Oil Reserve Estimation and the Impact of Oil Price

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(N.B. For details of the above authors' careers, see the relevant chapters in Peak Oil Personalities, Campbell, 2011.)

Abstract

This paper gives observations on oil reserve estimation based on the personal experiences of the authors. One of us was a petroleum exploration geologist, and the other in charge of petroleum production engineering. The paper contrasts the different approaches to oil reserves estimation of these two disciplines. In addition, it discusses of the impacts of changes in oil price, and also a range of often under-recognised commercial and 'political' factors, on such estimates.

1. Introduction

Many think the reported reserves of a new oil field to be a reliable scientific estimate of the volume of oil recoverable from the field, without realising that economics, and especially price predictions, play a dominant role in this calculation. In this paper we examine the different viewpoints on oil reserves estimation of the exploration geologist compared to that of the production engineer, and focus in particular on the impact of oil price on such estimates. The paper also looks at other factors that play a part.

In the context of reserves data, one of us (Campbell) offers a caveat on the oil production forecasts given in *Campbell's Atlas of Oil and Gas Depletion,* which reviewed the status of oil and gas depletion by country as of 2010. The preface to the Atlas recognises that *"probably the only correct numbers in this book are the page numbers"*, but this statement may be particularly true of the reserves data that underpin the detailed by-country oil forecasts in the Atlas. These reserves data may have paid insufficient attention to the critical impact of oil price on oil reserve reporting, and as a result, and given the recent (and expected) on-average high price of oil, the forecasts in the Atlas may predict oil production declines for some countries earlier than will in fact be the case. Time will tell, and it will be fascinating to watch how higher oil prices impact future production in the countries in question.

2. Difference between 'Geological' and 'Engineering' views of an oil field's reserves

Now we examine the differences of view in evaluating the oil reserves of a new field between that of a petroleum exploration geologist and a petroleum production engineer. These differences result from the following:

In the early days of the oil industry, estimates of field reserves were often based on a rule of thumb, such as the US practice of determining reserves on the basis of 200 barrels per acre-foot (acre for the area of the trap, and foot for the average thickness of the reservoir).

But more recently when considering seeking drilling approval for a new oil prospect, the exploration geologist first makes an estimate of the total oil in-place within the indicated trap that comprises the potential field. This is based on a range of factors including an understanding of the general geology of the prospect, analogy with drilling data from adjacent areas, and from the seismic data available.

Then a technically-based preliminary estimate of the recoverable oil from the potential field is generated by assigning from experience a value for the recovery efficiency, the fraction recoverable of the oil in-place. This estimate becomes the basis for proposing the prospect to management for exploration drilling. Generally - at least in the past - no detailed forecasts of cost and revenue streams from a potential discovery and development were made at this point, although the current (and anticipated) price of oil were considered; with many an exploration geologist being disappointed in having a good prospect turned down when the oil price was low, or conversely seeing a less-than-certain prospect approved for exploration when the price was high. The explorers were largely motivated by their quest for more information on the geology of little known new areas. Governments likewise wanted information on the potential of new areas under their control. The Soviet system permitted exploration drilling for information, but countries in the rest of the world were under commercial pressures.

If the project gets the go-ahead from management then exploration drilling takes place.

Importantly, once a prospect has been verified as economically viable by exploration drilling, the petroleum engineers responsible for the field then face a different task. They work in much more detail, and take into account not just the technical parameters defining the discovery, but also the cost of infrastructure to develop it, and the economic conditions which may be expected during its producing life. These calculations are listed in Section 3 below, and typically yield a different (and often significantly lower) estimate of the field's reserves to that previously given by the exploration geologists.

In understanding this difference in approach to estimating a field's reserves, it is crucial to recognise that while the cost of a preliminary exploration well (or wells) may be tens of millions of dollars (and up to perhaps a few hundreds of millions in the case for example of a remote deep offshore well), the cost of production facilities for a field can typically be at least an order of magnitude larger (and up to several tens of billion dollars in the case of a large and difficult new development such as the Kashagan Field). It is thus no wonder that the need for detailed oil-price sensitivity calculations is much greater in the engineering calculations.

