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How much oil remains for the world to produce? Comparing assessment methods, and separating fact from fiction

Jean Laherrère [a,d], Charles A.S. Hall [b,*], Roger Bentley [c,e]

[a] Exploration Techniques, Total, France
[b] College of Environmental Science and Forestry, State University of New York, Syracuse, NY, USA
[c] The Oil Age, Petroleum Analysis Centre, Ballydehob, Ireland
[d] President ASPO, France
[e] Former Dept. Cybernetics, University of Reading, UK

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ABSTRACT

This paper assesses how much oil remains to be produced, and whether this poses a significant constraint to global development. We describe the different categories of oil and related liquid fuels, and show that public-domain by-country and global proved (1P) oil reserves data, such as from the EIA or BP *Statistical Review*, are very misleading and should not be used. Better data are oil consultancy proved-plus-probable (2P) reserves. These data are generally backdated, i.e. with later changes in a field's estimated volume being attributed to the date of field discovery. Even some of these data, we suggest, need reduction by some 300 Gb for probable overstatement of Middle East OPEC reserves, and likewise by 100 Gb for overstatement of FSU reserves. The statistic that best assesses 'how much oil is left to produce' is a region's estimated ultimately recoverable resource (URR) for each of its various categories of oil, from which production to-date needs to be subtracted. We use Hubbert linearization to estimate the global URR for four aggregate classes of oil, and show that these range from 2500 Gb for conventional oil to 5000 Gb for 'all-liquids'. Subtracting oil produced to-date gives estimates of global reserves of conventional oil at about half the EIA estimate. We then use our estimated URR values, combined with the observation that oil production in a region usually reaches one or more maxima when roughly half its URR has been produced, to forecast the expected dates of global *resource-limited* production maxima of these classes of oil. These dates range from 2019 (i.e., already past) for conventional oil to around 2040 for 'all-liquids'. These oil production maxima are likely to have significant economic, political and sustainability consequences. Our forecasts differ sharply from those of the EIA, but our resource-limited production maxima roughly match the mainly demand-driven maxima envisaged in the IEA's 2021 'Stated Policies' scenario. Finally, in agreement with others, our forecasts indicate that the IPCC's 'high-CO_2' scenarios appear infeasible by assuming unrealistically high rates of oil production, but also indicate that considerable oil must be left in the ground if climate change targets are to be met. As the world seeks to move towards sustainability, these perspectives on the future availability of oil are important to take into account.

1. Introduction

While the world's attention and policy initiatives have been on climate change, including the role of oil in contributing to this, a potentially equally important issue has continued in the background - the world's relentless depletion of its reservoirs of oil. In this paper we ask: 'How much oil is left to produce?', and hence determine if we are likely to face soon a global shortage of oil.

Below we show that official estimates of the remaining reserves of oil as used by many analysts are very misleading, in part due to poor reporting and methodology, and that these reserves data should not be used. We also show that the basic Hubbert logic of oil production, that of increase, then peak (or peaks) and then decline, is playing out relentlessly (if not exactly) for nearly all oil producing countries. While dismissal of Hubbert logic by economists, with faith in technology to increase oil production, has been seemingly supported by the fracking revolution of the last decade and a half, this had little impact on the longer-range inevitability of oil depletion driven by global resource

* Corresponding author.
E-mail address: chall@esf.edu (C.A.S. Hall).

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limits. Analyses by others and ourselves of the patterns in the global discovery and production of oil show that the world's rate of use of oil has long been much greater than its rate of finding oil, and hence the future global production of oil at prices that are sustainable to society is inevitably downward.

We recognize the urgent calls for humanity to reduce its dependence on carbon-based fuels, and many believe that we are quickly replacing these with renewable energy sources. But there are strong pressures globally to continue, and even to increase, the usage of fossil fuels. This is because there is general agreement that much of the wealth of the modern world has been based on the greatly increased use of these fuels, first of coal, then of oil and gas, in agriculture, industrial production, transport and in the economy in general (Smil, 2017; Hall and Klitgaard, 2017). Nearly all politicians promise growth, and, at least so far, economic growth has required fossil fuels.

More specifically, the global increase in wealth, in particular from 1945 to 1975 (called by some the 'Thirty Glorious Years'), can be attributed in large part to growth in the use specifically of oil. As shown in Fig. 1, oil consumption has been on an upward trend since 1857, albeit interrupted by the oil shocks of the 1970s and other financial crises as in 2008; and subsequently by the Covid pandemic of 2020. With the impact of Covid now decreasing in many industrial nations, oil use has partially resumed its upward trajectory.

It seems reasonable that if oil use continues at the present or greater rate, then the old issue of how much oil is left for the world to produce, and hence whether 'peak oil' is close, remains important to examine. James Schlesinger, former US Energy Secretary, claimed at the September 2007 Association for the Study of Peak Oil conference in Ireland that "intellectual arguments over peak oil had been won", i.e., that we all could accept the reality that oil production had peaked. But in 2008 the 'shale oil' revolution began and seemed to give lie to the idea of peak oil. Now it seems that shale oil did indeed delay the peak, but only by a decade or so. So, again, we need to ask whether peak oil has arrived, or will do so soon. To address this question we ask: 'How much oil remains in the ground for us to extract?' To answer this, we need first to define what is meant by 'oil' as different classes of oil have significantly different remaining volumes.

2. What is 'oil'?

Oil is an energy-dense hydrocarbon fuel derived from organic deposits within geological strata. However, as Fig. 2 indicates, there are many types of oil, and also of 'other liquids' that can be used in the place of oil for at least some applications.

In Fig. 2, 'Other crude' is oil produced from oil fields by standard extraction methods. "Crude oil" includes light-tight ('shale') oil produced by hydraulic fracturing ('fracking') of the rock within extensive tight oil plays, and condensate, the gaseous fractions associated with either oil or gas production that condense to liquids when pressure is released as liquids are brought to the surface. The US Energy Information Administration (EIA) further defines condensate as either produced at a source without further processing ('lease condensate') or as derived from processing ('plant condensate'), while the International Energy Agency (IEA) classes condensate by whether it is sold with crude oil or natural gas liquids.

Note that under OPEC rules production of condensate is excluded from quotas. By producing condensate, OPEC members can exceed their quota limits, hence reducing pressure to increase quotas. Production of natural gas liquids (NGLs), which has increased rapidly in recent years as global gas production has increased, includes condensate from natural gas sources plus ethane, propane, butanes and pentanes from these sources. Not shown are synthetic fuels, where, if energy is cheap, such

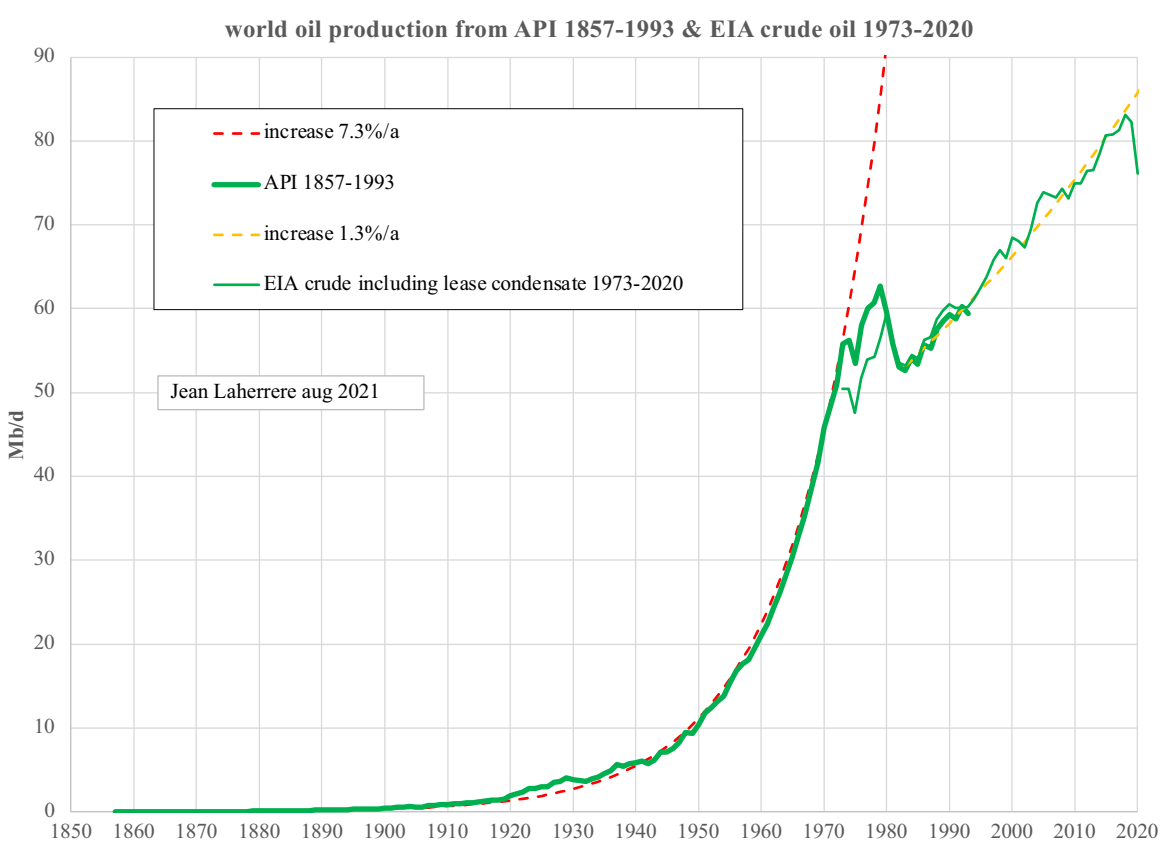


Fig. 1. World oil production, 1857–2020. From 1880 to the 1973 oil shock world oil production increased at an average rate of 7.3% per year, and at 1.3% per year from 1983 to 2019.
Sources: 1857–1993: American Petroleum Institute (API); 1900–2020: US Energy Information Administration (EIA).

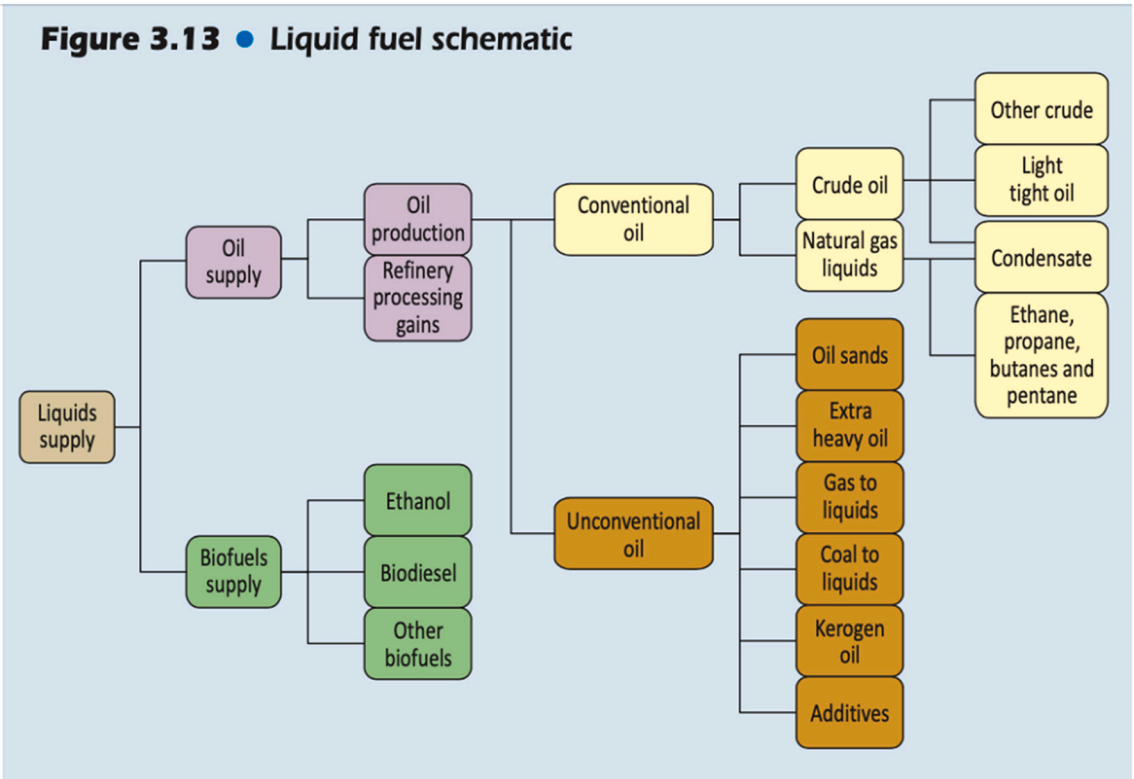


Fig. 2. Schematic of various fuels classed as oil or related liquids.
Notes: - The IEA's definition of condensate is ambiguous, being classed as either crude oil or natural gas liquids depending on how it is sold. - Omitted are synthetic fuels.
Source: International Energy Agency.

fuels can be made in volume using widely available feedstocks such as carbon dioxide and water (Siemens, 2021; Bosch, 2021).

As Fig. 2 shows, the IEA defines 'conventional' oil as crude oil plus NGLs, although elsewhere they exclude NGLs. Unconventional oil, by contrast, includes tar sands and extra heavy oils, plus the 'other liquids' of coal and gas to liquids, 'oil shale' which is oil produced thermally from kerogen, and chemicals added during refining. Biofuels are usually accounted for separately, although generally included in 'all-liquids' totals. For more information on oil data sources, and the reliability of the data they contain, see (Laherrère et al., 2017).

