

Background & Objectives

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

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

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

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

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

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

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Editorial

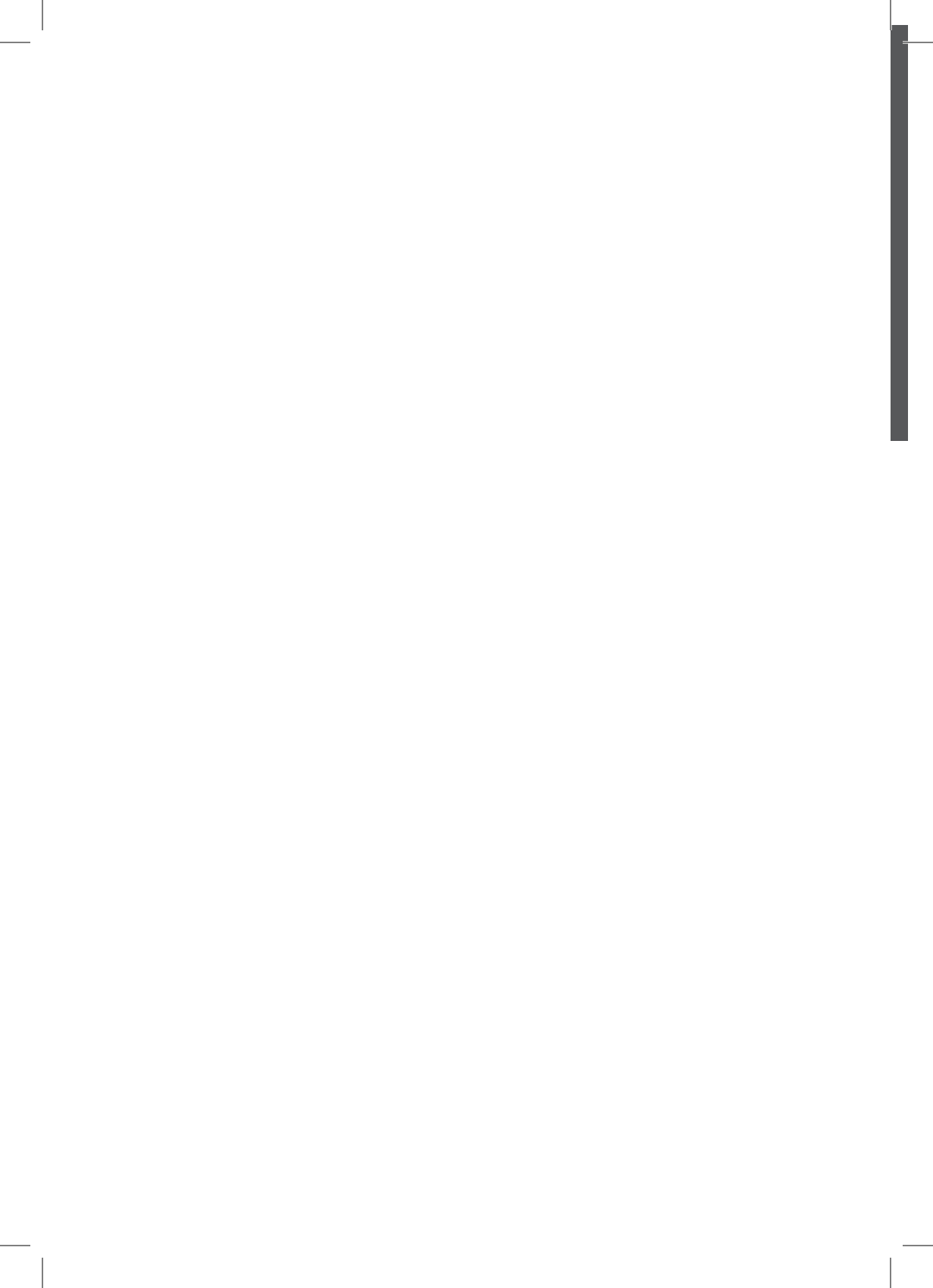
Welcome to the Winter 2016 issue of this journal. The first thing to say is that - as you cannot have failed to notice - this issue is not being published in the Winter of 2016, but in the Spring of 2017. We much apologise for this delay, caused simply by the amount of work it took to produce now three parts of the Laherrère et al. paper on the reliability of data used for oil forecasting; and where Part-2 is given here. Part-3 will be published as the Spring 2017 issue.

We recognise that some readers will find this paper unnecessarily detailed, but given the extraordinary catalogue of data problems highlighted in the paper, we thought it merited publication at length. We much look forward to criticism and feedback on this paper, in part to judge whether its intended audience of oil forecasters, and those who rely on such forecasts, have thought it useful. And, as mentioned previously, if we get sufficient useful feedback it is our intention to publish a corrected, updated, version of this paper at a future date; either in the journal itself, or perhaps online.

But to reassure those readers for whom the three parts of this paper are indeed too dense to read, we will return in future issues to more accessible papers, and ones that cover some of the wider topics of the history, societal impact, and production of other energies, that recognition of the constraints on global oil production are likely to make of interest.

Incidentally, as with Part-1 of this paper, we recognise that a number of the charts here may be difficult to read in black and white. As a result, subscribers to this journal may receive free of charge a PDF version of the paper, giving the charts in colour, by contacting Noreen Dalton at: theoilage@gmail.com.

- R.W. Bentley, April 24th 2017.



Oil Forecasting: Data Sources and Data Problems – Part-2

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Abstract

This is the second part of a three-part paper that looks at the data needed to make forecasts of oil production, and highlights some of the significant problems with these data. The paper is primarily intended for those that forecast oil production, but will be of interest also to those who use such forecasts, to judge the quality of the data employed and hence this aspect of a forecast's reliability.

The first part of this paper discussed the data by *type* (e.g. data on production, consumption, and reserves) and pointed out areas where these data are unreliable, in particular with regards to reserves data. This second part of the paper includes annexes on oil gravity and energy content, oil net-energy, greenhouse gas emissions, and importantly, comparison of proved ('1P') vs. proved-plus-probable ('2P') reserves.

The third part of the paper will discuss data by source (e.g. the data from the IEA, IHS Energy, and JODI) and again points out areas where the data are unreliable or must be treated with caution. In addition, this part of the paper includes annexes on use of data to forecast oil production, and the accuracy of past oil forecasts and projections.

1. Introduction to Part-2

This part of the paper presents annexes that support and elaborate the information in Part-1. Annexes 1 and 2 were included in Part-1, so this Part-2 starts with Annex 3.

The annexes here look at data on oil gravity and energy content; oil net-energy; the greenhouse gas emissions produced by the combustion of oil; and importantly, the comparison of proved ('1P') vs. proved-plus-probable ('2P') reserves.

Part-3 of this paper will look at oil data by data source (e.g. the data from the IEA, IHS Energy, and JODI), and points out areas where these data are unreliable or must be treated with caution.

Finally in this introduction, we note that this paper will undoubtedly have errors as well as significant omissions. We welcome corrections and comments.

Annexes continued from Part-1:

Annex 3: Oil by Density and Energy Content; & Condensate

Section A2.1 on 'Definitions' in Part-1 of this paper looked at the different classes of oil that exist, and in Figure A2.1 presented the classification of oil by degrees API, and by density.

In this annex we cover the topic of oil density data in greater detail, and examine also the important topics of oil energy content by class of oil, and the uncertainty on condensate production data.

A3.1 Oil by Density

A problem with oil production data is that generally each field (and project, in the case of non-conventional oil) produces a fluid of different density and quality (the latter in terms of heat content, and of contaminants - particularly sulphur). Production is typically reported by volume (barrels, or m³); but in terms of energy content, reporting by weight is generally more informative; and best – though least often done – is by energy content itself. The latter can be measured, for example, in joules or Btu, though often the ‘ton of oil equivalent’ is used, where the latter - if this ‘ton’ is the metric ton (tonne) of 2204.6 lbs - has an energy content of approximately 42 GJ.

In terms of density, Figure A2.1 compared terminology for ‘oil density’ (e.g., light oil vs. heavy etc.) with actual density (in kg/m³), and with °API, over a range of densities from 800 to 1075 kg/m³, equivalent to the range 0.1 to 45.4 °API; where:

$$^{\circ}\text{API} = ((141.5 * 1000)/(\text{density in kg/m}^3)) - 131.5$$

Figure A3.1 again shows this relationship between density (here in terms of specific gravity) and °API; and also that between the inverse of density - here in terms of barrels per tonne (b/t) - and °API.

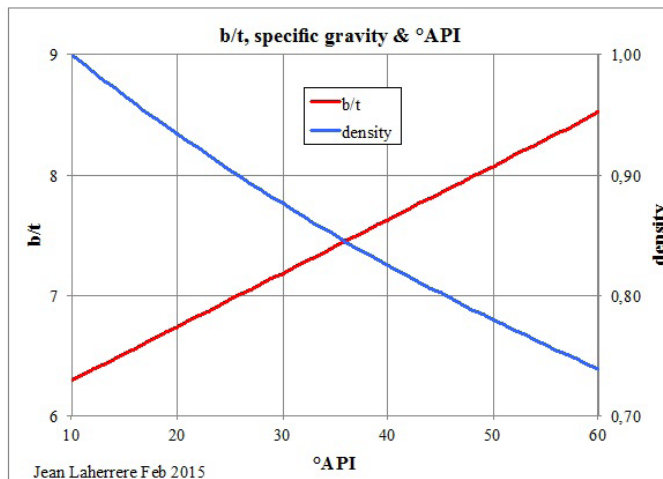


Figure A3.1 Plots of Density vs. °API; and of the Inverse of density (in b/t) vs. °API.

Blue line (reads from right-hand scale to the horizontal scale): The relationship between specific gravity (equivalent to density in g/cc) and °API.

Red line (reads from left-hand scale to the horizontal scale): The relationship between the inverse of density in barrels per metric tonne and °API.

In terms of oil types, the density range is wide. The source: (https://en.wikipedia.org/wiki/List_of_crude_oil_products) lists some 250 types of crude oil ranging from 10°API (Boscan) to 69°API (Bintulu condensate), and with a range of sulphur content from 0.001% (Algerian condensate) to 5.7% (Boscan).

Figure A3.2 shows the variation of oil density, expressed in b/t, in terms of the global proved ('1P') reserves as listed in BP's *Statistical Review*, where these include heavy non-conventional oils, such as a Canadian tar sands and Venezuelan Orinoco oil, up to very light oils. This range, in terms of barrel/tonne, is from 6.2 to 9.0; with the *Statistical Review's* Appendix giving the approximate conversion factor as 1 tonne = 7.33 barrels.

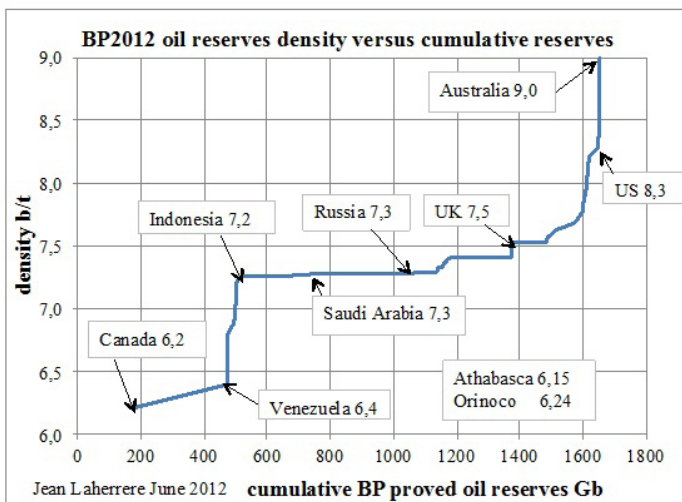


Figure A3.2 Global Proved ('1P') Oil Reserves by Approximate Average Density

- Global proved oil reserves data from BP Statistical Review of World Energy, 2012 edition. (But note the strong caveats about the use of oil proved reserves for oil forecasting set out in Part-1 of this paper.)

- 'Density' here is the inverse of density (i.e. volume/mass), in barrels per metric tonne. These b/t values are derived from the by-country production data in the BP Statistical Review (as this gives production in both barrels and tonnes); and where these b/t values are applied to the proved reserves data in the same publication.

Source: Jean Laherrère.

In terms of US data, Figures A3.3 and A3.4 show how the composition of US oil production has changed in recent years by density (here in degrees API).

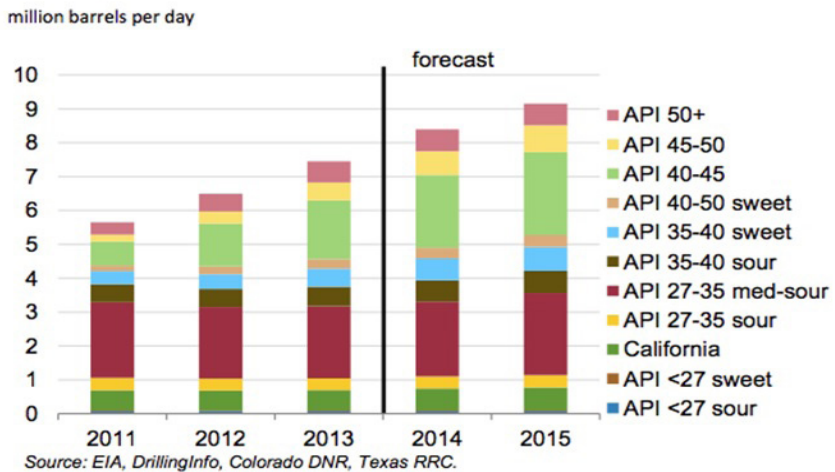


Figure A3.3 US Oil Production by °API, and by Sulphur content

Source: <https://www.eia.gov/analysis/petroleum/crudetypes>

As Figure A3.3 shows, the recent increases in US production have been of light oil ('light-tight' oil from fracking). A corresponding picture emerges from Figure A3.3, where the inverse of density in b/toe has risen from 7.41 to 7.54 over the period 2011 to 2015.

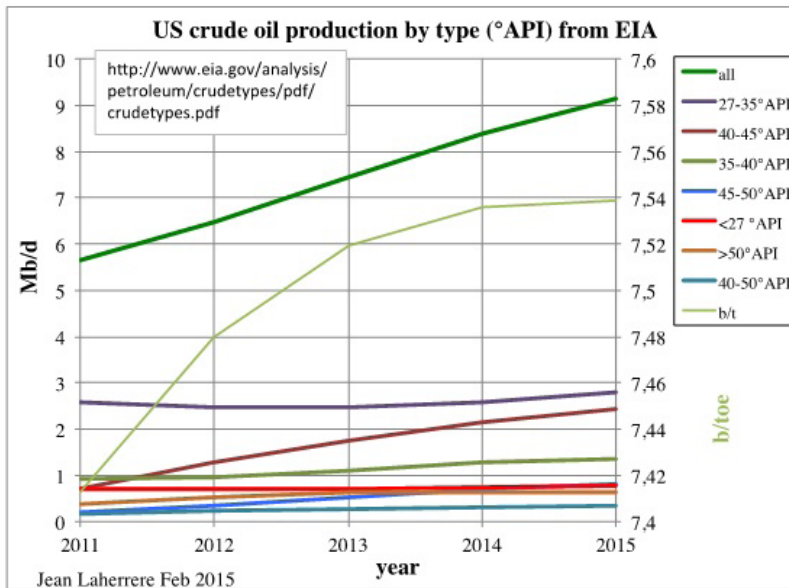


Figure A3.4 US Oil Production in Mb/d and in °API. Also shown is the corresponding change in the inverse of density, in barrels/tonne of oil equivalent (b/toe)

Source: Jean Laherrère, from source listed in the Figure.

A3.2 Energy Content of Various Classes of Oil

Now we turn from the density of different oils to that of their energy content. As the global production of conventional oil (essentially, oil in fields) declines, and a greater percentage of the world's oil supply comes from NGLs and the non-conventional oils, the topic will be of increasing importance.

A.3.2.1 Specific energy content

Figure A3.5 shows EIA data on the changes in *specific* energy content (i.e., energy per unit volume) of both US crude oil and NGPLs, and of global and US oil consumption, from 1980 to 2013.

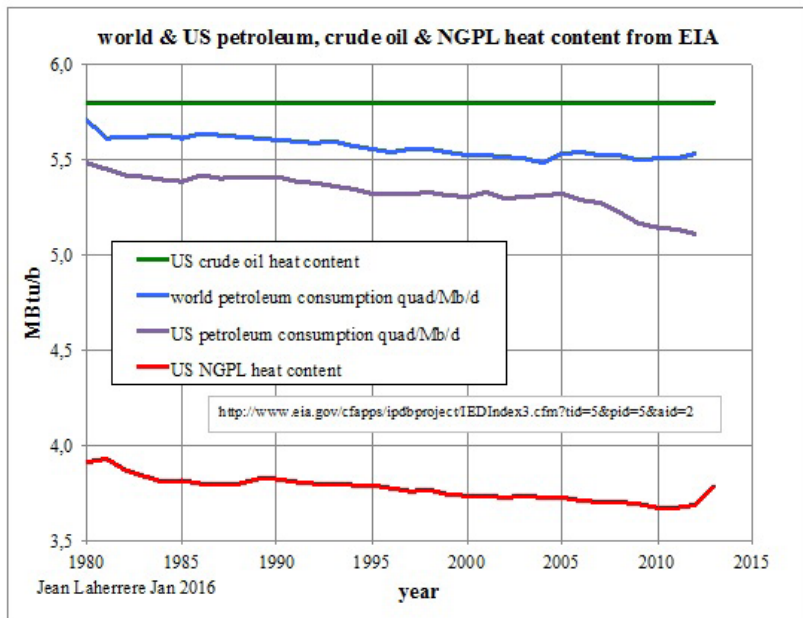


Figure A3.5 EIA data on Change in Specific Energy Content (Energy per Unit Volume) of US Oil and NGPLs, and of Global and US Oil Consumption, 1980 to 2013. Units: The y-axis is in million Btu per barrel. The US and world consumption data are based on annual energy totals, given in quads per year, where a quad is a (US) quadrillion (10^{15}) Btu. When specific energy content is expressed in [quad/(Mb/d)] this translates as [(quad/y) / (0.365Gb/y)], i.e. $[(10^{15} \text{ Btu/y}) / (10^9 \text{ b/y})] = \text{MBtu/b}$.

Source: J. Laherrère, from source listed in the Figure.

As can be seen in Figure A3.5, the US NGPL, and world and US consumption, specific energy data show changes over time. This is not the case with the EIA data for US crude oil specific energy because the EIA did not get the adequate data from the individual US states until recently (private communication: A. Sieminski to J. Laherrère).

A similar picture of variation over time in the specific energy data for different classes of oil, except for 'US crude oil production and export', can be seen in Figure A3.6. Here the data are over a longer time period (since 1950) than in Figure A3.5. Laherrère

notes: 'EIA reports crude oil production since 1950 as having a constant heat content despite the recent light-tight oil ('shale oil') boom: US crude is now lighter, which produces less energy per unit volume.'

