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Uncertainty on data and forecasts

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-Problems of wording

Petroleum = *an oily flammable bituminous liquid in upper strata of the earth*
Oil = *any of numerous unctuous combustible substances that are liquid*
Oil is an ambiguous term and includes biofuels (olive oil) and alcohols
Oil should not be confused with petroleum or hydrocarbons
Production of oil = oil production,
Peak of production of oil = oil production peak or oil peak
Peak oil (Google >4 000 000) = oil with a peak
or oil peak (<200 000) = peak of oil
Why such difference when the date is often the debate**? My answer = ASPO**

-Reporting data

-publishing data is a political act and depends upon the image the author wants to give (rich in front of a banker or for quotas, poor in front of a tax collector).
-OPEC productions are ruled by quotas, but because OPEC members were cheating on quotas, OPEC oil productions are flawed and unreliable. Real data on oil transported by tankers have to be bought from spy companies (Petrologistics in Geneva).
-oil field reserves are confidential except in UK, Norway and US federal lands.
-words such as **energy, oil, reserves, conventional, reasonable, sustainable, dangerous are badly or not defined on purpose**
-reporting any data with more than 2 significant digits shows that the author is incompetent

-Oil Production: reported in barrel by some countries and in tonne by others

-Volume

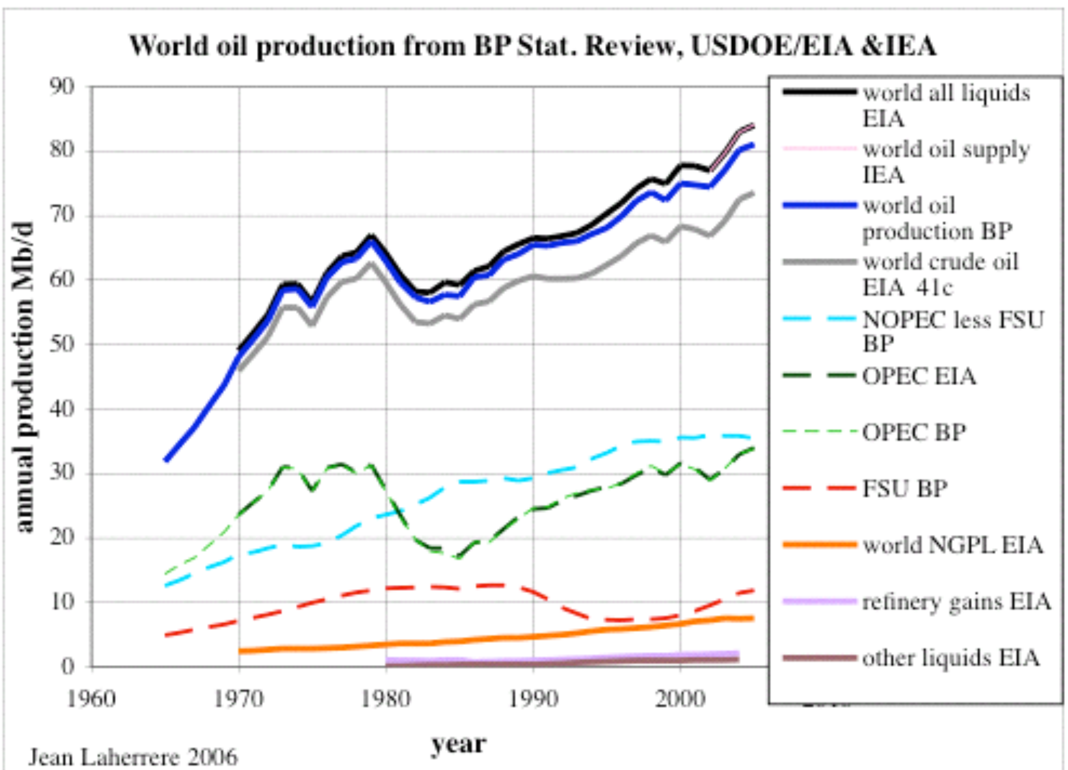
Oil production is reported for 2005 in Mb/d

-Campbell "*regular oil*"	**66,6**
-Crude less extra-heavy	**71,3**
-USDOE/EIA crude oil including lease condensate	**73,5**
-Campbell liquids (oil & gas)	**80**
-BP oil	**81,1**
-USDOE/EIA all liquids	**84**
-IEA oil supply	**84,1**

All liquids include crude oil, condensate, natural gas plant liquids (NGPL), refinery processing gains, and other liquids from extra-heavy oil, bitumen, natural gas (GTL) coal (CTL), oil shale (classified into lignites) and biomass (BTL)).

BP excludes CTL and BTL, and seems to ignore refinery gains.
Refinery gains comes from making oil lighter by increasing the volume with cracking and hydrogenation (hydrogen mostly from natural gas), which is in fact GTL gas to oil!
USDOE/EIA reports the most detailed database with the International Energy Annual from 1980 to 2004 under the title *world petroleum data*
-crude oil including lease condensate *table 22*
-natural gas plants liquids *table 23*
-crude oil +NGPL +other liquids *table g1*
-crude oil +NGPL + other liquids + refinery gains *table g2*
-refinery gains and other liquids *table g3*
-other liquids *table g4* include CTL (South Africa), alcohol fuels: BTL (Brazil & US) (despite the title of *petroleum data*), MTBE (Saudi Arabia), Orimulsion (but not other Orinoco production?) and other hydrogen and hydrocarbons for refinery feedstocks
-refinery processing gains *table g5*

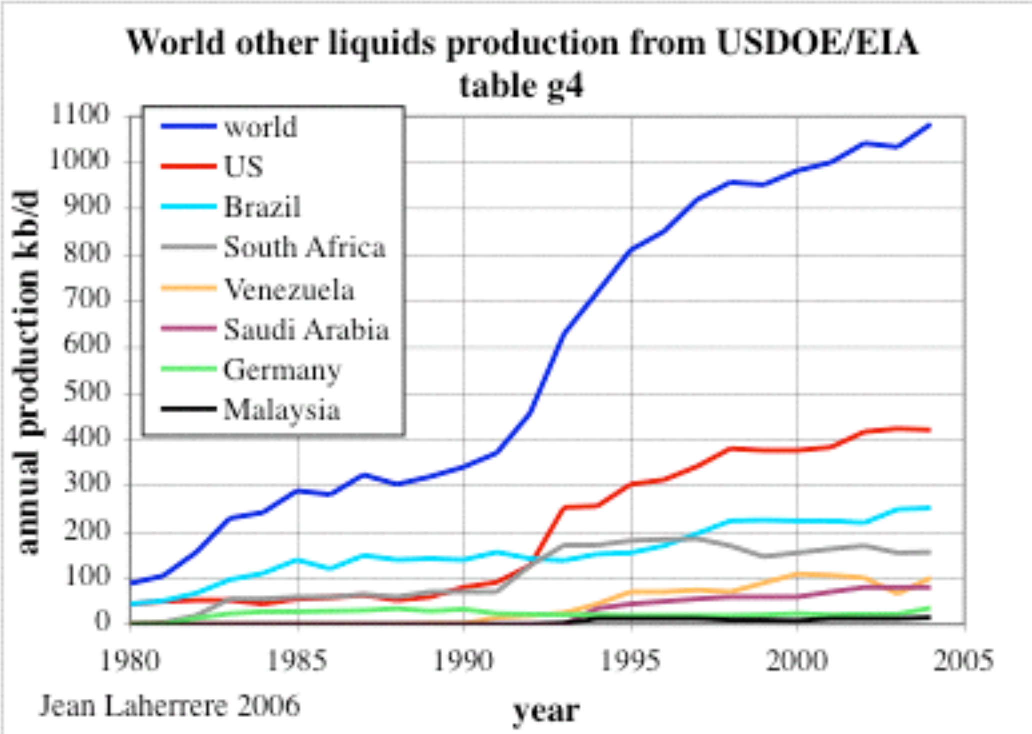
In the International Petroleum monthly EIA reports in *table 4.1a, 4.1b and 4.1c* the world crude oil since 1970 for the main producing countries.
Figure 1: **World oil supply (production) from different sources 1965-2005**



The world NGPL (natural gas plant liquids) is important (7 Mb/d) compared to other liquids (1 Mb/d) and refinery gains (2 Mb/d)
The other liquids has increased sharply since 1990 and is not negligible because it includes what is considered as the future alternative for oil as GTL, CTL and BTL. The main producers are US (MTBE, biofuels), Brazil (ethanol), South Africa (CTL),

Venezuela, Saudi Arabia (MTBE), Germany, Malaysia (GTL) as Estonia (oil shale), Hungary, Morocco and Australia (oil shale closed in 2004).

Figure 2: **World other liquids production from USDOE/EIA 1980-2004**



-Mass

The world oil production is reported by BP and IEA in Mt/a:

	BP	IEA	% BP to IEA
1990	3 170.59	3 130.616	+1.3
2000	3 613.8	3 581.082	+0.9
2004	**3 865.32**	**3 765.397**	+2.7

again there is no logic in the difference. Who is right?

The difference between world production and world consumption shows some intriguing values. For 2005 BP Review reports an oil production minus oil consumption being positive in tonnes and negative in barrels: **why**?

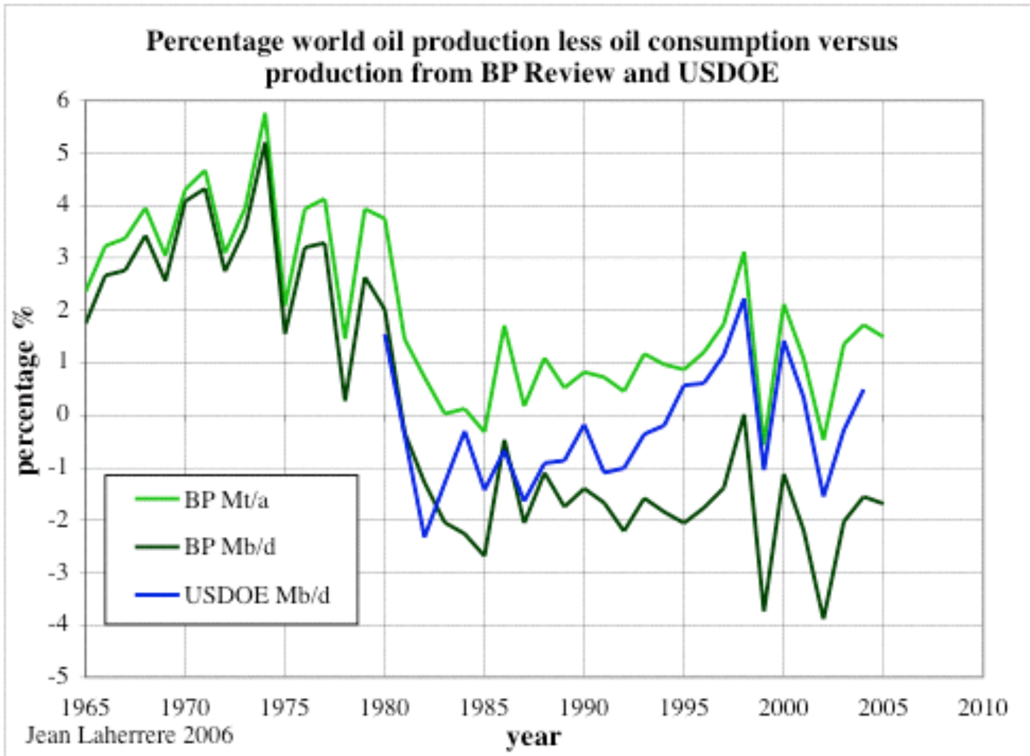
	Gt/a	Mb/d
Oil production	3.895	81.088
Oil consumption	3.836 8	82.459
Production minus consumption .	**+0.058 2**	**-1.371**

The difference must be due to refinery gains and NGL, acting differently in mass or volume, but this difference should be explained by BP Review and it is not

BP comments for oil:

Differences between these world consumption figures and world production statistics are accounted for by stock changes, consumption of non-petroleum additives and

substitute fuels, and unavoidable disparities in the definition, measurement or conversion of oil supply and demand data.
The comparison with USDOE/EIA in percentage shows agreement on short term and disagreement on long term.
Figure 3: **World: Percentage of oil production less oil consumption versus oil production from BP Review and USDOE/EIA**

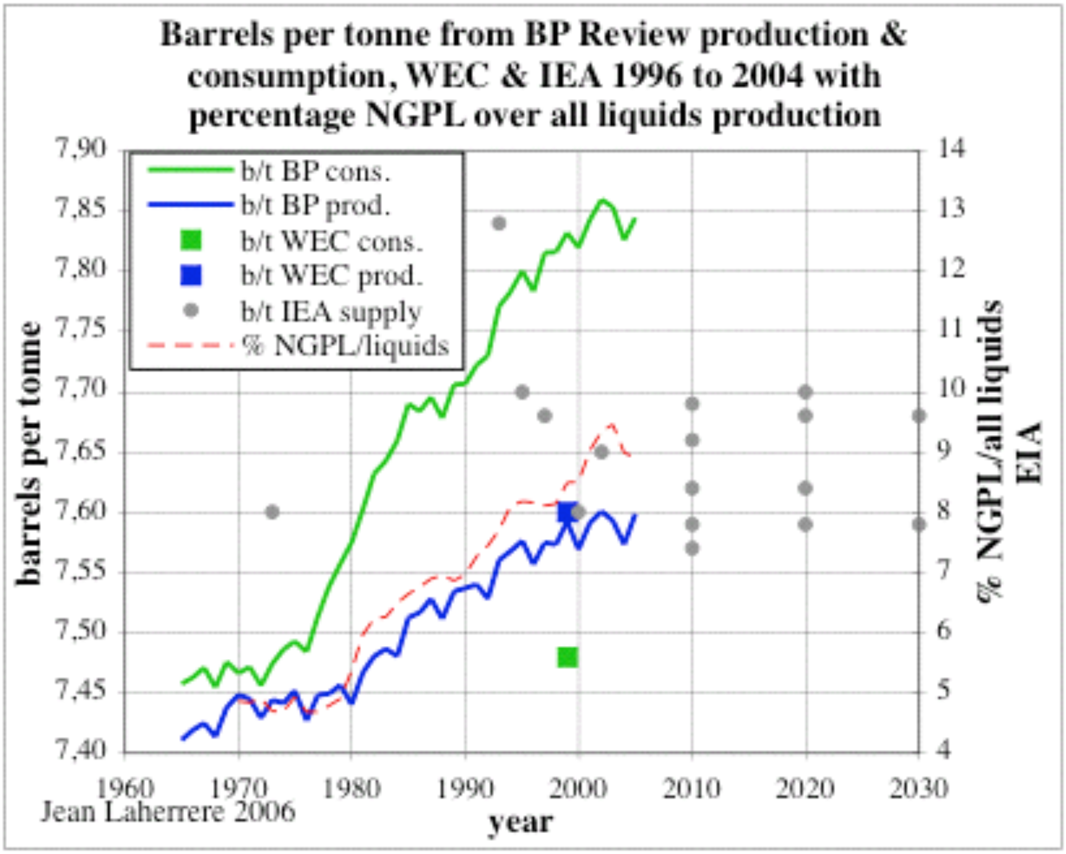


The discrepancy between BP and USDOE is erratic in long-term.
The conclusion is that BP data is not homogeneous between production and consumption. The obvious conclusion is that BP database is unreliable (and notices incomplete), as the others. An official world agency (JODI?) should make an inventory of the different world databases in order to make them more comparable and more reliable.

-Problem of conversion of tonnes into barrels

The ratio for BP Review increases (lighter oil) from 7.4 in 1965 to 7.6 in 2005 for production and from 7.45 to 7.85 in 2005 for consumption. This evolution seems to mean that more and more NGL are added. But BP values do not agree with other sources. IEA reports 1996 to 2004 display variables ratio around 7.65 b/t.
The WEC 2001 report uses 7.38 b/t for oil proved reserves, 7.36 b/t for oil resources, 7.60 b/t for oil production including NGL (compared to 7.58 for BP) and **7.48 for oil consumption (compared to 7.82 for BP).**
There is a large discrepancy between BP and WEC on oil consumption!
DTI reports UK production in tonne and barrels the ratio varies slightly around 7.6 b/t, but UK oil is light compared to world average.

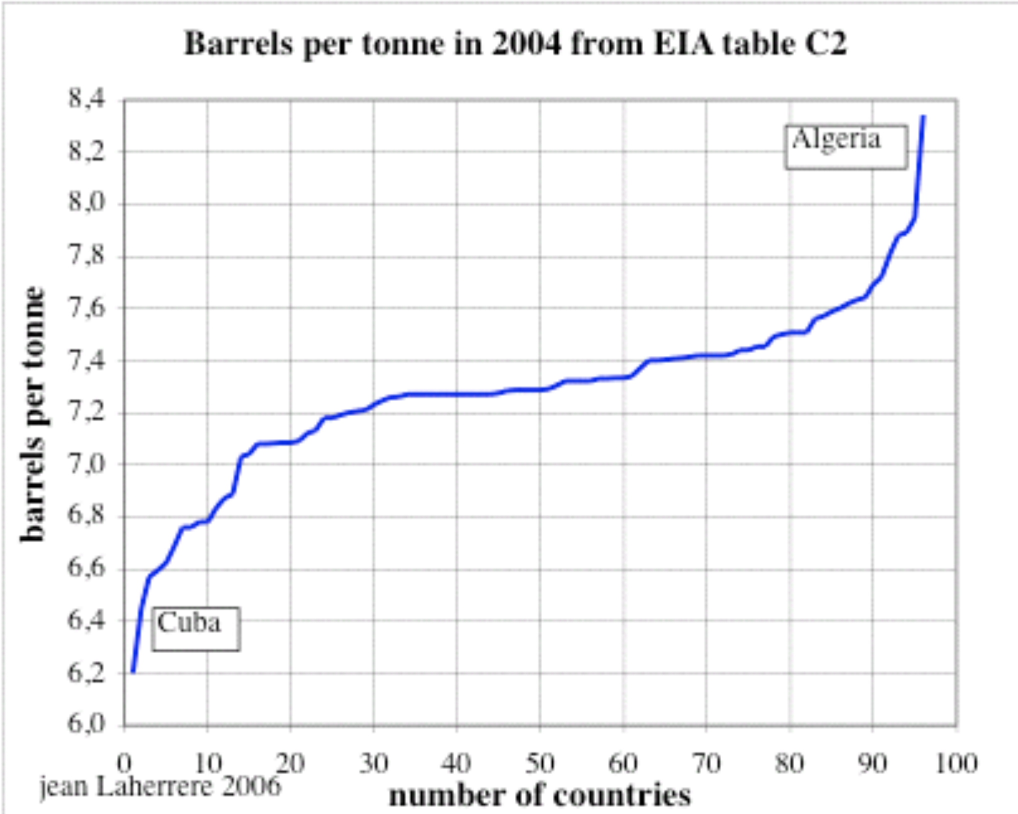
Figure 4: **Barrels per tonne from BP Review 2006, WEC 2001 & IEA 1996 to 2004**



It is obvious that the different sources do not agree on the conversion mass-volume.

USDOE/EIA in table C2 gives the number of barrels per tonne for 96 countries with an average of 7.3 b/t The largest (lightest crude) with 8.3 b/t is East Timor followed by Algeria with 7,95 b/t and the lowest are Suriname 6.2 and Cuba 6.4

Figure 5: **Barrels per tonne per country in 2004 from EIA**



The oil production data in barrels or tonnes are accurate of about 2 or 3% from the product is defined and more when it is not. Giving more than 2 digits is useless!

-Reserves

Reserves represent the expected cumulative production to be recovered at the end when the field is abandoned. **Recoverable reserves is a pleonasm**.

There is no consensus on how to assess reserves and there is no world organisation to impose one. The oil industry has issued some rules (SPE/WPC 1997), but they are used only in internal estimates.

UN Framework Classifications (1997, 2004) were completely ignored by the industry.

Reserves estimates are uncertain (except when the field is abandoned), but many definitions, as the SEC (US Securities and Exchange Commission) 1977 obsolete rules (coming from very old SPE rules), deal with "*reasonable certainty* " and refuse the probabilistic approach because the risk aversion of bankers and shareholders.

Russian oil reserves are a State secret (disclosure = 7 years jail) .

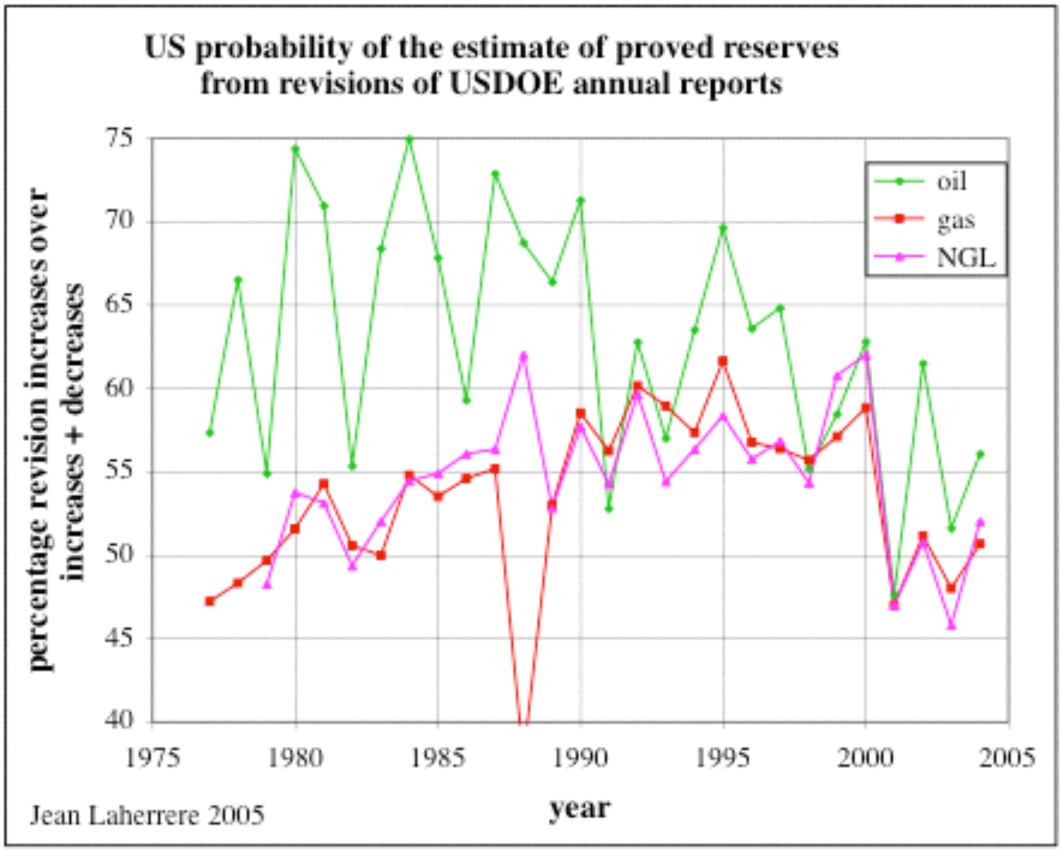
Field reserves are confidential because competition in exploration in most countries, except Norway, UK and US federal lands. It is surprising to see so many countries where oil belongs to the country accepting that field data is kept confidential (as in France!).

Reserves represent what will be recovered in future, in a probabilistic approach it has to be the expected value, but it is better to give a range (mini, mean, maxi) or (low, best, high)

Resource is what is in the ground; reserves are only a small part of resource.
There are several reserve definitions in use:
-US = all companies listed on the US Stock Market are obliged to report only proved =1P ≈ assumed to be the minimum?, but SEC rules = reasonable certainty: what is reasonable?: probability of 51 or 99 %?
-FSU classification = maximum theoretical recovery ≈ proven + probable +possible = 3P ≈ maximum
-Rest of the world = SPE/WPC 1997 rules (I was a member of the task force) = proven + probable = 2P ≈ expected value (should be the mean ≈ P40, when given as the median P50, but often confused with the mode (most likely) ≈ P65); range 1P=90%, 3P=10%
Proved reserves (1P) tell bankers that the company could not be bankrupted, but development decisions are taken on mean reserves (2P)
All the attempts to improve the data have failed, despite all the claims of good will by governments and agencies, in particular the JODI (Joint Oil Data Initiative) gathering seven international agencies under the UN since 2000, providing only some incomplete production data.
Reserve growth occurs when reserves are reported as the minimum (proved), but does not occur statistically when reported as mean (expected) value.

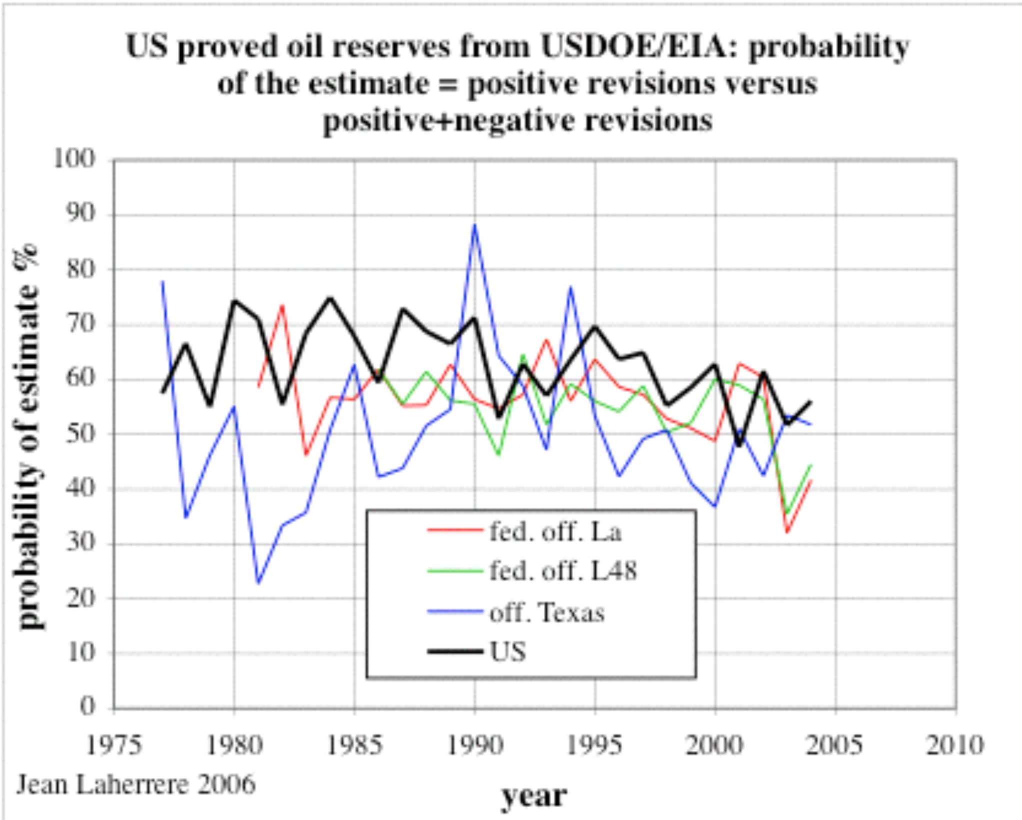
-Reluctance to risk = Probability

-US banks are reluctant to accept uncertainty and probabilistic approach
-US rules (SEC) oblige companies to omit probable reserves and to report only proved reserves, defined with *reasonable certainty* (without defining reasonable!), assumed by many to be conservative: they were in the past, but not anymore.
The so-called proved reserves are not proven at all, because presently in USDOE annual reports, negative revisions of proved reserves are as large as positive revisions.
It is easy to estimate the probability of the estimate by computing the percentage of positive revisions versus the sum of positive and negative revisions.
Figure 6: **US proved reserves from USDOE/EIA: probability of the estimate**



Present probability of US proved reserves is about 50%, far from the SPE/WPC definition of proved = 90%, and the maximum value is 75% once.
It means that *Reasonable* varies from less than 50% to 75 %!
The FDA (Food and Drug Administration) uses the same wording of *reasonable certainty of no harm* to allow the sale of a new product. It is not surprising then to see the withdrawal of several medicines (Vioxx) with such bad definition!

Offshore reserves are now below 50% probability!
Figure 7: **US proved oil reserves: probability of the estimate for offshore**



Probabilistic approach in oil reserve estimate is subjective as every field is different, contrary to a random distribution.
The subjective probability involves guessing what is the minimum, most likely and maximum of the parameters: area, pay, porosity, and saturation. Only post-mortem evaluation is the key of improvement for evaluators. But many do not want to display their past errors! Recognizing error is the best way of future success!

