

Review by Jean Laherrere for Petroleum Geoscience
on

16 July 2004

TITLE: Reserve growth in oil fields of the North Sea

PAPER NO: PG620

AUTHORS: T R Klett & D L Gautier

I call USGS the reserve values given in their paper

The goal to study the reserve growth of the North Sea oilfields is a good one, because it is now a mature oil province where all the data are published and a synthesis is needed.

The breakdown between clastic and chalk fields is also an important point.

But reserve growth depends mainly on the definition of reserves, because there are several definitions and most are ambiguous.

DTI rules in UK (SORP) are different from NPD classification.

Proved reserves in US to comply with SEC rules (which reject probabilistic approach) cannot be compared to proven + probable, which is assumed to correspond to a probability of 50%. Nothing in the text defines the reserve, only Table 2 indicates that proven and probable are included.

I give a historical review of reserve definition in

-Laherrère J.H. 2004 «Shell's reserves decline and SEC obsolete rules» Energy Politics in review, draft <http://www.hubbertypeak.com/laherrere/ShellDecline2004.pdf>

The SPE/WPC rules (I was a member of the 1997 task force headed by Anibal Martinez) define proven + probable (2P) as P50 (I was the one to propose it) when DTI rules is that only probable is P50

But the probability of field reserves does not come from a scientific formula, but from a subjective estimate, which is more a guess, and some authors use the most likely (mode or about a probability of 65%), others the median P50, and most authors the mean or expected value (probability of about 40%), as only mean values can be added to get the global mean value

UK DTI rules are

http://www.og.dti.gov.uk/information/bb_updates/chapters/Table4_3.htm

UKCS OIL Reserves 2003

Proven - those reserves, which on the available evidence are virtually certain to be technically and economically producible (i.e. having a better than 90 per cent chance of being produced).

Probable - those reserves which are not yet proven but which are estimated to have a better than 50 per cent chance of being technically and economically producible.

But the UK operator has the choice under the SORP between different definitions

OT02200 - Oil Industry Accounting Disclosure of Commercial Reserve Quantities

Disclosure of commercial reserve quantities is covered by the oil industry SORP issued January 2000 and updated 7 June 2001.

Commercial reserves may, at a company's option, be taken as either;

- 1. Proven and probable oil and gas reserves, or*
- 2. Proved developed and undeveloped oil and gas reserves.*

Heiberg NPD was the head of a UN task force and issued the following paper where he recommends to use «mean» (expected value) instead of the median

4th National Data Repository Meeting

NPD, Stavanger 5. – 7. March 2002

Resource Accounts, National and International standardization

By Sigurd Heiberg, Per Blystad and Erik Søndena

SPE/WPC

The reserves definitions, which were adopted before the resource classification, also allow quantities associated with immature projects to be included as uncertain probable and possible reserves. This leaves a weakness in the system that is likely to correct itself through practise. As the less mature quantities are properly reclassified as contingent resources, the reserves base will by necessity become more restricted, and more certain.

As a consequence, it could be considered to recommend shifting the main reporting point from proved reserves to the expected value of reserves. There are several advantages to this: The gross under-reporting of reserves that takes place at aggregated levels when proved reserves are added will disappear.

Probabilistic and deterministic methods may both easily relate to the expected value, bringing the two methods together when reporting the highlights.

Explanations of changes from period to period may be performed in an additive mode. This is what most readers will expect.

There are however good reasons to continue to report proved reserves, as the concept reflects not only a reasonably certain value statistically, but also the quantities that have been confirmed through direct observations. Proved reserves could therefore remain in the reports, but then as an aggregated number at the level that the report addresses (a field, a company or a country).

Figure 13:

		SPE/WPC/AAPG			NPD/FUN		Russian classification												
		Resource class			Project status category		Reserves					Resources							
							Stages of Commercial Development	A	B	C1	C2	Non commercial	C3	D1	D1	D2			
Total petroleum initially in place	Discovered petroleum initially in place	Sold and delivered petroleum			0	Sold and delivered	Produced												
		Reserves	On production	1	On production	Under development													
			Under development	2A/F	Approved development plan	Prepared for development													
			Planned for development	3A/F	Decided recovery														
		Contingent resources	Development pending	4A/F	In Planning	Being explored													
			Development on hold	5A/F	Unclassified														
			Development not viable	6	Not very likely	Conserved													
				7A/F	Not evaluated														
		Undiscovered petroleum initially in place	Unrecoverable																
			Prospective resources	Prospect	8	Prospect	Undiscovered fields												
Lead	9			Lead															
Play																			
Unrecoverable																			

Conclusions

This comparative analysis has shown:

Probabilistic forecasting better reflects our understanding and therefore facilitates better management.

Needs for resource management and business management on one hand, and financial management on the other are likely to require different classifications also in the future.

Differences may be reduced by:

Reporting mean values of reserves as a basis for change explanations.

Reporting proved reserves as a supplement.

Using forward prices for forecasts instead of historical prices.

The internationalisation of finance requires international standards.

Classifications must evolve in a continuous way and not change abruptly. Conversion matrices may facilitate transitions.

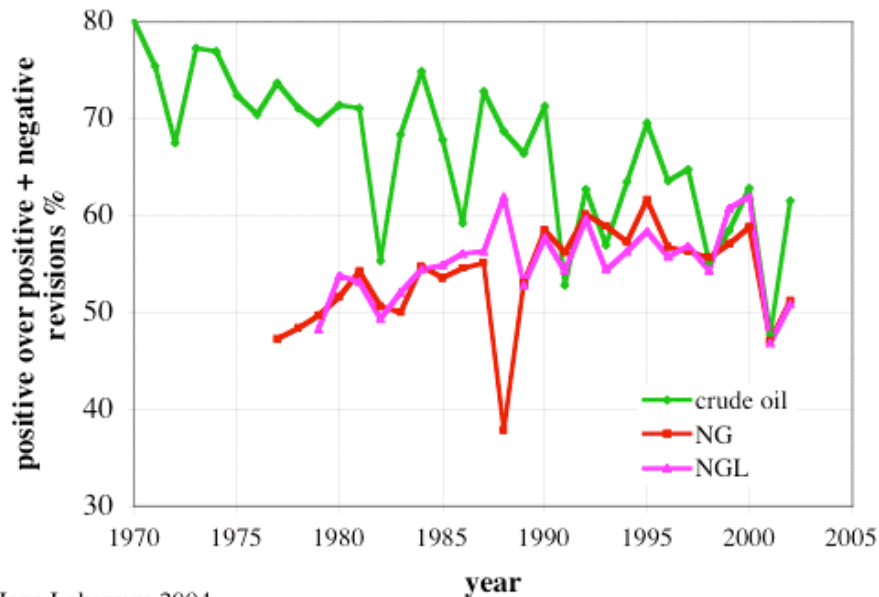
UNFC new version (<http://www.unece/ie/reserves-UNFC>) which wanted to homogenise the reserve definitions for petroleum, coal and uranium is a poor compromise where, under a 3D scheme (geology, economy and technique), each domain keep their wording (G1 being “reasonably assumed“ for petroleum and “measured” for coal; it is just plain words, short for comparison and far from a scientific approach) and the probabilistic approach is rejected (as it is by the SEC, mainly just because most consultants do not understand it).

Klett & Gautier write: <<Reserve estimates change through time for a variety of geologic, engineering, operational, and economic reasons.>>

It changes also in the same time between the authors (geologist or reservoir engineer or economist), the rules (SEC obliging to omit probable reserves, SORP in UK asking for proven plus probable) and it is well known that each oil company has several sets of reserves depending the destination and the department (see Prudhoe Bay below)

Everyone in the US is convinced that the US proved reserves (SEC rules with reasonable certainty to be recovered) correspond to a high probability estimate, (as for SPE/WPC a P90), but it is very easy to plot the probability of proved reserves from the annual USDOE reports by using the ratio of annual positive revisions versus the annual positive plus negative revisions. This plot shows clearly that for oil the probability was around 75% in the 70s but in the 00s it is about 55% (fart from the SPC/WPC P90), even in 2001 it was below 50% as negative revisions were higher than the positive revisions.

