Global Oil and Gas Depletion - An Open Letter to the Energy Modelling Community

R.W. Bentley, c/o Department of Cybernetics, The University of Reading, Reading, RG6 6AY, UK. (Phone: +44 118 931 6796 ; r.w.bentley@reading.ac.uk)
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Abstract

Combining geological knowledge with 'P50' discovery data indicates that over sixty countries are now past their resource-limited peak of conventional oil production. The data also show that the global peak in conventional oil production is close, and the peak for conventional gas within sight.

Most analysts rely on proved oil reserves data. These contain no information about the true size of discoveries, being variously under-reported, over-reported and not reported. This has led to a number of misconceptions including the notion that oil forecasts have been unreliable, that oil reserves see large increases due to technology, and that global supply is ensured if sufficient investment is forthcoming to 'turn resources into reserves'. These misconceptions are widely held within governments, some oil companies, and organisations like the IEA.

In addition to conventional oil, the world contains large quantities of non-conventional oil and oil substitutes. All current detailed models show that past peak these other oils will not come on-stream fast enough to offset conventional oil's decline. However better modelling is required to determine the fundamental rate limits for these oils, examining their technology, lead-time, investment, pollution and net-energy constraints.

The approaching peak in conventional oil requires a number of other issues to be examined. These include the need for far better oil reserves data in certain countries, better modelling of the date of peak, updated predictions for CO_2 emissions, understanding the impacts on GDP, and evaluating the effectiveness and fairness of the market in response to a dwindling resource. Integrated energy modelling is likely to be an important tool in dealing with the complexities that lie ahead.

Introduction

This letter requests the energy modelling community to move rapidly to understanding depletion of the world's conventional oil and gas, so that significant effort can be put into analysis of the problems that arise.

Part A of the letter discusses the two data sets generally used to examine the global depletion of conventional hydrocarbons to explain why different views of depletion exist. Other topics presented include reserves growth, the reliability of past forecasts, and examination of a common 'economic' view of depletion. Part B lists the problems raised by conventional hydrocarbon depletion that seem to this author to call for urgent analysis.

PART A: DEPLETION OF THE WORLD'S RESOURCES OF CONVENTIONAL OIL AND GAS

There are two very different views about the seriousness of conventional oil and gas depletion. One view maintains that the resource-limited peak in the global production of conventional oil is near, and that the corresponding peak for conventional gas is within sight. The other view sees no near-term resource limits to either oil or gas supply, and fears that if society listens to the 'near-term peakers' damaging economic policies will result.

The fundamental reason for this divergence of view is the existence of two very different data sets. The *industry 'P50'* data on oil discovery indicate that the conventional oil peak is imminent, and the gas peak not too distant. But if *proved reserves* are used a very different picture emerges, namely one that supports a cohesive economic view which dismisses any near-term threatto hydrocarbon supply.

The following sections examine these two very different data sets.

1. Industry P50 Oil Discovery Data

1.1 Results from the P50 data

Industry data on the amount of oil discovered in individual fields are held by national and private oil companies; data companies such as IHS Energy (formerly Petroconsultants), Wood Mackenzie, Energyfiles and PFC Energy; and by petroleum or mineral institutes such as Germany's BGR or France's IFP. Such data are not held by organisations such as the IEA, the US' EIA, or IIASA.

In examining industry data on discovery, energy analysts generally need to use the 'P50' reserves values. 'P50' designates 50% probable, and is an industry estimate at a given date for the most likely size of a field's reserves. P50 estimates are often approximated quite well by 'proved plus probable' reserves.

Combining P50 discovery data with geological knowledge indicates that about two-thirds of the world's oil producing countries are now past their *resource-limited* peak of conventional oil production, and hence in terminal production decline. [1] Some are small producers, but Chevron reports that production is in decline in 33 of the world's 48 largest oil producing countries. [2, 3] Large countries past peak include the US, Iran, Libya, Indonesia, UK and Norway. In addition, Russia is past its resource mid-point if not technically past peak P50 discovery data show that many more countries will soon go past peak, including major producers such as China and Mexico. [4]

Germany provides a good example of how P50 discovery data, coupled with geological knowledge, indicates that a country is past its *resource-limited* production peak of conventional oil.

Figure 1 shows oil liquids production in Germany from 1900 to 2000. Production has clearly gone over some kind of peak, but maybe this was an artefact of economic conditions or government policy over this period. And maybe there are large amounts of new oil in Germany waiting to be discovered. Figure 2 addresses these questions by adding the P50 annual discovery data. As can be seen, discovery controls production, and the peak was a direct result of the amount of oil that was found. If more oil had been found the peak would have been higher or later; if less it would have been lower or earlier. The same data are shownin Figure 3, but with discovery plotted as a five-year average to allow the eye to better judge how discovery has driven production.

Government policy can be an important factor, of course. German discovery might have been limited if exploration had been restricted for certain periods (as is the case for some countries), or in certain regions (as is the case with the US today). And production would have been affected if Germany had set pro-rationing in place, as in the US before 1970, or applied quotas such as OPEC's. But the fundamental things apply: once the amount of discovered oil is known from the P50 data, an upper limit is also known for what can be produced and when.

The question then remains as to whether Germany has much new oil to find. This can only be answered fully by combining the message from Germany's falling discovery trend with geological knowledge. The big finds of the 1940s and '50s were due to the introduction of seismic, while the large late find in 1980 was in Germany's rather small offshore area that became open for exploration. Figure 4 shows the same data as previously, but on a cumulative basis. As can be seen, Germany's P50 cumulative discovery trend (its 'creaming curve') has been flattening out since about 1960.

Estimates for the total amount of recoverable oil in Germany potentially accessible by a fairly distant future date have been made by various geological groups. Such estimates are loosely termed 'ultimates' because they approximate the country's ultimately recoverable reserves, i.e. its original endowment of recoverable oil. These estimates are best illustrated on a plot like Figure 4, which here presents four estimates for Germany's 'ultimate':

- BGR's 1997 assessment of EUR, 2.3 Gb;
- USGS' year-2000 median assessment on a 'non-grown' basis, incl. NGLs, 2.14 Gb;
- Campbell/University of Uppsala end-2004 model, 2.75 Gb;
- Energy Files end-2004 assessment, 2.6 Gb. [5]

As can be seen, these 'ultimates' are in reasonable agreement with each other and with the apparent asymptote of the P50 discovery curve. The geologists are pretty certain that no significant new quantities of oil will be found in Germany, where this reflects both geological knowledge and over a hundred years' of discovery effort and technological progress.

Like other regions of the world, Germany, despite having applied enhanced oil recovery (EOR) techniques since 1985, still has a considerable amount of oil judged currently unrecoverable in existing fields. However, barring some extraordinary new recovery technique, Germany is now close to the end of her conventional oil: at ~2.0 Gb her total production to-date has consumed about 80% of her ultimate.

So where do economics come into this picture? Economic factors are important, of course. A higher oil price encourages exploration, brings on economically marginal fields, permits more expensive recovery, and reduces demand. But in a country well past peak the effects are small. More exploration just moves the country a bit further along the declining discovery trend; the economically marginal fields are known, and are usually small or difficult; more expensive recovery techniques can be identified and their impacts calculated. In general, though each country needs specific analysis, the ability of a higher oil price to significantly impact the geologically-based estimates of ultimate is limited.

Another example of using P50 discovery data to predict production is the UK. As Figure 5 shows, here also the P50 discovery data explain the subsequent production trend. But, as with Germany, knowing that that the UK's 1999 production peak was *resource-limited* depends on combining the UK's long-term falling discovery trend with geological knowledge.

The UK still has several significant future potential sources of oil. It may have quite large quantities still undiscovered in subtle stratigraphic traps; it may have significant new potential towards the deeper Atlantic; and it certainly has large amounts of oil in-place that are currently deemed unrecoverable. But geological and reservoir/production knowledge says it is virtually certain that none of this oil, if it exists, can found rapidly enough to push UK production back up past the 1999 peak. The subtle traps, even if they hold significant amounts of oil, will need highly calibrated seismic to find, so will not be found rapidly; the deeper Atlantic will offer surprises but is not thought especially prospective due to poor source rock and traps; while the many routes to improved recovery in existing fields have already seen much trial and analysis. Overall, as with Germany, the UK's P50 discovery data coupled with geological knowledge indicates that the country's resource-limited conventional oil peak is past.

Figure 6 gives the UK's cumulative plot and includes a UK government estimate of 'ultimate' made back in 1974, plus more recent estimates from Campbell, USGS, and Energyfiles. [6, 7] As with Germany, these 'ultimates' are in reasonable agreement, and with the apparent asymptote of the discovery creaming curve. The UK's peak in 1999 should have been no surprise at all. Energyfiles' forecast of the UK production decline is given in Figure 7.

Analyses of this type, combining P50 discovery data with geological knowledge, have been applied to all the world's oil-producing countries. As mentioned above, they show that about two-thirds of the countries are now almost certainly past resource-limited conventional oil production peak [8, 9]

Figures 8 and 9 give plots for the world as a whole. Figure 8 shows that the world is living off its past exploration success, with the large finds from the 1940s to the 1970s being drawn down since about 1980, the historical turning point when global production began to exceed discovery. [10] The cumulative plot of Figure 9 shows that the world's consumption has reached about half of its discovery of conventional oil to-date. This plot also shows how very high are some of the estimates of global 'ultimate', particularly the 'grown' estimates, when compared to the long-run global discovery trend.

Summarising, for some countries, we have:

	Peak of P50 discovery	Peak of production
US	1930s	1971
Germany	1950s	1967
UK	1970s	1999
Norway	1970s	2001
World	1960s	~2005 - 2015

A list of discovery and production peak dates by country from the Campbell/Uppsala model is at www.peakoil.net. A full list of the 64 or so countries past peak can be purchased from Energyfiles.

P50 discovery data coupled with geological knowledge can be used to predict the future of global conventional oil production. Such calculations are included in the models discussed in Section 4, below.

1.2 Getting access to the aggregate P50 data

In the past, those who doubt the near-term conventional oil peak have complained - with at least some justification - that as they could not get to see the industry data, they could not judge the data's correctness, nor that of the conclusions drawn. [11]

'Proved plus probable' reserves data for *individual fields* are available from numerous industry and government sources, and these numbers are often the same, or at least similar, to the industry P50 estimates. But the difficulty is of realistically assembling and assessing these often disparate field data to give credible country, regional, and world totals. Such totals are necessary if conclusions on overall discovery rate are to be drawn. It is for the onerous but vital task of assembling reliable field data that the data companies, in part, get paid.

Full datasets by field from most data companies are indeed expensive. IHS Energy's suite of world data plus analysis has an annual licence fee in excess of $1 million. Fortunately much cheaper *aggregate* industry P50 data on oil discovery are available, and useful amounts of the P50 data, in various adjusted forms, are now also available in the public domain.

IHS Energy provides a global set of oil and gas P50 discovery and production data *by country* (rather than by field) that can be purchased for about $5,000; this is the resource part of their 'PEPS' dataset. The UK company Energyfiles is another excellent source for such data. They specifically aim at providing comprehensive data on an inexpensive basis, including forecasts of future production by country, regions, and the world as a whole. Energyfiles' global report, including access to the underlying country descriptions and data, costs about $3,000. Both companies' datasets give invaluable information about the current state of global oil and gas depletion, and are within the budgets of company research departments and academic groups. [12]

Though analysts can buy these data they are not allowed to publish results except with permission (as granted here for Figures 1 to 9). By contrast, increasing amounts of aggregate P50 data are available in the public domain. Such data are usually drawn from a variety of industry sources, and are often adjusted where the data providers judge the underlying data to be over- or understated. Despite such adjustments, 'public-domain' aggregate P50 data are a key resource for the analysis of hydrocarbon depletion.

Public-domain aggregate P50 data are available from:

- Data companies, in the form of publicity material. This information is generally sparse, but can be extremely valuable. [13]
- USGS assessments. The year-2000 assessment, for example, gives end-1995 P50 reserves by country from the IHS Energy data set. [14]
- A wide variety of publications by Jean Laherrère, see, e.g., www.oilcrisis.com/laherrere. [15]
- The Campbell/Uppsala model, available on the ASPO website: www.peakoil.net. The P50 reserves data here apply to 'regular' oil (see Note 3), are based on a variety of sources, and are usually adjusted for perceived over or under-reporting in the industry databases.
- Various books by Colin Campbell, and the monthly 'country analyses' in the *ASPO Newsletters*. These reflect the same data as in the Campbell/Uppsala model. Plots are provided of discovery vs. production, but as discovery is usually to its own scale the numbers need to be read off and re-plotted if graphs like Figures 1 to 9 are to be generated. *ASPO Newsletters* to-date (October 2005) have reported on some 42 countries. [16]

2. Proved Reserves

2.1 The poor quality of proved reserves data

We now turn from the industry P50 data to the proved reserves data. The latter are quite unusable for calculating future oil production as they exhibit serious errors of under-reporting, over-reporting, and non-reporting. These data problems have not been adequately recognised by much of the energy modelling community, leading to serious errors of analysis.

(a). Under-reporting

It has been known for a very long time that the proved reserves data for a field, a company or a region are usually very conservative numbers. Proved reserves generally report only the oil that is *just about to be brought to market*, rather than *the total amount of oil that has been discovered*. (The latter quantity, as explained above, is tallied by the P50 numbers.)

Confusion, however, between the two data sets is still widespread and has fuelled nearly every aspect of the oil depletion debate. The IEA, IIASA and IFP have all published tables listing proved reserves alongside P50 reserves without any comment on the datasets' intrinsic difference; while both the EU's *Energy Security Green Paper* and the UK's *Energy White Paper* clearly imply that proved reserves are meaningful estimates of total remaining oil.

BP's widely respected annual *Statistical Review of World Energy* makes the same mistake. It defines proved reserves as " … 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". This is hopelessly wide of the mark, as proved reserves usually report quantities of oil *well below* what can be recovered with reasonable certainty under existing conditions.

Some examples will illustrate this point.

For the past 20 years the UK's proved reserves have hovered consistently around 4 to 5 Gb, see Table 1. By stark contrast, the UK's P50 reserves stood at 20 Gb in 1980 and have been falling steadily since. Today they stand at about 10 Gb, still twice the proved reserves number. [17]

Norway is another example. In its early history the Norwegian Petroleum Directorate (NPD) calculated the country's reserves simply by totalling oil company submissions of SEC-defined proved reserves. But later the NPD realised that, with little in the way of new finds or improved recovery, the country had produced far more oil than the proved reserves could account for. The NPD switched in 1995 to reporting *all* categories of reserves, including P50 data and on up to higher estimates.

But the best example of the consistently conservative nature of proved reserves is the US. Here the reserves numbers have changed hardly at all for decades, staying broadly in the ~30 to 40 Gb range, with a slight peak after Prudhoe's reserves were included. Once again the reason is because proved reserves do not report the *total* oil discovered, but simply that portion judged close to production under SEC rules. On a rolling basis, as the existing reserves are produced, the companies put in the investment and infrastructure needed, and gain the permissions, to bring the next tranches of discovered oil close to market, and hence within the SEC definition. As a consequence, the US R/P ratio has also stayed virtually constant over the period, at around 10 years.