In this paper for simplicity of analysis we separate 'all-liquids' into the following: conventional oil; light-tight oil (LTO); extra-heavy oil (XH), referring primarily to Canadian tar sand and Venezuelan Orinoco oil; and 'other liquids', primarily NGLs, but with currently relatively small amounts of gas and coal to liquids, refinery gain, and bio- and synthetic fuels, see Table A1.1. We choose these classes of oil as they reflect different sources and production methods, and hence different intrinsic costs and limits to extraction rate.

By defining conventional oil as excluding LTO and XH oil we match the standard definition used for many years, for example in many of the URR estimates in Table A4.1, in Campbell and Laherrère's '*The End of Cheap Oil*' (Campbell and Laherrère, 1998), and by the IEA in its *World Energy Outlooks*. In line with the US EIA, in this paper we thus define 'crude oil' as including conventional, LTO and XH oils.

For many years conventional oil was abundant, and there was little reason to consider these other classes of oil. However conventional oil reached its *resource-limited* global production plateau in 2005, at least for oil prices up to well above $100/bbl (Bentley et al., 2020). To meet global oil demand following 2005, the world has had to increasingly rely on production of unconventional oils and 'other liquids', oil sources which are often more expensive, less useful, and more energy-intensive to obtain. (For analysis of the latter factor, see (Delannoy et al., 2021)). The high oil price driven by the high marginal production costs of these unconventional oils helped trigger the 2008 financial crisis, and contributed to the subsequent period of weaker economic growth.

3. Oil discovery data

In estimating how much oil is left to exploit, we need to understand how data on oil discovery are generated. According to Sorrell and Speirs (Sorrell and Speirs, 2010), there are three main sources of data on how much oil is in an oil field: seismic data, results of drilling (including well logging and well testing), and production data over time. A more detailed summary is given in Appendix A.

4. Oil reserves data

To assess how much oil remains, we turn first to oil reserves. As normally used, 'reserves' specify the quantity of oil that has been discovered at a given date but not yet produced. These can be categorized as follows: proved (or proven), abbreviated as 1P; proved-plus-probable (2P); and proved-plus-probable-plus-possible (3P). These categories are often associated with corresponding probabilities, where 1P reserves are judged approximately 90% likely (i.e., almost certain) to be producible, 2P as 50% likely (i.e., most likely to be correct, with an equal chance the actual amount producible being greater or less than this 2P value); and 3P as only 10% likely to be producible. In principle, each year reserves are incremented by the oil found through exploration and development and decreased by the oil produced.

4.1. Problems with estimates of proved oil reserves

However, it is important to understand that oil reserves data are far from straightforward. Firstly, for individual fields, for many years oil

companies had to report proved oil reserves under US Securities and Exchange Commission (SEC) financial rules, and often this continues to be the case. SEC rules require the reporting of very conservative oil reserves data (itself an outcome of much earlier exaggerated reporting), and at least one oil major lost its chairman over violating these rules, even though the reserves the company reported may have been approved under subsequent rules.

Secondly, when calculating total reserves of multiple fields, adding several 90%-likely ('proved') reserves together yields a total that is more cautious (smaller) than the true 90% total, with the reverse being true for a 10% ('3P') total; only adding 50% data generates a total that is statistically correct, see Supplementary Material. Note that some authorities make the error of classifying probable reserves as the most-likely quantity of oil to be producible, whereas this applies only to proved-plus-probable (2P) reserves.

Thirdly, 1P data for a given year usually include *annual revisions and extensions to old fields*. Often such oil is in long-discovered fields with long-planned developments but which have recently received sufficient approval to be judged as close to market, and hence be reclassified from 2P to 1P. This process contributes to 'reserve growth', particularly if there has been an increase in the price of oil, as 1P reserves are based on the current price of oil while 2P reserves reflect estimated future price. In recent years reserves growth (i.e., revisions and extensions to existing fields, as opposed to finding new fields) has usually been the largest category of oil added to the proved reserves of conventional oil, and is often mistakenly reported by agencies as brand-new oil. In reality, much of this oil was discovered, and also its likely volume assessed accurately, long ago (Campbell and Gilbert, 2017).

4.2. Additional problems with public-domain proved oil reserves by country

Now we turn to problems specifically with public-domain data on proved oil reserves *by country* (and hence also as aggregated for the world as a whole). These data are provided by sources including the US EIA, OPEC, BP *Statistical Review of World Energy*, *Oil and Gas Journal* and *World Oil,* and are copied into sites such as *Our World in Data* and *Worldometer*. These then become the oil reserves usually quoted in analysts' reports from banks, investment houses and organizations such as Reuters, *The Economist*, the *Oil Price* website, and in the media more generally. Despite this widespread distribution, these data are extraordinarily misleading and should not be used as explained below.

Fig. 3 shows the evolution of public-domain global proved oil reserves from a number of sources, generated from corresponding country-by-country data. As indicated, at the end of 2020 reported global proved oil reserves varied from 1549 gigabarrels (Gb) for data from OPEC (which exclude Athabasca tar sands oil), to 1732 Gb for *BP Stats.* data (which include NGLs as well as the extra-heavy oils, mainly Athabasca

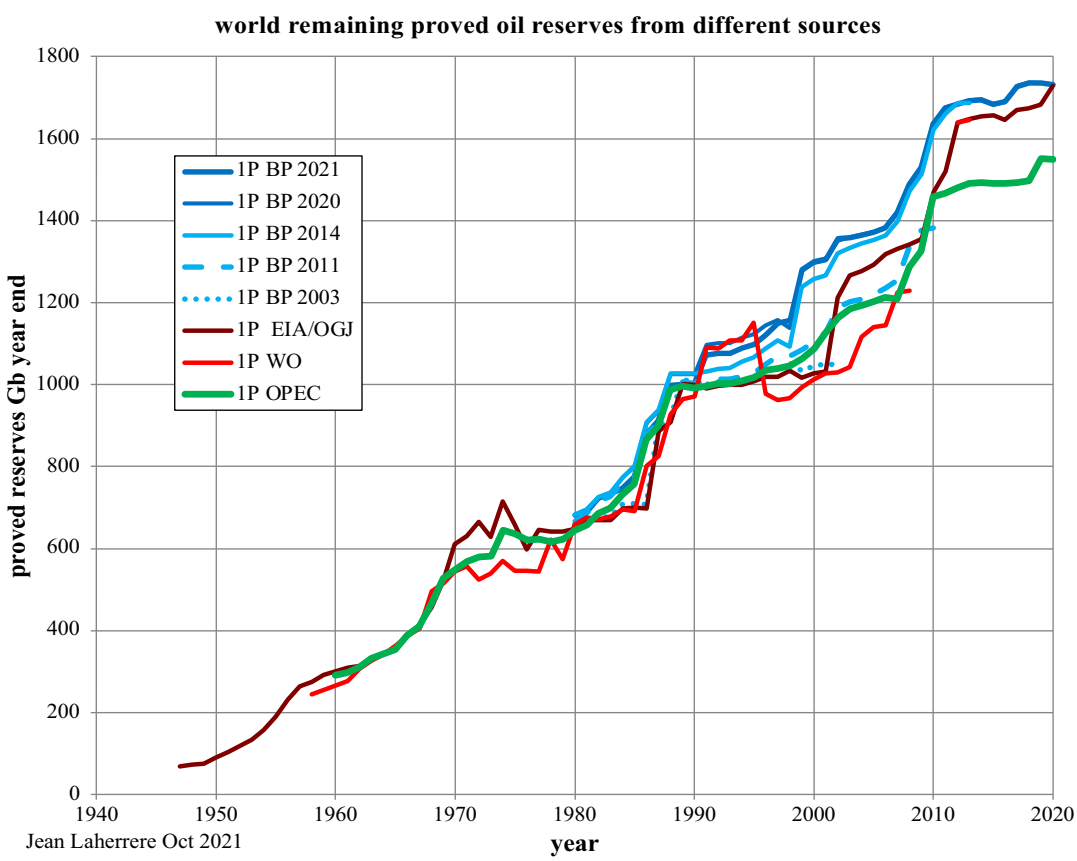


Fig. 3. Public-domain global proved (1P) oil reserves data by source.
Key: - BP: BP *Statistical Review of World Energy*, various issues 2003 to 2021, reporting historical reserves data since 1980. These series vary with date; shown here specifically for issues 2003, 2011, 2014, 2020 & 2021. - EIA/OGJ: *Oil and Gas Journal*, annual data in December for reserves on 1st January of the following year, covering the period from 1947 to 2020 (7th Dec); and as copied by the U.S. Energy Information Agency. - WO: *World Oil* magazine, last two years data, covering the period from August 1958 to September 2014. - OPEC: OPEC ASB (Annual Statistical Bulletin) 2021; historical reserves data (T3.1) for the period 1960 to 2020 (year-end).
Notes: - Reserves data assume an oil price, although this is usually not specified. - Differences between these data are mainly due to what the sources count as 'oil', and also when this definition has changed over time (even within a given data source). - Large step-changes in these data prior to 2008 are explained in the text, and include OPEC 'quota-wars' increases in the mid and late 1980s; increases after 2008 mainly reflect inclusion of reserves of light-tight ('shale') oil. - The impression in this figure that global oil reserves have steadily increased for many years is incorrect; see text.

tar sands and Orinoco oil). Thus, the standard answer to the question posed in this paper, of 'how much oil remains to produce?' is 'quite a lot'. This is because these reserves, at about 1550–1730 Gb depending on which oil classes are included, represent a seemingly comfortable 50-plus years of current oil use, of roughly 30 Gb/year. Moreover, as shown, these reserves have apparently increased steadily for decades, giving an even greater sense of oil security.

But now we need to ask three questions rarely asked: 'How are these proved oil reserve estimates by country obtained?'; 'How reliable are they?'; and hence: 'Is it possible that analysts, political leaders and the public are accepting a narrative on oil supply that has little relation to reality?'

The first main problem with the public-domain proved oil reserves data is how they are obtained. Each year in the fall the *Oil and Gas Journal* (OGJ) surveys national oil agencies, asking them what their country's proved reserves of oil will be on the first of January of the following year.

This timing is odd, as these agencies are then still waiting for oil producers to report their oil discoveries and production for the full year. For this and other reasons, only a few national agencies answer the survey. For the countries that do not answer, OGJ generally uses the same reserves as the year before. As a result, year after year the official proved reserves for many oil producing countries remain unchanged - as if annual discovery were exactly equal to annual production, which is almost never the case. For example, on 6 December 2021, OGJ reported that 74 countries (69% of the 107 countries that produce significant quantities of oil) did not report any change in reserves from the previous year. This represents 35% of the world remaining proved reserves, and 62% of 2020 annual production. Of particular note in terms of unchanged reserves are those of some of the OPEC countries, whose declared proved oil reserves have remained essentially unchanged for decades (Bentley, 2018).

The by-country proved oil reserves data provided by the US EIA are simply copies of these OGJ data, and we understand that *World Oil*, BP and OPEC use somewhat similar procedures although it is difficult to find these described explicitly.

Now we turn to the second problem with public-domain proved oil reserves data, that of significant overstatement of the oil reserves of some Middle East OPEC countries. Since there is no vetting of these data by an independent agency, and because OPEC allowable oil production is in part a function of reserves, the reserves for some of these countries are 'political' rather than geological estimates. Fig. A2.1 in Appendix B illustrates the 1980s 'quota wars' step-change increases in the declared proved reserves of Iran, Iraq, Saudi Arabia and Kuwait. These and similar increases across other OPEC countries have led to the extraordinary situation today where total OPEC proved oil reserves as reported by the BP *Stats. Review* at 1216 Gb is some eight times Rystad Energy's assessment of the correct value, which is just 149 Gb. Moreover, the reported 1216 Gb of proved reserves is some 60% greater than Rystad's estimate of OPEC's '2PCX' reserves, where the latter are 2P reserves plus "contingent resources in discoveries, plus risked prospective resources in yet undiscovered fields" (Rystad Energy, 2021). Such overestimates of OPEC reserves have long been recognized within the oil industry, and were highlighted for example by Sadad al Husseini, former VP E&P Saudi Aramco at the London 2007 'Oil and Money' conference, where he identified some 300 Gb of Middle East oil reserves as "speculative" resources.

The final major problem with public-domain proved oil reserve estimates has been the inclusion of non-conventional oil in quantities far exceeding any accepted definition of 'proved'. Venezuelan Orinoco heavy oil was discovered 1936 to 1939 and first produced in 1979. Some of this class of oil was added to Venezuela's proved oil reserves in the mid-1980s, and a further 200 Gb in 2008–2010. Another inclusion has been that of 130 Gb of Canadian Athabascan tar sands oil in 1999, oil discovered in 1719 and first produced in 1967. The potential recoverable resources of both Orinoco and Canadian tar sands oil are indeed large, but to count these as 'proved' reserves is not correct. Rystad Energy (Rystad Energy, 2021), for example, judges Canada's proved oil reserves as only 32 Gb if reported under Society of Petroleum Engineers' rules, compared to 168 Gb in the BP *Stats. Review*; and Venezuela's proved oil reserves to be 3 Gb, just 1% of the 304 Gb reported in BP *Stats. Review*! The reality is that most non-conventional oils are still far from market, being difficult and energy-intensive to produce (Poisson and Hall, 2013), and where only some 20 Gb in total has been produced to date despite massive efforts.

4.3. 'Scout' (oil-industry) proved-plus-probable ('2P') oil reserves

We turn now from the flawed public-domain proved oil reserves data to the more accurate proved-plus-probable (2P) reserves as estimated by the oil industry, and made available on a commercial basis by a relatively small number of oil consultancies. The latter are sometimes called 'scout' companies because they scout for the data they sell. They include IHS Energy (a continuation of the earlier Petroconsultants), Wood Mackenzie, Rystad Energy and Globalshift Ltd.