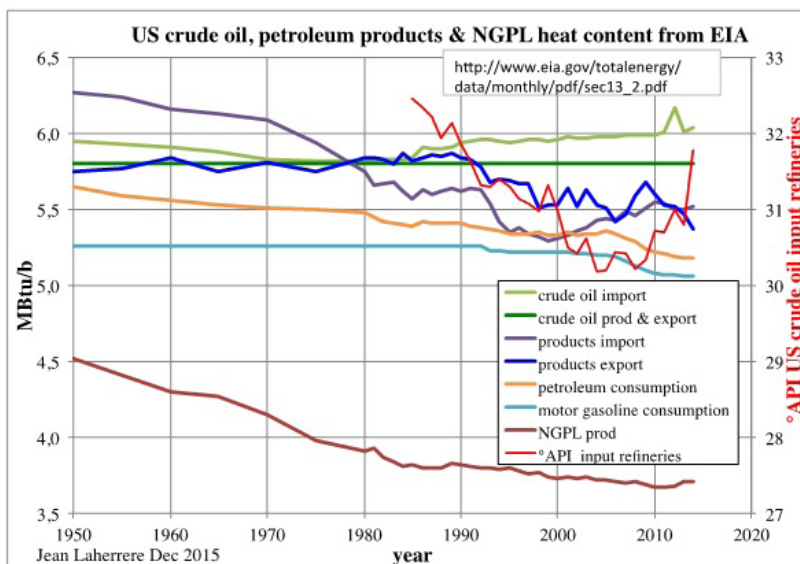


Figure A3.6 EIA data on Changes in Specific Energy Content (Energy per Unit Volume) of Various Classes of US Oil, and of NGPL. Also shows the °API gravity of US crude oil shipped to refineries.

Units: See the discussion in Figure A3.5

Source: J. Laherrère, from Source listed in the Figure.

As Figure A3.6 also shows, the specific energy content of NGPLs is significantly below that of the other oil types, a fact not always accounted for in some oil forecasts; and it has fallen by roughly 18% since 1950 (possibly in part because of increased production of shale gas). Of this chart Laherrère notes: 'The EIA was unable to report production data by °API (as opposed to that of oil into refineries) before 2011, because the states did not report this.' Indeed, the EIA does not get precise data from the US states, and we understand is obliged to estimate production by state through enquiries with a relatively small number of producers, perhaps some 450 or so out

of perhaps 13 000 or so; (see: <https://www.eia.gov/petroleum/production/pdf/eia914methodology.pdf>).

Figure A3.7 shows specific energy content vs. °API data for Canada.

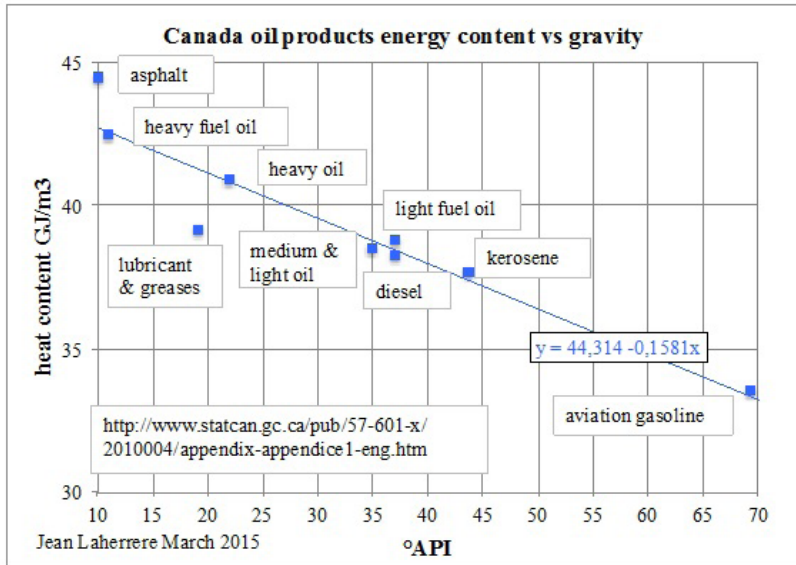


Figure A3.7 Canadian data on Specific Energy Content vs. Density (in °API) for Classes of Oil and Products

Source: J. Laherrère, from source listed in the Figure.

Finally in this subsection, we look at the global variation in specific heat content vs. production. This is shown in Figure A3.8.

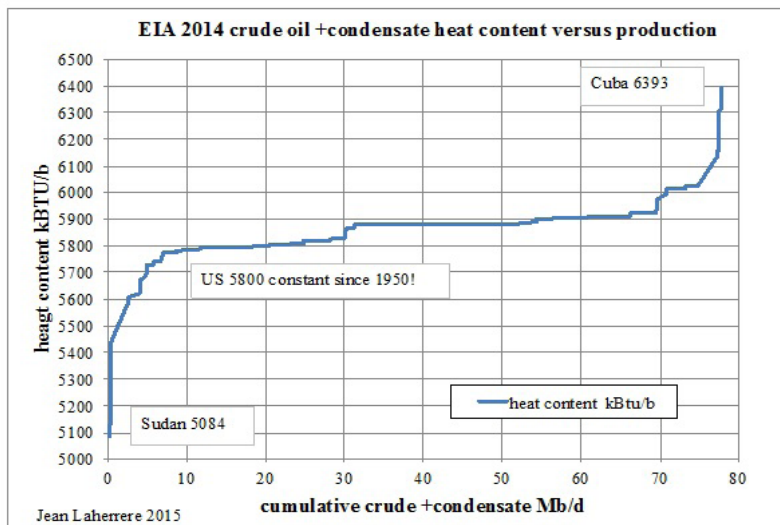


Figure A3.8 Variation in Global Specific Heat Content of Crude Oil plus Condensate, vs. Production Level.

Source: J. Laherrère, from EIA data.

The lesson from the above Figures is that the variation in specific heat content for the various classes of oil and products can be quite significant, and indicates the need to take account of such differences when generating (or interpreting) oil forecasts.

A.3.2.2 Total energy content

Now we turn from examining specific energy content (that per unit volume) of oil production data to the total energy content of oil consumption. Like production data, also for consumption data it is important recognise that each product stream has its own heat content, and that data by weight is better than by volume, and where best is consumption measured in terms of energy.

The EIA reports consumption in both Mb/d and in quads, and the plots for the world and the US are shown in Figure A3.9.

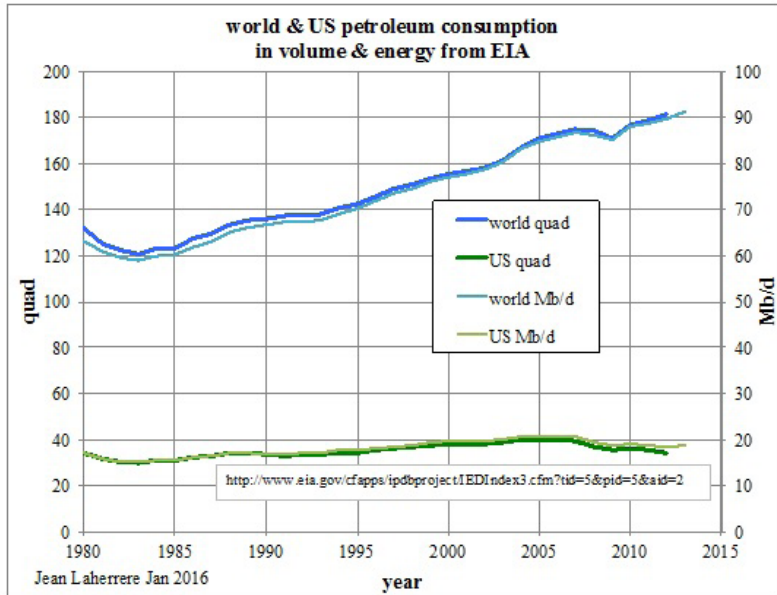


Figure A3.9 EIA data on the Variation over time in the Difference between Petroleum Consumption as Measured in Volume and Energy Terms.

Source: J. Laherrère, from the source listed in the Figure.

As Figure A3.9 shows, though both sets of data have matched pretty well over the years, there is a fall-off in recent years in the amounts of energy consumed vs. the volumes consumed, and where this is particularly significant in the US data.

As mentioned in the introduction to this section (Section A3.2), the need for correct calculations in this area will become increasingly important as the world moves away from consumption of conventional oil to greater use of NGPLs, and a wide range of non-conventional oils. Indeed, despite the current increased production of extra-heavy oil (which is then upgraded), oil production for the moment is getting lighter - and hence less energetic - because of the increased production of NGLs; yet another reason why modelling of oil production should not be by barrel, but by barrel of

oil equivalent in energy terms.

A3.3 Condensate

Finally in this Annex on differences between classes of oil we look at the data on production of condensate. The problem here is illustrated in Figure A3.10, which shows that condensate can be classed either in the crude oil stream, or that of the NGLs.

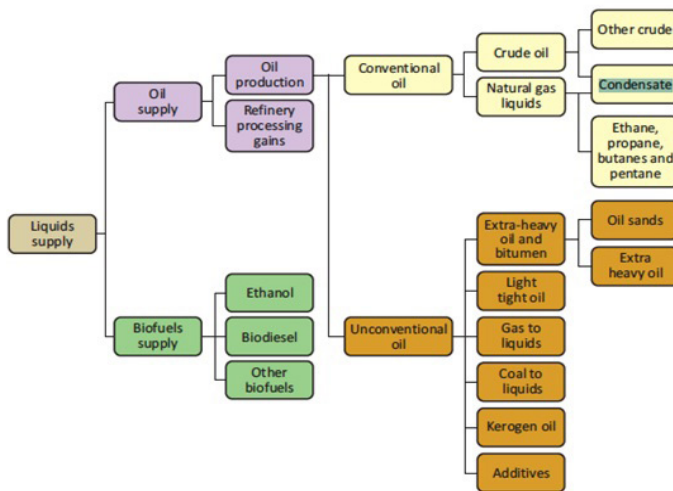


Figure A3.10 Classification of Liquid Fuels: Shows the two streams that can contribute to condensate production.

- Note that this classification is at variance with that assumed by other sources. The EIA, for example, puts much of the non-conventional oils into 'crude oil' production.

Source: IEA WEO 2015, Annex C.

Global data

First we look at global data. To give a feel for the volumes of oil being considered, Figure A3.11 shows the differences since 1980 in the production of the three main categories of oil reported by the EIA, viz.: Crude plus condensate; this plus NGPLs; and in turn, All-liquids; see the definitions in Annex 2 in Part-1 of this paper.

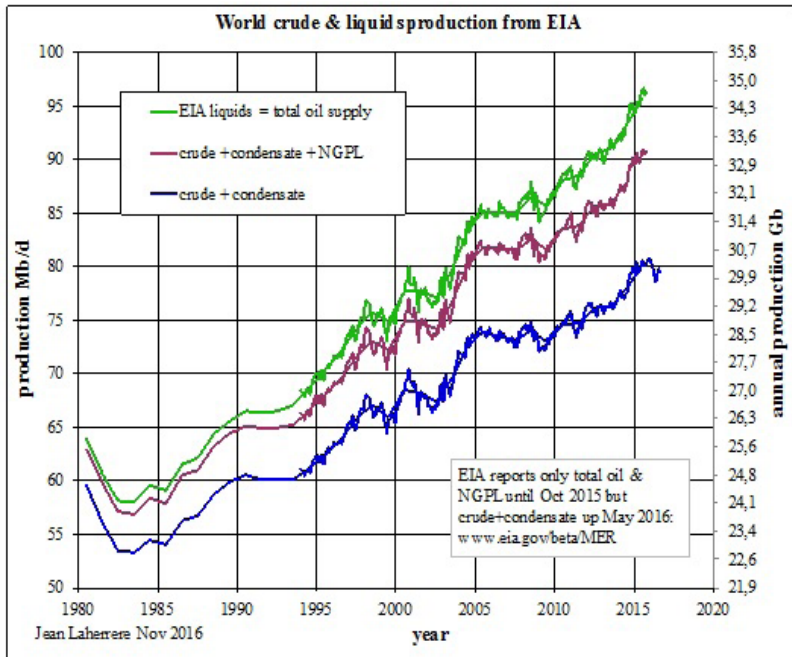


Figure A3.11 Global Production of Oil Liquids by EIA category.

Source: J. Laherrère.

On the question of condensate production, we now show data from a number of sources. The IEA for example, follows the approach of the NPD in Norway, where condensate is included with crude oil if sold with crude, or with the NGLs if sold with NGL. This means that the classification of condensate production can change with time, as indicated by production data for the Asgard field, Figure A3.12.

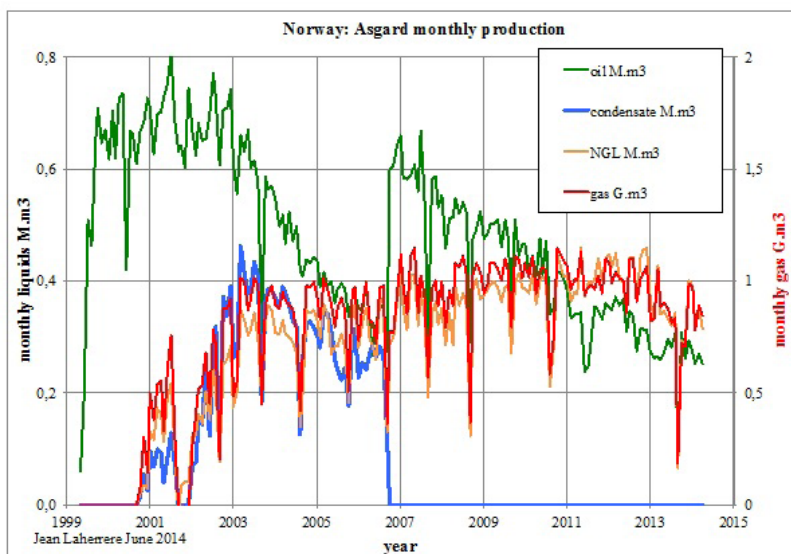


Figure A3.12 Monthly production of the Asgard Oil Field

- Production of condensate goes to zero about mid-2006, with this production then being classed as 'oil'.

Source: Laherrère, from NPD monthly production field data.

However, IEA data on crude oil production should not be compared to that of the EIA, as the former sometimes includes condensate, whereas the latter data always does. Only IEA data for 'crude +NGL' should directly compared to the EIA 'crude +NGPL' data; and even here there has typically been a 2 Mb/d difference between the IEA NGL production data and that of the EIA NGPL data, and where this difference increases in their forecasts, reaching perhaps 7 Mb/d by 2040; see Figure A3.13. (Note that a contributing factor for the ambiguity over the definition of condensate may be that the latter is not included in OPEC quotas, and hence there is a degree of flexibility about how this production is accounted.)

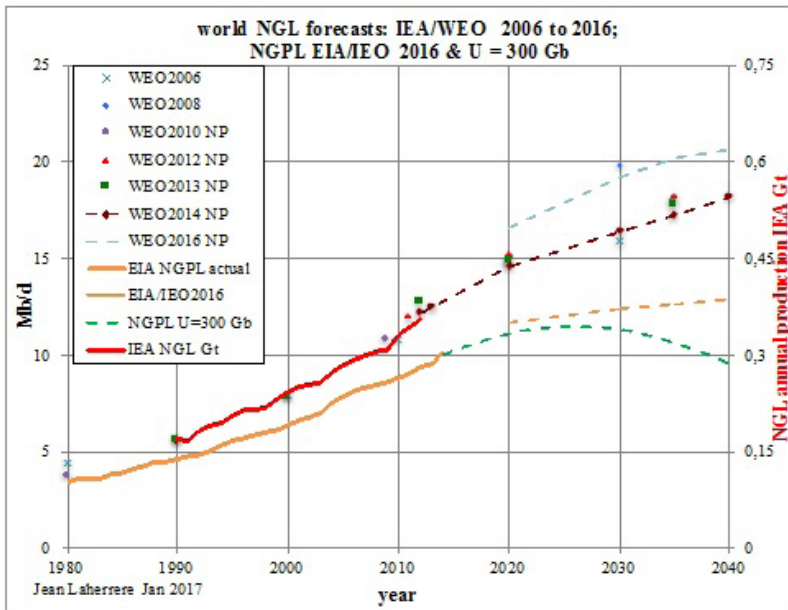


Figure A3.13 Comparison of Historical data and Forecasts for Global NGL & NGPL Production; and also Comparison to a forecast corresponding to an assumed URR of 300 Gb.

Legend:

Left-hand scale:

- WEO & date: IEA World Energy Outlook, as of date shown; and where 'NP' means New Policies scenario.
- EIA NGPL actual. Historical data from EIA on global NGPL production.
- EIA/IEO2014. Forecast of global NGPL production in EIA International Energy Outlook, 2014.
- NGPL U-300 Gb. Assumed roughly symmetric 'Hubbert' curve of global NGPL production if the corresponding URR is 300 Gb.

Right-hand scale:

- IEA NGL Gt. IEA historical data for global annual NGL production, in Gt/y.

Source: Laherrère, from sources as given in the legend.

(Note also in Figure A3.13 shows, the IEA and EIA forecasts for production of either NGLs or NGPLs may be judged somewhat optimistic, if set against a likely corresponding URR value of 300 Gb, where the latter is derived from the corresponding gas URR estimate.)

Data by country

Now we look at data by country. On US data, Laherrère notes: “To deal with US data on the production of crude oil plus NGLs, to ‘crude plus condensate’ you have to add the US NGPL production. This has recently sharply increased, by more than 1 Mb/d to 3.2 Mb/d in 2015, but its heat content is down to 3.75 MBtu/b against 5.8 MBtu/b for crude oil, a figure which has been constant since 1950 (despite becoming lighter with light-tight oil)”; see Figure A3.14.

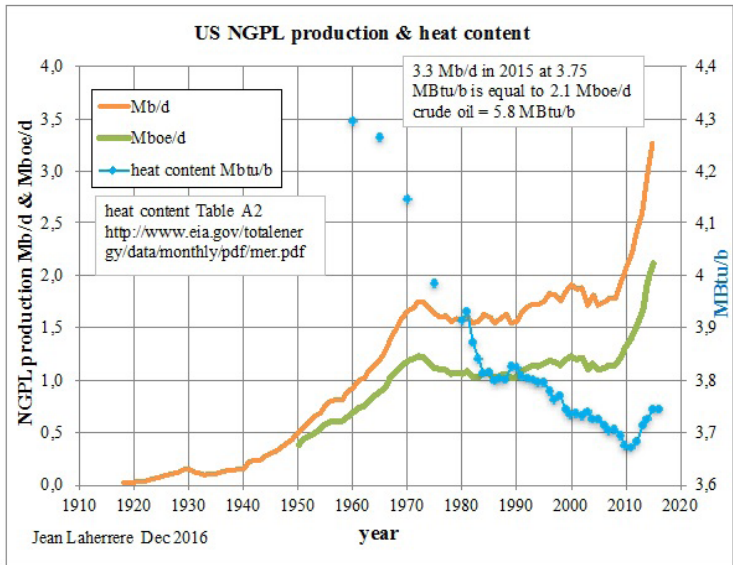


Figure A3.14 US NGPL Production, and Heat Content.

Source: J. Laherrère; from EIA data.

Further, Laherrère notes: “*The problem with EIA oil data for the US is that in the past crude oil production was including condensate because in many small fields oil and condensate were produced together, but now EIA reports for reserves and for production crude oil separately, and-crude-oil-plus-condensate, but only since 1977*”; see Figure A3.15.

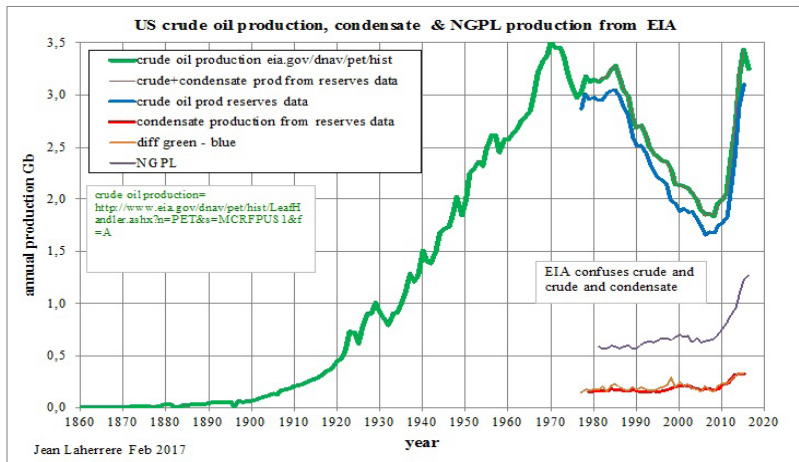


Figure A3.15 Comparison of US Crude Oil and Condensate Production; different EIA data.