-Change in shareholders

Good oil practices were 50 years ago to get maximum recovery, but now good practices are to get maximum profit to please shareholders (pension funds)

-Discrepancy between published data = proved reserves: who is right? none

USDOE/EIA reserves end of 2004 publication 31 May 2006

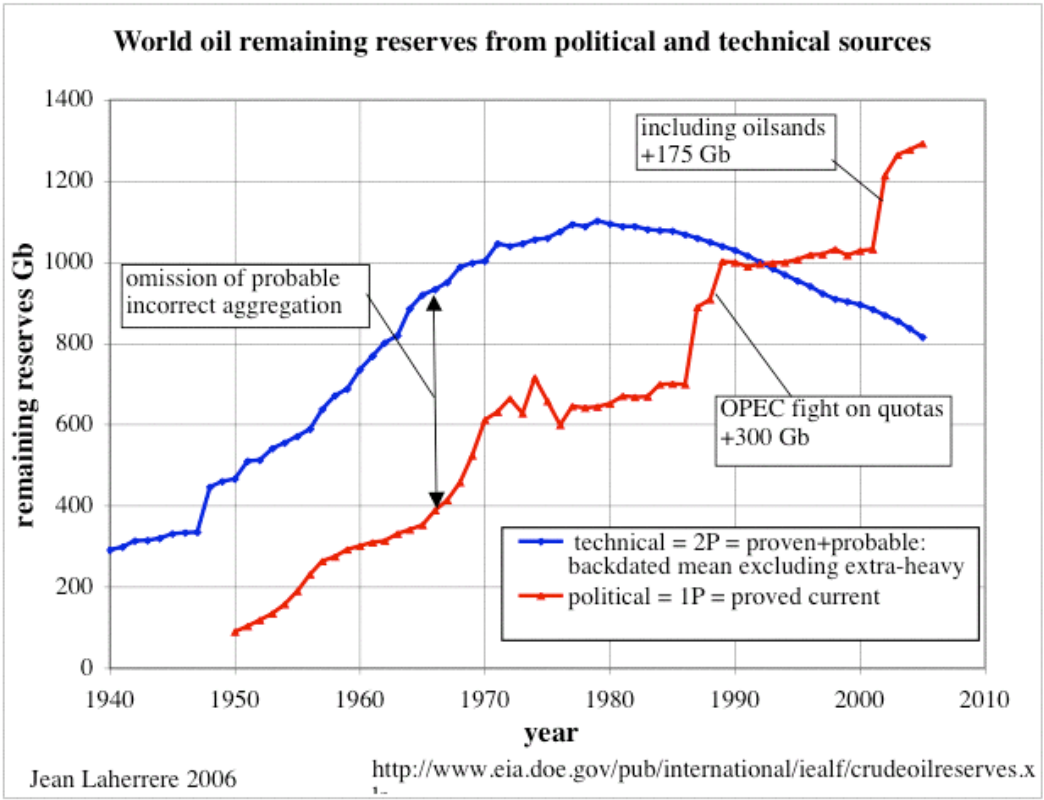
	Oil & Gas journal	World Oil	Cedigaz	OGJ/WO
Crude oil Gb				
world	1 277,181 992	1 081,813		*1,18*
Russia	60.000	67,137 9		*0,89*
Natural gas Tcf				
world	6 043,677	6 997,767 4	6 362,043 5	*0,86*
Russia	1 680.000	2 361,053 2	1 695,120	*0,71*

End of 2005	OGJ	BP	OGJ/BP
Oil Gb			
World	1 292,549 534	1200,708 502 619	*1,08*
Russia	60,000	74,436 476 05	*0,81*
Norway	7,705	9,672 727 8	*0,80*
Canada	178,7924	16,5	***10,8***
China	18,25	16,038 12	*1,14*
Gas Tcf			
World	6 112,144	6 348,068 437 8	*0,96*
Russia	1 680.000	1 688,046	*0,99*
Norway	84,26	84,896 5	*0,99*
Canada	56,577	55,950 5	*1,01*
China	53,325	82,955	***0,64***

The variation is about 30%. Giving more than 2 digits (13 for BP) is **completely stupid** and shows that the author incompetent, having no knowledge of what accuracy means, and straight aggregation of proved reserves is incorrect!
Most of people believe that addition must be right and that 1000 + 1 = 1001, when in fact 1 is a negligible quantity in front of the imprecise rounded 1000, suggesting that its accuracy should be around 100, so the correct addition is 1000 + 1 = 1000.

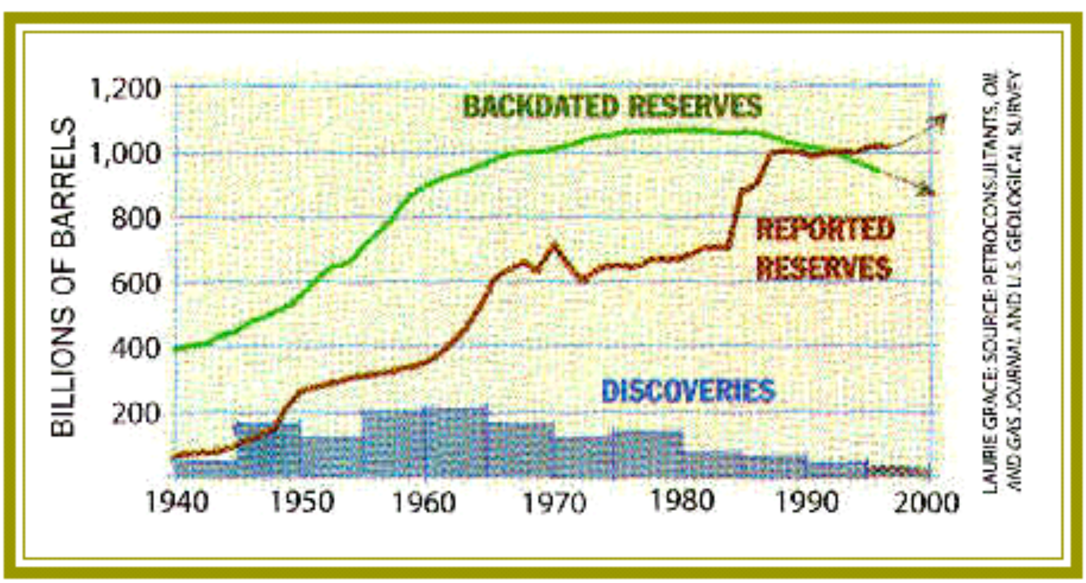
-Political and technical data

Oil remaining reserves (known discoveries minus cumulative production) can be compared from political sources giving current proved values and from technical sources after correction of US Lower 48 and FSU to obtain the backdated mean (expected) crude oil (less extra-heavy) value.
The following graph display my technical data, which is the compilation of several heterogeneous databases, corrected to best represent the world mean reserves from field, backdated to the year discovery. The best way should be to backdate to the year where investment are made but it is impossible to obtain it worldwide by lack of data.
Figure 8: **World remaining conventional oil & gas reserves from political and technical sources**



In our Scientific American March 1998: "*The end of cheap oil*" Campbell & Laherrere, we expected an increase of political data but not as sharp as the 2002 jump of OGJ with tarsands and the technical data decrease is as expected.

Figure 9: **Word conventional remaining reserves from political & technical sources from 1998 Scientific American graph**



Political data do not diverge much because it is the compilation of each country report from national agencies, when technical data coming from different scout vary largely and choosing one mean value is not too easy when the range is wild. The problem is now that scout companies now do not want to upset the national oil companies (NOCs), which are their new clients, when many international oil companies IOCs have disappeared. So now, scout companies accept NOC political values and lose reliability. Political data is always rising from 1950 to now, when from the technical sources, oil remaining reserves has peaked in 1980! It is well recognized by almost every IOC that, since 1980, oil discovery is less than oil production

From 1950 to 1979 (oil shock) proved reserves were roughly half of the mean value, the difference representing the omission of the probable reserves and the incorrect aggregation.

-Incorrect aggregation

It is incorrect to add the field minimum value to get the minimum of a country, this aggregation underestimates the real minimum of the whole, because it is very unlikely that all fields are at the minimum value. It is also incorrect to add the field maximum to get the maximum of the whole, this aggregation overestimates the real maximum. It is necessary to know the probability distribution of these estimates and to run a Monte-Carlo simulation (usually 50 000 runs) to get the real minimum (and maximum) value of the whole.

In the USGS 2000 study of undiscovered oil, using a probability distribution of minimum = 95 % or F95 and maximum = 5% or F5, the Monte Carlo procedure for the eight regions listed in the study gives (table 1 of Executive summary DDS-60) for the world outside the US undiscovered oil and gas gives the following results:

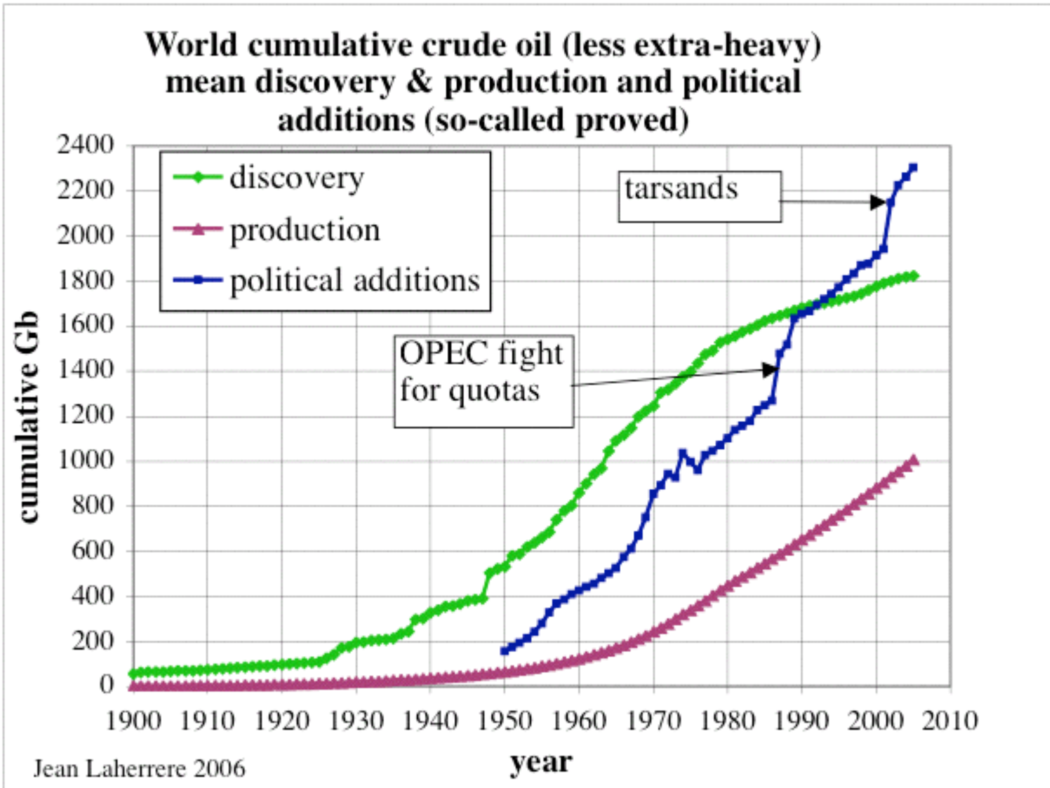
	F95	F50	mean	F5
oil				
Monte Carlo	339 Gb	607 Gb	649 Gb	1107 Gb
Straight addition	179 Gb	606	649 Gb	1282 Gb
Wrong by	**- 46%**	**- 0.2%**	**0 %**	**+16%**
gas				
Monte Carlo	2299 Tcf	4333 Tcf	4669 Tcf	8174 Tcf
Straight addition	1239 Tcf	4267 Tcf	4669 Tcf	9463 Tcf
Wrong by	**- 46%**	**- 2%**	**0%**	**+16 %**

Only the *mean* value is the same under both calculations as forecasted by the theory. This aggregation is from the region analysis, taking from the country or from the field will worsen the gap.

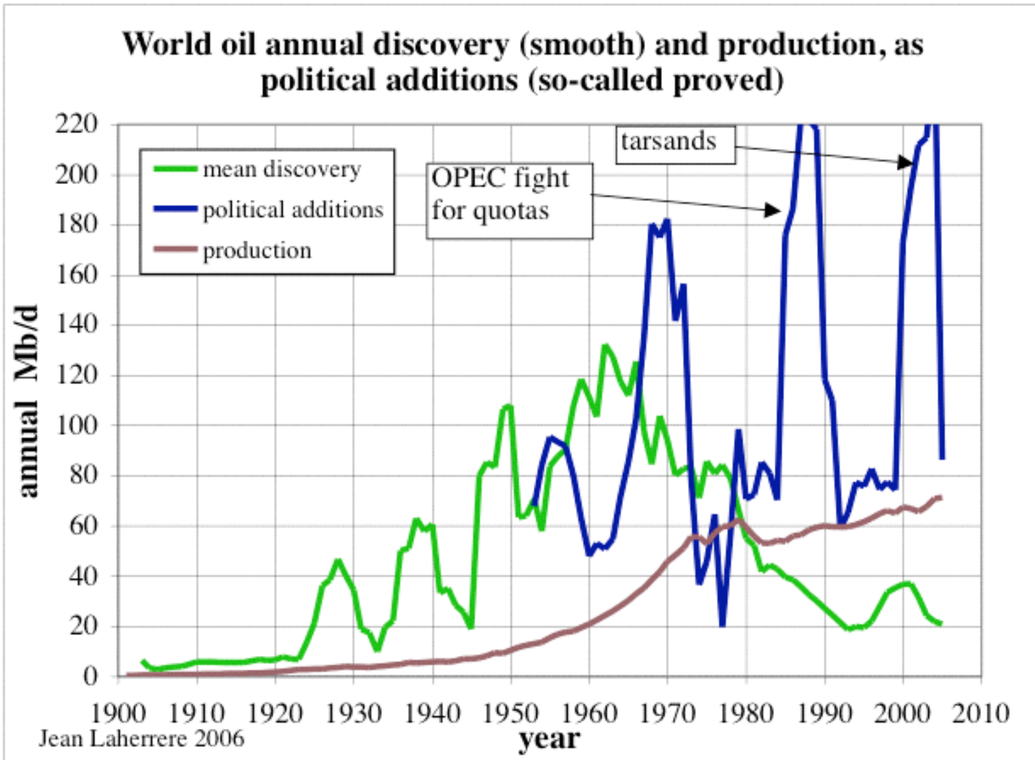
This confirms that incorrect aggregation of proved reserves can underestimate the real proved value by half and explain a good part of proved reserve growth.

Economists have only access to political data reported to cheer bankers, but useless for forecasting.

Adding the cumulative production to the previous graph, the comparison between the **cumulative discovery** from technical sources and political sources is striking:
Figure 10: **World cumulative crude oil (less extra-heavy) mean discovery & production and political additions (so-called proved)**



The same data **annually** shows very well the artefacts of political reporting, compared to the truth, which is that finding new reserves is a nightmare for oil companies (Scaroni 2006) and that since 1980 the world oil production is much higher than oil discovery.
Figure 11: **World annual crude oil (less extra-heavy) mean discovery & production and political additions (so-called proved)**



Any work, study or forecast using proved reserves has to be discarded as useless, following the GIGO principle: Garbage In, Garbage Out.

-Technical sources for crude oil less extra-heavy

Up to last year only IHS database was worldwide and it was easy to rely on technical data coming from one source. But now Wood Mackenzie (WM) database is almost complete covering 79 countries totalling 1609 Gb, excluding only 50 countries having with IHS 20 Gb out of 1966 Gb for the world outside US + Canada.

The discrepancy between IHS and WM is huge, more than 300 Gb for the world outside US + Canada, WM representing only 83 % of IHS!

Comparison of IHS and WM cumulative discovery for continent where both reporting

cont	Number of countries	IHS O+C Gb	WM O+C Gb	**WM/IHS**	IHS G Tcf	WM G Tcf	**WM/IHS**
Africa	26	200	177	0,89	624	532	0,85
LatAm	9	230	187	0,81	575	297	0,52
Europe	11	75	76	1,01	544	542	1,00
ME	11	969	717	0,74	3002	2037	0,68
Asia	16	138	119	0,86	977	768	0,79
FSU	6	336	333	0,99	2636	2181	0,83
all	79	1946	1609	0,83	8358	6356	0,76

Examples of large discrepancy in ratio IHS/WM oil +condensate cumulative discovery:

Top twelve:

country	IHS Gb	WM Gb	IHS/WM
UAE	83,4	42,7	2,0
Myanmar	1,2	0,7	1,6
Peru	5,0	3,3	1,5
Iran	193,1	127,4	1,5
Thailand	1,8	1,2	1,5
Vietnam	4,5	3,2	1,4
Saudi Arabia +NZ/2	401,6	282,3	1,4
Libya	51,7	36,7	1,4
Venezuela	101,0	72,4	1,4
Bolivia	1,5	1,1	1,3
Brazil	30,0	23,2	1,3
Kuwait+DZ/2	93,4	72,6	1,3

Kuwait reserves have been reported by Jan.2006 PIW to be overestimated by a factor of two (only 24 Gb of proven, rest in probable), the remaining reserves at end 2005 are 56 Gb for IHS and 36 Gb for WM (2P), when USDOE reports 104 Gb (1P). In fact the factor could be three!

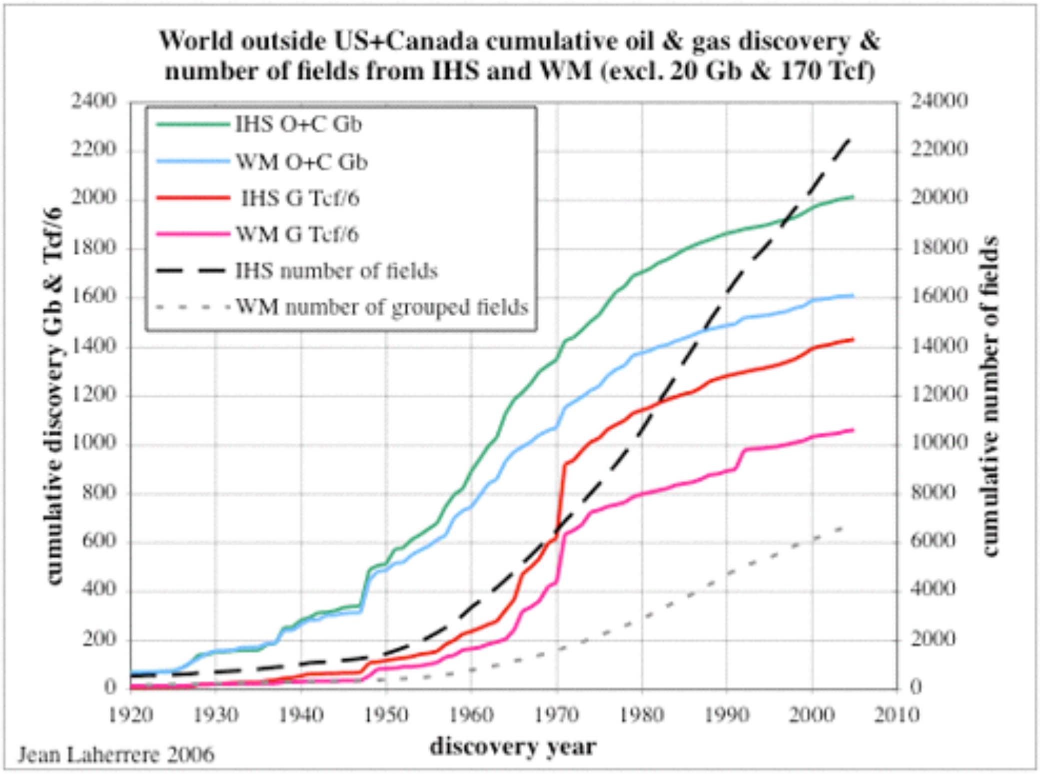
Bottom six:

Turkey	1,1	1,1	0,9
Denmark	2,7	3,1	0,9
Algeria	32,3	36,3	0,9
Turkmenistan	5,0	5,7	0,9
Sudan	2,8	3,6	0,8
Qatar	40,5	64,2	0,6

There is little discrepancy in countries where field data are published as in UK and Norway.

The cumulative discovery from IHS and WM shows that the discrepancy occurs mainly from 1960 to 1980 during the peak of discovery

Figure 12: **World outside US+Canada cumulative oil and gas discovery from IHS and WM**



IHS does not report cumulative production, when WM does it, as OPEC.
The comparison for oil (as oil + condensate not subject to quotas) is given for WM 2006 and OPEC at end 2004.
The difference is up to 15% (UAE), justifying that giving more than 2 digits is wrong!
Cumulative production from WM and OPEC for OPEC countries

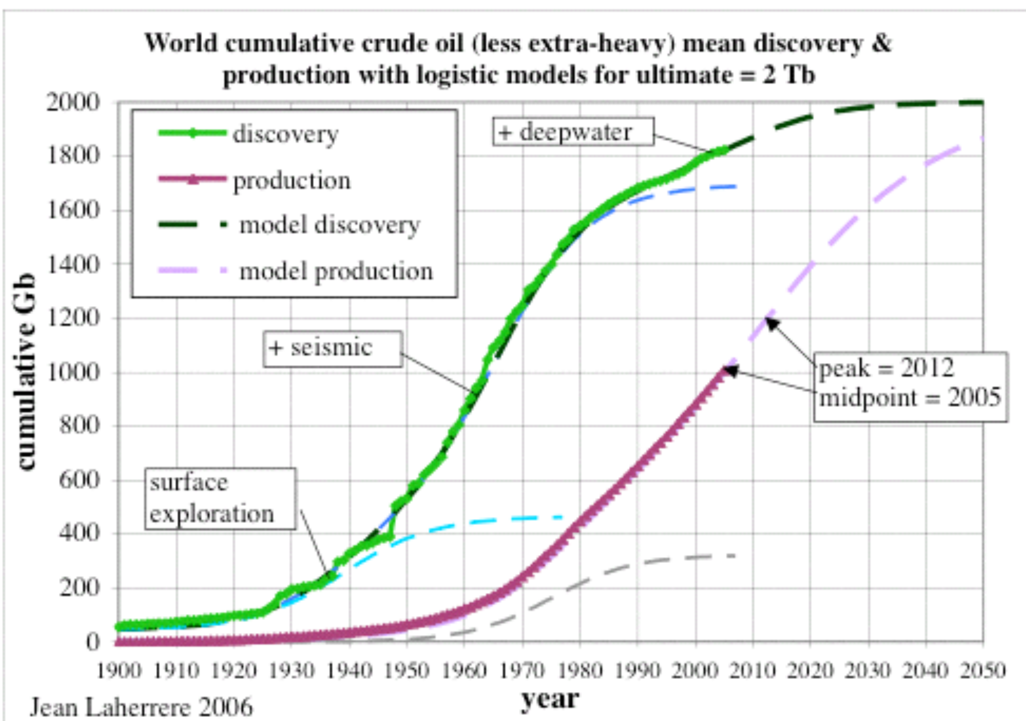
country	WM CP O 2006	WM CP O+C	OPEC CP 2004
Algeria	13,7	24,1	13,2
Indonesia	21,2	23,1	20,5
Iran	60,7	61,4	56,6
Iraq	30,1	30,1	29,9
Kuwait	36,9	36,9	35
Libya	25,2	25,3	24
Nigeria	23,7	24,9	23,6
Qatar	6,9	7,4	7
Saudi Arabia	106,2	106,2	103,1
UAE	26,3	26,9	22,9
Venezuela	59,9	60,3	55,9
Venezuela Orinoco	0,8	0,8	

As WM oilfield estimates are closer than IHS to the ultimates from the oil decline extrapolations (annual production versus cumulative production) of a large number of major fields, we consider WM as more reliable (except for FSU where both they take the

Russian database reported in fact as 3P). Unfortunately WM group fields in many countries and backdating is difficult.
I use the complete IHS database by applying the following corrections:

Africa	0,89
Europe	1
FSU	0,7
Latin America	0,81
Middle East	0,74
Asia	0,86

Then Canada and US (coming from USDOE 534-1990 2P estimates) are added. The cumulative mean discovery is plotted, giving a cumulative discovery at end of 2005 of about 1800 Gb and modelled with 3 logistic models corresponding:
-up to 1940 = surface exploration
-1940-1990 = seismic exploration
-since 1990 = deepwater
and the ultimate is close to the round number of 2000 Gb, that I have chosen in order to show the uncertainty of the estimate (as Hubbert in 1956 has taken 2000 Gb for the US Lower 48, being the highest value of W.Pratt Delphi enquiry). It means that the undiscovered is less than 200 Gb or less than the difference between IHS and WM, meaning less than the accuracy of the ultimate !
Figure 13: **World cumulative crude oil (less extra-heavy) mean discovery & production with forecast for an ultimate of 2 Tb 1900-2050**



It is interesting to notice that the cumulative production can be also easily modelled with two logistic curves for an ultimate of 2 Tb.

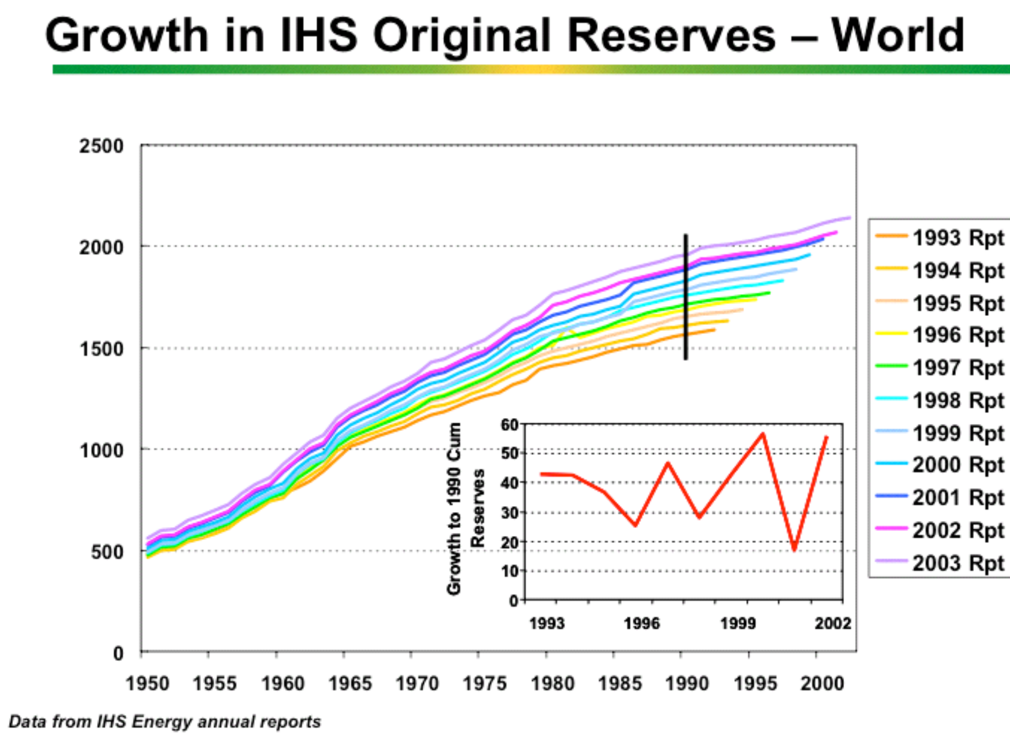
The modelling with two curves leads to a middle point at 2005 when the oil peak is at 2012. The middle-point does not coincide with the peak, when the model is not a single symmetrical curve !

-Reserve growth in IHS database due to incomplete files

Francis Harper « Oil reserves growth potential » ASPO 2004 Berlin 25 May

Harper stated that IHS has increased reserves with time from 1993 to 2003, but I objected that the files were incomplete and that the number of fields has increased too

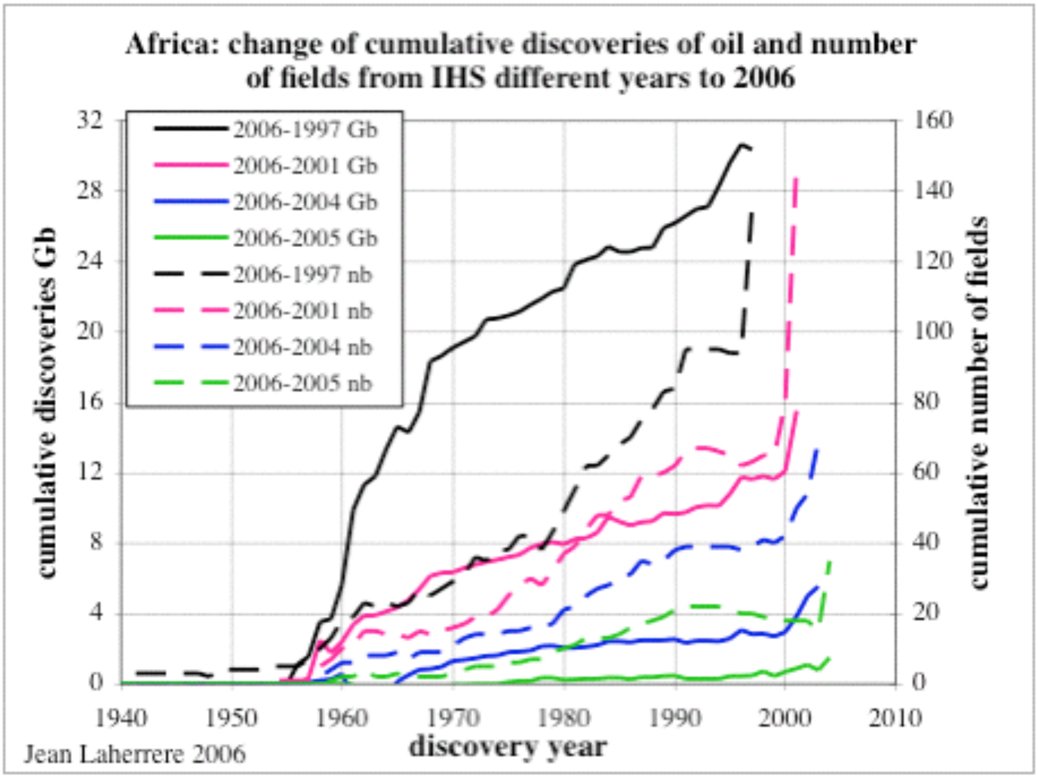
Figure 14: **IHS reserve growth 1993-2003 from Harper ASPO Berlin 2004**



IHS has mainly increased reserves in OPEC countries, obliged to report field values published by OPEC members, as already mentioned. But IHS has also increased the reserves by adding many missing fields.

For Africa 1996 discoveries, the number of fields from 1997 to 2006 files has increased about by 100 fields and 30 Gb; from 2001 to 2006 files by 60 fields and 12 Gb; from 2004 to 2006 files by 38 fields and 3 Gb.

Figure 15: **Africa: IHS growth of number of fields due to incomplete files 1997-2006**



It takes few years to have the files correctly completed. The recent years are then questionable! And later corrections are more political than technical!

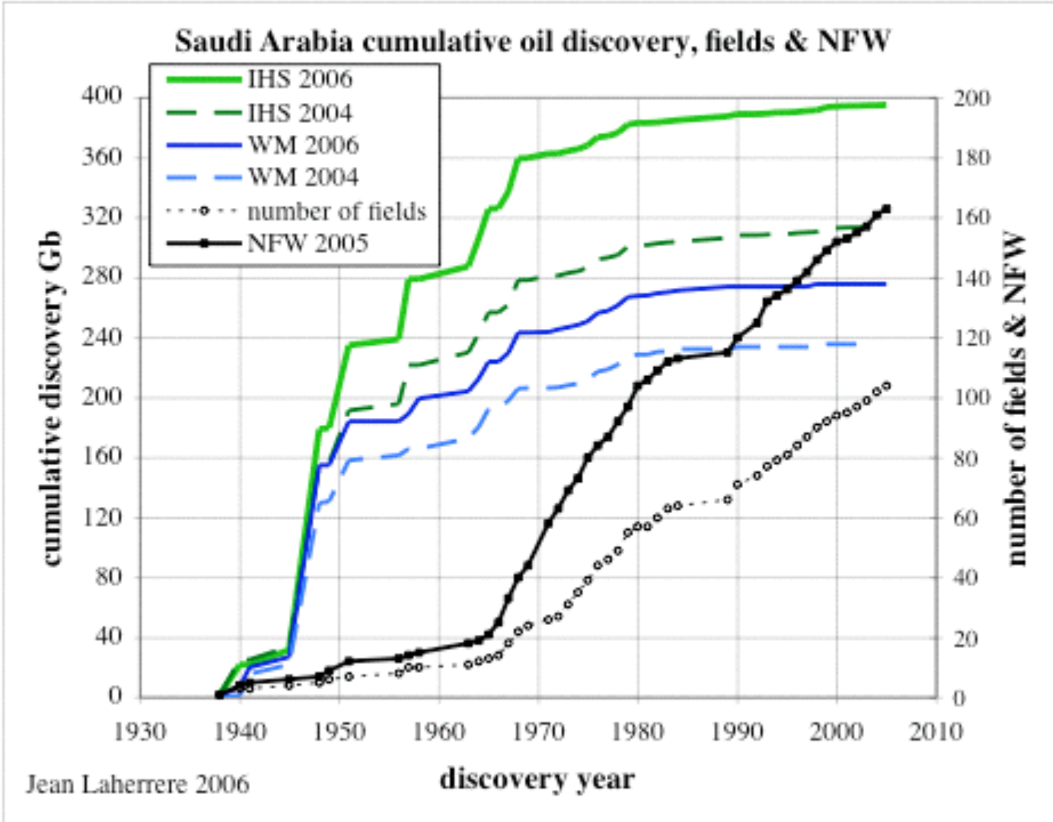
Reserve growth due to technology has to be obvious on the oil decline. If not, the growth is due to poor reporting.