IHS Energy holds US data very differently from that of other countries. The company generates P50 reserves for other countries by totalling its P50 field discovery data and subtracting cumulative production. But for the US they add cumulative production to *published proved* reserves, to generate what in effect are 'proved discovery' data. This difference is clear when a cumulative plot like Figure 4 is generated for the US. For nearly all other countries the backdated cumulative P50 discovery in such a plot shows a steep rise resulting from large early finds. In the US the 'proved discovery' curve simply stays just ahead of production - by the R/P ratio of about 10 years - for virtually the whole of the more than 100 years' of data.

Laherrère points out, however, that US 'proved and probable' data are available up to 1988 in the US DoE/EIA-0534 1990 report; where for more recent discoveries, which by volume are mostly offshore, the fairly mild MMS three-fold growth factor can be applied.

In summary *proved reserves* for a field, a company or a region are usually significantly under-reported when compared to the actual quantity of oil that has been found. Table 1 compares P50 reserves data from two industry sources with proved reserves. As can be seen, the UK, Norway, US, FSU and China are all 'normal' countries, i.e. countries where P50 reserves are larger than the proved reserves.

(b). Over-reporting

A second serious problem with the proved reserves data is the opposite of the above. For the main Middle East OPEC countries their P50 reserves data held by industry are considerably *smaller* than their proved reserves. This anomaly was due to the 'quota wars' increases of the late 1980s, where allowable production under OPEC's quota was driven in part by the size of a country's reported proved reserves. As Table 1 shows, the changes adopted by the countries were dramatic, doubling proved reserves overnight in a number of countries and trebling them in the case of Abu Dhabi. In total the increases added 300 Gb to global proved reserves. [18]

A number of analysts, apparently unaware of the reason for the OPEC increases in proved reserves, interpreted these as representing genuine additions to the global oil supply, either from discoveries or revisions. In 1997 at a key IEA meeting Laherrère and Campbell gave presentations about global oil peaking based on P50 data. Odell then said: 'Now let's use some real data' and put up the global proved reserves data from DeGolyer & MacNaughton. Because this sequence of reserves included the 'quota wars' jumps, the increase in proved reserves over the period was greater than global cumulative production, from which Odell concluded that the world was "running into oil". The same analysis was presented by others, including Davies. [19]

Table 1 includes the P50 data for the OPEC countries where these reserves are smaller than their proved reserves.

(c) Non-reporting

The third problem with proved reserves, and now the most serious, is non-reporting. Each year in recent years proved reserves for the majority of countries have not changed, with these static data sometimes running for a decade or more, see Table 1. [20]

Overall, the key idea to retain about proved reserves is that for the majority of countries in the world, and especially the large producers, the data have no bearing at all on true reserves.

2.2 Determining the date of peak from proved reserves data

Not surprisingly, the date at which a country goes over its production peak cannot be determined simply from its proved reserves data; additional analysis is needed as set out in Section 3.1.

As Table 1 shows, none of the US 1971, UK 1999 or Norway 2001 peaks can be deduced simply from the proved reserves data. This is because leading up to the peak, and likewise following, the proved reserves stay at roughly the same level For the UK and Norway the data fluctuate primarily from the whims of reserves reporting.

Despite these data making clear that proved reserves give no direct information about peak, it was said by one of the 'running into oil' protagonists that there could be no credence to oil peaking fears until there had been several years' fall in world proved reserves. This view is not sensible. The date at which data-driven analysis of peaking could be undertaken was when sufficient regions were past peak (primarily US states) for the mechanisms of peaking to become clear. Analyses of this sort were carried out by Hubbert in the 1940s. Confidence about the predicted date of global peak became fairly solid in the 1970s once global P50 discovery was in decline and its trend clear. The date at which rational planning for global decline should probably have started was in the 1980s, once the P50 reserves began to fall. [21] Waiting until *proved* reserves start to decline is to wait until the peak is long past.

2.3 Misleading conclusions from using proved reserves data

Does it matter that proved reserves have been reported conservatively?

It has mattered a great deal, and is the prime reason that the oil depletion debate is taking place at all. What looks at first blush like a staid and respectable policy on reserves reporting has had serious side-effects.

Most of these have resulted from the mistaken belief that proved reserves are a reasonable measure of the oil remaining at a given date. For example in the 1970s many believed that the world would 'run out of oil' in about thirty years, as it had thirty years' of proved reserves left. Today, with forty years' of proved reserves remaining, the impression is widely held that oil forecasting is therefore unreliable. The real explanation, that the 1970s proved reserves data simply took no account of the known probable oil, nor of the yet-to-find, is still largely unrecognised.

From the same reasons it has become accepted that it is difficult to measure the amount of oil in a reservoir. In fact the oil-in-place in structures is usually known quite accurately, especially if quoted statistically across a range of related fields; while the predicted recovery factor of a specific method today is also usually broadly correct. For large fields today the assessed quantity of recoverable oil is an output of detailed finite-element modelling.

As another example, the observation that reserves are frequently replaced without significant new discoveries is widely explained by the likes of the IEA or the UK's DTI as being due to advances in technology, including directional drilling and 3-D seismic. The IEA's use of a graph showing an apparent three-fold increase in the amount of oil in the North Sea between that deriving from 1986 'proven technology' and from 1999 'new technology' is one such example. [22] Examination of individual fields however shows that most of apparent technology-driven growth is explained by conservative original reporting, either of proved reserves, or 'production engineering' estimates of proved plus probable reserves.

Another misleading outcome of conservative reserves reporting is that analysts such as Adelman explain the very long run of almost constant US proved reserves by proposing that investment is the primary determinant of reserves. This view maintains that it is investment that turns "resources into reserves", and that the size of the underlying resource is of no concern, being both "unknown and unknowable".

As set out above, this explanation has an element of truth, as under SEC rules it is investment, or at least the intention to commercialise, that brings already-discovered oil into the proved reserves category. Where the analysis falls down utterly is in failing to recognise that the real size of the US reserves has long been known, and that their long-term reduction is also well documented. To get at these real reserves the proved reserves have to be 'grown', as Hubbert and others have shown (Section 3.1). Hubbert, for example, showed that US Lower-48 'grown' discovery per foot drilled declined inexorably since the 1930s. It is hard to imagine that anyone who has looked at this graph could think that the US reserves of conventional oil are solely a function of investment.

However, this 'resources into reserves' view is deeply embedded, and has recently had an extraordinary exemplar. The IEA has just published a report with effectively this title. This report more-or-less correctly identifies the large amounts of hydrocarbons in the world, but completely misses the significance of the peaking of conventional oil, concluding, for example, that: " ... none of this [peak oil discussion] is a cause for concern. Hydrocarbon resources around the world are abundant, and will easily fuel the world through its transition to a sustainable energy future. What is badly needed, however, is capital investment ..." [23]

The report does refer to decline in existing fields, and notes that: "Most [non Middle East OPEC] countries have passed their peaks in conventional oil production, or will do so shortly." It also has a section ('Box 2', pp 38-39) on peak oil, but concludes that "discussion of these [peak oil] questions is outside the scope of this [report]". It is useful that the IEA is looking at aspects of the total oil resource, but omission of the implications of the conventional oil peak is quite unforgivable in an IEA report. This is especially so given the immense efforts of many well-informed people to encourage the IEA towards an understanding of peaking, including its own former staff (Wigley, Miller and Bourdaire), and representations by many other organisations including ASPO and the University of Reading 'Oil Group', of which I am a member. Until the IEA achieves comprehension of oil peaking there is little chance of cohesive multi-national action on the serious problems that will arise.

The fundamental reason for the IEA's ignorance of the peaking arguments is almost certainly due to the evolution of an 'economic view' of oil supply, as explained next.

2.4 An 'Economic view' of oil supply

The broad set of misunderstandings described above, driven largely by thinking proved reserves to be a useful measure of remaining oil, fed into a cohesive 'economic view' on oil supply. This view is summarised in the Annex. Its main tenets are:

- Price, investment and technology are the main drivers of supply, not resources.
- Past forecasts failed because they assumed the resource base to be fixed.
- Should supply difficulties approach, they will be signalled by rising price and

falling proved reserves.

- Any supply difficulties are most efficiently corrected by the market - short-run increases in price will limit demand and bring on adequate new supplies.

Those who hold this view see it has having been solidly corroborated by history:

- The 1970s price shocks turned out to be simply political, and were not driven by resource shortage as was widely believed at the time.
- OPEC did not remain in the driving seat, and the oil price did not continue to escalate as many had forecast. Instead the higher prices brought in competing sources of oil, and the price fell.
- Despite recurrent predictions of shortage, proved reserves have consistently been replaced.

History in fact tells a very different story:

- The 1970s shocks were driven fundamentally by the US peak, but no authoritative body at the time thought that oil exhaustion was close; it was generally documented that the peak (not exhaustion) would not occur before about the year 2000 (see Section 3.4, below). [24]
- With the world still on the up-side of the Hubbert curve, excess production was indeed likely that would limit OPEC's power for a time. Importantly this new oil (Alaska, North Sea, new Mexican fields, and so on) had been found *before* the oil shocks, not after as even a former chairman of Shell supposed.
- As already discussed, proved reserves replacement gives almost no information about real reserves, nor about future supply.

However such is the academic standing of this 'economic view', and its degree of apparent support by history, that it has held almost complete sway within the world's oil companies, at oil conferences, and in the corridors of power now for about the last twenty years. Moreover this view removed the need for any quantitative analysis of depletion, so over most of this period there have been extraordinarily few analysts - certainly fewer than ten in total worldwide, across all of industry, academia, government and independents - who were quantitatively examining the production limits set by the size of world's recoverable resources of conventional hydrocarbon.

Also as a result of the dominance of this 'economic view', any modelling over this period that was resources-based and which did not explicitly include the effects of price and technology was dismissed out-of-hand by the economists. In return, the many studies by the economists where the resource base was treated as effectively infinite - only the demand needed modelling - were dismissed by the geologists. For about twenty years there has been almost complete lack of dialogue between these two groups in the matter of global hydrocarbon supply.

To end this section, a recent quote from Peter Davies, BP's Chief economist, shows that this 'economic view' is still alive and well: "... the world has since produced 80% of the proved reserves of 1980 - and we are still left with 70% more reserves than when we stated - as a result of exploration successes and new technologies. ... There is no global oil resource or reserve shortage. Oil production continues to be replaced - through a combination of new discoveries and extensions and additions." Though Davies makes no reference to conservative reporting as the reason for this apparent reserves replacement, he does elsewhere refer to peaking and the OPEC late-1980s increases, a great advance on speeches in previous years. [25, 26]

3. Other Aspects of Modelling Hydrocarbon Supply

This section discusses some of the other aspects of oil and gas depletion that call for better comprehension. Here we look at reserves growth, use of the Hubbert curve, and the reliability of past oil forecasts.

3.1 Reserves growth

Reserves growth is a complex topic, and needs careful analysis. As used here, and generally, reserves growth refers to the increase over time in the reported original volume of recoverable oil in a specific field or group of fields. [27]

(i). 'Reporting' reserves growth

Odell reported an average of nine-fold growth in field size over total field life for Western Canadian fields. In the US six-fold field growth was used for on-shore fields, and three-fold for offshore. Such very large growth factors were to be expected because of the conservative nature of proved reserves reporting. In particular, reserves growth was the norm under SEC rules for large fields as increasing portions of the original field were brought closer to market; for example, by being drilled-up with additional production wells. (But see Note 38 where Laherrère's analysis shows that scope for US field growth is now considerably reduced.)

If the proved reserves for *a group* of fields is being quoted then other factors enter also. In the case of the UK, for example, much of the small size of the proved reserves is almost certainly due to exclusion of discovered fields that had not yet received government production sanction. As time moved on, such newer fields received sanction and were added to the proved reserves data, which therefore stayed roughly constant as the reserves of the older fields declined through production.

For the US, analysts like Hubbert recognised the need to 'grow' the proved reserves of fields if a realistic estimate was to be obtained of the amount of oil the fields would yield over their lifetime. The method uses the historical sequences of proved reserves and production data to generate 'proved' discovery by year. These annual numbers are then increased by the amounts that past experience has shown likely for fields of different ages, thus generating realistic 'grown' discovery data. Hubbert used such data in a number of powerful analyses, including the very telling statistic on US discovery per foot drilled mentioned above. The latter showed that the US lower-48 'grown' discovery had peaked in the 1930s and fallen dramatically ever since.

(ii). 'Real' reserves growth

The above all refers to what might be called 'reporting' reserves growth. Of great interest also is technical or 'real' reserves growth, where a field yields more oil over time due to better knowledge of its reservoir, or the introduction of a technology that increases its recovery factor, such as water-flood or tertiary recovery. A higher oil price can of course contribute directly to such real reserves growth, by bringing in a procedure that was already known but previously uneconomic for the field in question.

A key question is: How much real reserves growth do we expect in the industry P50 data?

Some analysts such as Campbell have expected little. After all, the P50 figure is supposed to be the best estimate for each field's ultimately recoverable reserves ('URR'), i.e., the amount of oil that will have been extracted when the field is finally shut-in. In the IHS Energy database these field URRs include the reasonable application of current and expected technology to the field. But globally the *theoretical scope* for recovery improvement is very large indeed, as averaged across all fields the world currently recovers only something like 50% by volume (about 35% vs. number of fields) of its total conventional oil-in-place.

In answering the question of how much real reserves growth to expect in P50 data it must be recognised that much of industry P50 data, including those held by IHS Energy, are 'backdated'. This simply means that when the size of a field is revised the new information replaces the old. Since the database holds this information against the year that the field was discovered, the change appears as an increase to the world's discovery at that date. To see how the size of a specific field has changed one therefore needs to access past database records for the field in question. Systematic studies of this type have been carried out for the North Sea and a few other regions, but not I think many.

In general, therefore, real reserves growth in the industry data needs to be assessed by other means; for example by looking at plots of field production vs. cumulative production to see if step-changes appeared in the extrapolated URRs; or by considering the impact of specific changes in recovery technology. The oil company studies that I know of suggest fairly modest numbers for real reserves growth once secondary recovery is in place. But this is an area which merits more detailed research.

3.2 The USGS' perspective on reserves growth

In its year-2000 Assessment the USGS included data on reserves growth that have proved controversial, especially since bodies such as the IEA and the 'WETO' study group base their forecasts on the USGS estimates of global 'ultimate' that incorporate these reserves growth factors.

The primary aim of the periodic USGS global oil and gas assessments is to estimate the total amounts of oil "available for discovery" in specific basins over a realistic time period, and to sum these to country and regional totals. However, the USGS does at the same time generate estimates of 'ultimates' for countries, by adding the yet-to-find estimates to IHS Energy P50 reserves data and cumulative production. For past assessments the USGS explicitly discounted the need to 'grow' the global P50 reserves data, stating that in most parts of the world they judged the P50 numbers to be pretty good estimates of the 'ultimate reserves' of existing fields. This approach changed in the USGS year-2000 assessment, with quite large reserves growth factors, based on US field-growth experience (for proved reserves) being applied to countries outside the US (with 'proved plus probable' reserves). This process added 690 Gb in total to the mean globally assessed 'ultimate'. The USGS did note, however, that they were unsure how to model reserves growth outside the US, and that they took this approach as much to raise awareness of the issue as to be certain that it would give the correct results.