US revisions of proved reserves of crude oil and natural gas: probability of the estimate



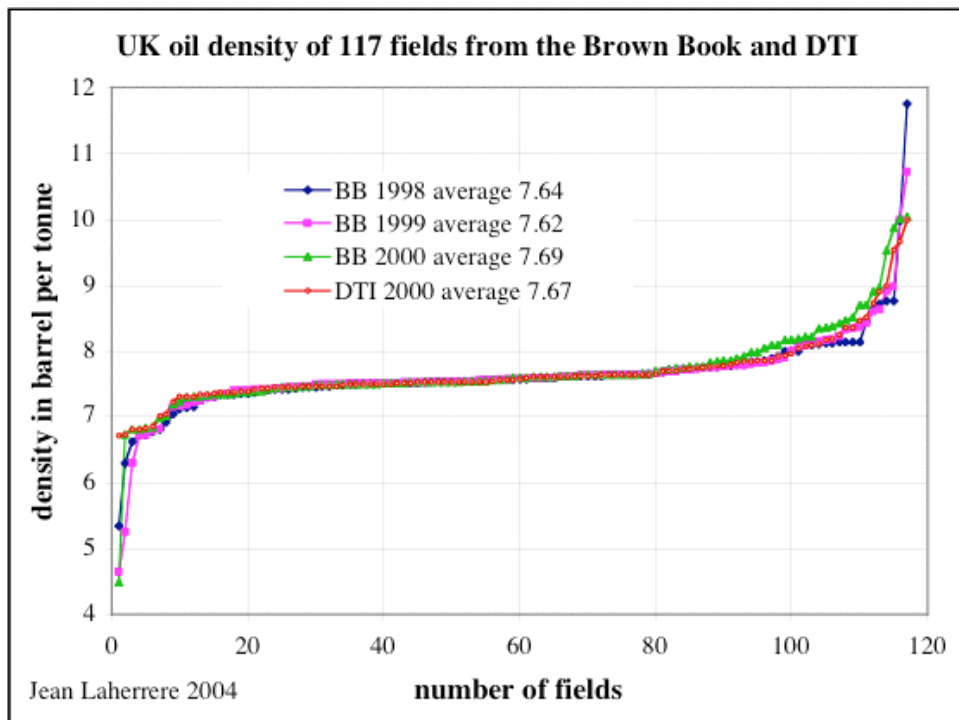
Jean Laherrere 2004

The SEC rules are obsolete as they deal with certainty (one value) when reserves should deal with uncertainty (range or 3 values)

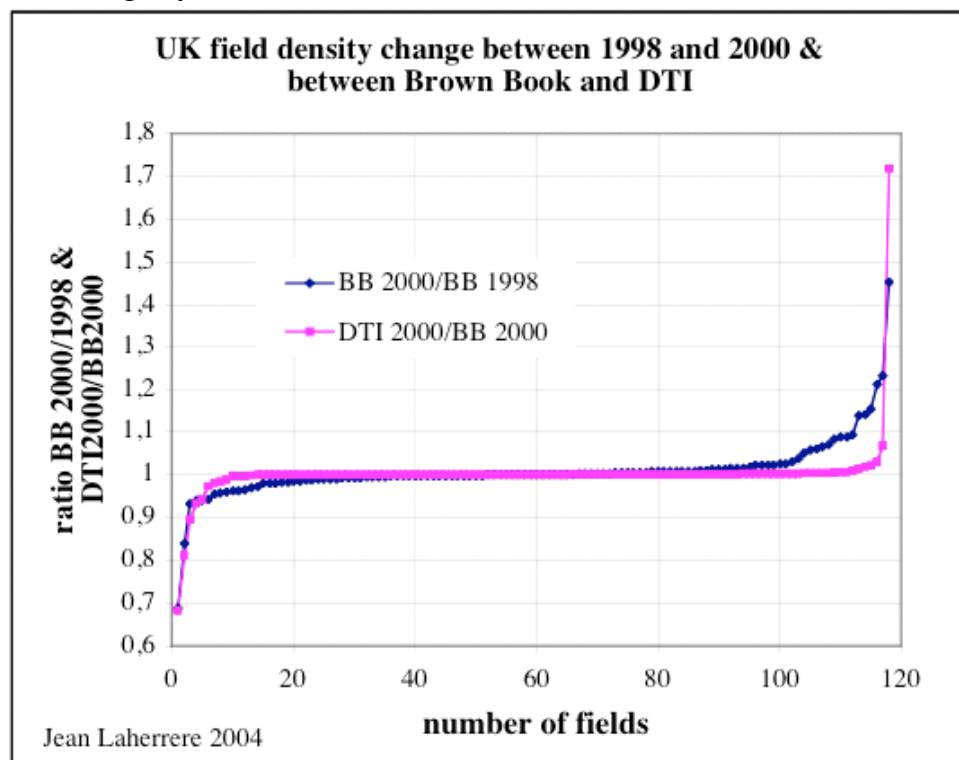
The word «oil» is not defined either and nothing indicates if condensate is included, or NGL. In fact condensate and NGL are included in some USGS values, but not on all (Brent 2000). The reporting of condensate and NGL is different between UK and Norway. For UK the percentage of condensate to total production is about 2.5 % and 7.5 % for NGL, totalling 10%.

The Brown Book in UK was mainly operator's estimates and it is well known that partners have different views from the operator. It is reported for Ormen Lange field in the July 6, 2004 Deutsche Bank paper: «The reserves are 2.6 Gboe 2P, but reported only 20% by Shell, 27% by Statoil, 49% by Norsk Hydro, 70% by BP». IHS reports for Orman Lange 2.35 Gboe and Wood Mackenzie 2.39 Gboe. Operator's estimate depends upon its motive. (Frigg gas reserves were reported optimistically at 225 G.m3 in order to get the highest DCQ, when in fact the real value is about 190 G.m3).

As I said many times, publishing reserve values is a political act and depends upon the image the author wants to give (poor against taxes or rich for the banker or shareholder): one value is chosen within a large range to be either close to the minimum or close to the maximum. Another cause of uncertainty for UK is that production is given in cubic meter and reserves in tonnes, as density varies largely with time and between fields as shown in the production values from the Brown Book for 1998, 1999 and 2000 and DTI report for 2000.



The change by field between 1998 and 2000 can be also over 50%.



The discrepancy can go up to more than 50%, showing that the inaccuracy of data in cubic meter can be large just coming from conversion.

The conversion of tonne in cubic meter for UK reserves should be indicated by the authors (global average or by field), DTI indicates a global ratio of 7.5 b/t, hen in fact it is higher

The uncertainty on reserve is of the order of reserve growth and this inaccuracy (or discrepancy between sources) should be better mentioned.

Statistical plot should be based on more geology and on historical cases.

The difference between clastic and chalk could be studied more in detail.

At the beginning of production in the North sea, water flooding in clastic reservoirs was assumed to leave a certain amount of oil behind (30%) but this assumption was too conservative and in good reservoirs water flooding has pushed all the oil, leaving none behind. This increase in reserve was not due to technology but due to good Nature. The largest reserve growth happens to Ekofisk in chalk reservoir as the reservoir has collapsed giving a seafloor subsidence of more than 6 m, obliging to raise the platforms with very expensive investments. It is not very often that such collapse occurs. And such collapse, which leads to an increase in recovery by compaction of the reservoir, is not mentioned. The best way to check if a reserve growth is due to bad reporting or technology improvement is to plot the annual production versus cumulative production. Any improvement must lead to a lower decline. I have shown several years ago the example of Forties

-Laherrère J.H. 1998 "The evolution of the world's hydrocarbons reserves" translation of SPE June 17, <http://dieoff.com/page178.htm>

Examples of Reserve Revision by Field

North Sea

A 1998 study by the Department of Trade & Industry (1998) on UK oilfields shows both positive and negative revisions over the period 1986-1996 as given in the following table. The corresponding revisions as based on SPE/WPC guidelines is given in parenthesis.

<i>Reserves</i>	<i>No. of fields</i>	<i>Positive Revision</i>	<i>No Revision</i>	<i>Negative Revision</i>
<i>3P >10 Mboe</i>	<i>144</i>	<i>70 (14)</i>	<i>7</i>	<i>72</i>
<i>2P>10 Mboe</i>	<i>86</i>	<i>46 (40)</i>	<i>5</i>	<i>35 (40)</i>
<i>P>10 Mboe</i>	<i>58</i>	<i>44</i>	<i>4</i>	<i>10 (5)</i>
<i>2P>50 Mboe</i>	<i>66</i>	<i>33 (31)</i>	<i>4</i>	<i>29 (31)</i>

A number of observations may be made:

The low number of Proved (P) estimates shows that the US system is not applied in the North Sea;

The Proved + Probable + Possible (3P) estimates are too low, having been exceeded 70 times rather than the 14 times indicated by definition

The Proved (P) estimates are too high, having failed 10 times rather than 5 as indicated by definition

The Proved + Probable (2P) estimates are close to a 50% probability especially in the case of the larger fields (>50 Mboe)

Another study by BP (Dromgoole 1997) shows that there have been as many positive as negative revisions, and that the simple fields tend to be underestimated whereas the more complex ones are overestimated. A Statoil study (Hermanrud 1996) shows that the revision of Norwegian fields has been more or less random.

The case of the Forties Field is illustrated in Figures 8a and 8b, based on BP's data. Figure 8a shows the growth of cumulative production and published reserves. It is evident that the 1986 reserve estimate was too close to Cumulative Production and was due for upward revision, irrespective of the construction of a fifth platform and the application of gas lift in 1987. Figure 8b shows annual production as a function of Cumulative Production with a straight decline trend demonstrating that the additional platform and gas lift temporarily increased production without affecting the reserves. It is a compelling argument against the widely promoted view that technology increases reserves.