-Political pollution in technical databases:

Saudi Arabia has been controlling OPEC for a long time because holding enough spare capacity to increase quickly when in needs (or to fight on market share as in 1986) or to reduce production. They want to keep their leading role of swing producer, so they need to claim high reserves. Up to now, field data were confidential, but in front of Matt Simmons' claim of overestimate, they have released some field data; which are now accepted by the scout companies as IHS and WM.

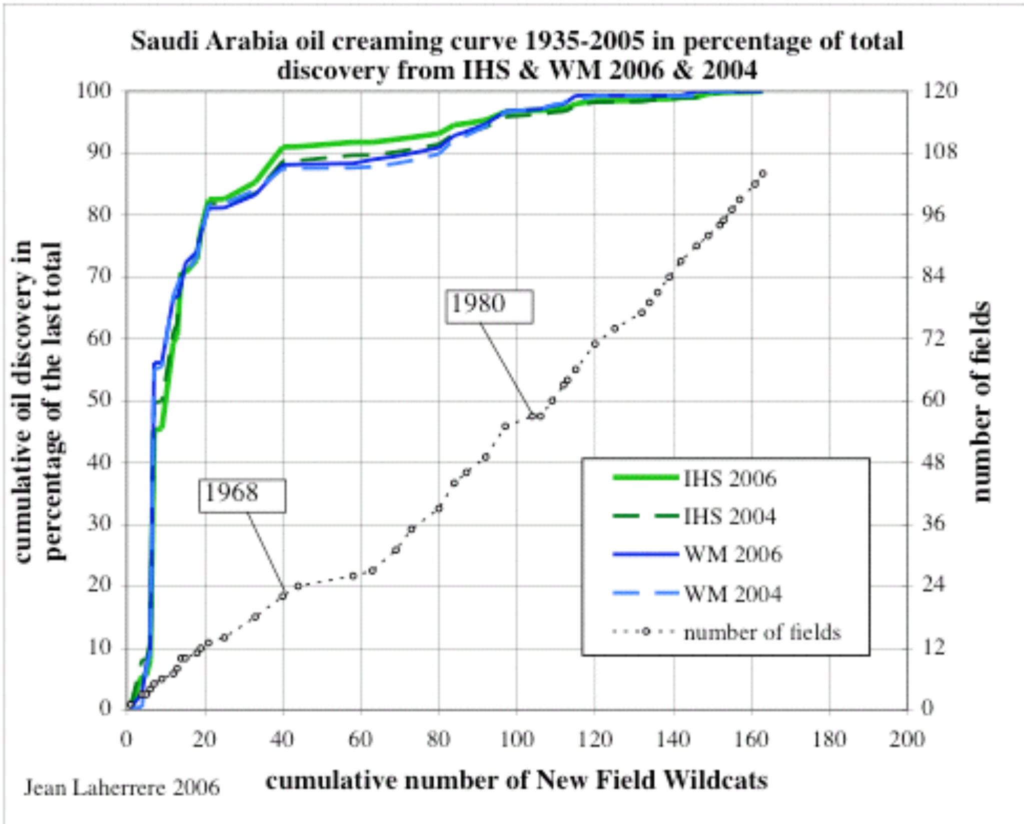
The large increase can be seen from 2004 to 2006.

Figure 16: **Saudi Arabia cumulative oil discovery from IHS and WM 2004 & 2006**



The percentage of the last cumulative discovery displays a very close curve for IHS and WM, confirming that more than 80% of the total discovery was found with 20 NFW (12%) when the last 20 NFW found only 1%

Figure 17: **Saudi Arabia cumulative oil discovery from IHS and WM in percentage of the last cumulative versus cumulative number of New Field Wildcats**



This graph shows obviously that Saudi Arabia is thoroughly explored despite all the claims that the Middle East is underexplored: it is another myth!

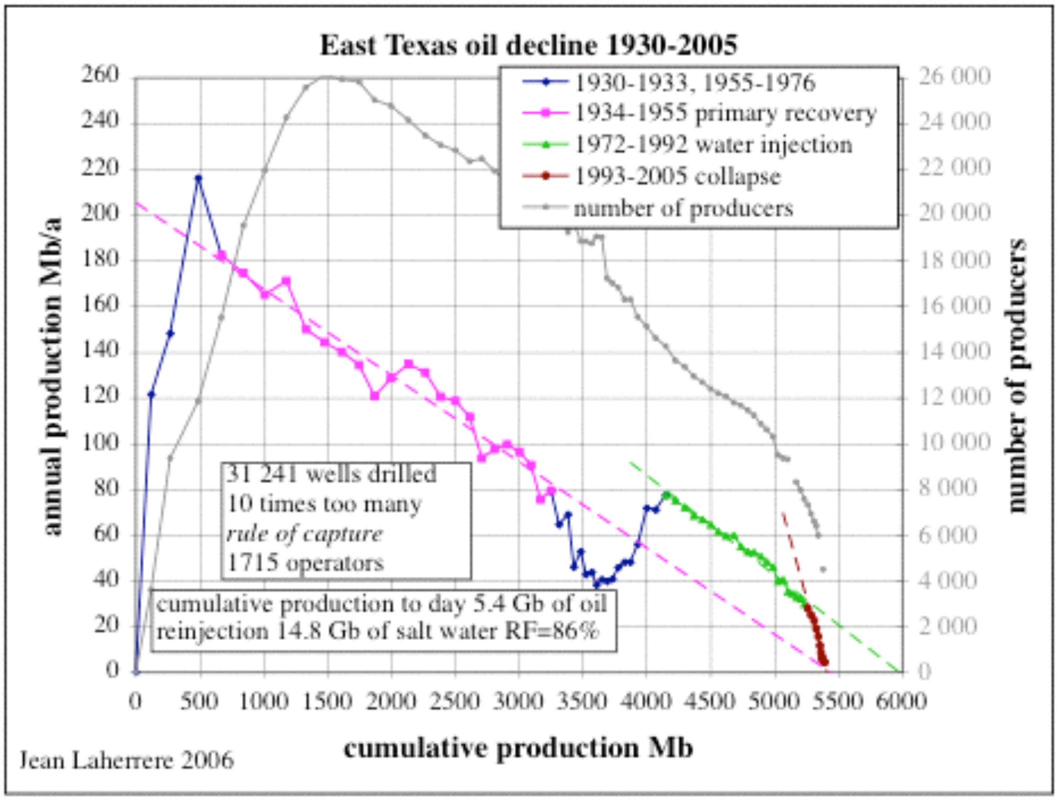
-Reserve growth from USGS

Reserve growth is the main argument of the present USGS head of reserves estimate: T.Ahlbrandt, in contrary to his predecessor Ch. Masters, who was denying any growth by using inferred estimates (and not proved values).
USGS 2000 estimates are as end of 1995, almost 10 years old, but still used by many to justify oil abundance (Exxon-Mobil 2006)! Even past data is wrong, as world cumulative gas production by 15% (1752 Tcf against 2025 Tcf *Salvador AAPG 2005*).
USGS 2000 report estimated (?) world reserve growth at 730 Gb, by applying the proved reserve growth of US old fields to the rest of the world proven+probable reserves (IHS 1996 data). It is comparing oranges and apples, which is an **unscientific approach**. They justified it by saying that world reserve growth is unknown, but instead of doing nothing, they prefer to use US growth. The definition of reserve is different (1P compared to 2P), as the product: US old unconventional onshore fields (Midway-Sunset or Kern River (Maugery Science 2004 example) heavy oil fields using steam, reaching peak after one century of production when keeping drilling new wells) compared to new offshore fields (produced in few years with appraisal and most drilling done before starting production).
Applying old growth to new fields assumes no progress in assessment technology!

US reserve growth of proved data comes from the omitted probable value and also because it is incorrect to add the proved (minimum) field (or country) estimate to obtain the proved country (or world) value (called **illegal addition** by E. Capen 1996).
Such aggregation underestimates largely the minimum value of the whole, as mentioned above.
All world proved reserves estimate is done this way, without any concern by those who reproduce it that it is incorrect !
US reserve growth is mainly due to bad practice of reporting only proved reserves (contrary to the rest of the world), ignoring the expected value (proven+probable) which is the base of all development decisions!
Exxon-Mobil states in WPC 2006 that the **oil peak is decades away**, but it is based on USGS study which is as end of 1995, when we are in 2006. Furthermore the USGS reserve growth estimate is based on unscientific comparison!
In contrary Chevron in their site states that the era **of easy oil is over.**
US Army Corps of Engineers follows ASPO forecasts and dismisses USGS estimates.

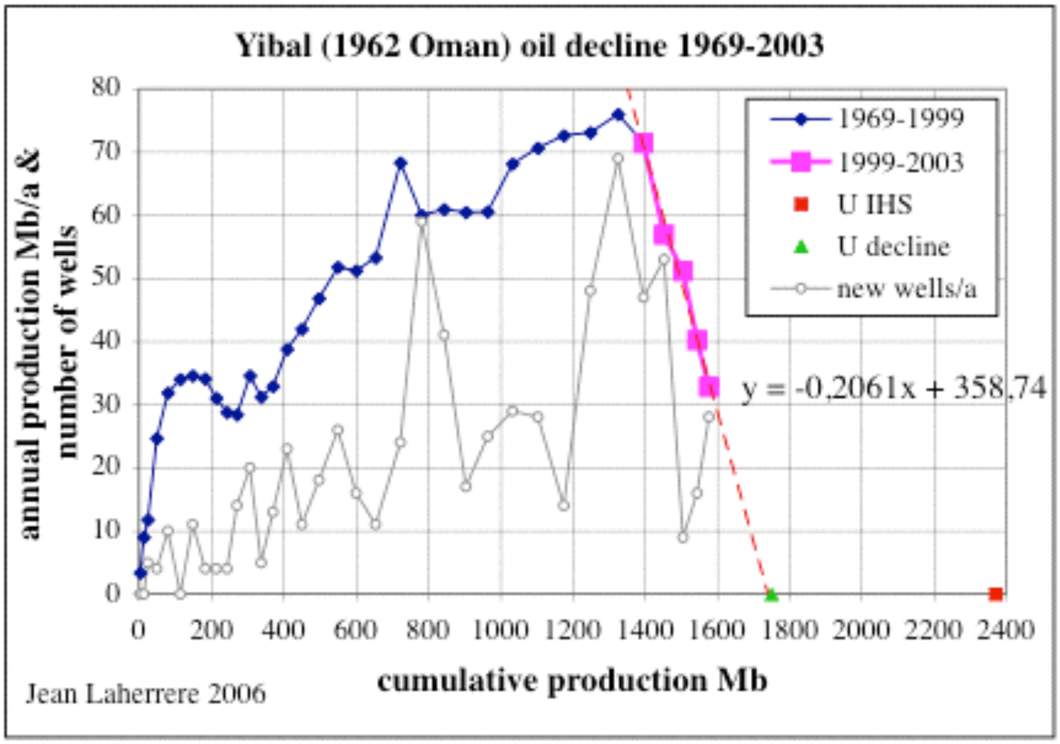
-**Examples of negative reserve growth due to overinvestment:**

Contrary to what is said using new (?) technology as horizontal drilling (over 30 years old) or infill drilling leads to quicker and larger production, detrimental to the total recovery
Reserve growth is often negative at the end, contrary to hopes before, as the largest oilfield in the US Lower 48, East Texas, which was estimated for a long time to hold 6 Gb, but now near exhaustion only 5.4 Gb
Figure 18: **Oil decline of East Texas, largest US L48 oilfield 1930-2005**



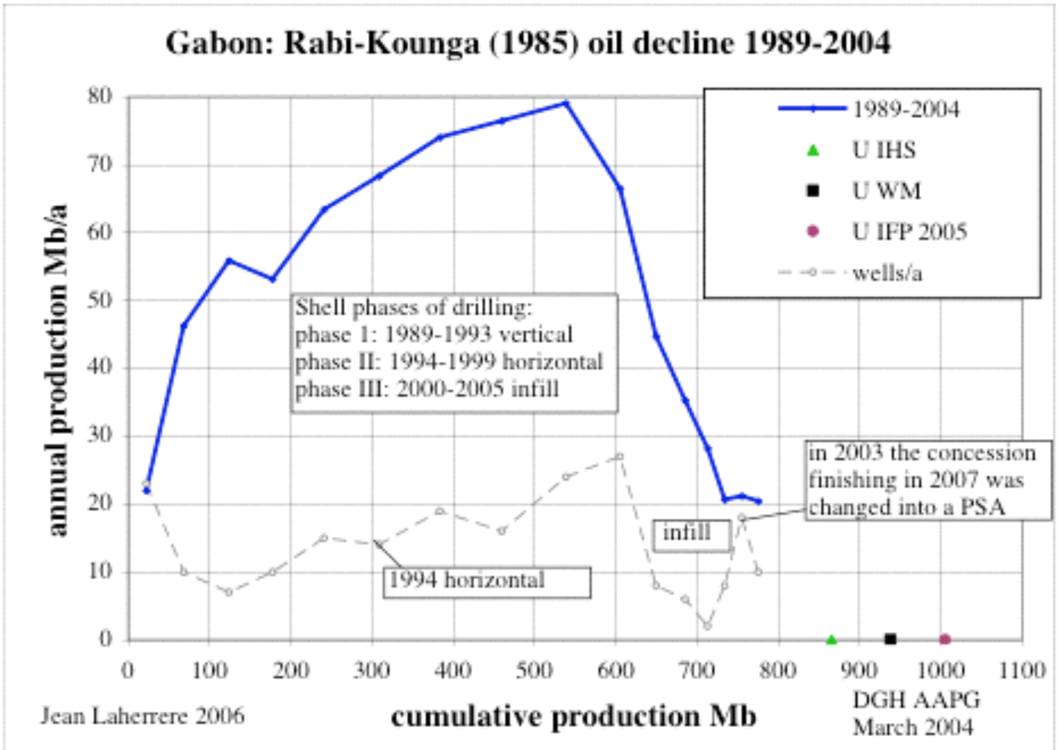
Over 30 000 wells have been drilled (by over 1700 different operators) 10 times too many (spacing of 4 acres per well, when 40 acres/w was largely enough), because of *rule of capture*! There is a very active water drive and **the recovery is estimated at 86 %**. **Present water cut is over 98%** =14 000 b/d of oil with 1 000 000 b/d of water from 4500 wells! = 3 bo/d/w and 220 bw/d/w

Modern production aims to get maximum production to get maximum profit.
Using multi-branch horizontal wells increase the production, but not the total recovery as shown by Yibal the largest oilfield in Oman.
Figure 19: **Oil decline of Yibal, largest field in Oman 1969-2003,** operated by Shell



Horizontal wells allow faster production. Field production pattern usually declines slowly (old good practice = maximum oil recovery), as shown by Forties. Now good practice is to get current maximum profit (pressure from shareholders to get 15% ROR, mainly pension plans)! Oil produced ten years later has little present value today when discounted at 15%/a!

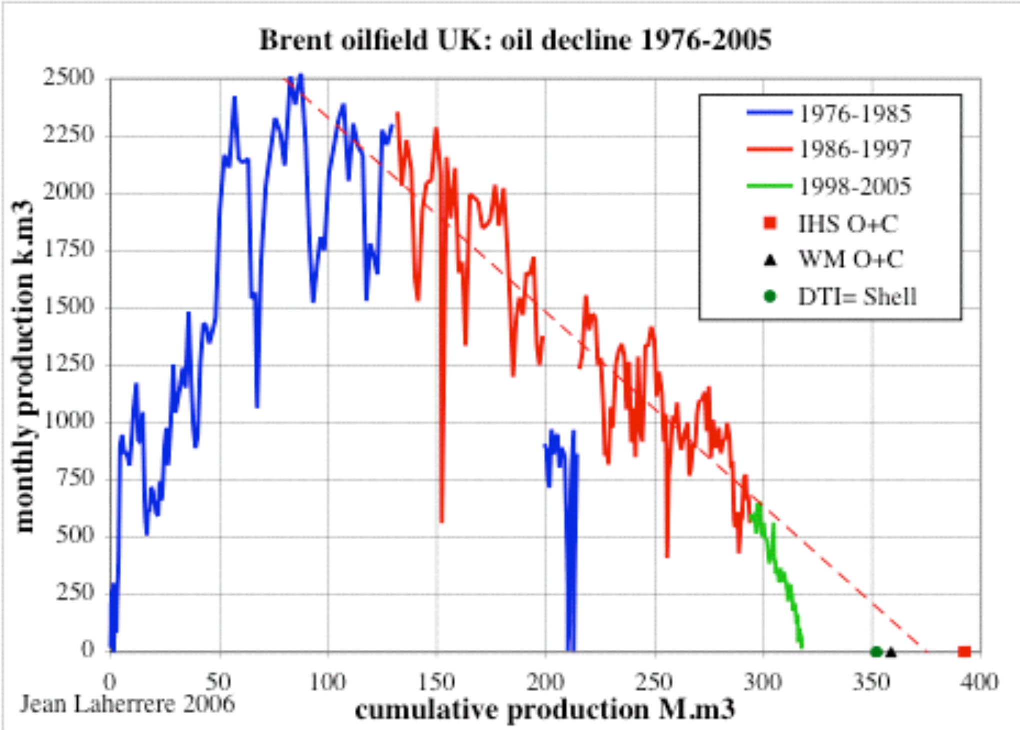
Shell also overproduces also Rabi-Kounga, largest oilfield in Gabon by using overdrilling
Figure 20: **Oil decline of Rabi-Kounga, largest field in Gabon 1985-2004,** operated by Shell



It is interesting to observe the oil decline in North Sea oilfields, which are, now close to be depleted, and also because it is the only place were published data is the technical value reported by DTI and NPD. Texas RRC (RailRoad Commission) and California State publish also good data on some fields as East Texas, Yates, Kern River and Midway-Sunset.

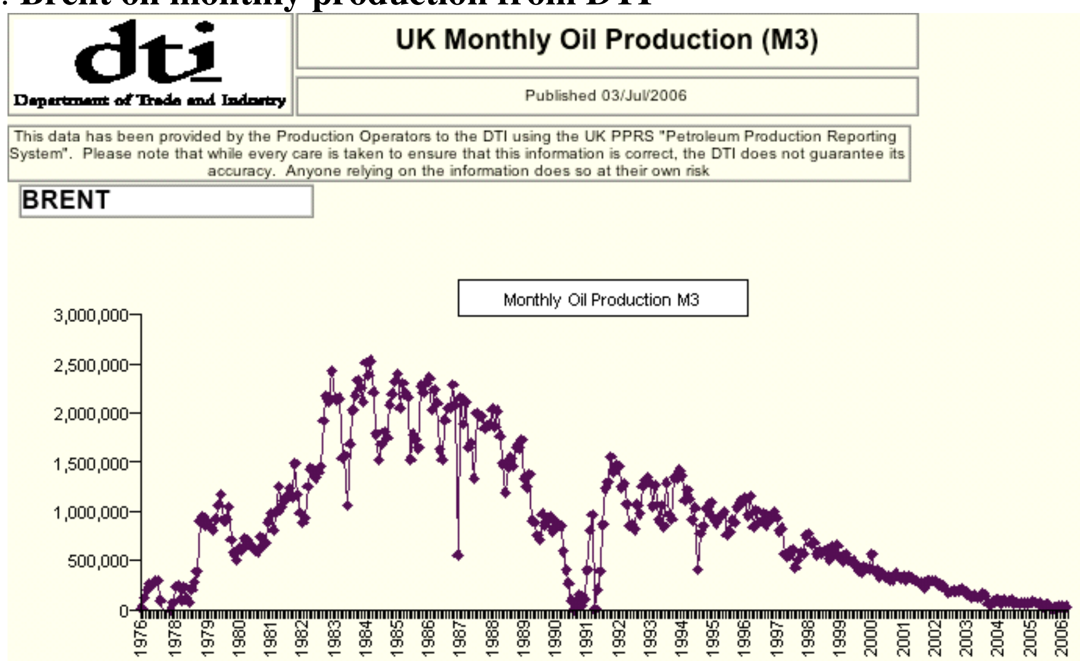
-**Example of final decline collapse leading to a negative reserve growth**.

The decline of annual production versus cumulative production is most of the times close to a straight line, but some shows, as East Texas, a collapse at the end, making the straight line extrapolation an optimistic estimate, as in the Brent decline (outside the trough in 1989-91 for works on gas repressuring).
Up to 1997 oil ultimate were estimated to be around 350 to 400 M.m3, but production from 1998 to 2005 (green curve) shows that the ultimate will be around 320 M.m3. There is a break in the oil decline from 1986-1997 and 1998-2005.
Figure 21: **Brent oil decline showing a late collapse 1976-2005:**



But the decline in time looks smooth without any break

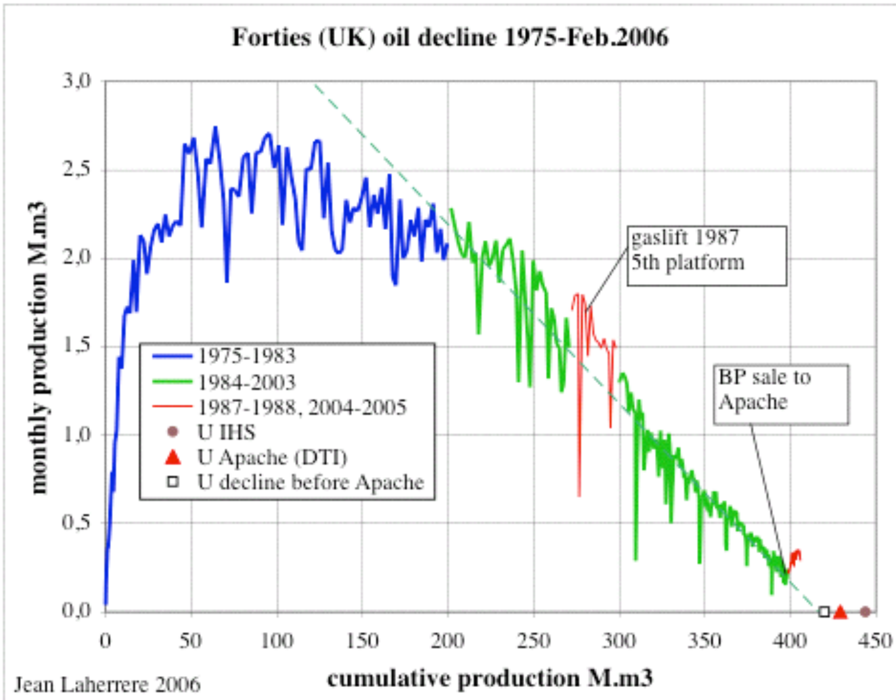
Figure 22: **Brent oil monthly production from DTI**



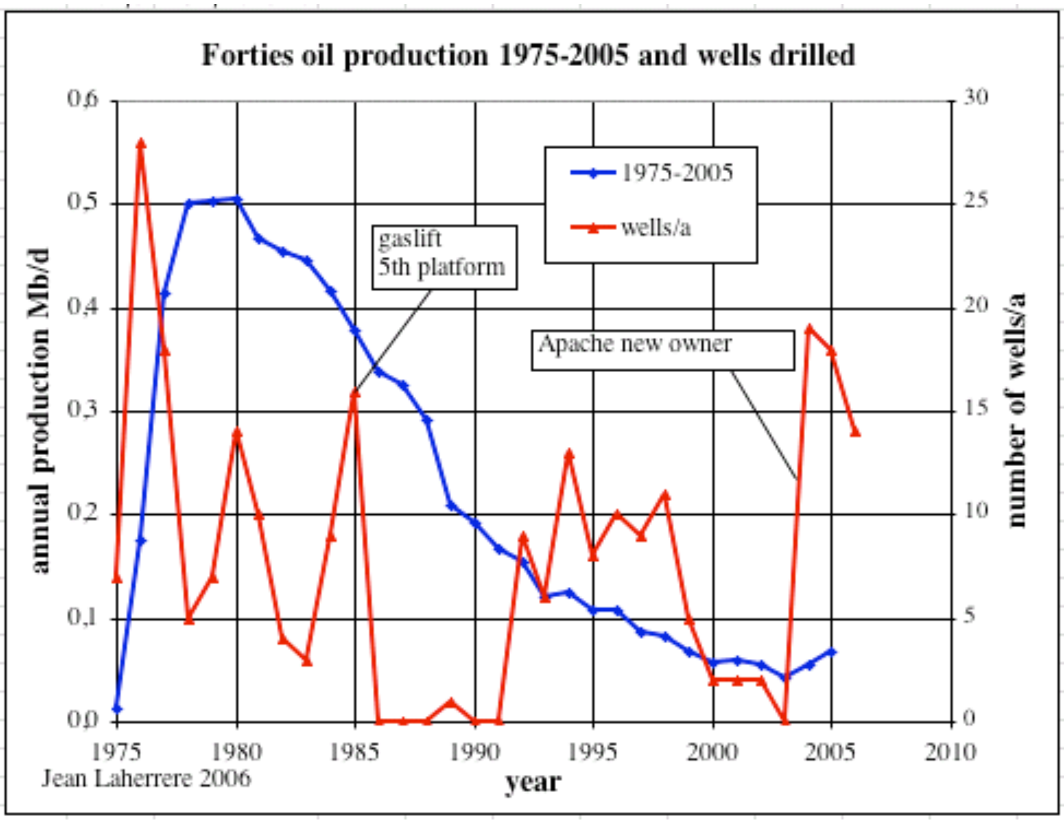
It is funny to notice that the two main oil markers for price in North Sea and Middle East are the Brent, & Dubai, both close to complete depletion!

-Example of no reserve growth

The UK largest oilfield Forties is about 90% depleted and was sold by BP to Apache, BP saying that they have better place to invest (deepwater, Russia?)which is not the case for the independent Apache.
Already in 1987 a fifth platform with gaslift decreased the decline for two years but soon the decline went back towards the same ultimate.
Figure 23: **Oil decline of Forties (UK North Sea) 1984-2005** operated by BP & sold to Apache

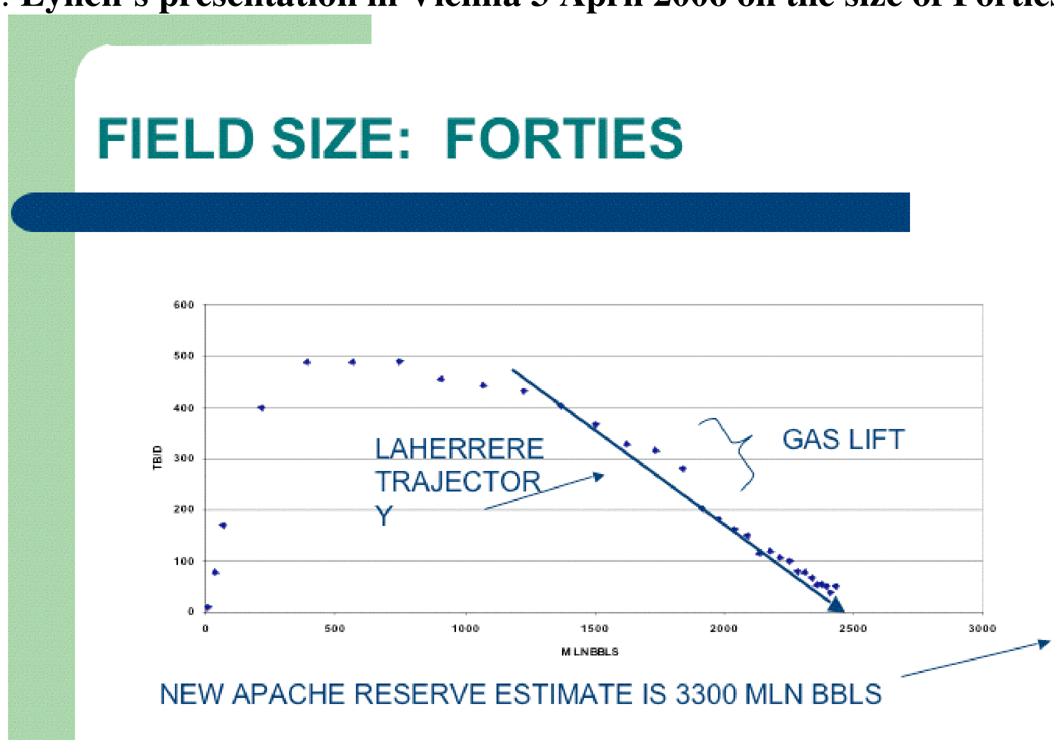


In Forties, Apache drilled 51 wells in 3 years from 2004 to 2006, compared to 200 wells before by BP in 30 years, which is 2.5 times more.
Figure 24: **Forties oil production 1975-2005 and number of wells drilled per year**

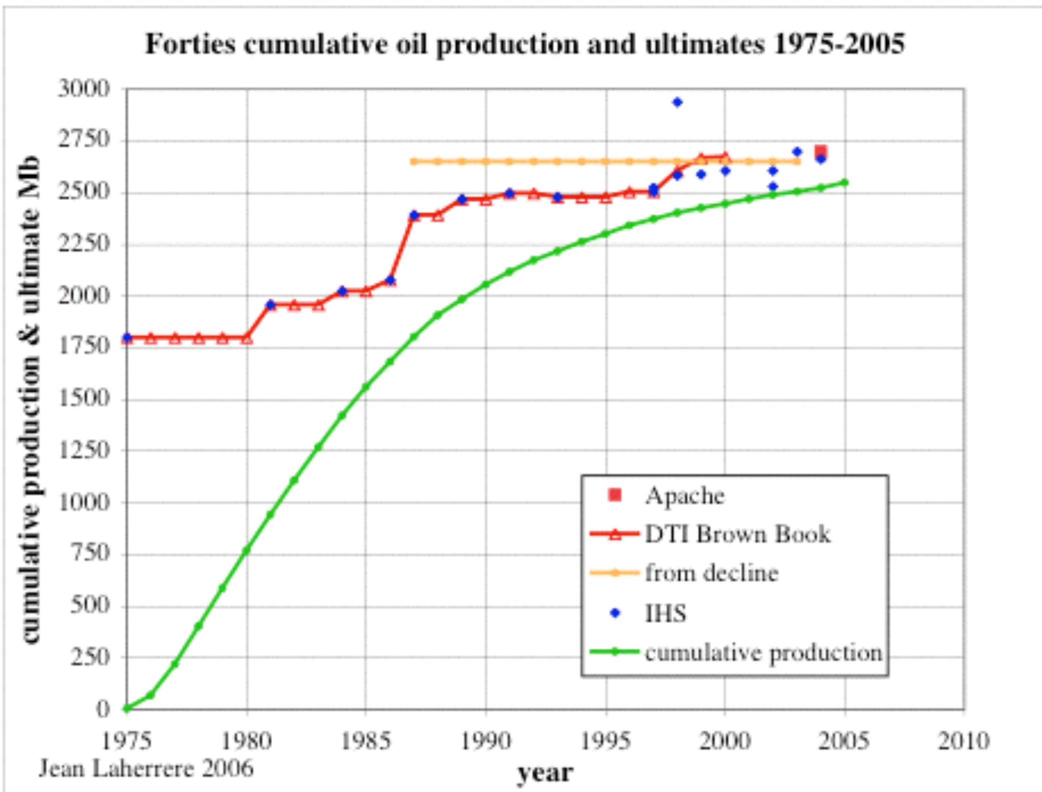


In a debate on peak oil in EGU (European Geosciences Union) in Vienna on 3 April 2006 between Deffeyes, Lynch, Mathieu (IFP) and myself, Lynch accused me to have underestimate Forties ultimate at 2.5 Gb (400 M.m3) when he claims that Apache estimate is at 3300 Mb or 800 Mb higher.

