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Peak oil and related peaks!

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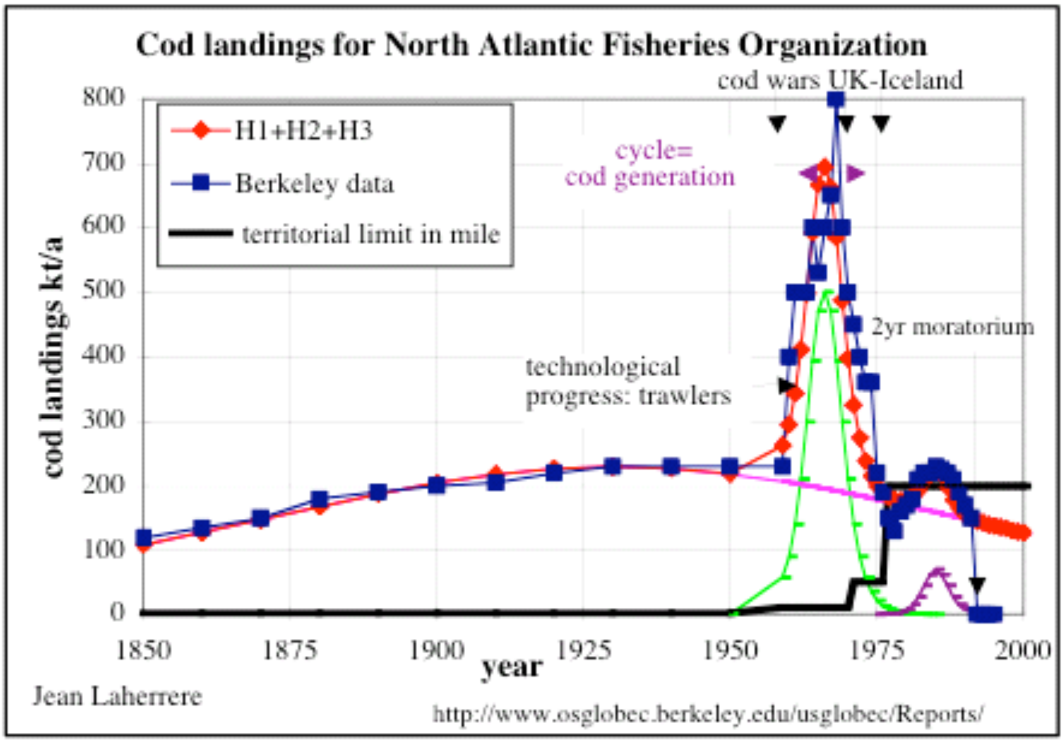
Part 1

Paul Valery wrote: "*All that is simple is false and all that complex is useless*"
I am not sure how to find and to tell the truth, but for me a graph is worth a thousand words, but as long as data is not flawed!
Reliability of data is the big problem

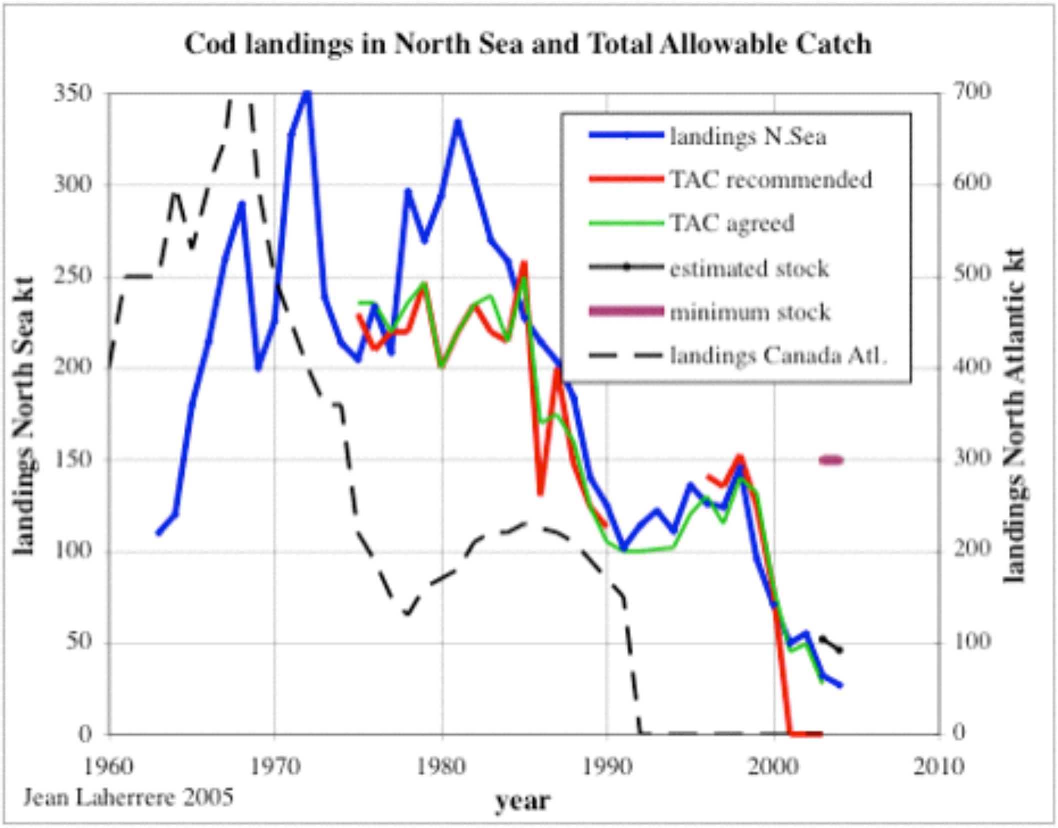
-Present basic facts
-what goes up must come down, life is cycle
-what was born will die: sun, earth, mankind and civilization
-constant growth has no future in a limited world
-natural events display several peaks and usually can be modelled with symmetrical cycles (like Fourier analysis)
-US oil production has peaked in 1970, world production will peak (maximum) one day
-North Atlantic cod landings has peaked in 1965 and cod is considered as extinct in the Grand Banks. Cod fishing was suspended temporarily in 1992 and definitively in 2002.
Figure 1: **Cod landings in Northern Atlantic**



Technology (trawlers) has increased production, but has killed the cod species after bad estimation of the resources (quotas were designed to fish 20% of the cod resources when in fact they fished 60% plus fishing their food) !

North Sea cod fishing is going exactly the same way with 15 years delay

Figure 2: Cod landings in North Sea and Total Allowable Catch (TAC) compared to North Atlantic



-Problems of wording

Petroleum = *an oily flammable bituminous liquid*

Oil = *any of numerous combustible substance that are liquid*

Oil is reported for 2005 production varying from **crude oil (71 Mb/d)** to **all liquids (84 Mb/d = oil demand)**

Barrel = no legal definition, official reports need to add 42 US gallons (Texas official liquid barrel = 31.5 gallons)

For me, production of oil = oil production, peak of production of oil = oil production peak or oil peak

Peak oil (Google 4 000 000) **or oil peak** (200 000)**?**

Why such difference? My answer = ASPO

The highest level or only a high point (lower following year)**?**

Annual high or monthly high?

All liquids production since 1857 had **18 annual peaks**: 1862, 1866, 1870, 1875, 1882, 1891, 1893, 1904, 1929, 1937, 1941, 1948, 1974, 1979, 1984, 1990, 1998, 2001

If peak = 3 lower following years = 3 peaks: 1868, 1929, 1979.

If peak = 5 lower following years = 1 peak: 1979

One peak model (one cycle = Hubbert peak) **or several peaks model** (several cycles)**?**
Peak by lack of demand or by lack of supply?
Peak or bumpy plateau?
There is a consensus for no consensus on definition in order to deal with ambiguity and to use usual term, which are not clearly defined.

-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, OPEC oil productions are flawed and unreliable. Real data on oil transported by tankers have to be bought from spy companies (Petrologistics in Geneva).
-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
There are three worlds:
-economists **having only access to political data, believing that money and technology can do anything**
-managers or politicians **who have to show growth to be well considered**
-technicians **having access to real data and knowing the limits of techniques but hardly free to speak, only if retired**

-Reserves
Reserves represents the expected cumulative production at the time where 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.
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) 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 close by exploration in most countries except Norway, UK and US federal lands.

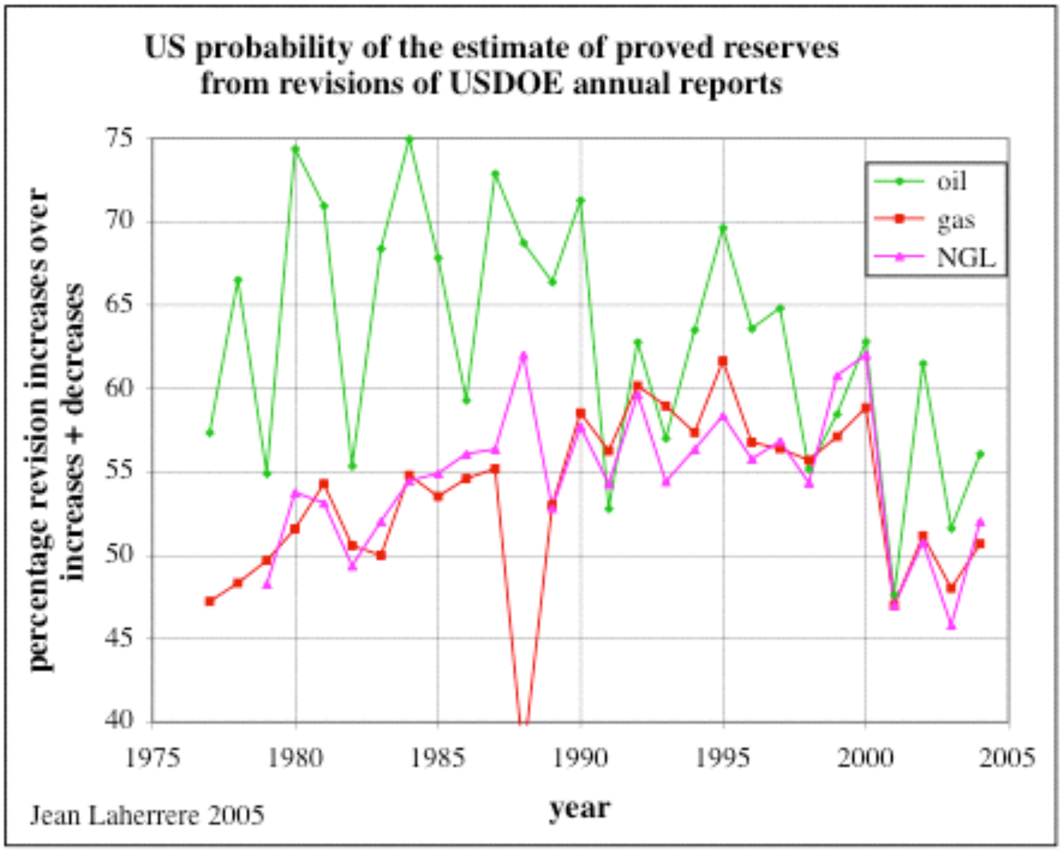
Reserves represent what will be recovered in future, in a probabilistic approach has to be the expected value, but it is better to give a range (mini, mean, maxi)
Resource is what is in the ground; reserves are only a small part of resource
There are several reserve definitions in use:
-US = all companies 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%
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.
Reserve growth occurs when reserves are reported as the minimum (proved), but does not occur statistically when reported as mean (expected) value

-Reluctance to change

-world oil industry is dominated by US practices (barrel) and US rules (proved)
-US industry reluctant to adopt the metric system (crash of Mars Climate Orbitor in 1999) and US shops the credit card with a chip

-Reluctance to risk = Probability

-US banks reluctant to accept uncertainty and probabilistic approach
-US rules 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
Figure 3: **US revisions of proved oil & gas reserves giving the probability of the estimate**



Present probability of US proved reserves is about 50%, far from the SPE/WPC definition of proved = 90%. 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!

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!
Probability reporting to the medias is often based on wishful thinking, as the NASA reporting a crash in 1 out of 100 000 before 1986 Challenger crash (25th flight), then at the crash enquiry Nobel price Feynman estimated at 1 out of 100. But the 2003 Columbia second crash at the 107th flight shows that he was maybe too optimistic.
Higgs boson (goal of the CERN next particle accelerator) was claimed in 2000 to have been discovered with a probability of only 2, 3, 4, 6 and 90 (varying with authors on the web) out of 1000 to be wrong and it is hard for me to see how the

"about 3 σ" was estimated with such a narrow confidence level, compared to the uncertainty of this disputed discovery (now rejected by almost every scientist)!

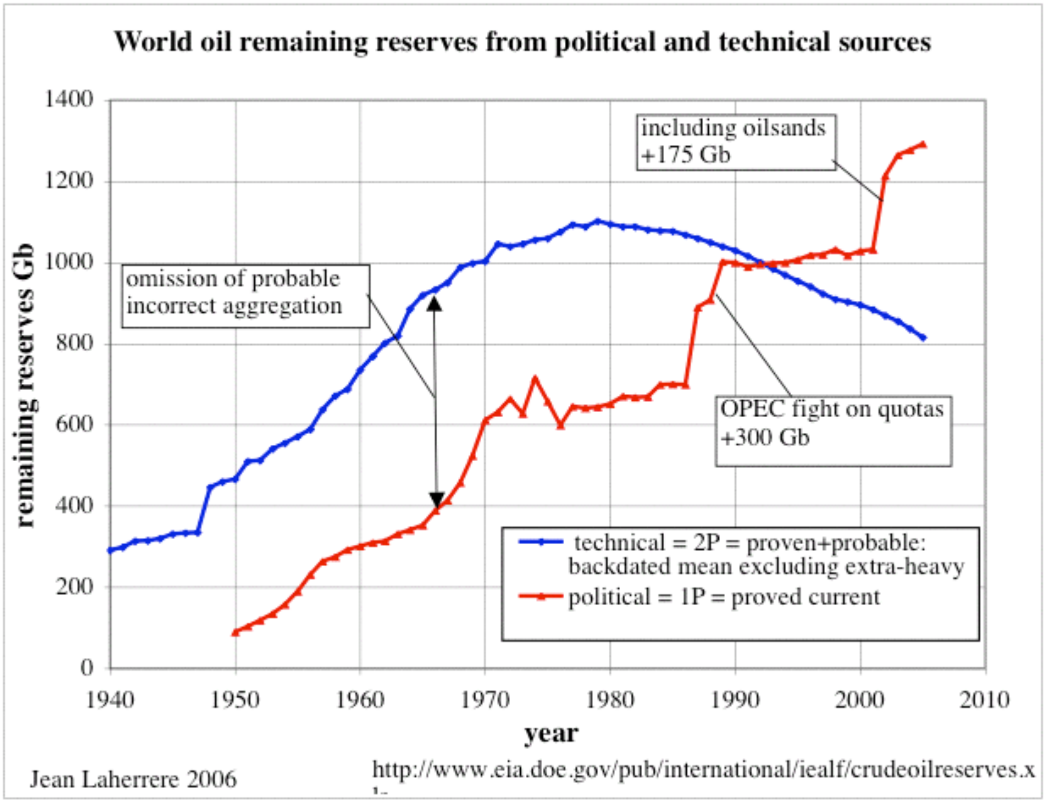
-Change in shareholders

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

-**Confidentiality**

Technical reserves are confidential
-Oilfield reserves are confidential in every country except in UK (DTI), Norway (NPD) and US federal (MMS)
-Technical reserves database must be bought from different scout (spy) companies as IHS or Wood Mackenzie (WM) or Infields.
-These technical sources display very large differences, far larger than the undiscovered oil estimate
-Published oil reserves are financial (Securities and Exchange Commission) or political (OPEC)

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 4: **World remaining conventional oil & gas reserves from political and technical sources**



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 do not want to upset the national oil companies (NOCs), which are now their clients, when many international oil companies IOCs have disappeared and they accept their political values

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.