Fig 8a **Forties: cumulative production versus time and reserves estimates**

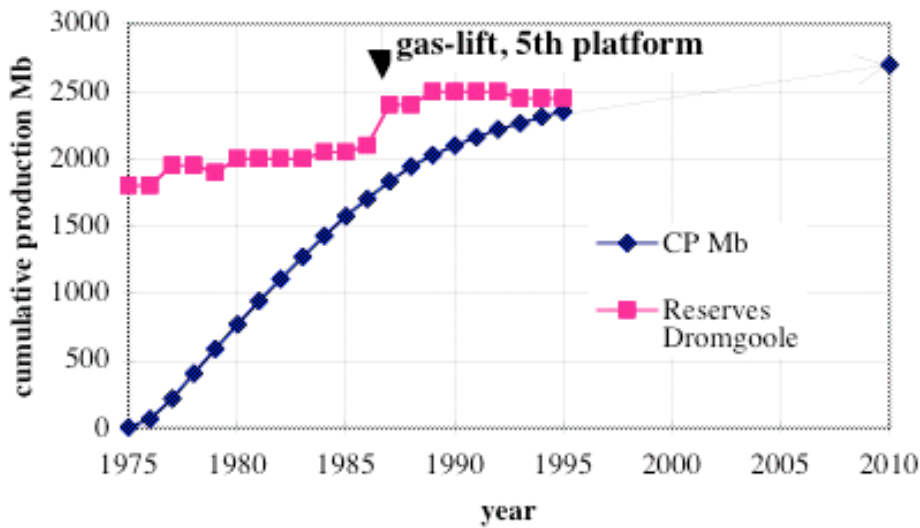
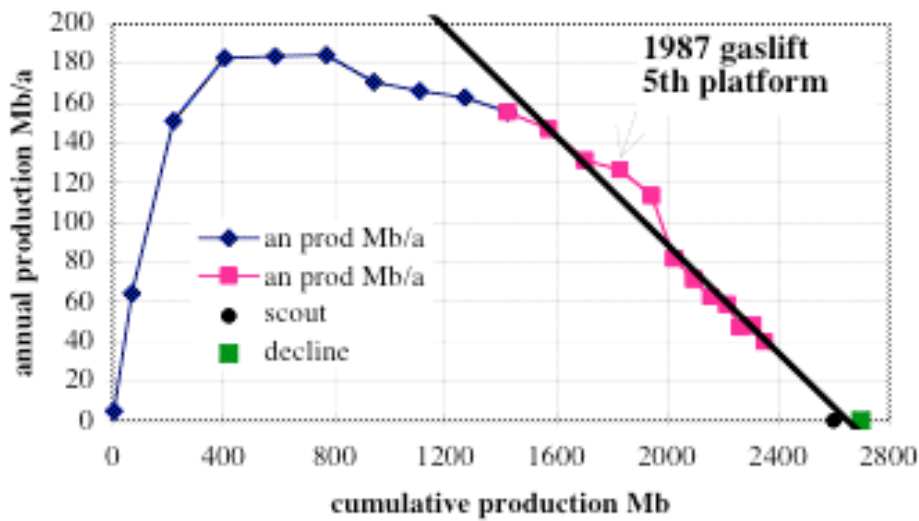
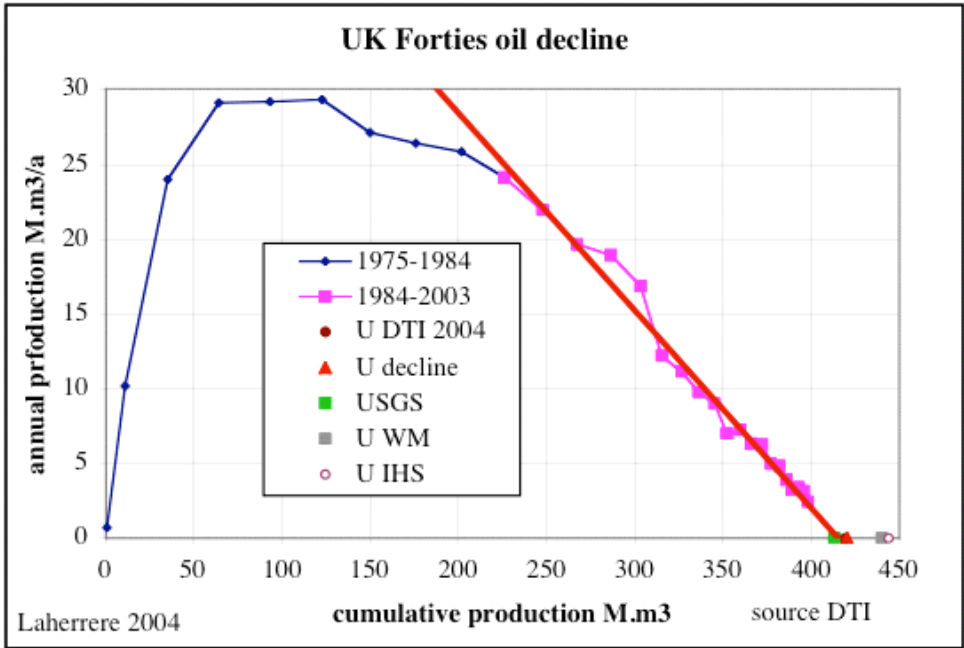


Fig 8b **Forties: annual production versus cumulative production**



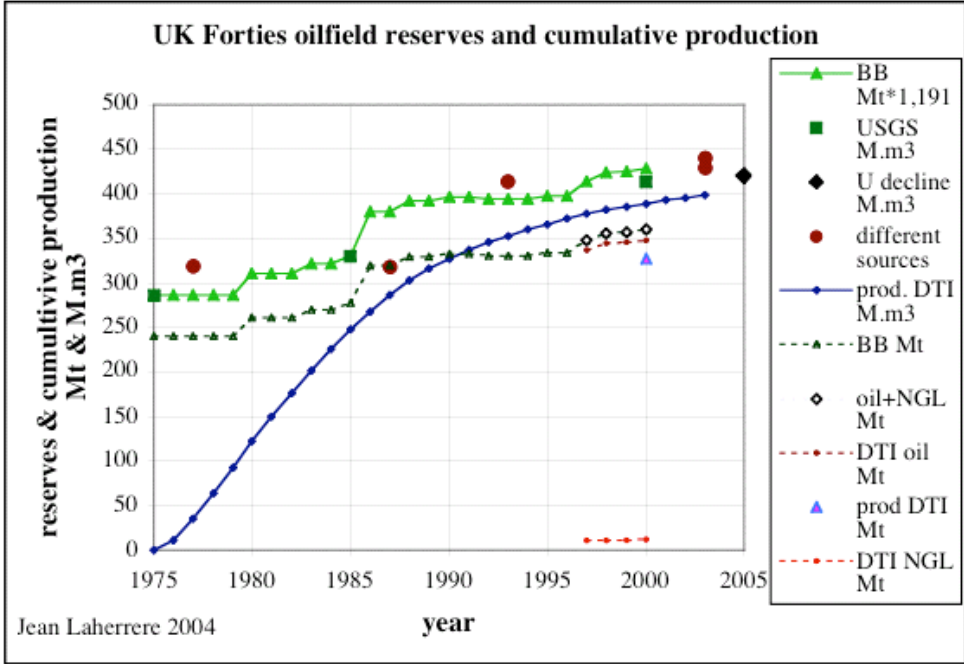
The new decline forecast from data up to 2003 is similar to the forecast up to 1995.



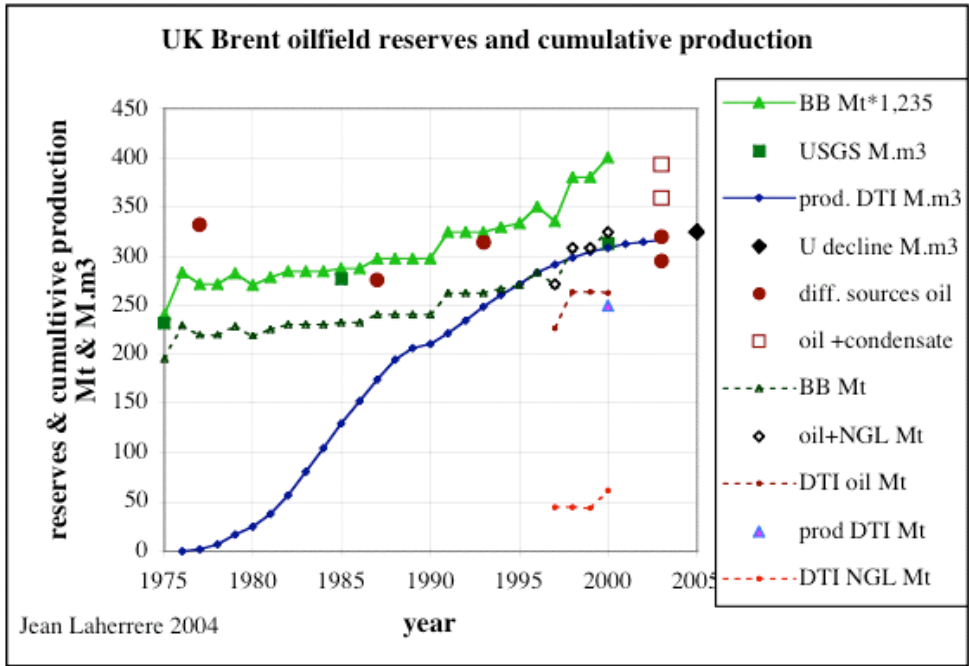
It is interesting to see the evolution of the data from the Brown Book (in tonne converted in cubic meter by using a ratio of 1.191 m³/t), being in agreement with the USGS data for 1975, 1985 and 2000, which correspond to DTI data (report 1998 to 2001) for oil +NGL.

It is obvious that the reserve estimate increased in 1986 on the assumption that gaslift will increase reserves but in fact outside 1987 & 1988 the decline up to 2003 is in line with the decline before 1987.