In these consultancy databases, 2P reserves are derived from assessment of the quantities of oil discovered in individual fields (or likely to be produced in projects in the case of non-conventional oils), and then subtracting the corresponding cumulative production to-date. The aim of these commercial databases is to report either 2P reserves as provided by the oil producers of the fields and projects in question, or in-house estimates as close as possible to these values. Although there are differences between these databases, their data are generally seen as the 'gold standard' for accurate information on oil fields and projects, only exceeded in accuracy by the commercially-restricted data held by the operators of these fields and projects. As an indication of the value of these scout data, we note that oil consultancy databases of global exploration and production (E&P) data by field and project have an annual license fee typically in the region of $100,000. People in the know in the oil business are not likely to pay high prices for inaccurate data from the scout companies.

In these databases, total oil reserves for countries and for the world are generated by aggregation of individual field and project reserves. Importantly, and in marked contrast to the 1P data, 2P estimates are generally backdated. This means that revisions to the estimated oil reserves of a given field (or project in the case of non-conventional oil) are recorded against the year the field was initially discovered, or project initially approved. By contrast, 1P reserves are recorded on a 'current basis', i.e., revisions to field size are reported for the date the revision is announced. But recall that much of the apparent 'reserve growth' of 1P reserves results simply from 2P reserves being reclassified over time as 1P fields get developed. While both approaches, backdating and current basis, have some merit, the advantage of backdating is that it gives a clear picture of how much oil was actually discovered by a given date, see '*Backdating is the key*' (Laherrère, 2017).

Although oil consultancy data are generally expensive to purchase (albeit sometimes being available at a considerable academic discount), and are relied on extensively by the oil industry, they are not without potential problems. Most important of these is the probable overstatement of 2P oil reserves for older fields in certain Middle East OPEC countries, and where this relates in part to the OPEC 'quota-wars' discussed above in connection with 1P reserves. We suggest that at least some oil consultancy data on 2P Middle East OPEC oil reserves should be reduced in total by around 300 Gb to account for probable overstatement of these reserves. A second problem is in the reporting of ABC1 reserves for former Soviet Union (FSU) oil fields, and where here we suggest these reserves should be reduced by around 100 Gb to bring them into line with the standard 2P reserves definition. Appendix C explains these potential adjustments in more detail.

4.4. Oil-industry 2P oil discovery data versus oil production

Fig. 4 shows oil consultancy (scout) 2P data for the global quantities of oil that have been discovered annually, and also the corresponding global oil production. The plot combines data from three oil consultancies for discovery of crude oil, less 'extra-heavy' (Canadian tar sands and Orinoco) oil, with revisions and extensions backdated to the year of discovery. The data thus include light-tight ('shale') oil and lease condensate but exclude other condensates and NGLs. In line with the above discussion, these data have been reduced by 300 Gb for probable overstatement of Middle East OPEC discoveries, and by 100 Gb for FSU 'ABC1' discoveries. The global annual oil production data shown here also exclude extra-heavy oils.

As Fig. 4 shows, initially the global rate of finding oil increased over time, including giant discoveries such as Ghawar in 1948; and then grew further with the increased application of digital seismic analysis and the opening of offshore areas, until reaching a maximum annual discovery rate around 1965, over 50 years ago. Subsequently, oil discoveries have tailed off, albeit bolstered by non-conventional oil in recent years, but where significant finds of conventional oil, such as recently in offshore Guyana and South Africa, are now few. Crucially, as the figure shows, from 1900 until about 1985 the rate of finding oil was greater than that of oil use, and hence global 2P reserves increased. After this date oil use outpaced discoveries, drawing down global 2P oil reserves as indicated in Fig. 5.

4.5. Comparison of global oil reserves: public-domain 1P data vs. adjusted scout 2P data

With the above information in hand, we are now able to compare public-domain current-basis 1P oil reserves with oil industry back-dated 2P reserves. This is done in Fig. 5, but note that there are significant differences in what is included in the data shown, as explained below.

In Fig. 5, 'political/financial' sources refer to the 1P current-basis oil reserves estimates, where these can be seen as 'financial' in the sense of being compliant with SEC (or similar) strongly conservative rules requiring proved oil reserves to be close to market (except for LTO reserves); or as 'political', where these reflect the probable over-reporting of reserves due to 'quota wars' revisions by some OPEC countries mentioned earlier. By contrast, 'technical' sources refer to oil consultancy ('scout') company 2P back-dated oil reserves, which as discussed above are taken to be generally the same as, or close to, oil-producers' own 2P estimates. In Fig. 5 the upper ('EIA/OGJ') curve for 1P reserves includes NGLs and the extra-heavy oil, but neither of these categories are in the 2P data shown.

However, despite these differences in terms of inclusion or exclusion of the reserves of NGLs and extra-heavy oils, and of our downward adjustment to the 2P data by 400 Gb in total, the main lesson from Fig. 5 is dramatic: That while the world's proved (1P) reserves of oil have been on an apparent ever-upward path according to the main suppliers of this information (including national reporting agencies) and now stand at up

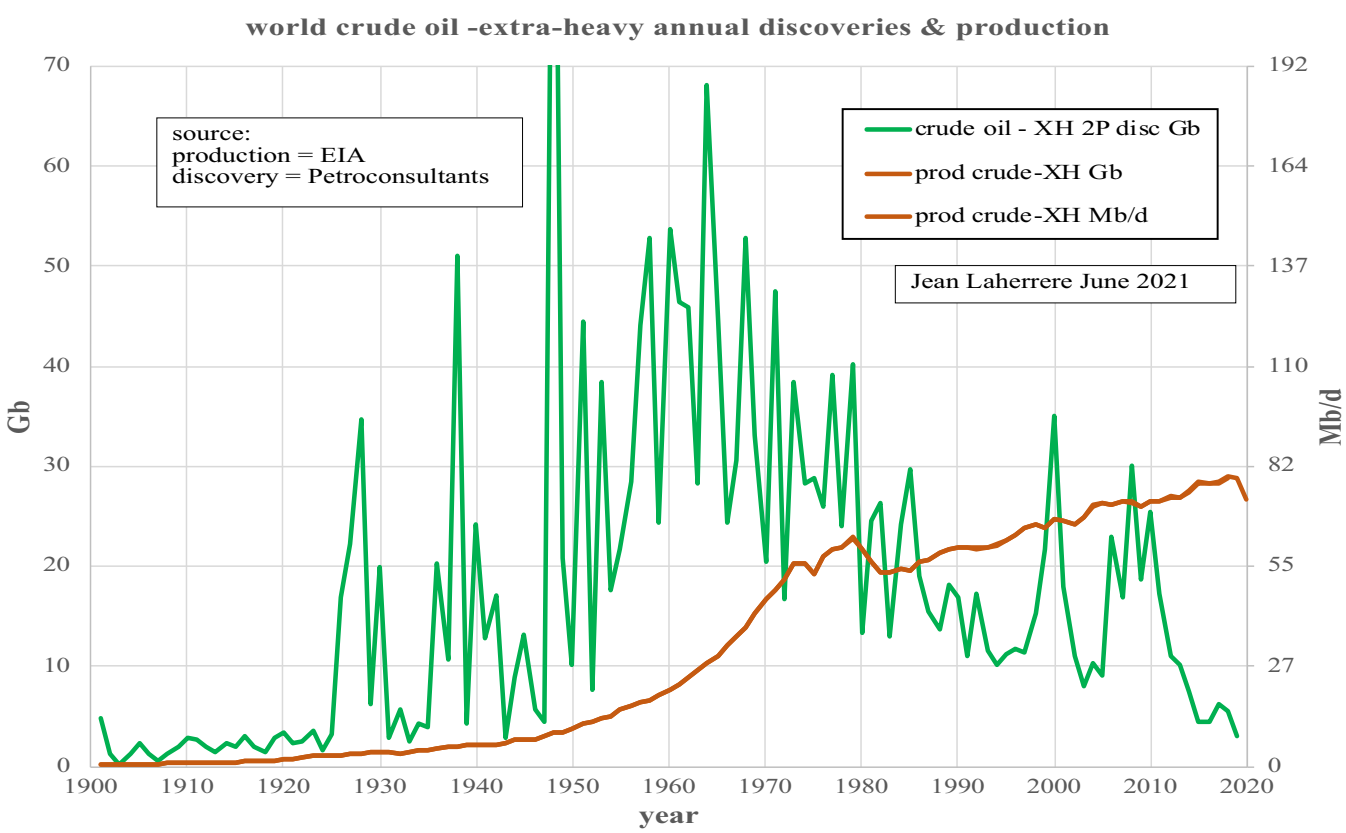


Fig. 4. 2P annual global oil discovery 1900 to 2019, adjusted for probable Middle East and FSU overstatements by 400 Gb (see text); and global annual oil production 1900 to 2020. Data exclude tar sands and Orinoco oil.

Key: - crude oil - XH 2P disc Gb (green line): Annual global proved-plus-probable backdated oil discovery data, in Gb/y, excluding Canadian tar sands and Venezuelan extra heavy oil, and adjusted downward by 300 Gb for probable overstatement of Middle East discoveries, and by a further 100 Gb in total for probable overstatement of FSU ABC1 discoveries. - prod crude-XH Gb (brown line): EIA data for annual global oil production, in both Gb/y (left-hand axis) and Mb/d (right-hand axis), excluding Canadian tar sands and Venezuelan extra heavy oil.

Notes: For analysis of the fairly small variability between estimates of 2P oil discovery from Rystad Energy and four other independent 'scout' companies, see Laherrère, 2018. For additional charts of oil consultancy annual global 2P oil discovery data see, e.g., Bentley et al., 2020. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

Data sources: - Oil discovery: Data to 2010: IHS Energy (Petroconsultants) data. Post-2010: A combination of IHS Energy and Rystad Energy annual published data.

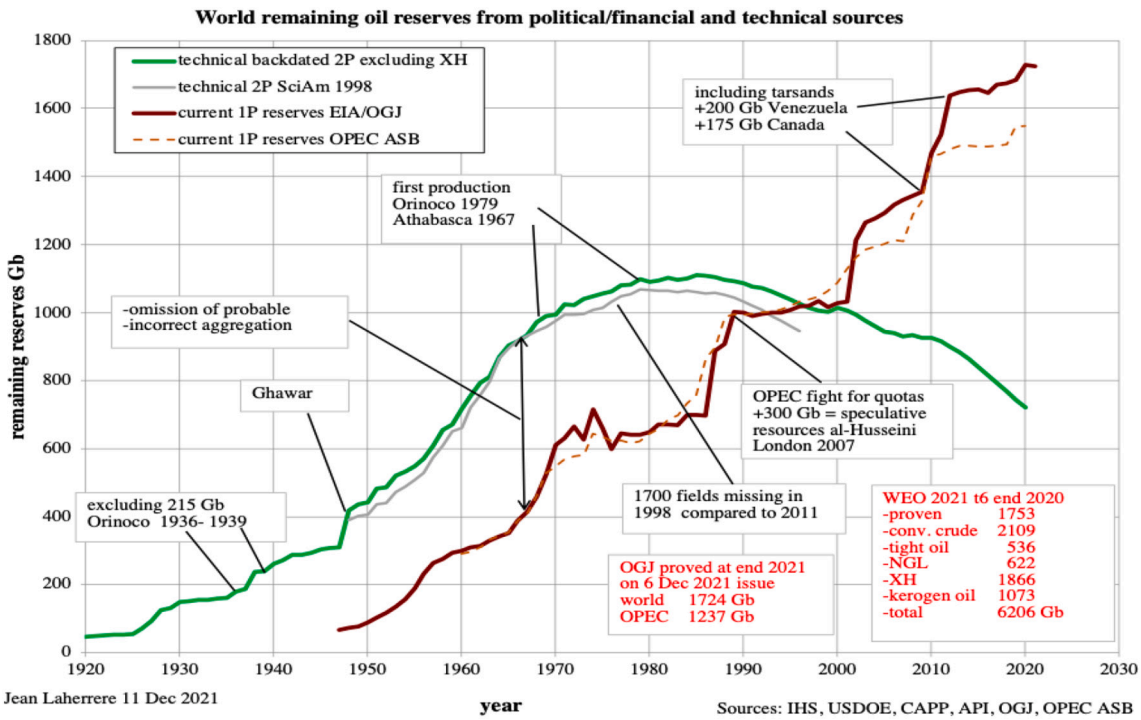


Fig. 5. Comparison of global 1P vs. 2P oil reserves.
Shows the evolution over time of global proved (1P) oil reserves (including extra-heavy oils) as reported on a current basis by public-domain sources, versus global backdated proved-plus-probable (2P) oil reserves (excluding extra-heavy oils, and adjusted for likely overstatement of Middle East and FSU reserves) as reported by oil consultancy ('scout') sources.
Key: - technical back-dated 2P excl XH (green line): Global 2P reserves of crude oil (less extra-heavy oils, and adjusted downward by 300 Gb for probable overstatement of Middle East discoveries, and by100 Gb for FSU discoveries) as reported on a back-dated basis by recent oil consultancy ('scout') data. - technical 2P SciAm 1998 (grey line): Global 2P reserves of crude oil (less extra-heavy oils) as given in Petroconsultants data (later shown to have 1700 missing fields) used in the *Scientific American* article, *The End of Cheap Oil*, Campbell and Laherrère (1998). - current 1P reserves EIA/OGJ (solid brown line): Global 1P reserves of crude oil (including extra-heavy oils) as reported on a current basis by US EIA and OGJ. - current 1P reserves OPEC (dotted brown line): Ditto, as reported by OPEC. - [In box at lower right]: WEO 2021 t 6 end 2020: Data from Table 6 of IEA *World Energy Outlook*, 2021. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)
Note: Extra-heavy oils are primarily Canadian tar sands and Venezuelan Orinoco oil.
Sources: Data to 2010: IHS Energy (but primarily Petroconsultants data). Data post-2010: A combination of IHS Energy and Rystad Energy data.

to 1700 Gb or so, our adjusted oil-industry data for global proved-plus-probable (2P) oil reserves reached a peak around 1985, and have been in steady decline since. Thus, we suggest that the global reserves of 'realistically-accessible' oil (essentially, conventional oil including 'light-tight' oil) are probably only about 750 Gb or so, once the extra heavy oils and adjustments for probable overstatements of Middle East and FSU reserves have been subtracted. Moreover, this measure of oil reserves has been on a declining trend for over 35 years, and would last only about 25 years at current rates of production.