Laherrère notes: “*It appears that in the huge increase of light-tight oil, condensate plays only a small part!*”

Source: J. Laherrère.

Other examples of other reporting differences in this area are given in Figure A3.16.

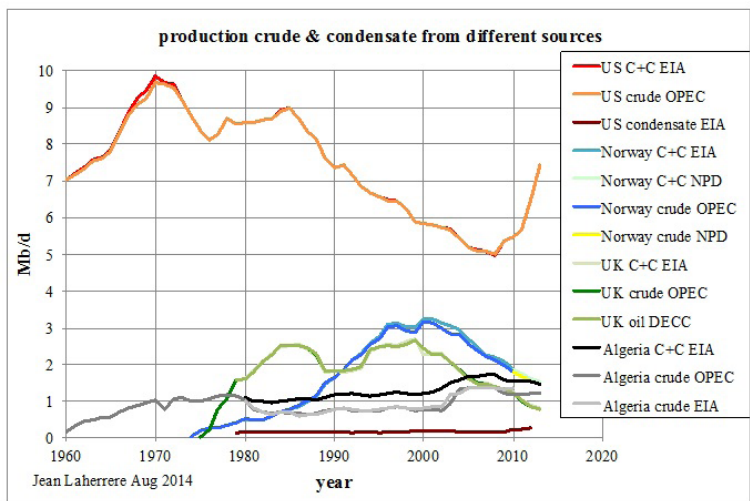


Figure A3.16 Data of Production of Crude oil plus Condensate, by Country, Different sources.

Terminology: C+C: crude oil plus condensate. crude: crude oil. EIA: US Energy Information Administration. NPDP: Norwegian Petroleum Directorate. DECC: UK Dept. for Energy and Climate Change.

Annex 4: Classes of Oil by Net-Energy, and by Greenhouse Gas Emissions

In Annex 3 we looked at the different classes of oil liquids by density and by energy content. Here we look at two further and very important aspects of these liquids: their net-energy content, and their emissions of greenhouse gasses. We start with net-energy.

A4.1 Net-Energy

Separate from the energy content of different oil liquids (i.e., how much energy is obtained from combustion of a given quantity of

liquid) discussed in Section A3.2, is the important topic of their net-energies, which gives their ratio of energy return to energy invested ('EROEI'), i.e. the ratio of the energy delivered by combusting the fuel to the energy required to produce that fuel. (Note that often the term EROI is used instead of EROEI, but this can be confusing, as sometimes EROI is used to mean 'energy return on money invested'.) This topic of net-energy, despite its importance, is so far included in very few oil, or wider energy, forecasts.

If EROEI data are not included in a forecast, it is in danger of giving very misleading results. Perhaps the most vivid example of this are forecasts that consider how practical it is to move to an 'all renewable energy' world. Such forecasts usually point to the very large quantity of solar energy impinging annually on the earth (roughly 10 000 times that produced annually by global commercial energy), and hence these forecasts often include large percentages of photovoltaic (PV) systems in the energy mix.

But this ignores the hard constraints imposed by EROEI ratios. While a long-term 'high PV use' world may be possible, and is certainly desirable, getting there is not easy.

To-date fully-installed PV systems have perhaps averaged a fairly modest PV EROEI of 8 or so. (Note that this value is open to question: some studies have suggested a considerably lower EROEI, but see also Raugei, 2017; while for more recent PV systems this ratio may be higher, see Koppelaar, 2016.) But if an EROEI of 8 is assumed, and this is coupled with the rapid rate that PV has been deployed around the world, to-date mankind has received no net-energy from the ~250 GW_p or so of PV that has been installed. This is simply because the building of the rapidly expanding quantities of PV has used more energy than these systems – so far – have delivered; see, e.g., Dale and Benson (2013).

Of course the owner of a PV system is happy, they are receiving energy from the system. But in global terms, when you see a PV system on a roof or in a field you are looking - to-date - at part of a global energy sink, not an energy source. It is true that once the growth of PV installations slows, then positive net-energy does return to society, but even then less than simple 'energy yield' calculations show. It is certainly the case that PV is rather an extreme example – combining as it does a modest EROEI with

a rapid installation rate, but the same general lesson is true for all energy-generating (and also energy-saving) technologies: their EROEI ratios must be included into forecasts if a correct picture of mankind's energy future is to be obtained.

A4.1.1 Data on net-energy return

As the world moves away from conventional oil, it is important to recognise that nearly all of the non-conventional oils have lower net-energy ratios, sometimes significantly so.

The data are hard to establish unequivocally, but Guilford et al. (2011) and Hall (personal communication) suggest for example that the EROEI for conventional oil was about 30:1 in the 1930s, rising to 40:1 in the 1970s as scale increased and technology improved, and subsequently falling with production of the more difficult conventional oils, such as deep offshore or Arctic oil, to an average ratio of perhaps 14:1 today.

As mentioned, by contrast nearly all non-conventional oils have lower net-energy ratios; tar sands, for example, being quoted as having ratios of from 1.5 to 8:1, and corn ethanol as only perhaps 2 or 3:1 (probably higher in Brazil, and in some cases perhaps lower than 1).

For general data on EROEI ratios, including caveats on how they should be calculated, in the first instance see Hall (2016) and also the references given there, as well as Hall's latest book, Hall (2017), to be published by Springer. For data on Bakken light-tight oil see Brandt et al. (2015); for data on US corn ethanol see Pimentel (1991), Pimentel et al. (1994), Patzek (2004, 2005), Pimentel and Patzek (2005), and Chavanne and Frangi (2007, 2008, 2011). In terms of forecasting, the only detailed oil forecast model so far to include EROEI data to our knowledge is that by Campbell (2015).

Overall, since Hall et al. (2009) and Lambert et al. (2014) calculate that modern society will have difficulty in functioning if its fuels have net-energy ratios of less than perhaps 5:1 - 10:1, the EROEI impacts of the current transition from mainly conventional oil to increasing quantities of non-conventional oil needs to be understood.

A4.1.2 Exergy

A somewhat related topic to net-energy is that of exergy (the maximum useful work possible during a process that brings a system into equilibrium with a heat reservoir), and it seems likely that this will also need consideration in future energy forecasts. Like EROEI, the exergy of real systems may be difficult to measure, but useful data are given in Warr *et al.* (2010); and see comments on this in Laherrère (2014); in Ayers and Voudouris (2014), and Ayers (2016); and see also the website: <https://ruayres.wordpress.com>

A4.2 Greenhouse gas (GHG) emissions

Now we turn from EROEI ratios of different oil liquids to their greenhouse gas emissions, particularly that of CO₂. In general, current-year calculations of GHG emissions are done by the mainstream energy forecasting organisations in adequate detail, where for example the IEA writes:

“[Calculations of the CO₂ emissions] from petroleum and coal account for differences in product-level consumption patterns and emissions factors. For example, in the case of petroleum, residual fuel oil has a significantly higher emissions factor than motor gasoline. The calculation methodology therefore applies emissions factors to individual petroleum product consumption data, and then sums to obtain total carbon dioxide emissions from the consumption of petroleum. ... Emissions data from the consumption of petroleum also incorporates carbon sequestration due to non-fuel use (for example, asphalt used for street paving). This is done by applying: (1) rates of non-fuel use and (2) sequestration rates of non-fuel use to individual products. Product-level emissions are accordingly reduced to account for carbon that is sequestered rather than combusted and emitted as carbon dioxide.”

But the main problem with GHG emissions of oil liquids, and indeed of all fossil fuels, is not the current-year calculations but the forecasts. This is because there are significant differences in emissions forecasts, driven in part by the very different URR values assumed (or implied) for these fuels - as was discussed, for example, in the case of oil in Section 11 of Part-1 of this paper.

This difference in emissions forecasts is illustrated by the next two Figures. Figure A4.1 shows the view of Laherrère, as given in Durand and Laherrère (2015). This forecasts global fossil fuel production by fuel type, and hence CO2 emissions, out to 2200.

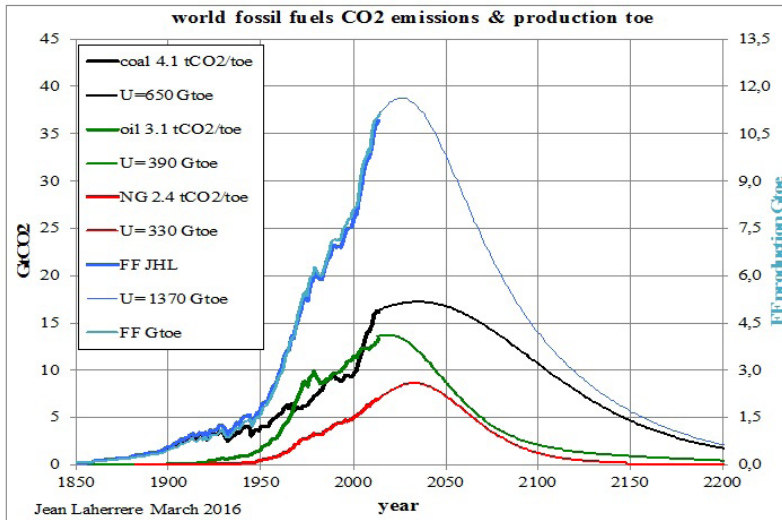


Figure A4.1 Historical data, and Laherrère’s forecast, of Annual Global Production of Fossil Fuels, and hence of CO₂ Emissions, 1850 to 2200.

Legend:

Left-hand scale:

- coal 4.1 tCO₂/toe: Historical data of global coal production, converted to Gt CO₂ using 4.1 tCO₂/toe.
- U=650 G toe: A ‘Hubbert’ curve fitted to global historical coal production and sized to reflect an ultimately recoverable coal resource (URR) of 650 gigatonnes of oil equivalent, converted to Gt CO₂ using 4.1 tCO₂/toe.
- oil 3.1 tCO₂/toe: Historical data of global oil production, converted to Gt CO₂ using 3.1 tCO₂/toe.
- U= 390 G toe: A ‘Hubbert’ curve fitted to global historical oil production and sized to reflect an ultimately recoverable oil resource (URR) of 390 gigatonnes of oil, converted to Gt CO₂ using 3.1 tCO₂/toe.
- NG 2.4 tCO₂/toe: Historical data of global natural gas production, converted to Gt CO₂ using 2.4 tCO₂/toe.
- U= 330 G toe: A ‘Hubbert’ curve fitted to global historical gas production and sized to reflect an ultimately recoverable gas resource (URR) of 330 gigatonnes of oil equivalent, converted to Gt CO₂ using 2.4 tCO₂/toe.

Right-hand scale only:

- FF EIA: EIA historical data on total global production of fossil fuels.

Right-hand and left-hand scale:

- U= 1370 G toe: A ‘Hubbert’ curve fitted to global historical all fossil fuel production, and sized to reflect an ultimately recoverable resource

(URR) of 1370 gigatonnes of oil equivalent, converted to Gt CO₂ using the weighted average of tCO₂/toe conversion factor for coal, oil and gas, of ~3.4 tCO₂/toe.

- FF Gtoe: Total historical production fossil fuels, in terms of Gt CO₂ emissions, obtained by summing the three individual CO₂ emissions curves for coal, oil and gas shown on the plot.

Notes:

- Assumes no above-ground constraints.
- Different sources list different conversion factors to convert global average fuel production of any one fossil fuel type into the corresponding CO₂ emissions. In this Figure the following conversion factors have been used: oil: 3.1; natural gas: 2.4 and coal: 4.1 tCO₂/toe, respectively.
- The individual lines for oil, gas and coal should be read against the left-hand axis, which is gigatonnes of CO₂ per year. Only the fossil fuel total can also be read against the right-hand axis, of gigatonnes of oil equivalent (in energy terms) per year.

Source: Durand B. & Laherrère J.H. (2015).

As can be seen in Figure A4.1, this forecast expects global CO₂ emissions from fossil fuels to peak by about 2025, driven by resource availability constraints of these fuels, and where the total emissions peak reflects the individual peaks for oil, gas and coal as shown.

Crucial to this forecast are the underlying URR estimates assumed. These are 390, 330 and 650 Gtoe for oil, gas and coal respectively. For oil, the URR is for conventional plus non-conventional oil, but excludes any significant quantity of oil from kerogen; and that for gas is for conventional plus gas non-conventional gas, but excludes significant amounts of gas from deep brines, methane hydrates etc., as these are thought by Laherrère as unlikely to see significant production in the near or medium term.

The URR for coal, of 650 Gtoe, is the most controversial estimate. Many authorities see very large amounts of coal as being available, but other studies, such as Mohr et al. (2015) see coal availability as much less. Mohr (private correspondence) notes:

“In terms of coal resources, I think there needs to be substantial research. Of the 6 countries that contribute ~85% of the coal

resources, I'm happy that South African and Australian resources are being monitored reasonably well (in Australia most of the coal is measured to the JORC specifications and government agencies collate and make public the data). The remaining four countries of China, Russia-plus-Ukraine, America and India have substantial issues in terms of data quality, and in trying to figure out realistic recoverable resource numbers.

Personally I think what is needed (at a minimum) would be 4 PhDs (or postdocs, or large research analyses, something like Matt Simmons did for Saudi Arabia) collating the data for these 4 countries (i.e. one coming up with number for China, one for USA, etc.). Until this happens the lack of transparency - particularly with Russia-plus-Ukraine, and Chinese numbers - means that any projection of coal production is heavily reliant on guesswork.

For oil, and to a lesser extent gas, industry numbers do exist and are heavily investigated and scrutinised, but for coal the belief is that it is abundant and this seems to be justification to not investigate further. That said, Chinese coal production is immense and I cannot see it continuing for too much longer on its current trajectory (though even knowing what the coal production numbers in China are is contested with wide disagreement - similar to the lack of certainty about Venezuelan oil production numbers)."

Likewise, Laherrère notes:

"The coal ultimate is speculative because of the very large discrepancy between resources (in the ground) and reserves (what will be produced). BGR reports higher values than 650 Gtoe for coal's global cumulative production plus remaining resource; while 'Hubbert linearisations' of global coal production to-date suggest a URR between 350 and 750 Gtoe. My best guess for coal's URR today is 650 Gtoe; and where this was 500 Gtoe 10 years ago, then 750 Gtoe, and now 650 Gtoe."

Overall it is clear that until the global coal URR estimate is better established, forecasts of those like Figure A4.1 must remain somewhat speculative. But the important point, however, is that forecasts like Figure A4.1 contrast sharply with the accepted wisdom on global projected fossil fuel CO₂ emissions, and in particular those included in IPCC calculations. This is illustrated in Figure A4.2.

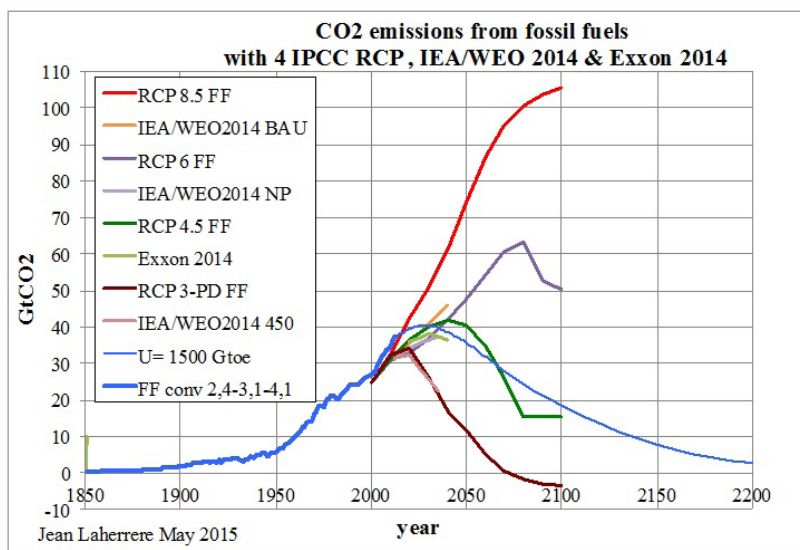


Figure A4.2 Historical data, Forecasts, and ‘Representative Pathways’ of Global CO₂ Emissions to 2100, and to 2200.

Legend:

- RCP 8.5 FF; RCP 6 FF; RCP 4.5 FF; RCP 3-PD FF: CO₂ emissions vs. date corresponding to the four main IPCC representative concentration pathways (RCPs). One is a high pathway for which radiative forcing reaches >8.5 W/m² by 2100 and continues to rise for some amount of time; two are intermediate “stabilization pathways” in which radiative forcing is stabilized at approximately 6 W/m² and 4.5 W/m² after 2100; and one is a pathway where radiative forcing peaks at approximately 3 W/m² before 2100 and then declines. Here Laherrère uses ‘FF’ to indicate that the corresponding CO₂ emissions are from fossil fuels only.

- IEA/WEO2014 BAU; IEA/WEO2014 NP; IEA/WEO2014 450: CO₂ emissions corresponding to the fossil fuel usage forecast in the IEA’s *World Energy Outlook 2014*; according to its ‘Business-as-usual’, ‘New policies’,

and '450 ppm' scenarios, respectively.

- Exxon 2014: CO₂ emissions corresponding to the fossil fuel usage in Exxon's 2014 global energy forecast

- U= 1500 G toe: CO₂ emissions from the combustion of fossil fuels that combine to a global URR of 1500 Gtoe (approximating URRs of 420, 300 and 750 Gtoe for oil, gas and coal, respectively). Note: This value was a slightly earlier estimate by Laherrère of the 'all-fossil-fuel' URR than the 1370 Gtoe estimate given in Figure A4.1.

- FF conv. 2,4-3,1-4,1: Historical data on CO₂ emissions from fossil fuels combustion, using the conversion factors of 2.4, 3.1 and 4.1 tCO₂/toe for gas, oil and coal, respectively.

Note: The four RCPs were chosen to reflect possible time paths for "emissions and concentrations of the full suite of GHGs and aerosols and chemically active gases, as well as land use/land cover changes"; but do not - we understand - so far include allowance for other potentially significant climate forcing mechanisms, such a change in albedo from ice loss, limits to ocean uptake of CO₂, or methane release from permafrost or hydrates.

Source: Laherrère, from the sources indicated.

In comparing the very different views of CO₂ emissions set out in Figure A4.2, Laherrère notes that: "The 40 SRES energy scenarios (on which, in part, the RCPs were based) were essentially storylines, whereas the data shown from the IEA, Exxon as well as myself are forecasts based on estimates of ultimate reserves."

The background to this controversy is that in 2000 earlier IPCC forecasts of CO₂ emissions from fossil fuels were updated by the IPCC's Special Report on Emissions Scenarios (SRES). The scenarios produced were 'reference' scenarios, meaning that they did not take into account current or future measures to limit GHG emissions (Wikipedia), and were used in the IPCC's Third and Fourth Assessments published in 2001 and 2007, respectively. A number of studies noted at the time that the higher CO₂ SRES scenarios were based on what seemed over-generous assumptions of the likely production of a range of non-conventional oil and gas sources, and on high-end estimates of coal resources. These studies concluded that the higher CO₂ SRES scenarios were very unlikely, and were potentially misleading discussion within the climate change debate; see for example the studies by Laherrère (2001), Aleklett (2012), Ward *et al.* (2012), Höök and Tang (2013), Durand

and Laherrère (2015), and Mohr et al. (2015). Laherrère's (2001) study was reported at an IIASA International Energy Workshop in June of that year, where he presented Figure A4.3.