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 if 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.

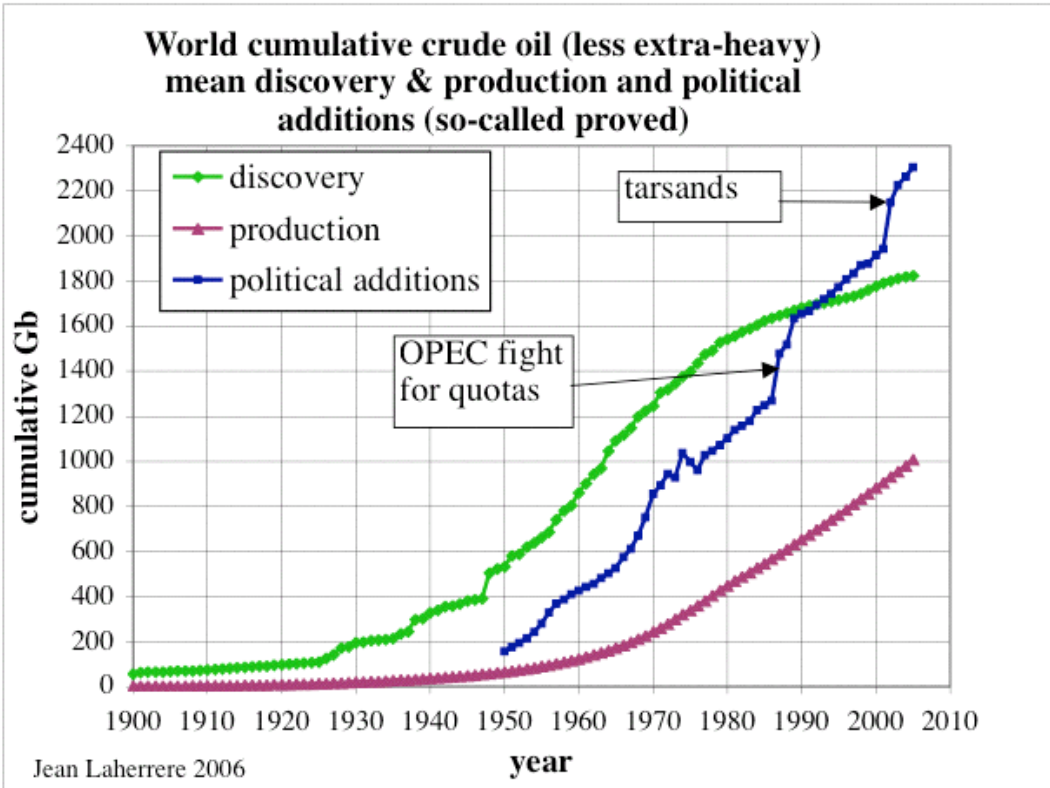
In the USGS 2000 study of undiscovered oil, using a probability distribution of minimum = 95 % or F95 and maximum = 5% or F5, the Monte Carlo procedure for the eight regions listed in the study gives (table 1 of Executive summary DDS-60) for the world outside the US undiscovered oil and gas gives the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

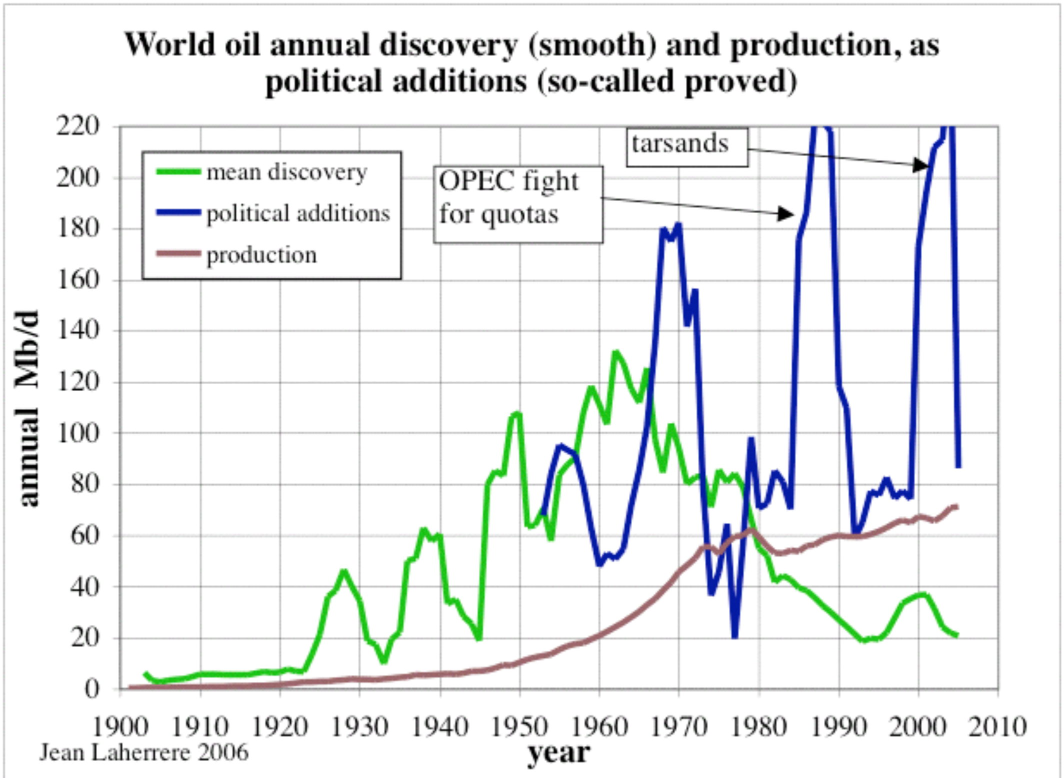
Economists have only access to political data reported to cheer bankers, but useless for forecasting.

Adding the cumulative production to the previous graph, the comparison between the **cumulative discovery** from technical sources and political sources is striking:
Figure 5: 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 6: World annual crude oil (less extra-heavy) mean discovery & production and political additions (so-called proved)



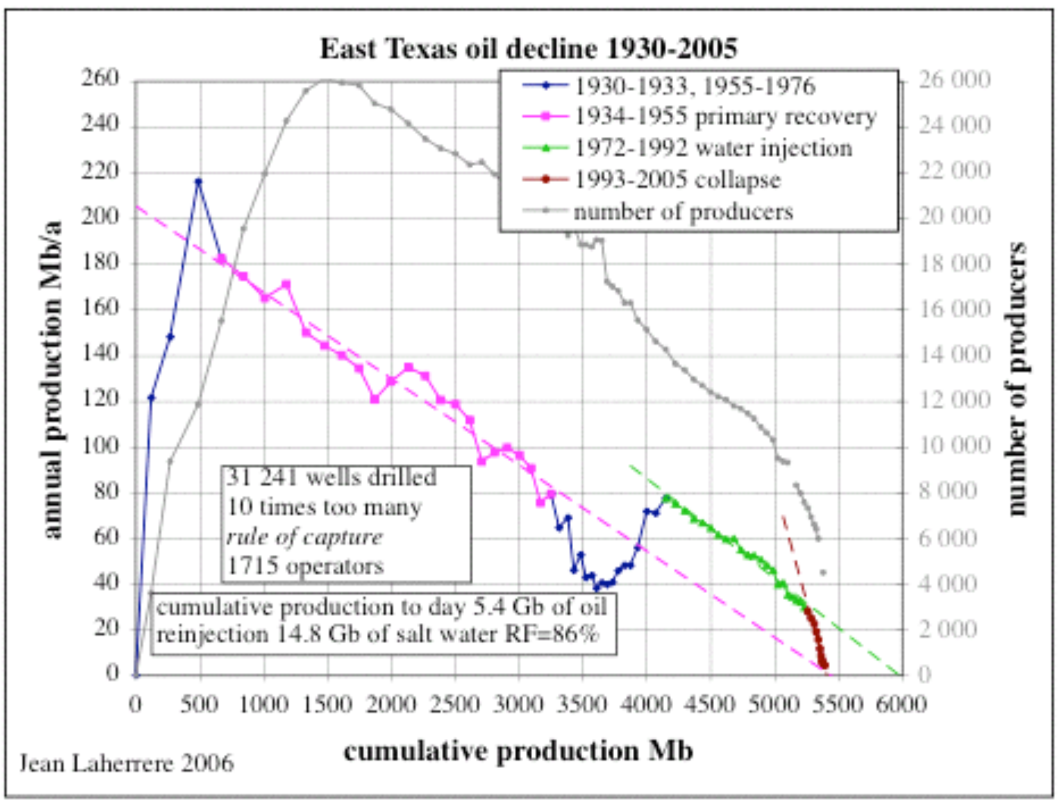
Any work, study or forecast using proved reserves has to be discarded as useless, following the GIGO principle: Garbage In, Garbage Out.

-**Reserve growth**

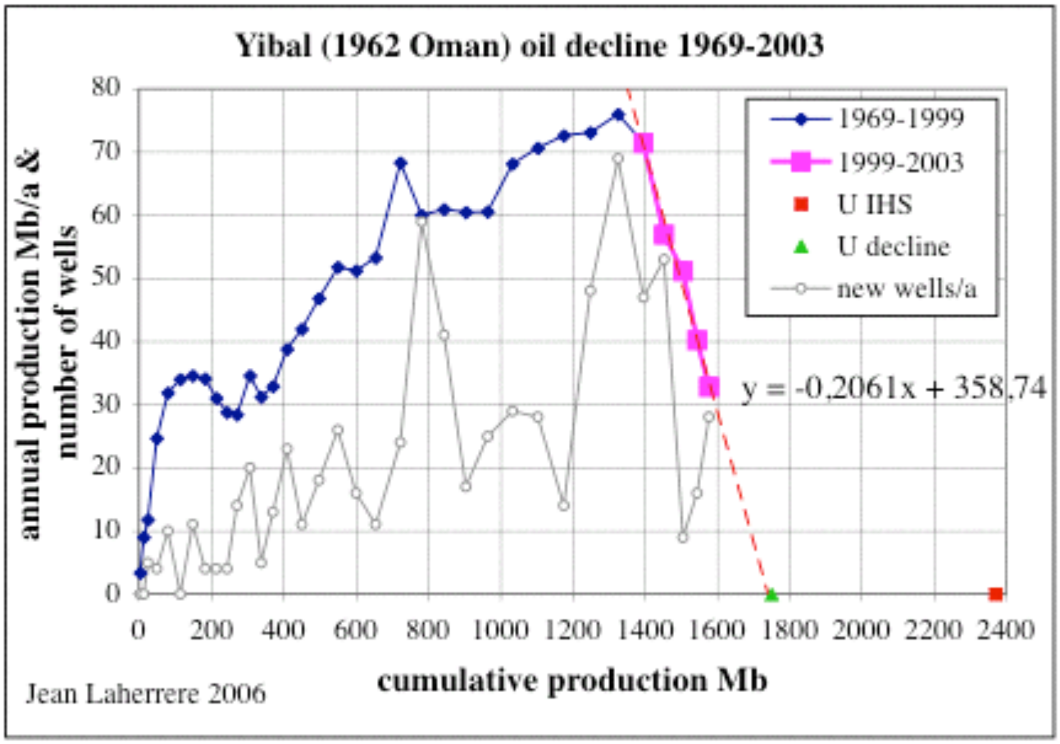
Reserve growth is the main argument of the present USGS head of reserves estimate: T.Ahlbrandt, in contrary to his predecessor Ch. Masters, who was denying any growth by using inferred estimates (and not proved values).
USGS 2000 estimates are as end of 1995, almost 10 years old, but still used by many to justify oil abundance (Exxon-Mobil 2006)! Even past data, as world cumulative gas production, is wrong by 15% = 1752 Tcf against 2025 Tcf (*Salvador AAPG 2005*).
USGS 2001 report guessed (?) world reserve growth at 700 Gb, based on US proved reserve growth of old fields applied 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 using steam, reaching peak after one century of production) compared to new offshore fields produced in few years. 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. Such aggregation underestimates largely the minimum value of the whole, as mentioned above.
All world proved 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 (contrary to the rest of the world), ignoring the expected value 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.
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
Furthermore reserve growth is often negative 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 7: **Oil decline of East Texas, largest US L48 oilfield 1930-2005**

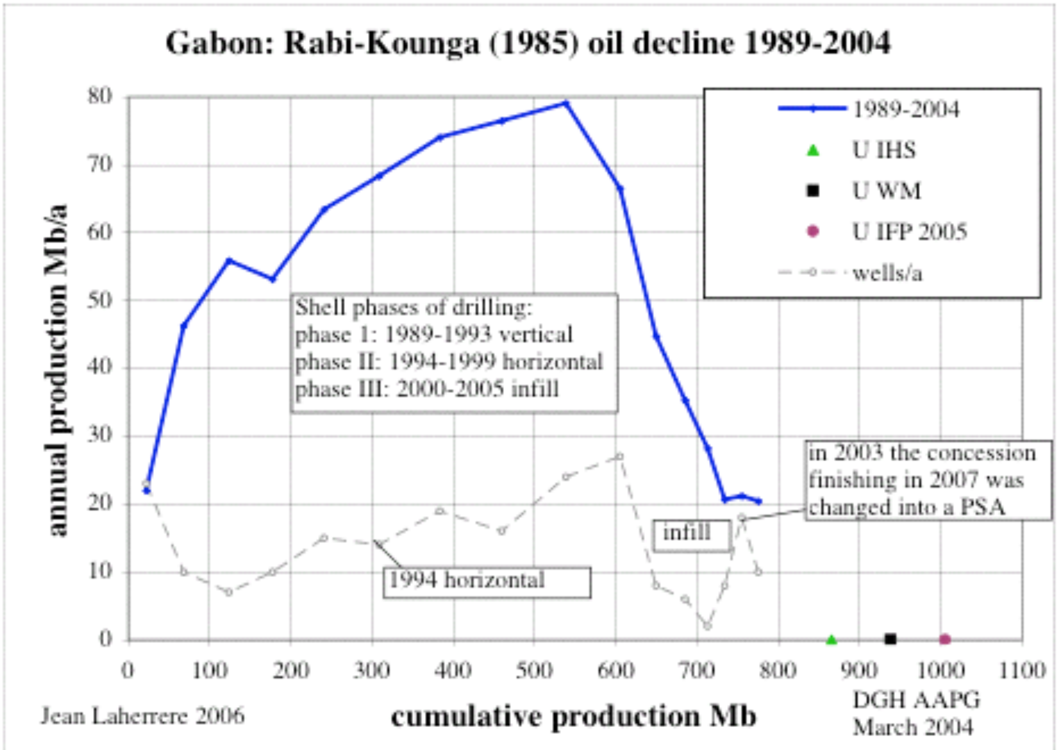


Over 30 000 wells have been drilled (by over 1700 different operators) 10 times too many, because *rule of capture*! There is a very active water drive and the recovery is estimated at 86 %. **Present water cut is over 98%** =14 000 b/d of oil with 1 000 000 b/d of water from 4500 wells!
Modern production 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 8: **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 East Texas and Forties. Now good practice is to get current maximum profit (pressure from shareholders, mainly pension plans)! Oil produced ten years later has little present value today!