Figure 25: **Lynch's presentation in Vienna 3 April 2006 on the size of Forties**



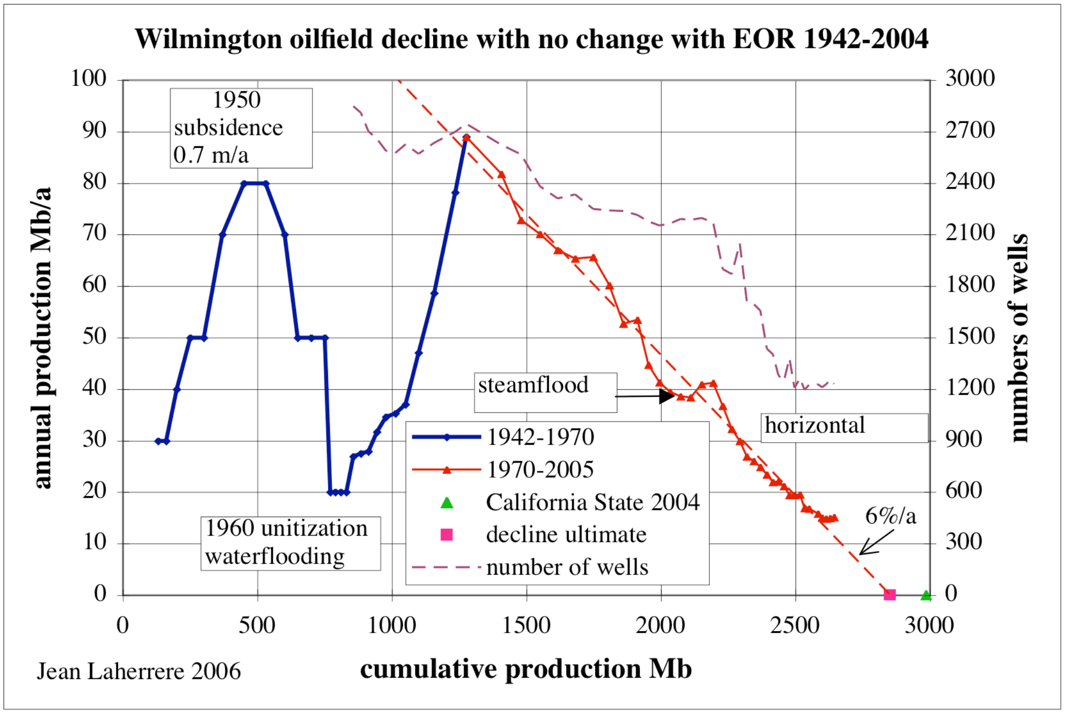
In fact Apache (Dec 2005) stated that they has found with new data that the oil in place is 800 Mb higher, being 5000 Mb instead of 4200 Mb. Lynch confuses, as usual, oil in place and reserves. The oil in place was reported by IHS to be 4200 Mb in 1998 and 4160 Mb in 2004 and 2P moving from 1800 Mb in 1976 to 2940 Mb in 1998 down to 2663 Mb in 2004
DTI reports (April 2006) on the UK oilfield reserves list Apache 2004 ultimate estimate at 355 Mt or 429 M.m3 or 2700 Mb, leaving 150 Mb for remaining reserves at end 2005, as the cumulative production is 405 M.m3 =2550 Mb at end 2005!
Increasing the OIP does not change necessary the reserves, but decreases the recovery factor!
Figure 26: **Forties cumulative oil production and ultimates 1975-2005**



In a 2006 paper Apache (R.Jones) stated that, in the last two years, production have increased by 50% and remaining reserves only by 20 %. Remaining reserves quoted in July 2003 being 147.6 Mb, so the increase is in fact of 30 Mb and not 800 Mb

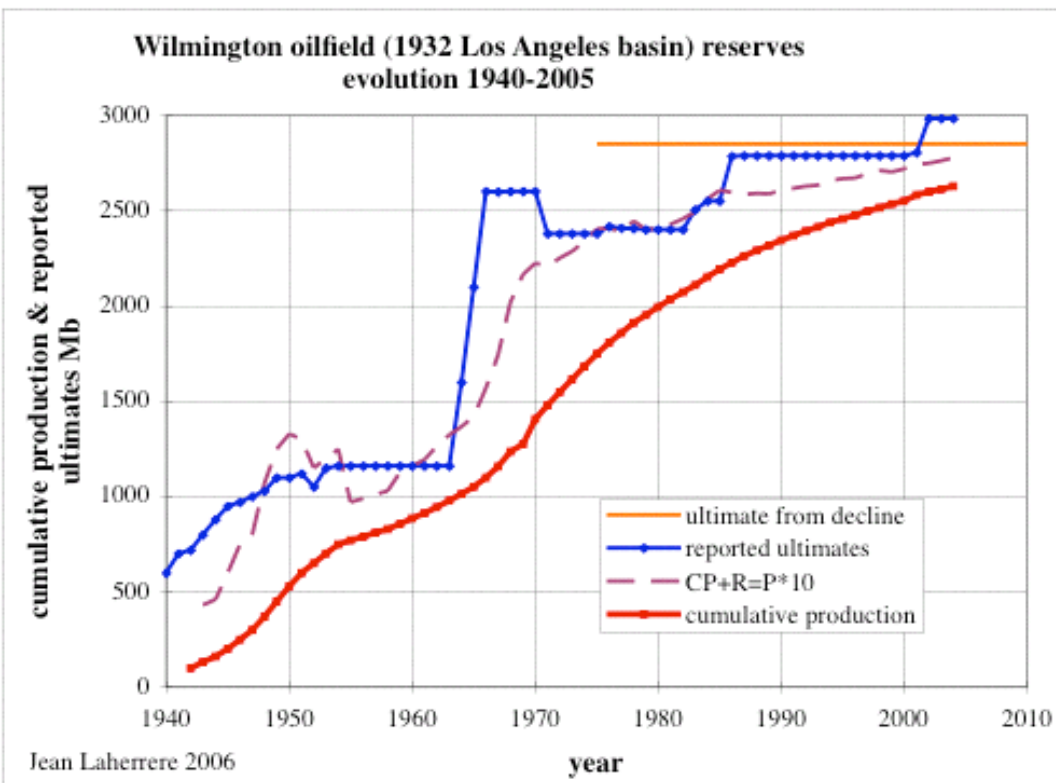
Wilmington was discovered in 1932 in the Los Angeles basin, but in 1950 the subsidence of the surface was 0.7 m/a and after unitization water flooding increased sharply the production, which peaked in 1970. Since 1970 the decline is about 6%/a despite EOR steamflood in the 80s and horizontal drilling

Figure 27: **Wilmington oil decline showing no change despite EOR**



The reported ultimate was 1,2 Tb in 1960 and about 3 Tb now. The ultimate growth follows roughly the curve of cumulative production plus reserves being 10 times the annual production. Ultimate is changed from time to time when the R/P is less than 10. In fact an ultimate of 2,8 Tb could have been estimated since 1975 from the decline .

Figure 28: **Wilmington cumulative production & ultimate evolution**

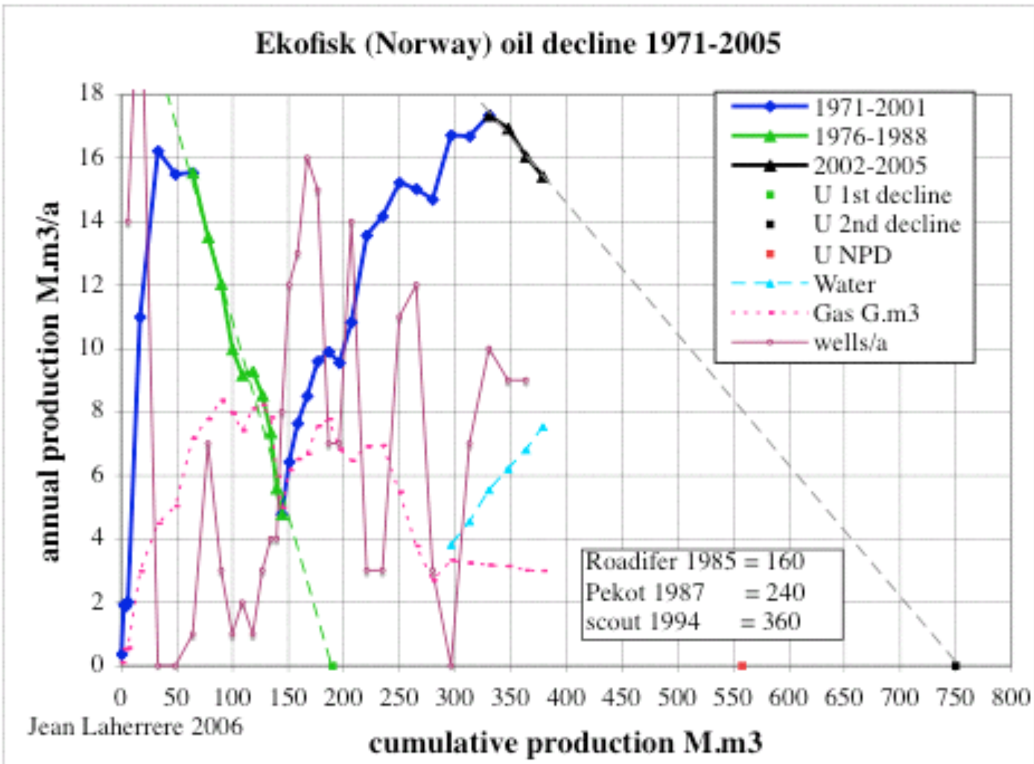


Wilmington is a good example that EOR does not improve the recovery.
Wilmington is also a good example of poor reporting but other fields in California (Kern River and Midway-Sunset display the same pattern of reserves estimated from the production.

-Example of positive reserve growth = exceptions

Ekofisk is the exception in North Sea, showing a drastic increase in recovery because its reservoir is a special chalk, which collapsed when pressure decreased, leading to a 7 m seafloor subsidence (platforms were heightened). Production jumped again in 1988 after many wells were drilled for water injection

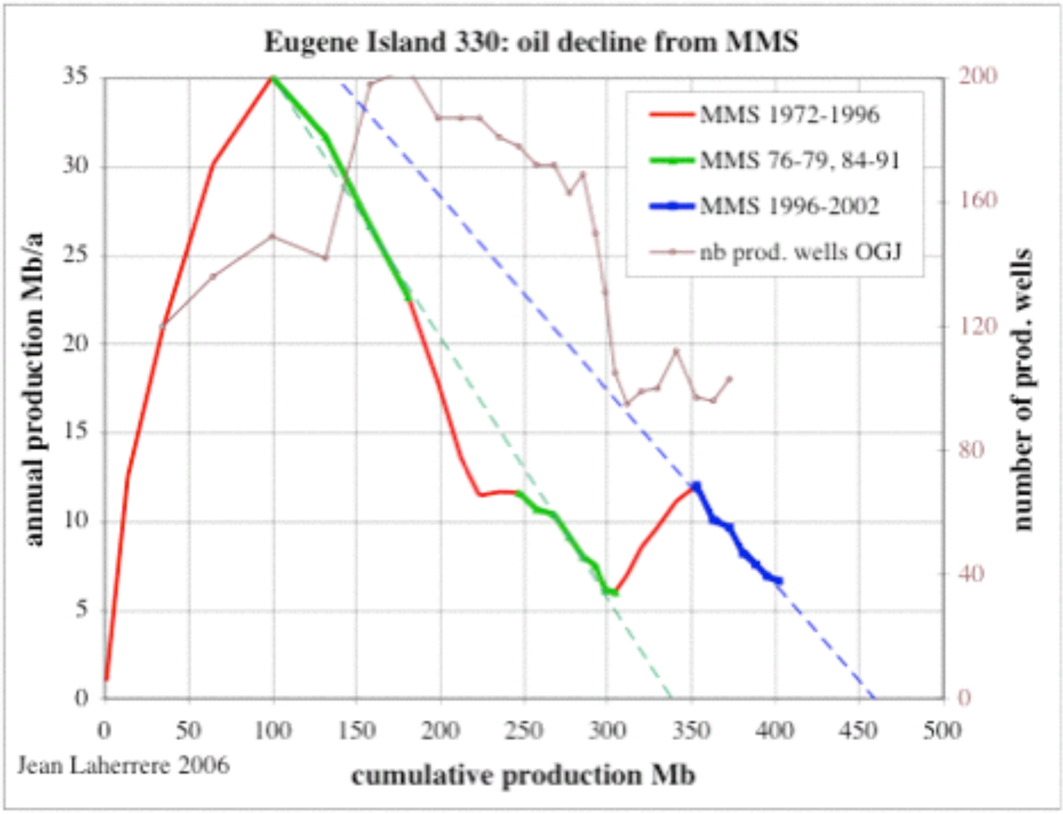
Figure 29: **Oil decline of Ekofisk (Norway) 1971-2003 = exception = particular chalk reservoir= compaction = 7 m seafloor subsidence**



Ekofisk is one of the few examples of positive reserve growth due to an exceptional reservoir.

Eugene Island gives also a positive reserve growth, due this time to an exceptional connection between the reservoir and the source rock, through one of the largest and well-known fault in the Gulf of Mexico (seismic surveys on the web)
There is a real change in decline due likely to the charge of the reservoir of oil coming from the source-rock through the large fault, but the increase is about 30%.

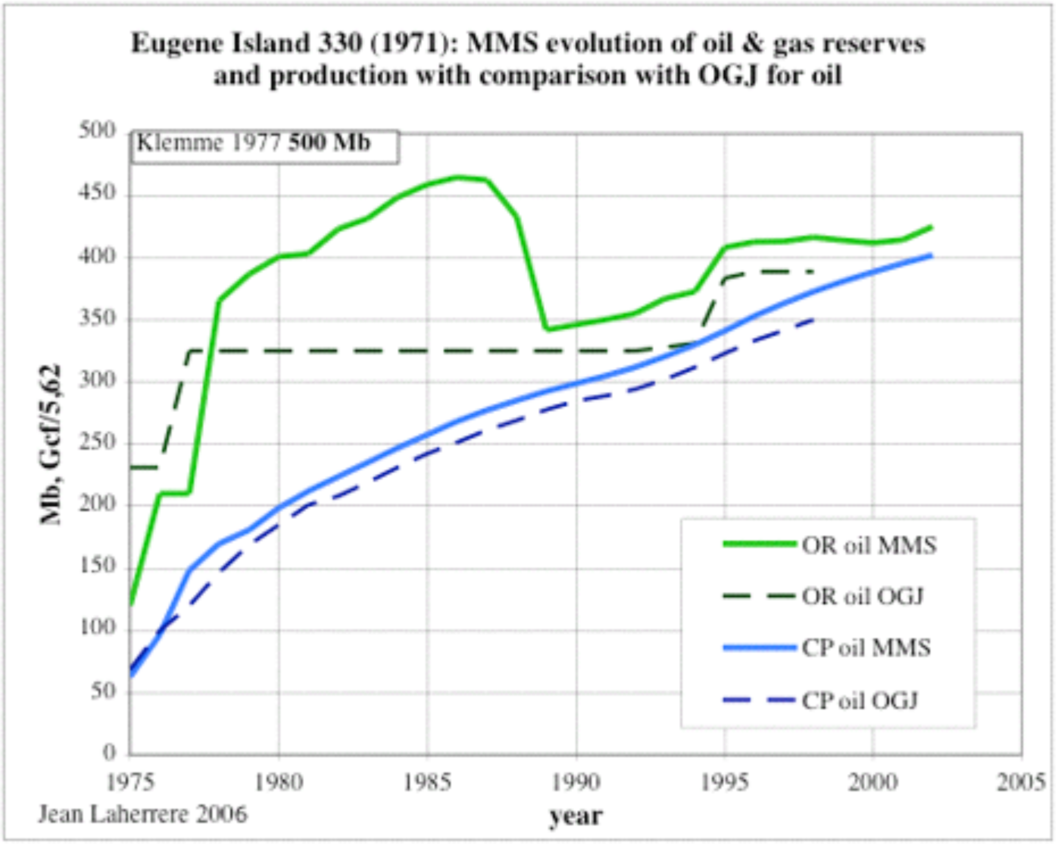
Figure 30: **Oil decline of Eugene island 330 (Gulf of Mexico)** 1972-2001**= exception** = large fault connecting source-rock and reservoir



Eugene Island 330 reserve growth was described by the Wall Street Journal (Cooper 1999) as huge (from 60 Mb to 400 Gb) and an example of abiogenic source coming from the mantle, even suggesting that oil is renewable and explaining the large increase of reserves in the ME!

But there is no positive reserve growth on data reported by the MMS (USDOI-Mineral Management Services) which rule the Gulf of Mexico, as in fact their present estimate is far below 1986 value and the ultimate of 450 Gb is below Klemme's (one of the best explorers at the time) estimate of 500 Mb in 1977.

Figure 31: **Oil reserve evolution of Eugene island 330 1972-2001**

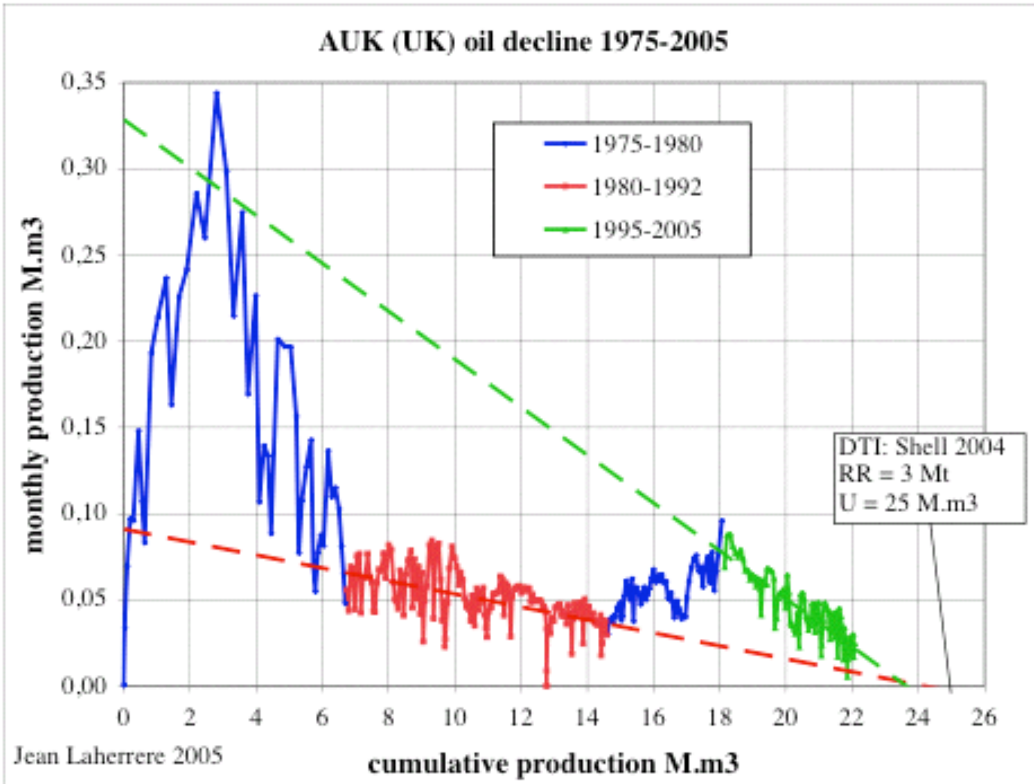


EI 330 is a good example of positive reserve growth on oil decline and a good example of negative reserve reporting when looking at MMS before the counter shock.

-Other examples of growth

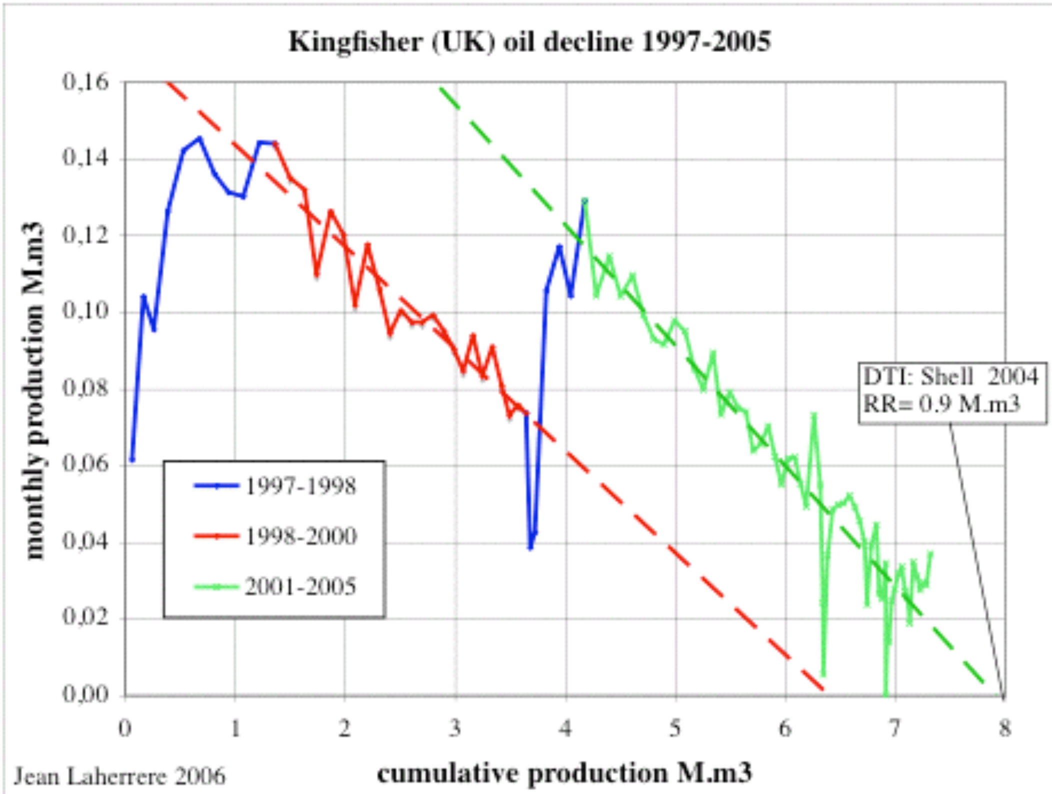
Auk (UK) was reported as an example of reserves growth by Sneider (2001 "New oil in old places"), because a new increase, but, as for East Texas, the new decline is trending toward the previous ultimate, **giving no growth at all**.

Figure 32: **Auk oil decline 1975-2005**



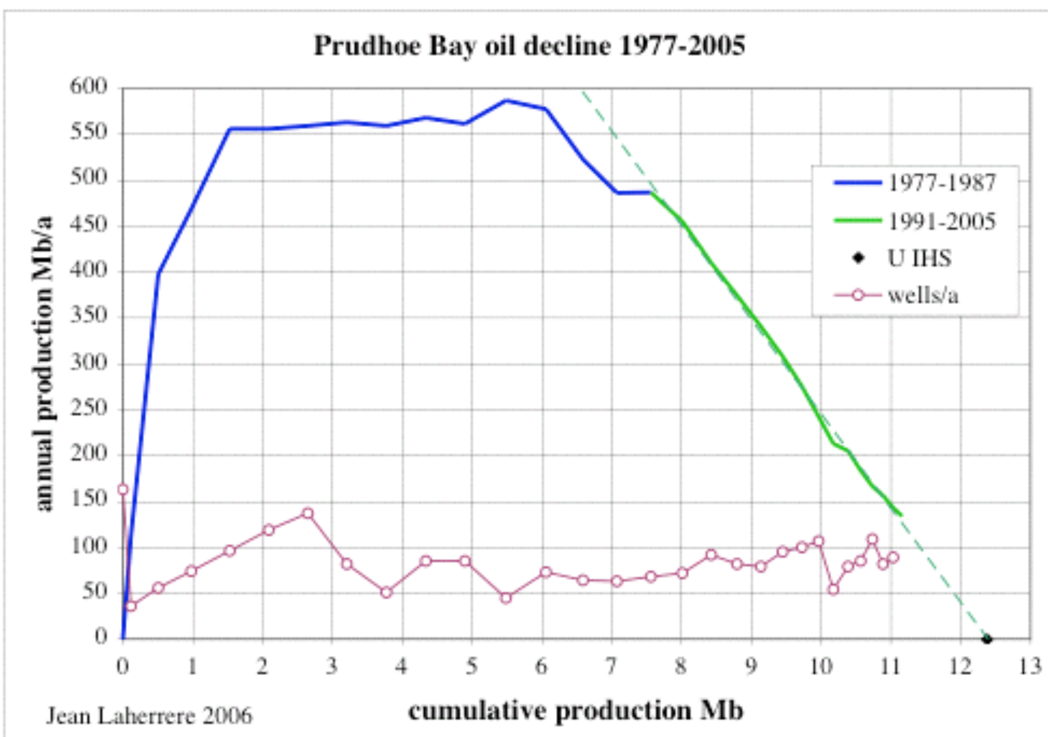
However the small UK oilfield Kingfisher shows a production increase in 2001, which leads to a reserves increase by 30% by drilling a fifth well. But this field is a small one, where one additional well changes the outcome.

Figure 33: **Kingfisher oil decline 1975-2005**



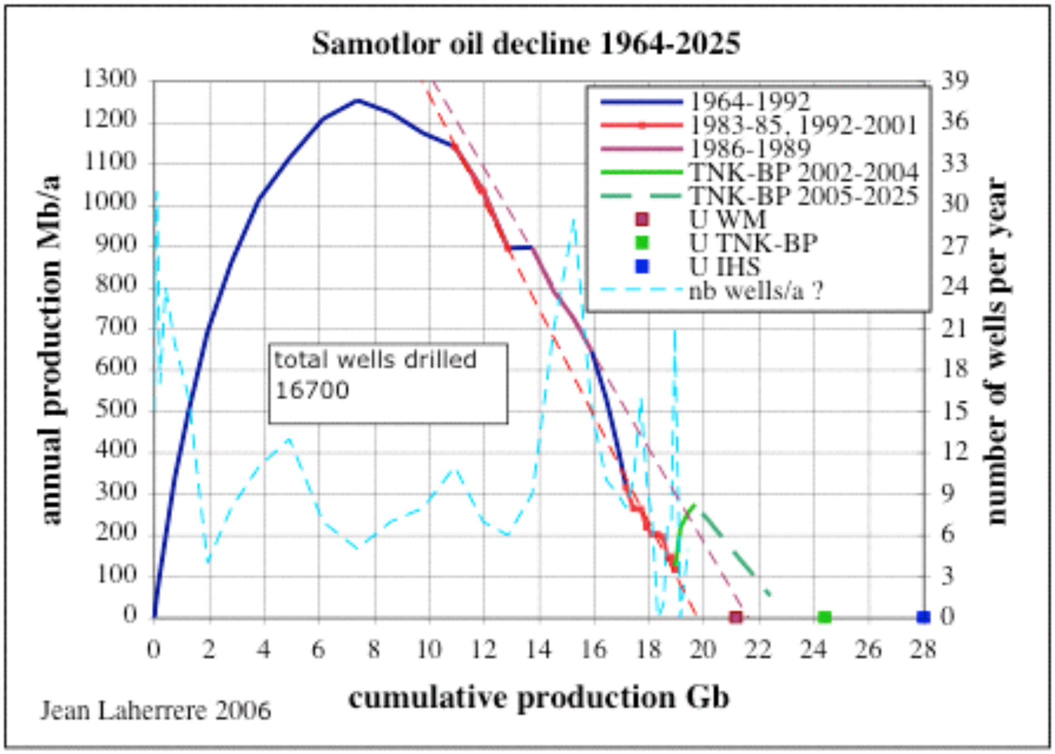
Prudhoe Bay in Alaska is estimated now with an ultimate of 12,5 Gb, when the original estimate was 15 Gb by geologists and 9.6 Gb by reservoir engineers (OGJ, Gilbert 2002).

Figure 34: **Prudhoe Bay Alaska oil production decline 1977-2005**



Russia largest oilfield Samotlor is now operated by TNK-BP with in 2003 a cumulative production of 19 Gb with 16 700 wells (IHS reports for 1964-2003 only 519 wells). TNK-BP since has increased the production with fracking, but their ultimate is 24 Gb Against 28 Gb for IHS and 21 Gb for WM.

Figure 35: **Samotlor Russia oil production decline 1964-2025 from IHS & TNK-BP**



In conclusion, there are many conventional fields showing negative reserves growth and few fields showing a sure positive reserves growth. The addition of a large number of the 2P field estimates should show statistically no change with time if estimate was correctly done

But every reported growth not shown on the decline versus cumulative is simply bad estimate or bad reporting.