3. Steps in an 'Engineering' Assessment of a Field's Oil Reserves

The following briefly outlines some of the steps that petroleum engineers take when estimating the oil reserves of a field.

Note that these apply primarily when making estimates of reserves of conventional oil. The procedures followed when developing estimates of reserves of non-conventional oil, such as tar sands oil, or 'tight' oil in very impermeable reservoirs, have to be somewhat different, as here the flow characteristics of the reservoir fluids are more complex and often poorly understood; and reliable estimates are usually not available until considerable production experience of the particular play under consideration has developed. Note also that there is no standard definition for the boundary between conventional and non-conventional oil deposits, which is a further source of complexity and confusion when considering reported reserves.

Step 1. The engineers re-estimate the hydrocarbon volume in-place in the trap, based on geological and geophysical mapping and on the characteristics of the reservoir rocks, including the porosity, permeability and water saturation, as revealed by the logging and testing of the successful exploration well, known as a *wildcat*.

Step 2. They decide on the well-spacing required to profitably drain the reservoir, and hence the number of producing wells to be drilled. In addition, the number and location of these producing wells determine how many offshore platforms or onshore production centres, both taking huge investments, would be needed. The aim is to maximise the profit from the discovery, drilling the minimum number of necessary wells, based on the company's internal oil price forecast and the cost of field operations. They also have to decide upon the export system to bring the oil and gas to a terminal or refinery. The cost of an offshore development generally greatly exceeds that of an onshore field of the same size.

Step 3. The engineers then have to determine for how long the field is likely to remain on production as reservoir pressure, and hence well off-take rates, declines. The end of the producing life of the field will come when the cashflow from production sales falls below the operating cost of the field; although tax considerations and the advantage of deferring the huge costs associated with field abandonment may sometimes prolong a field's life by some years (see also Section 4, below).

Forecasts of oil price for the entire producing life of the field are therefore essential to these calculations, meaning that the company has to build its own forecast of future oil prices.

In earlier times, when oil supply and demand conditions were fairly stable, forecasting these prices was not a particular challenge, but this has not been the case over recent decades. The following table shows the average price of oil by decade over the past century, based on information from the BP *Statistical Review,* which reports the oil price in real terms to discount the effects of inflation.

Date	Real-terms oil price ($/bbl)
1900-09	22.11
1910-19	27.57
1920-29	17.58
1930-39	17.39
1940-49	17.69
1950-59	16.89
1960-69	11.63
1970-79	103.20
1980-89	61.17
1990-99	29.35
2000-09	68.13
2010 to 2015	96.82

Table. Real-terms oil price vs. date.
Source. BP Statistical Review, 2015.

It is, of course, extremely difficult to forecast oil prices with any confidence.

In the past the supply of oil used to be substantially controlled by US pro-rationing, by the actions of the 'Seven Sisters' in preventing too much oil (especially from the mega fields of the Middle East) from coming to market, and subsequently by OPEC quotas. After a hiatus, today we still have a degree of OPEC control, and now - at least for the present - also agreement with some key non-OPEC players.

But despite this, as recent price fluctuations have shown, over the short term a very small difference between supply and demand can push the oil price significantly up or down; and when averaged over a longer period, other factors affecting the price come into play. These currently include:

- Significant risk of oil supply 'shocks' from short-term restrictions in supply.
- Possible limitations to supply from some exporters due to rising 'resource nationalism'.
- The fact that a high oil price limits demand growth; and too high a price destroys demand.
- The likely more widespread imposition of carbon taxes, and similar measures, to reduce climate change impacts (with this - possibly - leading to the 'peak demand' scenario).
- The fact that as the oil price rises it becomes increasingly viable to tap the generally more costly non-conventional oil sources, for example by those made accessible by hydraulic fracturing.