Shell also overproduces also Rabi-Kounga, largest oilfield in Gabon by using overdrilling
Figure 9: **Oil decline of Rabi-Kounga, largest field in Gabon 1985-2004,** operated by Shell



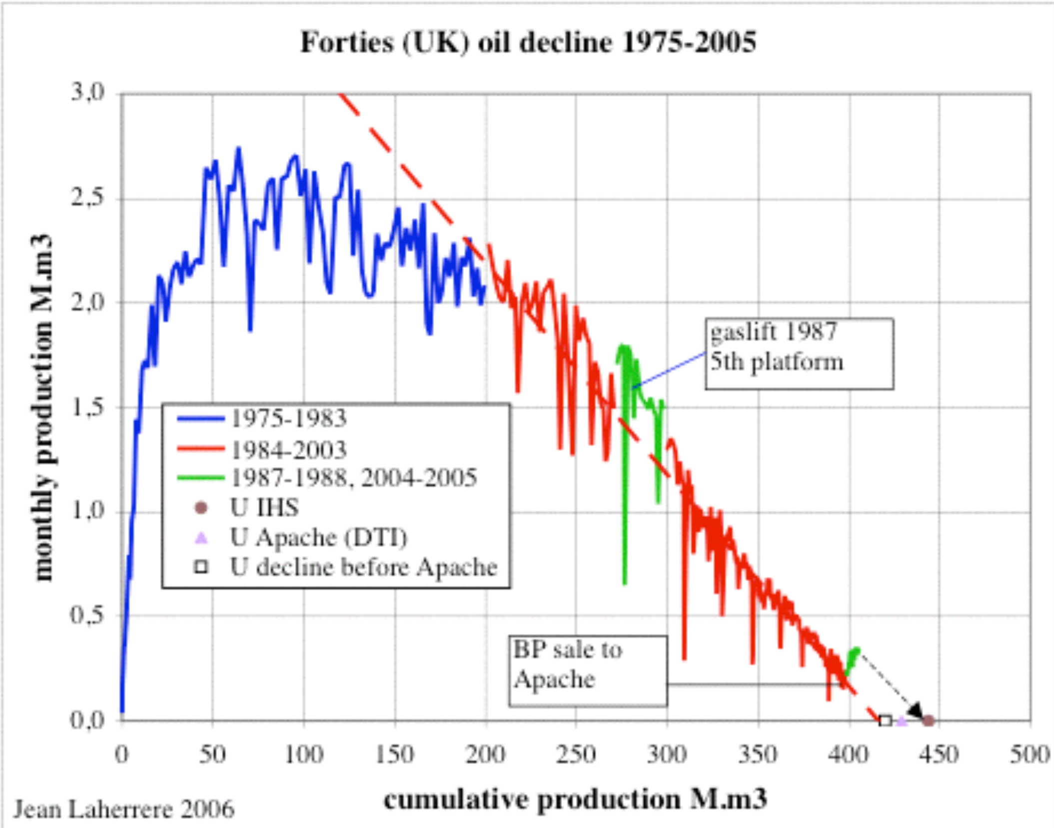
It is interesting to observe the oil decline in North Sea oilfields, which are, now close to be depleted, and also because it is the only place were the data is the technical value and is published by DTI and NPD. Texas RRC (RailRoad Commission) publishes also technical data on some fields as East Texas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

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.

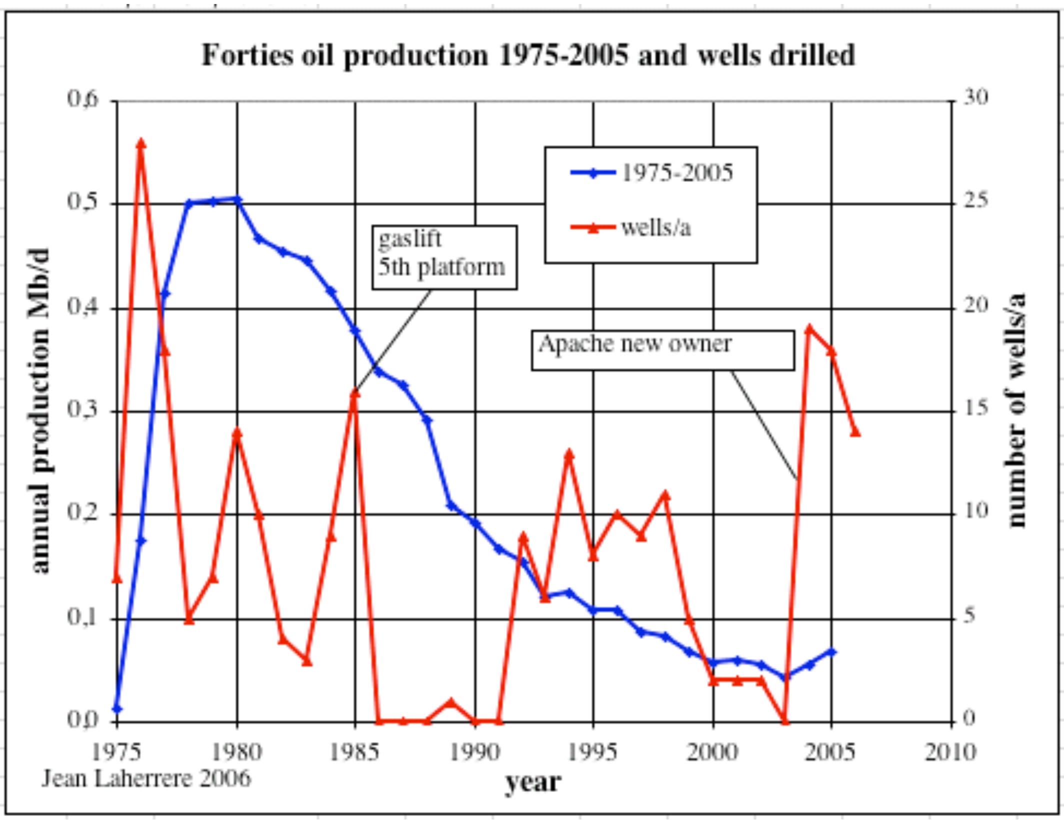
Already in 1987 a fifth platform with gaslift decreased the decline for two years but soon the decline went back towards the same ultimate.

Figure 10: **Oil decline of Forties (UK North Sea) 1984-2005** operated by BP & sold to Apache



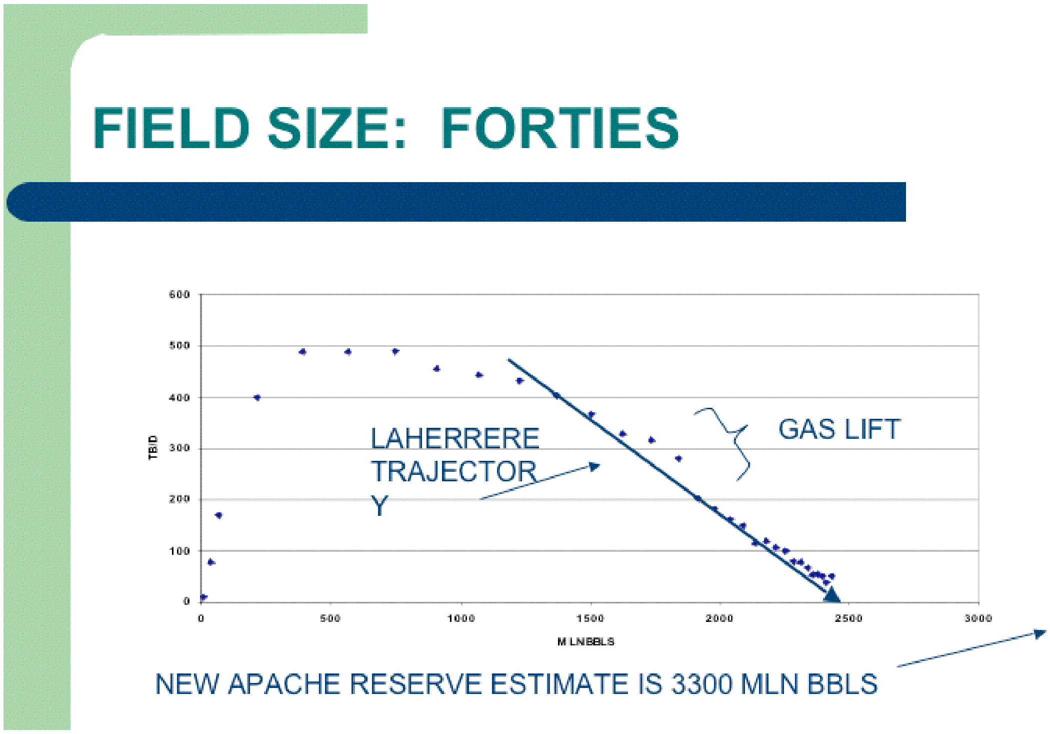
In Forties, Apache drilled 51 wells in 3 years from 2004 to 2006, compared to 200 wells before by BP in 30 years, which is 2.5 times more.

Figure 11: 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 12: Lynch's presentation in Vienna 3 April 2006 on the size of Forties

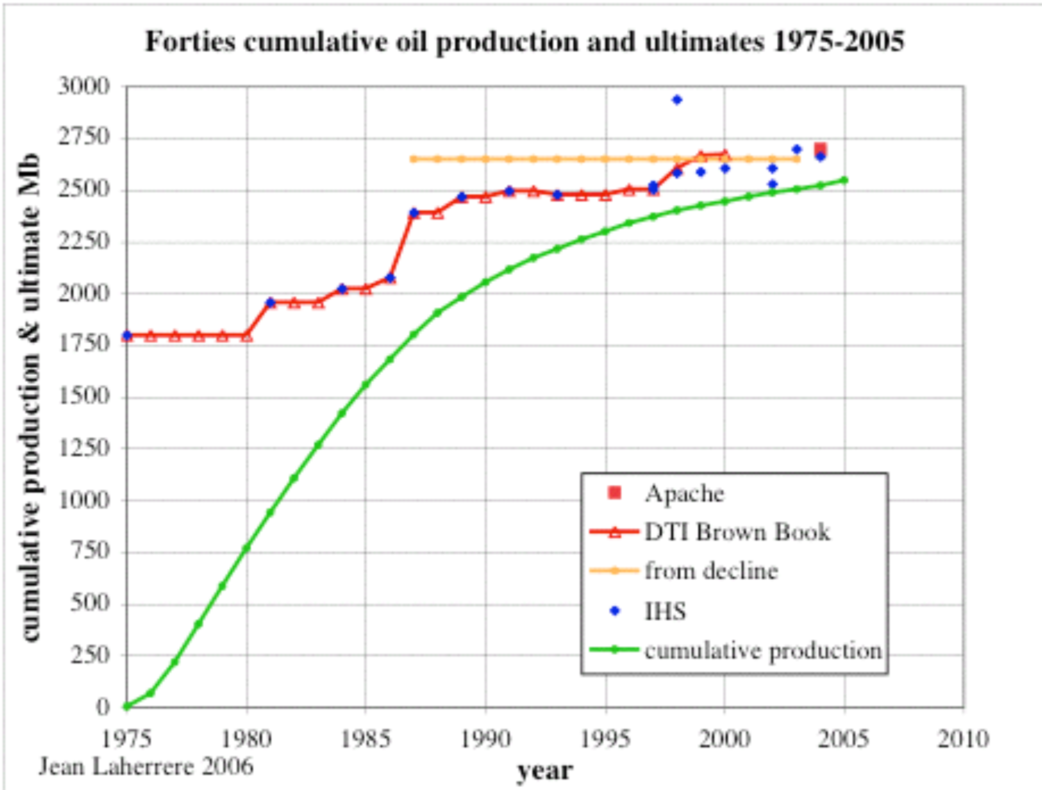


In fact Apache (Dec 2005) stated that they has found with new data that the oil in place is 800 Mb higher, being 5000 Mb instead of 4200 Mb. Lynch confuses, as usual, oil in place and reserves. The oil in place was reported by IHS to be 4200 Mb in 1998 and 4160 Mb in 2004 and 2P moving from 1800 Mb in 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 13: Forties cumulative oil production and ultimates 1975-2005