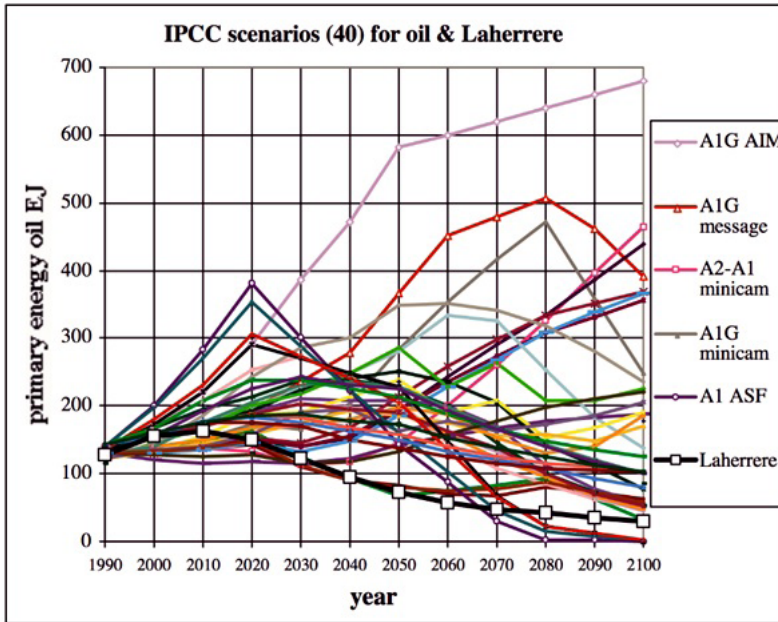


Figure A4.3 Plot by J.H. Laherrère from the IIASA 2001 International Energy Workshop showing the contrast between IPCC scenarios of energy production from oil to 2100, compared to Laherrère's own estimate.

Source: Laherrère (2001).

In 2014 the SRES scenarios were superseded by representative concentration pathways (RCPs), but these fairly closely matched the CO₂ emissions range of the original SRES scenarios. A number of more recent studies thus also found that the higher RCPs seemed unlikely, at least if driven only mainly by fossil fuel emissions (but see the note in Figure A4.2 on other potential forcing mechanisms that may well occur). Importantly, however, a number of these later studies concluded that even if the lower fossil fuel URR estimates are assumed, then the 2°C limit above pre-industrial temperatures still seems likely to be exceeded; see for example Wang J. et al.

(2016).

Overall, the conclusion to take from this section of Annex 4 is that there are significant differences between forecasts of the likely CO₂ emissions from fossil fuels, and that these differences need resolution if the climate change debate is to be correctly informed.

Annex 5: Analysis of Oil Reserves Data

This Annex supports the discussion of Section 7 in Part-1 of this paper on the differences between proved ('1P') and proved-plus-probable ('2P') oil reserves. It follows the same general sequence of Section 7, and looks at 1P, 2P, and 3P (proved-plus-probable-plus-possible) reserves data, and at comparisons between these.

A5.1 Proved ('1P') oil reserves

Section 7 in Part-1 looked at a number of aspects related to the reporting of proved oil reserves. These were: reporting under SEC (or similar) rules; the mathematical error introduced when proved reserves are aggregated by summation; problems with government reporting of proved reserves; the specific problem of OPEC 'quota wars' reserves increases; and the problem of proved reserves data remaining unchanged year on year, sometimes for many years in succession. We discuss these aspects in turn.

A5.1.1 Reporting oil reserves under SEC (or similar) rules

In the early days of oil exploration wild claims were made for the volume of oil in fields, often caused by ignorance of the field itself, but also by commercial pressures to exaggerate field size to attract investors. In time, in the US the Securities and Exchange Commission (SEC) stepped in and mandated sound conservative estimating procedures. Laherrère (2004) discussed this in an

article entitled: *'Shell's reserves decline and the SEC's obsolete rule book'*, and his summary of developments in the proved oil reserves reporting process is as follows:

- 1936 API: Reserves definitions with proved reserves.
- 1961 API-AGA: Proved = "beyond reasonable doubt".
- 1964 API, SPE: Proved = "reasonable certainty".
- 1975 USGS McKelvey: Classification of resources.
- 1978 SEC-FASB: Proved = "with reasonable certainty"
- 1979 Khalimov and Feign: Russian classification A+B+C1 reserves reported to be equivalent to proved reserves, despite a different determination.
- 1979 McKay Esso: Proved (1P) = probability 95 %; Proved+Probable (2P) = 50%; Proved+Probable+Possible (3P) = 5% ; but minimum = 99%, most likely = 50%, maximum = 1% probability.
- 1980 AAPG, SPE and API use SEC definitions.
- 1983 WPC (Martinez): Proved = "reasonable certainty", or 90% probability.
- 1985 Grossling: Expected value = 2.3 * Proved for Non-OPEC; 1.5 * Proved for OPEC.
- 1985 Bourdaire et al.: Proved (P) = 95% (minimum); 2P = mode (most likely); 3P = 5% (maximum); Mean = "Expected value" = Proved + 2/3 Probable + 1/3 Possible.
- 1987 WPC (Martinez): Proved = 85%-95% probability = "high degree of certainty".
- 1990 Laherrère: Proved (1P) = 85%-95%; 2P = 50%; 3P = 5%-15%.
- 1991 Caldwell: Proposes that "reasonable certainty" equates with a 75% probability; between Proved and Probable.
- 1991 SPE: Refuses to adopt the probabilistic approach.
- 1993 DeSorcy et al.: Proved = 80% probability; Probable = 40%-80% probability; Possible = 10%-40%; "Expected Reserves" = Proved + 0.6 Probable + 0.25 Possible; "Established Reserves" = Proved + 0.5 Probable.
- 1993 Khalimov: Russians reserves are "grossly exaggerated" because they are based on a maximum theoretical recovery.

- 1994 Ross: Proved = 75% probability.
 - 1994 NPD: Drops Proved, Probable and Possible in favour of 90%; 50% (called Most Probable?), and 10%; and defines 7 classes of resources.
 - 1994 PDVSA: Uses a probabilistic range of 80-50-20%.
 - 1995 SPE/WPC, Task force on reserve definition headed by A. Martinez (Laherrère notes that he was a member of this Task force): Proposes a hybrid system whereby the Determinist terms are defined as follows: Proved = “reasonable certainty”, but also having a “high degree of confidence”; Probable = “more likely than not”; Possible = “less likely than not”; and the Probabilistic terms are defined as follows: Proved (1P) = 80-85% probability; Proved + Probable (2P) = 40-60% probability; and Proved + Probable + Possible (3P) = 15% probability.
 - 1997 SPE/WPC final text for probabilistic reserves: 1P = 90%, 2P=50%, 3P=10% and Martinez approaches the SEC to adopt probabilistic approach (without success). Resources are not mentioned.
 - 2000 SPE/WPC/AAPG: Definitions of resources (contingent & prospective).
 - 2003 Canada National Instrument 51-101: Obliges reporting of proved as 90 % and 2P as 50%; 3P is optional.
 - 2004 International Accounting Standards Board (in UK) project to publish rules to be adopted by SEC, but date of completion likely after 2007. Most of reserves experts were very critical towards the US practice.
- [N.B. The ‘References’ section at the end of this paper gives the references for Khalimov and Feign (1979), Bourdairé *et al.* (1985), DeSorcy *et al.* (1993), and Khalimov (1993).]

Quotes:

- DeSorcy 1993: *“There are currently almost as many definitions for reserves as there are evaluators, oil and gas companies, securities commissions and government departments. Each one uses its own version of the definitions for its own purposes.”*
- Khalimov 1993: *“The resource base [of the former Soviet Union] appeared to be strongly exaggerated due to*

inclusion of reserves and resources that are neither reliable nor technologically nor economically viable.”

- Capen 1996: See quote in Section 12 of Part-1; Capen also noted the “*illegal addition of proved reserves.*”
- Ross 1998: “*The term ‘reserves’ often is treated as if it were synonymous with ‘proved reserves’. This practice completely ignores the fact that any prudent operator will have, at least internally, estimates of probable and possible reserves.*”

And see:

- Caldwell and Heather (1996): *Why our reserves definition don’t work anymore.*
- Tobin (1996): *Virtual reserves - and other measures designed to confuse the investing public.*

Recently, Laherrère authored a paper based on data from mature basins to show that proved current oil reserves are “completely unreliable”, and that only backdated 2P reserves should be used for oil forecasting. He noted that “*The SEC’s obsolete rules [for reserves reporting] are the law for almost all major companies listed on the US stock market, and it is unlikely that this will change.*” In comments to the US National Petroleum Council in connection with their 2007 report: *Hard truths – Facing the hard truths about energy - A comprehensive view to 2030 of global oil and natural gas*, Laherrère (2007) noted: “*As long as obsolete SEC proved reserves rules are used, reserves studies will be flawed. SEC rules were designed in 1978 in line with 1978 SPE rules, but SPE rules have been changed several times since, the last time being 2007.*”

A5.1.2 Mathematical error of proved reserves aggregated by summation

As noted previously in Section 7.1, because 1P reserves - if audited - are conservative values (sometimes judged as ‘P90’, that is, having a 90% chance of being exceeded), simple arithmetic addition of these reserves significantly underestimates the correct total at the probability level specified. For additional information see: www.

spe.org/industry/docs/PRMS_Guidelines_Nov2011.pdf: ‘*Guidelines for Application of the Petroleum Resources Management System.*’

A5.1.3 Government reporting of proved reserves

See some of the sections below for more information on government reporting of proved reserves in certain countries.

A5.1.4 OPEC ‘quota wars’ reserves increases

As mentioned in Section 7, though most countries’ public-domain proved (1P) oil reserves are, as one would expect, smaller than the industry 2P data, in some OPEC countries the reverse is true, and the country’s published 1P reserves *significantly exceed* the industry 2P reserves. These cases mainly result from the OPEC ‘quota wars’ step-changes in proved reserves that occurred in the 1980s, when OPEC’s allowed production of individual members was based in part on the size of declared reserves.

Table A5.1 shows the step-changes that occurred in the proved reserves data for six OPEC countries in the 1980s; and also the subsequent long periods of no change in some of these data. Also given are the countries’ production in 2015 to illustrate the magnitude of annual change one might have expected in the reserves data if there were no major new discoveries in the years concerned.

	UAE	Iran	Iraq	Kuwait	Saudi Arabia	Venezuela
1980	30.4	58.3	30.0	67.9	166.0	19.8
1981	32.2	57.0	32.0	67.7	167.9	19.9
1982	32.4	56.1	59.0	67.2	166.5	24.9
1983	32.3	56.3	65.0	67.0	168.8	25.9
1984	32.5	58.9	65.0	92.7	171.7	28.0
1985	33.0	59.0	65.0	92.5	171.5	54.5
1986	97.2	92.9	72.0	94.5	169.7	55.5
1987	98.1	92.9	100.0	94.5	169.6	58.1
1988	98.1	92.9	100.0	94.5	255.0	58.5
1989	98.1	92.9	100.0	97.1	260.0	59.0
1990	98.1	92.8	100.0	97.0	260.3	60.1
1991	98.1	92.9	100.0	96.5	260.9	62.6
1992	98.1	92.9	100.0	96.5	261.2	63.3
1993	98.1	92.9	100.0	96.5	261.4	64.4
1994	98.1	94.3	100.0	96.5	261.4	64.9
1995	98.1	93.7	100.0	96.5	261.5	66.3
1996	97.8	92.6	112.0	96.5	261.4	72.7
1997	97.8	92.6	112.5	96.5	261.5	74.9
1998	97.8	93.7	112.5	96.5	261.5	76.1
1999	97.8	93.1	112.5	96.5	262.8	76.8
2000	97.8	99.5	112.5	96.5	262.8	76.8
2001	97.8	99.1	115.0	96.5	262.7	77.7
2002	97.8	130.7	115.0	96.5	262.8	77.3
2003	97.8	133.3	115.0	99.0	262.7	77.2
2004	97.8	132.7	115.0	101.5	264.3	79.7
2005	97.8	137.5	115.0	101.5	264.2	80.0
2006	97.8	138.4	115.0	101.5	264.3	87.3
2007	97.8	138.2	115.0	101.5	264.2	99.4
2008	97.8	137.6	115.0	101.5	264.1	172.3
2009	97.8	137.0	115.0	101.5	264.6	211.2
2010	97.8	151.2	115.0	101.5	264.5	296.5
2011	97.8	151.2	143.1	101.5	265.4	296.5
2012	97.8	157.0	150.0	101.5	265.9	297.6
2013	97.8	157.0	150.0	101.5	265.9	298.3
2014	97.8	157.8	150.0	101.5	267.0	298.3
2015	97.8	157.8	143.1	101.5	267.0	300.0
Ann. prod.:	1.4	1.4	1.5	1.1	4.4	1.0

(Gb)
(Gby in 2015)

Table A5.1 ‘Quota Wars’ Step-changes in some OPEC Proved (1P) Reserves; and subsequent ‘Static’ Reserves data.

Notes:

- The earlier data highlighted indicate the large step-changes in proved reserves from 1982 to 1988 for the countries shown. These occurred at a time when the oil price had fallen sharply, and one factor in a country’s OPEC quota allowance was its declared proved reserves. Note that no major discoveries occurred at the dates highlighted; though Venezuela might legitimately argue that changes in extraction technology allowed more Orinoco oil to be ‘proved-up’.

- Also highlighted are more recent cases of possible ‘quota manoeuvring’ since 2008.

- Also shown are the long sequences of ‘static’ reserves (i.e., reserves that did not change over a number of years, despite significant levels of production having occurred).

Source: D. Freedman, drawn from the BP *Stats. Review*; new data added since 2011. Data may not be as of the date shown, but reflect that in one or more issues of the *Stats. Review*.)

The case has been made that some of the ‘step-changes’ shown in Table A5.1 reflect the countries’ newly nationalised industries reporting ‘true’ reserves, rather than more conservative values bequeathed them by the oil majors. There may well be a degree of truth to this, but this is a far from sufficient explanation of both the size and dates of these changes. Campbell’s reading of these data (personal communication) is as follows:

“I think that when Kuwait increased its reported reserves in 1984 it did so by reporting original, not remaining, reserves by not deducting past production. In fact this is industry practice for defining the relative ownership of a field that crosses a lease or national boundary, and it made sense for OPEC to use at a basis for setting quotas. [Then] in 1986 Kuwait announced a small possibly genuine increase, but this probably proved too much for the other OPEC countries that were competing for quota at a time of low oil prices as they desperately needed the revenue on which they had come to depend. In 1986 Abu Dhabi matched Kuwait, Iran went one better at 93 Gb, and Iraq capped both a year later at a rounded 100 Gb.”

Other sources also have pointed to probable problems with these OPEC reserves data. For example, the Wikipedia article: ‘Oil Reserves’ (accessed 28th March 2015, and here slightly edited) says:

- *“Sadad al-Husseini, former Head of Exploration and Production at Saudi Aramco, estimates 300 Gb of the world’s 1,200 Gb of proven reserves should be re-categorized as speculative resources, though he did not specify which countries had inflated their reserves. (Source: “Oil reserves over-inflated by 300bn barrels – al-Husseini”. October 30,*

2007. Retrieved 2008-08-23); [and see also:

<http://www.sargasso.nl/wp-content/uploads/2007/11/sadadibrahimalthusseini.pdf>]

- Dr. Ali Samsam Bakhtiari, a former senior expert of the National Iranian Oil Company, has estimated that Iran, Iraq, Kuwait, Saudi Arabia and the United Arab Emirates have overstated reserves by a combined 320 - 390 Gb and has said, "As for Iran, the usually accepted official 132 Gb is almost one hundred Gb over any realistic assay." (Source: "On Middle Eastern Oil Reserves". ASPO-USA's Peak Oil Review. February 20, 2006. Retrieved 2008-08-20.)

- Petroleum Intelligence Weekly reported that official confidential Kuwaiti documents estimate reserves of Kuwait [in 2001] were only 48 Gb, of which half were proven and half were possible. The combined value of proven and possible is half of the official public estimate of proven reserves [i.e., of 96.5 Gb in 2001, see Table A5.1]. (Source: "Oil Reserves Accounting: The Case Of Kuwait". Petroleum Intelligence Weekly. January 30, 2006. Retrieved 2008-08-23.)'

[On the basis of this, and similar doubts over Saudi Arabia's proved reserves, Petroleum Intelligence Weekly went on to write: "The Kuwaiti numbers vary so strikingly from those in the public domain that they could fundamentally alter many of the basic operating assumptions about the status of world oil reserves." Note that the article itself did not say half of the Kuwait 48 Gb reserves were 'possible', but 'nonproven'. For additional information on Kuwait reserves, see Section A5.4.3, below.]

A5.1.5 'Static' proved reserves

This is the problem of proved reserves data remaining unchanged year on year; sometimes for many years in succession. While the problem of the OPEC 'step-changes' in the proved reserves data is now fairly well known, the problem of 'static' data is much less so, although both problems were described clearly in the Campbell & Laherrère *Scientific American* article (1998). As Table A5.1 shows, for example the UAE proved reserves have stayed effectively

unchanged at close to 98 Gb from 1986 to to-day, despite the country's annual production averaging roughly 1 Gb/yr. over this nearly 30-year period.

This problem of 'static' proved reserves applies to many countries in addition to those in Table A5.1; in the end-2015 O&GJ data for 106 oil-producing countries, 68 countries reported no change in both oil & gas proved reserves, and 74 countries no change in oil proved reserves, compared to the corresponding end-2014 data.

Figure A5.1 shows the OPEC step changes as well as the long periods of essentially unchanging reserves; and also the large recent additions to 1P reserves recorded for Canada and Venezuela due to the addition of non-conventional oil.

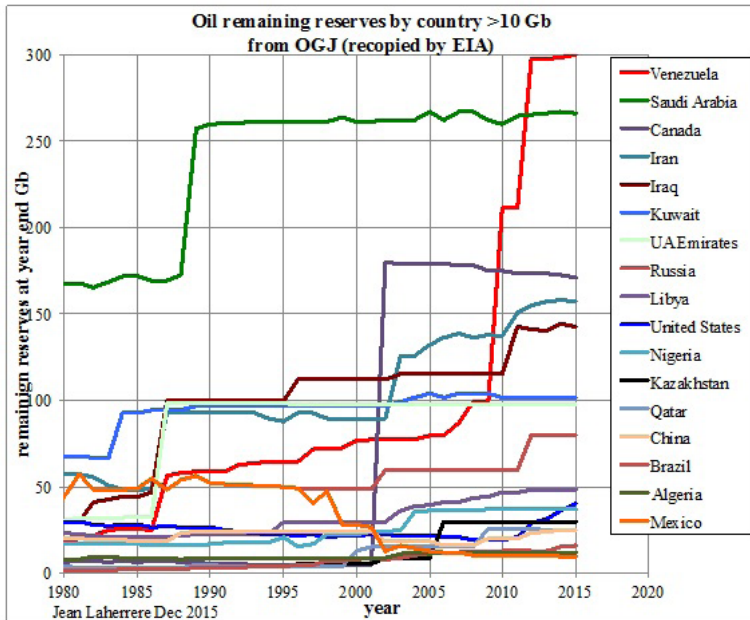


Figure A5.1 Evolution of proved (1P) reserves 1980 to 2015, for countries whose current 1P reserves are >10 Gb.