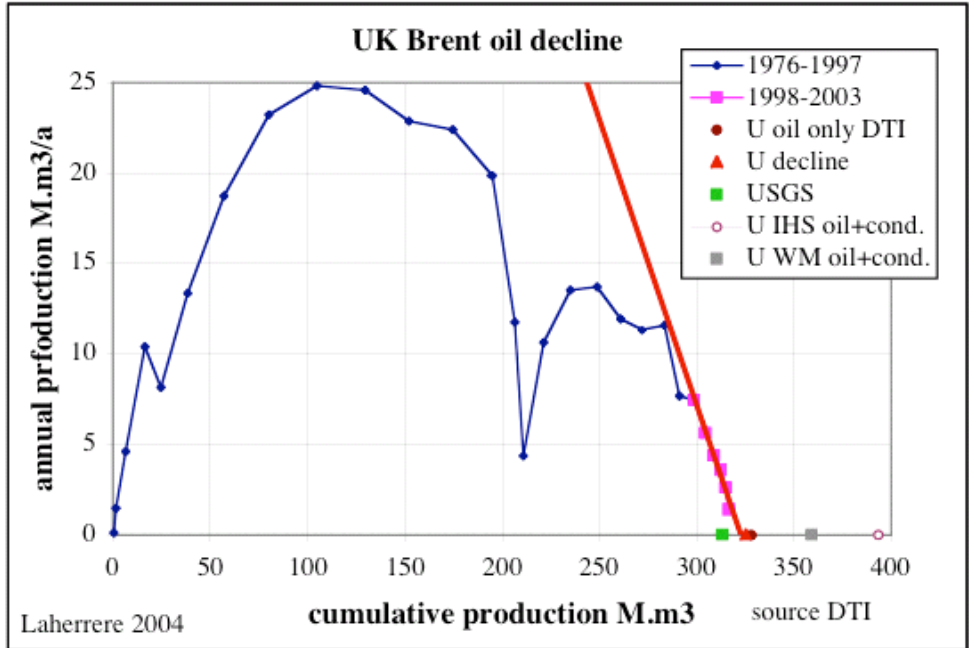
It is obvious that in 1984 looking at the estimate and the cumulative production that their estimate was underestimated. But it was cleverer for the operator to increase it when investing money. The fifth platform did not increase the reserves, but did increase the profit by producing faster.



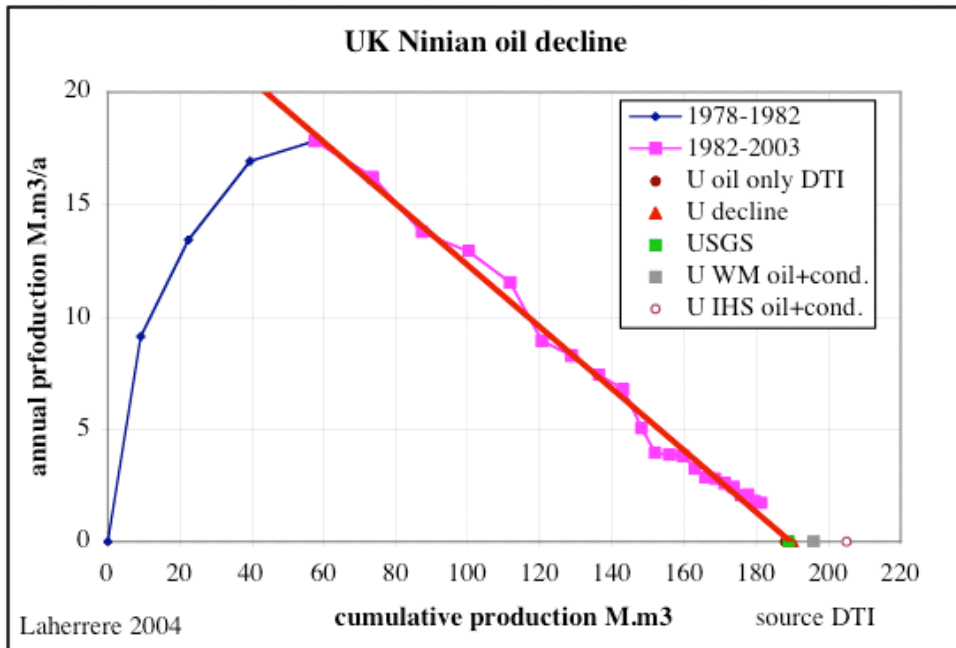
If the Forties graph shows that USGS values are for oil + NGL, the Brent graph shows the USGS values for 1975 and 1985 are for oil +condensate, but the 2000 value is for oil only, making the data to heterogeneous to be correctly analyzed.



The plot of Brent oilfield decline shows that oil production were disturbed for 3 years 1989-1991, but the present oil decline is in line with oil only DTI estimate as the field is almost depleted

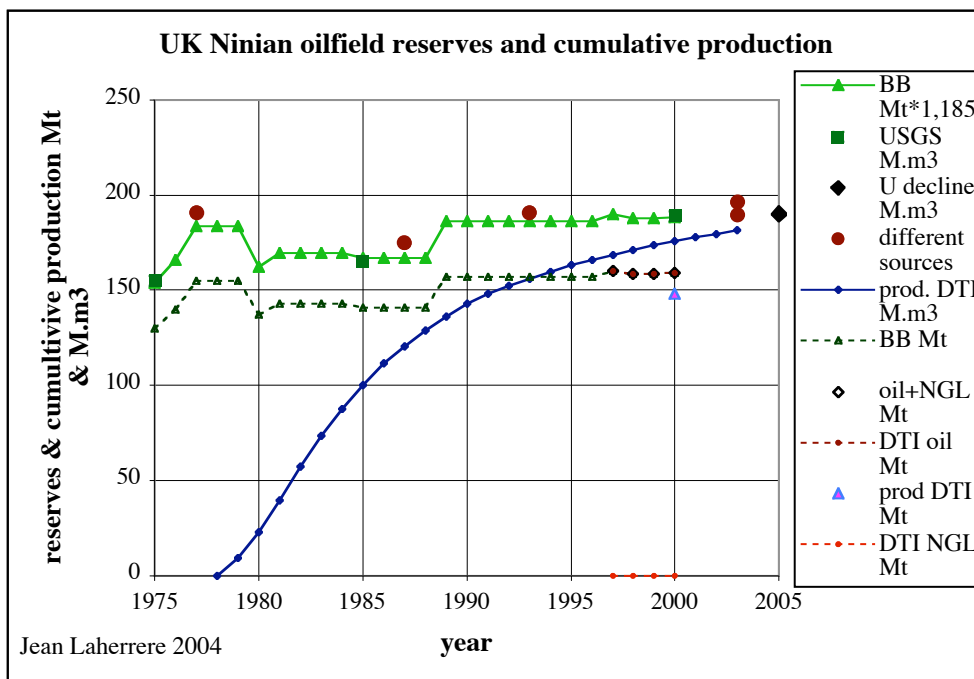


The other large field Ninian shows a normal decline

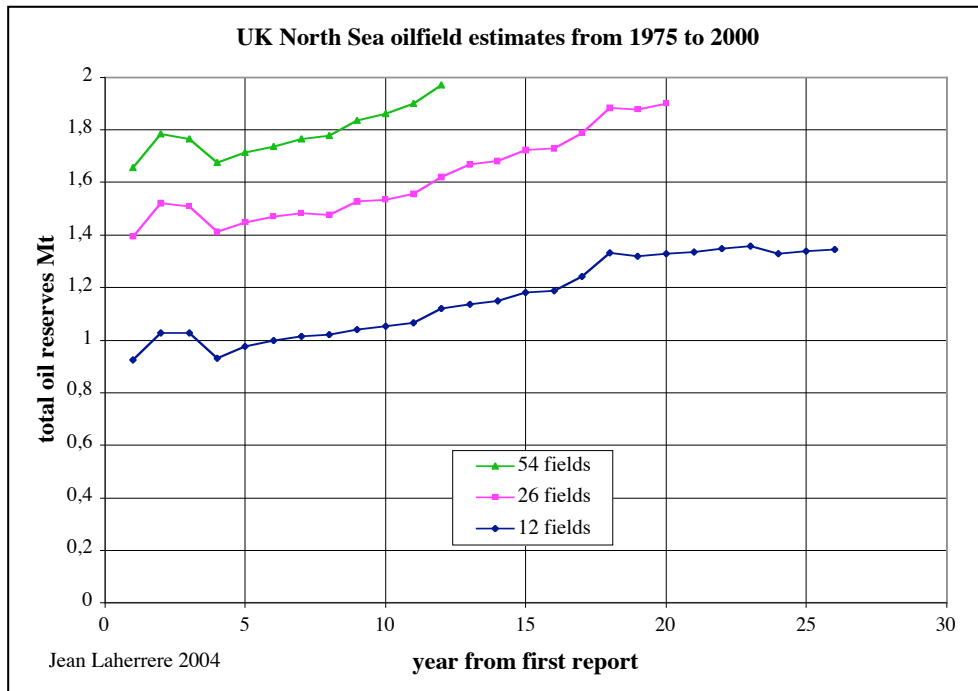


and a normal up and down evolution of estimate. There is no problem with condensate as there is none produced.

The estimate has oscillated towards the ultimate, within the inaccuracy of such estimate.