So the question is: How realistic is it to use USGS year-2000 'grown' data when assessing world peak?

The USGS was reportedly much encouraged in the wisdom of including large reserves growth factors when a study by IHS Energy found that its backdated global P50 discovery data, after taking out the discovery of new fields, had shown very large increases - in total some 464 Gb over the period 1995 to 2003. This has been taken by the USGS and others as proof of on-going very significant real reserves growth around the world, i.e., of large knowledge - and technology-driven increases in recovery factors across the globe.

However, it was recognised that as the growth applied to global *aggregate* data, any one of a number other reasons, such as including new classes of oil, switching to different data sets, or missing early fields could also have generated these increases. IHS Energy therefore examined their data more closely; looking, for example, at US data (which are proved, and hence expected to grow); at FSU data for which new data sources had become available; and at the Middle East numbers where these were known to be very uncertain. As a result, the company stated that about only 175 Gb of the 464 Gb "seems a reasonable ball-park estimate ... that can properly be attributed to the ['real'] resource growth mechanism in pre-1995 discoveries during the period 1995-2003." Nevertheless, the company noted that when added to the new field and pool discoveries of 144 Gb over the same period this represented a 133% replacement of global liquids production. However, IHS Energy cautions that "It is impossible to quantify with accuracy the true contribution of the 'resource growth' phenomenon.[28] Note also that other datasets, for example Wood Mackenzie, carry a total world P50 discovered quite a bit lower than IHS Energy's, the difference being possibly a more conservative assessment of oil accessibility, and perhaps treatment of some Middle East reserves.

So the question remains as to how much 'real' (technology-driven) reserves growth will occur in the industry data sets in future, and crucially, how much of this 'extra oil' will get developed in time to have any effect on the global date of peak.

To support its case on reserves growth, the USGS looked at reserves growth in UK and Norwegian fields. Here changes over time in the public-domain 'proved and probable' reserves data were examined, and the increases identified[29] However even these data need to be examined carefully.

Firstly, of course, the growth that the USGS should be considering is that which has occurred in the IHS Energy database over time (as these are the P50 reserves data used in the year-2000 assessment), not in the 'proved plus probable' reserves data published by the North Sea countries. For example, using IHS Energy data the UK large fields have shown an average increase in size of 50% over the long term; with smaller fields showing a corresponding increase of 25%. Similar growth factors turn up for fields in other *non* North-American countries although the data are rather sparse. Increases of this sort of magnitude are significant and need proper handling in the modelling, but are far smaller than the many-fold growth factors encountered when the US *proven*, and Canadian *developed* data are examined. As mentioned above, it was reserves growth factors based on the US growth factor that were applied to the world data in the USGS year-2000 assessment.

Secondly the USGS analysis of North Sea field growth also needs to be careful not to be confused by the early Norwegian data that reflected only SEC-reported reserves. Thirdly it has long been known that for large fields early public-domain 'proved plus probable' reserves are usually on the conservative side, as for example with Prudhoe Bay in the US and Forties in the UK. Such early conservatism usually reflects engineering pragmatism on the size of infrastructure to build early in a field's life; and also perhaps a wish to avoid being over-optimistic to the market on an asset should problems arise later.

3.3 Analysis Using the Hubbert Curve

In the energy modelling literature there has been considerable misunderstanding of the 'Hubbert' curve, which is the derivative of the logistic curve. Here we look at this curve from three points of view: how well it matches discovery and production; use of the curve to predict the date of peak; and criticism of the curve.

(a). Using the Hubbert curve to match Production

The curve is misunderstood despite Hubbert's very clear original papers, coverage in a wide range of energy textbooks in the 1970s and 80s, and the excellent present-day explanations by Deffeyes, Campbell and others. The key idea to understand is that the curve is a mathematically-tractable approximation for estimating the date of a region's production peak which is both useful and robust. It was never intended as a precise forecast of production long into decline.

Hubbert studied peaking for many US states, and the production curves shown in his papers resemble that of Germany. Today, there are many more examples to look at. Well over a hundred sizeable regions of the world are now far enough into decline for the shape of their long-term production curves to become clear. Such regions include most of the US states, many of the 65 or so countries past peak, and many individual oil provinces including separate on-shore and offshore regions. By far the majority of these areas show production curves like Germany's, where production goes up rather like the left-hand side of a bell curve and down roughly exponentially.

Where a region has clear phases of discovery, production generally follows the above production profile for each discovery phase. For example, the US production curve follows a close approximation of this curve for most of its Lower-48 production, with a similar but smaller curve added for Alaskan production - the latter not surprising since Prudhoe Bay, the largest single US field by far, was found very late compared to the bulk of Lower-48 finds. US production will now show the addition of a third, yet smaller, curve due to production from the recent offshore deepwater finds.

Chilean production is another good example. This has a two-humped 'camel' profile, but examination of the underlying data shows that this simply reflects the addition of 'Germany-shaped' production curves for its on-shore and subsequent offshore regions. Indonesian production likewise reflects separate on-shore and offshore discovery phases, though here the timing and relative magnitudes of these phases has resulted in a declining plateau-like production curve. Germany itself is now exhibiting the addition of its relatively small offshore production curve to its primary on-shore curve. (In the UK, however, the 'camel' profile has different causes: there was a small second phase of discovery but the primary cause of the profile was safety work across all fields resulting from the Piper-Alpha disaster, combined probably with a delay in start-up of some mid-sized fields awaiting change to the Petroleum Revenue tax.)

Note that a 'Germany-like' production profile is to be expected mathematically as a result of a region's larger fields generally getting into production before its smaller ones. [30] As mentioned earlier, the conclusion from the above wealth of data is that virtually all countries and regions exhibit long-term production curves that look like Germany's. [31]

<u>(b). Use of the Hubbert curve to predict the date of peak.</u>

So how did Hubbert use the Hubbert curve?

Hubbert sought to determine the date of the US peak. In his early work he drew by hand curves having a 'Germany'-shape that covered total areas equalling estimates of the US conventional oil ultimate obtained from industry sources. Such curves then directly gave estimates for the date of peak.

However, estimates for the size of the US ultimate then began to rise, and so later Hubbert sought instead a prediction method that depended solely on US historical production data. Using data from those regions already past peak, Hubbert found - after trying many curves - that the logistic curve fitted cumulative production in these regions pretty well. It also had the advantage of being one of the simpler curves able to capture the zero-peak-zero production of a finite resource.

Hubbert used a linearisation approach to fit this logistic curve to the US historical cumulative production data. This generated an estimate for the date of peak without the need to assume an ultimate. The method can in theory be applied using just three data points, i.e., right at the beginning of a region's production, but Hubbert found in practice that about a third of the full production cycle had to elapse before the data yielded consistent estimates for the date of peak. It is this 'later-Hubbert' method that was recently applied by Deffeyes to world production to give an estimated date of peak as this year (2005). [32]

The Hubbert curve can also be used to predict peak in other ways. One is to make an estimate for ultimate, and combine this with the symmetry of the Hubbert curve to predict that peak will occur when production reaches 50% of the ultimate. This method was used by the 1995 Petroconsultants' study and is currently used in the Campbell/Uppsala model. [33]

So the question for these models is: Does production peak at 50% of ultimate? This has been looked at by a number of authors, and, again as Figure 1 indicates, the usual answer is that a region's peak occurs at less than 50% of ultimate; though the spread is fairly wide, from as low as 10% of ultimate (usually for regions with rather few fields) up to 60%, the latter tending to be cases where policy or some other factor, such as accident as in the case of the UK, constrained production before the peak occurred. Of course, where higher estimates of 'ultimate' are used, for example the USGS mean estimates, then the historical peak occurred at correspondingly lower percentages. Overall, 'mid-point peaking' is a reasonable first-cut approximation to apply to many regions, bearing in mind that it has a tendency to predict peak later than actually occurs.

Note that the Petroconsultants 1995 and Campbell/Uppsala calculations use 'mid-point peaking', but do not assume a Hubbert profile for production. Instead they use a production growth function that depends on the region being modelled up till peak is reached, and then exponential decline (the 'tail' away to the right shown in the Germany curve) post peak, where this decline is calculated from the quantity of oil remaining, itself a function of ultimate. Note also that many of the current detailed models make no use at all of the Hubbert curve, including those of Energyfiles, Miller of BP, the BGR and PFC Energy, though all of course owe a debt to Hubbert for the general concept of peaking. [34, 35]

If the Hubbert curve is a good approximation - but not an exact one - to production, how well does it model discovery? This is discussed next.

(c). Using the Hubbert curve to match Discovery

Hubbert postulated that discovery also follows a logistic curve. This is true for US 'proved discovery', as this is just production advanced 10 years by the proved reserves R/P ratio. But the logistic curve is a poor approximation for backdated 'real' discovery data, as any industry dataset will show, simply because in practice the large fields tend to get found first. It is this tendency that gives discovery its characteristic 'creaming curve' shape, with a steep rise followed by exponential flattening.

However, both Ivanhoe (for the world discovery data) and Laherrère (for many regions and countries) do model discovery by a logistic curve, in the latter case using multiple curves where there have been distinct phases of discovery such as Alaska in the US. They then predict production as a delayed 'mirror' of discovery. This approach is in fact very effective, provided the logistic curve is aligned to capture the bulk of the discovery shape. Laherrère's many graphs of this type are essential reading.

(d). Criticism of the Hubbert curve

Despite all the foregoing being well documented, a number of analysts - including Davies and Weston, and a retired Exxon employee writing in the IAEE *Newsletter* - criticise use of the Hubbert curve, citing as primary evidence the fact that US production far on the downside of peak departs from the curve. These authors emphasise that the *percentage* (not absolute) error increases the further down the production curve one goes. Given what has been said above this criticism betrays a lack of understanding of both the background and purpose of the curve, and almost certainly indicates that the critics have examined few regional depletion curves in detail. The mass of evidence indicates that Hubbert's insights and analysis are essentially valid, and have given society a powerful set of quantitative tools with which to forecast the date of peak.

3.4 Past Forecasts

Finally in this section on oil topics that call for better comprehension, we look at past forecasts of oil production. These need examination because most who doubt the imminence of the conventional oil peak, such as Yergin at CERA, point to the apparent failure of past forecasts to conclude that oil forecasting is impossible. So the question is: Did these forecasts really 'cry wolf'? Like reserves growth, this is an area where careful analysis is needed.

Given the importance of oil, it is not surprising that for many years there were fears that it might run out, with forecasts from the 19th century up to the Second World War being concerned about the adequacy of supplies. Most, perhaps all, of these forecasts were based just on oil in specific regions, and so it is not surprising that they predicted declines in output.

However, in terms of *world endowment*, though Ghawar had been identified before the war it was not drilled until 1948, and it was some further years before its full size was recognised. Without Ghawar no sensible estimate of the world total was possible, and it was only with the widespread use of digital seismic from the 1960s that a true picture of the world endowment could emerge. Not surprisingly, for example, the industry estimate used by Hubbert in the 1950's for the global endowment of conventional oil 1350 Gb was therefore on the low side. Only by about the early 1970s did realistic estimates become available of the global conventional oil endowment, at around 2000 Gb.

Once this ~2000 Gb figure was known, realistic estimates for the date of the global peak also became possible. Many such estimates from recognised sources were generated in the 1970s and '80s, as listed in Table 2 and in many of the energy textbooks from that period. Hubbert's forecast from the time used Nehring's estimate of 2000 Gb for the global conventional oil 'ultimate'. Nearly all these forecasts predicted that world oil production would continue upwards for some 30 years, and peak around the year 2000.

Also that that time, however, there were many who misunderstood the conservative nature of proved reserves, and who wrote that global oil would *run out* in 30 years. Others looked at the exponential rate of growth in production that had been occurring, about 7% p.a., and pointed out correctly that such growth could not be sustained for very long more-or-less regardless of the size of the resource. [36]

However, even the 'recognised source' predictions have come under fire. Odell, Davies, John Mitchell and more recently by Vaclav Smil have all claimed that BP's prediction of a 1985 peak in *Oil crisis .... again?* was a classic failure of 'fixed-volume' oil forecasting. Others have likewise pointed to failure of Hubbert's prediction of a 1996 world peak, based on a 2000 Gb ultimate, as giving similar cause for scepticism.

Like so much of the oil peaking debate, these criticisms show as much as anything the lack of careful analysis on the part of the critics. In the case of the BP prediction, this was for the non-communist world and taking out NGLs (as can bee seen by matching the early part of the prediction to historical production). The forecast then used a *resource* figure that still looks realistic today, but assumed that global production would grow during the 1980s, rather than fall as was the case, due to the effects of price on demand. The same explanation applies to the Hubbert 'unconstrained' forecast of a 1996 peak. That is, both these forecasts were 'geological' forecasts, using sensible resource numbers but not correctly including the impact - perhaps then still not clearly known - of price on demand. What these forecasts do not do is demonstrate the failure of 'fixed resource' modelling.

A closer look at a range of hydrocarbon forecasts is given in the next section.

4. Predicting Global Oil and Gas Production

4.1 The models

Forecast of global oil production have been carried out by a wide variety of methods, each having advantages and disadvantages. A number such calculations by different individuals and organisations are listed in Tables 2 and 3. The models can be categorised into three broad groups based on how the authors see future oil production:

Group 1 calculations indicate that global oil production will reach a resource-limited maximum sometime between the years 1996 and 2020, and thereafter decline. Some of these calculations relate to conventional oil only, others to both conventional and non-conventional oil.

Group 2 forecasts terminate in 2020 or 2030, and find that the resource base is sufficient for global oil production to meet anticipated demand to these dates. These 'business-as-usual' forecasts give no indication if a resource-limited peak is subsequently expected.

Group 3 analyses dismiss the possibility of a hydrocarbon resource-limited peak occurring in the near or medium term, and hence see no need to quantitatively assess future oil production.

Most Group 1 models assess the oil resource base by adding industry P50 discovery data to an estimate of yet-to-find. They then use one of the following to calculate future production:
- 'mid-point' peaking (e.g., Hubbert, Petroconsultants '95, or Campbell/Uppsala);
- (partly) field-by-field modelling plus assumed production profiles (Energyfiles, Miller, PFC).

Alternative powerful techniques used by Group 1 modellers include the techniques already mentioned earlier, of a linearised production plot based on the logistic curve (later-Hubbert, Deffeyes), or modelling production as an approximate delayed 'mirror' of discovery (Ivanhoe, Laherrère).

Group 2 forecasts either assume that large quantities of non-conventional oil will come smoothly on-stream as conventional declines (Shell; maybe Exxon); or else place reliance on the USGS year-2000 assessment without paying attention also to the potential discovery rate, nor to reserves growth factors outside the US (IEA, US DoE, 'WETO' study).