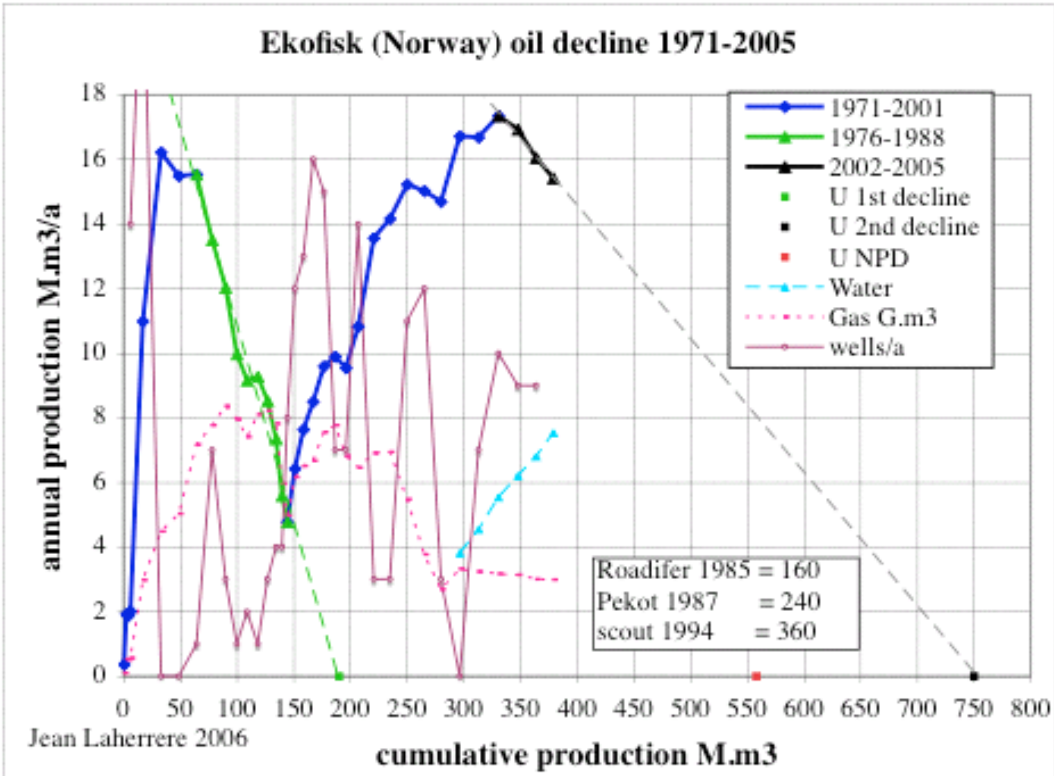


In a 2006 paper Apache (R.Jones) stated that, in the last two years, production have increased by 50% and remaining reserves only by 20 %. Remaining reserves quoted in July 2003 being 147.6 Mb, so the increase is in fact of 30 Mb and not 800 Mb

Example of positive reserve growth

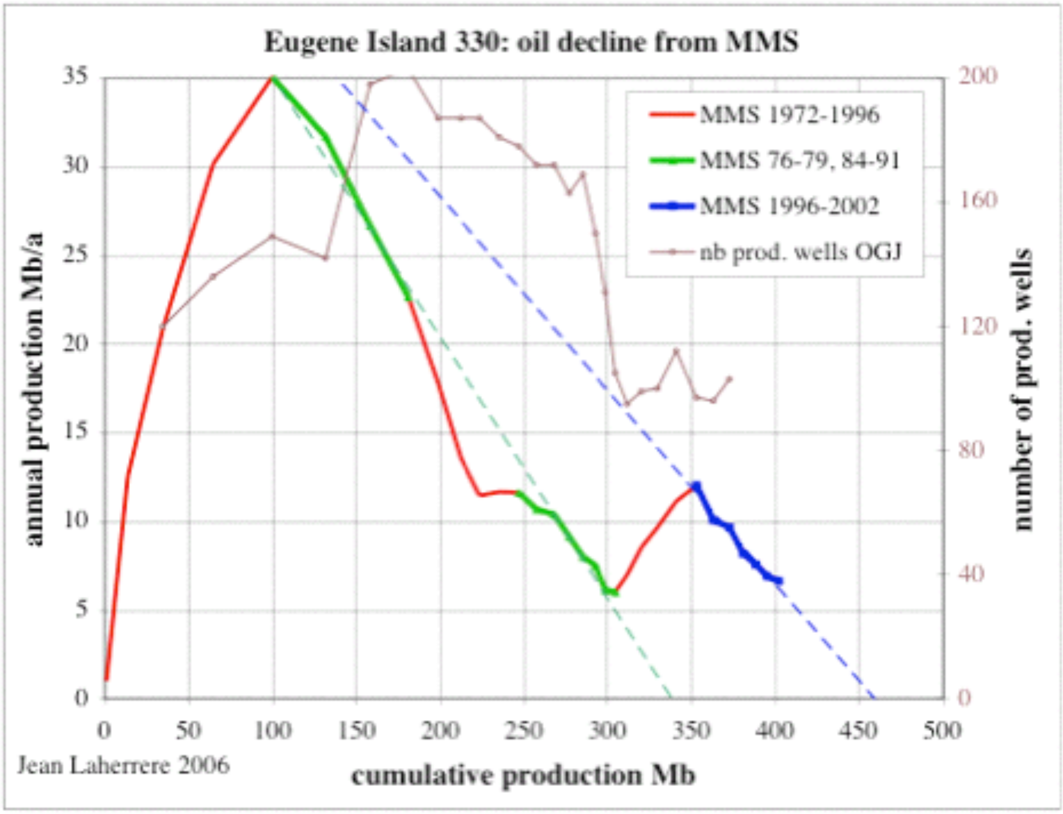
Ekofisk is the exception in North Sea, showing a drastic increase in recovery because its reservoir is a special chalk, which collapsed when pressure decreased, leading to a 7 m seafloor subsidence. Production jumped again in 1988 after many wells were drilled for water injection

Figure 14: **Oil decline of Ekofisk (Norway) 1971-2003**

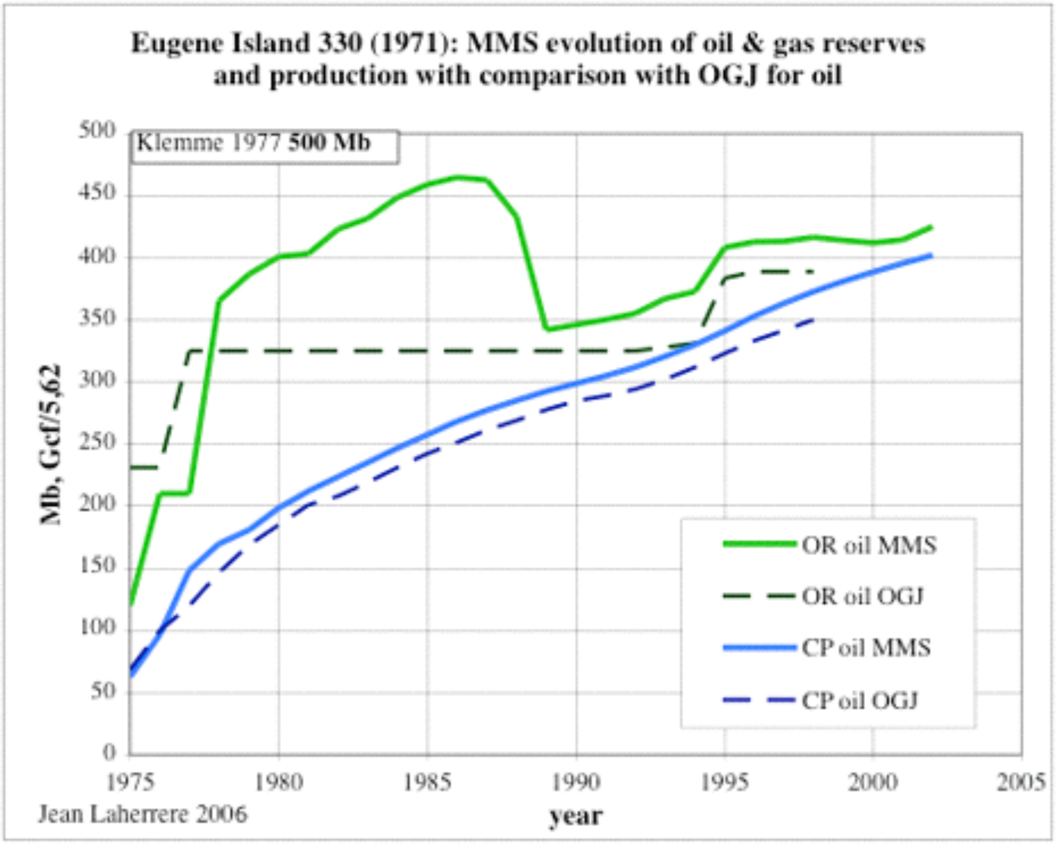


Ekofisk is one of the few examples of positive reserve growth due to exceptional reservoir.

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 15: **Oil decline of Eugene island 330 (Gulf of Mexico)** 1972-2001**=**



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



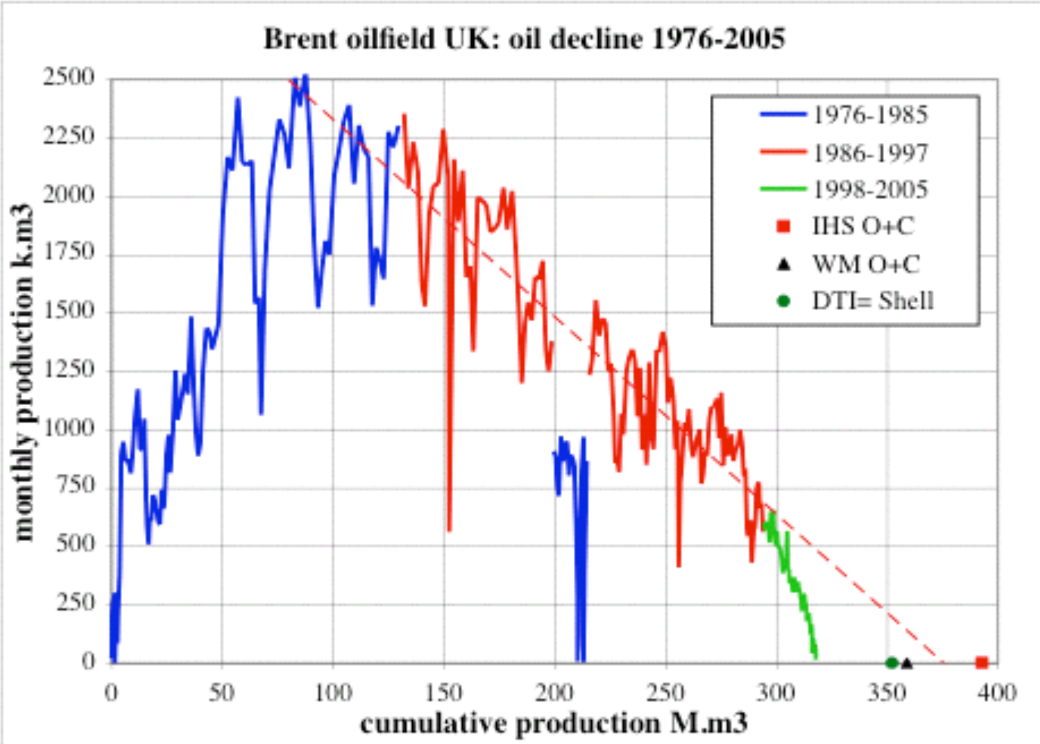
EI 330 is a good example of positive reserve growth on oil decline and a good example of negative reserve reporting when looking at MMS before the counter shock.

Decline in straight line on the plot annual versus cumulative production

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).

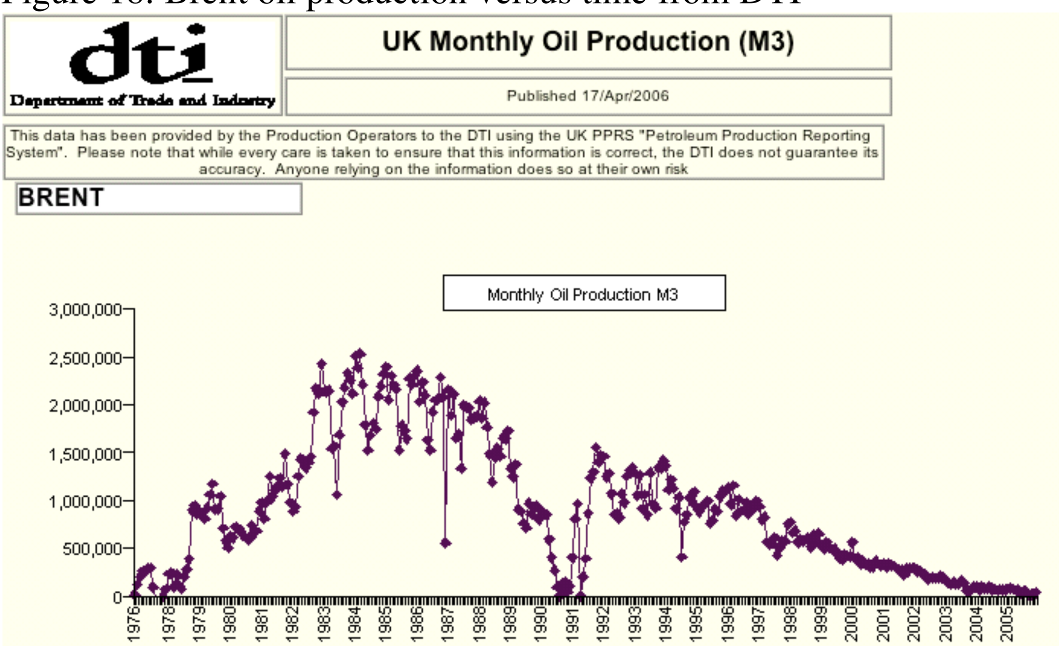
Up to 1997 oil ultimate were estimated to be between 350 to 400 M.m3, but production from 1998 to 2005 (green curve) shows that the ultimate will be around 320 M.m3. There is a break in the oil decline from 1986-1997 and 1998-2005.