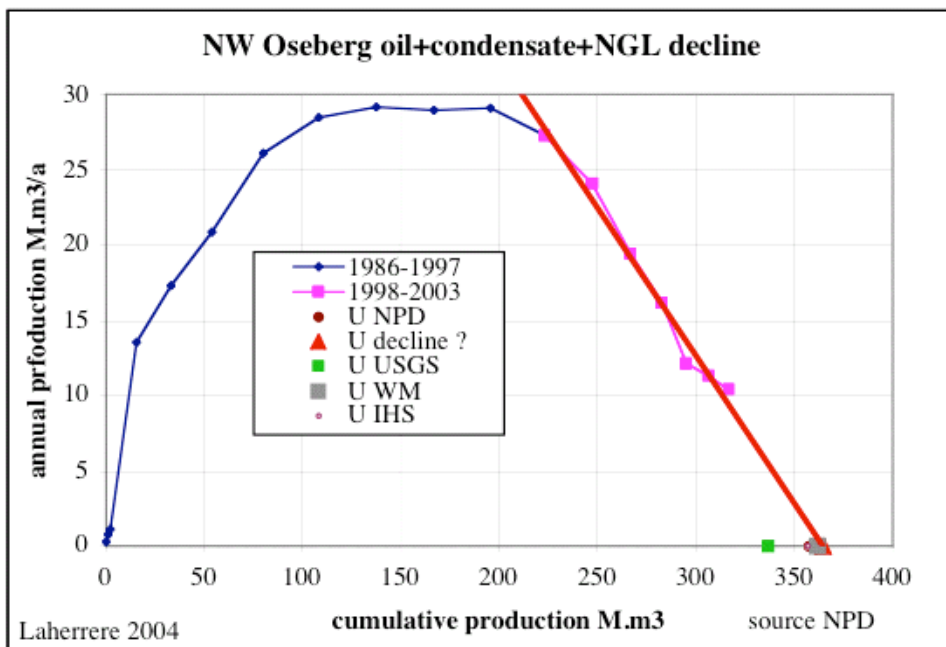
For UK the aggregation of fields from the year of first report shows that for the first five years it was almost flat, then increase from 5 to 18 years then flat.

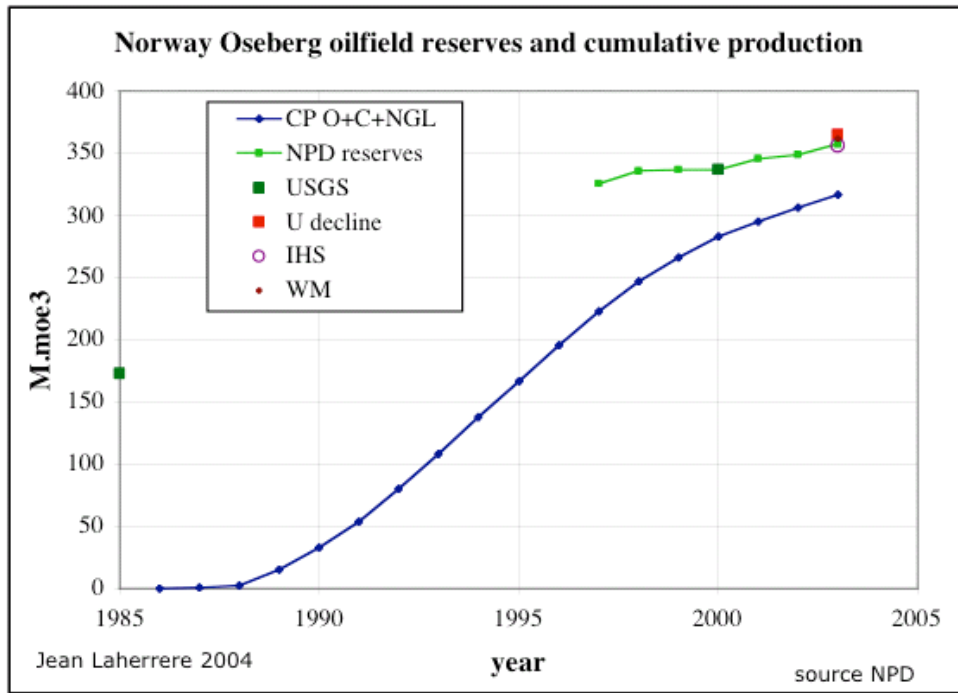


But a linear extrapolation after 25 years is not sure, looking at Australia fall experience after 35 years (see below)

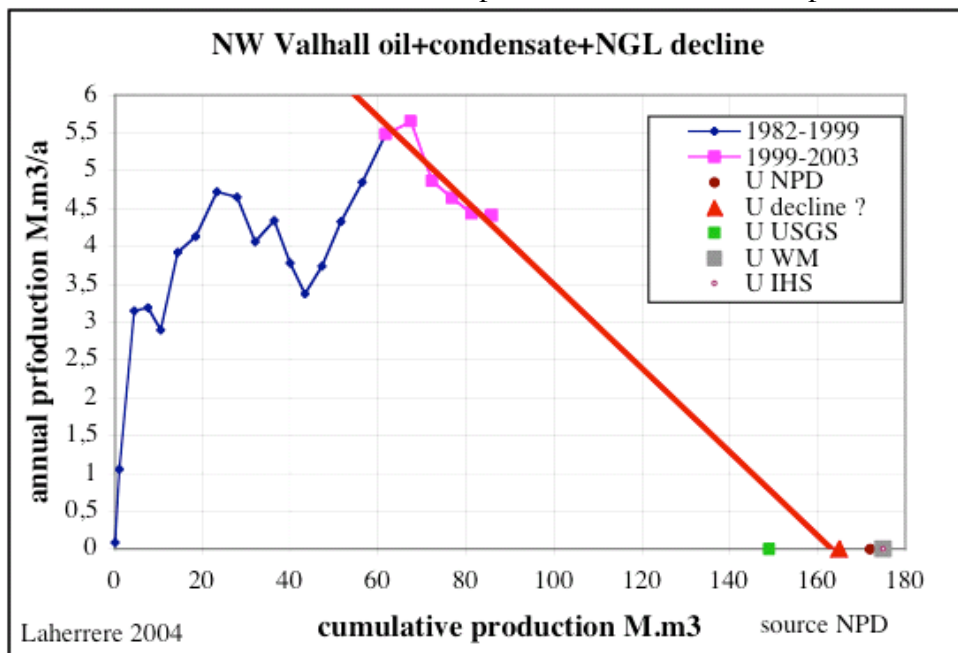
For Norway, unfortunately I do not have in my computer the history of NPD estimates before 1997, as I do from DTI.

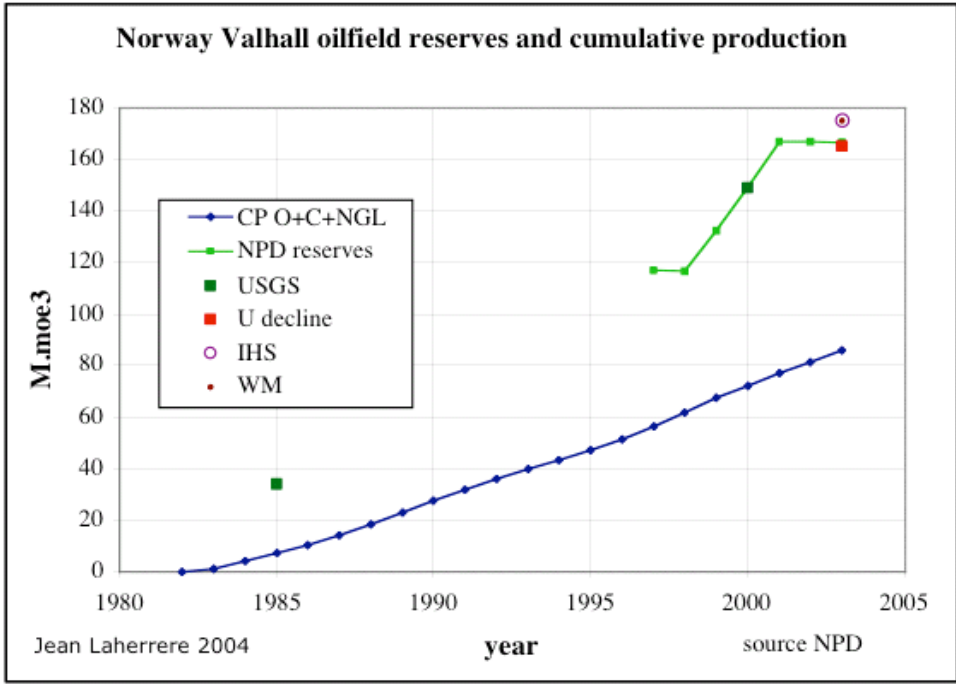
The clastic Oseberg field shows a normal decline with little difference between the several sources