But unconventional fields have to be considered differently from conventional fields.

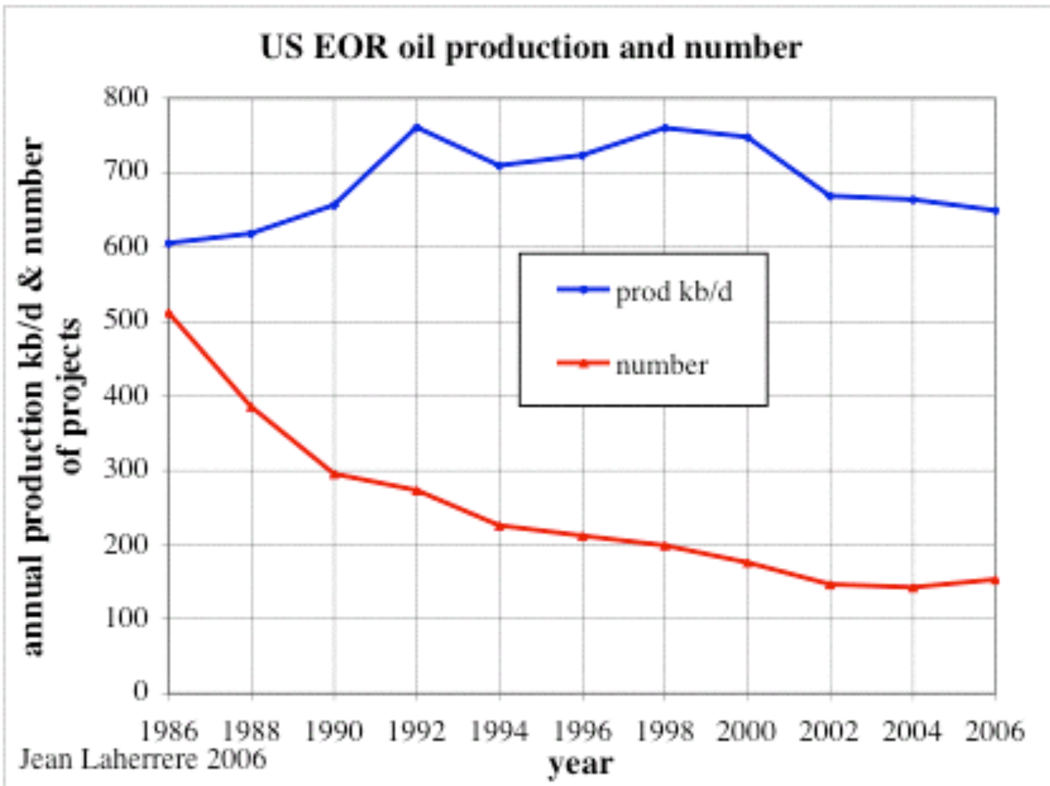
-Unconventional oilfields

-EOR (Enhanced Oil Recovery)

EOR is defined as non-conventional and EOR growth should not be applied to conventional (water and gas injection increasing only the pressure) reserves.

EOR or tertiary recovery changes the characteristics (outside pressure) of the fluids (oil or water) using steam, heat, gas miscible, chemicals, bacteria or even fire (combustion or nuclear bombs). EOR has been used since a long time, mainly in the US, but also in Algeria with Hassi Messaoud (miscible gas). In the 2005 seminar OAPEC-IFP, G.Fries IFP ("Additional reserves: the role of new technologies. A global perspective on EOR-

IOR") defined secondary recovery as only water injecting, which usually covers also gas injection when to maintain pressure. He reports for EOR only 1.8 Mb/d (67% thermal, 19% miscible gas, 12% CO2, nitrogen and chemical less than 1%), when E.Robein Total ("Technology for optimized EOR investments and benefits") reports 2.5 Mb/d (60% thermal, 30% gas and 10% chemicals) compared to 1 Mb/d in 1980 (70% thermal and 30% gas). It is about the same order as the world refinery gain, which is 1.9 Mb/d and neglected by most in the oil production. There are 307 active EOR projects with 125 with steam and 16 with in situ combustion.
US EOR has peaked in 1998 and the number of projects is in decline since 1986 (counter shock). Increase in oil price has not increase EOR production.
Figure 36: **US EOR production from OGJ surveys 1986-2006**

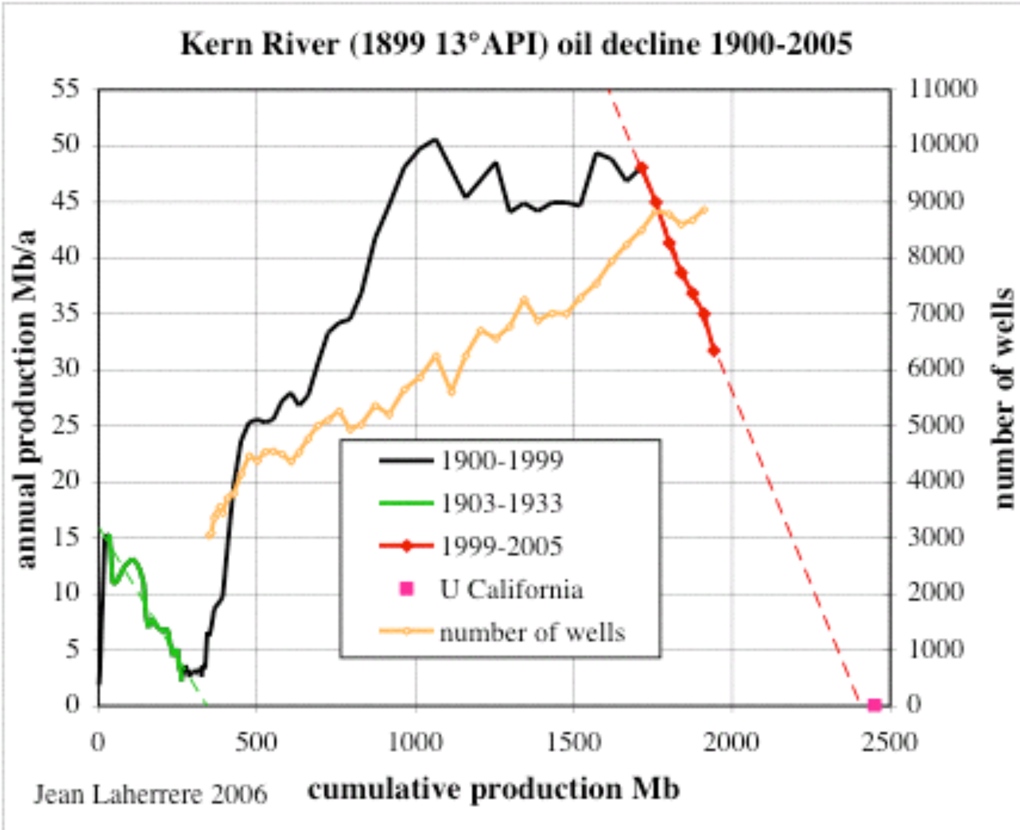


Few EOR projects work on special fields (Farouq SPE 2003 "Projections of EOR production") and when successful cannot be used to be extrapolated to every conventional fields.

-EOR with steam

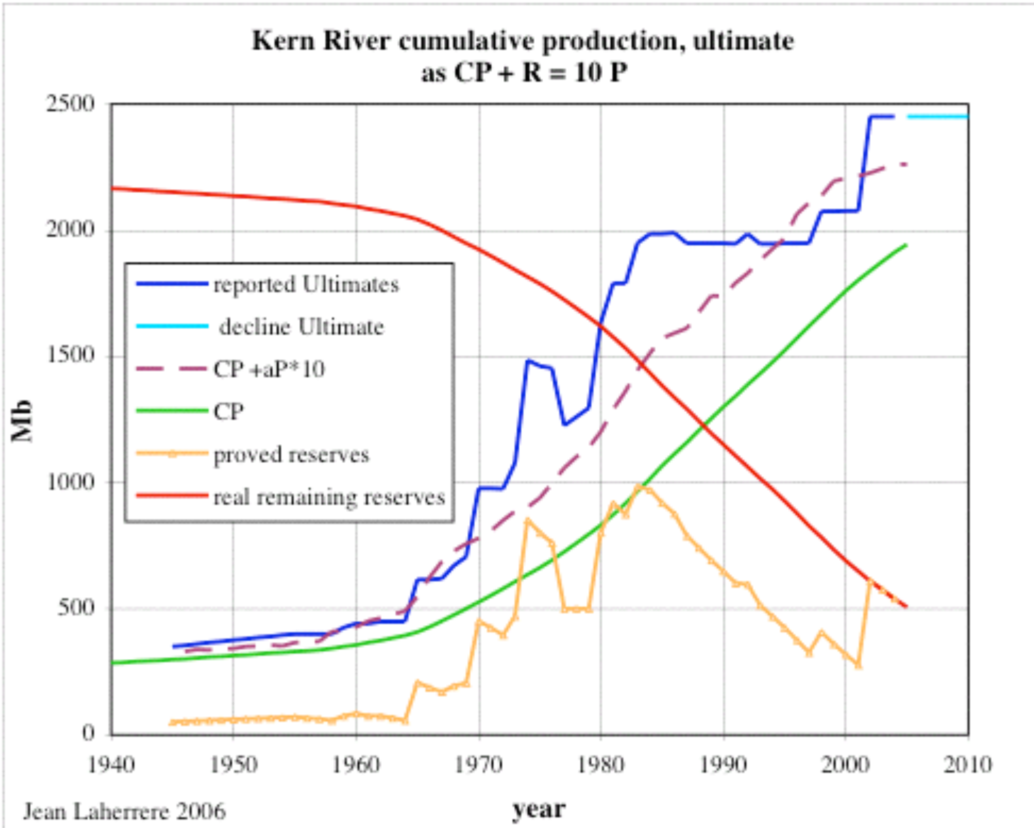
Wilmington (figures 27 & 28) oil recovery was not improved with steamflooding.
As for steam many heavy oilfields in California use it as Kern River (13°API) which peaked in 1999 exactly 100 years after discovery, because production was increased by drilling more wells for injecting steam. The decline started in 1999 (7%/a) trending towards an ultimate of 2.45 Gb which is the value given by the California state oil agency.

Figure 37: **Kern River oil decline 1900-2005**



The cumulative production is plotted (using the excellent report by M.Tennyson 2005 USGS Bul. 2172-H) as the ultimate recovery (being cumulative production + proved reserves). The cumulative production plus one tenth of annual production is plotted (assuming that R/P = 10 years) and it is striking to see that the trend is similar. In fact proved reserves were increased only when R/P started to be less than 10.

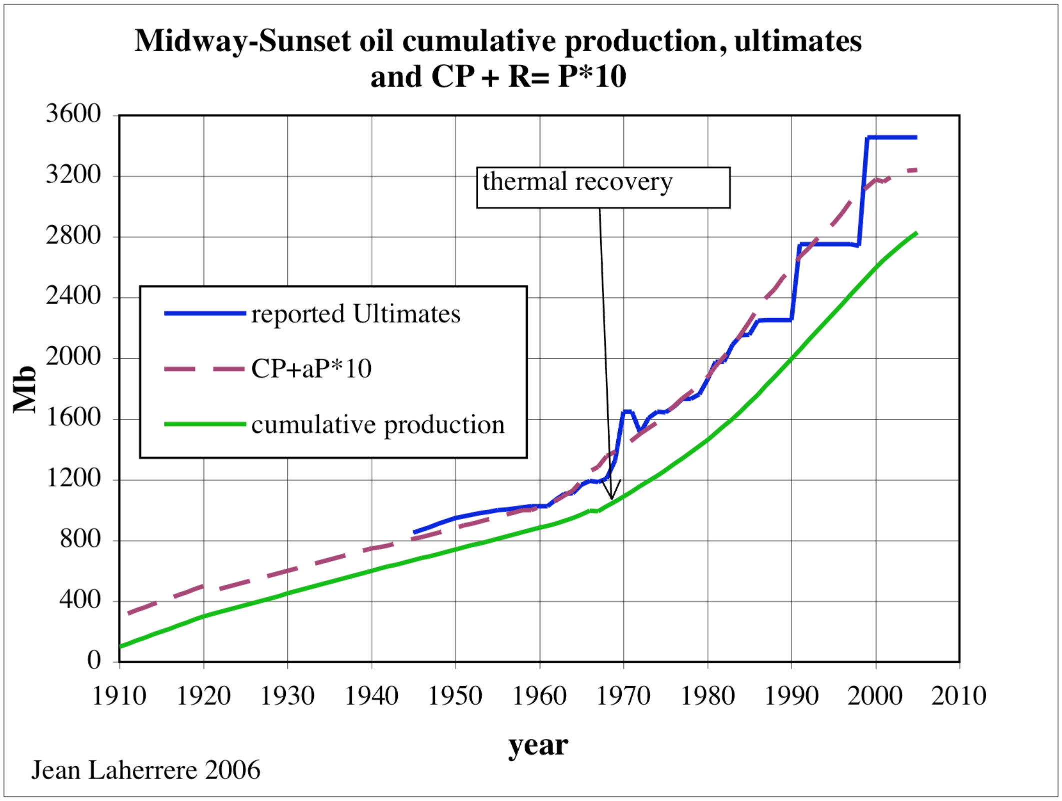
Figure 38: **Kern River cumulative production and reported ultimates as CP+R=P*10**



This graph shows that, in the old days, proved reserves were estimated in a primitive way, using mainly a R/P value, ultimate was increased only because drilling more wells, and **proved reserve growth is mainly due to poor reporting**.

We did the same plot for Midway-Sunset found in 1894, same basin and same heavy oil.

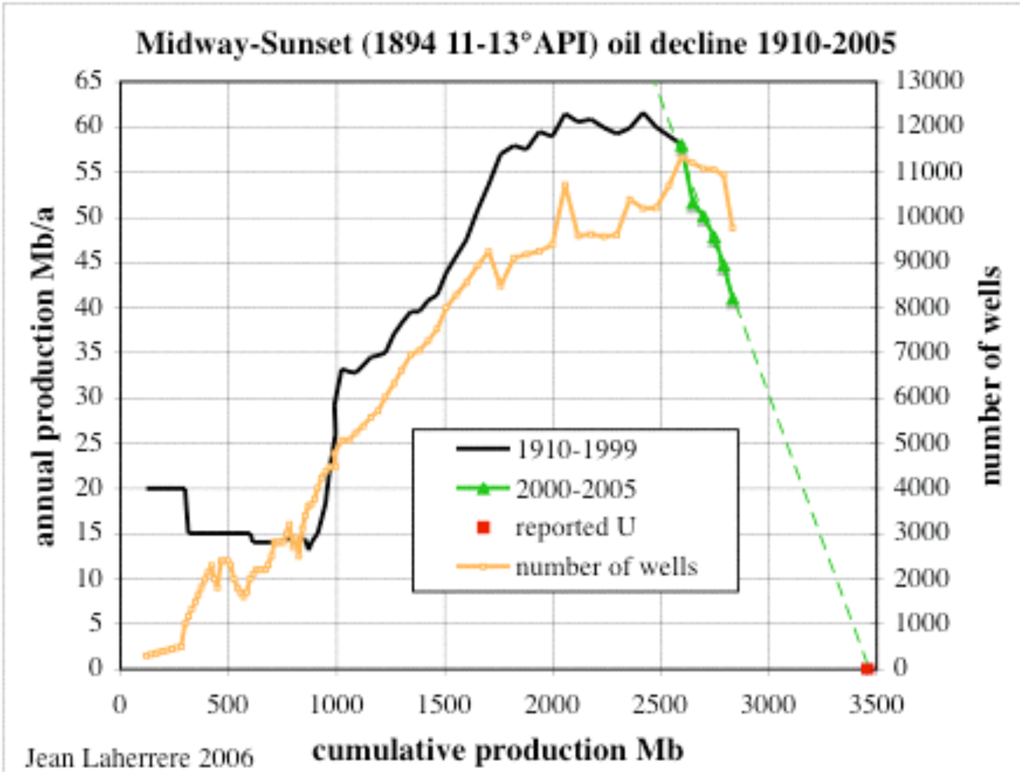
Figure 39: **Midway-Sunset cumulative production, reported ultimates as CP+R=P*10**



It is the same conclusion proved reserves were estimated as being close to 10 P, ultimate been changed only when R/P was less than 10

Midway-Sunset oil decline occurs in 2000, 106 years after its discovery, because the number of producing wells did increase up this date, the decline is about 7%/a (as Kern River) towards the now reported ultimate of 3457 Mb.

Figure 40: **Midway-Sunset oil decline 1910-2005**

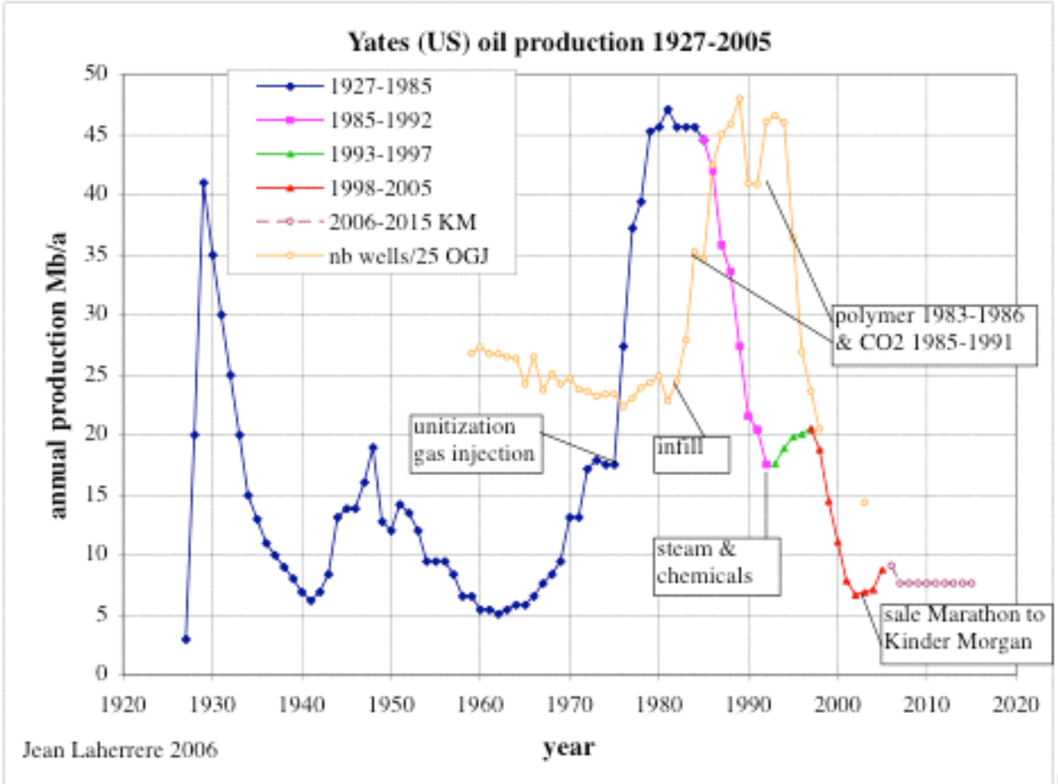


-EOR with CO2

There are many papers on the potential of using CO2 to increase oil reserves. CO2 was used for a long time in the US

Yates (Permian basin in Texas) oil production has several peaks, the first one in 1929 quickly after primary depletion, a minor one in 1948 and the third in 1981 after unitization and gas lift the third one in 1998 after chemicals and CO2 injection

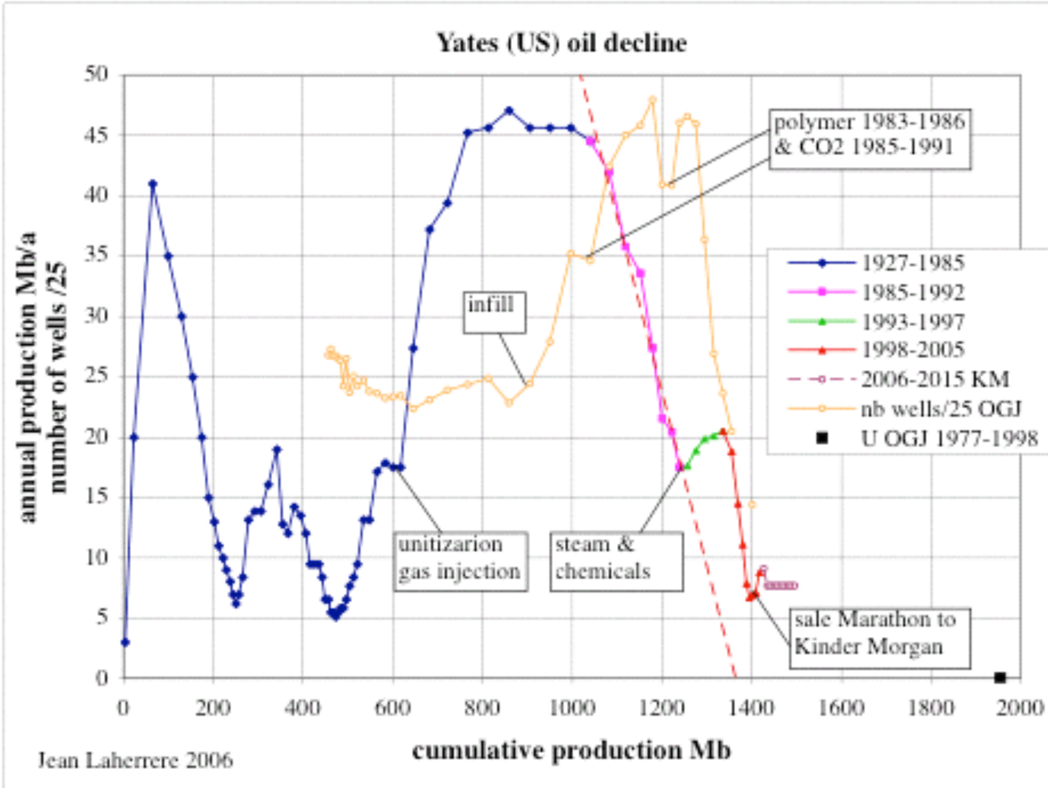
Figure 41: **Yates oil decline 1927-2005 versus time**



Marathon, after several attempts of EOR (chemicals and CO2), sold Yates to Kinder Morgan, which, as Apache in Brent, will increase drilling, but it could be a temporary improvement.

The cumulative production to end 2005 is about 1.4 Gb when the ultimate was reported by OGJ from 1977 to 1998 at 1.95 Gb. The decline versus cumulative production trends at the most towards 1.6 Gb.

Figure 42: **Yates oil decline 1927-2005 cumulative production**

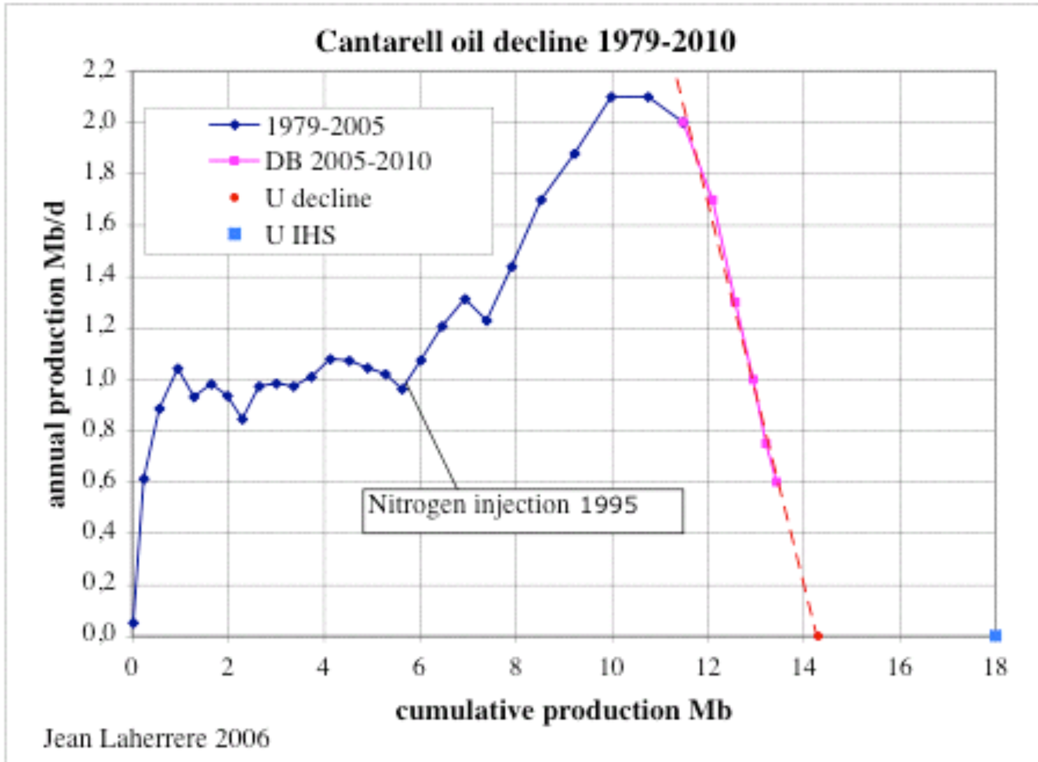


Nehring in OGJ 3, 17, 24 April 2006 claims *Hubbert's unreliability* on the example of the Permian basin estimates based on the lack of recognizing reserve growth, but he estimates Yates ultimate at 2 Gb (close to OGJ), meaning over 500 Mb remaining reserves; estimate which looks unrealistic from the previous graph, because the operator plans to stay at 8 Mb/a for the next 10 years. With Nehring's estimate this plateau should have to continue for over 70 years. In contrary, I expect a future negative reserve growth for Yates, as for East Texas. The sale of Yates by Marathon to Kinder Morgan (as by BP for Brent) announces that the end is close! Nehring, as the SEC, refuses the probabilistic approach, they are 30 years behind! It is the proved reserves, which are unreliable!

-EOR with nitrogen

The largest oilfield in Mexico Cantarell has been enhanced since 1995 with a very expensive nitrogen injection. But the peak has come in 2004 and Deutsche Bank forecasts a sharp decline, trending towards an ultimate of less than 15 Gb when IHS reports 18 Gb and WM 18 Gb oil + 1 Gb condensate

Figure 43: **Cantarell oil decline 1979-2010 from Deutsche Bank**



All the previous graphs are a good demonstration that the US proved reserve growth is due to the obsolete SEC rules and that US proved 1P reserve growth function on old fields cannot be applied on new US fields and absolutely not on the rest of the world 2P reserves.
USGS 2000 world estimates are definitely too old (as end of 1995) and too unreliable on reserve growth to be quoted by reliable authors.
USGS 2000 forecasted for the period 1996 to 2025 that US oil and NGL reserve growth will be 76 Gb (25.3 Gb/10 years) and undiscovery 83 Gb (27,7 Gb/10 years). The USDOE annual reports for the period 1996 to 2004 reports reserve growth (revisions + adjustments) of 8.2 Gb (9.1 Gb/10 years) or **36%** of USGS forecast and total discoveries (extension +new field +new reservoir) of 16,8 Gb or **60%** of USGS forecast. The next 20 years is not supposed to catch the deficit!
USGS 1996-2025 estimate is not confirmed by the last 9 years results, in particular for reserve growth.

-Impact of technology

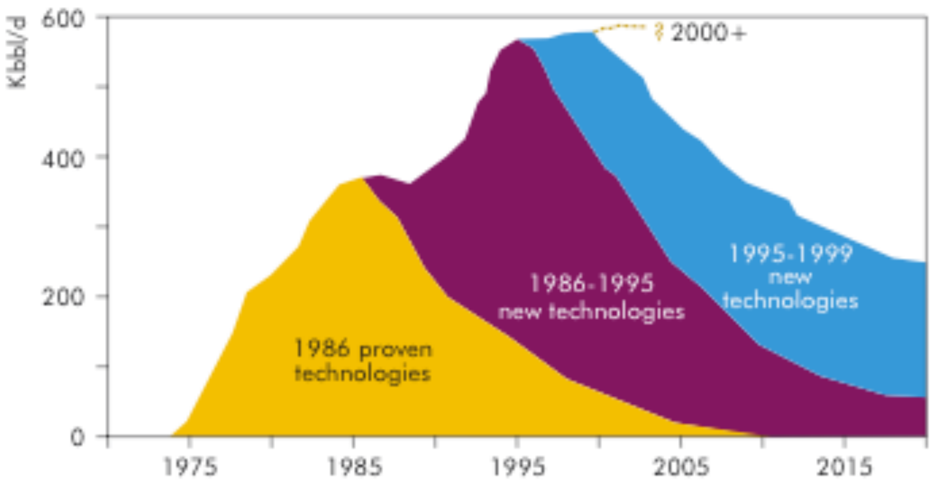
-Manipulated graphs

It is interesting to find that major companies or official agencies which claims that peak oil is decades away, quote always old works by others, never their own.
Exxon-Mobil 2006 quotes USGS 2000 (10 years old as being at end of 1995), Shell in 2002 quoted EneRG (1999), IEA in 2005 quoted Shell 2002! IFP quotes Wood Mac!
Is it to say, if found wrong, that it is not their works?

IEA in May 2005 *Resources to reserves* claims that reserve growth is due to technology, justified by a flawed North Sea old graph published by Shell 2002 coming from *European Network for Research in Geo-Energy* (unknown report 1999?), and badly drafted (wrong scale: 0.6 Mb/d instead of 6 Mb/d)

Figure 44: **May 2005 IEA graph titled *Impact of technology on production from the North Sea* quoting Shell**

Figure 1.20 • *Impact of technology on production from the North Sea, in thousand barrels per day*



Source: European Network for Research in Geo-Energy - ENeRG - courtesy of Shell.

There is a curve suggesting that 2000 will add more production but in fact the blue line to 2005 represents the reality as shown by figure 45 (below).

The 1988 trough is partly due to Piper Alpha oilfield blow out (160 dead) and Brent oilfield works for gas repressuring as shown in Tzimas et al "Enhanced oil recovery using carbon dioxide in the European Energy System" 2005

Figure 45: **North Sea oil production from Tzimas 2005 showing that the trough is mainly due to the collapse of UK two fields (in brown and light blue)**

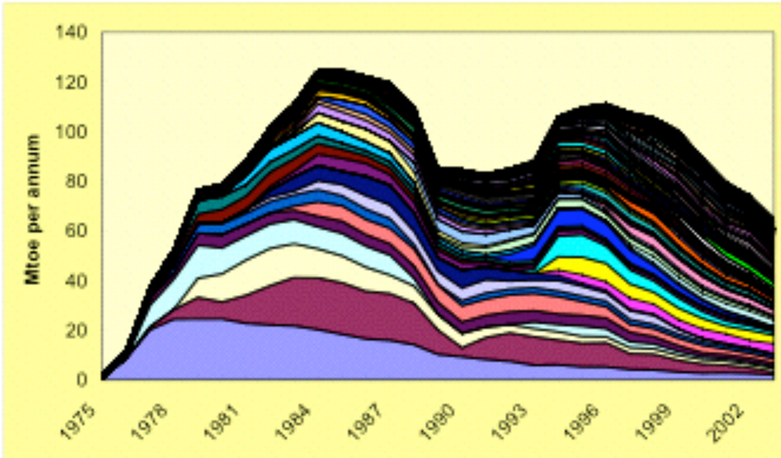


Figure 4.2 : North Sea oil production, UK sector excluding West of Shetland. Different colours represent different fields.