The 'WETO' model for example assumes a conventional oil 'ultimate' of 4500 Gb, based on aggressive assumptions on reserves growth (in effect adding rapid reserves growth to already-grown USGS numbers). Such an ultimate must be compared to the global discovered conventional oil to-date (incl. NGLs) in the range of only 2000 - 2200 Gb, and the discovery rate of new-field oil of about 10 Gb annually on a generally declining trend. Thus the 'WETO' study and other authors who propose conventional oil ultimates much above ~2400 Gb (incl. NGLs) must explain in detail the discovery data, and the technical arguments behind the anticipated recovery factors, that support their estimates. (The reality is probably simply that the 'WETO' authors, for example, have not compared their forecast production curves with the actual production curves of the numerous countries past peak.)

Group 3 analyses include those by Paul Stevens, Peter Davies, M. Adelman, Michael Lynch, Peter McCabe and Leonardo Maugeri. These analyses rule out the need to examine the oil resource base for a variety of reasons:
- Some assume that higher prices will bring on sufficient new conventional oil to prevent difficulties in supply;
- Others assume high prices will gently reduce demand, thus bringing supply/demand back into balance without serious economic disruption;
- Still others consider conventional and non-conventional oil to be economically indistinguishable, and that the non-conventional resource (including shales, and perhaps hydrates) is so large that limits to conventional oil production will have no economic significance.

In broader terms, many of the Group 3 analysts express what might be called the 'standard economic view' of oil depletion as set out in the Annex. The arguments are rational enough, and many are based on well-established economic theory. But as shown throughout this 'open letter' quite a number of the assumptions behind these views do not stand up to scrutiny. There is however more work to be done to fully clarify the situation, and some of these issues that need better analysis are listed in Part B of this letter.

4.2 Is the peak right now, or should we expect a mini-glut of oil?

I will close Part A by asking whether the resource-limited peak in the global production of conventional oil is right now, as for example Deffeyes predicts, or should we expect a 'mini-glut' of oil over the next few years? If the peak is indeed not yet past, this puts the world still on the up-side of the Hubbert curve, still with potential excess capacity.

Based on the resource data in most current models (BGR, Energyfiles, PFC Energy, Campbell/Uppsala, BP's Miller) the answer is that a mini-glut is expected. In these models increased production from a number of regions including deep offshore US and Africa, from Kazakhstan and Russia, and from new tar sands plant more than offsets the declines in production elsewhere. This is also the current view of CERA, who are very bullish on near-term supply.

The situation, however, is not so clear cut.

On the up-side, in addition to the already discovered fields listed above, the current high oil price will certainly bring on more marginal fields, as well as in-fill drilling and work-overs in the mainstream fields as happened with the last oil shocks. Moreover demand will also be dampened or even reduced. This spells 'mini-glut'. The affect on price will then be controlled by how well OPEC can manage supply, since the new sources oil will all need to produce to the maximum to see returns on investment.

On the down-side, however, Skrebowski who has the same data as CERA sees a lower level of supply, asking whether the oil that undoubtedly exists can in fact come on-steam as fast as expected. Current information from rig analysts and the like bear out this more pessimistic view. (Sadly it is necessary to ask if CERA has properly modelled the declines elsewhere: attention to production from new fields and forgetting to model the declines underway in the old fields was a common mistake by a number of reputable organisations throughout the 1990s.)

But the biggest reason to think that peak may be sooner than most current models predict is that they may all be using over-estimated Middle East reserves. This is a serious potential problem, as Simmons and Zagar have highlighted.[37] Moreover as the data indicating the approaching peak become ever clearer, it may well be that producers will switch, as they did during the 1970s shocks, to a 'conservation' strategy - slower, high-priced, low-investment production - rather than the current high-production strategy that maximises up-front volumes.

PART B: PROBLEMS THAT MERIT ANALYSIS

Based on the information provided in Part A the following problems seem to be urgent, and merit detailed analysis.

(i). Better understanding of the past.

Careful reading of Part A will show a number of significant lacunae, places where I and maybe no-one has a good quantitative understanding of what happened. This includes the details of proved reserves reporting in the UK, Norway and the US.

In the UK, for example, what exactly was included in the UK proved reserves data? How much of the conservatism was low numbers for specific fields, and how much (I would guess the larger part) were entire fields such as Clair that were always seen as too far from market to count as proved? And why was there the sudden fall from 'proved plus probable' to just proved reserves in the BP *Statistical Review*.

Similar questions apply to Norway, but because some of its fields are more recent and some of the NPD personnel who were part of the change in reporting are still in post, Norway could carry out a quantitative field-by-field retrospective analysis of the difference between the original SEC reserves submitted by the companies and the higher reserves subsequently published.

For the US, there have been a number of efforts to clarify the reporting evolution of proved reserves over time, but this is still very poorly understood subject. To an even greater degree than in the UK, in the US some of the key information may now have been lost to the swirl of history, but one can't help thinking that by focussing on specific fields where the long-term documentation is good a detailed quantitative analysis of the process should emerge. [38]

(ii). Better modelling of the conventional oil peak

There is clearly a need to get a much better handle on the date of the conventional oil peak, and the expected rate of subsequent decline. Factors here include uncertainty in some key data (particularly Middle East and to a lesser extent FSU reserves); better data on the likely effects of price and technology on all large fields, and on classes of smaller fields; and sophistication in the modelling. [39]

On price and technology, these are usually not modelled explicitly in most peaking calculations (a fact noted by the economists), but the current PFC Energy model does include sensitivity analysis for these factors (and finds them to be only second-order determinants of future production for the parameter ranges examined). More explicit handling of these two factors is clearly called for in all models.

At present, not many groups around the world can do the sort of modelling required. In the US for example, this capability is currently limited to the USGS (but where production forecasting is outside their remit) and those who have access to the industry data including the oil companies and consultancies such as PFC Energy and IHS Energy (recently joined with CERA). Except for PFC Energy, I think none of these organisations is doing quantitative global oil production forecasting. In addition, other US groups could and should be doing these calculations, but need first to obtain licences or other access to the P50 discovery data.

(iii). Availability of Non-Conventional oil

Past peak, the global supply of conventional oil declines at about 3% per year, about 2 million barrels/day. Since anticipated demand is forecast to increase by half this, the 'conventional oil gap' will increase each year by about 3 million barrels per day if there is to be 'business-as-usual', i.e., no shortfall against anticipated demand. Within 10 years this represents a need to replace close to 40 million barrels per day of oil, a very large amount of energy to save, or to supply from other sources.

A part of this new supply will undoubtedly come from non-conventional oil, primarily in the near-term from Orinoco heavy oil and Athabasca tar sands, though later gas-to-liquids, oil from shale and coal-to-oil may all become significant.

A number of models make assumptions on the rate that non-conventional oil will become available to offset the decline in conventional. All the detailed models of which I am aware, including those by the BGR, Energyfiles, PFC Energy and Campbell/Uppsala, find that the non-conventional comes in too slowly to offset conventional's decline. But it is probably fair to say that all these models are based on fairly simple projections of announced and likely new plant, and do not model what may happen when conventional supplies get really tight. For this situation, a different sort of modelling is required, one that takes account of *intrinsic limits* to the rate that these new sources of supply can come on-stream. In the case of the non-conventional oils these limits include: readiness of the technology; cost; availability of finance, labour and materials constraints (including water availability); energy-source limits (such as the availability of nearby stranded gas); net-energy rate limits; and pollution, including spoil, water pollution and CO_2 emissions.[40]

Many of these intrinsic limits apply to any energy change, whether bringing on a new energy source, or implementing measures for energy saving. These limits are discussed next.

(iv). Rate limits to Energy change

As conventional oil supply becomes difficult, the world will look to other energy sources. The problem with many of these other sources lies not in their potential magnitude. Each of non-conventional oil, coal, solar energy, breeder fission, fusion and deep-geothermal has a supply potential that is very large compared to current world energy demand. So the problems raised by the transition from conventional hydrocarbons are instead those of technology, cost, rate of availability, and CO_2 emissions.

(a). Technology. The technologies for fusion and for significant quantities of deep geothermal are not yet known. The technology for breeder fission is questionable. The technologies for shale, coal with CO_2 sequestration, coal to gas or liquids, and solar all need improvement and also wide-scale demonstration if they are to become credible large-scale sources of energy. With the global oil peak occurring within the next few years, there is almost certainly insufficient time for such developments to take place.

(b). Cost. Most alternatives to conventional oil (and later to conventional gas) are intrinsically more expensive to produce, in part because of their higher energy requirements per unit of energy ('EROEI'), and in part the technical difficulty of winning these energy sources, requiring larger plant and more investment per unit of energy. In terms of the global economy, the comparison of the cost of a new source of energy should not be with the oil *price* (currently running above $40/bbl) but with the global average oil production *cost* (perhaps $15/bbl?). A high price just transfers rent from consumers to producers; but costs of alternatives much above the real current oil production cost leads, depending on extent, to reduced global economic activity, recession, or depression.

(c). Rate. The *rates* that energy savings and other energy sources can be brought on-stream as conventional hydrocarbons decline are not currently known. Key limits are the availability of technology and Kyoto restrictions, see (a) above and Section (v); the availability of investment funds, and net-energy considerations. The availability of investment funds depends on the state of the global economy, the working of the free market, and the degree of government regulation and support encouraging change.

Net-energy limits to the rate of energy change may be pivotal. Because of the energy required for new-plant construction, if an energy source is brought on-stream more rapidly than a certain rate then during its entire growth phase there is no net energy yield to society. Some of the renewables are already exceeding this rate; and calculations in the 1970s set out the rate limit for the introduction of nuclear plant.

A net-energy limit does not matter for a new energy source in its infancy, as there is plenty of other energy to subsidise it. But if society is driven rapidly to substantial new energy investments because of energy declines elsewhere, then switching may not be possible at the rate required, as the excess energy needed may simply not be available. The same consideration also applies to any rapid programme to introduce large energy savings, as many energy saving measures also carry significant up-front energy needs for materials manufacture, transport and installation. Calculations are therefore required for both new energy supplies and savings to determine if net-energy limits will set significant constraints on future energy paths.

(v). Predicting CO_2 emissions

The issues here are complex and interrelated, and need elucidation before future CO_2 emissions can be predicted:

- Data in SRES hydrocarbon emissions scenarios are thought by some experts to not correctly reflect global energy resources, and need better analysis.
- Decline in conventional hydrocarbons reduces their emissions.
- The decline in conventional hydrocarbons probably also increases all fuel prices, and hence reduces demand, and hence all-energy emissions. But increasing use of non-conventional hydrocarbons and coal increases CO_2 emissions, unless sequestration takes place, because of higher emissions per unit of energy.
- Nearly all other changes in energy supply and energy savings have greenhouse gas implications that are often overlooked. Examples include methane leakage from long gas pipelines unless upgraded; significant CO_2 emissions from nuclear fission on a full-cycle basis (particularly once the world is forced to lower grade ore); and the CO_2 emissions associated with renewable energy systems if the energy of manufacture comes from fossil fuels. Energy savings systems likewise can generate significant CO_2 loads related to their energy of manufacture, transport and installation.

(vi). Impact of higher energy costs on GDP

Over time, new technologies are usually accompanied by declining costs as economies of scale take effect, and as human inventiveness produces more efficient technology. But as explained above, currently at least we should expect the new energy sources to be more expensive than the conventional hydrocarbons, resulting in a negative impact on the global product. Most current economic thinking on this simply says that since energy is a small percentage of a country's GDP, so a higher energy price will only have a proportionately small impact of that country's GDP. It is very probable that this is an overly naive view. The long-term statistical linkage between energy price jumps and subsequent recessions would seem to point to a more complex interaction. It may simply be that a higher energy price translates to lower energy usage, which directly impacts both the quantity of physical output and productive efficiency, and hence impacts GDP. Certainly a number of authors are indicating that the energy price to GDP relationship needs to be much better understood. [41]

(vii). The market: How well will it cope with diminishing supplies of conventional hydrocarbon?

The above leads on to the question of how well the market will cope with diminishing supplies of conventional hydrocarbon. The economic view is that the market is efficient: given complete information it will take the economically best decisions as to which new energy supplies and savings measures to bring on, and the optimal timing for these changes.

There are a number of objections to this view.

Because of the nature of the decisions taken by both producers and consumers, the energy price generally reflects only the very short term micro-balance between supply and demand, and contains very little information about the longer term supply. For example if the mini-glut of Section 4.2 comes to pass, and if OPEC are not quick to rein in supply, then the oil price could fall back to the 1999 level of $10/bbl as excess supply from the new producers who cannot afford to shut in capacity comes onto the market. This price drop would reflect a short-term market, and not reflect the fundamentals of the approaching shortage of conventional oil that have been known since the 1970s. [42]

Without such long-term price information, the long-term lead times necessary for significant energy change do not get addressed by the market. The recent study by Hirsch, Bezdek and Wendling is salutary in this regard, pointing out that even 'crash' programmes need a relatively long time to take effect, and the impact on the economy is severe if such programmes are not undertaken well before supply constraints start to bite. [43]

A second reason to doubt the market's ability to handle declining hydrocarbons well is its inability to address issues that are not in the cost function. This is stating the obvious but is important. Where a factor is not in the cost function, no matter how well the market performs, the issue is not addressed. If society wants the issue to be tackled, then it is up individuals through boycotts or similar, or governments via legislation, to take society down the desired road. Examples include paying for blue-sky research, reducing pollution (e.g., lead in petrol, CO_2 emissions) and providing for social equity (such as free schooling). In the latter category comes rationing in the time of shortage, to avoid the rationing of the market - simply by price and hence ability to pay. [44]

(viii). Integrated Energy-system modelling

The above sections have raised a number of complex and competing issues that society needs properly to understand. These issues include hydrocarbon depletion, new-source production, energy costs, energy savings, demand change, net-energy rate limits, global financing capabilities, global economic stability parameters, CO_2 emissions, and climate change. Useful quantitative predictions about these are probably possible, but will require detailed modelling and scenario building. And, as explained above, a primary need is for good oil reserves data.

Significant modelling capability exists in a number of quarters, and can be drawn on from the past. Past examples include the WAES, 'Limits to Growth', G. Leach et al., and UK government's SARUM models; while recent studies that might be used or expanded include those by R. Hirsch *et al.* for the US DoE, K. Illum's 'Sesame' model for the Danish and EU governments, the UK Open University's energy systems model, and the study used by the UK's Royal Commission on Environmental Pollution.

The purpose of this letter is to encourage such modelling to take place.

Notes & References

(For a list of abbreviations see below.)