Despite these large uncertainties, it might be reasonable to think of the oil price as likely to be in the $70 - $90 per barrel (real-terms) range over at least the medium term.

Step 4. Once the number of production wells and the initial well off-take rates have been fixed, then calculations are made of how these production rates will decline with time. Such calculations involve building a numerical model of the reservoir, matching the output of the model to the observed early production performance of the field by altering the input rock and fluid description, and then running the model forwards in time. These well performance estimates, combined with the predicted life of the field, allow the calculation of most-likely field reserves under natural depletion, and hence the recovery efficiency, namely the fraction of oil-in-place that is recoverable. These models are often probabilistic, and range of net-present-value calculations performed to optimise anticipated field production against statistically-weighted possible eventualities.

If the recovery factor seems anomalously low compared with that observed previously in similar reservoirs then the engineers consider whether some form of secondary recovery can be applied to the field. This involves estimating the cost of injecting water or gas into the reservoir, and then calculating the increase in recovery that would result. If this process is seen to be economic, then the additional *Probable Reserves* can be booked, and once the new process is in place, then an increase in *Proved Reserves* can be claimed.

Step 5. If the estimated volume of oil in a trap is large, the engineers might be able to drill on a fairly wide spacing, thereby reducing the number of wells required to achieve adequate drainage, and hence the initial investment. They have to balance the many elements involved to deliver the best possible long-term profit.

Step 6. The management has to review a range of such proposals from their company's discoveries around the world, taking into account many other economic and political factors, and find some combination of projects that would deliver a good annual overall corporate profit. There are often complex tiers of committees in the company and many internal political factors involved. Furthermore, in most cases, the concession holding the discovery is owned by several companies in a joint venture. This adds to the difficulty, as a compromise development plan that is acceptable to all the partners has to be defined.

Step 7. Eventually, the management makes a decision to proceed to develop the oil find or, if the development is insufficiently attractive economically, to defer it in the hope that economic conditions may improve. There is also the likelihood that should development be deferred then technical advances over time, such as chemical methods of increasing water viscosity, changing rock wettability or more efficient thermal stimulation may significantly increase the efficiency of complex secondary recovery techniques. It is reported, for example, that Norway has as much as 3 billion barrels (Gb) of oil in undeveloped discoveries awaiting better economic or technical conditions before their development meets economic criteria.

Step 8. If it is decided to proceed with field development, the first set of development wells will be drilled and placed on production. As indicated above, it is desirable to drill the minimum number of these necessary to deliver a reasonable profit.

The estimated future production from the field can be reported publically under two categories. The *Proved-plus-Probable Reserves* give the expected most-likely value of total production from the field by the time production stops. By contrast, a considerably more conservative figure of *Proved Reserves* is more usually reported, this must follow detailed and strictly-enforced rules on its calculation. In particular, the procedures defined by the US Securities Exchange Commission (SEC) are those most widely followed; and until fairly recently the reserves data given in oil company annual reports had to provide only SEC *Proved Reserves* values. Currently company reports can report both classes of reserves estimates, but must make the distinction clear.

Step 9. Production from the initial wells progressively declines as reservoir pressure falls and the thickness of the remaining oil column in the reservoir reduces. This in turn often prompts the drilling of infill wells, between the existing producers, and also the tapping of any subsidiary traps or reservoirs identified on the flanks of the field in the course of its development. These later developments are often of higher risk, and may deliver lower profits being more vulnerable to falls in oil price.

4. The 'U-shaped' Reserves reporting curve

Given the discussion in Sections 2 and 3 above, it is not surprising that there can occur what might be called the 'U-shaped reserves reporting curve'. This is where the initial estimate of a field's likely reserves (i.e. proved-plus-probable reserves) from the exploration geologist takes a certain value and that of the initial engineering estimate a significantly lower value, driven by the need to fund initial production infrastructure; but where, as the field gets developed over time and subsequent infrastructure and improved recovery methods are employed, this 'engineering' estimate of the field's original reserves climbs back towards the geological estimate. This evolution of reserves estimates is observed, for example, in the case of the Prudhoe Bay field in Alaska.