Note that a further issue with proved reserves data is that these are reported at first of the year, when reserves should be reported at end-year.

Source: Laherrère: *Oil and Gas Journal* data reported by the EIA.

In summary, on proven (1P) oil reserves, Laherrère notes:

“1P estimates are carried out to protect bankers and shareholders against oil promoters; and where bankers hope to recover the minimum value if the company goes broke. They have nothing to do with forecasting the future (as also with R/1P ratios), nor with the reserves as estimated by reliable companies when they decide to develop a field. In the latter case such companies use the Net Present Value calculations which simulate (using Monte Carlo runs and a large number of cells, a minimum 10 000, up to 100 million for Ghawar) the full life of the field from development to production and abandonment, creating scenarios based on assumptions for mean (i.e., ~P50, ~2P) reserves, future expenditures, future income, and future oil price. For more detail on Monte Carlo estimation, see Lumenaut (2008).

1P data are used by oil companies listed on the US stock market (hence all the majors) to comply with the SEC rules, which are obsolete rules, but requiring audits (paid for by the oil companies): this is borne out by the fact that since 2010 BOEM has ceased reporting proven reserves, and now reports 2P estimates.

Proven reserves is used also by OPEC countries to comply with OPEC quotas, but they are not audited and are completely unreliable. The best proof of this is the statement referred to earlier by former Aramco VIP Sadad al-Husseini (being retired by his minister Naimi for having written a paper on peak oil) at the 2007 in London (Oil and Money Conference) that the increase from 1986 to 1989 of 300 Gb by OPEC countries (except the Neutral Zone) in their fight for quotas was “speculative resources”. The problem here is that proven reserves announced by governments cannot be questioned for diplomatic reasons, but where the underlying problem are not the estimates themselves, but in the definition of terms, as in this context reserves are confused often with resources.”

A5.2 Proved-plus-probable ('2P') oil reserves

2P data on reserves for fields and projects can come in published form from operators and governments. The commercial databases reflect these sources and also other 'scout' information. But even here Colin Campbell strikes a note of caution:

“The reporting of reserves is subject to heavy commercial and political pressures as I recall from my days in the oil business. Us explorers had to exaggerate to get the money to drill an exploration well and learn more of the prospects. But the engineers on developing a find were rightly very cautious, reporting the minimum needed to make it a viable project. This was reasonable enough considering the major expenses incurred and the uncertainties of future prices. The oil companies themselves were under stock market pressures with their primary motive to make regular profits. It made sense for them to under-report and thereby deliver a picture of steady growth which was welcomed by the shareholders and the stock market traders. Tax too played an important role with expenses being written off against tax: I had many free meals!

Another issue worth mentioning is the difficulty of defining a field, which may have several minor related subsidiary traps and reservoirs that are tapped late in its life. Again there are many commercial pressures.”

And in this context, Laherrère notes:

“Many scientific organisations confuse 2P (proven+probable; ~ P50) with probable alone; and likewise 3P (~P10) with possible alone, for example:

- IFP in 2005 wrote (<http://www.hubbertpeak.com/laherrere/comm-oapec-ifp2005.pdf>) “P50 ou 2P ce sont les réserves probables”: P50, les reserves possibles dites encore P10 ou 3P.”

- And despite my criticisms of this back in 2005, IFP continues

to be in error today in 2016 (<http://www.ifpenergiesnouvelles.fr/index.php/Espace-Decouverte/Les-grands-debats/Quel-avenir-pour-le-petrole/La-notion-de-reserves#1>) which says: “Les réserves probables concernent, pour un gisement identifié, les quantités de pétrole ayant une probabilité supérieure à 50 % d’être économiquement exploitables. On parle de réserves possibles lorsque cette probabilité tombe à 10 %.”

- See also GEOExpro (following Schlumberger: www.glossary.oilfield.slb.com) (http://assets.geoexpro.com/uploads/b9814627-a4a3-428c-8e73-b61621ea62c4/GEO-ExPro_v12i6.pdf).

A5.3 Society of Petroleum Engineers (SPE) Definitions

As mentioned in Section A5.4.1 below, the UK has recently adopted the SPE’s oil reserves definitions. On these the SPE writes:

“Petroleum Reserves & Resources Definitions

(From <http://www.spe.org/industry/reserves.php>)

New Reserves Classification Guidelines: The SPE Oil and Gas Reserves Committee (OGRC) released Guidelines for Application of the Petroleum Resources Management System (pdf) (PRMS) in 2011. The 221-page document replaces the 2001 “Guidelines for Evaluation of Reserves and Resources” with expanded content that is updated to focus on using the 2007 PRMS to classify petroleum reserves and resources.

The guidelines represent a collaboration of SPE, the American Association of Petroleum Geologists, the Society of Exploration Geophysicists, the Society of Petroleum Evaluation Engineers, and the World Petroleum Council. More than 40 subject-matter experts were involved in writing and review of the guidelines, headed by Satinder Purewal, chairman of the OGRC’s Applications Document Subcommittee. See: Guidelines for Application of the Petroleum Resources Management System (pdf)

- *Petroleum Resources Management System: Approved by the SPE Board in March 2007, this system for defining reserves and resources was developed by an international group of reserves evaluation experts and endorsed by the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, and the Society of Exploration Geophysicists. Learn about the process (pdf) by which the new definitions were developed or read a quick overview (pdf) of the PRMS for non-technical users.*

- *Mapping of Reserve Definitions: Around the world, government agencies and other organizations use slightly different definitions. This mapping provides a comparison of many of these definitions. See: GRC mapping (pdf)*

- *Estimating and Auditing Standards for Reserves: To assist those responsible for estimating reserves, or auditing those estimates, a standard approach has been outlined, along with minimum qualifications for those involved in reserves auditing. See: Reserves Auditing Standards (2007) (pdf)*

- *Joint Committee on Reserves Evaluator Training (JCRET). [This] exists to meet the need for high-quality, industry-recognized training for individuals responsible for petroleum reserves and resources evaluation.*

- *Historical Archives:*

- *White Paper: Why a Universal Language for Evaluating Reserves is Needed*

- *Guidelines for the Evaluation of Reserves and Resources - 2001 (pdf)*

- *Definitions Development to 2005*

- *Petroleum Reserves Definitions - 1997*

- *Petroleum Resources Classifications - 2000*

- *Glossary of Reserves/Resources Terminology - 2005*

- *Estimating and Auditing Standards for Reserves - 2001 (pdf)*

A5.4 Comparison of 1P, 2P and 3P reserves

Now we turn to data that compare 1, 2 and 3P oil reserves. As noted in Bentley et al. (2007) and Bentley (2016), not understanding the differences between classes of reserves has been the largest contributor to the long-standing confusion over ‘peak oil’.

To make this clear, here we examine some examples of 1P, 2P and 3P data by country. We start with the data of the UK, which are - perhaps surprisingly - in some aspects extraordinarily poor.

A5.4.1 UK data

Until recently, the main UK government information on oil reserves was at:

<https://www.gov.uk/guidance/oil-and-gas-uk-field-data>
and this used the following definitions:

Reserves	Description
Proven	Reserves that on the available evidence, are virtually certain to be technically and commercially producible, i.e. have a better than 90% chance of being produced
Probable	Reserves that are not yet proven, but which are estimated to have a better than 50% chance of being technically and commercially producible
Possible	Reserves that at present cannot be regarded as probable, but which are estimated to have a significant – but less than 50% – chance of being technically and commercially producible

More recently the UK Oil and Gas Authority (OGA) noted:

“The Oil and Gas Authority (OGA) aggregation of UK reserves and resources as at the end of 2015 is based on data collected from operators during February and March 2016. In total, 755 fields and potential developments or past discoveries, both offshore and onshore, were reviewed.

The OGA has changed the way we report Reserves and Contingent Resources this year to be compliant with the latest SPE PRMS guidelines. Reserves have therefore been counted for approved and producing fields only. Resources from other significant discoveries where field development plans are under discussion and Extended Oil Recovery (EOR) potential have been counted as Contingent Resources. The above change has resulted in a net reclassification of circa 600 million barrels of oil equivalent (mmboe) previously reported as Reserves now being reported as Contingent Resources.

This change has also resulted in some modifications to the way we report Contingent Resources for discoveries in the Summary Table ... Information about the data:

- *Analysis in the oil and gas tables is focused on remaining reserves. ...*
- *Overall summary page presents tabular figures for discovered resources only, and offers an explanatory paragraph that takes account of the estimates for undiscovered resources to arrive at a best estimate of remaining recoverable UKCS hydrocarbon resources.*

Definitions:

- Estimated ultimate recovery: Total recovery from a field, i.e. reserves plus past production.

- Reserves: Discovered, remaining reserves that are recoverable and commercial. Can be proven, probable or possible depending on confidence level (as described below)

- Contingent resources: Contingent resources are those quantities of petroleum estimated to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development. Includes future planned developments where development plans are under discussion that have not been approved, and "Potential Additional Resources" (PARS) which are discovered resources that are not currently technically or commercially producible.

- Undiscovered resources: Undiscovered potentially recoverable resources in mapped leads."

Note that definitions of reserves, as ‘proven’, ‘probable’ or ‘possible’, did not change from that given above. Note also that the OGA: “*launched a new website [www.ogauthority.co.uk] on 3 October 2016 to reflect its new status as a government company*”. However, this uses the same classifications as given above.

But despite these efforts at classification, the story of the UK’s presentation of its information on oil discovered, and likely to be discovered, has been truly dreadful.

This is best exemplified by the evolution of data given in the annual government-produced booklets: *UK Energy in Brief*. For many years these reported only proved (1P) reserves, so the picture was of reserves continually being replaced, with this being ascribed in the text to advances in technology, rather than simply being oil re-classified from probable to proved. Later for some reason the evolution of UK discovery was reported in terms of 3P, rather than 2P reserves. And most recently, while now 2P reserves are reported, an extraordinary misleading new error has been introduced. This is illustrated by the 2016 *UK Energy in Brief*, p 22, which says:

“The Estimated Ultimate Recovery (EUR) shows the cumulative total of production to the end of the years given and [meaning ‘plus’] the total of proven plus probable reserves as estimated at the end of those years. For both oil and gas, EUR has grown substantially since 1980, increasing by 116% for oil and 93% for gas. This reflects increased new discoveries and the effect of new technology allowing exploitation of resources that were previously regarded as uncommercial. Total cumulative production of oil and gas are 87% and 70% respectively greater than the estimated EUR in 1980.”

The serious error here is that the EUR of a region at a given date is not defined as cumulative production plus the 2P reserves of fields found by that date, but simply as the estimated ultimate recovery from the region, including anticipated future discoveries.

What makes this *UK Energy in Brief* error so extraordinary is that the UK government’s ‘Brown Books’ have been reporting

sensible values for the UK's proper EUR since 1974, i.e., from even before offshore production had started - but after all the initial major offshore fields had been discovered. The 1974 Brown Book oil EUR estimate was 4 500 million tonnes. By 1977 more fields had been discovered, and the government now gave a range for the EUR, of between 3 000 and 4 500 Mt. Subsequently this EUR range widened, but the average stayed roughly in the 4 000 to 5 000 Mt range, and where the current value is not so very different from that estimated back in 1974.

Thus rather than being misled by apparent 'reserves replacement', and identification of technology gains as the cause, the most striking lesson from these proper UK EUR estimates is how easy it has been to make a reasonable estimate for the date of the UK oil production peak. For example if the original 1974 estimate for the UK's ultimate of 4 500 Mt is combined with the 'mid-point peaking' rule, then the UK's oil resource-limited peak would be expected when cumulative production reached ~2 250 Mt. This was not in 1984, the first apparent peak, as by then cumulative production had reached only 730 Mt, but in 1997; and where the actual date of peak was 1999.

Given the general straightness of the cumulative production line, despite the production trough from 1985 to 1995, this date of peak could be - and was - predicted with reasonable precision from the outset of offshore production. The discussion of this in Bentley (2016) concluded: *'piece of cake, really'*. It is thus still an open question as to how the UK government managed to get its understanding of its oil data so consistently wrong over so long a period, including to the present day.

The following sections give some of the UK oil data in greater detail, and amplify the discussion of misunderstandings of the data, and ambiguity of terms.

Table A5.2 gives UK government data on the evolution of its offshore 1P, 2P and 3P reserves, and also production.

OIL + NGL	million tonnes	million tonnes	million tonnes	million tonnes	million tonnes	million tonnes
Year End	Proven Reserves	Probable Reserves	Proven and Probable Reserves	Possible Reserves	Annual Production	Cumulative Production
1973	895	395	1290	260	0	0
1974	1060	305	1365	435	0	1
1975	1350	580	1930	360	2	2
1976	1380	570	1950	550	12	15
1977	1405	625	2030	590	38	53
1978	1397	509	1906	605	54	107
1979	1200	625	1825	575	78	185
1980	1125	575	1700	600	80	266
1981	1050	575	1625	675	89	355
1982	993	475	1468	625	103	458
1983	925	450	1375	625	115	573
1984	800	500	1300	650	126	699
1985	750	480	1230	650	128	827
1986	710	620	1330	720	127	954
1987	690	600	1290	640	123	1077
1988	570	620	1190	610	114	1192
1989	510	690	1200	610	92	1284
1990	535	660	1195	620	92	1375
1991	555	675	1230	730	91	1466
1992	610	755	1365	710	94	1561
1993	605	800	1405	695	100	1661
1994	575	920	1495	580	127	1787
1995	605	765	1370	520	130	1917
1996	665	690	1355	670	130	2047
1997	690	700	1390	625	128	2175
1998	685	575	1260	540	133	2308
1999	665	455	1120	545	137	2445
2000	630	380	1010	480	126	2571
2001	605	350	955	475	117	2688
2002	595	325	920	425	116	2804
2003	571	286	857	410	106	2910
2004	533	283	816	512	95	3005
2005	516	300	816	451	85	3090
2006	479	298	776	478	77	3167
2007	452	328	780	399	77	3243
2008	408	361	770	360	72	3315
2009	378	390	769	343	68	3383
2010	374	377	751	342	63	3446
2011	413	374	788	319	52	3498
2012	405	405	811	253	45	3542
2013	404	342	746	338	41	3583
2014	374	342	746	344	40.0	3623

Notes on source of data

- 1 Reserves data for 1973 to 2000 taken from figures published in brown books
- 2 Reserves data from 2001 onwards taken from figures published on our website

Table A5.2 UK government Offshore Oil Data, 1973 – 2014.

Source: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/441395/Appendix_2_Historic_UK_Oil_and_Gas_Reserves_and_Production_2015.pdf

Figure A5.2 compares graphically the 1P and 2P reserves data given in Table A5.2.

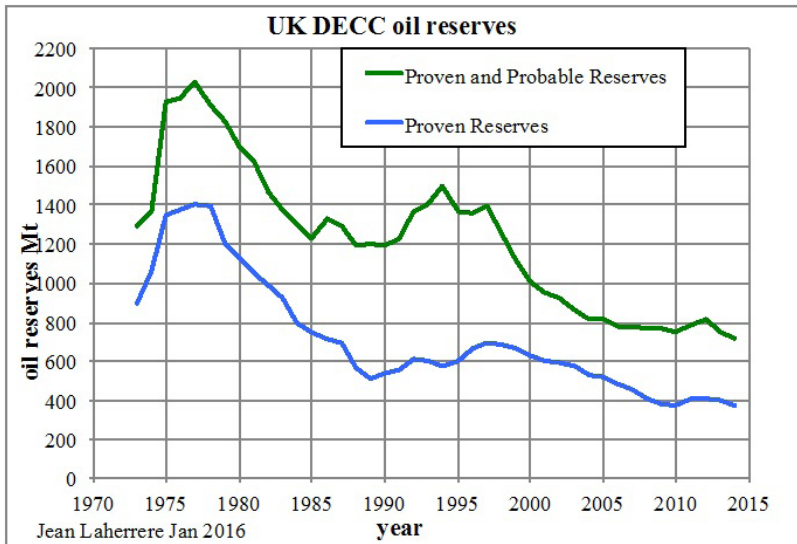


Figure A5.2 Comparison of UK Government data on Proved (1P) vs. Proved-plus-probable (2P) Oil Reserves, 1973 – 2014.

Source: Laherrère; see source for Table A5.2.

As can be seen, UK Government 1P oil reserves were typically in the region of half the corresponding 2P reserves, but where this ratio has varied significantly over time. The reason that the 1P reserves have been so much below the 2P data needs elucidating. It almost certainly reflects, in part, reserves reporting by oil companies under US SEC rules, but possibly also the non-inclusion of reserves of discovered fields until the latter were sanctioned by government for development.

Now we return to the issue of the UK government estimates for EUR. As stated above, in the Brown Books perfectly sensible EUR estimates were given, but more recently erroneous - and also differing - calculation methods have been introduced. This is indicated in Table A5.3.

Estimates of UK Oil Reserves and Ultimate Recovery at 31 December 2014 ⁽¹⁾⁽²⁾					
Oil Reserves units - million tonnes	[figures in brackets for end 2013]				
	Proven	Probable	Proven & Probable	Possible ⁽⁶⁾	Maximum ⁽³⁾
Fields in production or under development ⁽⁴⁾	374 [404]	255 [243]	630 [648]	312 [301]	942 [949]
Other significant discoveries where development plans are under discussion	0 [0]	86 [98]	86 [98]	32 [37]	118 [135]
Total Oil Reserves in million tonnes⁽⁴⁾	374 [404]	342 [342]	716 [746]	344 [338]	1,060 [1,084]
Cumulative Oil Production to end 2014⁽⁵⁾	3,623 [3,583]				
Estimated Ultimate Recovery in million tonnes	3,997 [3,987]	342 [342]	4,339 [4,329]	344 [338]	4,683 [4,667]

Table A5.3 UK Government Oil Data, end-2014.

Notes (from original table):

- (1) Includes onshore as well as offshore fields. All figures include condensate, gas liquids and liquefied products.
- (2) All entries are rounded to the nearest one million tonnes
- (3) Maximum is the sum of proven, probable and possible reserves.
- (4) The oil reserves include 104 (58) proven, 65 (59) probable and 42 (38) possible million tonnes in approved fields under development but not yet producing.
- (5) Cumulative oil production includes 145 (101) million tonnes from decommissioned oil fields.
- (6) Possibles include 82.2 million tonnes for EOR potential

Note that there are also "Potential Additional Resources" (PARs) in fields and drilled prospects for which there are no current plans for development. These are listed in a separate section on the website.

Source: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/441082/UK_Oil_Reserves_and_EUR_2015.pdf

The first thing to note from Table A5.3 is that its definition for EUR is that given in the accompanying document: "*Cumulative oil production to the end of 2014 has been added to (remaining) oil reserves to give the estimated ultimate recovery figures*", where the '(remaining) oil reserves' is the 3P value as shown in the table.

i.e. on this calculation:

EUR = Cum. prodn. + 3P reserves (including EOR judged likely to see production).

This has two problems:

- It contradicts the definition used in the 2016 UK Energy in Brief, which had:

EUR = Cum. prodn. + 2P (not 3P) reserves (and with no EOR allowance).

- And it definitely contradicts the accepted definition of:

EUR = Cum. prodn. + P50 (~2P) reserves, where this includes EOR judged likely to see production + 'PARs', again where likely to be produced + yet-to-find.

The fact that the current DECC / BEIS definition of EUR takes no account of yet-to-find is a significant oversight, plus the fact that it does not include that part of the potential additional resources (PARs) that judgement suggests is likely to be produced. This magnitude of this error - particularly large in the early years - is shown in Figure A5.3, which is from the same document as Table 5.3.