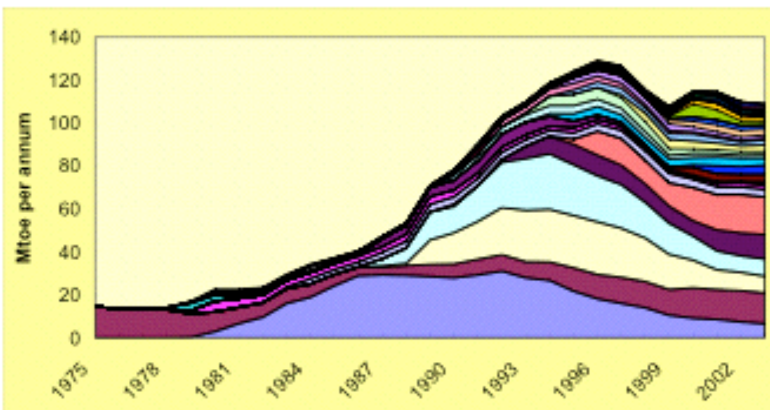
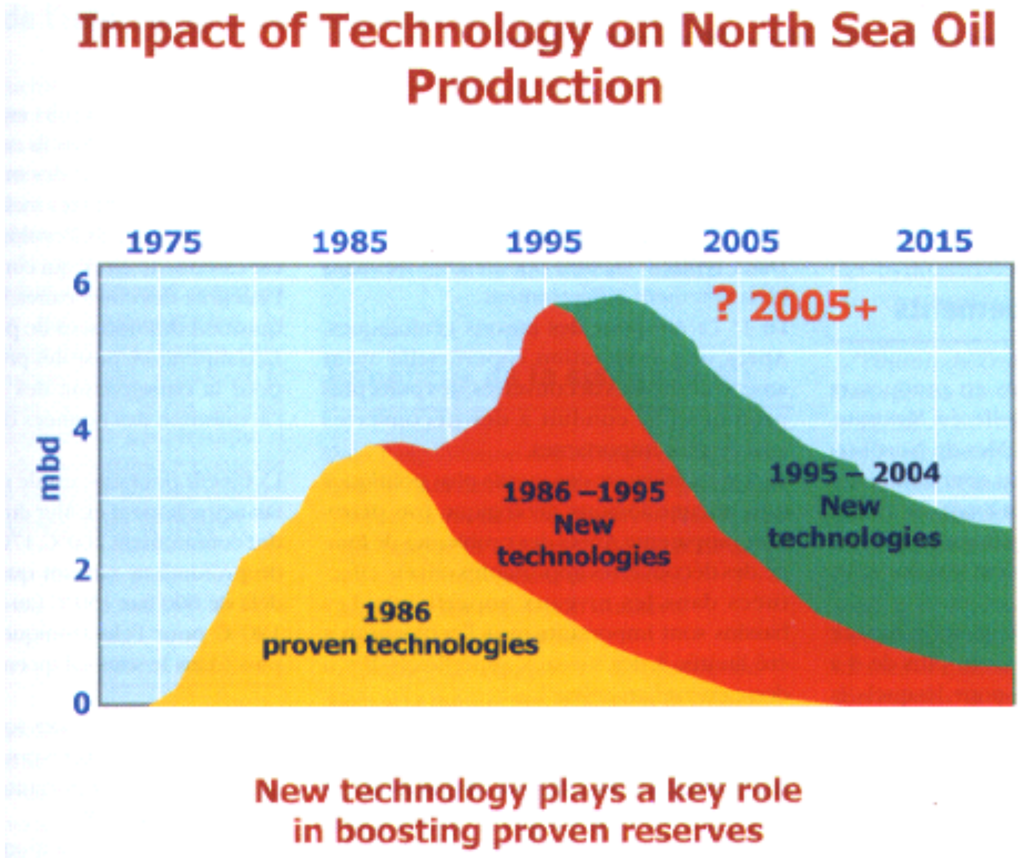


Figure 4.3: North Sea oil production, Norwegian sector excluding Norwegian Sea. Different colours represent different fields.

IEA shows in October 2005 (*Jan. 2006 Petrole & Gaz Information p.19)* the same May 2005 graph but redrafted by replacing 1999 by 2004 (!!) and suggesting a good surprise thanks to 2005+? In the same bulletin p.84, Shell (Rodriguez) displays exactly the same graph as IEA but without the IEA change of 1999 by 2004 and 2000 by 2005. It is amazing to see such manipulation!

Figure 46: **October 2005 IEA (Pochettino) graph titled *Impact of technology on production from the North Sea,* changing dates, but Shell is not anymore quoted**



North Sea oil production has peaked in 1999 and the green line is right down to 2005 as shown on figure 28! It is hard to see what is bringing 2005+

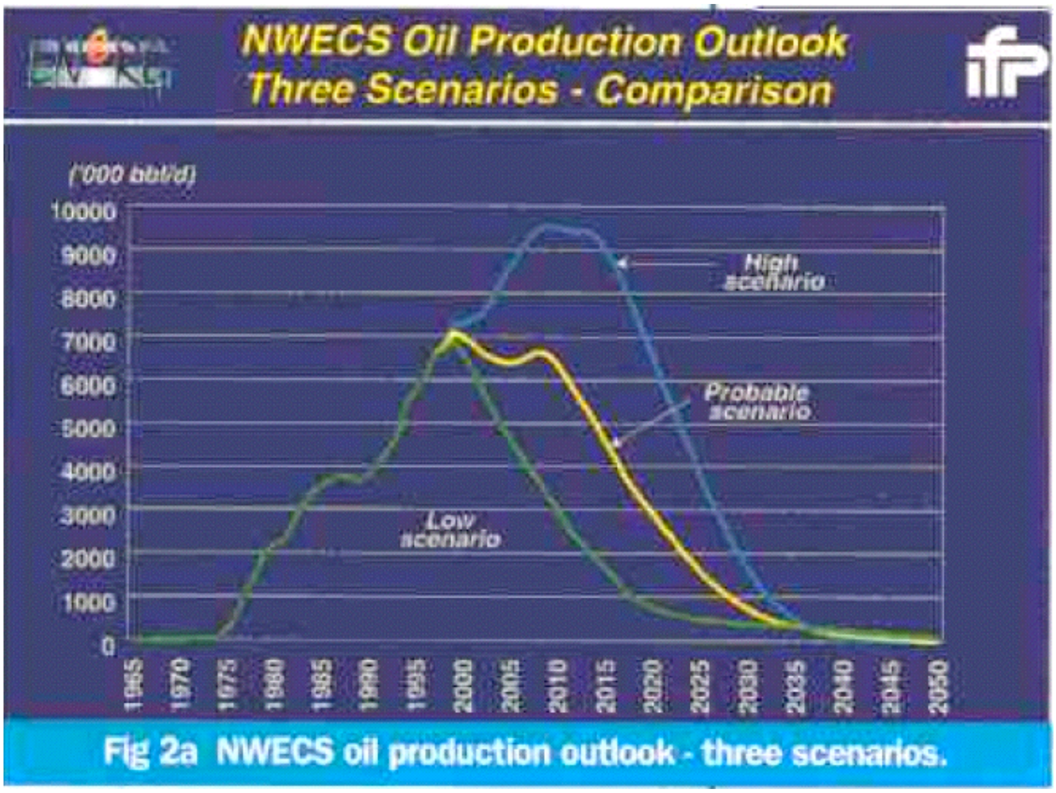
IEA display of so poor and manipulated graph to justify the impact of technology leaves to think that IEA did not find any better ones! Where are the better ones?

-"Optimistic" presentations

Wishful thinking are presented as the most probable scenario and the most likely forecast is presented as the minimum scenario

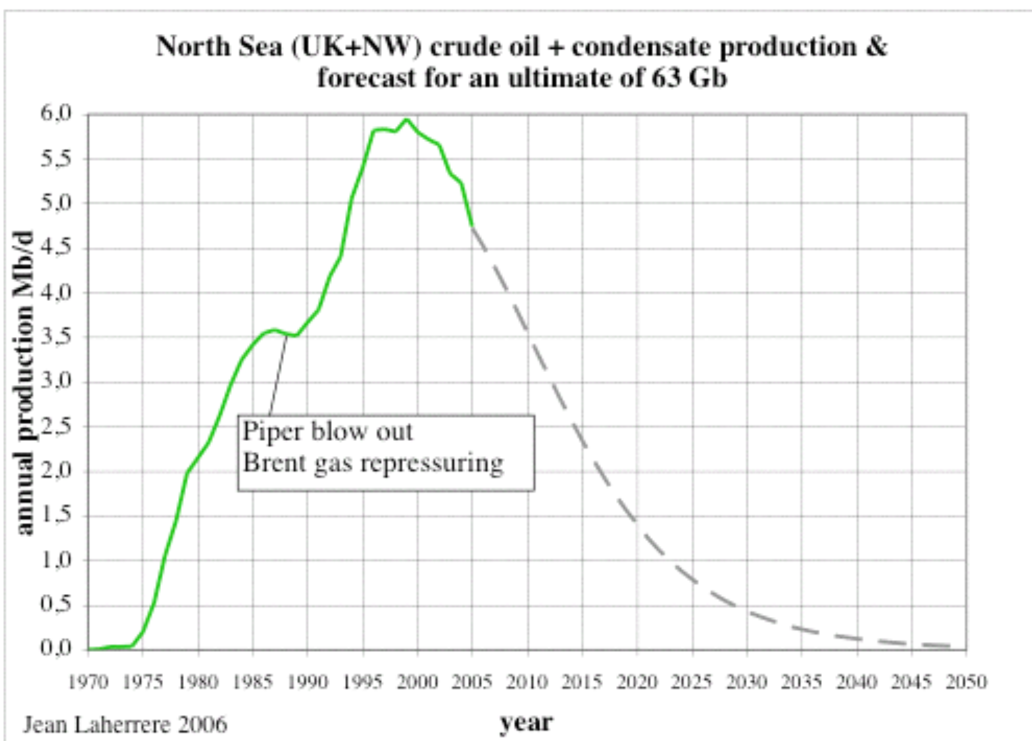
European Network for Research in Geo-Energy gathers the research centres in Europe. ENeRG newsletter Feb 1998 "North Sea oil and gas production outlook- a major challenge" claimed that North Sea production will be delayed by 10 years!

Figure 47: **North Sea Oil production Scenarios IFP 1998**



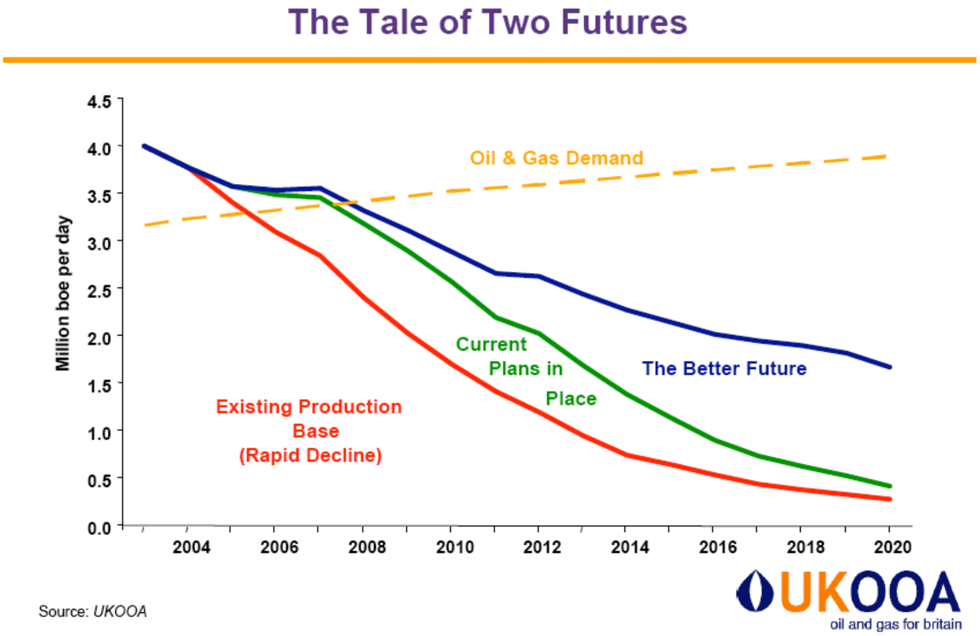
Production has peaked in 1999 at 6 Mb/d and follows as end 2005 exactly the low scenario being at 4,7 Mb/d, when the probable scenario forecasted 6,3 Mb/d (+ 35%)

Figure 48: **North Sea (UK+NW) oil production at end 2005 with forecast for an ultimate of 63 Gb**



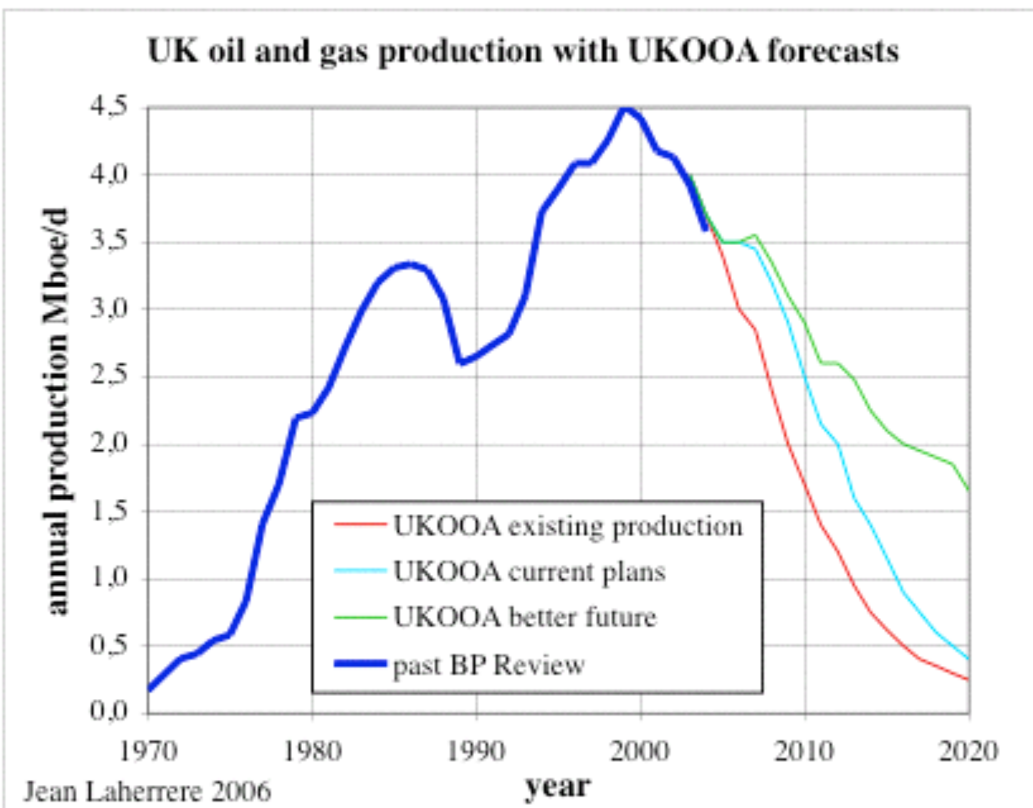
UKOOA M.Webbs «The future for Britain's oil and gas» 29 April 2005

Figure 49: **UK Oil & Gas production forecast from 2005 UKOOA 2003-2020**



The past data (from BP Review) is plotted together with UKOOA forecasts.

Figure 50: **UK Oil & Gas production as UKOOA forecasts 1970-2020**

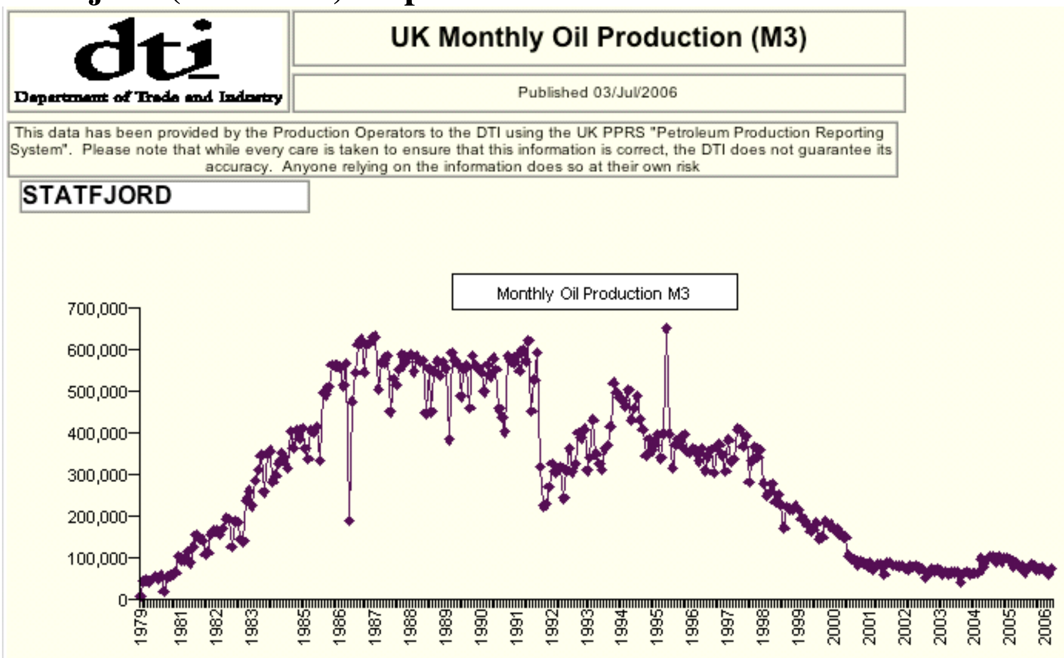


-Claim on Statfjord

Statfjord is shared between UK and Norway, but operated by Statoil.

From DTI

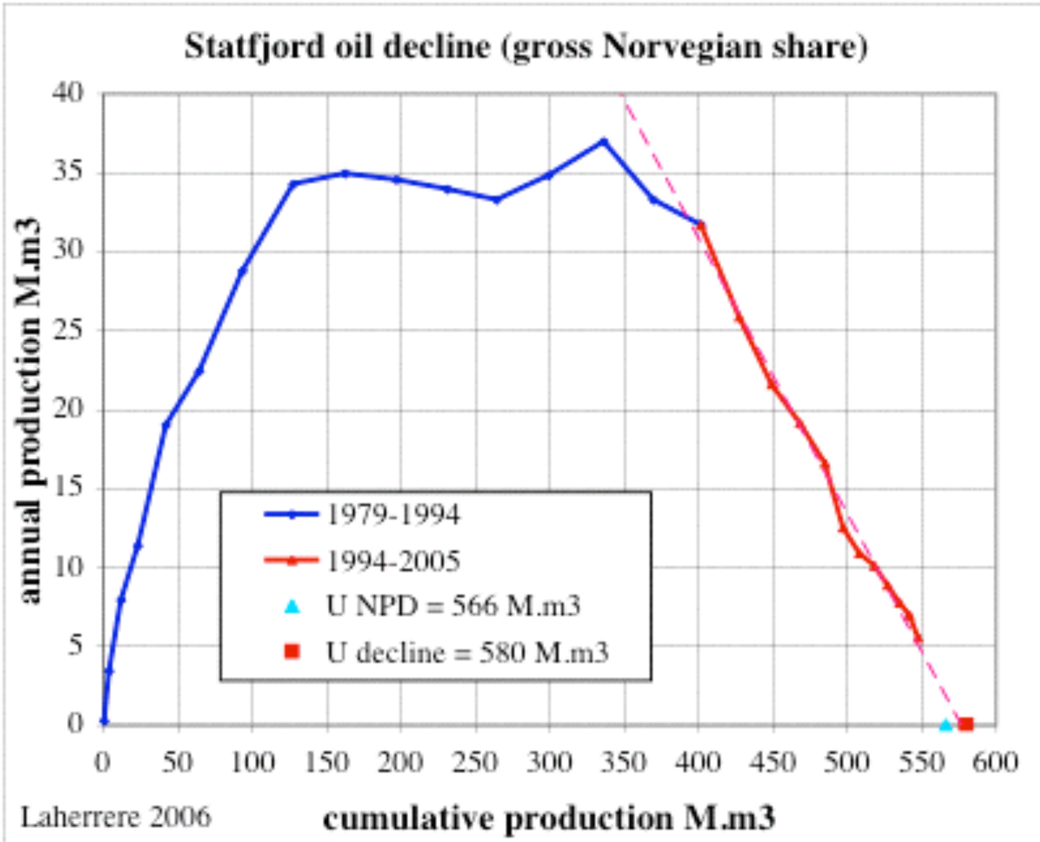
Figure 51: **Statfjord (UK share) oil production from DTI versus time**



From NPD

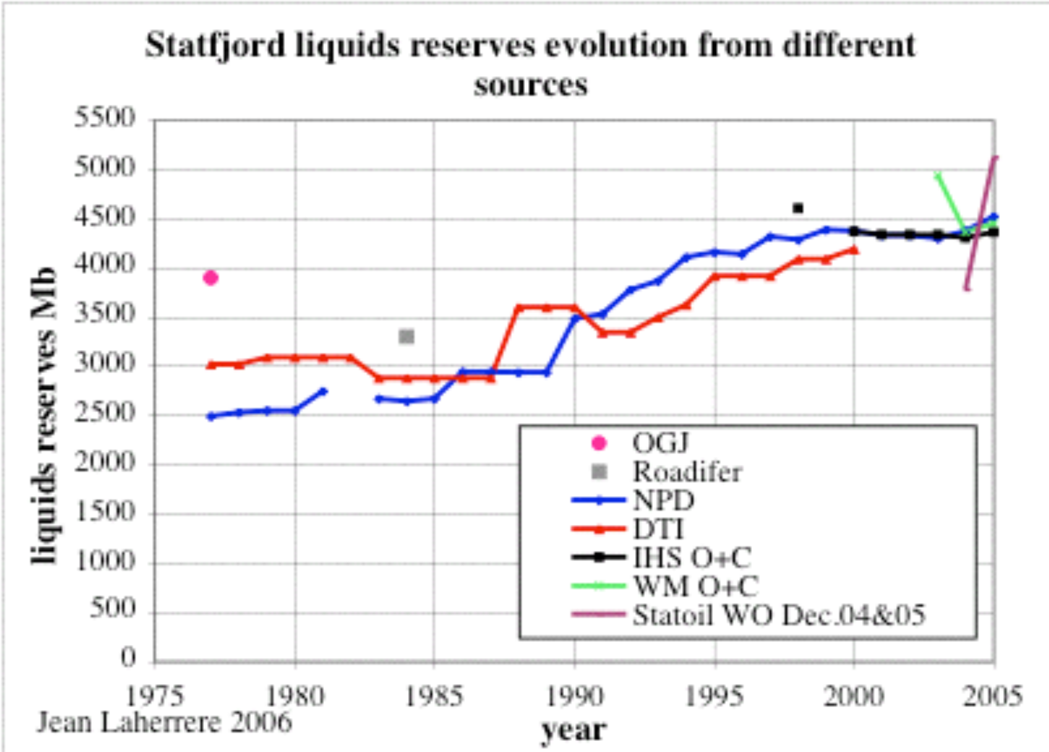
The annual production versus cumulative production displays a straight decline since 1994.

Figure 52: **Statfjord (Norway share) oil production from NPD versus cumulative production**



There are claims that improved recovery is occurring on Statfjord, but these claims are confusing! In World Oil (WO) December 2005, CEO Statoil T.Overvik stated that Statfjord has recovered **64 % of 8 Gb oil in place** (OIP), compared to 48 % in 1979, hoping to reach 70% in the future. But in WO December 2004 Overvik stated having produced **63 % of 6 Gb OIP**. Is the change of OIP a typing mistake or is OIP a wild guess?
IHS reported, in 1998, an OIP of 6.3 Gb with oil+condensate (O+C) 2P= 4,60 Gb giving a recovery factor of 73 % and, in 2005, an OIP of 6.1 Gb with O+C 2P=4,36 Gb giving a RF of 72 %. IHS does not see any improvement in recovery factor, being already very high in 1998!

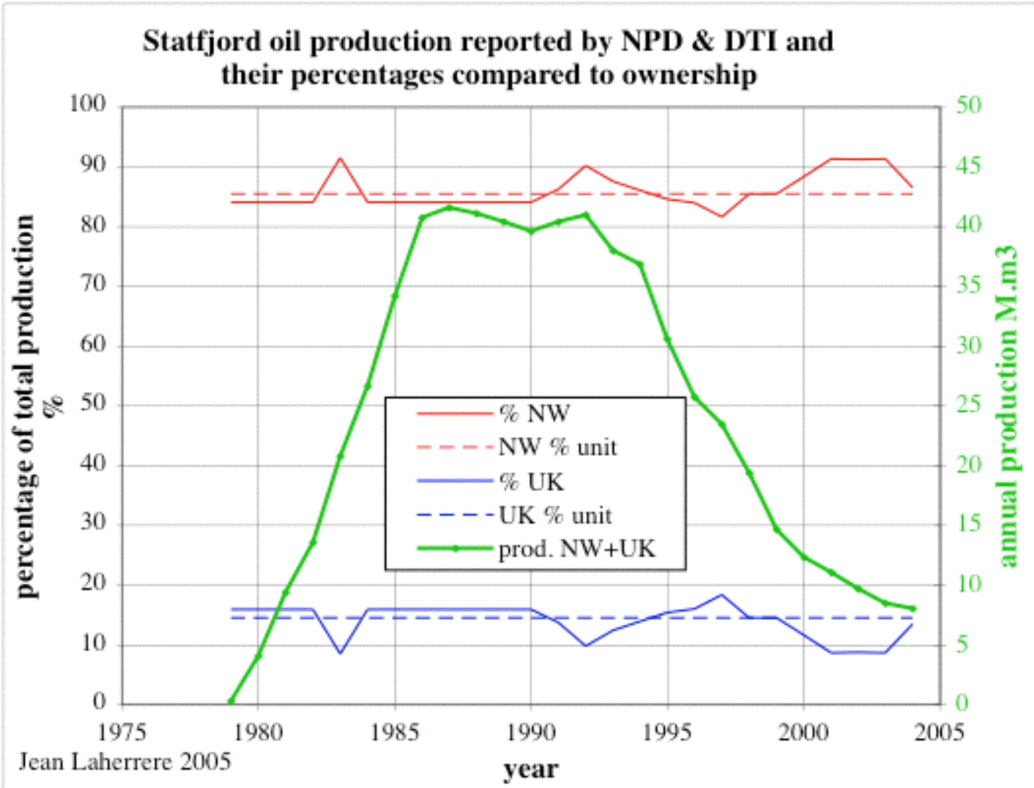
Statfjord reserves estimate reported by different sources (DTI Brown Book, NPD, IHS, WM) show an increase from 1985 to 2000, but none since except in Statoil 2005 CEO statement with WO.
Figure 53: **Statfjord liquids reserves evolution from different sources 1977-2005**



But the comparison between NPD and DTI production data gives an interesting result. The percentage of each country from the total UK + Norway does not fit exactly the percentage of the unitized field (85.47% for Norway and 14,53% for UK). During some time a country receives more than its share and this is partly compensated later. Cumulated at end 2004 Norway got 85.65 % instead of 85,47 %!

Is it bad reporting or bad sharing? This kind of discrepancy should be stated by NPD, which is assumed to be a reliable source.

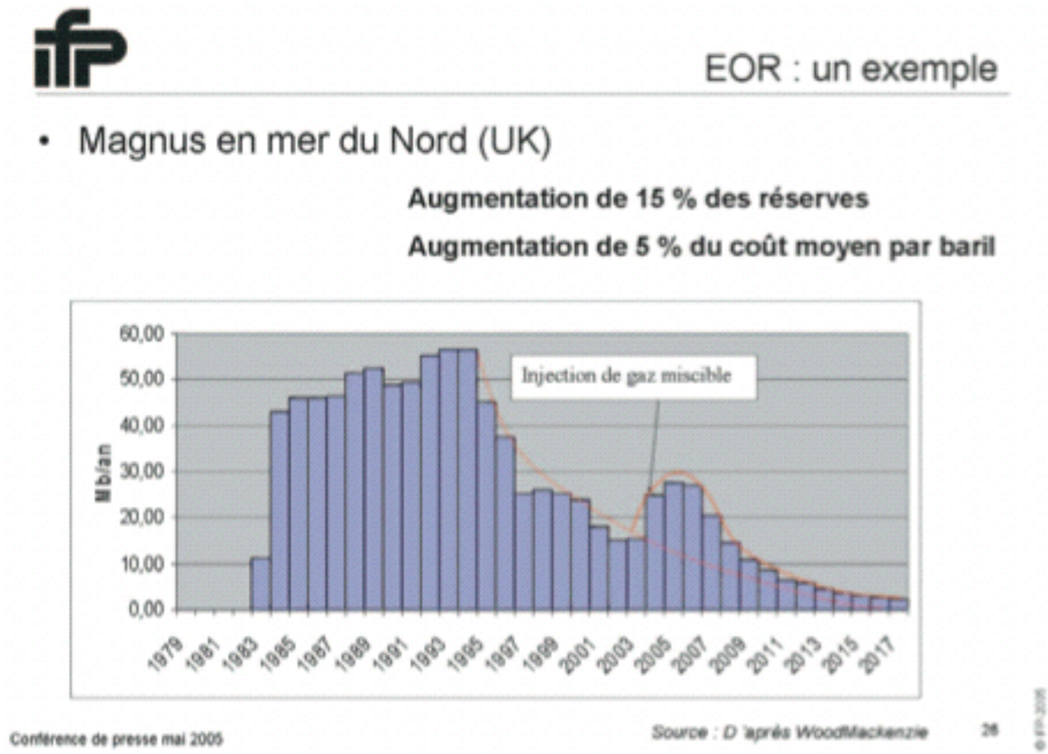
Figure 54: **Statfjord total production reported by DTI and NPD and their percentage compared to ownership**



-Claim on Magnus

IFP press conference 31 Mai 2005 ("Comment accroitre et renouveler les reserves de petrole et de gaz? - Avancees de la technologie et strategie de recherche de l'IFP" O.Appert, J.Lecourtier, G.Fries) claims that Magnus will increase production in 2005 with EOR (miscible gas).