1. Energyfiles Ltd. reports that 64 out of the world's 100 or so oil producing countries are in resource-driven decline, but the company cautions that a few of these may see a late discovery phase, with a consequent late reversal of their current production decline trend (though in general not such that production will exceed the historical peak). Contact: info@energyfiles.com.
2. Chevron in a sequence of advertisements in the global press, August 2005 (see www.willyoujoinus.com/issues/alternatives) quoting *Vital Signs*, Worldwatch Institute, 2005, p. 30.
3. Campbell/Uppsala data show that 53 of the world's largest 65 countries by size of conventional oil resource are past peak, see www.peakoil.net. These data rank countries by quantity of original recoverable resource of 'regular' oil (i.e., excluding polar, deepwater, heavies and NGLs).
4. Countries soon to go over peak are from many models, e.g., PFC Energy, Energyfiles, Campbell/Uppsala, and Miller of BP; see also Skrebowski in *Petroleum Review* (various editions), Energy Institute, London. [See data sources in Note 5, below.]
5. Data sources:
   - BGR (the German Federal Institute for Mineral Resources): K. Hiller. *Future World Supplies and Constraints*, Erdöl Erdgas Kohle, 113, Jahrgang, Heft 9, Sept. 1997, pp 349-352. This gives an estimated ultimate recovery (EUR) for Germany of 313 Mt.
   - United States Geological Survey (USGS): World Petroleum Assessment 2000; http://pubs.usgs.gov/dds/dds-060/. This ultimate is the mean estimate for Germany, on a 'non-grown' basis. USGS data sum only basins evaluated; one basin (possibly the offshore) may not be in this USGS total.
   - University of Campbell/Uppsala, end-2004 model, see www.peakoil.net.
   - Energyfiles: *Oil and Gas 2006: Global Ten-year Projection*. Contact: info@energyfiles.com

   Notes:
   - Some of these data (for example, Campbell/Uppsala data) exclude NGLs.
   - Three of the groups recognise that future extraction technology and policies are unknown, so specifically note that their figures should not be seen as definitive estimates of 'true' ultimates (i.e. original endowments of recoverable conventional oil when extraction terminates). Instead the data refer to quantities of oil considered recoverable over reasonably long time spans. The USGS say they evaluate oil that will be available for discovery by 2030 (though there has been ambiguity reported around the meaning of this date). The Campbell/Uppsala model no longer lists ultimate, but 'total regular oil production to 2075'. (As noted earlier, 'regular' oil here excludes polar, deepwater, very heavy oils and NGLs. In the model these latter oils are assessed separately, and summed in the production totals.) Energyfiles quantifies oil that will have been produced by 2145. The BGR is the only organisation that uses the label 'estimated ultimate recovery', but probably would apply the same caveat as the others if asked
   - It was a surprise to both Thomas Ahlbrandt of the USGS and Colin Campbell that their 'ultimates' turn out to be very close for many countries (though not particularly close here for Germany); [personal communications]. The reason is simple. Their yet-to-find numbers can be quite dissimilar, with the USGS' 'general oiliness'

yet-to-finds often being quite a bit larger than the Campbell/Uppsala combination of geological knowledge with extrapolation of 'what the drill bit has found'. But as yet-to-finds are now quite small for nearly all countries, USGS and Campbell estimates of 'ultimate' are usually quite similar, once 'non-regular' categories of oil are added back into the Campbell/Uppsala data.

6. The reason that the UK Department of Energy's estimate in 1974 for the UK ultimate could be so accurate, even before UK offshore production had started, was simply that by 1974 most of the big fields had already been discovered as Figure 5 shows, so the P50 discovery decline curve at that date gave a reliable indication of the total amount of oil likely to be found.
7. This USGS 'ultimate' covers only the UK North Sea, and misses out the West of Shetlands. The latter basin has apparently been evaluated separately, but so far I have not found the data on the year-2000 Assessment CDs. The data will increase the 'ultimate' given here.
8. Evaluations that indicate countries past their resource-limited peak of conventional oil production include those by Campbell, *The Golden Century of Oil 1950-2050: The Depletion of a Resource*, Kluwer Academic, Dordrecht, 1991; Petroconsultants 1995; Campbell, *The Coming Oil Crisis*, Multi-Science Publishing, UK (updated as *The Oil Crisis* in 2005); BGR *Reserven, Ressourcen und Verfügbarkeit von Energierohstoffen,* Hanover 2002; Energyfiles 2003 to-date; BP (Miller) 2004; PFC Energy 2004.
9. To increase confidence in the geological assessments that underlay oil peaking studies, in 2001 I organised for the Oil Depletion Analysis Centre (ODAC), a UK charity, to pay for Dr. Michael Smith of Energyfiles to spend a week with Dr. Colin Campbell to compare respective assessments of 'ultimate' for nearly every oil-producing country in the world. Despite different data sources, geological experience, and countries where they had worked personally on exploration and evaluation, their assessments of ultimate by country were generally close.
10. For updated versions of Figure 8, see *ASPO Newsletters*, at www.peakoil.net
11. E.g., M.C. Lynch in *The new Pessimism about Petroleum Resources: Debunking the Hubbert Model (and Hubbert Modelers)*. See www.gasresources.net/Lynch(Hubbert-Deffeyes).htm; section entitled: 'Opaque Work, Unproven Assertions'. It is true that the industry data can be expensive, but it is also true that when I show graphs like Figures 1 to 9 at conferences virtually no-one asks about the data (including Lynch at an IAEE meeting in Prague).
12. Note for the resource part of the 'PEPS' dataset it is necessary to purchase the 'history' CD, otherwise only the most recent 10 years' data are provided There may be other companies that provide aggregate P50 discovery data relatively inexpensively; I am happy to publish an *Addendum* to this 'open letter' if additional data sources or other corrections are made known to me.
13. PFC Energy's publicly-available plot of Egyptian oil P50 discovery and production contradicts Maugeri's contention in *Nature* that Egypt disproves the Hubbert curve. PFC Energy data show that Egypt has behaved just like Germany, with P50 discovery peaking first, and then production (in 1995). Egypt has the classic profile of a country past peak, and her output is forecast to show steady decline. If Maugeri's company holds P50 discovery data on Egypt it seems likely that he did not study these.
14. Refer to Note 5 for the USGS source.
15. Laherrère terms P50 data 'technical' or 'scout' data as they are technically based and available from information scouting companies such as Petroconsultants. Moreover, he does not like the term 'P50' reserves as this implies a degree of rigour about the probability estimate, a hard thing to define meaningfully in terms of the reserves evaluation process; instead he prefers 'proved plus probable' as a more useful descriptor.

(In plain terms, it may be simplest to regard a P50 estimate as the best estimate of what the field contains. In practice, for most fields, there is usually not much uncertainty.)

16. Refer to Note 3 for the Campbell/Uppsala and ASPO sources. Campbell's latest book is: C.J. Campbell, 'Oil Crisis', Multi-Science Publishing Co., Brentwood, UK, (ISBN 0906522 39 0), 2005.
17. Table 1 shows the apparent dramatic fall in UK reserves in 1986, when proved reserves were reported by the BP *Statistical Review* instead of the 'proved plus probable' reserves. The table shows also that this more realistic estimate of reserves (though still not P50) stood at 19 Gb in 1977.
18. Not surprisingly, Laherrère calls these proved reserves 'political' data. Companies whose Middle East OPEC P50 reserves data are considerably *below* the corresponding published proved reserves include IHS Energy, PFC Energy and Energyfiles. Campbell's speculation on these 'quota wars' increases may be very revealing. He notes that:

    - Kuwait's proved reserves (excluding the Neutral Zone) at end-1983 were 64 Gb, by which date she had produced a total of 22 Gb of oil. In 1984 her reserves jumped to an exact 90 Gb. This therefore looks like approximately the *total* of oil she had discovered (i.e., reserves plus cumulative production). As oil prices were low at the time this increase allowed Kuwait to increase her production quota within OPEC.
    - Kuwait increased her reserves again slightly, to 91.9 Gb, in 1986 and it may have been this second increase that triggered some of the other OPEC countries to follow suit the following year. Abu Dhabi went 0.3 Gb higher to 92.2 Gb; Iran an exact 1 Gb higher (to 92.9 Gb); and Iraq to a nice round 100.0 Gb. Venezuela, who at least had some genuine Orinoco oil to include, roughly doubled her reserves to 56.3 Gb.
    - Saudi Arabia held reserves steady over this period, but to maintain quota was herself forced into an increase two years later. This increase, to 255 Gb, again in Campbell's estimation reflects roughly *total* discovered oil, i.e., reserves plus cumulative production. If these speculations are true then the consequences for global production are severe.
19. P. Davies and P. Weston. *Oil Resources: a Balanced Assessment*. Paper at The Energy Forum conference: 'Running on Empty? Prospects for World Supplies'. Rice University, Houston, May 19, 2000.
20. Odell has maintained that these static data indicate countries where discovery plus revisions has coincidentally matched production for the years in question. Given the exactness of reserves that repeat, and the number of occasions involved, this is obviously infeasible. Enquiries some years back to the *Oil and Gas Journal* and *World Oil* indicated that the static data were generated when the countries in question had either not replied to the survey forms sent out, in which case the journals published the prior year data; or that the countries had returned forms identical to the prior year.
21. Fortunately many useful steps *were* taken in the 1970s and 1980s: significant research was started on energy efficiency (smaller US cars, for example); on alternative hydrocarbons such as shale; and on a wide range of renewable energies. Humankind is lucky that this knowledge is now available. On the other hand, more could have been done. The US SERI report by Dennis Hayes following the 1970s oil shocks pointed out that if the US took a set of sensible energy-supply and energy-saving decisions it could wean itself off imported oil by about the year 2000. Continuing with imported oil has probably been the cheaper immediate option ('the wisdom of the market'), but the US may well regret that the other route was not taken. By ignoring President Carter's 'moral equivalent of war', the world has had to fight two real Middle East wars; and the presence of US troops in Saudi Arabia was one factor in the rise of terrorism. The costs of imported oil are high.

22. This graph is in the IEA's recent report: *Resources to Reserves*, Figure 1.20 'Impact of technology on production from the North Sea'. This shows "1986 proven technologies" as recovering ~22 Gb; whereas all technologies to 1999 recover ~66 Gb. These numbers look as if they are generated simply by adding 1986 North Sea cumulative production to 1986 *proved* reserves (see data for the UK and Norway in Table 1), and likewise for 1999; certainly the proved reserves data match the numbers in the IEA graph. But by 1986 all of Europe's large oil fields had been found (see government data, or e.g. the figure on page 390 of Campbell's recent book *Oil Crisis*), and examination by the USGS, BP and others of North Sea reserves growth of 'proved plus probable' reserves has shown nothing remotely approaching a three-fold increase (see Section 3.1). So this IEA graph is almost certainly yet another example of analysts confusing proved reserves with P50 reserves. The source given is the European Network for Research in Geo-Energy, courtesy of Shell. This IEA graph looks very similar to one in an earlier 2002 IEA publication, also used to demonstrate a multi-fold increase in the volume of North Sea oil due to technology gain. That graph had been produced by a UK consultancy for an EU report, using IFP input for the data (presumably simply with the IFP supplying standard proved reserves data). That none of these participants knew enough to distinguish between proved and 'proved and probable' reserves in generating or using the graph is very telling indeed. (See also the comments on North Sea forecasting by Simmons in ASPO's October 2005 *Newsletter*, item 609.)

Another example of the IEA being ill-informed on the nature of proved reserves is Figure 1.8 ('Evolution of proven oil reserves as a function of time') in the same report. This depicts the trend of global total proved reserves corresponding to the data in Table 1, below. Despite the reality that this plot compounds the effects of growth over time of conservative data with OPEC 'quota wars' increases and many years of static data, the IEA concludes: "Technology may even unlock access to previously unrecoverable hydrocarbons. In fact the level of 'remaining reserves' of oil has been remarkably constant historically, in spite of the volumes extracted each successive year ... The addition of new reserves has therefore roughly compensated for consumption." It is serious that so late in the day the IEA has not yet gained a proper understanding of the data it uses. Proved reserves data are atrocious; no useful conclusions can be drawn by looking at their evolution; the IEA ought to have known this long ago.

23. The report's key charts on the size of the various resources (Figures ES.1, and 1.5) may be a bit on the optimistic side. OPEC Middle East reserves at about 1100 Gb, including technological progress, may be based on working from the current proved data, rather than the smaller P50 reserves. A total conventional oil-in-place of about 6000 Gb may result from assuming a 35% global recovery factor, whereas other data indicate this is probably nearer 50% on a volume basis. Hydrates are still far from a known quantity, they may well disappoint. Overall, however, these data are fairly reasonable; the world is blessed with large resources of hydrocarbons. For other estimates on global quantities of hydrocarbons see e.g., Hubbert's papers; A. Perrodon, J.H. Laherrère, C.J. Campbell, *The World's Non-Conventional Oil and Gas*, The Petroleum Economist, London, 1998; F. Harper, *Ultimate Hydrocarbon Resources in the 21st Century*, Presentation at AAPG Conference on Oil and Gas in the 21st Century, Sept. 12-15, 1999, Birmingham, UK; R.W. Bentley, *Global oil and gas depletion: an overview*, Energy Policy, Vol. 30, No. 3, February 2002, pp 189-205, Elsevier, 2002; and energy textbooks.

24. The influence of the US peak on the 1970s shocks is often not recognised, despite the underlying facts being well documented (see, for example, D. Yergin's *The Prize*). In the early 1970s, 90% of the world's oil came from just three regions: the U.S., Russia and OPEC; with Russian oil largely dedicated to the Communist Bloc. Prior to the US peak

OPEC had several times tried cutbacks to force an increase in what it felt to be an unfairly low price for its 'once-for-all' endowment, but each time the US raised its pro-rationing allowances to compensate. However post the US peak this option was no longer possible, and OPEC was in the driving seat. When political upsets (the Yom Kippur war, and later the Iranian revolution) triggered cutbacks, global shortages resulted. Note that for the degree of this connection between the US peak and the '70s shocks to be quantified, the size of OPEC cutbacks and the spare capacity in US pro-rationing need to be examined. In terms of understanding the '70s shocks it is worth recalling that though the world still had large amounts of conventional oil in the ground, and a large non-conventional resource, this could not prevent the shocks. As today, the constraint was *rate of supply*, not total resource.

25. P. Davies. *Energy in Focus*. World Energy Review, August 2004 pp 14-17.

It may seem to some readers that this 'open letter' has been unnecessarily critical of Odell and Davies. The University of Reading 'Oil Group' has made representations on oil peaking to the UK's Department for Trade and Industry on four occasions but has always been rebuffed, being told variously that: 'the data of Davies disagree with this view'; 'oil is not important to the UK economy, being a small and declining share of GDP'; and that 'the market will take care of any problems that arise'. A submission to a committee of the House of Lords was countered a week later by Davies saying that the world had secure oil for 40 years, and more would be found. Submissions were also made to the UK's Royal Commission on Environmental Pollution, the DTI's Foresight Committee, the PIU and DTI in connection with the UK's *Energy White Paper*, the research funding councils NERC, EPSRC and ESRC; Ofgem; the Chief Scientist and UKERC. Only in the latter two cases has the peaking view not been dismissed out-of-hand. Communications have also taken place with the EU. A research proposal jointly between the BGR, IFP, the demand modelling arm of the IEA, IHS Energy and the University of Reading to clarify the peaking problem was submitted to the EU's DG-Research, with support from DG-TREN. This was turned down largely because oil peaking was not yet in view to the project's reviewers, but a letter to DG-TREN from the IEA's supply-side arm wanting to be distanced from mention of oil peaking did not help. Subsequent discussion with a DG-TREN official associated with the EU's *Green Paper* on energy was dismissed on the grounds that because both Reading and Odell use statistical methods and disagree, statistical approaches are unreliable. I list these experiences for the historical record.