Figure 17: Brent oil decline showing a late collapse



But the decline in time looks smooth without any break

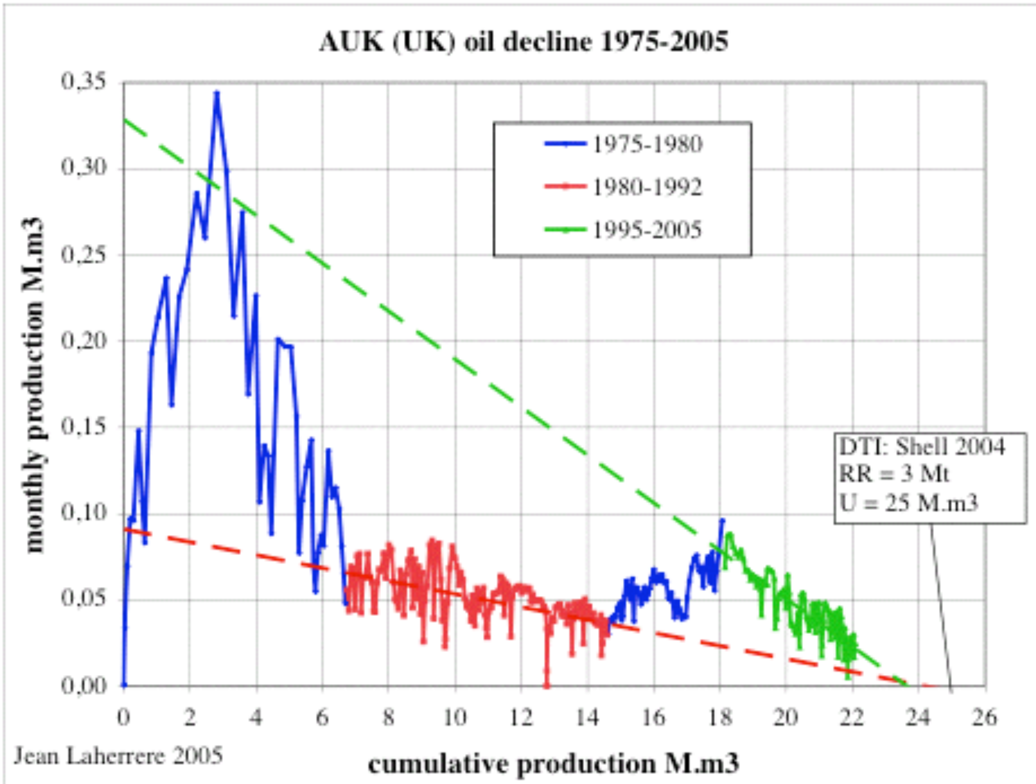
Figure 18: Brent oil production versus time from DTI



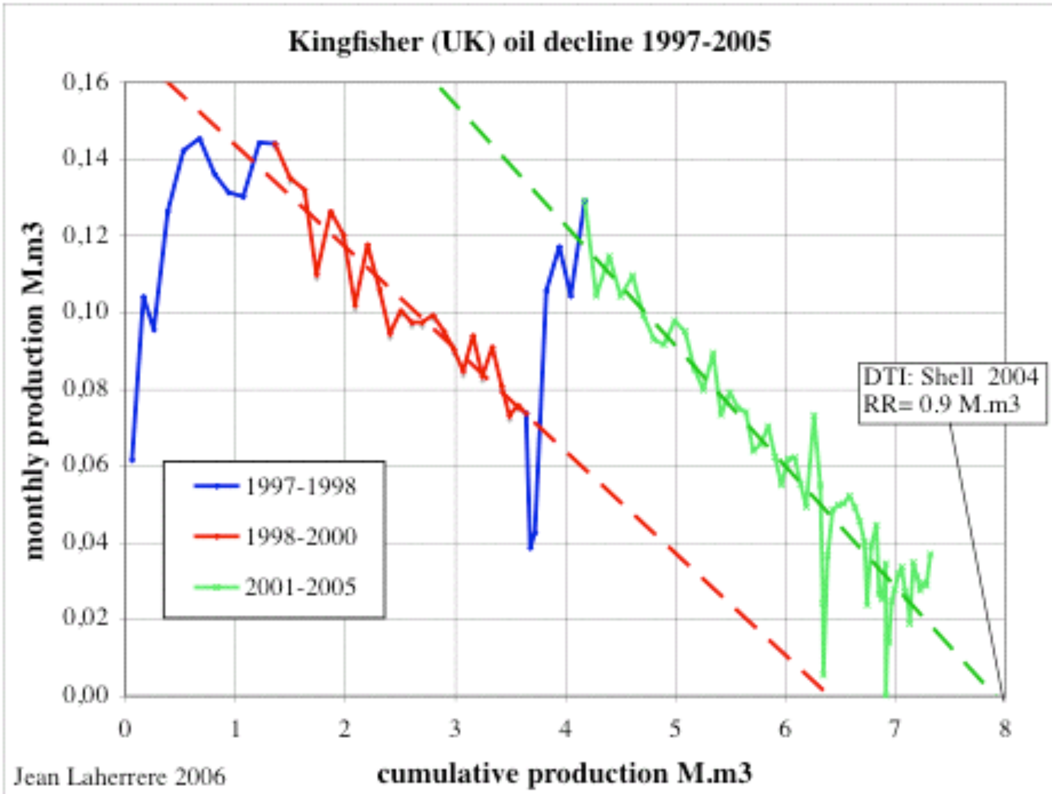
It is funny to notice that the three main oil markers for price are the Brent, Dubai and West Texas Intermediate, all three close to complete depletion!

False 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 19: 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
Figure 20: Kingfisher oil decline 1975-2005



So there are many fields, which show negative reserves growth, and few fields showing a sure positive 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.

EOR (Enhanced Oil Recovery)

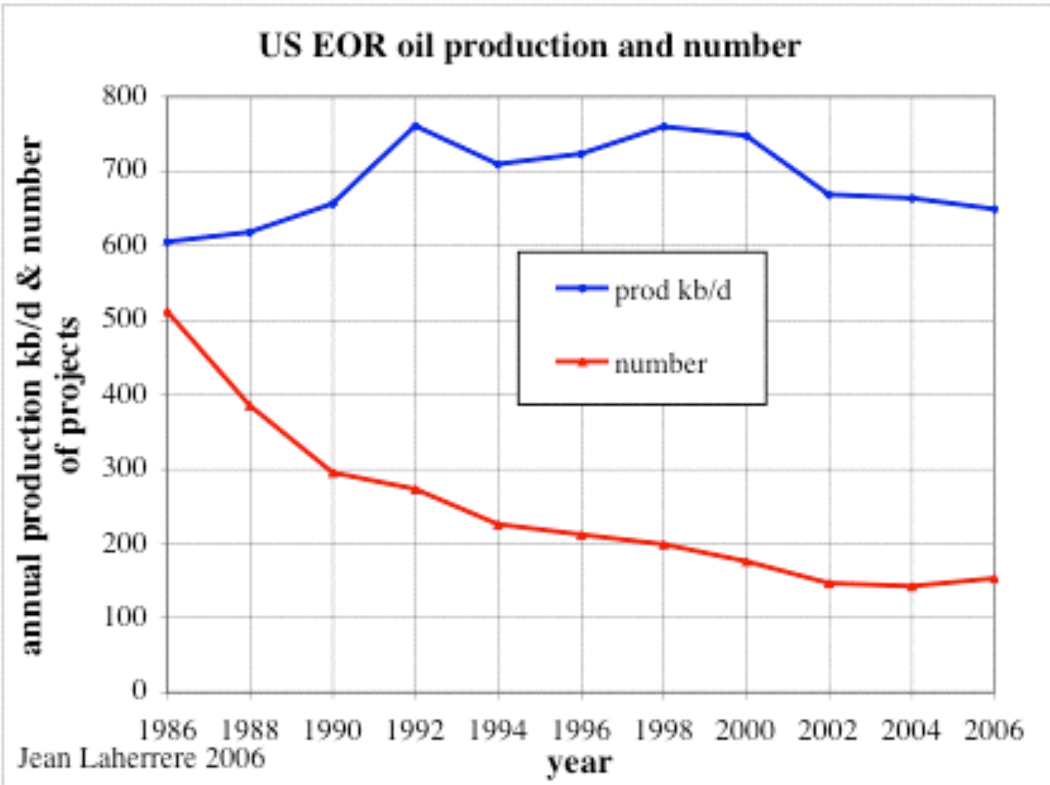
EOR is defined as non-conventional and growth from EOR should not be classified with conventional reserves.

EOR or tertiary recovery changes the characteristics 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 21: US EOR production from OGJ surveys 1986-2006

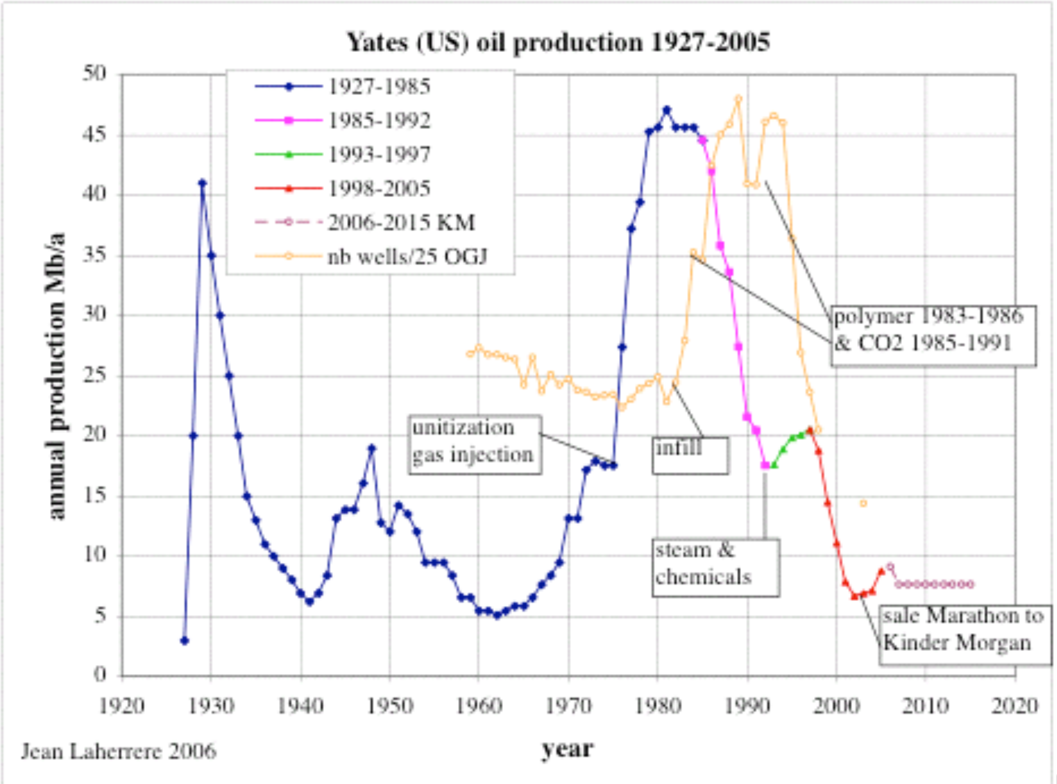


Few EOR work (Farouq SPE 2003 “Projections of EOR production”) on special fields and when successful cannot be used to be extrapolated to every conventional fields.

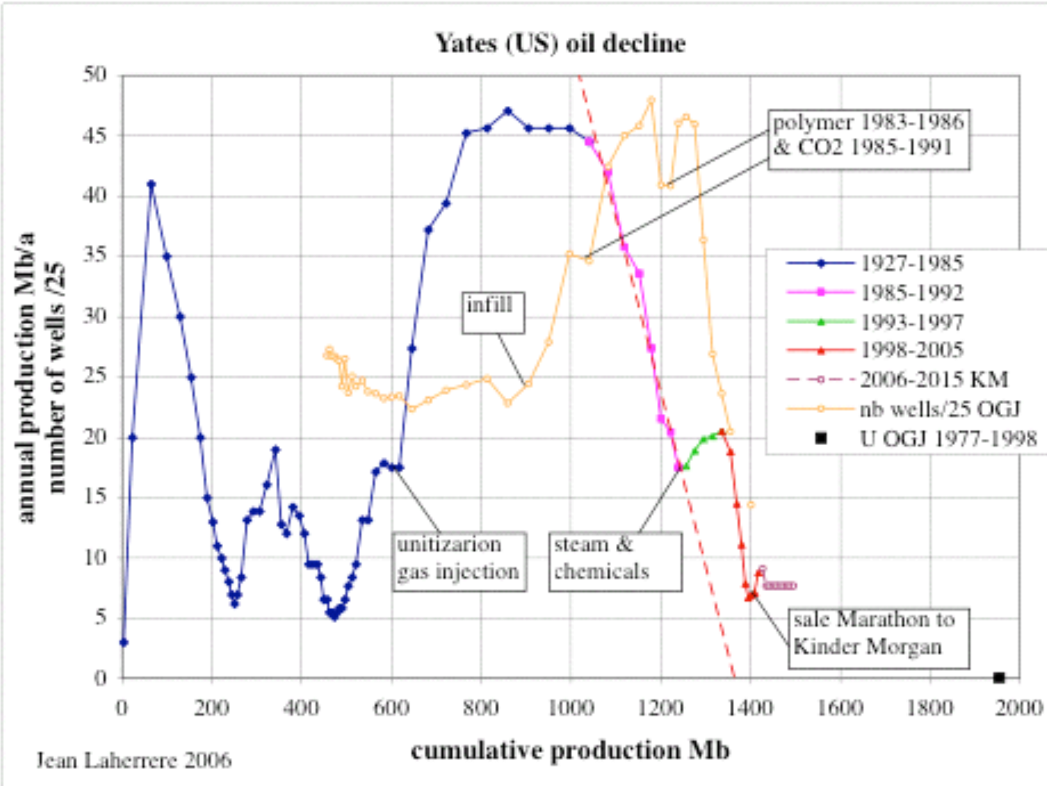
There are many papers on the potential of using CO2 to increase oil reserves. CO2 was used for a long time in the US

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 22: 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 increased 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 23: Yates oil decline 1927-2005 versus cumulative production



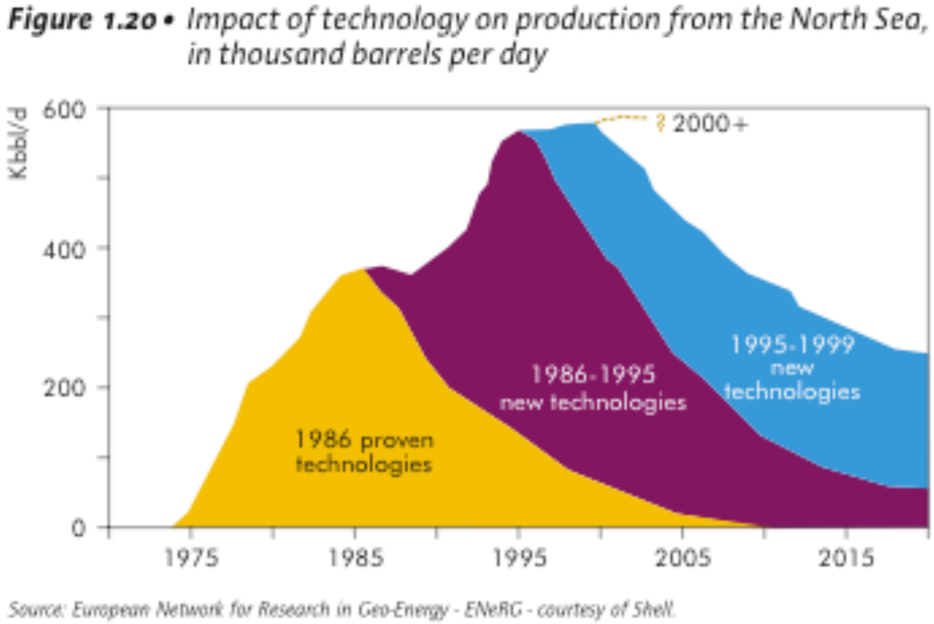
Nehring in OGJ 3, 17, 24 April 2006 claims *Hubbert's unreliability* on the example of the Permian basin estimates based on the lack of recognizing reserve growth, but he estimates Yates ultimate at 2 Gb (as OGJ), meaning over 500 Mb remaining reserves; estimate which looks unrealistic from the previous 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!