Figure 55: **Magnus oil production forecast from IFP quoting Wood Mac**



The miscible gas Magnus project (420 M$) using the stranded gas from Foinaven and Schiehallion oilfields carried out in 2002 was assumed to increase the production significantly in 2005 and the reserve by 50 Mb

Figure 56: **Magnus EOR (miscible gas) scheme**

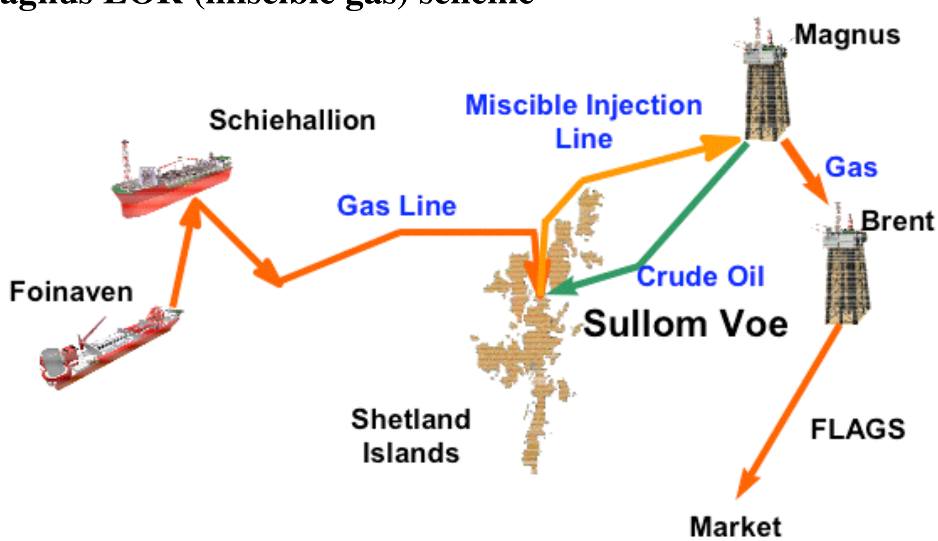
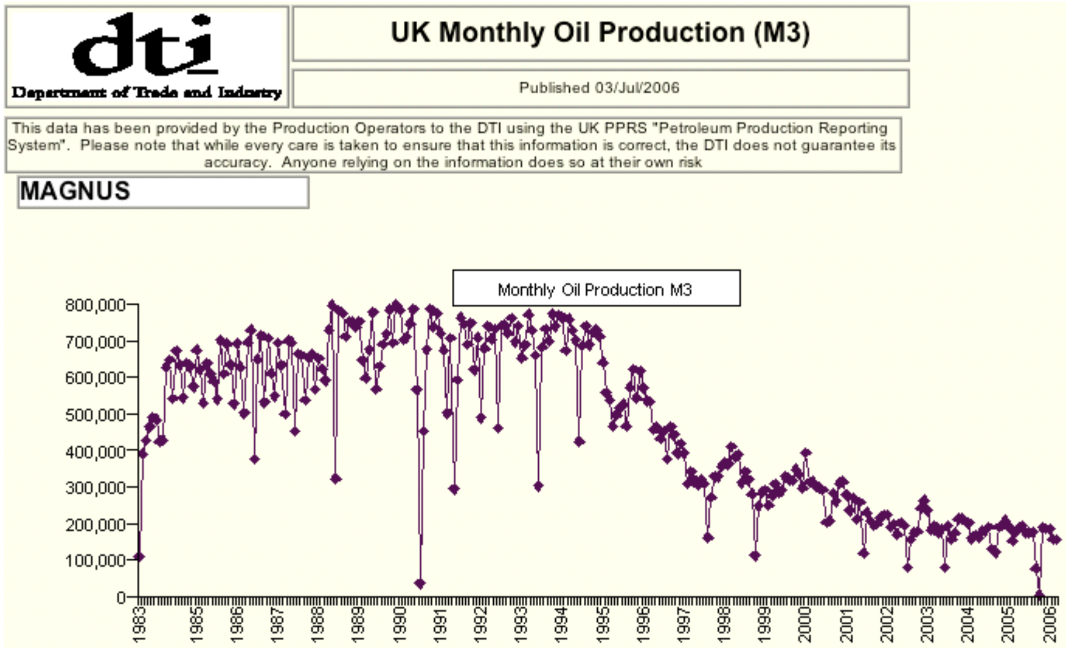


Figure 20: Schematic of Magnus EOR project.

The expected increase in 2005 did not show on DTI oil and gas production profiles.

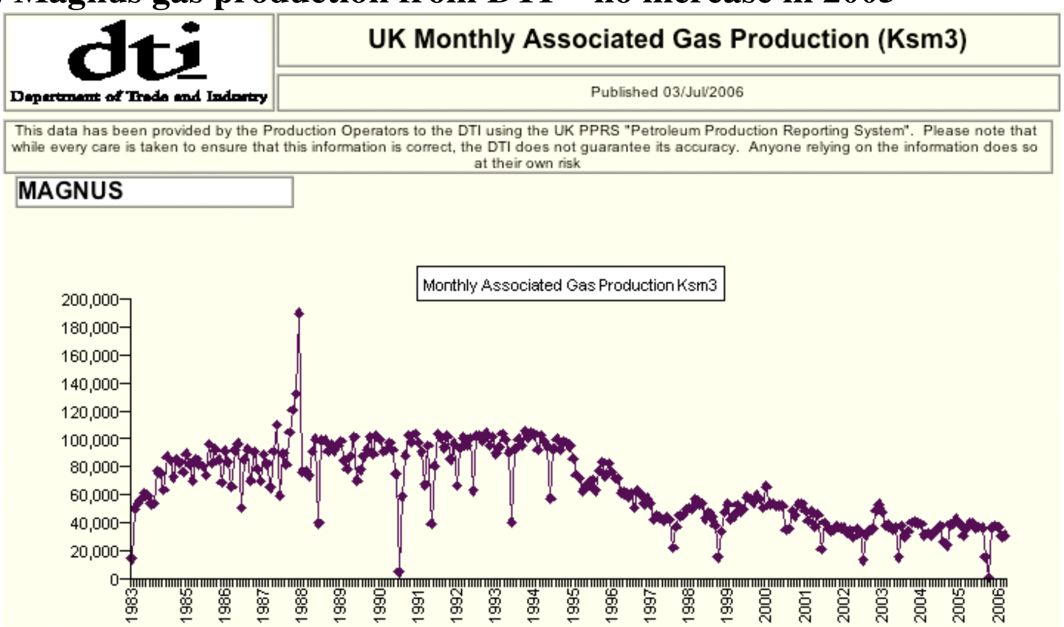
Oil production

Figure 57: **Magnus oil production from DTI = no increase in 2005**



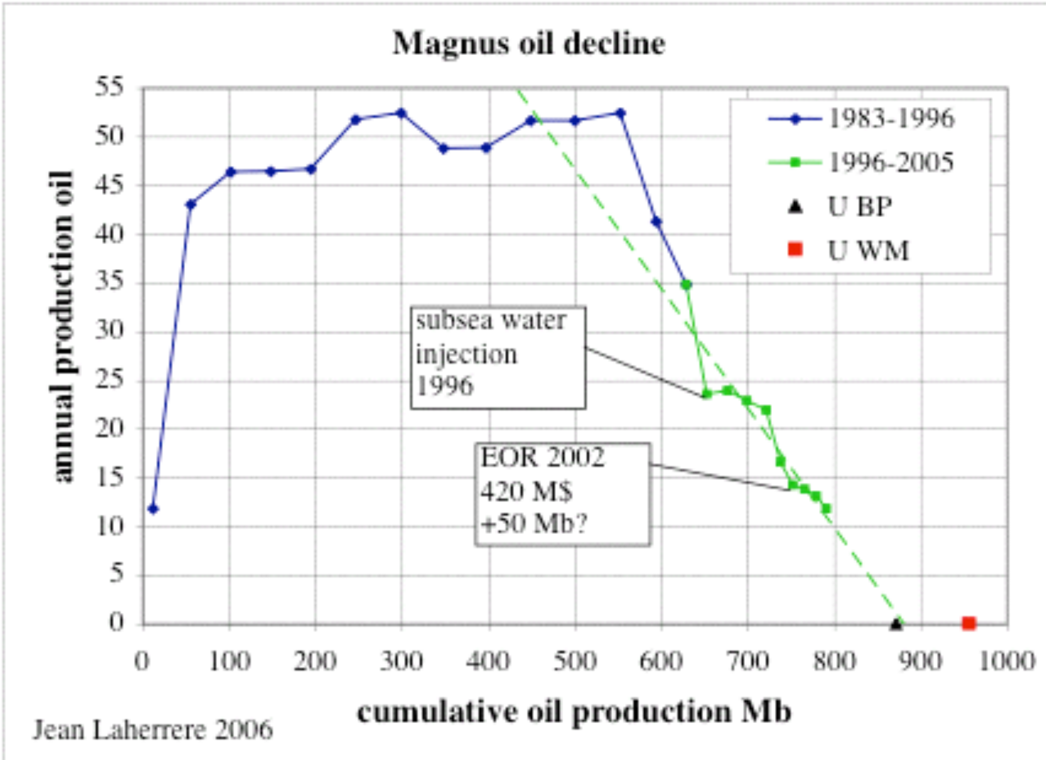
Neither in the gas production

Figure 58: **Magnus gas production from DTI = no increase in 2005**



The oil decline versus cumulative does not show in 2005 any significant reserve growth, the decline is in line with the value reported by BP (DTI). Only WM seems to believe IFP claim.

Figure 59: **Magnus oil decline showing no obvious increase in oil reserves**



Again the IFP claimed positive reserve growth is likely not to occur!

Technology (mainly multi-branch horizontal wells) is now used in conventional fields to produce faster and cheaper to get maximum profit, often detrimental to maximum recovery (Yibal Oman, Rabi-Kounga Gabon)
Few reserve positive growth occur in exceptional reservoir conditions as Ekofisk (compaction of chalk reservoir and seafloor subsidence) or Eugene Island 330.
Many reserve negative growth occur near the end (East Texas, Brent).
Statistically world mean reserve estimates will show no growth at the end.

But technology is a must for unconventional fields, but the question is not the size of the tank but the size of the tap. Athabasca and Orinoco extra-heavy oils need time and labour to build plants (also energy for steam because shallow gas is not enough).

-OPEC reserve growth

On figure 8 the remaining reserves reported by OPEC members grew by 300 Gb after the oil counter shock from 1985 to 1990 when quotas were in force based on reserves. Kuwait started first by increasing their reserves by 50%, followed by the others and Saudi Arabia was the last, but the Neutral Zone owned 50/50 by Kuwait and Saudi Arabia did not report any growth because their owners did not agree on the date of increase, in contrary remaining reserves have decreased in NZ but not in Kuwait and Saudi Arabia
Remaining reserves from OGJ in Gb

	Kuwait	Neutral Zone	Saudi Arabia	NZ/(Kuw+NZ+SA)
1980	65.4	6.26	164.3	2,7 %
1985	90	5,42	169	2 %
1990	94,5	5,2	255	1,5 %
2005	101	5	264	1,4 %

From 1980 to 2005

	production	reserves	total added	wildcats	Gb/wildcat
Kuwait	16,6 Gb	+36 Gb	52,6 Gb	9	5,8
Neutral Zone	4,2 Gb	-1,3 Gb	2,9 Gb	8	0,4
Saudi Arabia	70 Gb	100 Gb	170 Gb	64	2,7
NZ/Kuw+NZ+SA	4,6 %	-1 %	1,3 %	10 %	14 %

There were as many wildcats in NZ and in Kuwait, but the addition by wildcat in the last 25 years was more than 10 times higher in Kuwait than in NZ when the two areas are close. Kuwait reserves are overestimated as recognized by PIW (Petroleum Information Weekly) recently. It seems that Saudi Arabia reserves are also overstated, as claimed by M. Simmons in his book “Twilight in the desert”. The comparison of the OGJ data and Wood Mackenzie data for remaining reserves in 2005 confirms the overestimation first of Kuwait by 200%, of Saudi Arabia by 50% and Neutral Zone by 16%:

	Kuwait	Neutral Zone	Saudi Arabia	NZ/Kuw+NZ+SA
OGJ Gb	101	5	264	1,4
WM Gb	34	4,3	174	2
OGJ/WM	3	1,2	1,5	

It is obvious that Kuwait and Saudi Arabia have increased separately their national reserves for political reasons when they kept Neutral Zone joint reserves at the right values because they were acting separately

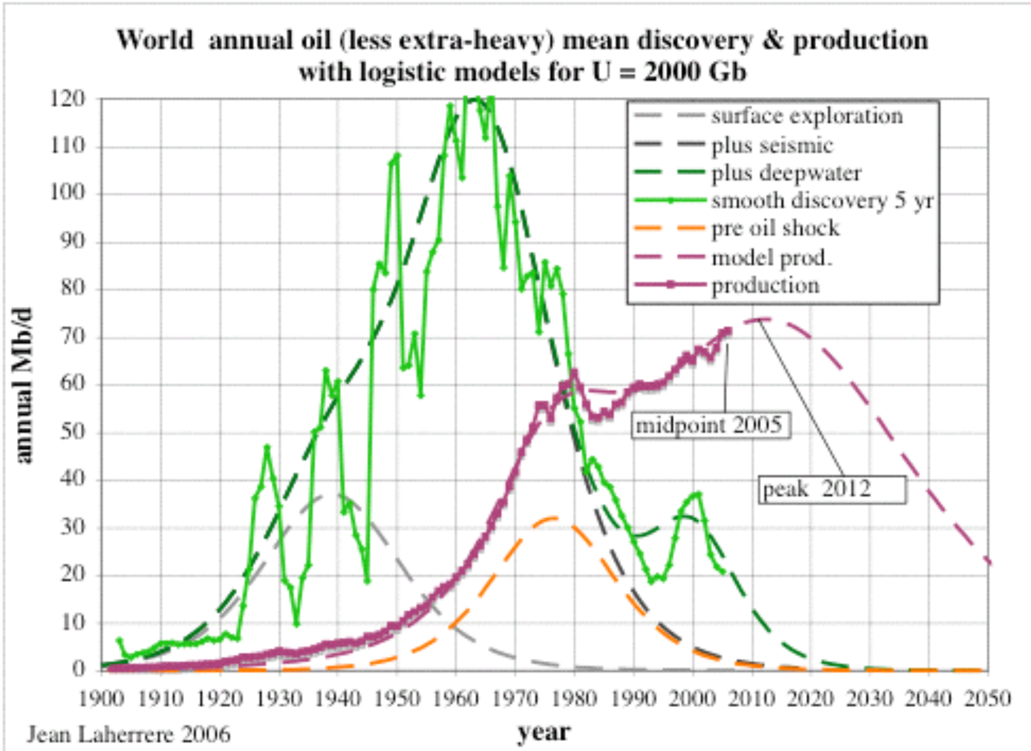
-Oil production forecasts

-World crude less extra-heavy oil production

From the above figure 13 estimating the ultimate of world crude less extra-heavy oil at 2 Tb when modelling the cumulative discovery from the technical database with three logistic curves, the annual discovery and annual production is easy to obtained.

The world annual crude less extra-heavy oil discovery has peaked around 1960 and the production will peak around 2010, if there is no demand or investment constraint. If there is some constraint from demand or investment, oil peak will be changed in a bumpy plateau!

Figure 60: **World annual crude less extra-heavy oil mean discovery and production with logistic model for U = 2000 Gb** (no demand or investment constraint)



The last minor oil discovery peak in 2000 was due to deepwater

-World "oil" production

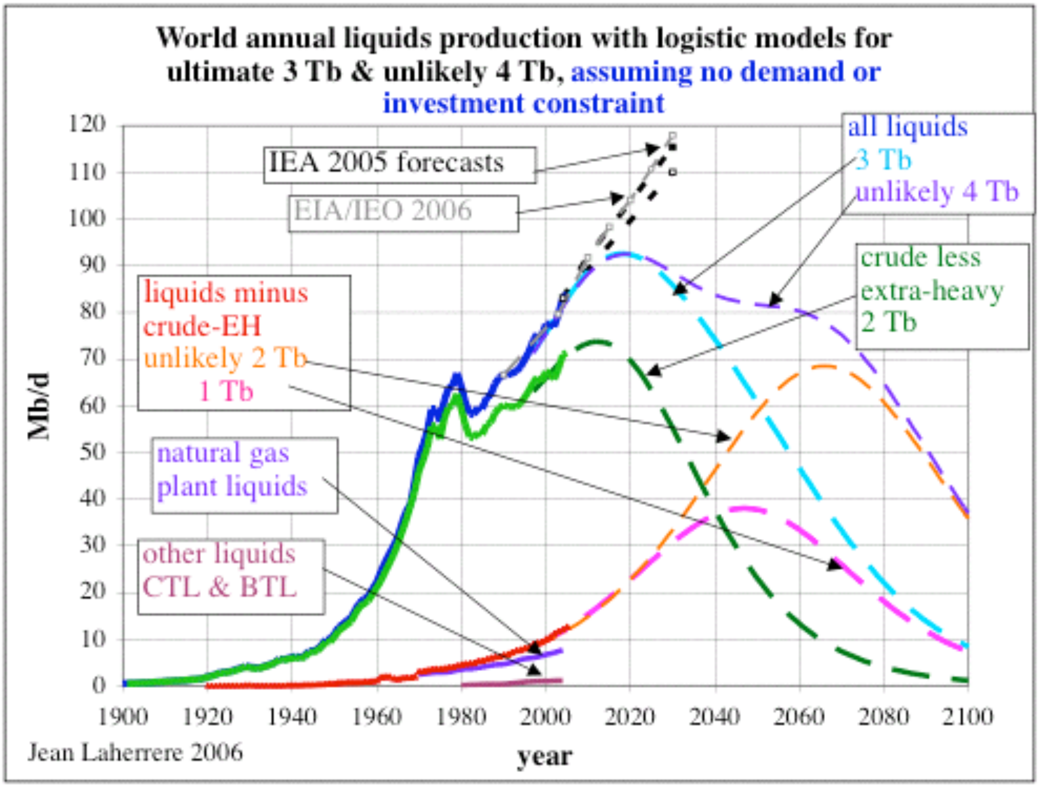
In our 1998 Scientific American paper, we (Campbell and myself) were considering only conventional oil and we realize later that our forecast was far from the oil demand, which includes all liquids.

As already stated, world oil demand is not filled only by crude oil (73 Mb/d) and natural gas liquids (7 Mb/d), but also by synthetic oils (upgraded bitumen from mining, GTL, CTL (coal) and BTL (biomass)) (now 1 Mb/d), as refinery gains (now 2 Mb/d). The oil demand is reported as including all these liquids and we need to forecast the supply to fill the oil demand. It means including CTL and BTL despite that they do not come from oil and gas. But in fact there is s a continuum between coal and oil and gas, some oil source-rocks are coals and coals give coalbed methane and oil can be changed into gas. Colin Campbell forecasts all liquids but excluding CTL and BTL. His all liquids ultimate is 2.4 Tb, when mine is 3 Tb.

Ultimate liquids = 3 Tb is the sum of 2000 Gb for crude less extra-heavy +500 Gb for extra-heavy +250 Gb for natural gas liquids & GTL + 250 Gb for synthetic (CTL, BTL) & refinery gains.

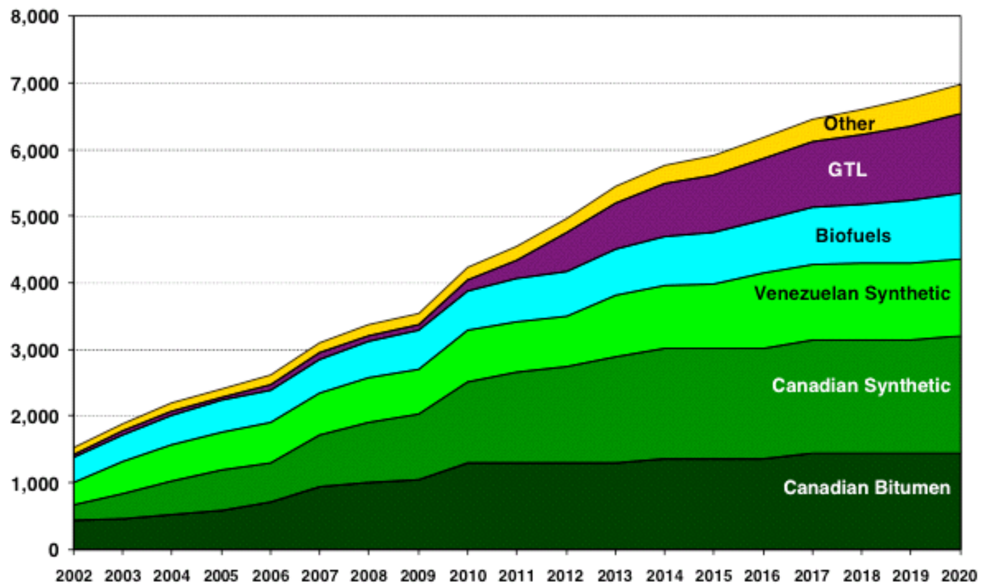
The forecast is then the previous forecast for cheap oil = crude oil less extra-heavy oil with an ultimate of 2000 Gb plus adding the expensive oil with an ultimate of 1000 Gb which will peak (to fit with the past production in value and slope) around 2050 at less than 40 Mb/d (against 12 today).

The liquids peak will be in the 2010s, if there is no demand or investment constraint. But the likely coming economic crisis (2004 forecast of Paul Volcker in the five years with a probability of 75%) will turn the peak into a **bumpy plateau** and chaotic oil prices.
In the unlikely case where expensive oil has an ultimate of 2 Tb instead of 1 Tb (making the total ultimate at 4 Tb) the peak would be around 2070 at 70 Mb/d, but the liquids peak will not change only the slope.
Figure 61: **World liquids production** (no demand or investment constraint)



Oxford Institute for Energy Studies (Skinner & Arnott 2005) forecasts that unconventional oil including biofuels and GTL will reach only 7 Mb/d in 2020, with growth slowing down for the last 5 years. My forecast for NGL, extra-heavy oils, CTL, BTL and refinery gains is about 20 Mb/d in 2020. I cannot be called pessimistic!
Figure 62: **Non-conventional oil production 2002-2020 by OIES**

Figure 23: Total unconventional oil supply 2000-2020



Source: OIES estimates.

-Comparison of different oil forecasts

BGR 2004 forecasts an oil peak around 2015 just over 90 Mb/d, with non-conventional increasing slowly and its importance increasing far after the oil peak.

Figure 63: **BGR oil projection peaking around 2015 at 4.7 Gt = 93 Mb/d**

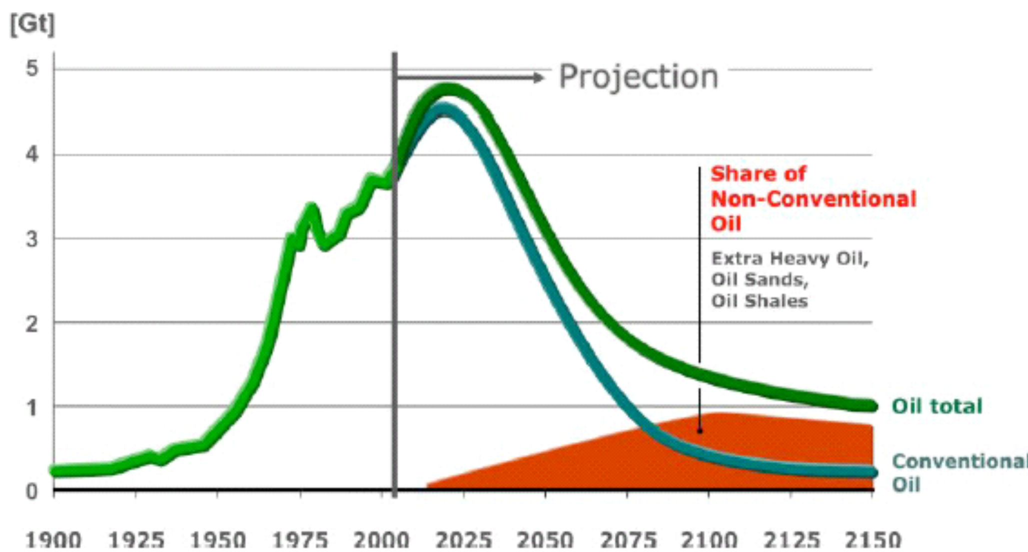


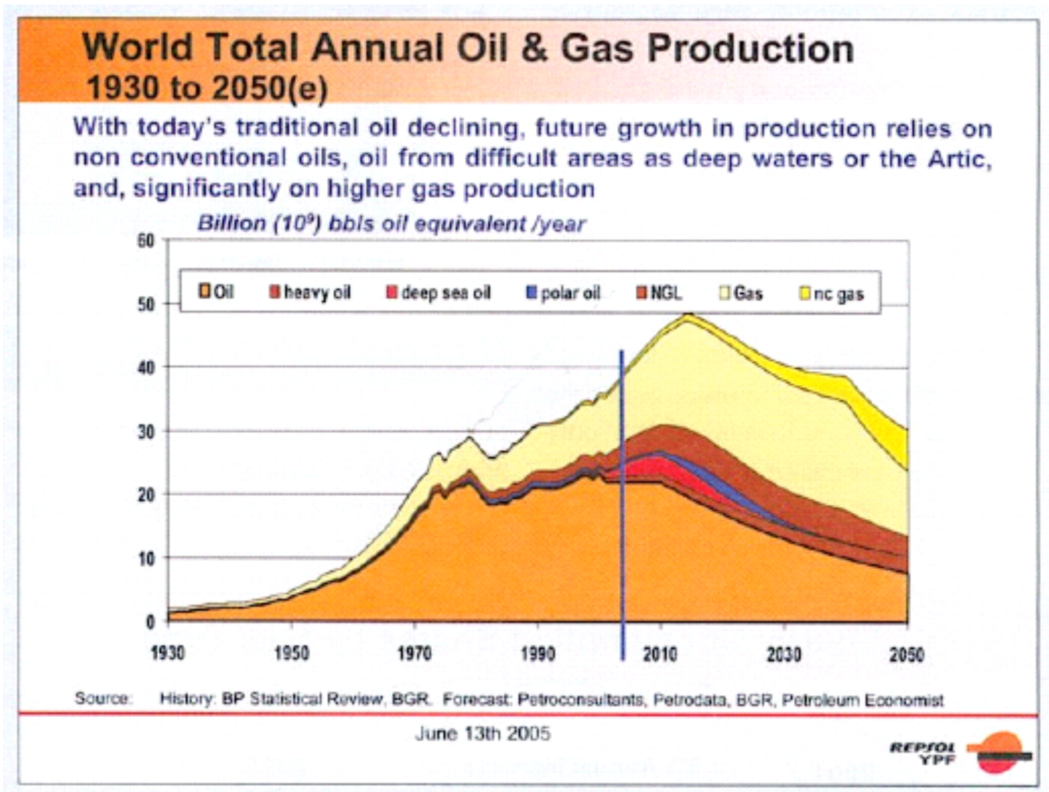
Fig. 17: Worldwide oil production from 1900 until 2150 – Historical development and attempt of an outlook.

BGR peak is close to our and in 2050 they forecast 3 Gt/a or 60 Mb/d, which is also close to our 3 Tb forecast (the 4 Tb being at 80 Mb/d).

But IEA forecast stops in 2030, showing no peak, no decline. Cl.Mandil head of IEA is now saying that their 115 Mb/d 2005 forecast for 2030 will not be reached!

We believe strongly that the 100 Mb/d will never be reached.