Reading's 'Oil Group' has been the UK's only academic group working quantitatively on global future hydrocarbon supply. It is a loose association of academics, and has consisted of variously: Professor Max Coleman (ex-BP) and Professor Bruce Sellwood of the Former Postgraduate Research Institute for Sedimentology; Professor Peter Dunn, Professor of Engineering Science; Professor Roger Booth (ex-Shell), Visiting Research Fellow, Royal Academy of Engineering Visiting Professor at the University of Oxford; Dr. John Burton and Dr. Rayner Mayer (Sciotech; ex-BP) of the Department of Engineering; Dr. George Whitfield and Dr. Roger Bentley (ex-Exxon) of the Department of Cybernetics; and affiliated: Dr. David Fleming, an independent economist.

26. One fairly recent high-profile example of the 'economic view' was in a *Newsweek* special issue on energy, April 8/15, 2002. Here the opening article is awash with oil inanities. Doubting the Bush Administration's warning of the "worst energy-supply crisis since the 1970s," the article says, for example:

- "We know there's a lot more oil worldwide now than in the 1970s. … surveys that once estimated total global reserves at 650 billion now find more than a trillion barrels.
- At present-day consumption rates, it looked in 1970 as if oil would run out in 33 years – that is, next year. This year, the same calculation puts the day of reckoning in 2046.
- In the U.S. … extending the expected life of reserves [means that] …the threat of a shortage is receding …
- The U.S. is also increasingly immune to oil shocks. In 1980, … the U.S. spent 8% of GDP on oil, and the shock produced a deep recession. In 1999, prices spiked by a similar magnitude, but the U.S. had cut oil costs to 3% of GDP, and many economists believe it's no accident that the recession was surprisingly mild. 'There's no question we're less vulnerable today' … "

27. The term 'field growth' is probably less ambiguous, since 'reserves growth' is sometimes used - for example by PFC Energy - to mean an increase in a region's reserves including by the discovery of new fields.
28. K. Chew. *World Petroleum Trends - 1994 to 2003, Version 4.4*; 22 Oct. 2004. Available from IHS Energy, Geneva, Switzerland.
29. Gautier and Klett, Petroleum Geoscience.
30. See, for example, the very simple model in the Annex of R.W. Bentley *Global oil and gas depletion: an overview*. Energy Policy, Vol. 30, No. 3, February 2002, pp 189-205, Elsevier; and the slightly more detailed model of Figure 2 in M.R. Smith. *Putting paid to unrealistic demand predictions,* Petroleum Review, October 2005 pp 32-34; Energy Institute, UK.
31. See profiles in e.g., ASPO *Newsletters*.
32. No-one should expect great precision from this method, as it is clear that the world production plot with its discontinuities due to the 1973 and 1978 oil shocks has not followed a pure logistic-derivative shape. Nevertheless one of the strengths of the Hubbert curve is the robustness of it date of peak to changes in input parameters, and the Deffeyes analysis should taken as a valid quantitative warning of what is imminent.
33. C.J. Campbell and J.H. Laherrère. *The World's Supply of Oil, 1930-2050.* Petroconsultants S.A., 1995; see also Campbell/Uppsala model; www.peakoil.net.
34. It is not necessary to use the detailed shape of the Hubbert curve to forecast peak. For example a simple isosceles triangle set to have an area equal to a region's estimated ultimate can be surprisingly accurate, see the plot for the US Lower-48 in the Annex of R.W. Bentley, Energy Policy, Vol. 30, No. 3, February 2002, *op. cit.* Alternatively just draw a triangle for UK production using the UK Dept. of Energy's 1976 estimate of ultimate of 4.5 G tonnes. The first three or four years of UK production are quite adequate to define the production trend, such that a triangle of 4.5 Gt area gives an accurate forecast of the UK peak had Piper Alpha not happened. Oil forecasting, far from being difficult is usually remarkably simple, provided the underlying data are reasonably accurate.

    Indeed, a far more pragmatic rule, given the actual shapes of the empirical P50 discovery and production curves for most regions, may be to dispense with the contentious notion of 'ultimate', or even discovery 'n' years in the future, and simply expect production in a region to peak when cumulative production has reached ~50% of the cumulative P50 discovery to the same date. This is still more complex than the linearised Hubbert production approach (as P50 discovery data are also required), but does recognise the reality that late discoveries (unless of a much larger new province altogether) have no impact on the date of peak.

35. ‘Mid-point peaking’ applies to *regions,* not to individual fields. It applies to regions because in a region, on average, the large fields get into production first, and at some point - typically from 30 - 50% of expected total production - the increasing production from the later smaller fields is insufficient to offset the declines from the large early fields. Very surprisingly as recently as a year ago a senior analyst from one of the oil data companies, despite having been in conversation with us for many years, complained that mid-point peaking was a flawed concept because there were so many *fields,* such as Forties, where the peak had occurred a long way before the production mid-point. It was this comment, among all too many others, that in part prompted this ‘open letter’ in an attempt to get the energy analysis community to understand *what is already known*, so that we can move forward to the tougher problems that await.
36. H.P. Garg in *Treatise on Solar Energy*, Volume 1, J. Wiley 1982, p 20, points out that if the OPEC restrictions of the 1970s had not come about the ~7% growth in global oil production preceding these shocks would in any event have become resource-limited in less than a decade. For a summary of past oil forecasts see: *Oil Forecasts, Past and Present.* R.W. Bentley. Energy Exploration and Exploitation, Vol. 20, No. 6, pp 481-492. Multi-Science Publishing Co. Ltd., 2002. (Originally given at the First International Workshop on Oil Depletion Uppsala, Sweden, May 23-24, 2002; www.peakoil.net; Proc. IWOOD2002.)
37. M. Simmons *Twilight in the Desert*, J. Wiley, 2005; J. Zagar, *Saudi Arabia - Can it Deliver?*, Proc. IV International Workshop on Oil Depletion, Lisbon, Portugal, May 2005, pp 30 - 31, Centro de Geofísica de Évora, University of Évora, Portugal
38. The US situation on reserves has historically been dogged by a range of problems, including: multiple ownership of fields; initial technical ignorance of the real size of many of the early fields; use of rules-of thumb for field estimation, including calculation of field size from field depletion on an assumed R/P ratio of 10 (!); and SEC reporting rules such that proved reserves are often only those in communication with a producing well, hence ‘drilling-up’ a field can produce large apparent reserves increases in large fields over time. (SEC rules recognise two categories of proved reserves: Proved Producing = estimated future production from current wells; Proved Undeveloped = estimated future production from, e.g., yet-to-be-drilled infill locations.) Laherrère has plotted revisions to US proved reserves data, comparing the proportion of positive to negative revisions, and concludes that for both oil and gas the proved reserves are getting close to P40 (= mean) numbers. In effect, the scope for US proved reserves to be revised upward by eating into ‘proved and probable’ reserves is coming to an end.

    As noted elsewhere in the letter, added to these ‘reporting issues’ are real technology gains, although often from introducing water-flood and other now-standard technologies already factored in when estimating the ultimate yields of current fields.
39. Improved oil recovery (IOR) can be over-estimated. It can have a large effect for heavy oil or difficult reservoirs (such as Ekofisk in chalk, where a low original recovery factor of 18% was assumed, and where subsequent extraction-caused slumping improved recovery), but in general IOR does not add so very much. Across the US for example only perhaps 10% of fields are susceptible for IOR techniques, and though there have been some exceptional successes, these techniques have typically added less than 10% to field volumes.
40. Odell models non-conventionals as smoothly taking over from conventional oil as the latter declines, implicitly saying that society will see no economic impact as non-conventional oil takes over. Given the issues set out here it is far from clear that this view is correct.
41. E.g., D. Fleming (2000), *After Oil*, Prospect, November 2000, pp 12-13; C. Hall, *The Need for Biophysical Economics*, Proc. IV International Workshop on Oil and Gas Depletion,

Lisbon, Portugal, 2005, pp 74-75, Centro de Geofísica de Évora, University of Évora, Portugal; R. Ayres, *On the Relationship between Energy, Work, Power and Economic Growth,* Proc. IV International Workshop on Oil and Gas Depletion, 2005, pp 57-58, *op cit.* See also works by Malcolm Slessor.

42. When the oil price fell to ~$10/bbl in 1999 the oil producers of the UK North Sea were forced to increase production to try and meet investors' expectations of returns; causing a little peak at the top of the main UK peak, and contributing in a small way to the existing global over-supply. Such short-term actions are characteristic of many *commodity* markets if cartels and 'cornering the market' are either not permitted, or not effective.
43. R. Hirsch, R. Bezdek, R. Wendling. *Peaking of World Oil Production: Impacts, Mitigation & Risk Management.* US Department of Energy, National Energy Technology Laboratory, February 2005.
44. Campbell's proposed 'Rimini Depletion Protocol' is a technically-driven rationing system that allocates supply fairly between nations, prevents producers from extracting large unearned rents ('price gouging'), and encourages technical innovation for supply substitution and saving. For an equitable 'cap & trade' mechanism to bring about an ordered reduction of hydrocarbon use within a country, see, e.g., D. Fleming, *Energy and the Common Purpose: Descending the Energy Staircase with Tradable Energy Quotas*. The Lean Economy Connection, London, ISBN 0-9550849-1-1; (see http://www.teqs.net).

List of Abbreviations

ASPO	Association for the Study of Peak Oil and Gas. A loose association of analysts (mostly scientists), generally affiliated to government, industry or academic institutions but not necessarily reflecting the views of these institutions.
BGR	Bundesanstalt für Geowissenschaften und Rohstoffe; German Federal Institute for Geosciences and Natural Resources.
CERA	Cambridge Energy Research Associates (Cambridge, USA).
DG-TREN	EU's Directorate General for Transport and Energy
DoE	US Department of Energy.
DTI	UK Department for Trade and Industry
EIA	US Energy Information Administration (within the DoE)
EOR	Enhanced oil recovery.
EPSRC	UK's Engineering and Physical Sciences Research Council
EROEI	Energy return on energy invested. The quantity of energy an energy source yields per unit energy input for energy extraction.
ESRC	UK's Economic and Social Research Council
EU	European Union
EUR	Estimated ultimate recoverable
FSU	Former Soviet Union
Gb	Billion barrels
GDP	Gross domestic product
IAEE	International Association for Energy Economics
IEA	International Energy Agency
IFP	Institut Français du Pétrole
IIASA	International Institute for Applied Systems Analysis
Lower-48	US 48 contiguous states
Mb/d	Million barrels per day

MMS	US Minerals Management Service
NERC	UK's Natural Environment Research Council
NGLs	Natural gas liquids. Liquids that can be used as oil generated from gas fields.
NPD	Norwegian Petroleum Directorate
OPEC	Organisation of Petroleum Exporting Countries
R/P	Ratio given by dividing a region's proved reserves by its annual production. As this ignores peaking, it can be a very misleading indicator of security of supply.
SEC	US Securities and Exchange Commission
SERI	US government's Solar Energy Research Institute (forerunner of the National Renewable Energy Laboratory, NREL).
SRES	Intergovernmental Panel on Climate Change (IPCC) Special Report on Emissions Scenarios
URR	Ultimately recoverable reserves
USGS	United States Geological Survey

Definitions

Conventional oil: Usually poorly defined. Sometimes taken as oil recovered by primary (own pressure or mechanical lift) or secondary (natural gas injection, water-flood, water sweep) recovery methods. Here the term is used rather loosely, generally including all flowing oil from primary, secondary and tertiary extraction methods, plus NGLs; i.e. excluding very heavy oils (such as Orinoco oil), oil from tar sands, oil from shale; and other oils such as bio-oils, oil from gas ('gas-to-liquids') and oil from coal.

P50 reserves: The quantity of oil in a field (or a region) thought by an industry source as the most likely amount to be extracted within a reasonable time horizon by reasonably expected means. Often the same as, or close to, a field's 'proved plus probable' reserves.

P50 discovery: For a field or region the total oil discovered to-date, i.e. cumulative production plus P50 reserves. For a field this figure is often close to, or the same as, the field's estimated URR (ultimately recoverable reserves).

Proved reserves: Whatever the reporting body chooses to define as proved reserves. Under SEC rules this is usually a fairly conservatively-defined quantity; under UK reporting, for example, may exclude oil in fields not yet placed in the proved category; for some countries very uncertain data.

Table 1: Proved Reserves from BP's *Statistical Review*, and 'P50' Reserves.

Year	UK	Norway	USA	FSU	China	UAE	Iran	Iraq	K'wt.	S .Arabia	Venez.
PROVED RESERVES											
1960			38.4	31.5			35.0	27.0	65.0	53.0	18.5
1965			39.4								
1966			39.8								
1967			40.0								
1968			39.3								
1969			37.8								
1970			46.7								
1971			45.4								
1972			43.1								
1973			41.8								
1974			40.6	83.4	25.0						
1975	16.0	7.0	38.9	80.4	20.0	32.2	64.5	34.3	71.2	151.8	17.7
1976	16.8	5.7	37.3	“	“	31.2	63.0	34.0	70.6	113.2	15.3
1977	19.0	6.0	35.5	75.0	“	32.4	62.0	34.5	70.1	153.1	18.2
1978	16.0	5.9	33.7	71.0	“	31.3	59.0	32.1	69.4	168.9	18.0
1979	15.4	5.8	32.7	67.0	“	29.4	58.0	31.0	68.5	166.5	17.9
1980	14.8	5.5	31.9	63.0	20.5	30.4	57.5	30.0	67.9	168.0	18.0
1981	14.8	7.6	36.5	“	19.9	32.2	57.0	29.7	67.7	167.9	20.3
1982	13.9	6.8	35.1	“	19.5	32.4	55.3	41.0	67.2	165.3	21.5
1983	13.2	7.7	34.5	“	19.1	31.8	51.0	43.0	66.7	168.9	24.9
1984	13.6	8.3	34.5	“	“	31.9	48.5	44.5	92.7	171.7	25.8
1985	13.0	10.9	35.9	61.0	18.4	32.4	47.9	44.1	“	171.5	25.6
1986	5.3	10.5	35.1	59.0	“	32.4	48.8	47.1	94.5	169.2	25.0
1987	5.2	14.8	35.4	“	“	96.2	92.9	100.0	“	169.6	56.3
1988	4.3	10.4	34.7	58.5	23.6	“	“	“	“	172.6	58.1
1989	3.8	11.6	33.6	58.4	24.0	98.1	“	“	97.1	257.6	58.5
1990	3.8	7.6	33.8	57.0	“	“	“	“	97.0	260.0	59.0
1991	4.0	7.6	33.7	“	“	“	“	“	96.5	260.3	59.1
1992	4.1	8.8	32.1	“	“	“	“	“	“	“	62.6
1993	4.6	9.3	31.2	“	“	“	“	“	“	261.2	63.3
1994	4.5	9.4	30.1	“	“	“	89.3	“	“	“	64.5
1995	4.3	8.4	29.9	“	“	“	88.2	“	“	“	“
1996	4.5	11.2	30.2	65.5	“	97.8	93.0	112.0	“	261.5	64.9
1997	5.0	10.4	29.8	65.4	“	“	“	112.5	“	“	71.7
1998	5.2	10.9	30.5	“	“	“	89.7	“	“	“	72.6
1999	5.2	10.8	28.9	“	“	“	“	“	“	263.5	“
2000	5.0	9.4	29.7	65.3	“	“	“	“	“	261.7	76.9
2001	4.9	9.4	30.4	65.4	“	“	“	“	“	261.8	77.7
2002	4.7	10.3	30.4	60†	18.3	“	“	“	“	“	77.8
2003	4.5	10.1	29.4	71.2	17.1	“	133.5	115.0	99.0	262.7	77.2
2004	4.5	9.7	29.4	72.3	“	“	132.5	“	“	“	“
'P50' RESERVES											
USGS	9.7	13.5	-	151.6	24.5	57.2	71.3	77.6	54.3	214.9	29.6
C/U	9.3	13.9	~45	113.0	24.3	49.5	59.9	62.2	63.0	146.7	34.6

Notes: Heavy line indicates step-change in reserves. Ditto mark (“) indicates value identical to previous year. UAE = Abu Dhabi. Dubai, Ras-al-Khaimah, Sharjah. Neutral Zone split between Kuwait and Saudi Arabia. Proved reserves are at year-end. Older US data: US 1950 R/P = 13 yrs; 1960 R/P = 12 yrs. Venezuela proved reserves includes some Orinoco oil. Note Saudi Arabia anomaly in 1976. † = Russian Federation (changed from Former Soviet Union, FSU). **P50 data:** USGS: IHS Energy end-1995 'ultimately recoverable reserves' (URR) from USGS year-2000 Assessment. As noted earlier, IHS Energy does not hold P50 data for the US. C/U: End-2004 ~'P50' reserves as given in the Campbell/University of Uppsala model (see www.peakoil.net).