Impact of technology

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 proven wrong, that it is not their work?

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 24: May 2005 IEA graph titled *Impact of technology on production from the North Sea* quoting 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 28
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 25: 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)

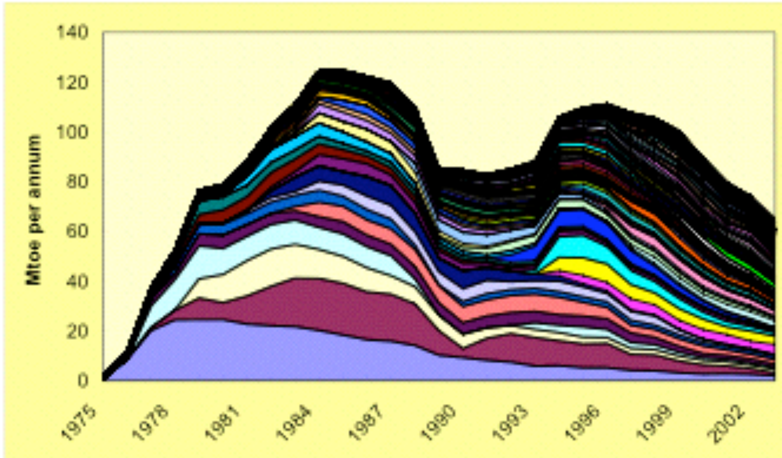


Figure 4.2 : North Sea oil production, UK sector excluding West of Shetland. Different colours represent different fields.

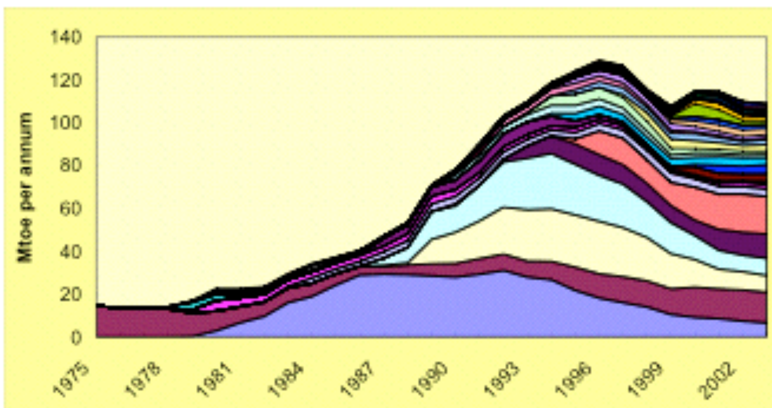
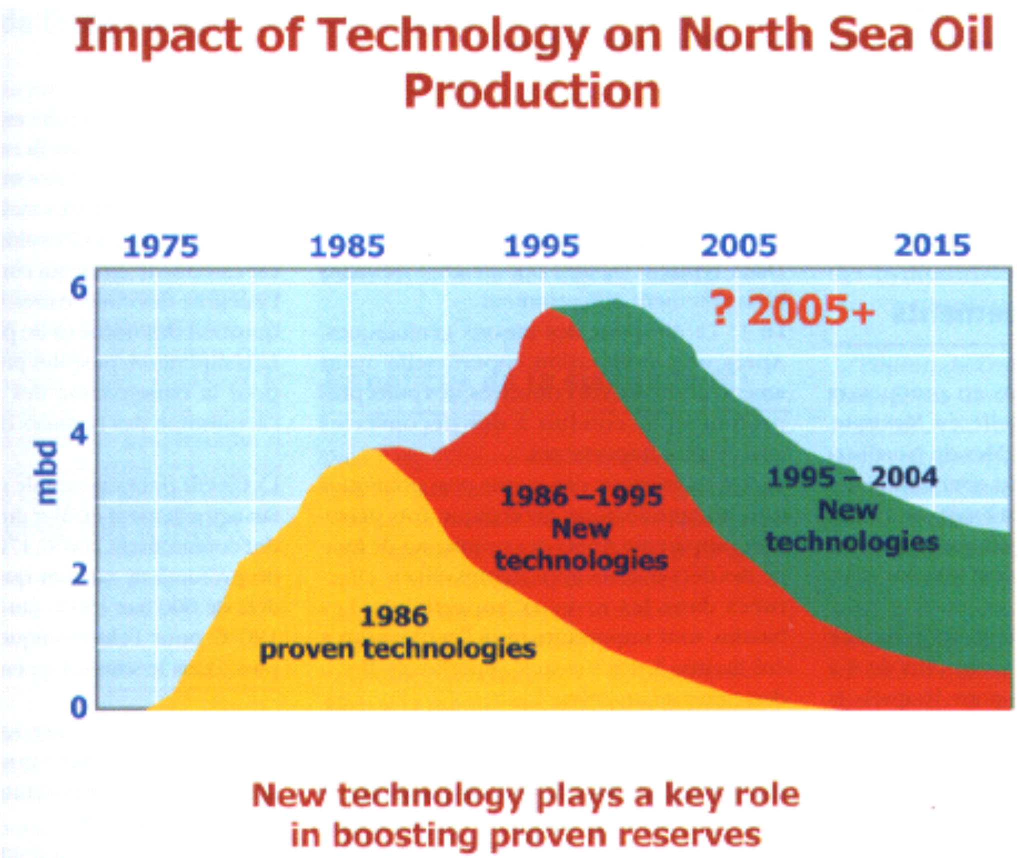


Figure 4.3: North Sea oil production, Norwegian sector excluding Norwegian Sea. Different colours represent different fields.

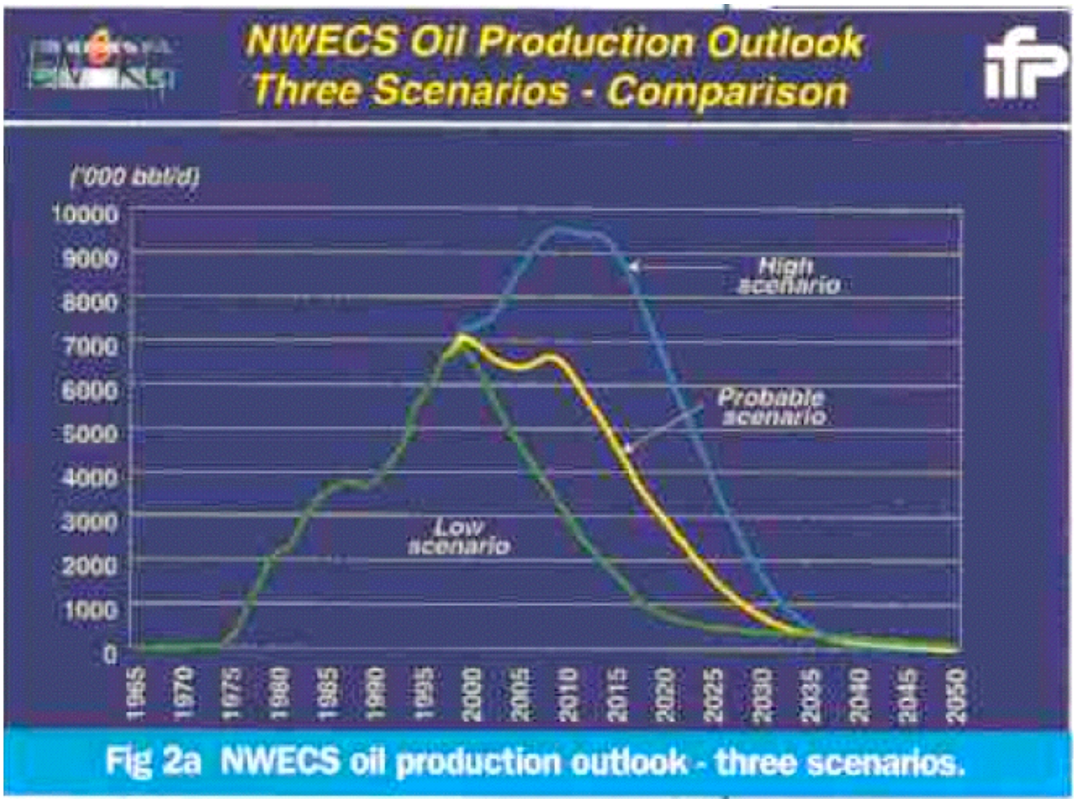
IEA shows in October 2005 (*Jan. 2006 Petrole & Gaz Information p.19)* the same May 2005 graph but redrafted by replacing 1999 by 2004 !! and suggesting a good surprise thanks to 2005+? In the same bulletin p.84, Shell (Rodriguez) displays exactly the same graph as IEA but without the IEA change of 1999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

Figure 26: October 2005 IEA (Pochettino) graph titled *Impact of technology on production from the North Sea,* but Shell is not anymore quoted



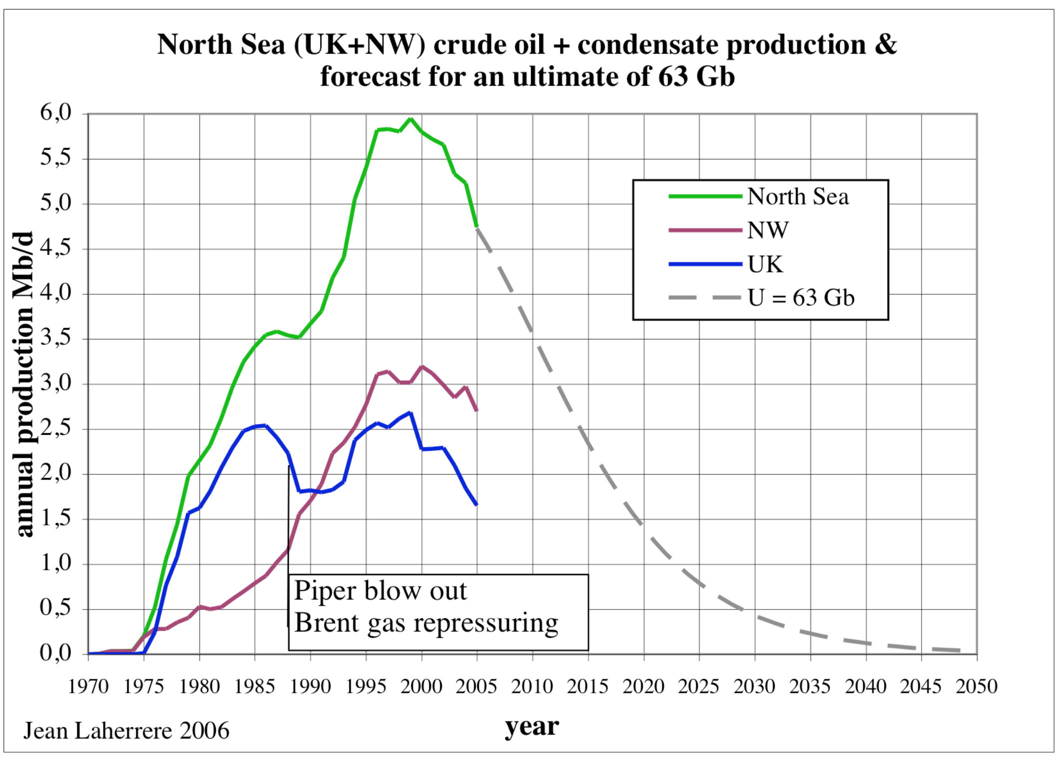
North Sea oil production has peaked in 1999 and the green line is right down to 2005 as shown on figure 28! It is hard to see what is bringing 2005+

European Network for Research in Geo-Energy newsletter Feb 1998 claims "North Sea oil and gas production outlook- a major challenge" production decline will be delayed by 10 years and the probable scenario has a second peak in 2010
Figure 27: North West European Continental shelf oil production with 3 scenarios by IFP 1998

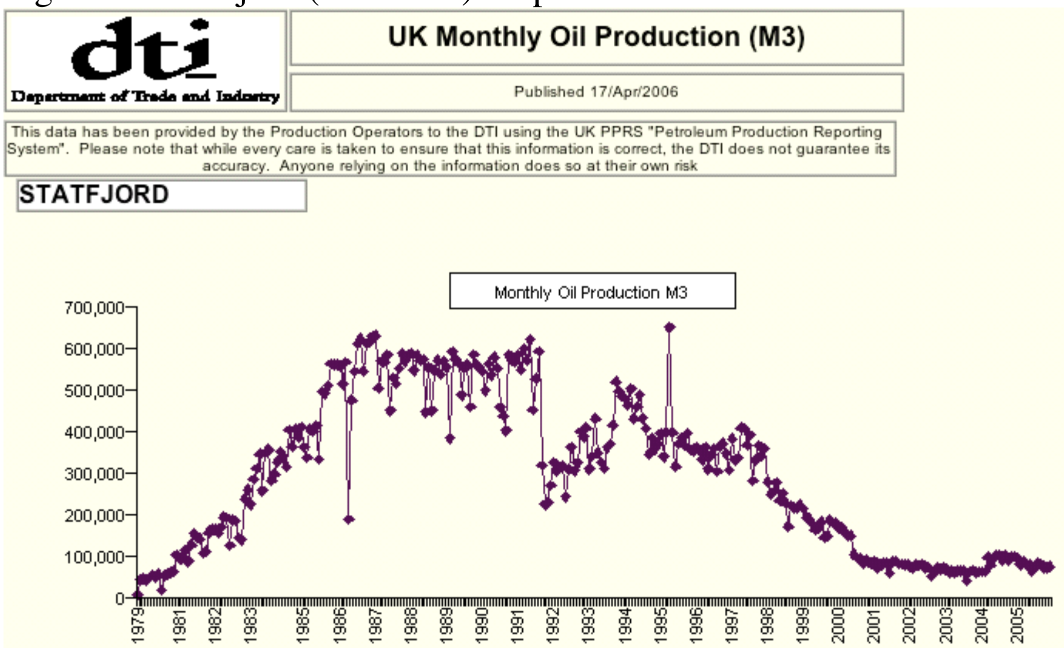


The real data up to 2005 follows the 1998 low scenario and the 1998 probable scenario was pure wishful thinking!