5. Commercial and 'Political' Realities

The situation set out above would appear fairly straightforward in terms how reserves estimates are made. In the real world however, reserves reporting is often more complex, with a wide variety of commercial, and also what might be termed 'political', realities enter the picture. These include:

(a). Engineering caution on large fields

As explained above, and for good reasons, engineering estimates of reserves often are (or start out) as lower than geology-based estimates. But if a field is large, the engineer can be doubly cautious; the field will see production anyway even if the reserve estimate is low; and if this value climbs over time the engineers can appear in a good light within the company, and the company in a good light to the market. A senior fellow at BP told one of us that he liked to 'keep a little back' in his reserves estimates, both to allow for unforeseen setbacks, but also to give the next person in his post some scope to shine.

(b). Geologist caution on large fields

Perhaps surprisingly, caution on field reserves can apply to the geologists also. As Laherrère reports: *"Sometimes we underestimated a prospect when it was very big in order not to appear too optimistic. This was the case for the reserves estimate of the Cusiana in Colombia; Cusiana is a giant oil field, but we presented the prospect as less to our management."*

(c). Geologist optimism on fields 'difficult-to-sell-to-management'

Conversely however, if a geologist thinks they will find a prospect difficult to sell to management, perhaps because the field is fairly small, or maybe difficult to produce for some reason, or the oil price is low, there is a natural tendancy to put a positive gloss on the various individual factors involved in estimating the field size, and hence derive a particularly optimistic estimate. And as mentioned above in this regards, the geologist is 'in competition' with other exploration groups within the company, and with outside prospects the company may to decide to participate in, if they are to get their prospect adopted.

And in this respect, geologist motivation needs to be properly understood. Campbell writes: *"I remember in my days we tried to get the company to drill exploration wells in new areas, in part to provide the information needed to evaluate it, and in many cases [we] cheated on reserve estimates to get it past the company economists. The Russians had a better system that allowed exploration wells to be drilled just for information."*

(d). 'Small-company' optimism

An import element in recent years has been the growth of many small 'promotional' companies set up in the hope of being able to make a significant discovery on previously unexplored acreage, but whose development costs they would be unable to fund themselves, and need to sell on to a larger company. The seven major international companies, once known as the *Seven Sisters,* are now reduced to four, having found that more profit on the Stock Exchange was to be made by merger than by finding new oilfields from exploration. The small companies have every motive to exaggerate their reserves as they themselves try to raise investment on the Stock Market.

(e). Past flexibility of reporting rules

Companies previously had more freedom in their reserve reporting, the numbers often being the *minimum* needed to deliver a good image to the Stock Market. What rules existed were set to prevent fraudulent exaggeration, but smiled on under-reporting as laudable caution. Any such under-reporting provided the company with a balance that could be used to offset problems with fields, or any unexpected temporary decline that might set in around the world due to accident or political unrest.

(f). Oil price uncertainty

In recent years, with a return to wide price oscillations, the difficulties facing oil companies in forecasting future oil prices, and hence in turn the volumes of economically recoverable reserves, has become very large. Although the expectation is for oil prices going forward to be high *on-average,* wide fluctuations in price are still to be expected, and it may be that new guidance on reserves estimation will be required.

(g). Field abandonment

A topic of increasing recent importance in reserves estimates is that of field abandonment. Management finds itself in the difficult position having to decide on whether to abandon a producing field that is no longer profitable at low prices, while recognising that prices may soon recover. The internal pressures must be enormous as the premature abandonment of a field leads to curtailment of reserves for that field, as well as to job losses and all manner of tensions. This is particularly true if the field is offshore, where the chances of restarting a now-low-reserves field once the infrastructure has been removed are virtually nil.