Table 2: Results of some 'Group 1' calculations.

Date	Author	Hydrocarbon	Ultimate Gb	Date of global peak
1972	ESSO	Pr. Cv. oil	2100	"increasingly scarce from ~ 2000."
1972	Report: UN Confr.	Ditto.	2500	"likely peak by 2000."
1974	SPRU, UK	Ditto.	1800-2480	n/a
1976	UK DoE	Ditto.	n/a	"about 2000"
1977	Hubbert	Cv. oil	2000	1996
1977	Ehrlich et al.	Ditto.	1900	2000
1978	WEC / IFP	Pr. Cv. oil	1803	n/a
1979	Shell	Ditto.	n/a	"plateau within the next 25 years."
1979	BP	Ditto.	n/a	Peak (non-communist world): 1985
1981	World Bank	Ditto	1900	"plateau ~turn of the century."
1992	D. Meadows *et al.*	Ditto	1800-2500	n/a
1995	Petroconsultants, '95.	Cv. oil (xN)	1800	About 2005
1996	Ivanhoe	Cv. oil	~2000	About 2010.
1997	Edwards	Pr. Cv. oil	2836	2020.
1997	Laherrère	All liquids	2700	n/a
1998	IEA: *WEO 1998*	Cv. oil	2300 ref.case	2014
1999	Magoon of the USGS	Pr. Cv. oil	~2000	Peak ~2010.
2000	Bartlett	Ditto.	2000 & 3000	2004 & 2019, respectively.
2002	BGR (Germany)	Cv.&Ncv. oil	Cv.: 2670	Combined peak in 2017.
2003	Deffeyes	Cv. oil*		'Later-Hubbert' method ~2005.
2003	P-R Bauquis	All liquids.	3000	Combined peak in 2020.
2003	Campbell/ U. Uppsala	All h'carbons		Combined peak ~2015.
2003	Laherrère	All liquids	3000	n/a
2003	Energyfiles Ltd.	All liquids	Cv: 2338	2011 (if 2% demand growth).
2003	Energyfiles Ltd.	All h'carbons		Comb'd pk. ~ 2020 (if 0% growth).
2003	Bahktiari model.	Pr. Cv. oil		2006 - 7
2004	Miller, BP - own model	Cv.&Ncv. oil		2025: All poss. OPEC prodn. used.
2004	PFC Energy	Cv.&Ncv. oil		2018 - base case

Notes: Table is not complete, one notable omission is the WAES study from the late 70s / early 80s. Pr.: Probably; Cv.: Conventional; xN: ex-NGLs; +N: incl. NGLs; All liquids: Conv. and Non-conv. oil plus NGLs; All h'drocabons: Conv. and Non-conv. oil and gas. * = and probably all-oil.
'Ultimate': ultimately recoverable reserves (URR); is equal to the recoverable portion of the original total in-place resource. Gb: billion barrels.

Table 3: Results of some 'Group 2' calculations.

Date	Author	Hydrocarbon	Ultimate (Gb)	F'cast date of peak (by study end-date)	World prod. Mb/d 2020	2030
1998	WEC/IIASA-A2	Cv. oil		No peak	90	100
2000	IEA: *WEO 2000*	Cv. oil (+N)	3345	No peak	103	-
2001	US DoE EIA	Cv. oil	3303	2016 / 2037	Various	
2002	US DoE	Ditto		No peak	109	-
2002	Shell Scenario	Cv.&Ncv. oil	~4000*	Plateau: 2025 - 2040	100	105
2003	'WETO' study	Ditto	4500**	No peak	102	120
2004	ExxonMobil	Ditto		No peak	114	118

Notes: *Shell's ultimate of 4000 Gb is composed of: ~2300 Gb of conventional oil (incl. NGLs); plus ~600 Gb of 'scope for further recovery' (SFR) oil; plus 1000 Gb of non-conventional oil.

**WETO's ultimate of 4500 Gb is for conventional oil only; it starts with a USGS figure of 2800 Gb, then grown by assuming large and rapid recovery factor gains to 2030. Mb/d: Million barrels per day.

Annex: Summary of the 'Economic View' of Oil Depletion

A number of influential energy economists have espoused the following ideas to varying degrees. Discussion of many of these topics has been given in the main body of the 'open letter' above; additional footnotes are given below.

1. The cost of any mineral reflects a race between depletion of its resource and mankind's increasing technological skill at extraction. To-date, for no significant mineral has this race been lost, and empirical data indicate that the long-term extraction cost of nearly all minerals has always fallen. There is no reason to expect oil to be an exception.
2. The price of oil price indicates future supply. Currently neither price nor more detailed economic metrics indicate approaching supply difficulties. These indicators will give sufficient warning should such difficulties approach. [a]
3. Markets function very well. Were an oil shortage to be imminent, the price of oil would rise. This would increase exploration, exploitation of currently uneconomic fields, recovery factors, the use of alternative oils, and substitution away from oil. These changes, in combination with a fall in demand also driven by price, would bring the market back into balance. In essence, oil (and energy also) is simply a commodity; supply is best left to the market. [b]
4. For most countries, the cost of oil is only a small percentage of GDP; even a substantial rise in oil price will have only a modest impact on their economies.
5. There are over 40 years' of proven oil reserves. This is secure, known oil extractable at to-day's prices. More oil will also be found. Any potential oil supply problem must be many decades into the future.
6. There are still plenty of places to look for oil. Large oil discoveries have been made in the Caspian, deep offshore, etc., and there are still many promising oil basins that have seen little exploration.
7. Moreover, the bulk of 'new oil' comes not from discovery, but from revisions and extensions to existing fields. Such 'reserves growth' will be a key contributor to future supply.
8. Indeed, oil reserves are merely 'inventory'. Oil companies keep a given number of years' supply on their books, and as supply falters more of the effectively infinite oil resource base gets turned into reserves. The data confirm this has always happened in the past.
9. In addition, there exist vast resources of non-conventional oil. These include 300 billion barrels of recoverable oil each in the Orinoco basin and Athabasca, with the total in-place oil resource at these sites amounting to several trillions of barrels. There is an even larger amount of oil in shale deposits around the world. This distribution is expressed by a 'resource pyramid', with a small volume of low-cost oil at the top, and an ever-increasing volume of more expensive, or otherwise less desirable oil, further down the pyramid. [c]
10. Should the supply of oil itself ever become difficult, it can be substituted by gas, of which there are large stranded supplies; by gas-to-liquids, biofuels and other oil substitutes; and, if the need arises, by coal. Large volumes of gas hydrates may also prove economically extractable.
11. Finally, virtually none of the bodies one would expect to warn of impending supply shortages are currently predicting any risk to supply. These include oil companies and consultancies, as well as authorities such as the International Energy Agency, the US' Energy Information Administration or the United States Geological Survey.

In addition to the above general views, some economists have offered the following specific criticisms of the geologists' calculations:

12. Geologists rely on an industry data set that is not in the public domain. Other analysts cannot check that these data are correct, nor that the geologists are interpreting them correctly.
13. The geologists ignore the effects of price and technology gain. Without such obvious feedbacks, simple geology-based modelling is without validity.
14. Past oil forecasts have all been wrong. Thirty years ago it was believed that oil would run out in thirty years, to-day the world has forty years' worth of reserves. It is foolish of the geologists to forecast oil's future on the basis of an assumed fixed volume of oil.
15. The 'Hubbert curve', used by some geologists in their modelling, is a poor match to actual production.
16. The geologists who forecast a near-term oil production decline have shown a steady upward revision in the resource volumes they assume.

Taken together, the above is an impressive list. It appears to give almost incontrovertible evidence that no near-term oil supply problems lie ahead. Instead, as has been shown in the main body of this 'open letter' many of these arguments do not stand up to detailed examination; and where partly true, need both quantification and qualification if they are to usefully contribute to forecasting oil's future.

Annex Footnotes

(a). The lack of a price signal for oil peaking has been widely quoted at least up to about mid-2004 (indeed, was explicitly used as a reason to reject a research proposal on oil peaking submitted by the University of Reading to a recent UK NERC/EPSRC funding round). What the economists say in the face of the 2004 - 2005 price rises is not yet fully clear, though China demand and lack of refinery capacity are mentioned. In terms of understanding the price signal it is useful to recognise that sequestration of Middle East assets from the commercial oil companies by the national oil companies, followed by OPEC quotas, meant that higher cost oil (North Sea, Alaska, and now deep offshore) has been produced while lower cost Middle East oil has remained in the ground. Had the 'seven sisters' remained in power it is likely that a steady oil price rise would have taken place as the cheap oil was depleted first, sending a consistent signal of supply getting ever more difficult. Note that there *was* a price signal before 1970s oil shocks, but this was small and ignored. Mostly, however, as mentioned elsewhere, the oil price can only signal the *short-term* supply-demand balance.

(b). See comments by the University of Reading 'Oil Group' on Lord Lawson's views on 'energy as a commodity' in: R.W. Bentley, R.H. Booth, J.D. Burton, B.W. Sellwood, G.R. Whitfield. *The Oil Future - A Very Different View*. Newsletter, Int'l. Assocn. for Energy Economics, 4th Quarter, 1999.

(c). In terms of the 'resource pyramid' concept it is important to recognise that oil is not like a conventional mineral where the latter generally has a simple infinite continuum of lower concentration ores. For *conventional* oil there is a well-defined water boundary in most reservoirs below which there is no oil; oil comes in packets. So the 'lower concentration ores' are simply the smaller fields, and here it is easy to extrapolate both field size and discovery rate to calculate how much will be found with any specified discovery effort. Additionally, oil is also not like a normal mineral such as gold or aluminium, where if it is really needed it can be extracted at high cost (in these cases, from sea water or clay respectively). Oil is an energy source so is not worth extracting if this requires more energy than it yields. These special aspects of oil require the economists to be careful in the use of general theories if correct conclusions are to be drawn.

FIGURES

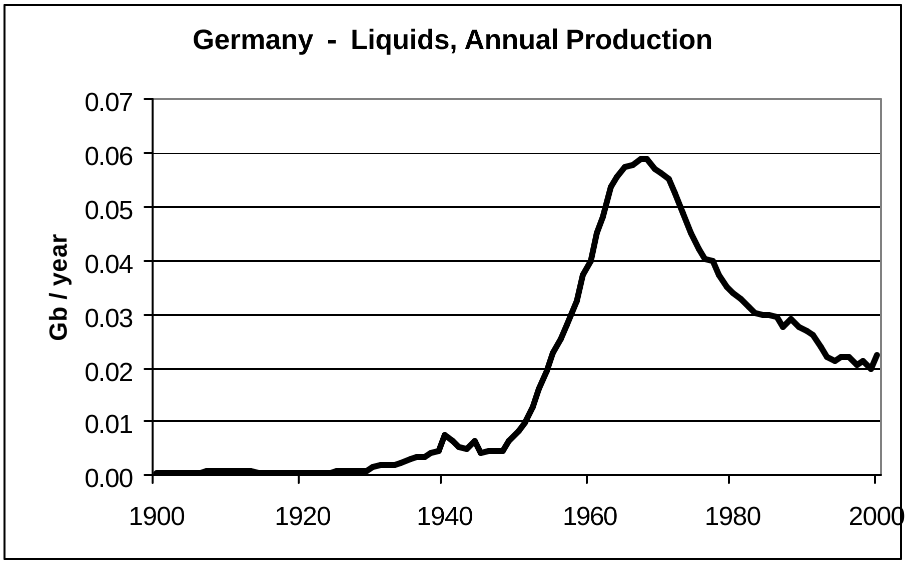

Figure 1. Germany: Annual production of petroleum liquids (oil plus NGLs), 1900- 2000. Source: IHS Energy.

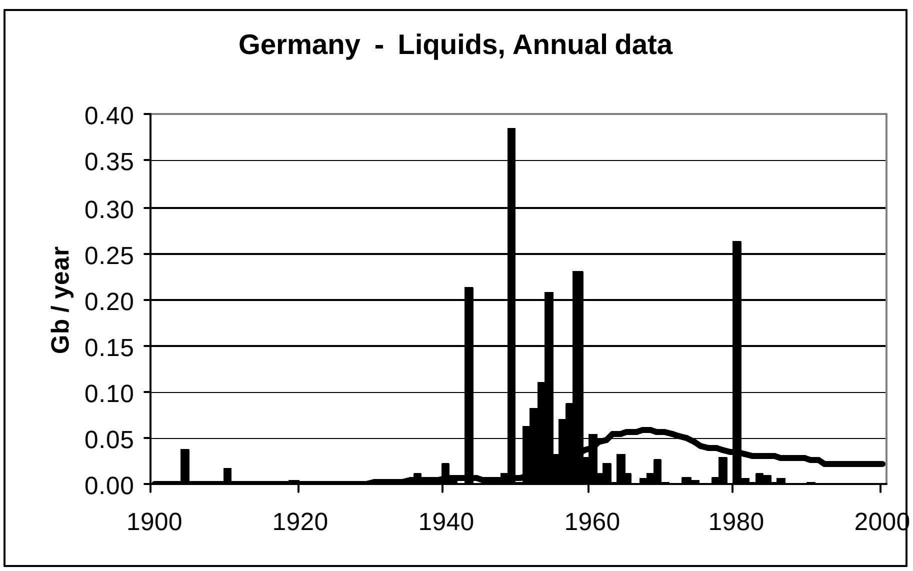

Figure 2. Germany: Annual 'P50' discovery and production of petroleum liquids (oil plus NGLs), 1900 - 2000. 'P50' discovery shown by vertical bars, production by the line. The bars are set to be a 'full year' in width, so the area covered by the bars on the graph corresponds to total quantity of oil discovered. This quantity can be compared to the total volume of oil produced, indicated by the area under the line. Source: IHS Energy.