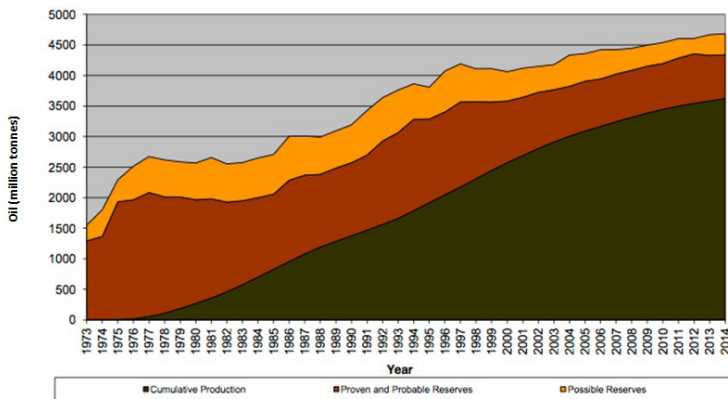


Figure A5.3 Evolution of the apparent UK Oil 'Estimated Ultimate Recovery' (EUR), where this reflects a new erroneous UK Government definition for EUR, 1973 – 2014.

Source: Laherrère; see source for Table A5.3.

The accompanying document to Figure A5.3 says: *"The chart shows how cumulative production and estimated ultimate recovery of oil have both grown over time"*; and where this chart shows EUR growing from 1 500 Mt in 1973 to ~4 700 Mt in 2014.

As explained earlier, these data are completely at variance with the correct and well-established UK EUR estimates, as published in UK Brown Books; which was 4 500 Mt in 1973, and averaged typically around this value since then. To not understand this stability of the UK EUR estimate, and hence its significance in terms of how much conventional oil the UK was likely to find and produce, and also why production of this oil peaked when it did, is a major flaw in government understanding.

Finally in this section we look at the UK's discovery history as given by commercial ('scout') backdated data to see why a correct estimate of the UK EUR was possible so early on. Figure A5.4 shows these discovery data vs. date.

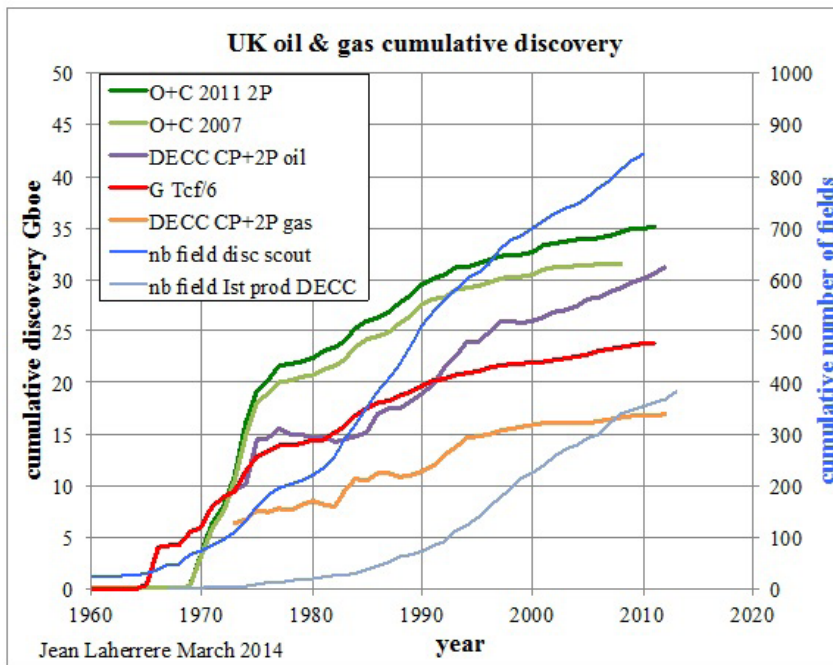


Figure A5.4 Comparison of Differences in Reporting the Cumulative Quantities of UK Oil and Gas Discovered, vs. Date.

Legend:

Left-hand scale:

- O+C 2011 2P: Industry 'scout' 2P data as of 2011 of the cumulative quantity of UK oil plus condensate discovered, vs. date shown.
- O+C 2007: Ditto, data as of 2007.
- DECC CP+2P oil: UK DECC oil plus condensate data for cumulative production plus 2P reserves.
- GTcf/6: 2P: Industry 'scout' 2P data as of 2011 of cumulative quantity of UK gas discovered, vs. date, converted to Gboe by dividing gas Tcf by 6.
- DECC CP+2P gas: UK DECC gas data for cumulative production plus 2P reserves.

Right-hand scale:

- nb field disc scout: Industry 'scout' data for cumulative number of oil plus gas fields discovered, vs. date.
- nb field 1st prod DECC: DECC data for cumulative number of oil plus gas fields vs. date of their initial production.

Source: Laherrère, from sources listed.

Figure A5.4 shows a number of interesting things, some of which go part way to explaining DECC's confusion over reporting UK oil discovery, and ultimate, as discussed earlier.

The two 'scout' discovery curves for oil plus condensate as of 2007 and 2011 indicate the rapid early discoveries of over half of the UK's total oil plus condensate volumes, and hence why - as in most countries - reasonable estimates of the region's URR were possible from a very early date. Secondly, the difference between these two curves may give an indication of the scope for 2P 'reserves growth' in the UK data, providing there were not other factors at play (such as different reporting criteria) that differentiate these two curves.

In the Figure the sharp difference is clear between the 'scout' oil plus condensate discovery trajectory and that apparently indicated by DECC data on cumulative production plus 2P reserves. In this context, the difference shown in the number of all oil plus gas fields reported as discovered by the 'scout' data, and that by the DECC 'fields into production' data, probably helps explain DECC's view of 'discovery'.

Finally, for gas, the Figure likewise shows the significant difference between the 'scout' discovery data, and the discovery apparent if only DECC cumulative production plus 2P reserves data are used.

As mentioned earlier, there are still explanations to be sought on how DTI/BERR/DECC and now BEIS have seen – and explained – the evolution of UK oil and gas data over time.

Figure A5.5 shows the UK’s discovery history more clearly, as given by commercial (‘scout’) backdated data in the form of a ‘creaming curve’ vs. number of fields.

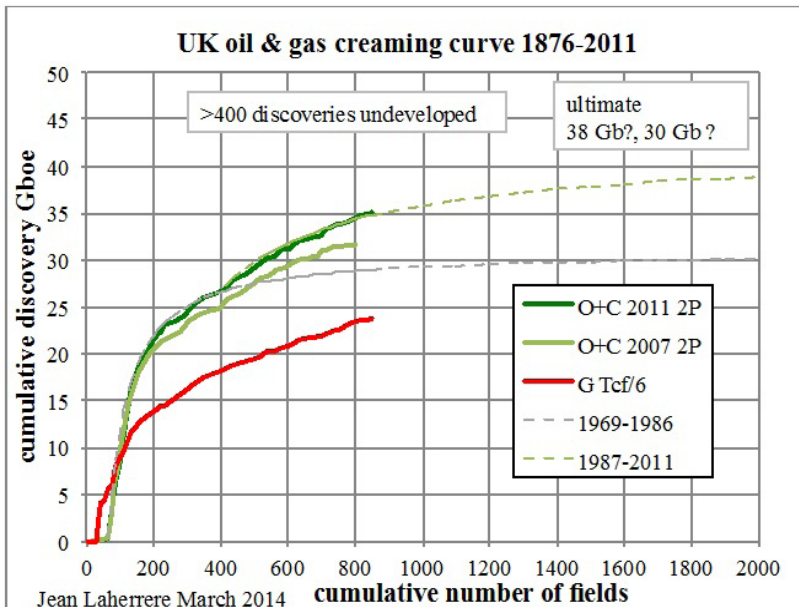


Figure A5.5 Creaming curve of UK oil plus condensate discovery.

Legend:

- O+C 2011 2P: Industry ‘scout’ 2P data as of 2011 of quantity of UK oil plus condensate discovered, vs. date shown
- O+C 2007: Ditto, data as of 2007
- G Tcf/6: 2P: Industry ‘scout’ 2P data of quantity of UK gas discovered, vs. date, converted to Gboe by dividing gas Tcf by 6.
- 1969-1986: Apparent trend of discovery, using data 1969 to 1986.
- 1987-2011: Apparent trend of discovery, using data 1987 to 2011.

Source: Laherrère.

Although Figure A5.5 shows discovery vs. number of fields discovered (as opposed to a creaming curve that shows discovery vs. exploration wells, ‘new-field wildcats’), it can be seen that this type of curve is generally better at indicating a region’s likely URR than discovery simply vs. date (as in Figure A5.4). Note that these scout data for the UK indicate some 400 fields in total as not yet developed, i.e., ‘fallow fields’, some of whose ultimate development may well be open to question, particularly in an offshore regime such as this where economic considerations can lead to relatively early dismantlement of rigs.

Note that in this section comparing 1P, 2P and 3P reserves data, here we have looked at the UK data in some detail. In part this is because the UK is generally seen as a ‘good’ provider of data, and also in part because - as shown above - there are still significant errors in how the government data are presented and explained, particularly in terms of the country’s discovery history and estimated ultimate, and hence how much oil was known about, and when.

We now turn from these UK data to look briefly at the reporting of oil reserves in some other countries, and start with Russia.

A5.4.2 Russian data

As indicated in Section 6.4.1 of Part-1 of this paper, on ‘long-term cumulative global 2P oil discovery data’, and in Figure 25 in particular, Laherrère, Campbell and a number of other analysts treat Russian ‘ABC1’ reserves data as nearer 3P than 2P, and typically multiply the ABC1 data by 0.7 to arrive at reasonable 2P (~P50) reserves. This view is supported by Table A5.4.

	As at 31 December				
	2011*	2012	2013	2014	2015
Natural gas, bcm					
Categories A+B+C ₁	35,046.9	35,169.8	35,696.6	36,101.4	36,147.3
Share of ABC ₁ reserves covered by the assessment under PRMS Standards	90%	94%	93%	94%	94%
Proved	19,212.6	19,133.0	18,939.3	18,894.7	18,791.2
Probable	3,631.5	4,254.1	4,325.2	4,616.0	4,913.8
Proved + probable	22,844.1	23,387.1	23,264.5	23,510.7	23,705.0
Gas condensate, mm tonnes					
Categories A+B+C ₁	1,395.5	1,386.1	1,384.4	1,447.0	1,499.5
Share of ABC ₁ reserves covered by the assessment under PRMS Standards	83%	89%	89%	92%	92%
Proved	605.2	633.8	638.8	642.3	699.5
Probable	152.6	174.9	193.6	206.3	233.8
Proved + probable	757.8	808.7	832.4	848.6	933.3
Crude oil, mm tonnes					
Categories A+B+C ₁	1,767.3	1,992.2	2,019.0	2,053.1	2,082.0
Share of ABC ₁ reserves covered by the assessment under PRMS Standards	89%	89%	89%	91%	92%
Proved	723.9	819.5	834.8	830.5	792.7
Probable	492.2	588.8	572.4	543.9	562.7
Proved + probable	1,216.1	1,408.3	1,407.2	1,374.4	1,355.4

* Excluding share of Gazprom Group in reserves of companies, investments in which are classified as joint operations.

Table A5.4 Hydrocarbon Reserves of the Gazprom Group in Russia.

Note: Except for the 2011 data, the data include Gazprom Group share in reserves of companies, investments in which are classified as joint operations.

Source: J. Wang, from Fact book "Gazprom in Figures 2011–2015."

As Table A5.4 shows, proved-plus-probable (2P) reserves are indicated by Gazprom as significantly less than ABC₁ reserves. In addition, we can look at the data for Russia's largest field, Samotlor. Production data are given in Figure A5.6; where after the fall of the Soviet Union Samotlor was jointly owned by TNK-Nizhnevartovsk and Samotlorneftgaz. Ownership then passed to TNK-BP in 2003, which in turn was bought out by Rosneft in 2013. As Figure A5.6 indicates, recent data on the field's production are somewhat mixed: IHS Energy 2011 data did not match that of 2010, but the former do match TNK-BP production data. Currently Rosneft do not seem to report all of production.

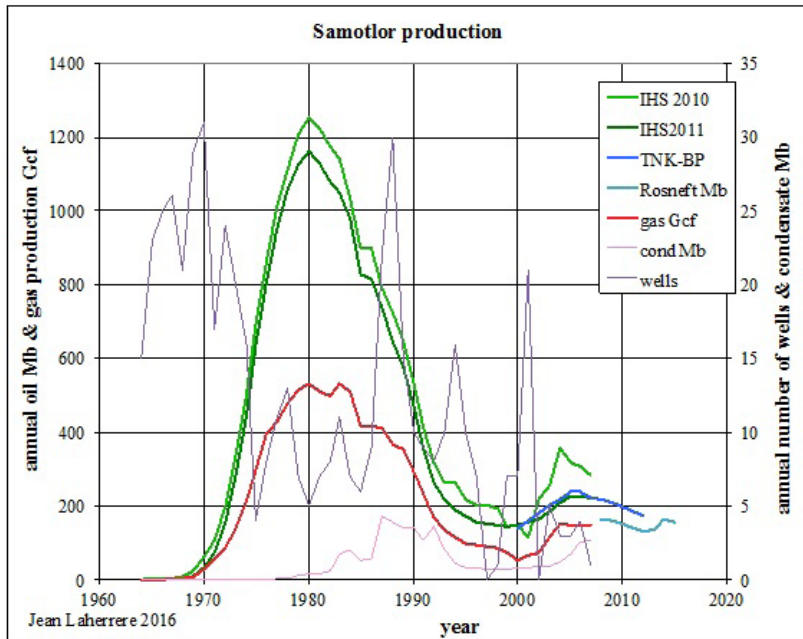


Figure A5.6 Reporting of Samotlor production, different sources.

Legend: Oil production data from IHS Energy (2010 & 2011 data), TNK-BP and Rosneft; also production of gas and condensate; and annual number of wells.

Source: Laherrère.

A view of the reserves data for Samotlor is provided by Figure A5.7.

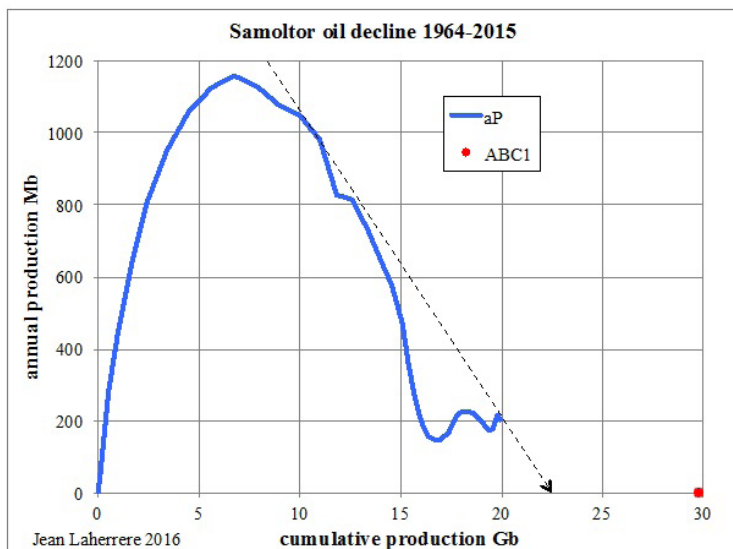


Figure A5.7 Estimations of Samotlor’s URR: A Plot of Annual Production vs. Cumulative Production.

Legend:

- aP: IHS Energy 2011 data of Samotlor annual production.
- ABC1. The estimate of Samotlor’s URR held in the IHS Energy database, corresponding to the ‘ABC1’ Russian estimate.

Source: J. Laherrère, 2016.

A plot like Figure A5.7 of a field’s annual production vs. its cumulative production linearises the field’s decline if it is exponential, and allows an estimate to be made of the field’s URR by extrapolation of the (approximately) straight line of decline.

As Figure A5.7 shows, for Samotlor this would seem to indicate a URR of below 25 Gb, in line with a TNK-BP estimate of ~24.5 Gb (which included considerable future work to maintain field production). In turn this TNK-BP value is considerably below the 30 Gb ‘ABC1’ value held (at least up to 2011) in the IHS Energy database. The latter data are treated by some analysts as proved-

plus-probable (2P), but are probably closer to proved-plus-probable-plus-possible (3P) values. It is based on these data, and on similar analysis for other fields, that Laherrère, Campbell and some others treat the Russian and other FSU reserves data as approximately 3P. For additional discussion of this, see Laherrère (2015).

A5.4.3 Kuwait data

As mentioned in Section A5.1.4, in 2006 *Petroleum Intelligence Weekly* reported that a Kuwaiti 2001 document had estimated Kuwait's oil reserves as only 48 Gb, of which half were proven and half 'nonproven', and that these reserves were "half of the official public estimate of proven reserves" at that date, of 96.5 Gb.

Similarly, on Kuwait's oil reserves Campbell (personal communication) commented:

"Recently the Kuwait Minister claimed 24 Gb proved and 54 Gb proved & probable; my current estimate gives Kuwait's 2P reserves as 56 Gb." He continues: "I think, as stated in the Atlas [Campbell (2013)] Introduction, Kuwait changed from reporting Remaining reserves to Original Reserves, namely by not subtracting past production. This in fact is normal industry practice by the oil industry in determining the ownership of a field that crosses a lease boundary or frontier, and made sense as a basis for determining OPEC quotas. Kuwait may have become aware of the practice following the dispute with Iraq over the relative ownership of the South Rumaila field, which was one of the tensions leading to the First Gulf War."

Rystad Energy, in Table 1 in Part-1 of this paper, supports both the 2006 *Petroleum Intelligence Weekly* report and Campbell's estimate, putting Kuwait's 1P reserves at 23 Gb, and its 2P reserves (including fields already discovered, but not yet in production) at 48 Gb; a little lower than the Campbell estimate.

This problem with the Kuwaiti (and other OPEC 'quota wars') proved reserves data is dramatically illustrated in Figure A5.8.

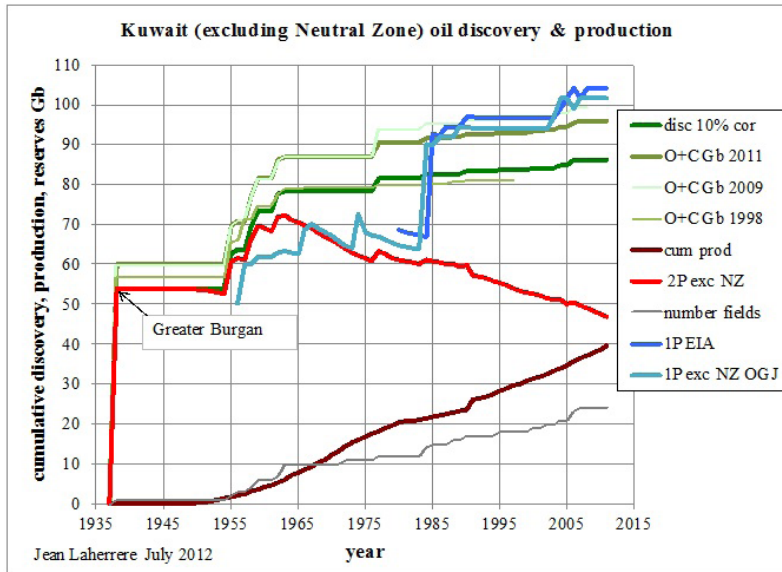


Figure A5.8 Evolution over time of Kuwait (less Neutral Zone) data on: Cumulative 2P Oil Discovery; 2P Oil Reserves; 1P Oil Reserves from different sources; Cumulative production; and Cumulative number of Fields Discovered.

