Global Oil and Gas Depletion – A Letter to the Energy Modelling Community

By Roger W. Bentley*

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

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 threat to 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. Some are small producers, but Chevron reports that production is in decline in 33 of the world's 48 largest oil producing countries. Large countries past peak include the U.S., 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.

Figure 1 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.

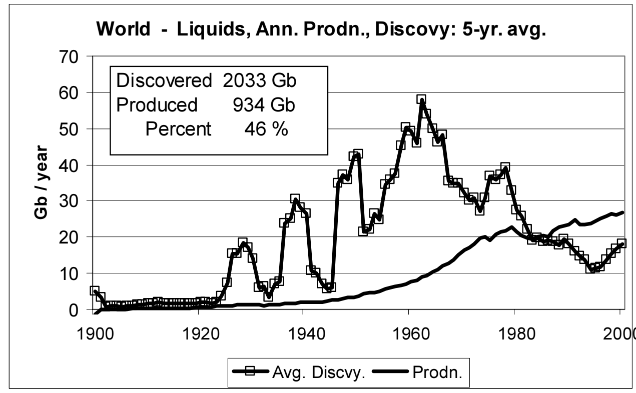

Figure 1
'P50' Discovery and Production of Petroleum Liquids (Oil plus NGLs) 1900-2000

Source: IHS Energy

Summarising, for some countries, we have:

	Peak of P50 discovery	Peak of production
U.S.	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.

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.

'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.

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.

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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.
- USGS assessments. The year-2000 assessment, for example, gives end-1995 P50 reserves by country from the IHS Energy dataset.
- A wide variety of publications by Jean Laherrère, see, e.g., www.oilcrisis.com/laherrere.
- 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. .

2. Proved Reserves

2.1 The poor quality of proved reserves data

Proved reserves data are quite unsuitable 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 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.

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 U.S.. 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 U.S. R/P ratio has also stayed virtually constant over the period, at around 10 years.

IHS Energy treats their U.S. 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 U.S. they work backwards, adding cumulative production to *published proved* reserves, to generate what in effect are 'proved discovery' data. 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 U.S. 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 U.S. 'proved and probable' data are available up to 1988 in the USDoE/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, 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.

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.

Table 1
Proved Reserves from BP's *Stastical 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	“	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	“	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 data do 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 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.

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 U.S. 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 global peaking could be undertaken was when sufficient regions were past peak (primarily U.S. 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 a number of 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 some analysts explain the very long run of almost constant U.S. 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 U.S. 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). It is hard to imagine that anyone who has looked at Hubbert's graph of U.S. Lower-48 'grown' discovery per foot drilled, where this declines inexorably since the 1930s, could think that the U.S. reserves of conventional oil are primarily 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, that concludes, "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 ..."

The fundamental reason for the IEA's ignoring 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.

- 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 U.S. peak, but no authoritative body at the time thought that the world peak was close; it was well documented that this would not occur before about the year 2000 (see Section 3.4, below).
- 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 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.

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.

(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 U.S. 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 the earlier note of Laherrère's analysis showing that continued scope for U.S. field growth is now considerably less).

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 U.S., 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 U.S. discovery per foot drilled mentioned above. The latter showed that the U.S. 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 waterflood 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 U.S. field-growth experience (for proved reserves) being applied to countries outside the U.S. (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 U.S., 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 U.S. 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. 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 datasets 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. 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 U.S. *proven*, and Canadian *developed* data are examined. As mentioned above, it was reserves growth factors based on the U.S. 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 U.S. 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.

More recently, the USGS has done a very useful study of field growth in the IHS Energy data. This identifies significant growth, though even here caution is needed on the apparent growth in Middle East fields.

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 U.S. states. 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 U.S. states, many of the 65 or so countries past peak, and many individual oil provinces including separate on-shore and off-shore regions. By far the majority of these areas show production curves 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 U.S. 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 U.S. field by far, was found very late compared to the bulk of Lower-48 finds. U.S. production will now show the addition of a third, yet smaller, curve due to production from the recent off-shore 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 production curves for its on-shore and subsequent off-shore regions. Indonesian production likewise reflects separate on-shore and off-shore discovery phases, though here the timing and relative magnitudes of these phases has resulted in a declining plateau-like production curve. Germany is now exhibiting the addition of its relatively small off-shore 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.

(b) Use of the Hubbert curve to predict the date of peak

So how did Hubbert use the Hubbert curve?

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

However, estimates for the size of the U.S. ultimate then began to rise, and so later Hubbert sought instead a prediction method that depended solely on U.S. 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 U.S. 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 2005.

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.

So the question for these models is: Does production peak at 50% of ultimate? This has been looked at by a number of authors. 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 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 peak occurs 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 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 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 and how this might be calculated.

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

(c) Using the Hubbert curve to match Discovery

Hubbert postulated that discovery also follows a logistic curve. This is true for U.S. '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 U.S.. 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 criticise use of the Hubbert curve, citing as primary evidence the fact that U.S. 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 - if any - in detail. The mass of evidence indicates that Hubbert's insights and analysis are by-and-large completely valid, and have given society a powerful set of quantitative tools with which to forecast the date of peak.

3.4 Past Forecasts

Past forecasts of oil production need examination because most who doubt the imminence of the conventional oil peak, 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 on just 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 the industry estimate used by Hubbert in the 1950's for global endowment of conventional oil 1350 Gb was, therefore, on the low side, as only by the early 1970s did realistic estimates became 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 and in many of the energy textbooks from that period. Hubbert's forecast at the time used Nehring's estimate of 2000 Gb for the global conventional oil 'ultimate'. All these forecasts predicted that world oil production would continue upwards for some 30 years, and peak around the year 2000.

Also at 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.

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 a lack of careful analysis. In the case of the BP prediction, this was for the non-communist world and taking out NGLs (as can be 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.

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. 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 techniques already mentioned earlier, such as the 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 U.S. (IEA, U.S. 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 that the 'WETO' authors, for example, have simply 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. The arguments are rational enough, and many are based on well-established economic theory. But as shown throughout this '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 will be discussed in a later article

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

Is the resource-limited peak in the global production of conventional oil 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 U.S. and Africa, from Kazakhstan and Russia, and from new tar sand plants more than offsets the declines in production elsewhere. This is also the current view of CERA, which is 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.

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-investment high-production strategy that maximises up-front volumes.