However, it is nearly always misleading to quote 'reserves-to-production' (R/P) ratios when considering future oil security. This is for three reasons: Firstly, most analysts who quote R/P ratios use just the public-domain proved (1P) oil reserves, data which we have shown above to be totally unreliable. Secondly, even if 2P oil reserves are used, a country or the world as a whole can have a healthy-looking R/P ratio of apparently many years of oil production left, but be close to, or already well past, its *resource-limited* peak in oil production. And thirdly, reserves can increase over time. To correctly understand the scope for future oil production we need to turn to the key topics of URR estimates, and 'mid-point peak'. This is done next.

5. Ultimately recoverable global oil resources (URRs)

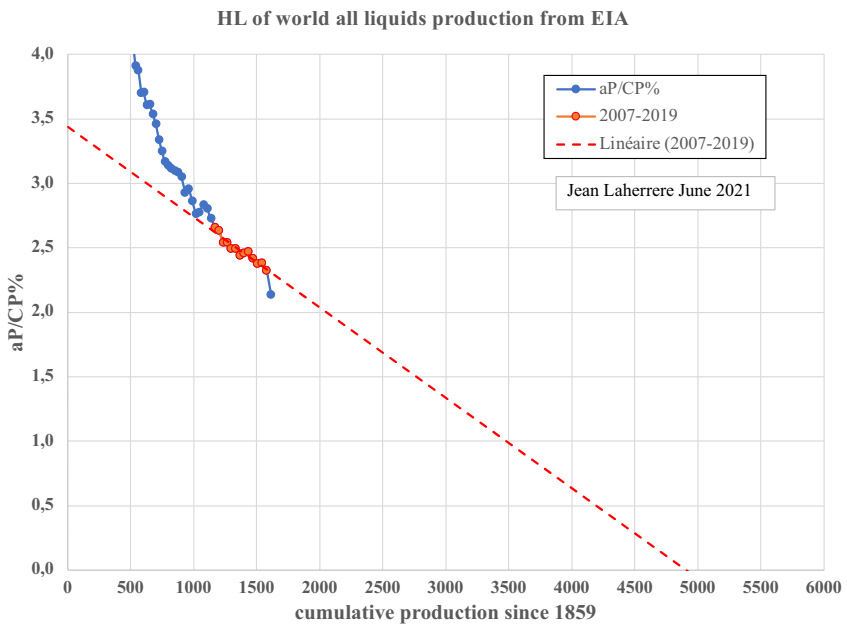
The above discussion on reserves is informative, but, as mentioned, it does not address the fact that over time reserves can increase as new oil fields are discovered, new projects of non-conventional oil get approved, oil extraction technology improves, the price of oil rises allowing access to previously uneconomic deposits, or when new classes of oil get included in reserves.

Thus one wants to know not 'how much discovered or project-approved oil remains today' (i.e., the reserves) but the more pertinent 'how much oil in total is likely to be producible in the future'. The way to obtain this is to first estimate the ultimately recoverable resource (URR, sometimes termed 'ultimately recoverable reserves') of each class of oil, from which the quantities remaining at a certain date for each class are found by subtracting the corresponding cumulative production to this date.

There are many ways to estimate URRs (see for example (Campbell and Laherrère, 1998; Hubbert, 1982; Sorrell et al., 2009; Bentley, 2016)), and there have been numerous estimates made over the years of global URRs for different classes of oil; see, e.g., Table A4.1 given in Appendix D, or the sources listed in Item 5 on the 'Oil Data & Analysis' page of www.theoilage.org. In this paper we use a technique called 'Hubbert linearization' as discussed next.

5.1. Estimating global oil URR using Hubbert linearization

Hubbert linearization (HL) is a means of extrapolating data on past production of an oil region to generate an estimate of the region's URR (Hubbert, 1982), see details in Appendix E. Fig. 6 gives the results of using this technique to generate estimates of the global URR for four increasingly restrictive definitions for 'oil'. At the upper end we estimate


HL of world all liquids production from EIA
aP/CP%
cumulative production since 1859
aP/CP%
2007-2019
Linéaire (2007-2019)
Jean Laherrere June 2021
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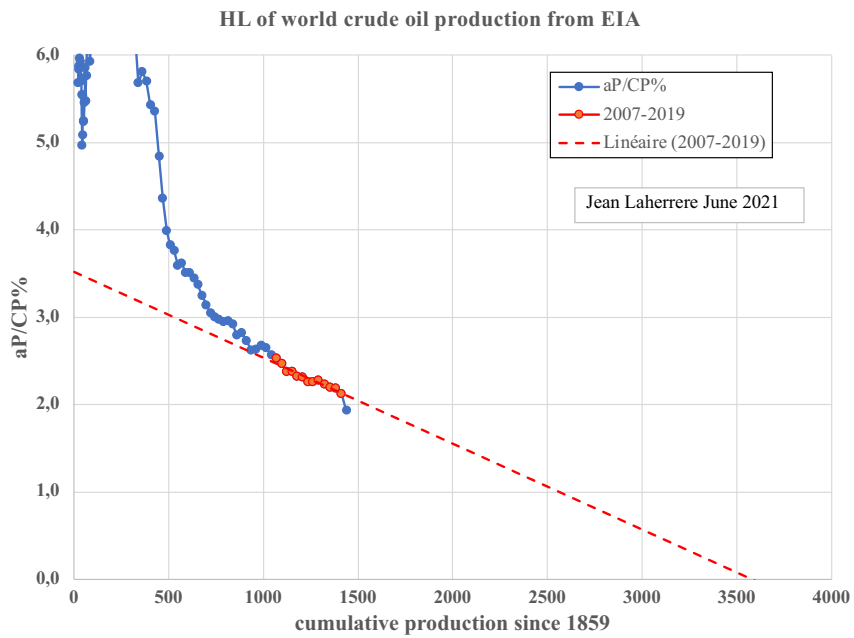
HL of world crude oil production from EIA
aP/CP%
cumulative production since 1859
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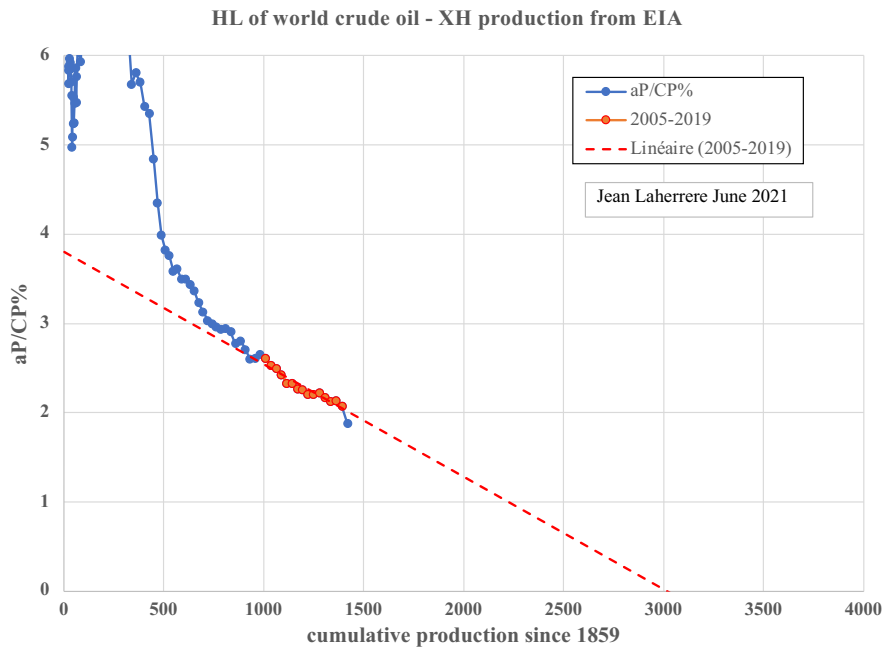
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cumulative production since 1859
aP/CP%
2005-2019
Linéaire (2005-2019)
Jean Laherrere June 2021
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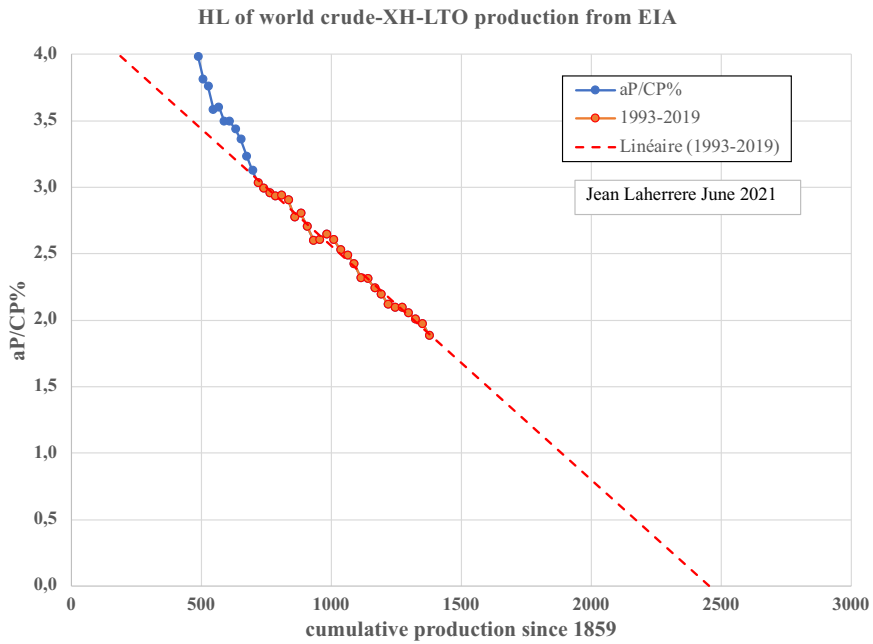
HL of world crude-XH-LTO production from EIA
aP/CP%
cumulative production since 1859
aP/CP%
1993-2019
Linéaire (1993-2019)
Jean Laherrere June 2021
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Fig. 6. Hubbert linearization estimates of global oil URR for four increasingly restrictive definitions of 'oil'. 5a (top left): Global 'all-liquids' production data from the US' EIA, and thus includes crude oil (including shale oil and condensate), extra heavy oils (including tar sands and Orinoco oil), other unconventional oils, NGLs, other liquids (including biofuels) and refinery gain. 5b (top right): Global 'crude oil' production, including the extra heavy oils. 5c (bottom left): Global 'crude oil' production less extra heavy oils. 5d (bottom right): Global 'conventional oil' production, being crude oil less extra heavy oil, and less light-tight ('shale') oil.
Key: - Red and blue markers: Annual production divided by cumulative production (aP/CP), expressed as %. - Red markers: Data for the years indicated (inclusive). - Dotted red lines: Linear trend lines for the years indicated (inclusive).
Notes: - Data are since 1869, though early years data are often off-scale. - Linearisation range is 13 years for plots 5a and 5b (2007–2019), 15 years for plot 5c (2005–2019), and 27 years for plot 5d (1993–2019). - The last data points in charts 5a to 5c show the impact of Covid-19. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)
Data source: Liquids oil production by category from the US' EIA.

the global URR of the US EIA's definition of 'all-liquids', as this is most inclusive, covering conventional oil, light-tight ('shale') oil, extra heavy oil (including tar sands and Orinoco oil), other unconventional oils, NGLs, other liquids (including biofuels), and refinery gain. At the lower end we estimate the global URR for this paper's definition of conventional oil, consisting of crude oil less extra-heavy oil less light-tight oil. The other two URRs estimated are for the EIA's definition of crude oil, and for crude oil less extra-heavy oil.

We accept that these HL plots start out far from linear, and hence from extrapolation over the more recent selected time periods we estimate rounded figures to indicate this uncertainty. Nevertheless, this technique has the virtue of using well accepted and available data, and the recent data points which are used look quite linear (except for the last Covid-impacted year). As can be seen, these plots suggest URRs ranging from about 5000 Gb for global 'all-liquids' down to about half this value, at 2500 Gb, for global conventional oil. These results are summarized in Table 1.

A key finding from Table 1 is that there remain large volumes of 'all-liquids' yet to exploit, and hence for concerns over anthropogenic CO_2 emissions. But a second finding is that if the focus is on conventional oil, on which our civilization has become so dependent, then we have already used well over half of this (1400 Gb), mostly in the last few decades. Combined with the usual observation of a region having its *resource-limited* production peak at or near the middle of its total extraction cycle, it is therefore no surprise that global production of conventional oil reached its maximum (for oil prices up to well over $100/bbl) in 2005, and has been on a plateau since. The technology of exploiting light-tight oil via fracking has bought us another decade or two, but the data suggest that we appear to be near the end of this relatively modest bonanza; while the rates of exploitation of some of the non-conventional oils (such as tar sands oil, and oil produced by thermal processing of kerogen) are limited by low energy-return ratios, high capital requirements and low profitability, and hence are seen as 'flow limited' rather than 'resource limited', and judged unlikely to make a large difference over the timescale of our assessment.