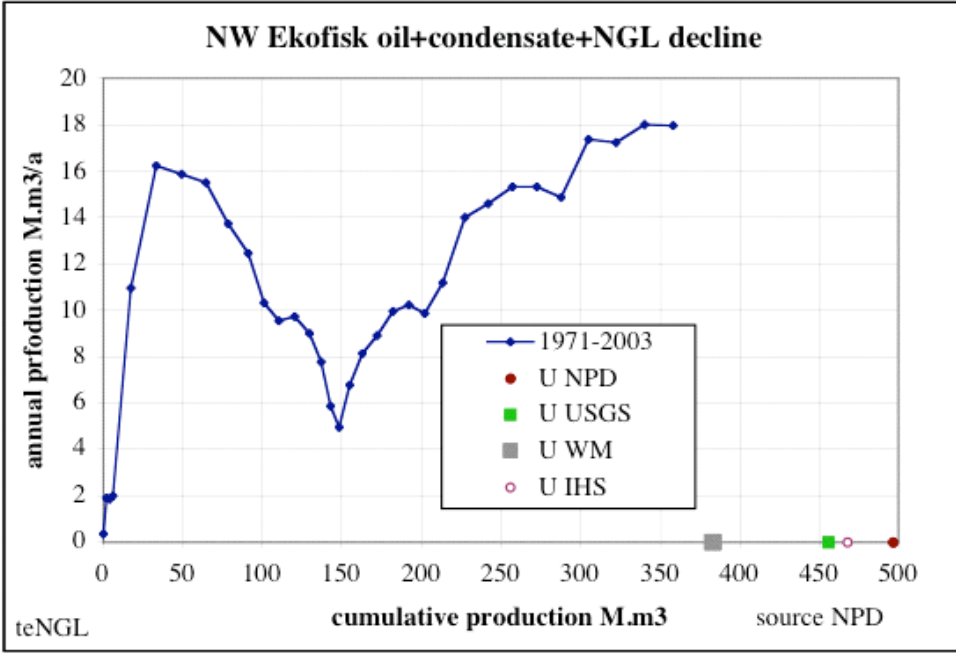


The chalk Valhall shows a more complex decline and more dispersed estimates

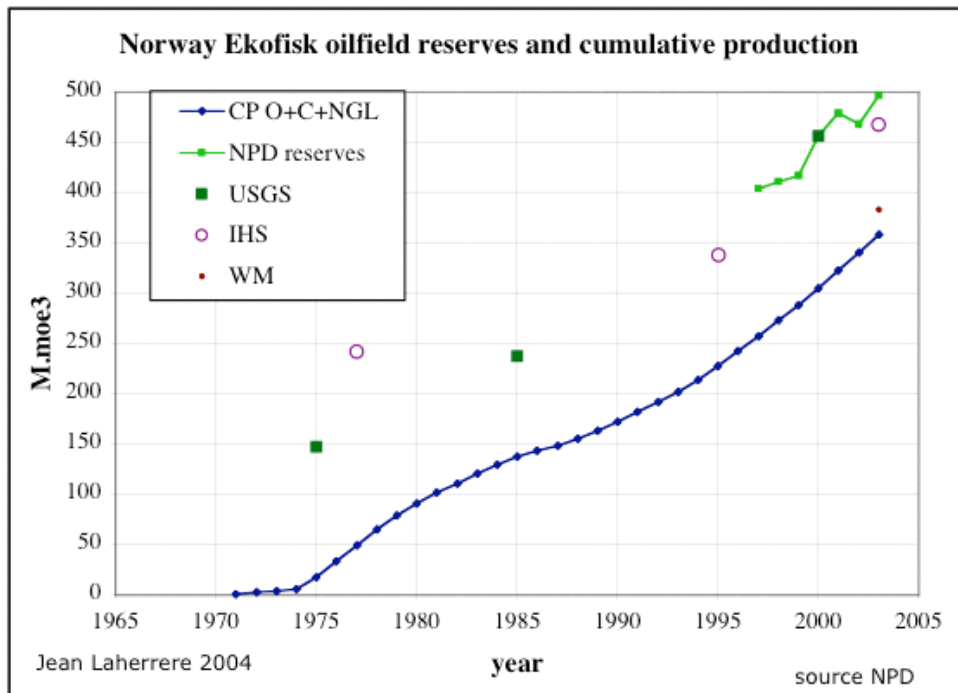




The chalk Ekofisk with a large seafloor subsidence displays a chaotic pattern and not yet any decline after 32 years of production and the difference between sources is large.



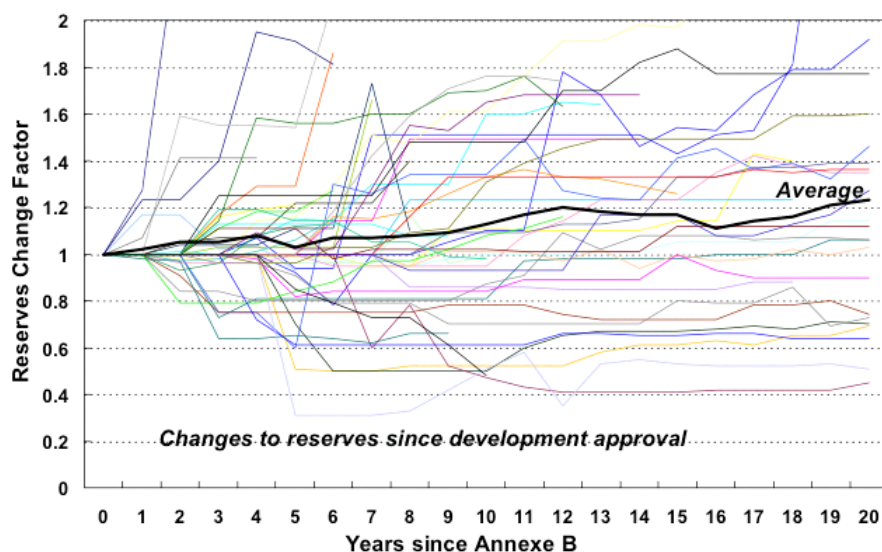
WM estimate looks too low!
 The evolution of estimate displays a large increase without knowing when it will stop



Instead of trying to find a mathematical formula for the reserve growth model within a cloud of data, examples should be given to try to see the reasons of reserve change. By plotting some field oil decline as above.

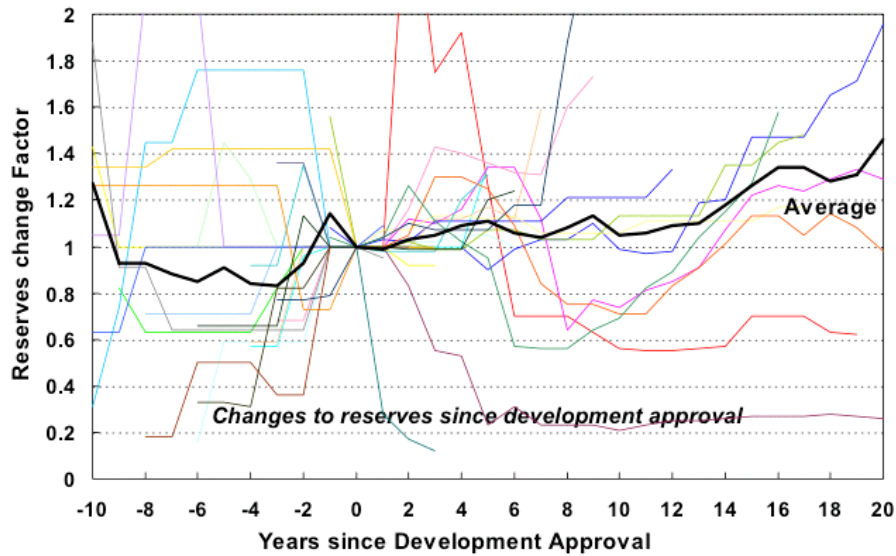
As shown by figure 8a the change since discovery is chaotic and only change from first production should be used. In the old past, studies of US reserve changes were assuming that the estimates of first six years after discovery were meaningless and should be ignored. There is no reference of any good articles on North Sea reserve growth. There are many as -Harper F.2004 "Oil reserve growth potential" ASPO Berlin May25 <http://www.peakoil.net> showing the huge cloud of oil and gas reserve change from production start, leading that the average (and the model) of such chaotic changes seems meaningless.

Oil Reserves Changes by Field - UK



Data from DTI annual "Brown Book" reports

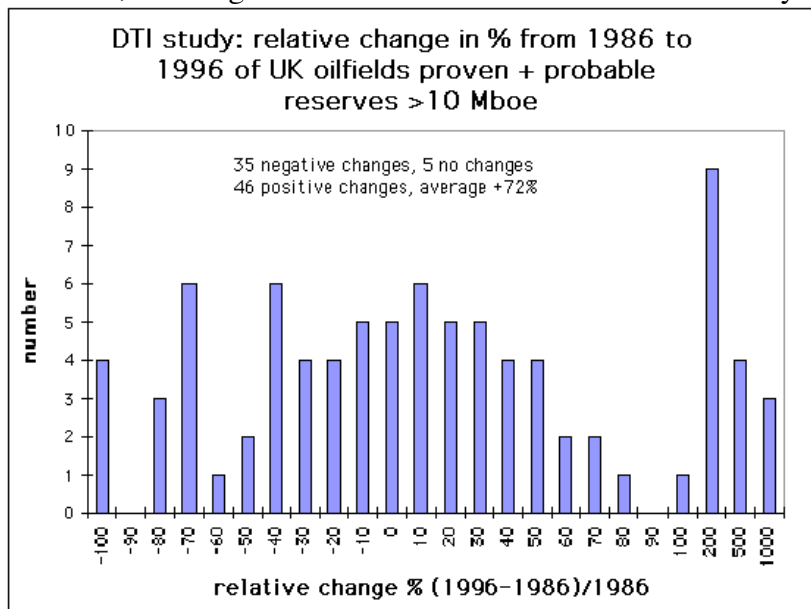
Oil Reserves Changes by Field - Norway



Data from NPD annual "White Book" reports

-Dromgoole P. & R.Speers 1997 "Geoscore: a method for quantifying uncertainty in field reserve estimates" Petroleum Geoscience v3/1 p1-12 (already quoted in my 1998 paper) showing that the simple reservoirs are usually underestimated and the complex ones overestimated.