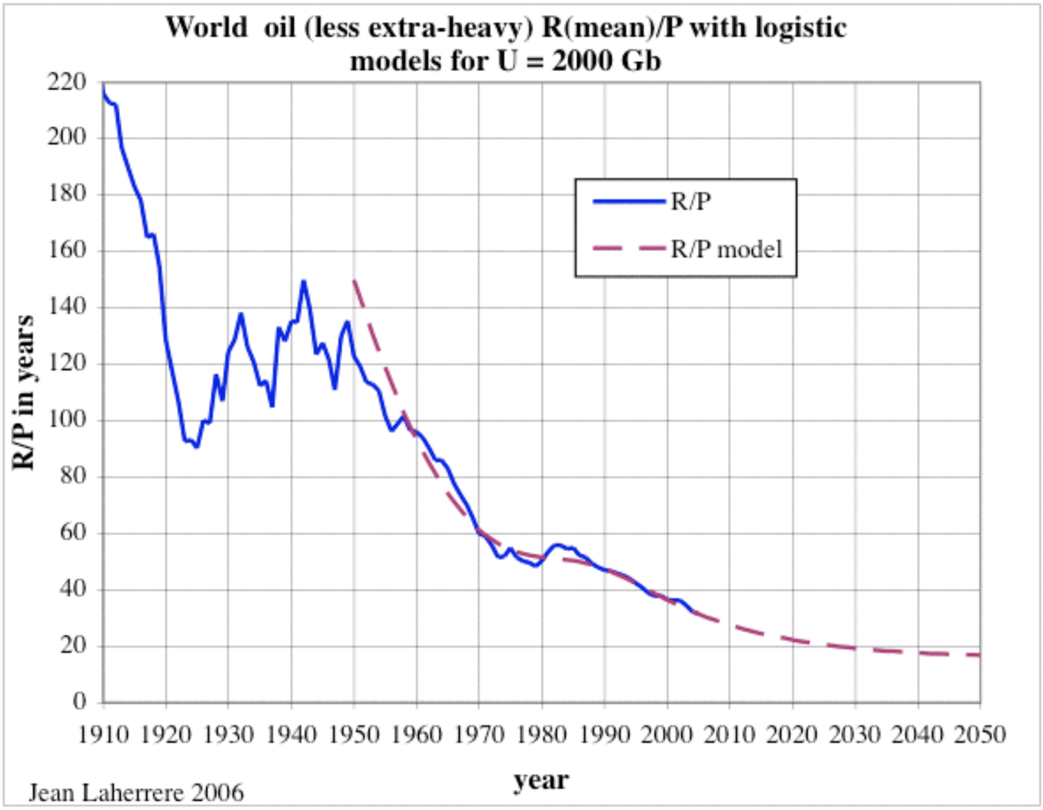
Repsol forecasts the oil peak around 2015 at 85 Mb/d.
Figure 64: **REPSOL oil projection peaking around 2015 at 31 Gb/a = 85 Mb/d**



Forecasts can be grouped into 3 groups
-peak at less than 100 Mb/d
-peak over 100 Mb/d before 2030
-no peak before 2030 = end of forecast = IEA, USDOE

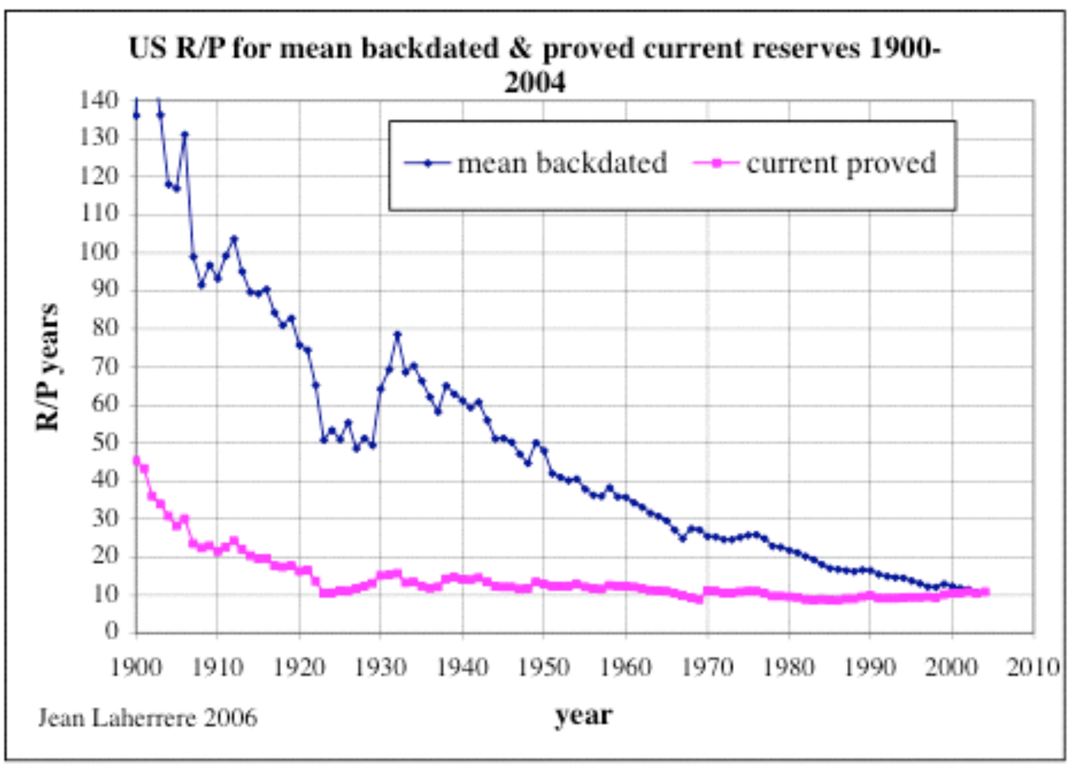
-R/P

Medias and politicians claimed that there is oil for the next 40 years and gas for 60 years, but it is using proved reserves from political or financial sources. The ratio is different when using technical data (backdated mean). As mean annual discovery can be modelled with several cycles, and production mimics discovery with a certain lag, the R/P is trending towards an asymptote depending upon the width of the last cycle.
E.Broto has a mathematical demonstration in the poster exhibition.
The world R/P from my technical database is presently at 35 years and trending towards about 20 years.
Figure 65: **World R/P from my technical database**

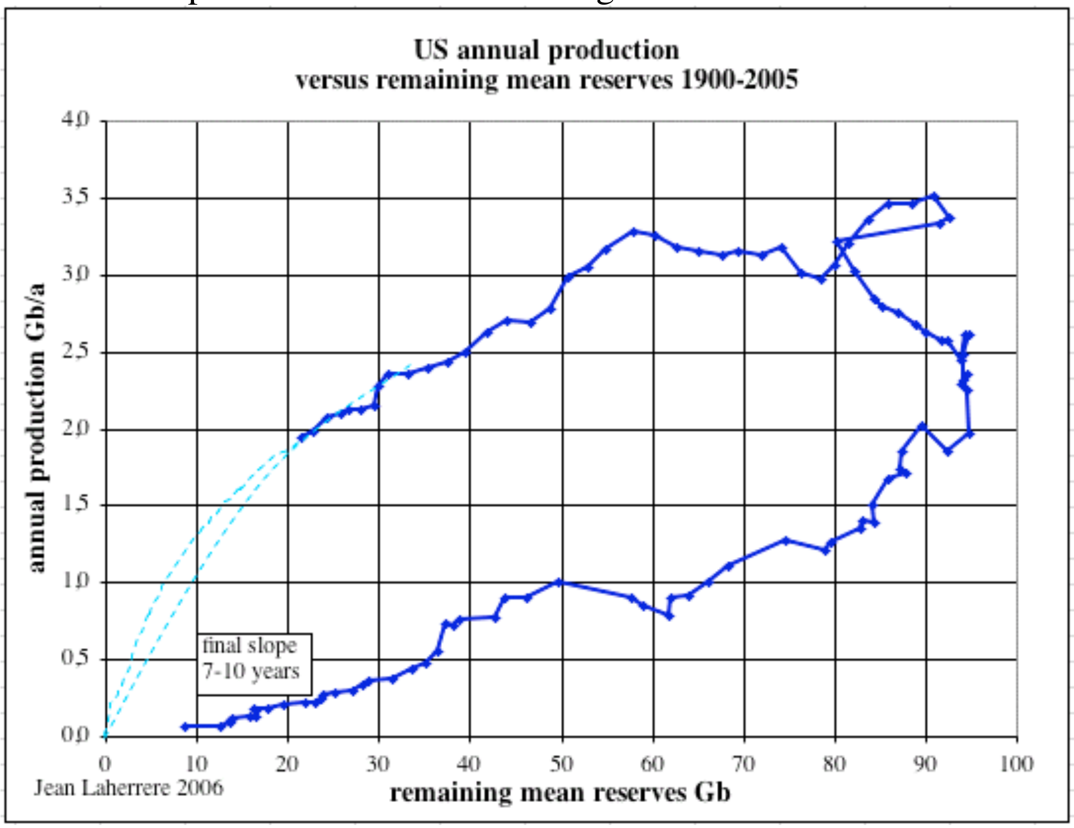


R/P from US proved reserves is about 10 years since the last 80 years, showing that this ratio is useless for forecasting, in fact it is used to estimate reserves as a thumb rule (even used by USGS) as demonstrated in figures 28, 38 & 39.

Figure 66: **US R/P from mean backdated reserves and from proved current**



The last US barrel will be produced with still 9 barrels reserves in the ground, barrels that will then go back to resource status.
The following plot is interesting because the end of the curve is known being zero production and zero remaining reserves. The final US R/P can be guessed as being about 7 to 10 years.
Figure 67: US annual production versus remaining mean reserves

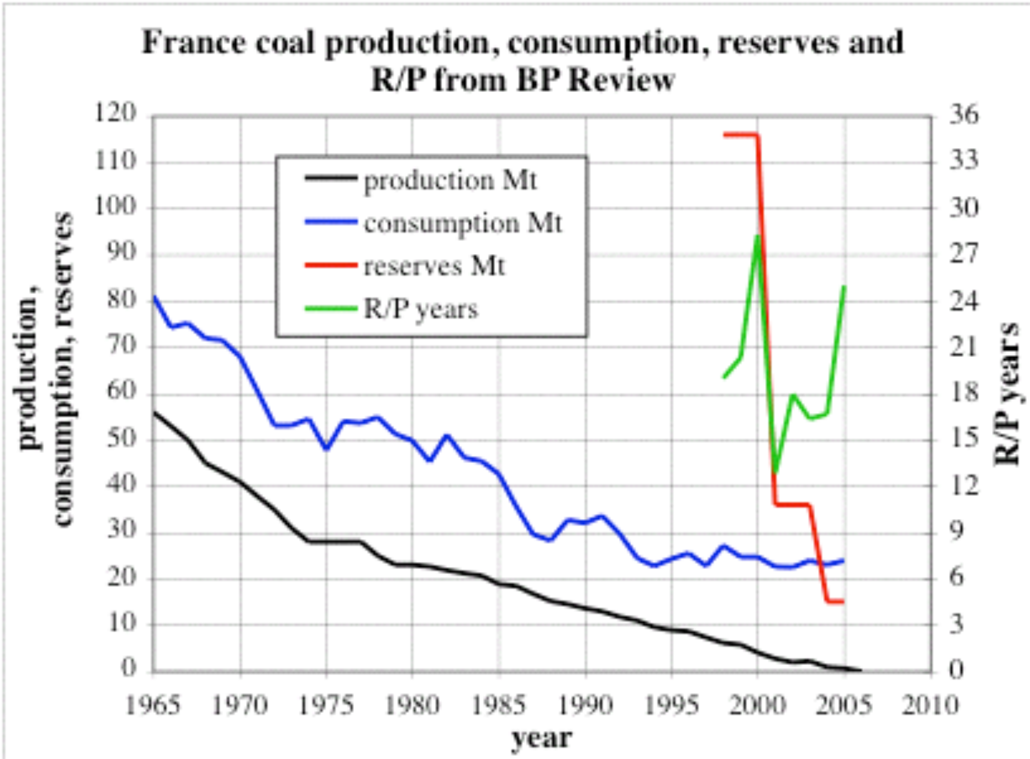


R/P is a very poor parameter, but used by all!

France coal reserves, production and R/P reported by BP Review:

	Reserves Mt	Production Mt/a	R/P years
2000	116	4.1	32
2001	36	2.8	15
2002	36	2	17
2003	36	2.2	16
2004	15	0.9	17
2005	15	0.6	25

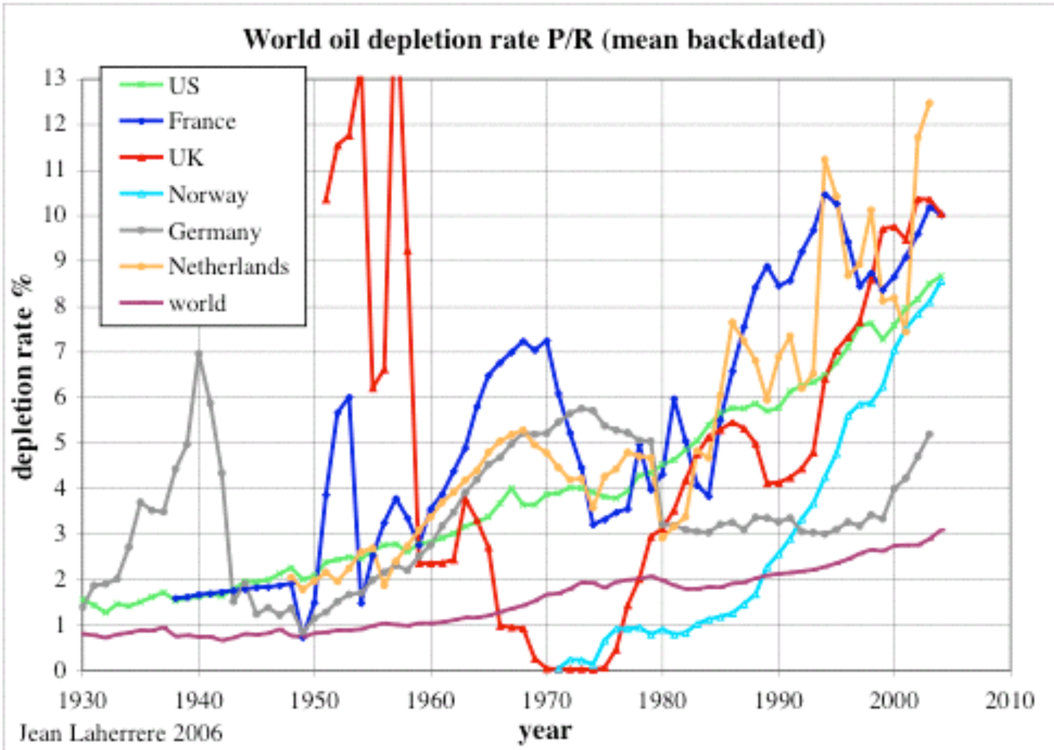
But in 2005 the last coal mines has been closed, meaning that reserves are now nil, been converted back into resources, but BP Review stated 25 years of reserves!
Figure 68: **France coal production, consumption, reserves and R/P from BP**



R/P is really useless, even worse, giving bad hopes!

The problem is that the inverse P/R is the depletion rate; as world R/P trends towards an asymptote of 20 years, depletion rate is trending also towards an asymptote of 5%. Using mean reserves the depletion rate displays for several countries a very rapid change: European countries rates have more than doubled in less than 20 years, but what goes up will come down!

Figure 69: **World depletion rates P/R for several countries**

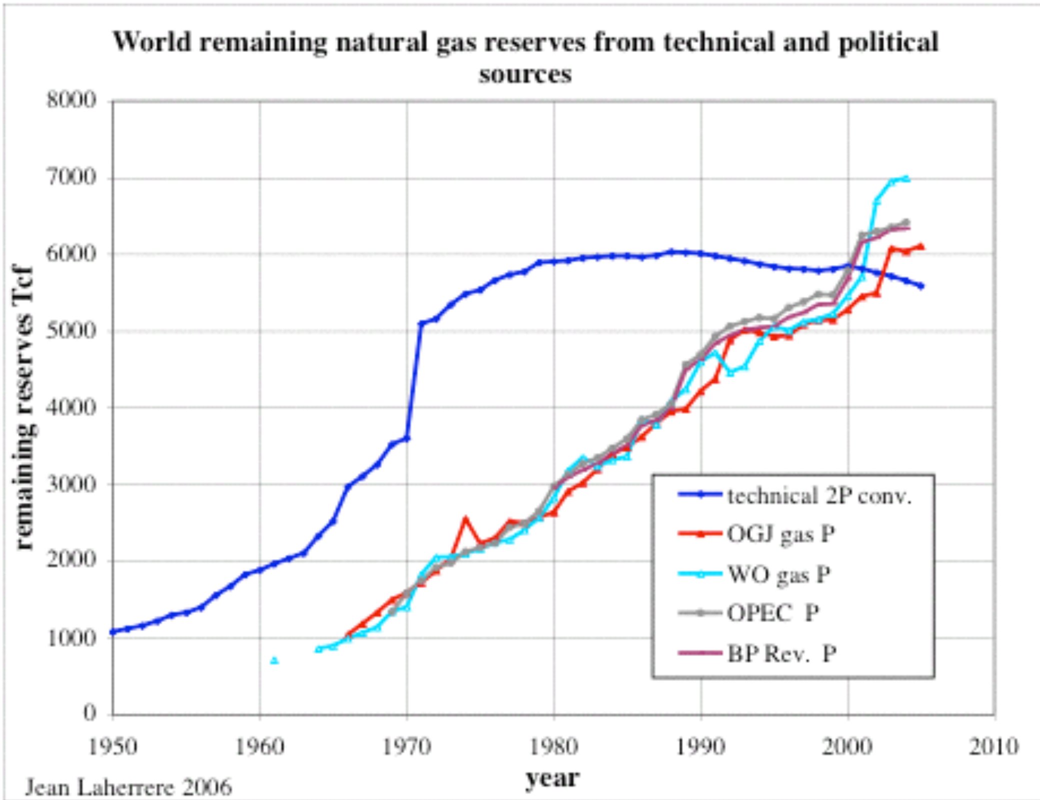


It seems difficult in this changing situation to have countries agreeing on a value!

-Natural gas

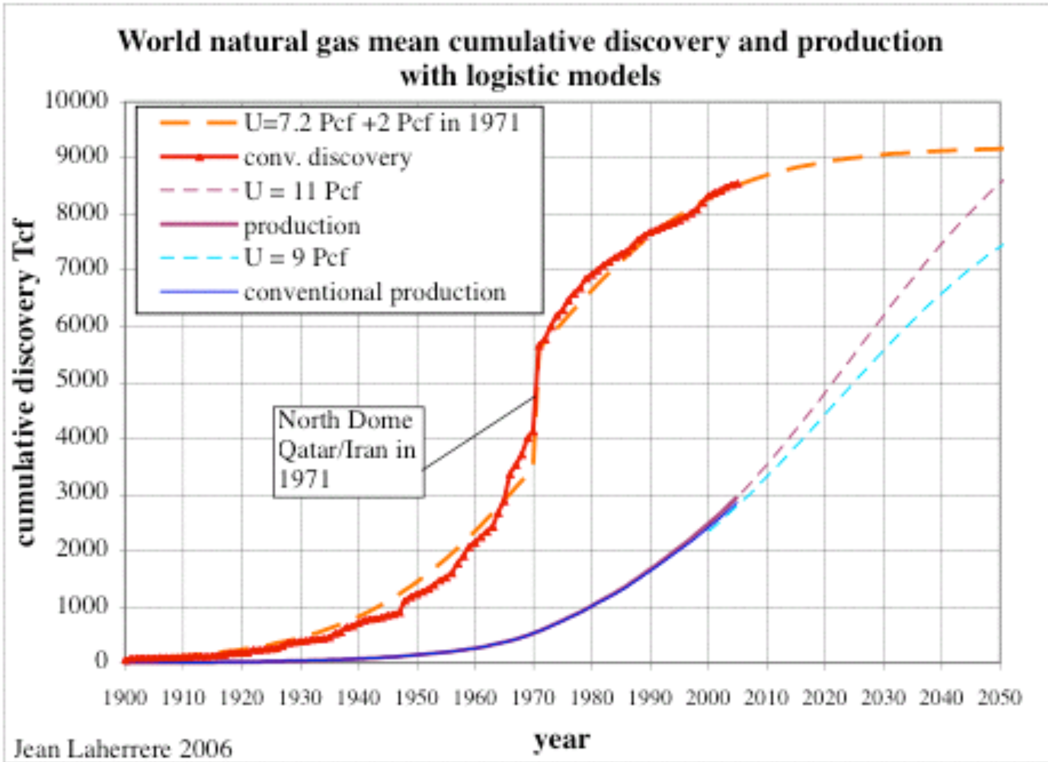
The remaining natural gas reserves reported as proved by nations display the same divergence with the technical data. The problem is that technical database is more difficult to obtain, because the difference between IHS and WM is wider than for oil as WM reports only so called technical gas, which can be produced when IHS reports discovery, including a lot of stranded gas. Technical data has peaked since 1980

Figure 70: **world remaining NG reserves from different sources**.



World cumulative discovery and production is modelled with a logistic curve but the largest gasfield (North Dome found in 1971 being North field in Qatar and South Pars in Iran reported as 1991 by IHS) represents about 15 % of the ultimate (Ghawar represents only 6%) and upsets the curve, so it is separated from the curve

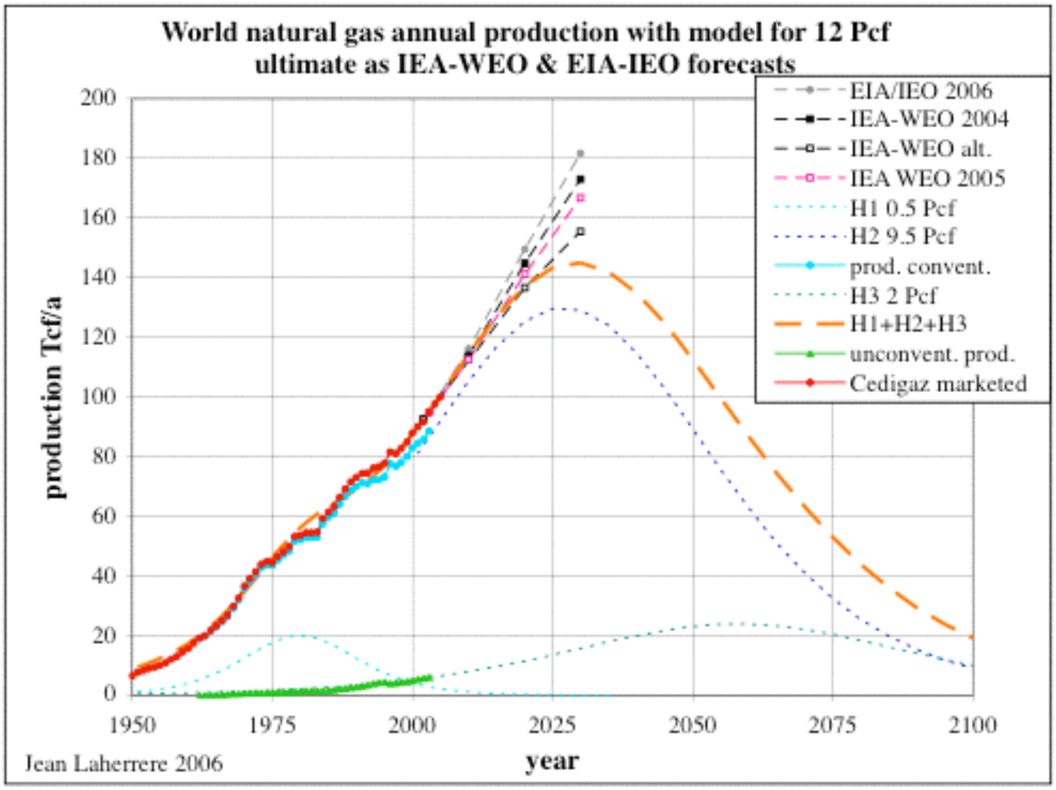
Figure 71: **2006 forecast: World conventional cumulative gas conventional discoveries and production with logistic models**



The ultimate NG was estimated at 10 000 Tcf (10 Pcf) 10 years ago (Laherrere, Perrodon, Campbell 1996) for conventional and 12 Pcf including non-conventional. We keep these values, as updated data confirm these round values, but if gasification of coal works (problem of sequestration of CO2), the ultimate can increase but it will not change the peak only the later decline.

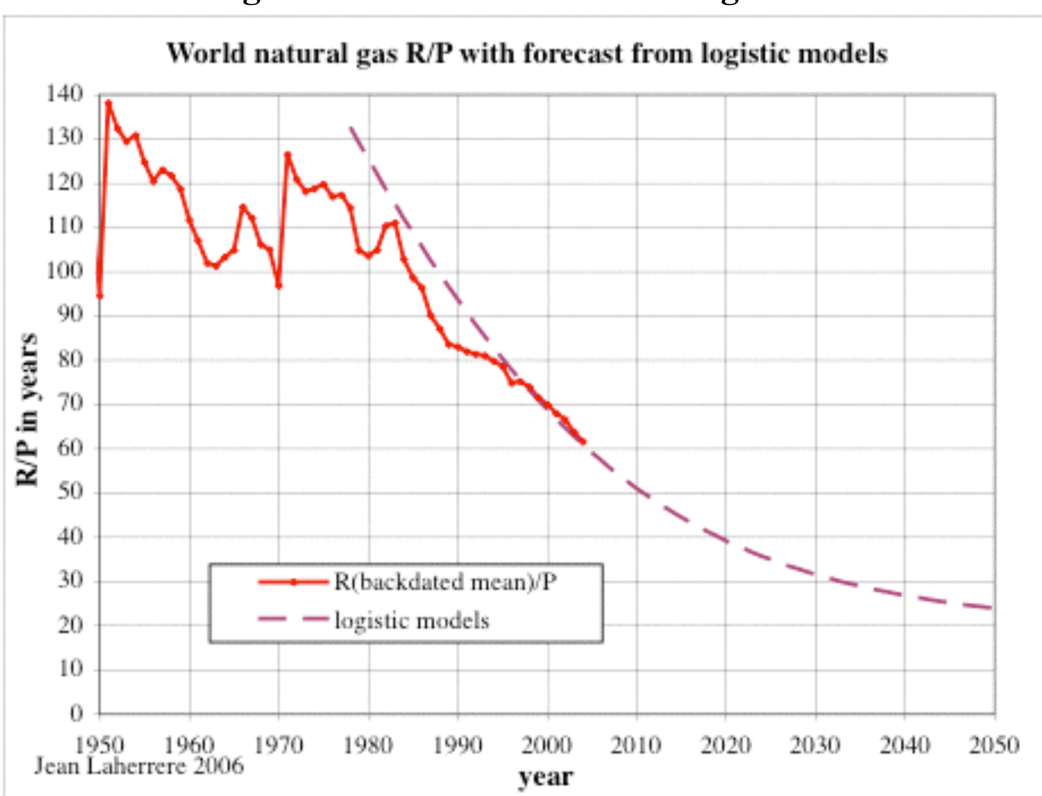
The world NG production will peak in 2030 about 140 Tcf/a when USDOE 2006 forecasts for 2030 182 Tcf/a and rising, but IEA 2005 has decreased from 2004 the value to 165 Tcf/a.

Figure 72: **World annual gas discovery & production as forecasts**



The R (backdated mean)/P has decreased from 140 years in 1950 to 60 years in 2005 and trends towards an asymptote of 20 years (as for oil).

Figure 73: **World natural gas R/P with forecasts from logistic models**

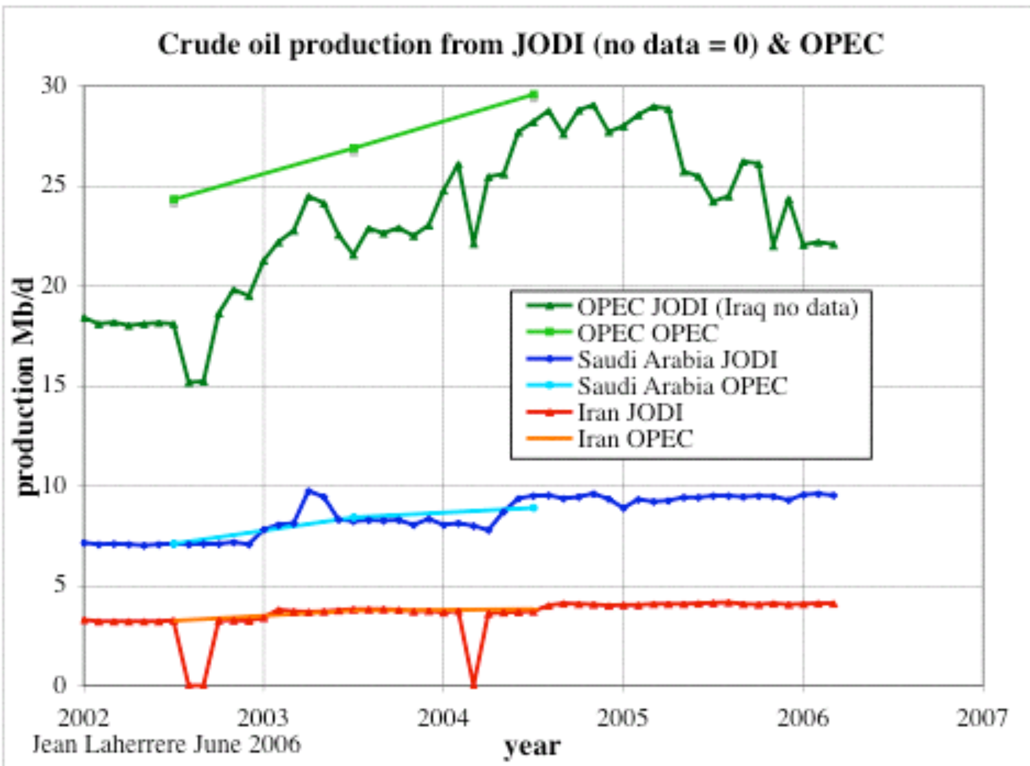


-Oil data transparency?

JODI (Joint Oil Data Initiative) gathers seven international organizations involved in oil statistics, namely, the Asia Pacific Energy Research Centre (APERC), the Statistical Office of the European Commission (Eurostat), the International Energy Agency (IEA-OECD), the International Energy Forum (IEFS), the Latin American Energy Organization (OLADE), the Organization of the Petroleum Exporting Countries (OPEC) and the Energy and Industry Statistics Section of the United Nations Statistics Division (UNSD)

JODI reports monthly data (www.jodidata.org) for a certain number of countries and the total for OPEC or for the top 30 producers without bothering, when adding, to check that no data does not mean a zero value! It means that JODI totals are wrong!

Figure 74: **crude oil monthly production from JODI 2002-2006**



JODI database for oil production is presently worthless as incomplete and incorrect additions.

JODI, being the official worldwide organisation dealing with oil data, should first make the inventory of the world oil databases and comment the discrepancies in order to make them more homogeneous. The first study should be to know exactly what is reported and asking for better definitions.

-Conclusions

Most actors favour ambiguity because publishing data is a political act and decline is still a politically incorrect term, because growth is the main goal for politicians and managers!

All data and definitions on production differ from sources and it is obvious that data are unreliable, even lousy.
Reserves data are published with a stupid accuracy (up to 13 digits) when the second digit is different!
Confidentiality of field reserves is difficult to remove in a competitive business if data is not released by governments, as it is done in UK and Norway. As long as OPEC quotas are based on reserves and as long as quotas are not definitely abandoned, reserves as production data will be flawed. The poor results of JODI are not a good sign.
US old and unconventional oilfields remaining reserves estimated by multiplying the annual production by 10 are chosen as examples of reserve growth by USGS 2000 and others.
Many examples lead to conclude that the US reserve growth is mainly bad reporting and that the USGS claim of 730 Gb of world reserve growth obtained by applying this poor and obsolete US proved growth to proved + probable reserves is scientifically wrong.
All forecasts using USGS 2000 results (at end 1995) are highly unreliable. A new world assessment is a must.
The 2005 IEA claim on the impact of technology on production in the North Sea is an old 1999 graph which was manipulated, suggesting that no other better example could not be found.
Scout companies should try to reject political data (as it was done in the past) in providing proven + probable estimate, neglecting proved value.
If countries do not release field data as UK and Norway, it is hoped that more complete and worldwide scout companies will emerge, not only for oil and gas, but also for coal and uranium. A world organism should also makes the inventory and the critics of the available databases.
Competition and truth cannot live together easily, but what is the truth in an uncertain world!
Hoping that reserve and production data will be reported truly and accurately by operators seems to be a wishful thinking.
R/P and P/R (depletion rate) are hopeless ratio, as long as reserves are confidential and/or badly reported!
Uncertainty is a reality of life and has to be accepted with a probabilistic approach by those who do not like it.
Range (mini, most likely, maxi) has to be reported instead of a single value.
It is easier to tell the truth with a large range than with a single value.
Confidentiality will disappear when competition will be replaced by working together to save energy in order to leave enough energy to our grandchildren. It means first that peak oil has to be recognized by all.
True data and clear definitions are a must because the reality is far from it!