With the above in mind, it is useful to look at forecasts of future oil production based on the HL estimated oil ultimates of Table 1, and this is done next.

6. Future oil production

6.1. Forecast oil production

For a region or nation, if it contains a significant number of oil fields, the pattern of production of *conventional* oil over time usually follows a roughly logistic-derivative ('bell') curve, with an initial more or less exponential increase, a peak (or often instead, two or more peaks) when about half the total recoverable oil in the region has been produced, and then a long production tail, i.e., generally following a 'Hubbert' curve. See (Bentley, 2016; Hubbert, 1956; Hubbert, 1969). The background to this curve and its underlying physical driver are explained in Appendix E. Most oil producing nations have followed a Hubbert curve with production declining post peak (Brandt, 2007; Hallock Jr. et al., 2014). The U.S. and several other large producers may not follow this pattern for various reasons, although the U.S. does more so if we model conventional and light-tight oil as independent curves. Changes in prices have modified these patterns only slightly except to encourage exploitation of lower grades of oil.

6.2. Forecasting global oil production based on the above HL URR estimates and on 'mid-point peak'

In this paper we combine our HL estimates of URR above with approximately 'Hubbert' production curves to generate forecasts of global production to 2100 for the four aggregations of classes of oil considered. The results are shown in Fig. 7.

As indicated, global production of conventional oil (purple line) has been on a plateau since 2005, and here is forecast as not likely to recover significantly from the Covid-19 fall before permanently declining. By contrast, production of conventional oil including LTO (blue line) has

Table 1
Summary of global oil cumulative production and HL-estimated ultimates.

(Data in Gb)	Cum. prodn. to end-2020	Estd. HL ultimate	Already discovered	Yet to find	Estd. yet to produce
All-liquids	1615	5000	-	-	~3400
Crude oil	1440	3500	-	-	~2100
Crude less XH	1420	3000	-	-	~1600
Conventional oil (i.e., crude oil less XH less LTO)	1400	2500	2150	350	~1100
Hence:					
NGLs + other liquids	175	*	-	-	
XH	20	*	500	-	~480
LTO	20	55**	?	-	~35**

Note: All data approximate.
Estd. HL ultimate: From Fig. 6 of this paper (rounded).
XH: Extra-heavy oils, in this case Canadian tar sands and Venezuelan Orinoco oil.
LTO: Light-tight ('shale') oil, mostly so far mainly from the US and Canada, but likely to be increasingly produced from other regions also.
- Data which are currently difficult to estimate.? Data not known to us.
* Due to significant rounding in estimating ultimates, these data cannot be generated with useful precision by subtraction between corresponding ultimates.
** Data for the US only. LTO estimates for other regions are not large at this point in time, in part due to problems now, and likely in future, with obtaining exploration and extraction permits.

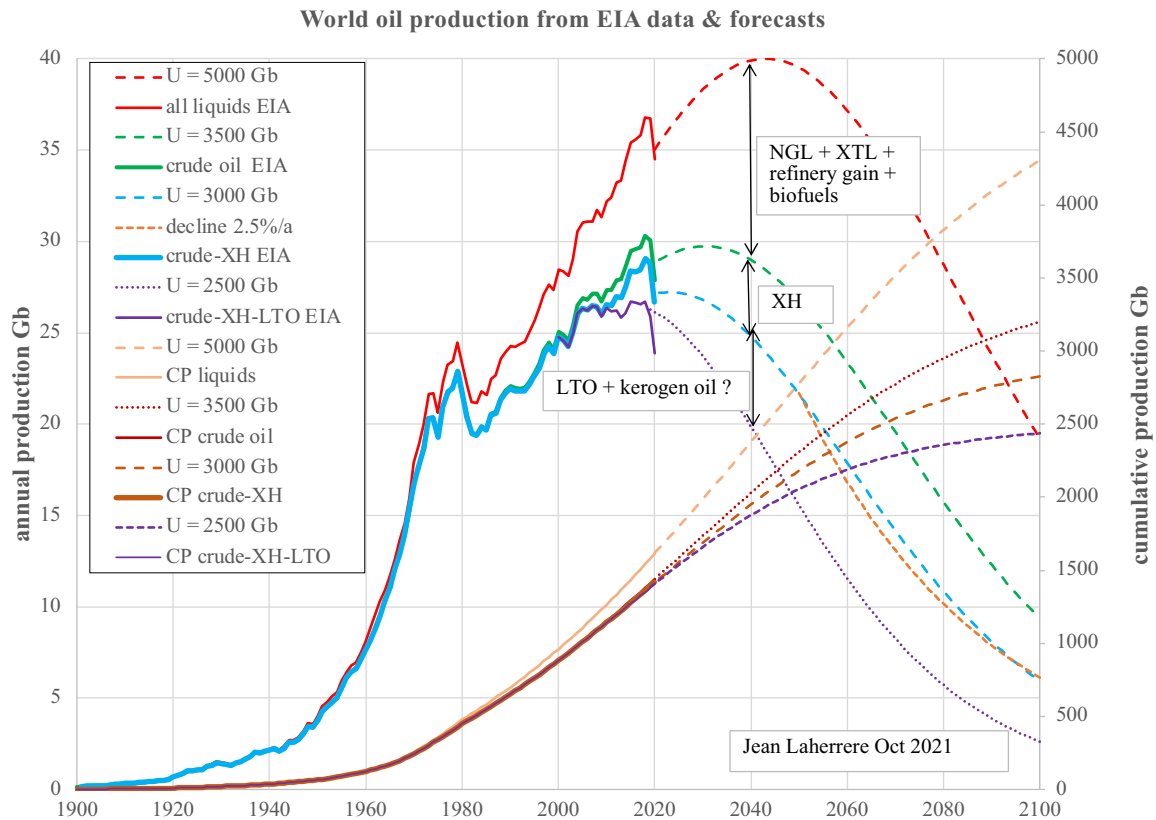

Fig. 7. Forecasts to 2100 of production of four aggregations of classes of oil, based on HL estimates of URR from Fig. 6.
Key: - Upper set of lines (left-hand scale): Solid line: Historical annual production data from the EIA. Dotted: Forecast production following a 'Hubbert' (derivative logistic) curve with cumulative total production matching the URRs indicated. - Lower set of lines (right-hand scale): Corresponding curves for cumulative production; historical: solid lines; forecast: dotted lines. - U: URR values, estimated by Hubbert linearization in Fig. 6. - CP: cumulative production. NGL: Natural gas liquids. XTL: coal or gas to liquids. XH: Extra-heavy oil. LTO: Light-tight oil.
Note: NGL volumes are somewhat uncertain, being reported differently by different sources.

been increasing, but even if we exploit this oil fully, it is forecast here to reach a peak roughly about now. If we assume in addition that we can rapidly and fully exploit the extra 500 Gb or so of heavy oil from Canada and Venezuela (green line), this delays the global peak to about 2030. Finally, the red line suggests that unconstrained access to 'all-liquids', including natural gas liquids, potentially delays the production peak to 2040 or a bit after.

In summary, these forecasts of oil aggregations, from conventional oil to 'all liquids', display production maxima ranging from 73 to 110 Mb/d, and dates of peak ranging from 2019 to 2040. Note that the large difference between the crude oil and 'all-liquids' peaks is due mainly to the production of NGLs, and by assuming the gas from which these are produced has its global production peak at around 2040.

Overall, the key conclusion of Fig. 7 is just how soon are the expected peaks of global production for all four aggregations of oil. This in turn reflects the nature of a Hubbert curve, where a significantly greater URR leads to a higher production peak but one not much postponed.

6.3. Comparison with other forecasts

Finally, in Fig. 8, we compare our forecasts with those from the US EIA and the IEA. Several lessons come out of this comparison. The first is the significant difference between the US EIA 2021 forecasts and those from the IEA of the same year for the latter's 'Stated Policies' scenario. US EIA 'ever-upward' forecasts have often been seen as on the optimistic side, assuming a large measure of what the US EIA calls 'learning by doing' (see, e.g. (Wang et al., 2019)). By contrast, the corresponding IEA forecast includes consideration of policies around the world to curb carbon emissions, so sees global 'all-oil' production as peaking around 2040 or so, due we assume mainly to a decline in demand.

As Fig. 8 shows, for conventional oil the IEA forecast sees production as continuing to decline due to *resource-limits*, but with the production of the extra-heavy oils, LTO and NGLs as increasing, at least out to the forecast horizon of 2050. Thus, compared to our HL-derived URR-based forecasts, the US' EIA forecast looks unobtainable in terms of resource availability, while our forecasts are roughly in agreement with the IEA's, but where theirs - at least in part - reflects demand-limit, and ours reflect the underlying global resource constraints for the classes of oil considered.

Overall, the key lesson of this Figure, and indeed of the 'downward-adjusted 2P reserves' of Fig. 5 (if 'peak at roughly mid-point' is taken into account), is that global production of conventional oil, which has been on resource-limited plateau since 2005, is forecast to soon decline, likely causing in our view significant strains across the global oil supply chain, and global economies more widely.

7. Discussion

In this section, we discuss briefly four aspects of the above findings: near-term oil prospects for certain countries; how our global oil URR estimates compare to those of others; how our findings relate to climate change; and sustainability, and hence some of the other constraints - in addition to oil supply - that will impact the global energy transition.

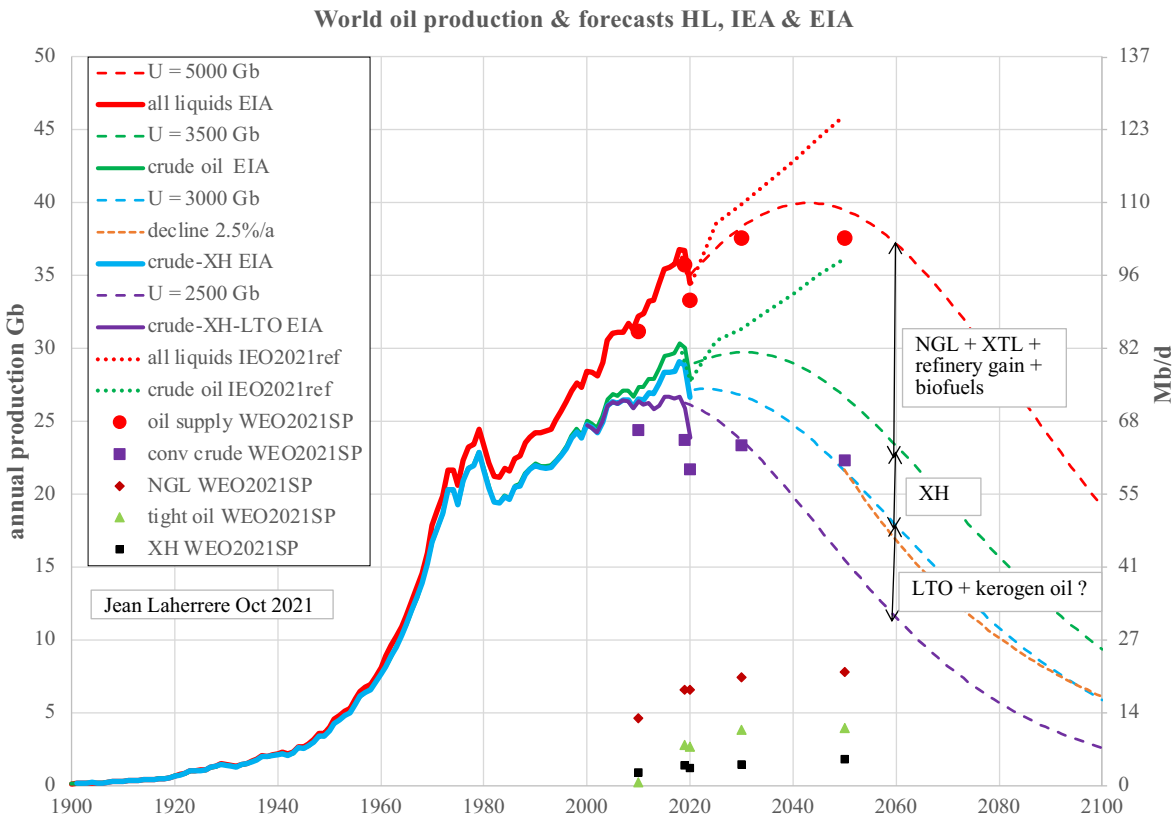

Fig. 8. Comparison of the global oil forecasts of this paper, based on URRs generated by HL of production data, with those of the IEA & US EIA.
Key: - Data are shown in both Gb/y (left-hand scale) and Mb/d (right-hand scale). - Solid and dashed lines are as in Fig. 7, showing EIA historical data (solid lines) and the URR estimates of Fig. 6 produced by Hubbert linearization (dashed lines). [Added is a dashed brown line from 2050 indicating a production profile from that date declining at 2.5%/y for the crude oil URR = 3000 Gb Hubbert curve.] (a). Forecasts to 2040 from the IEA's 2021 *World Energy Outlook*, 'Stated Policies' scenario (STEPS): - Red circles: Total global oil supply. - Purple squares: Conventional crude oil. - Small brown diamonds: NGLs. - Small green triangles: Light-tight ('shale') oil. - Small black squares: Extra-heavy oils (tar sands and Orinoco oil). (b). Forecasts to 2050 from the US EIA's 2021 *International Energy Outlook,* Reference case: - Upward-trending small red dots: All-liquids. - Upward-trending small green dots: Crude oil. (Note: EIA definition of crude oil includes LTO and XH oils, but excludes NGLs, other liquids and refinery gain.) (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

7.1. Near-term oil prospects for certain countries

Firstly, our findings suggest that unless the world rapidly weans itself off oil for reasons of climate change, there are likely to be significant economic and political consequences due to oil resource limits, as first conventional oil, and then all-oil, become supply-constrained. Particularly hard hit are likely to be developing countries, as without significant financial reserves accessing oil will be difficult, as is currently the case for Sri Lanka. Large oil importing economies, such as India and China, also may well see their economies contract; while large oil exporters will face very changed market conditions. The latter is because oil prices cannot go much higher for long, as this destroys demand as was clear in the early 1980s. Finally, the near-term aim of a number of countries to reduce their imports of Russian oil (and gas) due to the recent war in Ukraine is likely to further exacerbate petroleum supply/demand balances. Such findings suggest difficult times ahead.