-DTI, J.M.Thomas, 1998, "Estimation of ultimate recovery for UK oil fields: the results of the DTI questionnaire and a historical analysis": Petroleum Geoscience v 4.157-163
This study on reserve change from 1986 to 1996 finds 35 negative against 46 positive revisions, meaning that the estimate is close to the most likely



-Grosjean Y. et al. 2002 "New reserves in old fields: do not underestimate the geologic risk" WPC, Rio showing the complexity of example Alwyn

-Sneider R.M., Sneider J.S. 2001 "New oil in old places" AAPG Memoir 74 chap.6, p63-84
Laherrere Copenhagen 2003:

In AAPG memoir 74 Sneider (“New oil in old places”) claims that Auk oilfield in the UK was a good example of reserve growth with estimate at 93 Mb in 1988 and 180 Mb in 1998.

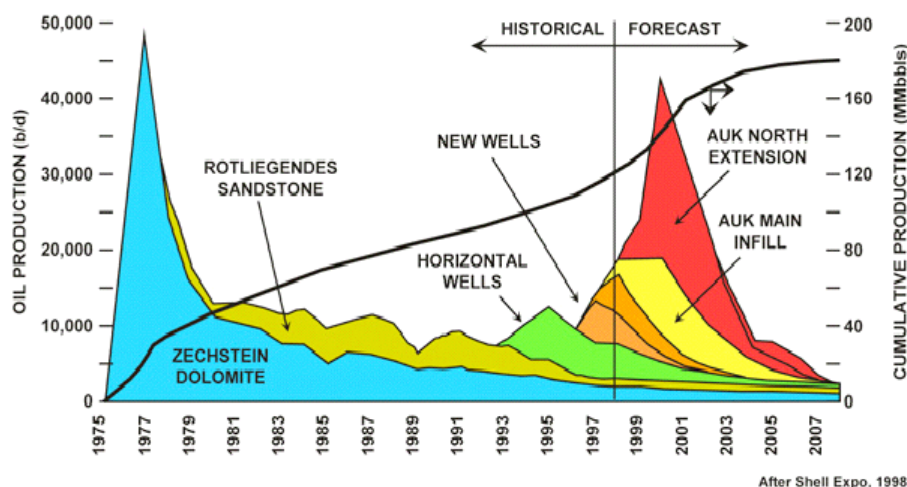
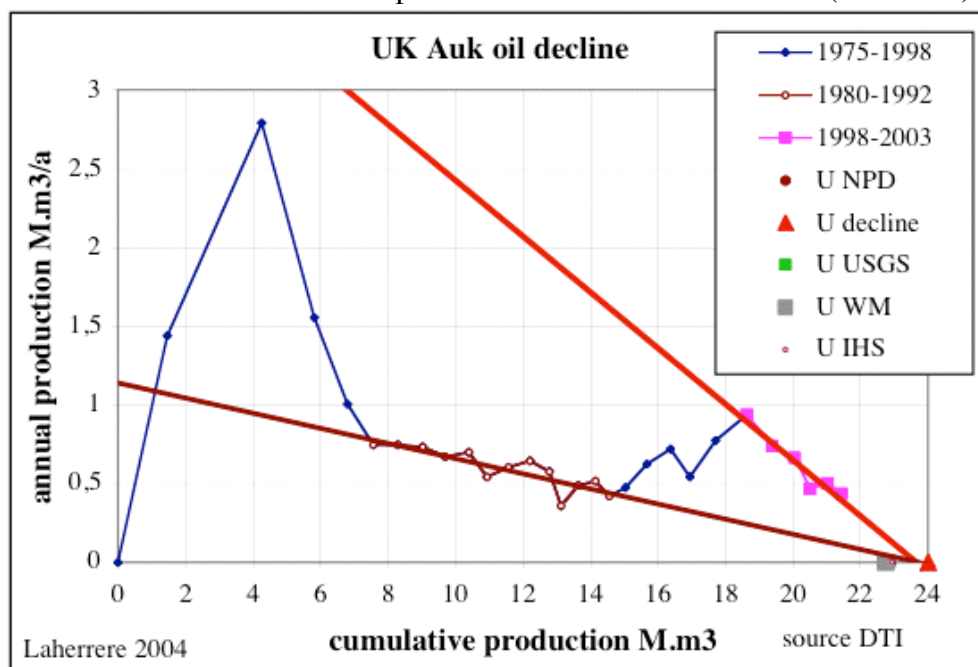
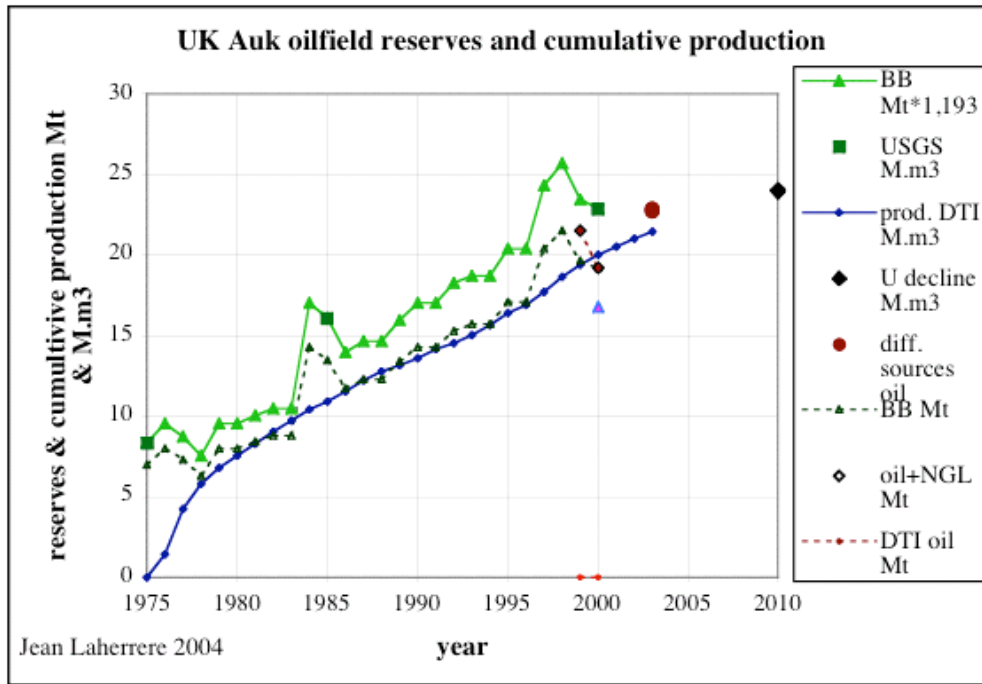


Figure 36. Production history and field development, Auk-Auk North field, central graben, North Sea.

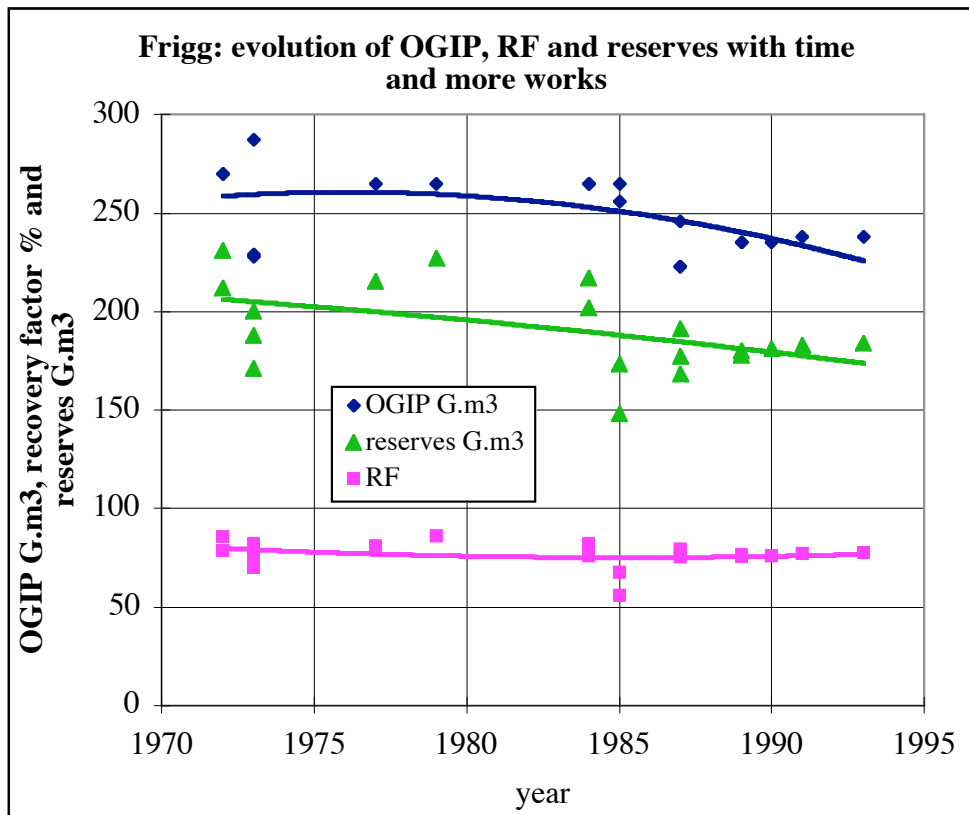
In fact in 1988 the oil decline on the following graph was already well established with ultimate around 160 Mb. From 1993 to 1998 annual production raises, thanks to more investment in horizontal wells, but in 1999 the decline was back and steeper (as usual after technology miracle) and ultimate from the decline is still around 150 Mb (cumulative production up to 2002 is 132 Gb, for Brown Book 162 Mb and for the operator 144 Mb. The claim by Sneider that recovery was improved from 17% to 30% by the new drilling is false. As for Forties, more investment gives faster production, but no more reserves. The decline from 1980 to 1992 gives the same ultimate as the decline from 1998 to 2003, more investments led to faster production but not more reserves (as Forties)