(As an example of the problem, the *Financial Times,* a UK newspaper, recently reported: *"As many as 50 North Sea oil and gas fields could cease production this year after a collapse in crude prices to 12-year lows industry experts have warned"*; with the consultancy Wood Mackenzie saying: *"Oil companies were likely to halt output at 140 offshore UK fields during the next five years, even if crude rebounded from $35 to $85 a barrel. This compares with just 38 new fields that are expected to be brought on stream during the same period."* In this regard, Paul Charlton, chief executive of engineering consultancy PDL, warned against rapid [North Sea] decommissioning, saying that the industry should co-operate to keep fields producing: *"Once they are gone, they're gone.")*

(h). OPEC 'quota-wars' reserves

In addition to the topics discussed above on reserves reporting there can be very significant wider political factors. This has been especially true in the case of reserves reporting by the OPEC countries. This was discussed at some length in Annex 5 in the paper: *Oil Forecasting: Data Sources and Data Problems – Part 2* (Laherrère et al., 2017). In at least some of these OPEC countries, for example Kuwait, the reported c*urrently remaining* proved reserves would seem to be close to the country's *original* recoverable reserves, i.e. the *proved-plus -probable* reserves before production started.

6. Discussion and conclusions

It is evident from the foregoing that reported reserves for a field may differ significantly from an estimate of the *technically possible* future production from a field. *Economically possible* recovery for a given field may be as little as half the volume of that technically recoverable when economics are ignored. Newly discovered fields have themselves progressively declined in size as the number of remaining giant fields dwindles, adding to the vulnerability of their development to price fluctuations.

In summary, however, there are just two fundamental issues to address, which are simple enough even if calculations are difficult:

(i). How much oil is in the ground (recognising all the different categories of oil). Oil-in-place is a quantity that can be measured by mapping the volume of a trap and the porosity and water saturation of the reservoir rock. The results are naturally subject to a degree of uncertainty as the parameters cannot be accurately determined, but a reasonable approximation can be made.

(ii). How much of this is commercially extractable, which depends on economic factors including:

1) Oil workers' wages
2) Cost of facilities (drilling rigs, platforms etc.)
3) Oil price
4) Forecasts of oil price
5) Rates of extraction
6) Cost of borrowing money
7) Tax on operations
8) Stock exchange movements on oil company shares.
9) Demand for oil (which depends on many factors, including general economic circumstances, population change, legislation, oil price, and changes in demand by sector - such as for transport vs. that for agriculture.)

Calculation of *Proved-plus-probable* (2P, or P50) reserves aims to take these factors into account, but with so many uncertain input parameters, the results are often in reality little more than a 'best guess'.

It is significant that the 2015 issue of the BP *Statistical Review,* a widely-quoted database, shows unchanged *Proved* Reserves for forty countries, although it is utterly implausible that new discovery or valid improved recovery should have exactly matched intervening production. It suggests that the government departments responsible have simply not released the updated data at their disposal, possibly for political reasons.

The challenges of estimating future world production have grown greatly. But that said, it seems evident that the future production of the giant fields, which have dominated world supply, is declining from natural depletion whatever the uncertainties of detail. That itself ushers in the *Second Half* of the Oil Age, when the world, having become very dependent on oil-based energy, faces radical changes. The tensions of the transition are likely to be severe, as perhaps already indicated by riots, revolutions and pressures for migration from people whose home countries can no longer support them.

Governments begin to face the challenges of the *Second Half* when the critical supplies of oil and gas that fuelled past expansion begin to decline due to natural depletion. They are likely to curb immigration, and provide greater devolved power to the regions making up their country, as an oblique recognition that communities will increasingly have to depend more on whatever their region can support.

Better efficiency in the use of oil will be part of the solution. For example, the main road through a typical small village in the West of Ireland is commonly choked by traffic, with many of the cars carrying no more than a single occupant. More efficient vehicles, car-sharing, and the giving of lifts could ease the situation greatly. Since oil is a major source of energy, both government authorities and people at large should have a better understanding of the nature of oil reserve determination and reporting as discussed herein. It is clearly a critically important subject.

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