7.2. Comparison of URR estimates generated in this paper by HL with other URR estimates

Next we compare our global oil URR estimates with those of others. Table A4.1 in Appendix D, expanded from (Bentley et al., 2020; Bentley, 2015), summarizes a wide range of global oil URR estimates made between 1949 and 2021. As the table shows, and contrary to the general perception, URR estimates for *global conventional* oil have been remarkably consistent over the seventy years or so since they were first estimated. If greater reliance is placed on URRs based on extrapolation of the global oil discovery trend, rather than on the higher USGS URR estimates which include significant allowance for future 'reserves growth', then URR estimates for global conventional oil have grown relatively little, from a range of about 1800–2500 Gb several decades ago to about 2200–2800 Gb today. This paper's HL-based URR estimate for conventional oil, at 2500 Gb, sits in the middle of the latter range.

7.3. Future oil production and climate change

An important question is whether there is enough remaining oil to generate a significant part of the temperature increase – as presumed to be due to CO_2 increases in the atmosphere – that the world is trying to avoid through international agreements. For some 20 years now there has been a significant disconnect between the 'high-CO_2' scenarios envisaged in climate-change models resulting from future oil production, and the emissions considered realistic in oil forecasts based on geology. The reasons for this are twofold:

Firstly, IPCC 'high-CO_2' emissions from oil are based on resource estimates originally from IIASA (Rogner, 1997; Rogner et al., 2012). Energy analyst Hans-Holger Rogner had been concerned, correctly, that some past calculations of CO_2 emissions had used only global *reserves* for

oil, gas and coal, even though these estimates - as we have pointed out above - are usually significantly below the *recoverable resources* of these fuels. Thus, the IIASA estimate for the oil resource included not just oil reserves, but the total then-current recoverable resources of conventional and non-conventional oils, and also of likely future non-conventional oil sources such as kerogen. Although these potential resources exist, geology-based forecasts of oil production tend to discount production of the more speculative of these (at least over the medium term) due to their difficulty of access, and hence high *intrinsic* production costs as evidenced by their low energy returns on energy invested (EROIs) (Hall et al., 2014).

But the second reason for the disconnect between the two types of forecast is more fundamental. The IPCC 'high-CO_2' scenarios do not consider the physics driving the 'mid-point' production peak which is probably characteristic of all fossil fuel resources, but erroneously assume instead 'ever-upward' production curves that increase in theory until the total potential recoverable resources are exhausted, and then drop sharply.

Perhaps the first publication on global CO_2 emissions from oil which drew attention to this more realistic 'geology-based' view was from Laherrère (Laherrère, 2001). Other such publications included (Leggett, 2005; Kharecha and Hansen, 2008; Höök et al., 2010; Ward et al., 2012; Höök and Tang, 2013; Wang et al., 2017a; Wang et al., 2017b). Most of these papers, including recently Laherrère (Laherrère, 2019), examine in addition to oil the discrepancy between CO_2 emissions in IPCC scenarios and geology-based models for all fossil fuels. But pointing out that IPCC 'high-CO_2' emissions scenarios are unrealistic for oil, and also for all fossil fuels, is only part of the picture. This is because current modelling finds the limit to future CO_2 emissions to meet the Glasgow COP26 goal of 1.5 °C is relatively small. For example, Welsby et al. (2021), building on earlier work by McGlade and Ekins (McGlade and Ekins, 2014; McGlade and Ekins, 2015), indicate that the allowable carbon release for the period 2018–2100 to meet a 50% probability of achieving 1.5 °C above pre-industrial is only 580 $GtCO_2$ (and see somewhat similar estimates in Matthews et al. (Matthews and Tokarska, 2021)).

Converting our estimate of remaining conventional oil of 1100 Gb (Table 1) to carbon gives ~470 $GtCO_2$, or, correspondingly, ~1900 $GtCO_2$ for our estimate of remaining 'all-liquids'. Thus the burning of just oil, even in its most restricted definition of conventional oil, is enough to approach the limit of total allowable carbon release for 1.5 °C; while the burning of all classes of oil, let alone of the other fossil fuels, will significantly exceed this limit; see Fig. A6.1 in Appendix F.

Thus, while it is important to point out that the IPCC 'high-CO_2' scenarios, which have informed a not inconsiderable part of the climate change debate and subsequent policy, are unrealistic, it also needs to be recognized that even Hubbert 'mid-point' peak modelling of the likely remaining practical resources of fossil fuels yields CO_2 emissions that breach significantly what is now judged as a sensible limit to global temperature rise. It is clear that if climate goals are to be met most of the remaining oil, especially the non-conventional oils, needs to be kept in the ground. Our guess is that there are likely to be extremely strong pressures to remove all oil possible.

7.4. Sustainability: other constraints to the global energy transition

The sustainability of modern society is one of the key existential questions of the day. It is a topic with many facets, including food and water supply, adequate housing, necessary industrial activity, ecosystem stability and regeneration, and adequate international governance to effect the changes needed. In this paper the focus is on the sustainability of the global energy supply, which in its simplest terms means providing enough energy to current and future populations to live fulfilling lives without undue stress, hunger or poverty. Above we have already discussed constraints to global oil supply and the need to meet climate-change goals. But there is a range of other constraints that seem likely to impede the global energy transition, and which in our view are also seeing insufficient consideration in most current energy modelling. These constraints are set out in *The Energy Pivot* report (Ratcliffe et al., 2021), and include the following:

- The near-term resource-limited maximum in the global production of conventional gas.

- Declining ore concentrations of many minerals, with impacts on mineral availability and on the energy used for their mining and benefaction, and hence on mineral price.

- The fact that the energy transition still has a long way to go, with currently the 'new' renewables of wind, solar, biomass and geothermal energy combined contributing only some 5% to global primary energy (BP, 2021).

The interlinkage between the various factors involved above are complex, and include population growth, rising economic expectations across many populations, the issues of hydrocarbon and minerals availability mentioned above, declining EROIs, the impact of 'dynamic' EROIs, and the need for a diversion of considerable financing to the energy sector (Hall et al., 2014; Perèz et al., 2020). Also important is the combined effect of these factors on GDP per capita, which some studies expect to see fall because of the energy transition. Perhaps only 'systems dynamics' modelling can handle the required degree of linkage, and here the results from the still relatively few systems dynamics models that look at these issues are unfortunately not encouraging; see for example (Perèz et al., 2020; King and van den Bergh, 2018; Solé et al., 2018). Perhaps of greatest concern is that if many people see a decline in their financial well-being, which they will perceive mostly as inflation, they will blame politicians or other groups, thus making governance more difficult, and the tackling of problems related to declining net energy delivered to society harder to achieve, as discussed by Ahmed (Ahmed, 2017).

8. Conclusions

Future availability of oil is a critically important issue that affects economies, carbon budgets, and international relations among other issues. But despite this, the world is generally unaware of this topic. One reason is that the most frequently cited data on the amount of oil remaining and how this quantity has changed over time are very misleading, and should not be used. These data are the proved oil reserves data *by country*, and as summed globally, as reported by the EIA, OPEC, BP *Statistical Review*, *Oil and Gas Journal* and other sources. Far better data are the proved-plus-probable (2P) oil reserves held by oil consultancies such as IHS Energy, Wood Mackenzie, Rystad Energy and Globalshift Ltd. These data are expensive and their publication is restricted, and even some of these data perhaps overstate the true global oil reserves by some 400 Gb in total. To know 'how much oil remains' the statistic to use is the estimated ultimately recoverable resource (URR) of the class of oil in question, from which production to-date must be subtracted. Certainly we need better and independent international vetting of data on oil resources.

There are many different ways to estimate URR values, but in this paper we use Hubbert linearisation as this requires only data on past oil production in a region, data which in general are both available and fairly reliable. We then combine our URR estimates with logistic production curves to forecast production of four aggregations of oil type. Our results suggest that global production of *conventional* oil, which has been at a resource-limited plateau since 2005, is now in decline, or will decline soon. This switch from production plateau to decline is expected

to place increasing strains on the global economy, exacerbated by the generally lower energy returns of the non-conventional oils and other liquids on which the global economy is increasingly dependent.

If we add to conventional oil production that of light-tight ('fracked') oil, our analysis suggests that the corresponding resource-limited production peak will occur soon, between perhaps 2022 to 2025. If then we add tar sands and Orinoco oil, the expected resource-limited total peak occurs around 2030, although there is a major question over whether significantly increased production rates of the latter two classes of oil is possible. Finally, the resource-limited production peak of global 'all-liquids' is expected about 2040 or a bit after if the latter liquids are also produced at the maximal rate.

We compare our oil forecasts with those the of the US EIA and the IEA. In our view the current US EIA oil forecast appears unrealistic, as it exceeds our estimates set by URR constraints. By contrast, the IEA's current 'Stated Policies' forecast is in general agreement with our forecasts, but where the IEA's sees future global oil production as declining due in part to *demand limits*, ours see similar declines but caused instead by *resource limits*.

In terms of climate change, in agreement with a number of earlier studies, we find that our URR calculations indicate that IPCC 'high-CO_2' scenarios appear infeasible due to resource limits, but also show that considerable amounts of oil must be left in the ground if current climate change targets are to be met.

Overall, we conclude that unless rapid and significant reductions in global oil demand are achieved by political measures to tackle climate change, the resource-limited oil supply constraints identified in this paper will continue to have increasingly significant economic and political consequences, and can be expected to have significant impacts on sustainability however defined or considered. Finally, we suggest that the data and 'production peak at about URR mid-point' model used in this paper be incorporated into wider energy and climate-change modelling to better inform policy-making.

Declaration of Competing Interest

We declare we have no competing interests, financial or otherwise.

Acknowledgements

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Appendix A. How oil is discovered and developed, and categories of oil

The first step in oil discovery is to explore a *petroleum system*, defined as a three-dimensional petroliferous region of the Earth with sedimentary rocks. There source rocks generate oil and gas from ancient, marine plankton or other biomass sources in a suitable 'kitchen' that cooks the organic material that has been protected from oxidation. Subsequently some of the resulting oil and gas migrates (usually upward) through the rock strata to the atmosphere unless stopped by impervious rock formations known as *traps*. It is usually oil in these traps that is exploited to obtain conventional oil. There are about 800 sedimentary basins in the world (Robertson, 2019), but, according to Wikipedia (accessed August 2021), only 226 contain significant quantities of oil or gas. And of the many tens of thousands of oil fields in the world, most of the oil we exploit comes from just a few hundred very large fields, nearly all of which were discovered many decades ago.

Virtually all oil discoveries now start with seismic data on the underground geological structure of the field and its environs, which tell geologists whether there are features that might trap oil from the source rock and to define the area of a potential oil-bearing structure. Whether or not there is any oil there usually can be determined only from the results of drilling, which shows whether there is at least some oil at a particular spot, and which can help access the thickness, porosity and oil saturation of an oil-bearing formation. Exploratory drilling examines whether there is exploitable oil in a new prospect, i.e., if oil is present in the geological trap, while development drilling helps define the extent of the field and if it is economical to exploit, while usually also extracting oil.

Combining seismic profiles and drilling results within that profile from both exploratory and development drilling can help interpret and extrapolate the seismic data. This requires skilled geologists and reservoir engineers to interpret and is often quite subjective. A third, independent, source on how much oil is held in a given field or region are data on *production*, i.e., how much oil is produced each day or year assessed over time, and also expressed as the cumulative amount. Extrapolation of production can indicate how much the field or region is likely to yield in total, absent significant later use of improved extraction technology. Today large computers and sophisticated programs are used to integrate the above information.

Note that for many of the non-conventional oils, such as tar sands oil, oil produced from kerogen, or coal-to-liquids, the concept of an oil reservoir waiting to be discovered is invalid. This is because these oils are generally geographically extensive and have been known about ('discovered') for many years. They include large regional resources such as Venezuelan heavy oil, Canadian tar sands oil and US kerogen. For such oils, production depends on an adequate extraction technology at a suitable price, as well as for oil demand not being satisfied by generally easier-to-produce conventional oil. While the potential recoverable resources of these non-conventional oils can be large, their exploitation is often difficult, capital and energy intensive, and expensive (Poisson and Hall, 2013; Bentley, 2015) Their exploitation is thus generally considered to be 'rate limited' rather than 'stock limited', and many of these oils are not likely to be produced at rates that make a large difference on a global scale; see forecasts at www.globalshift.co.uk. Note that a number of past investments in such resources have not been a commercial success, although a significant amount of Canadian tar sands oil is being produced today.

Table A1.1: Categories of oil.

In this paper, and particularly in terms of the URR estimates generated in Fig. 6, we define the categories of oil and other liquids as follows:

Conventional Oil:

- Light- and medium-density oil produced onshore or offshore in geographically defined oil fields by primary (own-pressure), secondary (gas or water drive), or tertiary (including heating or solvent) recovery techniques.