Legend:

- disc 10% cor: Cumulative 2P (proved-plus-probable) oil discovery data from a 'scout' database, reduced by 10% to roughly match the possibly more correct corresponding 1998 cumulative discovery data.
- O+C Gb year: Cumulative 2P discovery of oil plus condensate; from the version of the 'scout' database of the year indicated.
- cum prod: Cumulative production of oil plus condensate.
- 2P exc NZ: 2P reserves data from the industry 'scout' database; excluding the Neutral Zone (co-owned with Saudi Arabia).
- number fields: Cumulative number of oil fields discovered, as reported in the 'scout' database.
- 1P EIA: 1P (proved) oil reserves data, from the EIA.
- 1P exc NZ OGJ: 1P oil reserves data, for Kuwait excluding the Neutral Zone, from the *Oil & Gas Journal*.

Source: Laherrère, from sources listed.

As Figure A5.8 shows, the backdated 'scout' 2P data do indeed show Kuwait oil reserves as ~50 Gb in 2001, in line with the *Petroleum Intelligence Weekly* article and Campbell's and Rystad Energy's

estimates, and very different from the accepted 1P value (across all the main ‘public-domain’ sources of *O&GJ*, *WO*, OPEC, *BP Stats. Review*, and the US EIA) of currently ~100 Gb. It is in the face of data like these that analysts like us sometimes despair: How can such poor 1P data be so widely reported with so little comment, and be so widely trusted?

Figure A5.9 supports Figure A5.8 by showing the fairly recent evolution of these industry ‘scout’ data for cumulative oil 2P discovery for Kuwait excluding the Neutral Zone, but expressed here as a ‘creaming curve’ vs. the number of fields discovered.

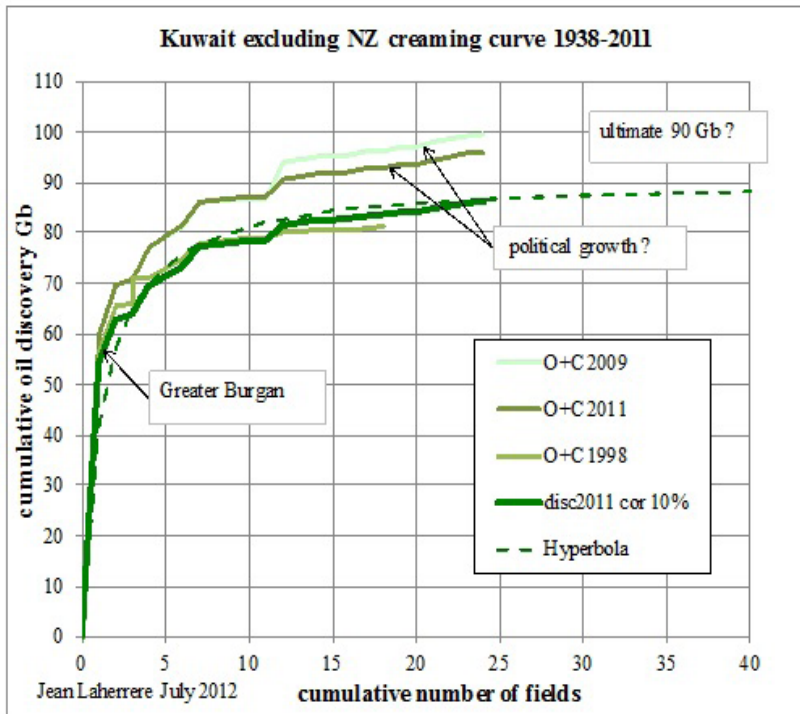


Figure A5.9 Evolution of Kuwait Cumulative Oil Discovery vs. Number of Fields discovered.

Legend:

- NZ: neutral zone.
- O+C date: Cumulative 2P discovery of oil plus condensate; from scout database at date indicated.

- disc.2011 cor 10%: Cumulative discovery reduced by 10% to roughly match the possibly more correct 1998 cumulative discovery data of the early fields.
 - Hyperbola: A modelling hyperbola is assumed that gives the ultimate for a limited number of future fields; here about 50 fields in total.
(Note: such 'creaming curves' are often modelled with several hyperbolae to match distinct exploration phases, such as onshore and offshore, but here only one hyperbola is used.)
- Source:** J. Laherrère; from an oil industry 'scout' database.
-

As can be seen in Figure A5.9, in the just over a decade from 1998 to 2009, early discoveries of oil in Kuwait were re-evaluated as holding about 10 Gb more of additional original recoverable reserves. The question then being: was this increase due to real gains in estimated original recoverable volumes, perhaps from subsequent better knowledge or recovery techniques, or an adjustment to make cumulative 2P discovery closer to the public-domain data on 1P reserves? Either way, these data, like those in Figure A5.8, also illustrate why Kuwait 1P reserves of ~100 Gb look unrealistic.

A5.4.4 Saudi Arabian data

Now we turn to the data for Saudi Arabia. Figure 26 in Part-1 gave a plot of the evolution of Saudi Arabian oil reserves data. Here Figure A5.10 shows essentially the same data, but in cumulative discovery form; i.e., without subtracting off cumulative production (which is also shown).

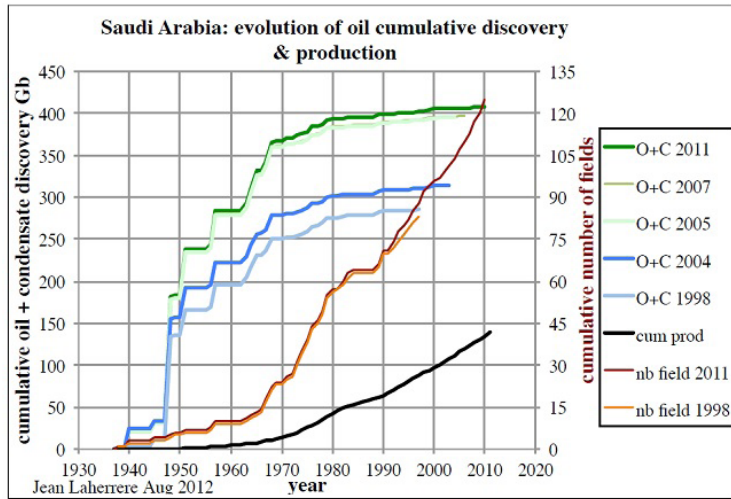


Figure A5.10 Evolution of Saudi Arabian Cumulative Oil Discovery, as reported in successive editions of the IHS Energy database; also Cumulative Production, and Number of Fields Discovered.

Legend:

Left-hand scale:

- O+C year: Backdated notionally '2P' Saudi Arabia cumulative discovery data for oil plus condensate, from the IHS Energy dataset of the year specified.
- cum prod: Saudi Arabian cumulative production of oil plus condensate.

Right-hand scale:

- nb field year: Number of fields discovered, plus year when data reported.

Source: J. Laherrère, Aug. 2012.

As mentioned in Part-1 of this paper, the large discrepancy between the IHS 2004 and IHS 2011 data may be because the latter reflects an adjustment to match the announced Saudi Arabian reserves data. Importantly, as the plot's data on the number of fields discovered shows, this discrepancy does not reflect any significant increase between these two dates in the number of fields in the database.

We now look in a little more detail at what the Saudi Arabia data can tell us about the country's likely URR.

Earlier, Figure A5.7 gave a plot of a field's annual production vs. its cumulative production. As explained this linearises a field's decline if exponential. A separate linearisation, devised by Hubbert, can be applied to production in a *region*. Here the region's [annual production divided by cumulative production] is plotted vs. [cumulative production]. This produces a linear result if production in the region is following a 'Hubbert' curve (the derivative of a logistic curve), and allows the region's URR to be estimated. Such a 'Hubbert linearisation' of Saudi Arabian production is shown in Figure A5.11.

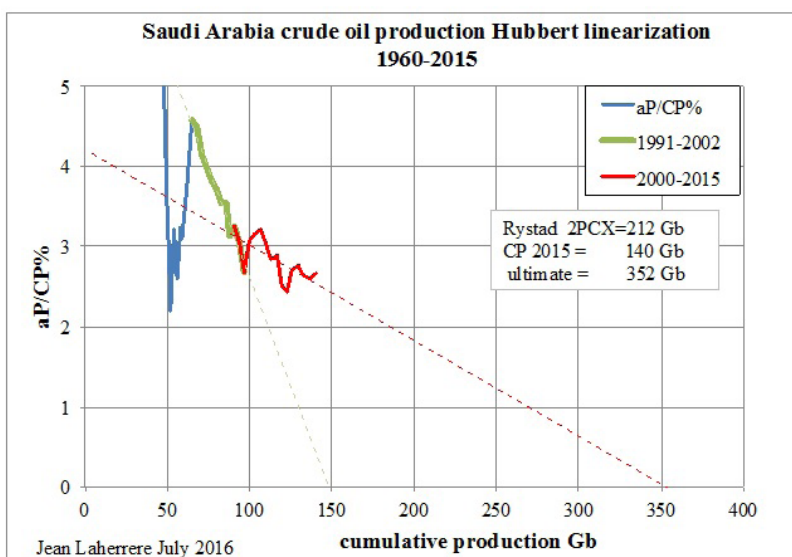


Figure A5.11 Hubbert linearisation of Oil Production in Saudi Arabia, using Annual Production data from 1960 to 2015.

Legend:

- aP/CP%: Saudi Arabian annual oil production divided by cumulative production; data from 1960 to 1990, expressed in %.
- 1991 – 2002: Ditto, for data 1991 to 2002.
- 2000 – 2015: Ditto, for data 2000 to 2015.

Source: Laherrère.

As Figure A5.11 shows, a variety of plausible straight lines could be drawn through such data, but a reasonable guess suggests - if

Saudi Arabian production is following a Hubbert curve fairly well - a URR for the country of around 350 Gb.

And as Section 6.4.1 in Part-1 of this paper showed, this estimate agrees well with that of Rystad Energy (which, adding cumulative production to-date of 140 Gb to their '2PCX' reserves estimate of 212 Gb, gives the URR as 352 Gb).

Hubbert linearisation can be done also on monthly production data, and this is shown in Figure A5.12.

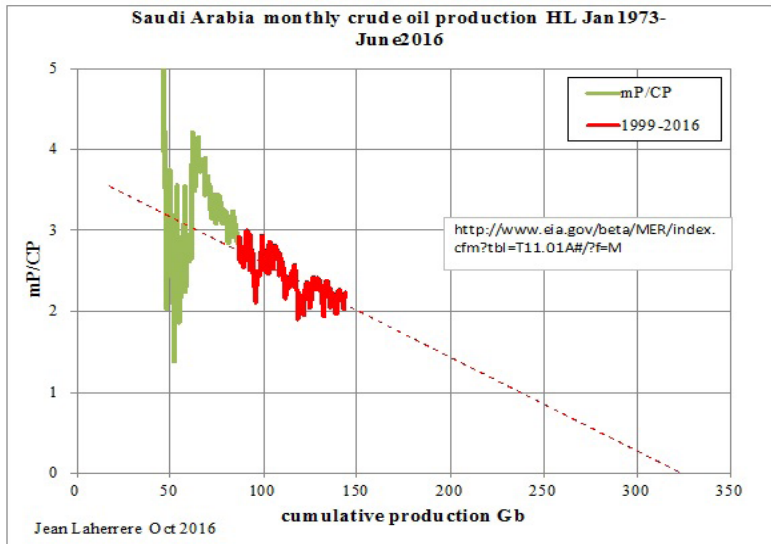


Figure A5.12 Hubbert linearisation of Oil Production in Saudi Arabia, using Monthly Production data from Jan. 1973 to June 2016

Legend:

- mP/CP: Saudi Arabian monthly oil production divided by cumulative production; data from 1973 to 1998.
- 1999 – 2016: Ditto, for data 1999 to 2016.

Source: Laherrère.

As Figure A5.12 shows, the linearisation of monthly data allows extrapolation to the abscissa (and hence estimation of the URR) with perhaps more confidence; here indicating a somewhat lower

URR of ~320 Gb.

Figure A5.13 reprises Figure A5.10, but with more recent data; and includes the URR estimate from Hubbert linearisation of annual data of ~350 Gb.

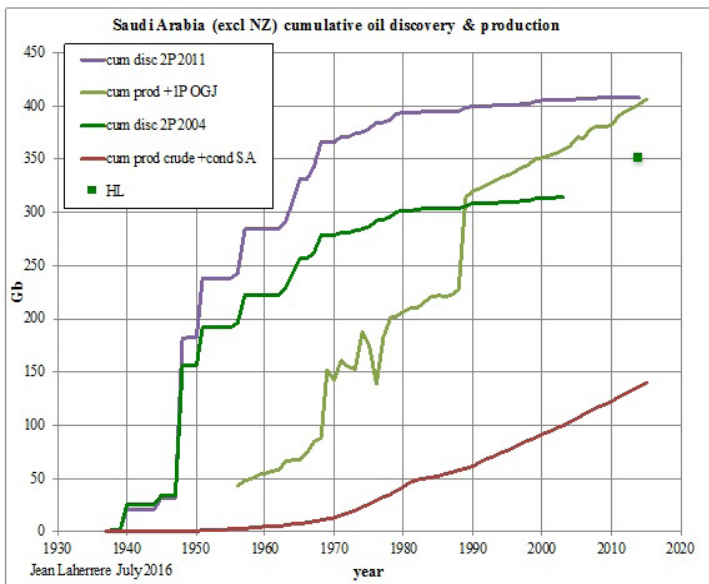


Figure A5.13 Evolution of Saudi Arabian Cumulative Oil plus Condensate Discovery, as reported in two successive editions of the IHS Energy database; also Cumulative Production of Oil plus Condensate, and an estimate of the country's URR.

Legend:

- cum disc 2P 2011; and cum disc 2P 2004: Backdated 2P oil
- plus-condensate discovery data for Saudi Arabia, as reported in the IHS Energy 2011 and 2004 datasets, respectively.
- cum prod+1P OGI: A reconstruction of Saudi Arabia's '1P oil discovery' data, created by adding at any given date the cumulative production at that date to the public-domain proved ('1P') oil reserves also at that date; where here these reserves data are from the *Oil & Gas Journal*.
- cum prod crude+cond SA: Saudi Arabian cumulative production of oil plus condensate.

- HL: URR obtained by a 'Hubbert linearisation' of Saudi Arabian annual production; where this estimate matches that from Rystad Energy.

Source: Laherrère.

Figure A5.13 tells us several things:

- Today the IHS Energy 2011 discovery data for Saudi Arabia matches that reconstructed by adding 1P reserves to cumulative production; and are approximately 90 Gb greater than indicated in the IHS Energy 2004 data.
- The Hubbert linearisation (and also Rystad Energy) estimate of the country's URR is more in line with the IHS Energy 2004 data than the 2011 data.
- As indicated Figure 26 in Part-1 of this paper, and analogous to the data disagreement shown in Figure A5.8 above for Kuwait, the widely available public-domain reserves data for Saudi Arabia, from for example the *Oil and Gas Journal*, *World Oil*, OPEC and Saudi Aramco themselves, are significantly in excess of what seem to be the likely 2P data; where for example Rystad Energy, in Table 1 in Part-1 of this paper, puts Saudi Arabia's 2P reserves (including in fields already discovered, but not yet in production) at 168 Gb.
- And finally, as also indicated in Part-1 of this paper, if a URR for Saudi Arabia of 350 Gb is assumed, this leads to the country reaching its mid-point peak of production a little before 2025. This date is significantly earlier than that from the IEA, who in their 2015 *WEO* 'New Policies' scenario, forecasts that Saudi Arabian oil-plus-all-NGLs production will not reach its production peak, at 13.4 Mb/d, until 2040. (Note however, it is recognised that for a country like Saudi Arabia, a simple 'mid-point' peak may be somewhat delayed by the long flat nature of the country's field production profiles - which delays peak, though speeds subsequent decline, in a simple regional 'field summation' model; and by the likely increased application of EOR.)

Figure A5.14 puts the above discussion into context, by looking at different forecasts for Saudi Arabian oil production.

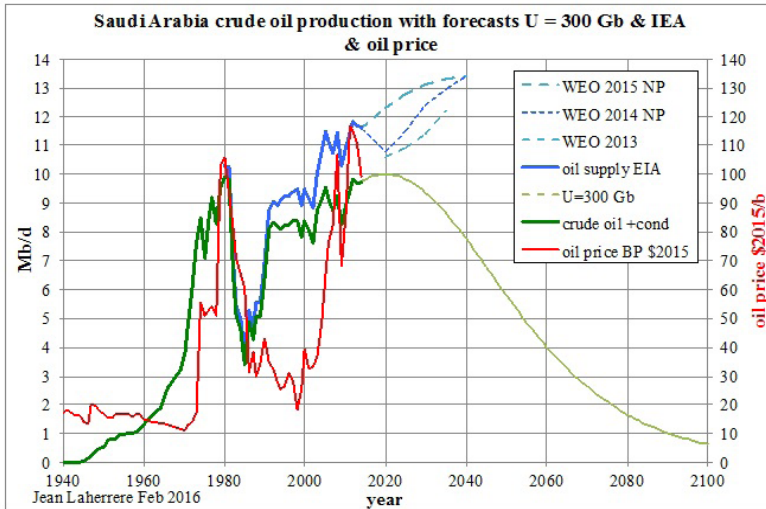


Figure A5.14 History and Forecasts of Saudi Arabian Oil Production

Legend:

Left-hand scale:

- WEO 2015 NP (also 2014; 2013): Forecast of Saudi Arabian production of oil-plus-all-NGLs (i.e., condensate plus NGPLs) to 2040, as set out in the IEA World Energy Outlook, 2015 edition under the 'New Policies' scenario; also ditto for the 2014 edition; and to 2035 in the WEO 2013 edition.
- oil supply EIA: Historical data on Saudi Arabian production of crude-plus-condensate, plus NGPLs, EIA data.
- U=300 Gb: An approximate 'Hubbert-curve' fit to Saudi Arabian crude-oil-plus-condensate production (i.e., excluding NGPLs), and forecast forward to meet a URR of 300 Gb. (Note that this line is shown dotted in the key, but solid on the chart. Note also that Laherrère specifies the accuracy of this URR estimate to only one significant figure, to reflect the underlying uncertainty of this estimate.)
- crude oil +cond: Historical EIA data on Saudi Arabian production of crude-plus-condensate (i.e., excluding NGPLs).

Right-hand scale:

- oil price BP \$2015: Real-terms oil price, in 2015 \$; from BP *Stats. Rev.*

Source: Laherrère.

Figure A5.14 is a fascinating graph. In terms of the historical narrative, it shows:

- The fairly modest rise in Saudi Arabian production though the 1950s and early '60s; at the time when some of the newer mega-fields in the Middle East (including in Saudi Arabia) were coming on-stream, but when also the oil majors were trying to restrict production in these fields - usually against the wishes of the owners of the oil - to prevent the oil price falling too disastrously; see Yergin (1991), and Bentley & Bentley (2015b).

- The short period of a very rapid rise in production in the late 1960s, early '70s to help meet global demand as the US first approached, and then passed, its production peak in 1970.

- The 1973 and 1978 price shocks, set against a steady rise in Saudi Arabian production; but with dips, almost certainly reflecting OPEC agreements, and other disruptions.

- The deep decline in production following the 1978 price shock, as all of OPEC took production cuts to try and maintain the oil price, but with Saudi Arabia taking the brunt of these.

- The resurgence of production after about 1984, once Saudi Arabia decided that the quotas game was too one-sided.