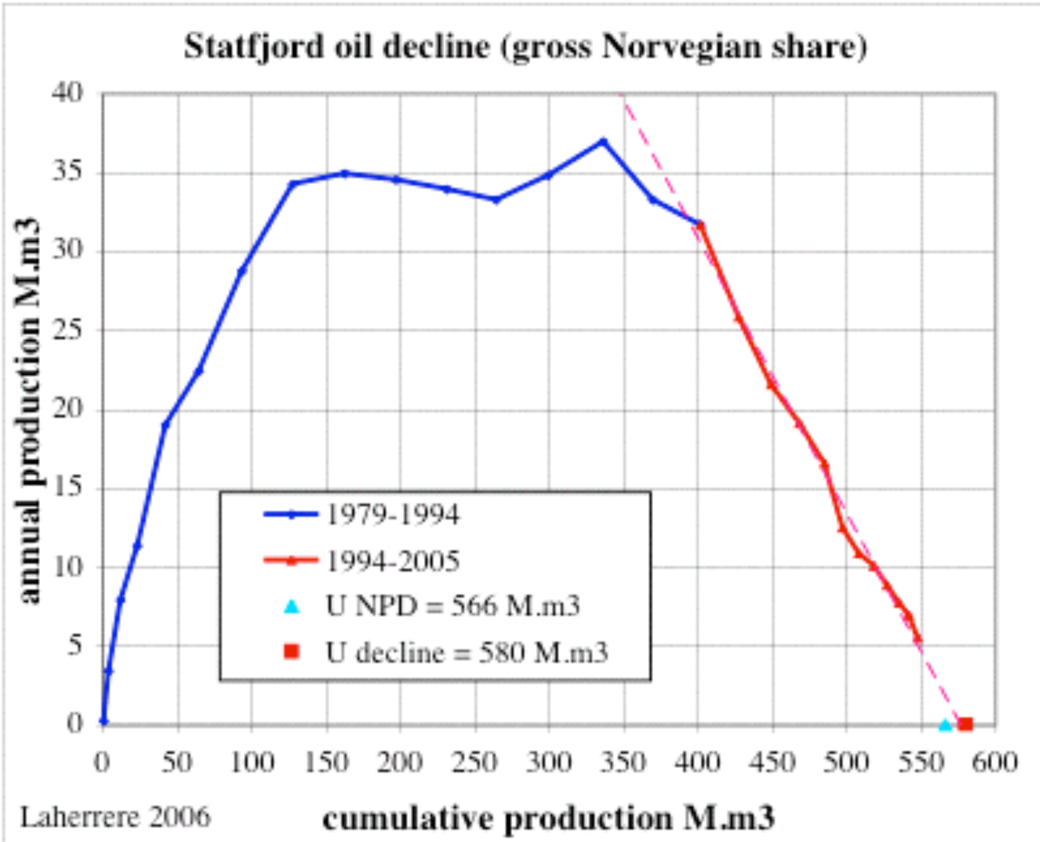
Figure 28: North Sea oil production showing that the IFP low scenario occurs



Statfjord
Statfjord is shared between UK and Norway, but operated by Statoil.
From DTI
Figure 29: Statfjord (UK share) oil production from DTI versus time

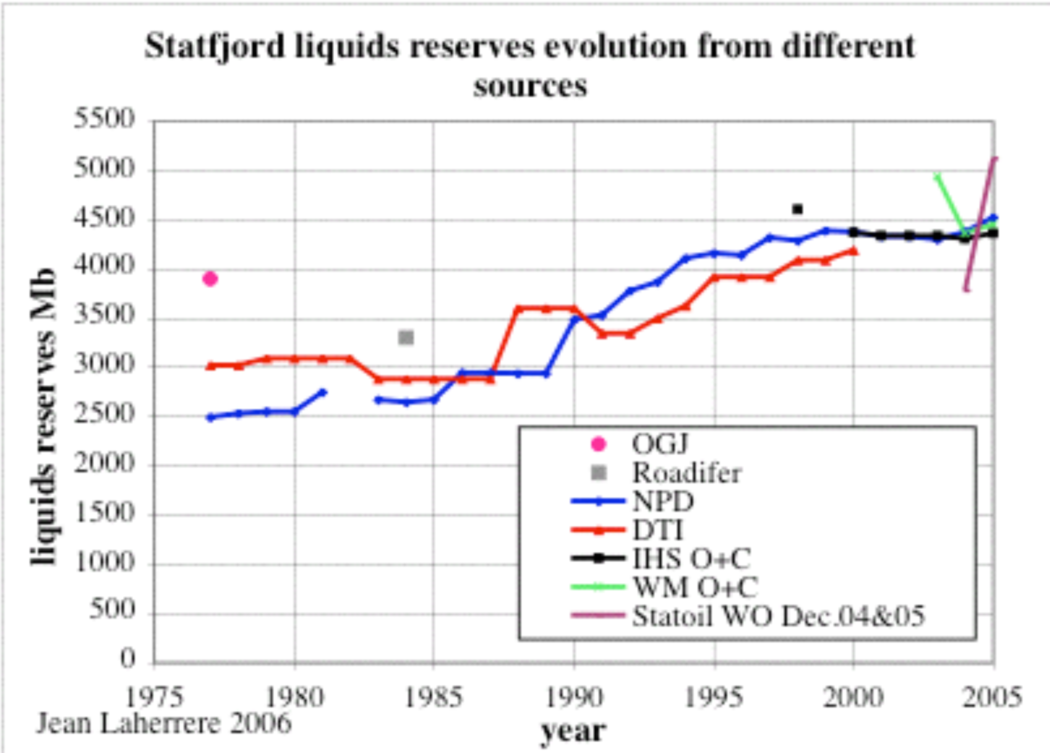


from NPD
Figure 30: Statfjord (Norway share) oil production from NPD versus cumulative production



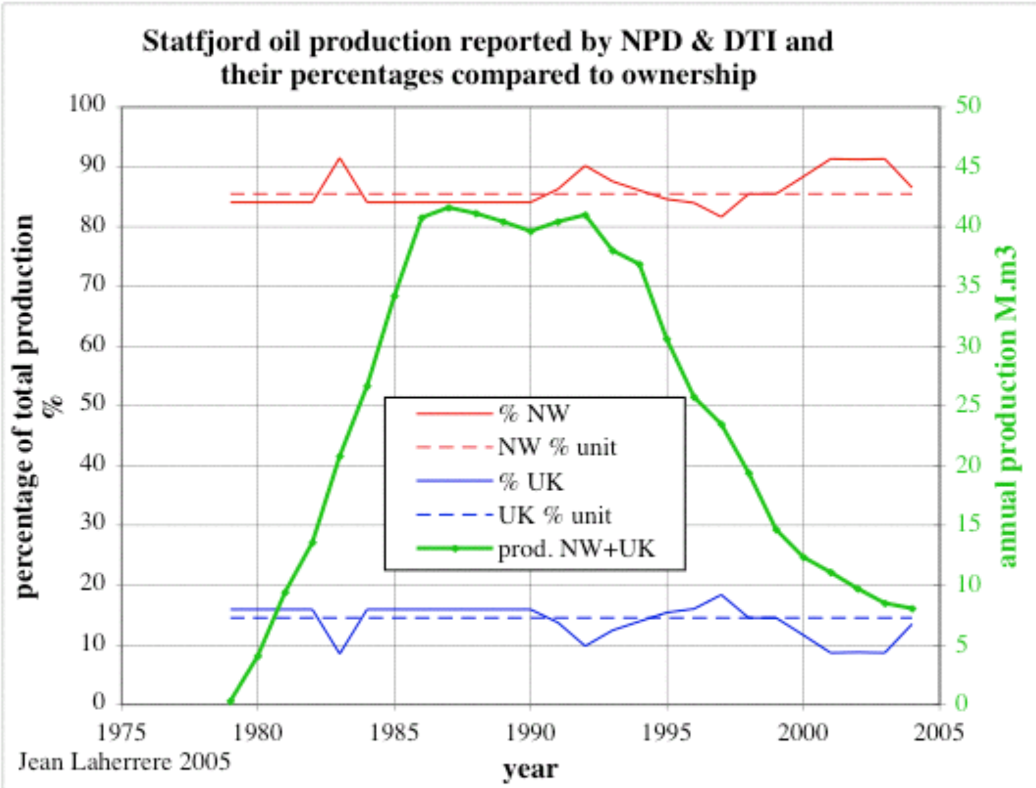
In World Oil December 2005, CEO Statoil T.Overvik stated that Statfjord is expected to recover **64 % of 8 Gb oil in place** (OIP), compared to 48 % in 1979, hoping to reach 70% in the future. But in WO December 2004 Overvik was talking about recovering **63 % of 6 Gb OIP**. Is the change of OIP a typing 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 31: 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?

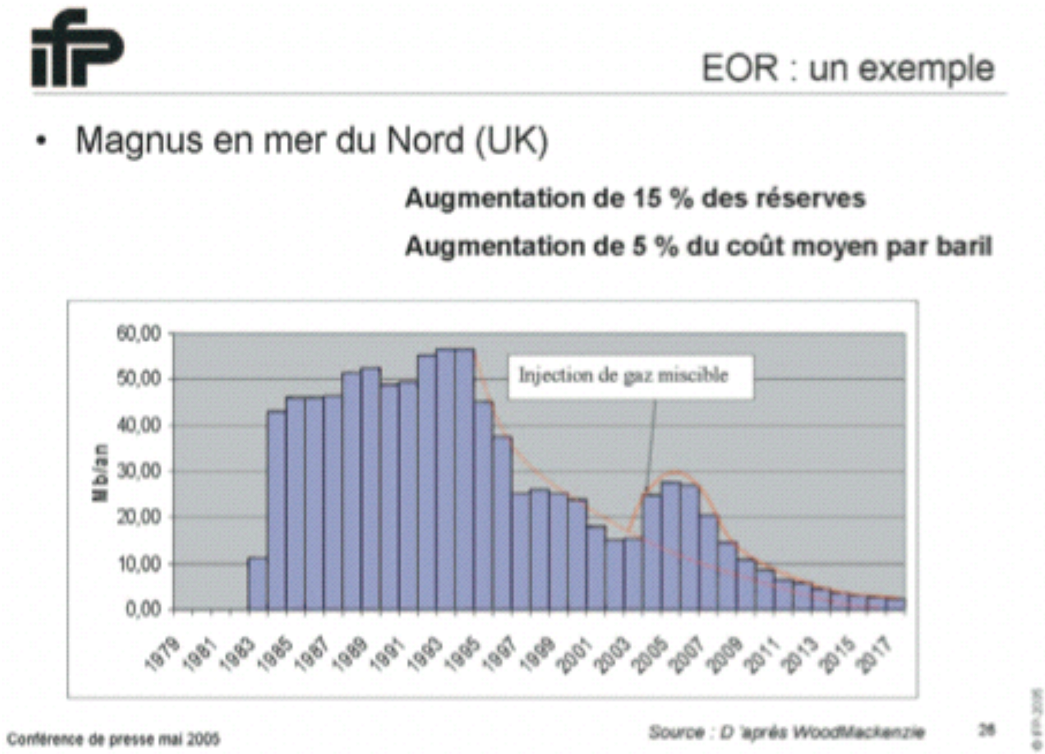
Figure 32: Statfjord total production reported by DTI and NPD and their percentage compared to ownership



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 33: 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 34: Magnus EOR (miscible gas) scheme

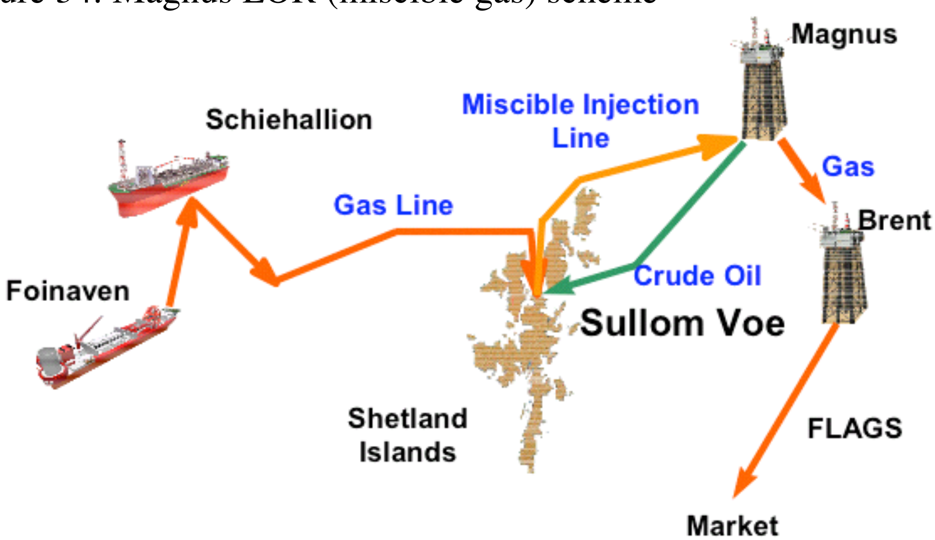
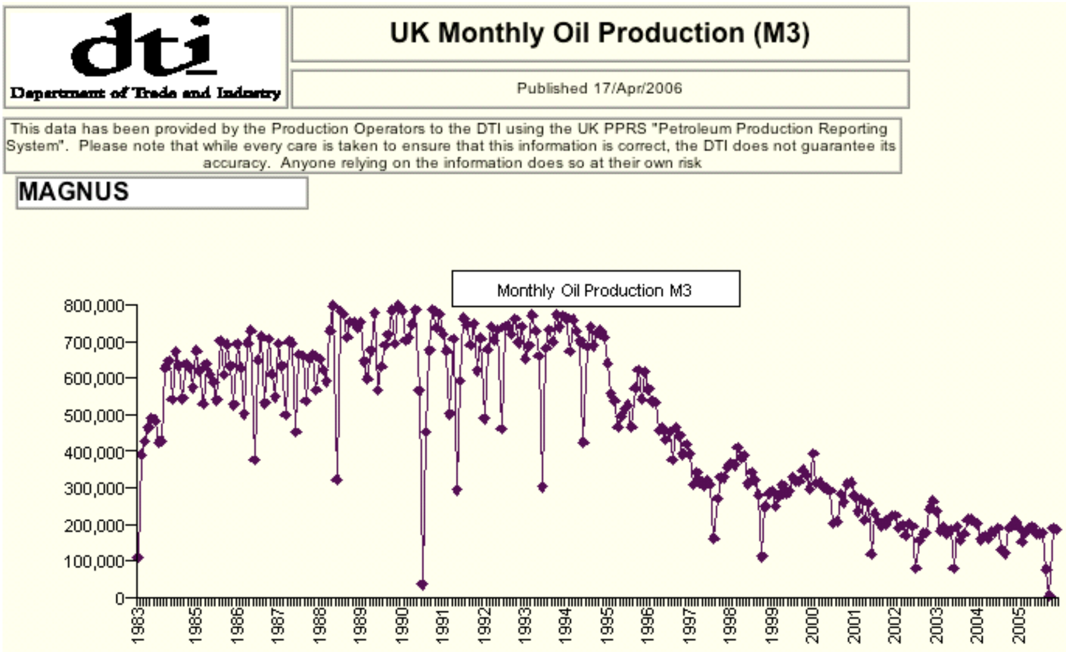


Figure 20: Schematic of Magnus EOR project.