- Heavy oil, including that recovered by heating, which is not included in the 'extra-heavy' category below.

- Condensate, gaseous fractions associated with either oil or gas production that condense to liquids when pressure is released at the surface, as included in the EIA's definition of oil.

Light-tight oil (LTO):

- Light oil produced from extensive regions of shale and similar rock, typically by a combination of horizontal drilling, hydraulic fracking and the use of proppants.

Extra-heavy oils (XH):

- Specifically, the extra-heavy oils produced from Canadian tar sands and the Orinoco basin. These oils are more dense than water, and are not held in a defined geological trap with oil above the water level, but instead are limited at the surface where they are eroded, and degraded by bacteria.

Crude oil:

- Conventional oil, plus light-tight oil, plus extra-heavy oil (all as defined above), and thus in agreement with the EIA's definition of crude oil.

Other-liquids:

- Includes natural gas liquids (NGLs); oil produced by retorting kerogen found within in 'oil shale' rock; liquids chemically produced from coal (coal-to-liquids, CTLs) or gas (gas-to-liquids, GTLs); synthetic oil produced chemically from a range of feedstocks, for example carbon dioxide and water; refinery gain, where the volume of liquids, but not their energy content, increases through the refining process; and biofuels, either liquids produced by refining bio-oils, such as from corn, or by more complex processes from other types of biomass.

All-liquids:

- Crude oil plus other liquids, and thus in agreement with the EIA's definition of all-liquids.

Appendix B. Step-changes in some OPEC proved oil reserves

Fig. A2.1 shows the evolution of the public-domain data on proved oil reserves for Iran, Iraq, Saudi Arabia and Kuwait. The sharp increases in these reserves in the 1980s and were due to OPEC countries competing for quota, a result of the oil demand fall from the 1970s price shocks combined with new oil from elsewhere. Subsequent increases in reserves may also reflect 'quota wars' maneuvering to some extent, including perhaps Iran/Iraq rivalry. Certainly, most of the post-1980 reserves increases were not associated with large oil discoveries, nor with significant gains in oil recovery.

Appendix C. Potential problems with oil consultancy 2P reserves data

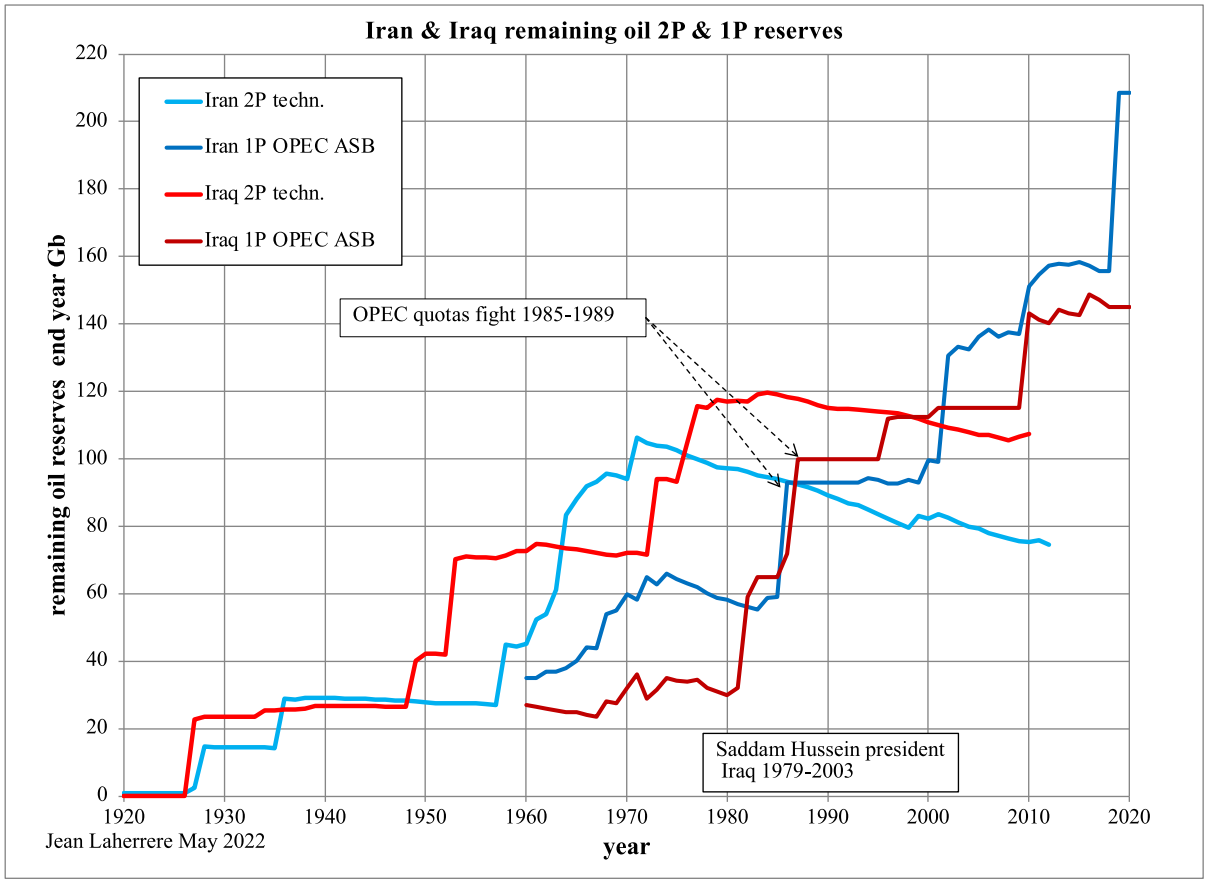
Oil consultancy ('scout') data for 2P oil reserves are not without possible problems. The first is the probable overstatement of the 2P oil reserves for older fields in a number of Middle East OPEC countries, and where this relates partly to the OPEC 'quota-wars' issue discussed above in connection with 1P reserves. We examine this problem by looking at historical IHS Energy data. Petroconsultants, which was later acquired by IHS in 1996, generally held data on the volumes of oil in individual fields that had been shared with Petroconsultants by oil companies working in the countries concerned. However, the corresponding data in the IHS database for some countries have grown significantly over time, suggesting perhaps that more recent reserves may now represent more 'political' than geological estimates of field sizes.

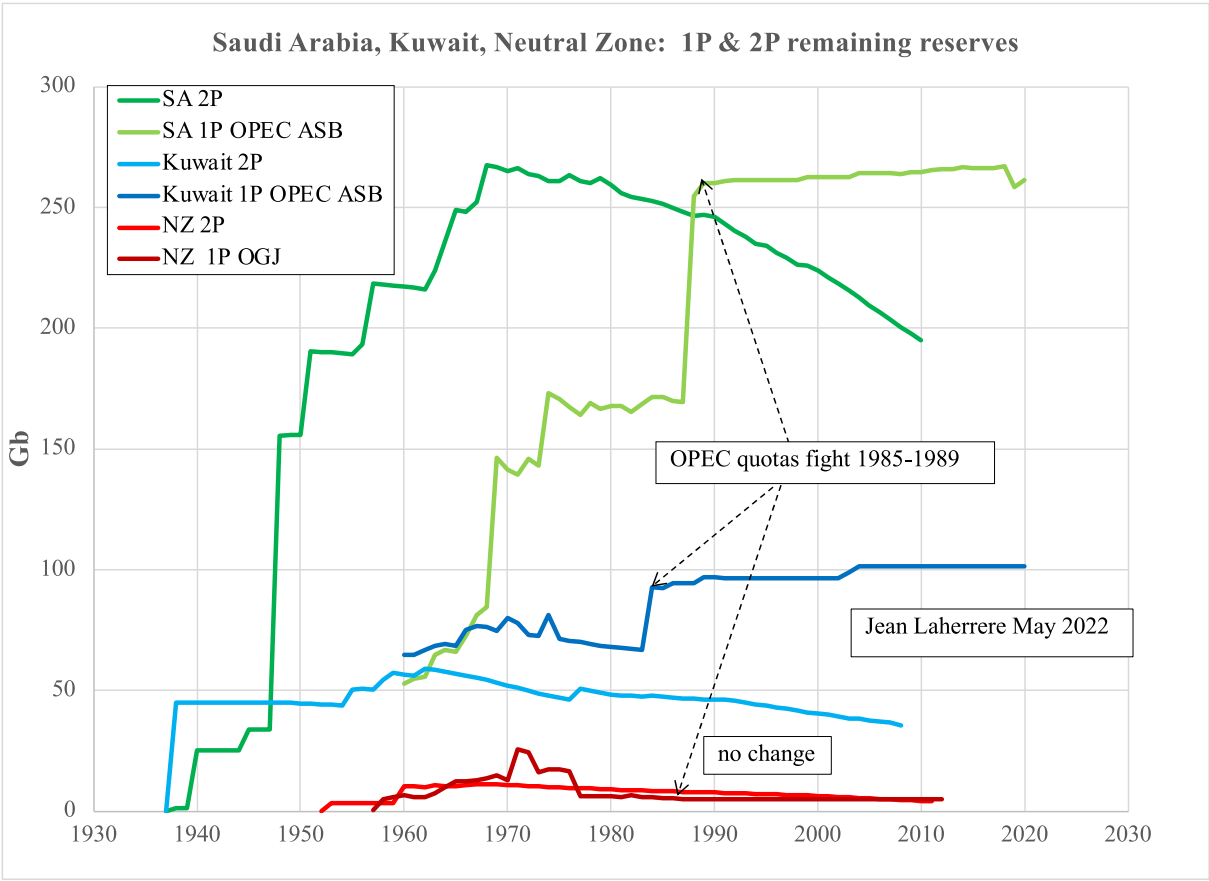
This is illustrated in Fig. A3.1 for Saudi Arabia, which shows the evolution from 1998 to 2011 of IHS 2P cumulative oil discovery data by date of discovery, as well as the number of fields discovered at these dates. As can be seen, the 2P volume of oil plus condensate in Saudi Arabian fields that had been discovered by 1990 was given as 310 Gb in the 2004 IHS database (dark blue line), assumed to reflect largely Petroconsultants data, but where this had risen to 400 Gb in the 2011 IHS Energy database (green line), even though, as the Figure shows, the number of fields reported as discovered by 1990 had changed very little. As a result, the current volumes of oil reported in this database for large old fields in Saudi Arabia are in doubt, as improvements in extraction techniques for these fields over the short period from 2004 to 2011 cannot account for an increase so large. This conclusion is supported by analysis of the production curves of some of the Saudi Arabian fields in question; by Hubbert linearization (see Section 5.1) of the country's total production, see Supplementary Material; and by analyses such as, for example, Zagar (2017).

Correcting for corresponding overstatements across Middle East OPEC countries as a whole indicates that the total 2P reserves in at least the IHS database (and perhaps others) for these countries should be reduced by about 300 Gb.

The second problem with 2P reserves data is in the reporting of reserves for former Soviet Union (FSU) oil fields. Here the size of discoveries was generally classed as 'ABC1', taken to indicate the maximum quantity of oil a field could yield without economic constraints. In its annual reports, Gazprom data indicate that generally only about 70% of the ABC1 estimates should be used to calculate the 2P estimates of field volumes. Again, analysis of production curves for individual fields supports this conclusion. Correcting for this reduces 2P reserves for FSU countries in total, as reported in this oil consultancy database (and again, probably others) by about 100 Gb in total.

More detail on the analyses supporting these significant adjustments downward of Middle East OPEC and FSU 2P oil discoveries is given in papers by one of us (Laherrère) carried on the ASPO France website: https://aspofrance.org/tag/jean-laherrere.





(caption on next page)

Fig. A2.1. Evolution of published proved (1P) and proved-plus-probable (2P) oil reserves for Iraq and Iran (above); and Saudi Arabia and Kuwait (below). Shows the large step-changes in claimed proved reserves; and comparison with 2P reserves.
Notes: - NZ: Neutral zone: 50% Kuwait, 50% Saudi Arabia. - 1P data are for 1960–2020. - For all four countries, public-domain reported 1P oil reserves are considerably greater than the 2P oil reserves data held in oil consultancy databases.
Sources: 1P data: OPEC, and *Oil and Gas Journal* (OGJ). 2P data: Data from Jean Laherrère, May 2022.

