model indicates. The model thus serves as a useful warning of the situation that is likely to lie ahead.

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