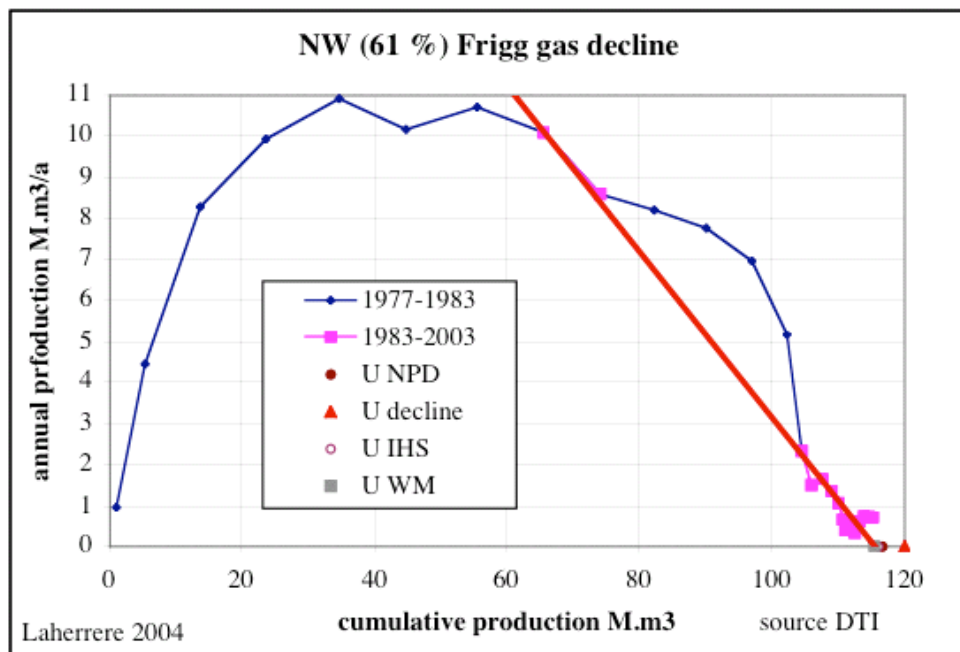
The evolution of the reserve estimate versus the cumulative production shows in 1990 the estimate was too low.



-Torheim E. 1996 "Changing perceptions of a gas field during its life cycle: a Frigg field case study" Quantification and prediction of HC resources NPF special publication 6 Elsevier Proc. NPSociety Dec 93 Stavanger
 In order to obtain a higher DCQ the operator overestimated the reserves (as quoted above)



The Frigg (Norway share) gas decline shows clearly that the gas was produced at the maximum rate to get the highest present net value



On US

-Gilbert J. 2002 "Technology and frontier areas: can they save the USA?" ASPO Workshop, Uppsala, May

Prudhoe Bay original reserves were 15 Gb by explorers and 9.6 Gb by engineers and now ultimate recovery is about 13 Gb, meaning a negative growth for explorers and positive for engineers

-Roadifer 1987 "Size distributions of the World's largest known oil and tar accumulations" AAPG studies in geology#25, p3-23

Reserves reported by Roadifer are compared with those from OGJ in 1977 as Petroconsultants in 1993, USGS in 1985 & 2000 and IHS and WM in 2004

Mb	OGJ 1977	USGS 1985	Roadifer 1987	Petroconsul. 1993	USGS 2000	IHS 2004	WM 2004
-Brent	2090	1742	1736	1976	1970	2010	1857
-Forties	2004	2073	2000	2600	2600	2700	2766
-Ninian	1200	1055	1100	1200	1189	1192	1235
-Ekofisk	1524	1491	1025	2265	2870	2943	2207
-Statfjord	3900	2151	3271	3680	3565	4139	4147
-Prudhoe Bay	10004		9365	12000		13000	13227

The discrepancy between sources can be higher than between years

-Geoscience Australia report: Oil and gas resources of Australia 2002

The Australian government (Geoscience Australia 2002) has used the USGS reserve growth function to fit their reserves change. It fits at the beginning but after 30 years the growth is trending to zero (figure 2.7 & 2.8)

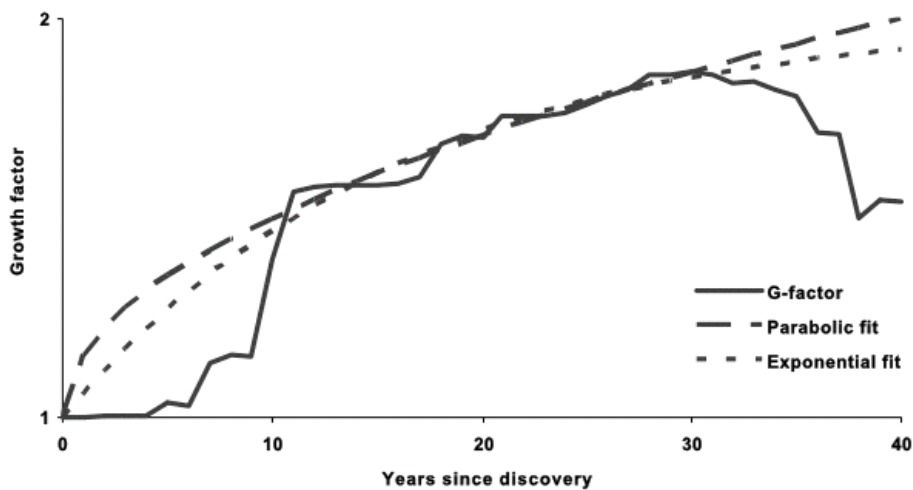


Figure 2.7 Reserves growth for Australian oil fields

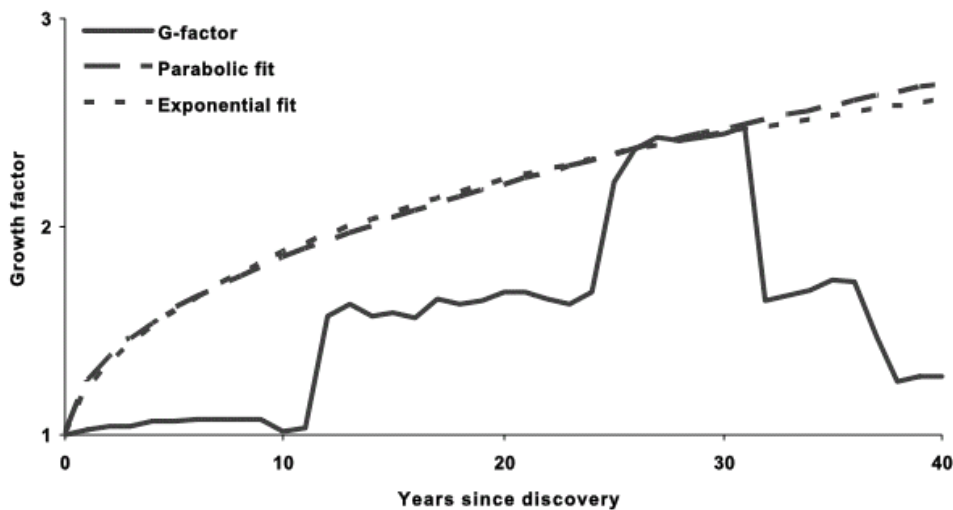


Figure 2.8 Reserves growth for Australian gas fields

It means that it is only at the end of depletion that wishful thinking are written off and increase for the first part cannot be extrapolated towards the end. It is more likely that North Sea will follow the same trend.

There are also several points to be revised

-Units= SI

Sm³ is incorrect as S is the symbol of Siemens, standard conditions has to be noted elsewhere. NPD uses Sm³ but they are wrong, as SI rules are quite clear

The number of decimal has to be adjusted to the accuracy of the measure and as reserves display large discrepancies, giving more than 3 significant digits is incorrect as total reserves = 2432.16 G.m³

-Aggregation of reserves

Aggregation of field reserves is correct only if the reserves are the mean value and if there are mean values statistically they should not be any growth, if not they are not the median value. Aggregation of proved reserves as it is done in most of papers is incorrect and should give a too low global proved value. For example in the USGS 2000 study the addition for the 8 regions of undiscovered F95 gives 179 Gb when the correct aggregation with Monte Carlo simulation gives 334 Gb

Correct aggregation will lead to a lower growth for proved reserves, which are mainly reported as proved in order to lead to growth, target of companies and governments. But decision of development are not taken on proved values but expected (mean value).

Conclusion the paper should be revised but it covers several interesting points and North Sea is now mature enough to be fully analyzed.

It is obvious that some oilfields have shown positive growth when many have shown no significant growth and some negative growth. Is the average of the hundred fields significant and the experience of North Sea may be applied to other area? The global synthesis needs to take into account the several hundreds of oil discovery still undeveloped and which have not been fully assessed. In the IHS file there are many still counting in the 2P North Sea reserves, most will see a write off when the main platforms will be dismantled. Should those discoveries be counted in the study?

Please forgive me for my broken English and for poorly constructed arguments written in a hurry as much time was spent chasing data and making graphs.