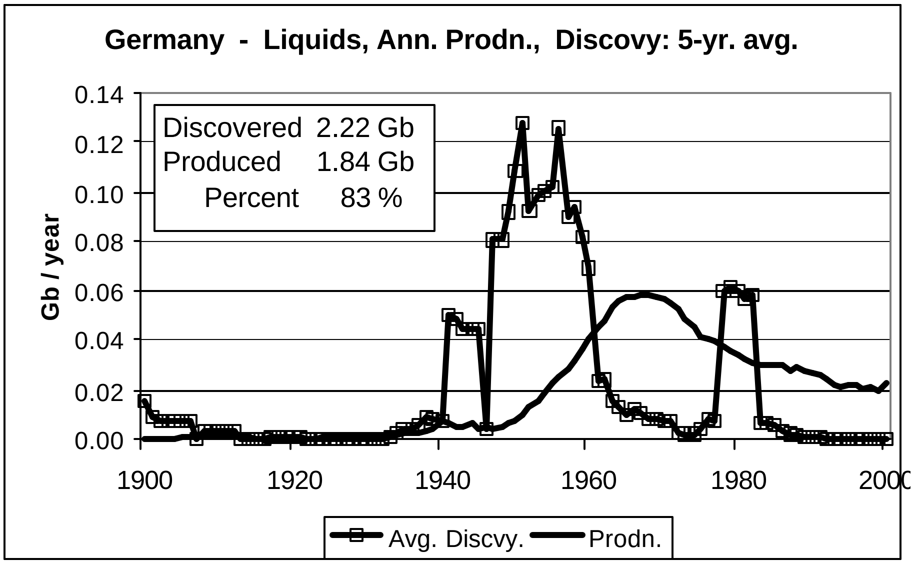

Figure 3. Data as in Figure 2, but with 'P50' discovery plotted as rolling 5-year average; to allow the eye to better judge the connection between discovery and production.
Source: IHS Energy.

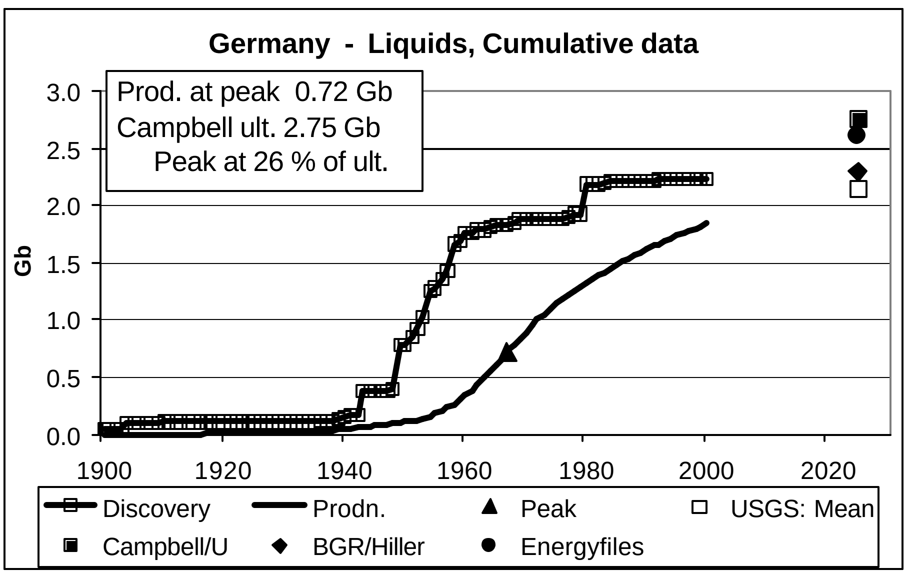

Figure 4. Same data as Figure 2, but plotted on a cumulative basis. Estimates for Germany's conventional oil 'ultimates' are shown against the year 2025. This is notionally the year that applies to the USGS estimate, but in practice all four 'ultimates' probably refer to much later dates. Campbell/Uppsala exclude NGLs. USGS may exclude Germany's offshore basin.
Sources: Discovery & Production: IHS Energy; 'Ultimates': See text.

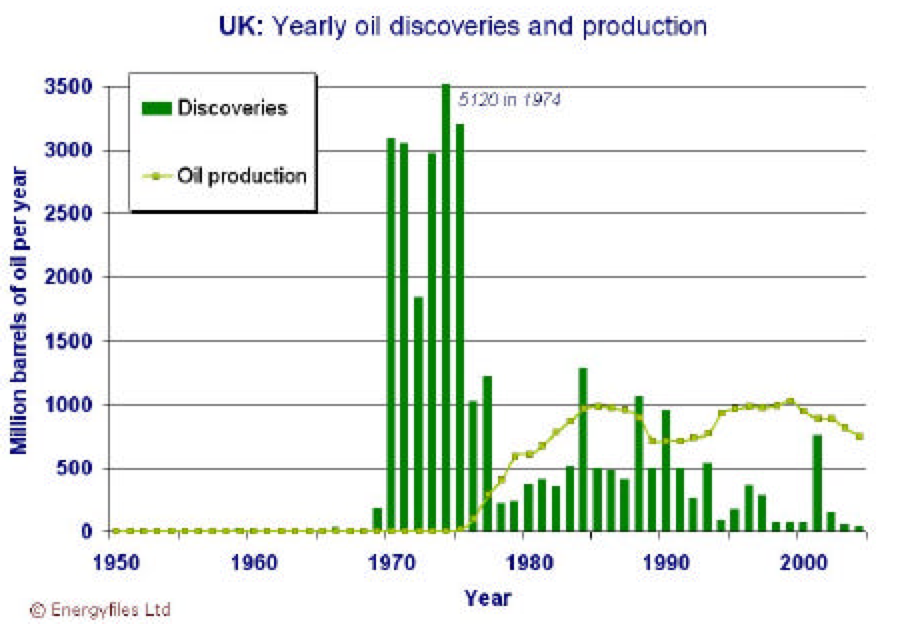

Figure 5. UK Annual 'P50' discoveries and production. Includes NGLs. Note that 1974 discovery is off-scale. Source: Energyfiles.

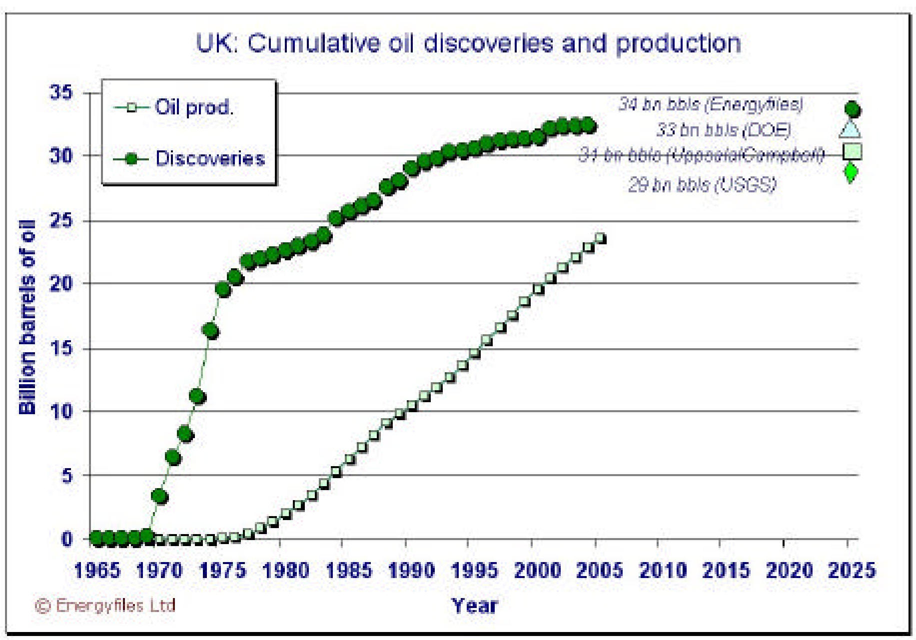

Figure 6. The same data as in Figure 5, but on a cumulative basis. Estimates for the UK's conventional oil 'ultimates' are shown against the year 2025. see comments on Figure 4. The UK Department of Energy's estimate ('DOE') is from 1976. Campbell/Uppsala and USGS data exclude NGLs (these add ~4.5 Gb). USGS data also excludes UK's West of Shetlands basins. Sources: Discovery & Production: Energyfiles; 'Ultimates': See text.

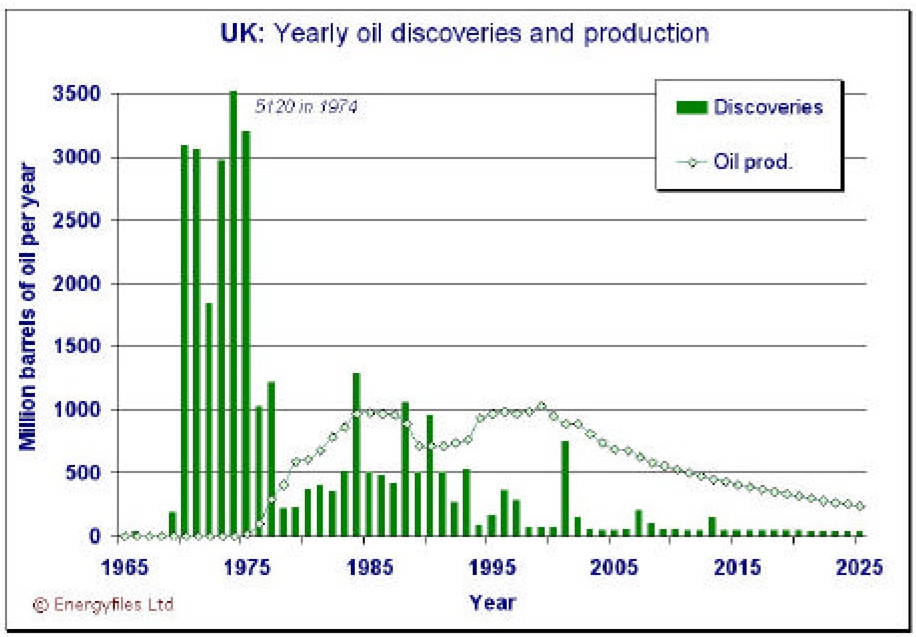

Figure 7. Forecast for liquids production for the UK, including NGLs. Note the simplified assumptions for discoveries assumed post-2005. Source: Energyfiles.

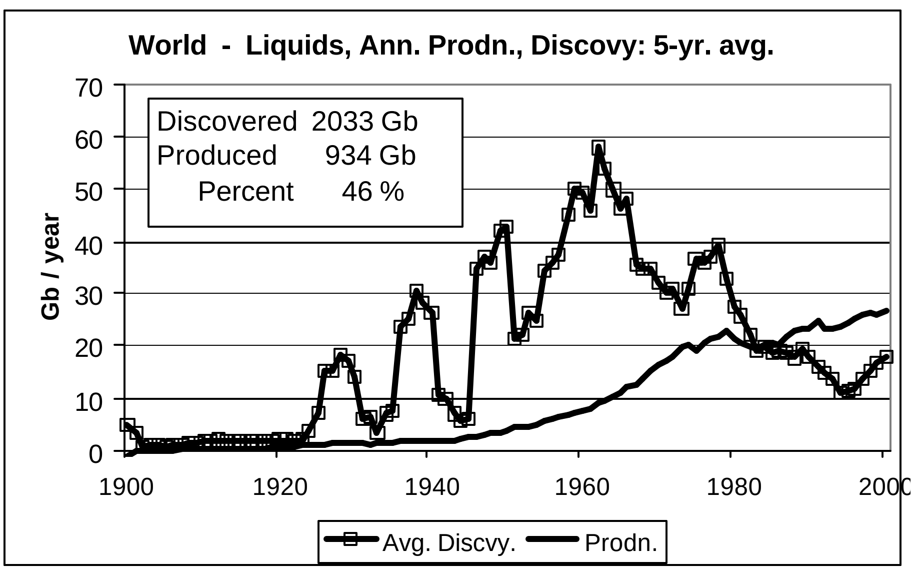

Figure 8. 'P50' Discovery and production of petroleum liquids (oil plus NGLs), 1900 - 2000. Discovery shown as a 5-year rolling average. Source: IHS Energy

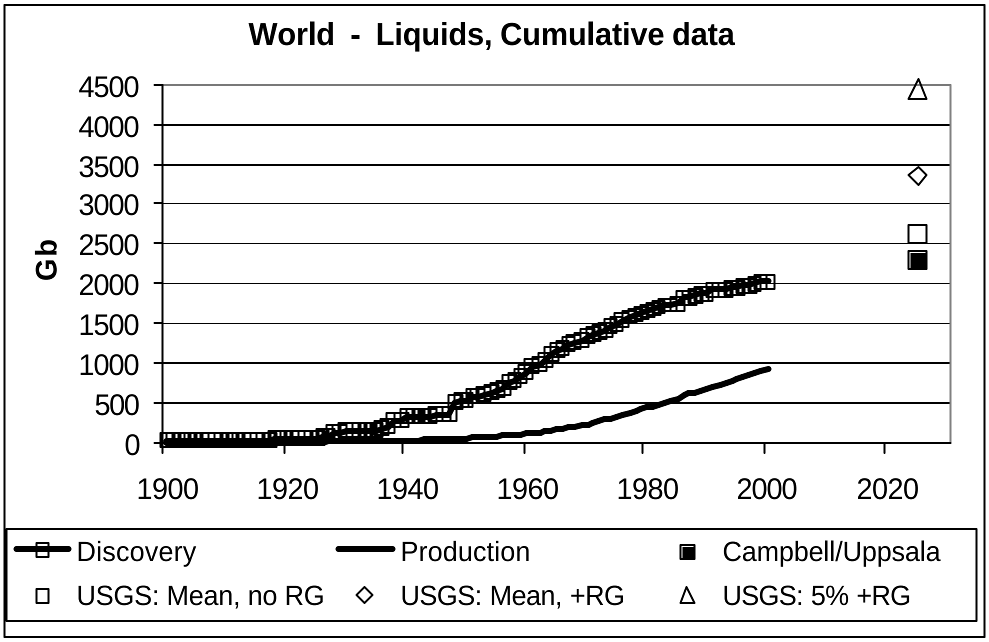

Figure 9. The same data as Figure 8, but on a cumulative basis. Estimates for the World's conventional oil 'ultimates' are shown against the year 2025, see comments for Figure 4. USGS 'ultimates' include NGLs; 'no RG' = assuming no reserves growth; '+RG' = including reserves growth; '5%' = estimate with 5% probability (high estimate). Campbell/Uppsala ultimate shown here is their 'regular' oil 'ultimate' plus my approximate estimated additions for polar, deepwater, and heavy oils (but not tar sands, etc.), plus NGLs. Note that the big finds of Burgan (Kuwait, 1938) and Ghawar (Saudi Arabia, 1948) are visible on this plot. The global rate of discovery has been in decline since the mid-1960s. Sources: Discovery & Production: IHS Energy; 'Ultimates': See text.