- The 2 Mb/d step-change increase in production after 2002, which may well have been a contributory factor - along with demand destruction due to the generally high price of oil, and to the 2008 recession; plus possible production increases elsewhere in the world; and perhaps speculation pressures - to the post-2008 sharp fall in the oil price.

Other factors to notice from Figure A5.14 include:

- The large amount (about 2Mb/d) of Saudi Arabia's total oil production that comes from NGPLs, in turn reflecting the country's high levels of gas production and installation of gas-processing plant.

- The significant difference in IEA *WEO* forecasts of Saudi Arabian production between 2013 and 2015.

- And the difference in forecasts of production between that of Laherrère (of oil less NGPLs), based on an assumed URR of 300 Gb, and that of the IEA (of oil plus NGPLs). It is true that production of NGPLs can be expected to rise as long as Saudi Arabian gas production increases; but the difference between the forecasts is significant, with the gap between them growing from 2 Mb/d today to 5.5 Mb/d by 2040. And more significantly, one forecast shows production as still increasing - if slowly - in

2040; the other shows production in decline from as soon as 2020 or so. It is thus important to strive for a better agreement between forecasts such as these, given the significance for the world.

A5.4.5 US data

Now we turn to looking at US oil discovery data. We look in particular at the reserves data, both 1P and 2P, as it these that have underlain many of the arguments in the peak oil debate - both for and against the case for 'peak oil'. Understanding the difference in these data is critical if the debate is to be clarified. To this end, four plots of US oil 2P discovery (or of 'apparent discovery', where the 1P data are used), 1P and 2P reserves, and production are given in Figures A5.15 to A5.18.

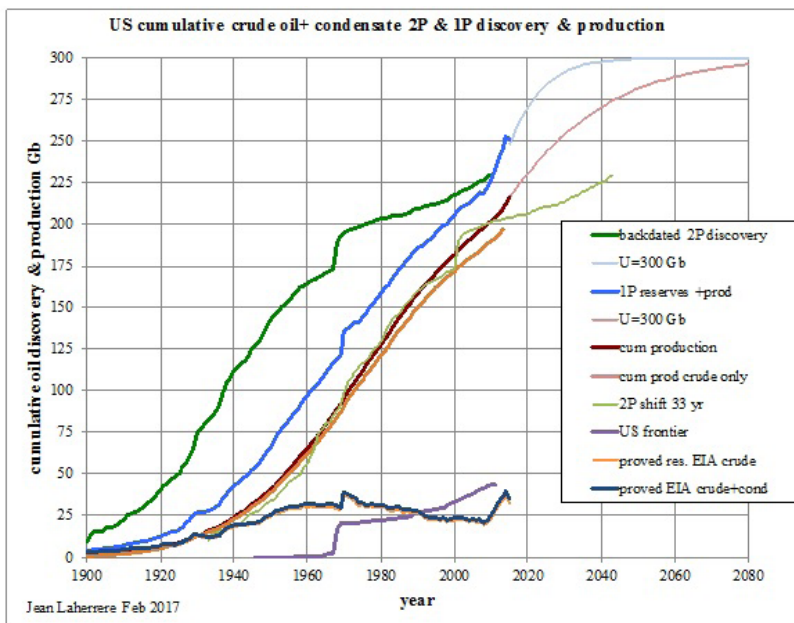


Figure A5.15 All-US Oil Discovery and Production, 1900 to 2015.

Legend:

- backdated 2P discovery: Cumulative backdated proved-plus-probable ('2P') US oil discovery data, 1900 to 2010. Data are from US DoE (1990) and Attanasi and Root (1994). The discovery of Prudhoe Bay, the US' largest conventional oilfield, in 1968 is clearly visible. Data exclude NGLs. (By the year 2000, cumulative production of NGLs added, very approx., ~35 Gb.)
 - U=300 Gb (thin blue line): An approximate 'Hubbert-curve' fit to the backdated 2P discovery data, extrapolated forward to meet a URR of 300 Gb.
 - 1P reserves +prod: The apparent US oil cumulative '1P discovery trend', 1900 to 2014, calculated as cumulative production plus proved ('1P') reserves.
 - U=300 Gb (thin mauve line): An approximate 'Hubbert-curve' fit to the cumulative production data, extrapolated forward to meet a URR of 300 Gb.
 - cum production: Historical data on US cumulative oil production; including condensate and NGPLs but excluding refinery gain and production of biofuels
 - cum prod crude only: Historical data on US cumulative crude-oil-plus-condensate production; i.e., excluding NGPLs, as well as refinery gain and biofuels.
 - 2P shift 33 yr: The backdated 2P discovery curve shifted by 33 years; i.e. so as to roughly match – and hence explain – the historical production data; and also – importantly – to indicate the scope for future production.
 - US frontier: Backdated cumulative 2P discovery data for the US 'frontier regions; primarily Alaska and deepwater offshore Gulf of Mexico.
 - proved res. EIA crude: EIA historical annual data on US oil proved ('1P') oil reserves, excluding condensate.
 - proved EIA crude+cond: EIA historical annual data on US oil proved ('1P') oil reserves; here including condensate.

Source: Laherrère.

Figure A5.15 shows the significant difference between the backdated 2P oil discovery curve, and the 'apparent 1P discovery' curve, where the latter is calculated by adding the 1P reserves at any given date to cumulative production at the same date.

As the plot shows, for the century 1900 - 2000, and excluding the frontier regions, the backdated 2P discovery rate per year started to diminish from about 1940, and has tailed off significantly since then. By contrast, the apparent '1P discovery' curve over this same period indicates perhaps a maximum in annual discovery at only about 1970, and where this '1P discovery' has continued

fairly consistently since then. (In the data since 2000 for these two curves, discoveries attributable to deepwater offshore in the Gulf of Mexico, and more recently to 'light-tight' oil, are visible.)

The Figure also shows that knowledge of the scope for future production in a region can be gained by shifting the backdated 2P discovery data (here by 33 years for the US) so that it roughly overlies the production data. This technique has been used by a number of analysts, including Ivanhoe (1996) and Laherrère (as here). (Incidentally, Hubbert used a similar technique, but where he shifted the '1P discovery' curve. While not nearly as informative as shifting the 2P data, this also gives some indication of the scope for future production.)

However in terms of understanding the 'peak oil' debate, one of the key things to observe from Figure A5.15 is that the apparent '1P discovery' curve (from adding the 1P reserves to cumulative production) has over time stayed just ahead of production for the whole period shown on the graph. In fact, the underlying proved reserves data show that for the US the standard R/P ratio (i.e., of 1P reserves/production) has remained roughly constant, at about 10 years' of supply of oil, for well over a century.

The important question is: What have analysts made of this extraordinary fact? The answers are illuminating:

- Many analysts failed to examine this problem of the continual replacement of proved reserves in any depth, and simply took - and still take - proved reserves to reflect the comforting but wholly incorrect definition given in the *BP Statistical Review*: "*Proved reserves: Generally taken to be those quantities that geological and engineering information indicates with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating conditions.*" Given this definition, the view has been that proved reserves replacement is the result of technological gain plus new discoveries. A recent example of this mistake was the statement by BP's Chief Economist, Spencer Dale, quoted in Part-1 of this paper; with very similar statements being made by his predecessors, Christof Rühl and Peter Davies (Bentley, 2016, p86). The major error of these analysts was not to realise that the quantities of oil that

- match the definition given above are the *proved-plus-probable* (2P) reserves, and not the *proved* ('1P') reserves.
- Some analysts did think about this 'reserves replacement' problem in more detail. In particular, some economists who looked at this judged - essentially correctly - the proved oil reserves to be "just inventory", to be replaced when called upon. But then, because this extra oil seemed to them to come from unmeasured sources, they drew the conclusion that the total amount of oil from which the reserves could come was essentially "unknown, probably unknowable" (Adelman, 1990). This conclusion, in turn, not surprisingly was incomprehensible to those exploration geologists who, decade after decade, had been mapping with some precision the ever-falling quantity of global oil-in-place being discovered in conventional oil fields. These geologists presented some of the extensive oil industry data on which this conclusion was drawn, but in part because the economists could not access these data themselves, the latter were not convinced: Adelman (1997), for example, saying: "*World-wide discovery rates are said [by the geologists] to have dwindled for 35 years. Yet production and proved reserves ... are at record levels. We hear only famine, and we see only plenty*".
 - Some other analysts - those with a science outlook and closer to the data - also thought about this problem of continual replacement of reserves. The USGS in particular has looked at this a number of times, e.g., Klett *et al.* (2005). But with individual US field data usually commercial, it was - and still is - very difficult to get the detailed field-by-field documentation needed to fully explain what was going on. And when the USGS used successive versions of the IHS Energy database to look at historical increases in the 2P discovery data for countries at any given date (a sensible approach in principle), this was confounded by other changes that had occurred within the database; in particular the addition of not previously reported fields, and perhaps more recently the 'OPEC uprating' issue mentioned above in connection with the Saudi Arabian data.
 - Even Hubbert originally got the meaning of the US proved reserves wrong; like others, initially believing they were

a reasonable indicator of the quantity of oil discovered (see Bentley 2015 & 2016, Part-3). But not long after he corrected this view, and first used estimates of ‘total oil likely to be discovered’ provided by others for his analysis, and then later developed his own ‘growth function’ to be applied to the US 1P data, to arrive at a reasonable estimate of the ‘true’ reserves.

- Today of course, those analysts who study the apparent ‘proved reserves replacement’ problem know that the fundamental driver has been simply that of the finite, generally well-estimated, 2P oil reserves seeing development over time and getting closer to production, and hence being reported within the more conservative 1P reserves category. This has applied not just to the US data (probably the most extreme example of ‘proved reserves replacement’), but has been true for virtually all countries.
- Today also, with the discovery of conventional oil having now fallen for 50 years, in many countries their 1P and 2P reserves estimates are now fairly close. But there remain the other serious problems with the 1P data as indicated earlier; primarily those of non-reporting of changes in the 1P data year after year, OPEC over-statement, and recently, the inclusion of very large quantities of non-conventional oil which are definitely not ‘proved’ under standard SEC definitions, these being mainly in Canada and Venezuela. Unfortunately, as a result, it is likely that examination of the proved reserves oil data will retain their ability to mislead less experienced analysts for many years to come.

The above is a salutary tale, and helps illuminate much of the past confusion that has bedevilled the ‘peak oil’ debate.

We turn now to data that apply only to the US Lower-48 states; see Figure A5.16. This Figure is similar to Figure A5.15, except that because it excludes Alaska, the clear ‘step’ in discovery that corresponds to Prudhoe Bay is absent. These Lower-48 data are historically significant in that it was explicitly only for the Lower-48 that Hubbert mainly took, and later made his own, estimates of the URR of conventional oil, and hence was able to forecast correctly the date of the US conventional oil peak in production.

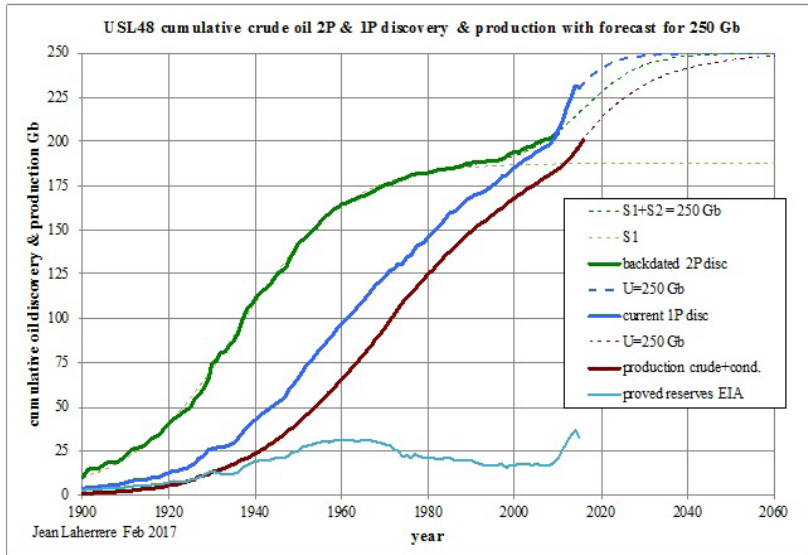


Figure A5.16 US Lower-48 States Oil Discovery and Production, 1900 to 2015.

Legend:

- $S1+S2 = 250$ Gb: Extrapolation of the backdated 2P discovery trend data, reflecting two cycles of discovery, S1 and S2, to an asymptote corresponding to a URR of 250 Gb.
- S1: Extrapolation of the backdated 2P discovery trend data, 1900 to about 1990, taken as reflecting one main cycle of discovery, S1, to an asymptote corresponding to a URR of ~190 Gb. This URR matches reasonably well the upper end of the range of URR values Hubbert estimated for US Lower-48 conventional oil (excluding NGLs).
- backdated 2P disc: Cumulative backdated proved-plus-probable ('2P') US Lower-48 oil discovery data, 1900 to 2010. Data are from US DOE (1990) and Attanasi and Root (1994). The period of major Lower-48 discoveries, from 1930 to about 1950, is visible. Data exclude NGLs; by the year 2000, cumulative production of NGLs added, very approx., ~35 Gb.
- $U=250$ Gb (thin blue line): Extrapolation of the apparent '1P discovery' data trend (i.e., of cumulative production plus proved reserves), to an asymptote corresponding to a URR of 250 Gb.
- current 1P disc: Historical data of apparent '1P discovery' (i.e., cumulative production plus proved reserves).
- $U=250$ Gb (thin brown line): Extrapolation of the crude-oil-plus-condensate production data to an asymptote corresponding to a URR of 250 Gb.

- production crude+cond.: Historical data of US Lower-48 production of crude-plus-condensate.

- Proved reserves EIA: EIA historical annual data on US oil proved ('1P') oil reserves, including condensate.

Source: Laherrère.

Figure A5.16 should be read in a similar manner to Figure A5.15, and indicates similar conclusions. Of significance is that even today, some sixty years after Hubbert's 1956 prediction, the estimated URR of the US Lower 48 conventional oil (excluding deepwater GoM, and 'light-tight' oil) stands at ~190 Gb; close to his range of estimates, and below the upper bound of 200 Gb (from an outside source) that he used in his 1956 forecast.

Figure A5.17 looks at the difference in R/P ratios for the US Lower-48 between the 'standard' R/P ratio (that based on 1P reserves), and the more realistic R/P ratio based on backdated 2P reserves. As can be seen, and has been pointed out above, the US standard '1P' R/P ratio has stayed at roughly 10 years' worth of production for now about a century. (Incidentally, as pointed out in the text to Figure 40 in Part-1 of this paper, R/P ratios however based should have no part in oil forecasting for the reasons given there.)

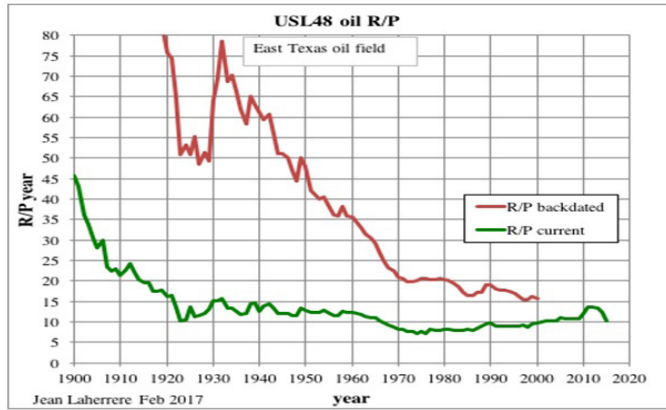


Figure A5.17 Comparison of US Lower-48 R/P ratios: That derived from backdated 2P reserves data vs. the ‘standard’ ratio derived from 1P reserves data.

Source: J. Laherrère; from sources listed in Figure A5.16.

Finally in this Section, Figure A5.18 ties together the above information for the US Lower-48 to produce a forecast to 2040 of total crude oil production, including deepwater Gulf of Mexico and ‘light-tight’ oil.

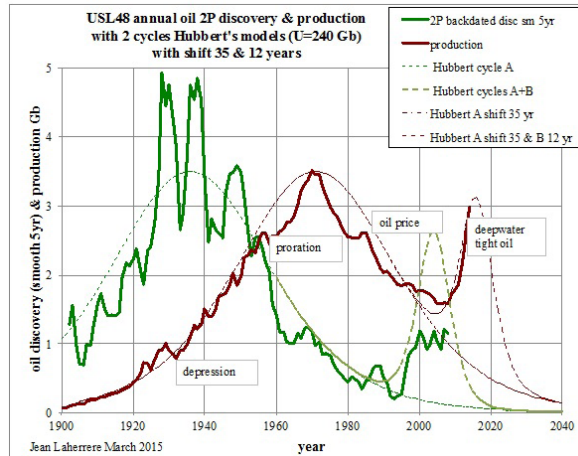


Figure A5.18 Historical data, and Forecasts, of US Lower-48 Annual Backdated 2P Oil Discovery and Annual Oil Production; including deepwater Gulf of Mexico oil, and Light-Tight oil produced by ‘fracking’.

Legend:

- 2P backdated disc sm 5yr: Backdated proved-plus-probable ('2P') US Lower-48 annual oil discovery data; 5-year smoothed. Data are from the sources listed in Figure A5.14
- production: US Lower-48 states annual oil production, including deepwater Gulf of Mexico oil, and light-tight oil.
- Hubbert cycle A: Hubbert curve that roughly matches the Lower-48 annual backdated 2P oil discovery data up to about 1995, i.e. 'discovery cycle A' covering the discovery of oil excluding deepwater and light-tight oil.
- Hubbert cycles A+B: Plot of the addition of two Hubbert curves that include the 'A cycle' described above plus a 'B cycle' of oil discovery since about 1995, comprising predominately discoveries of deepwater and light-tight oil.
- Hubbert A shift 35 yr: The Hubbert 'A cycle' discovery curve shifted by 35 years, to fit the production curve. This gives an indication of scope for future production of oil less deepwater and light-tight oil, based on the 2P discovery data of this class of oil.
- Hubbert A shift 35 & B 12 yr: Plot of the addition of two Hubbert curves: the Hubbert 'A cycle' discovery curve shifted by 35 years, and the Hubbert 'B cycle' discovery curve shifted by 12 years, to fit production curve of oil including deepwater and light-tight. This gives an indication of scope for future production of this class of oil for the US Lower-48 states out to 2040, based on the corresponding 2P discovery data.

Source: Laherrère.

As can be seen from Figure A5.18, if the assumptions on which the figure is based are valid, and these combined with the all-US 2P discovery data of Figure A5.15, then total US production of all-oil (including deepwater and light-tight oil) is likely to fall away steeply from about now. As mentioned elsewhere, this forecast does not include the contributions from NGPLs, biofuels or kerogen oil, nor of oil produced chemically, such as from gas or coal. But Laherrère suggests that these contributions, though very likely to increase (or in some cases, start) as the oil price rises, they are unlikely to much alter the US 'decline soon' prediction shown in this Figure.

A5.4.6 Global data

Finally in this section, we turn to the oil discovery data at the global level.

This was discussed in Part-1 of this paper, which covered the stark difference between the evolution of the backdated 2P global data on oil discovery, versus that indicated by the evolution of the global 1P data; and hence also the very misleading conclusions that many analysts have drawn from the latter; see in particular Figure 39 of Part-1 of this paper and the accompanying text. Understanding this difference is essential for anyone wishing to forecast the world's future supply of oil.

Notes:

- The authors are grateful to a several external reviewers who helped improve sections of this paper.

- Subscribers to *The Oil Age* may obtain without charge a PDF version of this paper giving the Figures in colour. Please contact Noreen Dalton at: theoilage@gmail.com.

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