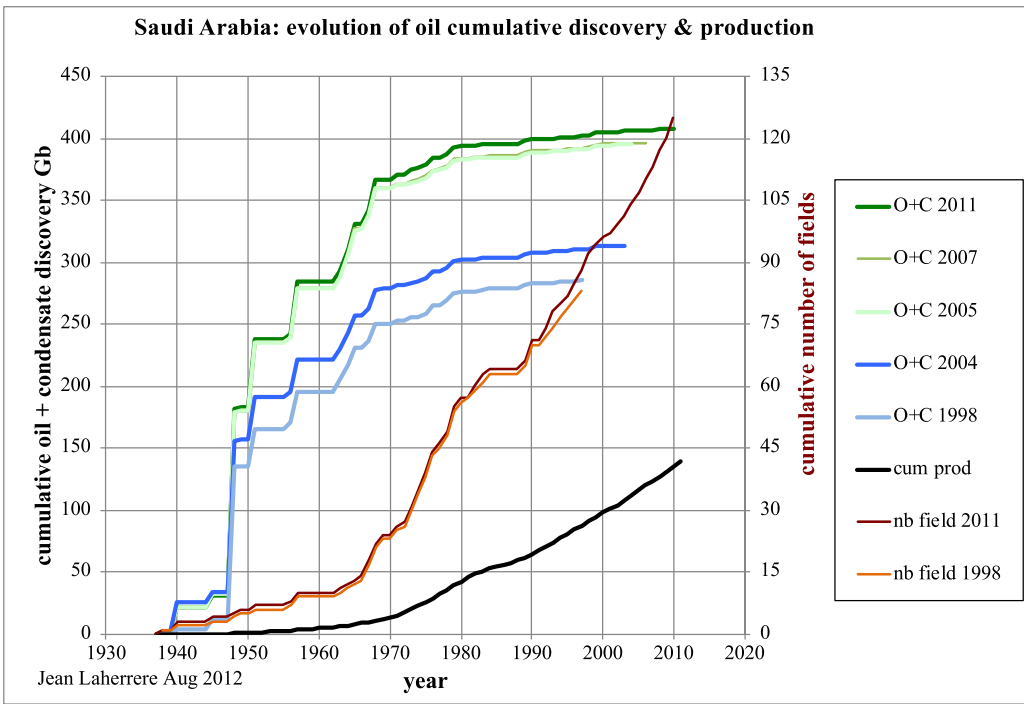


Fig. A3.1. Changes with time of IHS Energy data for Saudi Arabian cumulative 2P discovery of oil. We suggest that these numbers are inflated, being perhaps 'political' vs. 'geological', as the large discoveries required to generate these newer numbers have not been reported. For example, the total discovered by 1970 is 250 Gb as reported in 1998, ~280 Gb as reported in in 2004, ~360 Gb as reported in 2005 and ~ 370 Gb as reported in 2011.
Key: - O + C year: Cumulative discovery of oil plus condensate; 2P data from the edition of the IHS Energy database corresponding to the year indicated. - cum prod: Cumulative production to 2011. - nb field date: Cumulative number of oil fields discovered; data as of year indicated.

Appendix D. Estimates of Global Oil URR

This appendix summarizes a wide range of estimates, generated between 1949 and the present day, for the global ultimately recoverable resource (URR) of oil.

Table A4.1
Estimates of global URR by oil category (Gb).

Estimated global ultimately recoverable oil resource (URR)	Conventional oil[10]	All-oil + NGLs
Range of estimates 1949 to 1981[1]	1800–2500	
Campbell & Laherrère 1998	1800	
'Low' range of estimates 1992 to 2005[2]	1800–2836	2670–3000
'High' range of estimates 1998 to 2005[3]	3303	4000–4500
Campbell, data as of 2010[4]	~2200	
IEA 2013[5]	3800–4200	
Extrapolation of IHS, 2011 discovery data[6]	2500	
Extrapln. of IHS & Rystad data, 2017[7]	2700	
Globalshift 2018 production to 2100[8]		3250
Rystad Energy 2018[8]		3670
Laherrère estimates, 2018[8]	~2600–3000[11]	
IEA, data for end-2020[9]	3500	7800[13]
This paper, URR estimated by HL	2500[12]	5000

Key: - Conventional oil: Originally generally taken as crude oil excluding extra-heavy oils such as those produced by thermal means, as well as tar sands and Orinoco oil; and also excluding oil produced from kerogen. 'Conventional oil' also originally excluded light-tight ('shale') oil, as this was only recently identified as economically extractable. - All-oil: All crude oil. - NGLs: Natural gas liquids.
Notes: [1]Data from Table 1 of Bentley (2015); and where the URR estimates used by Hubbert for global conventional oil less NGLs were: in 1949: 2000 Gb; in 1956: 1250 Gb; in 1969: in the range 1350–2100 Gb. [2]Data from Table 2 of Bentley (2015), and excludes a 'what-if' outlier of 3000 Gb. [3]Data from Table 3 of Bentley (2015). 3303 Gb is an EIA estimate, and includes NGLs. [4]Data from Table 2 of Bentley et al. (2020). [5]Data from Fig. 4 of Bentley et al. (2020). Original source is Fig. 13.17 of

IEA report '*Resources to Reserves*', 2013; giving the URR range for conventional oil without, and with, EOR. [6]Extrapolation of 2P oil discovery data in Fig. 1 of Bentley et al. (2020). [7]Extrapolation of 2P oil discovery data in Fig. 2 of Bentley et al. (2020). [8]Data from Table 2 of Bentley et al. (2020). [9]Data from '*Table 6. Remaining technically recoverable fossil fuel resources, end-2020*' from IEA 2021 documentation of their World Energy Model (WEM) used for the IEA's *World Energy Outlook*, 2021. Individual data by class of oil are given in the inset box, lower right of Fig. 5 above, and as expanded in Supplementary Material. Since the data are for remaining recoverable resources, we add corresponding cumulative production to-date from Table 1 of this paper to generate the URR estimates shown here. [10]Early URR estimates for conventional oil exclude NGLs, later estimates may include some or all of NGLs. [11]Current Laherrère URR estimates, and as summarized in Table 1: Crude oil less extra-heavy oils: 3000 Gb; including extra-heavy oils: 3500 Gb. [12]Excluding light-tight oil. [13]Includes a URR of ~1000 Gb for oil from kerogen.
References: Bentley (2015); Bentley et al. (2020).

Appendix E. Hubbert linearization: background, strengths and limitations

M. King Hubbert was a geophysicist who worked at Shell Oil and also at several universities who helped develop a general physical theory for the production of a non-renewable resource, and applied this explicitly to oil (Hubbert, 1956; Hubbert, 1969). He maintained that cumulative production of a non-renewable resource in a region generally follows a logistic curve (and hence annual production over time a 'bell-shaped' curve), with production reaching a maximum when about half of the region's URR has been produced. In practice, rather than being symmetric, oil production in a region often displays something of a 'tail'; where Campbell for example models this by exponential decline once the resource-limited peak is past.

The physical driver for this curve is that the region will generally contain a relatively small number of large oil fields, and a larger number of smaller oil fields, and the production peak occurs when declining production from the large, easier-to-find, early fields can no longer be compensated by increasing production from the smaller, harder-to-find, later fields; see Bentley (2016) for a detailed explanation of this mechanism. And while economists often argue that oil price is the main determinant of production, and indeed price is very important, in regions without major long-term above-ground production constraints (such as limited access, strife or quotas) the Hubbert geologically-based production pattern has been the norm.

Examples of major oil-producing countries that are now almost certainly well past their *resource-limited* production peaks for *all-oil* include Libya, Iran, Kuwait, Indonesia, the UK and Norway; those more recently past peak include Algeria, Qatar, China and Mexico; and those that are just past or will soon peak include Nigeria and Russia. Charts of past and future production of all-fossil-oil by country, based on a detailed bottom-up by field and project model, can be accessed at: www.globalshift.co.uk.

For the non-conventional oils, the long-term production profiles are less clear, as many of these are still in their early stages of production. But it is probably reasonable to expect that for these oils also, production will follow a roughly 'Hubbert' curve as production from the small, later, more difficult to access sources of each these classes of oil becomes insufficient to offset the declining production from the larger, earlier, easier to access sources.

Note that to-date the *resource-limited* peaks in oil production in countries have nearly always come as a surprise to the countries concerned. Examples include the conventional oil peak for the United States in 1970, which was the trigger for the economically devastating 1970s oil price shocks; Indonesia's peak in 1977, which subsequently caused the country to leave OPEC; the UK's peak in 1999; and Norway's in 2001; as probably also Nigeria's either already past or expected soon. The reason these oil peaks come as a surprise to the countries concerned is because at the time of peak oil production in the country there has been a long upward trend in production, existing fields in the region still have very significant reserves, new fields are still being discovered, and discovery techniques and recovery factors are being improved by new technology. (Note that by contrast Russia's oil peak, expected in perhaps as little as 2 years from now (Rystad, 2021), has indeed been flagged by that country, possibly because Russia still has large resources of more difficult oil waiting to be exploited.)

Hubbert later extended his work on oil production to develop a technique to estimate a region's URR based simply on its past production, a technique Deffeyes (2005) termed 'Hubbert linearization' (HL). This approach thus includes an estimate of the undiscovered oil that has not yet been found. The technique is based on the assumption that cumulative production in the region is following a logistic curve, and generates a plot with cumulative oil production on the x-axis, and the ratio of annual production to cumulative production on the y-axis. The region's URR is then estimated by the intersection of the resulting trend line with the x-axis.

The HL approach has a number of limitations, including not being able to account well for step-changes in extraction techniques, nor for the inclusion of a new class of oil not reflected in past production data ('shale oil' in the US being a recent example). But the method has shown itself to give reliable estimates in the case of many countries (see, e.g., Campbell, 2013; and on-line publications by Laherrère), and has the advantage of giving an explicit and defensible estimate of how much oil the region will produce in total using a procedure that is subject to validation and sensitivity analysis.

Note that Campbell (2013) provides examples for many countries of comparing URR estimates generated by extrapolation of cumulative discoveries ('creaming curves') with those estimated by Hubbert linearization. And for more than 100 years the HL technique has correctly predicted the total quantity of U.S. anthracite coal produced from this now largely exhausted resource (Laherrère, 2018). The mathematical approach to generate a 'Hubbert curve' for remaining resources is given in Laherrère (2021).

Appendix F. Laherrère chart of all fossil fuel production, 1850–2200

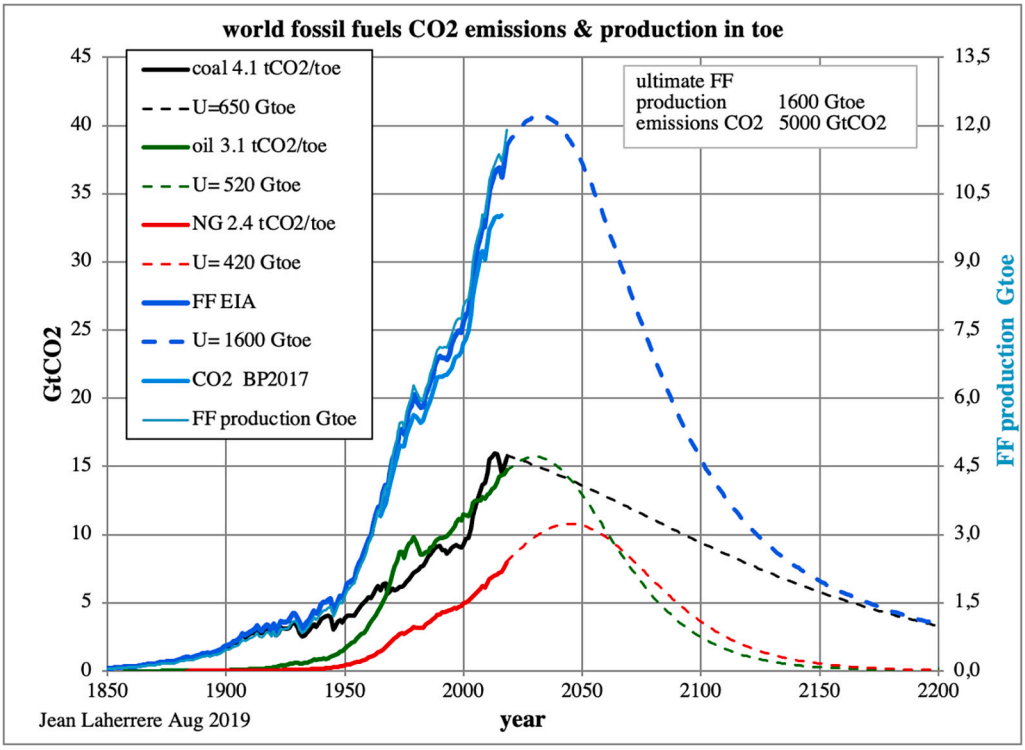


Fig. A6.1. Forecast of CO_2 emissions from all-fossil-fuels, based on approximate Hubbert 'mid-point peak' modelling.
Key: FF: All fossil fuels; BP: BP Stats. data, 2017 edition; U: URR; NG: Natural gas.
Notes: - The forecast for coal recognises an implicit EROI limit for coal, as it reflects only future coal production under 'realistic abstraction' constraints of: onshore coal sources, mined at less than 1500 m depth; and with more than 60 cm seam thickness.
Source: Page 11 of: Laherrère J.H. 2019 "*Are there enough fossil fuels to generate the IPCC CO2 baseline scenario?*" August. https://aspofrance.files.wordpress.com/2019/08/ipccco2rcp.pdf.

As the data by Laherrère (2019) reproduced above shows, the global CO_2 emissions in this 'geology-based' model for the period 2020–2100 are approximately 1000, 750 and 650 $GtCO_2$, respectively, for coal, oil and gas, for a total of some 2400 $GtCO_2$, with a further ~850 $GtCO_2$ being emitted beyond 2100. Clearly such emissions are incompatible with the 580 $GtCO_2$ limit to CO_2 emissions to 2100 assumed by Welsby et al. (Welsby et al., 2021) to meet 1.5 °C.

Indeed, an approximate calculation can be made. Total CO_2 emissions from pre-industrial times to 2020 are estimated by Laherrère (2021) at around 1750 $GtCO_2$, and have resulted in a corresponding temperature rise of some 1.1 °C. We recognize that the climate system involves numerous non-linear feedbacks, but on a simple linear basis the future all-fossil-fuels emissions in Laherrère's model, of very approximately 3250 $GtCO_2$, would add a further ~2 °C to global warming, for a total of ~3 °C above pre-industrial; and see Matthews and Tokarska (2021) on the use of a linear 'transient climate response to cumulative emissions' (TCRE) model. This calculation ignores the non-linearities mentioned above, and is only for the burning of fossil fuels, and thus ignores possible strong new feedbacks such as reduced absorption of CO_2 by the ocean or forests, or CO_2 and methane emissions from melting permafrost, etc. Thus, we also conclude, as is now widely accepted, that much of the total fossil fuel resource must be left in the ground.

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