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

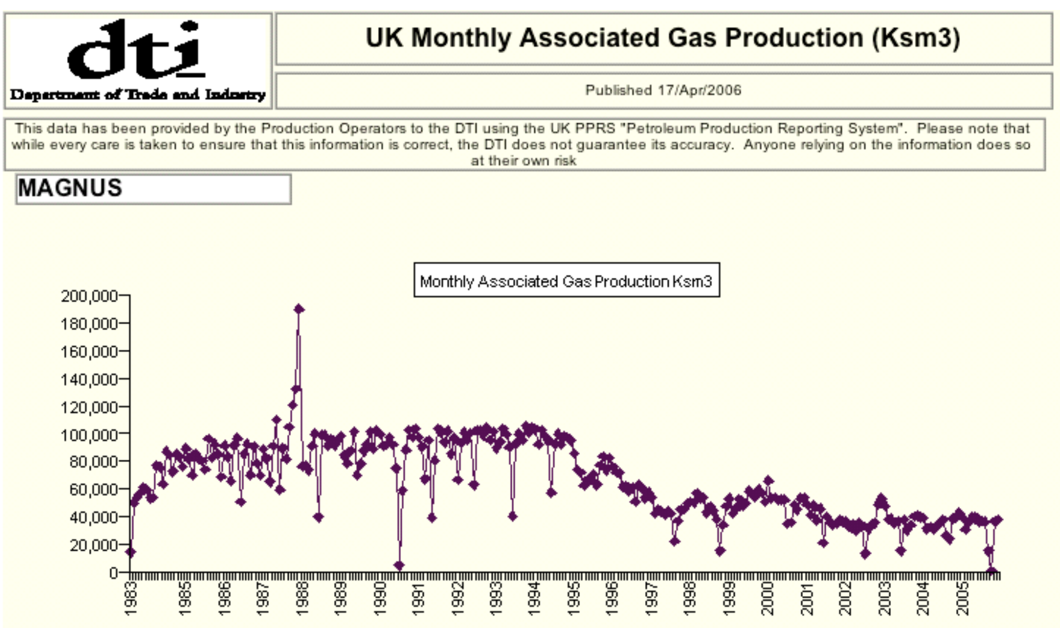
Oil production

Figure 35: Magnus oil production from DTI = no increase in 2005



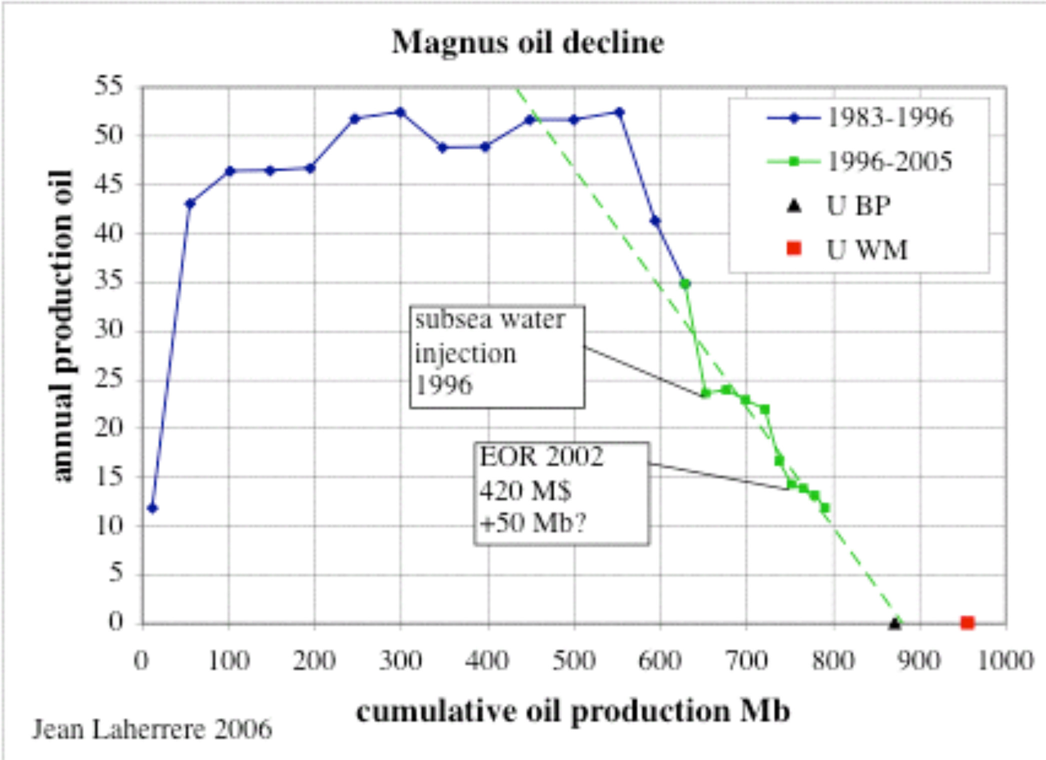
neither in the gas production

Figure 36: Magnus gas production from DTI = no increase in 2005



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

Figure 37: 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 oilfield).
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.

OPEC reserve growth

On figure 3 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
1980	65.4	6.26	164.3
1985	90	5,42	169
1990	94,5	5,2	255
2005	101	5	264

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

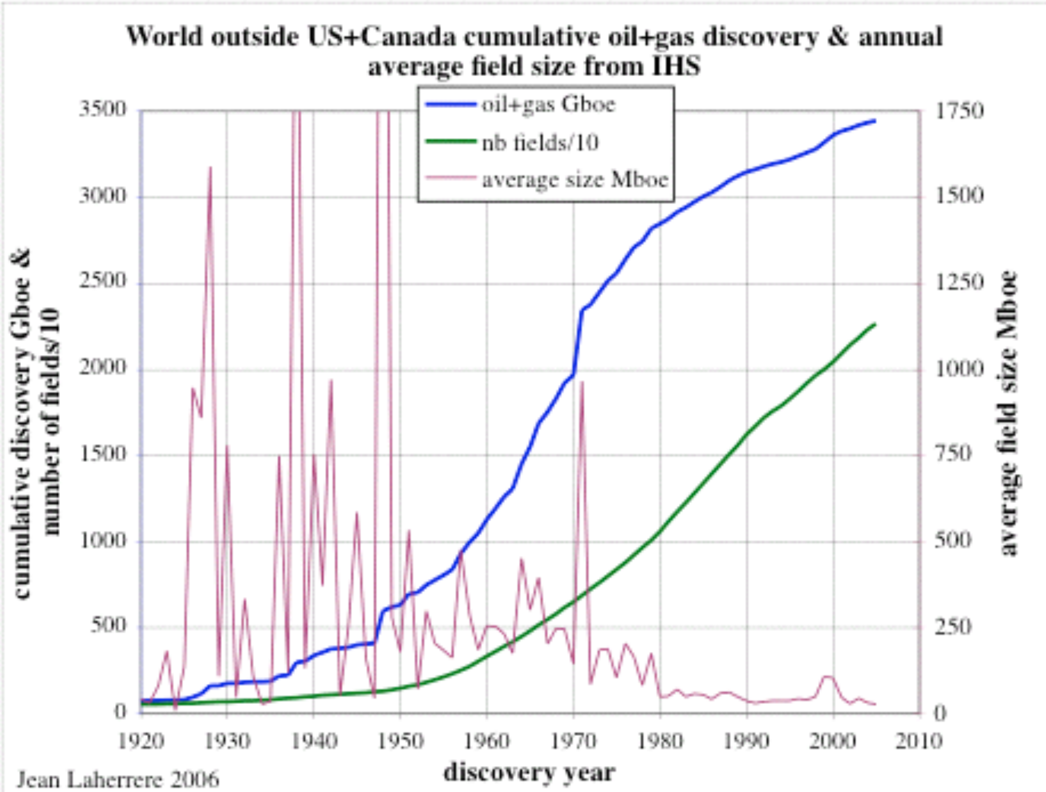
There were as many wildcats in NZ and in Kuwait, but the addition by wildcat in the last 25 years was more than 10 times higher in Kuwait than in NZ when the two areas are close. Kuwait reserves are overestimated as recognized by PIW (Petroleum Information Weekly) recently. It seems that Saudi Arabia 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
OGJ	101	5	264
WM	34	4,3	174
OGJ/WM	3	1,2	1,5

Field size decrease

IHS database reports, for the world outside US + Canada, a cumulative discovery of oil and gas up to 3500 Gboe and 23 000 fields in 2005. The average field size displays peaks higher than 1.5 Gboe before 1950 and a decrease since except in 1971 with North field discovery in Qatar/Iran and 1999 with Kashagan.

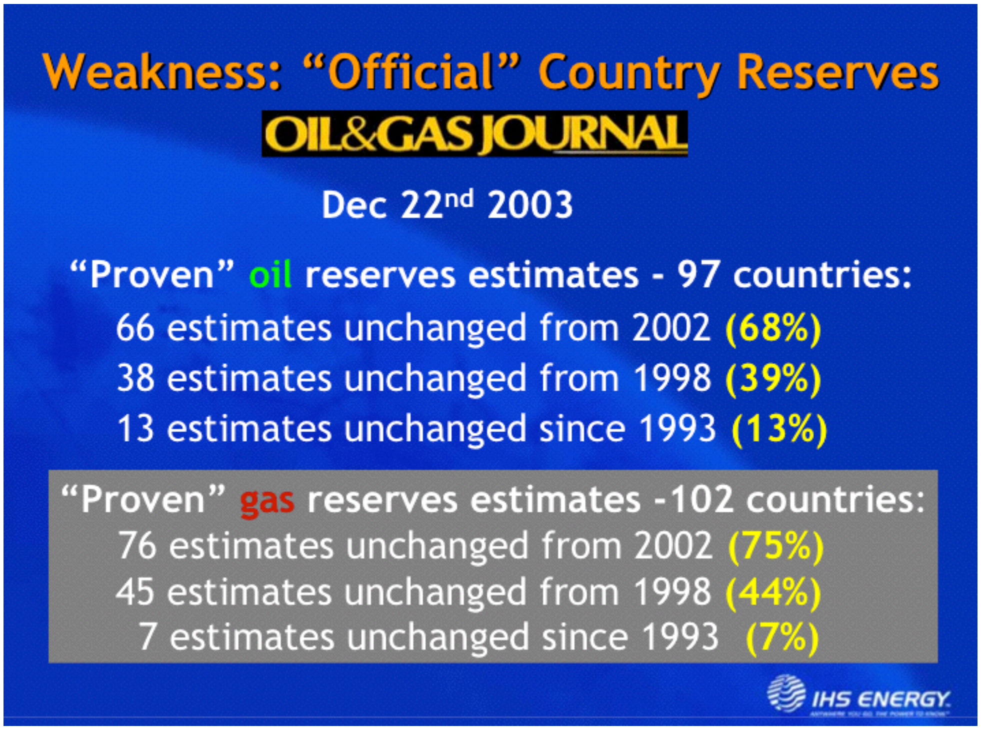
Figure 38: World outside US + Canada cumulative oil+gas discovery and average field size from IHS



-**Political reporting**

OPEC oil quotas are based on reserves and there is little change in OGJ reporting

Figure 39: IHS comments on Oil & Gas Journal 2003 reserve annual survey on last week of the year for the first of following year



OPEC members do not change because it will upset the quotas. Other countries do not bother to answer because the technical study is not yet carried out.

-Personal motives:

People in charge wants to show that he is better than his predecessor and changes completely the message, as it can be seen for the IEA when only the head of the long term analysis is changed

Figure 40: **IEA 1998 forecast by JM Bourdaire: there is a problem**

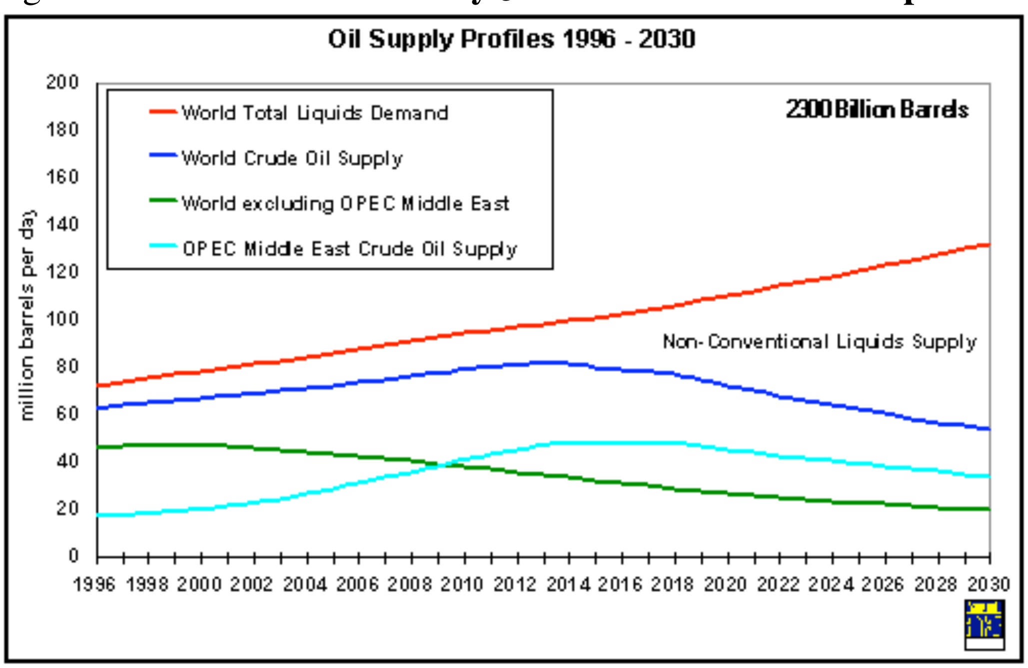


Figure 41: **IEA 2002 forecast by O. Appert: there is no problem,**

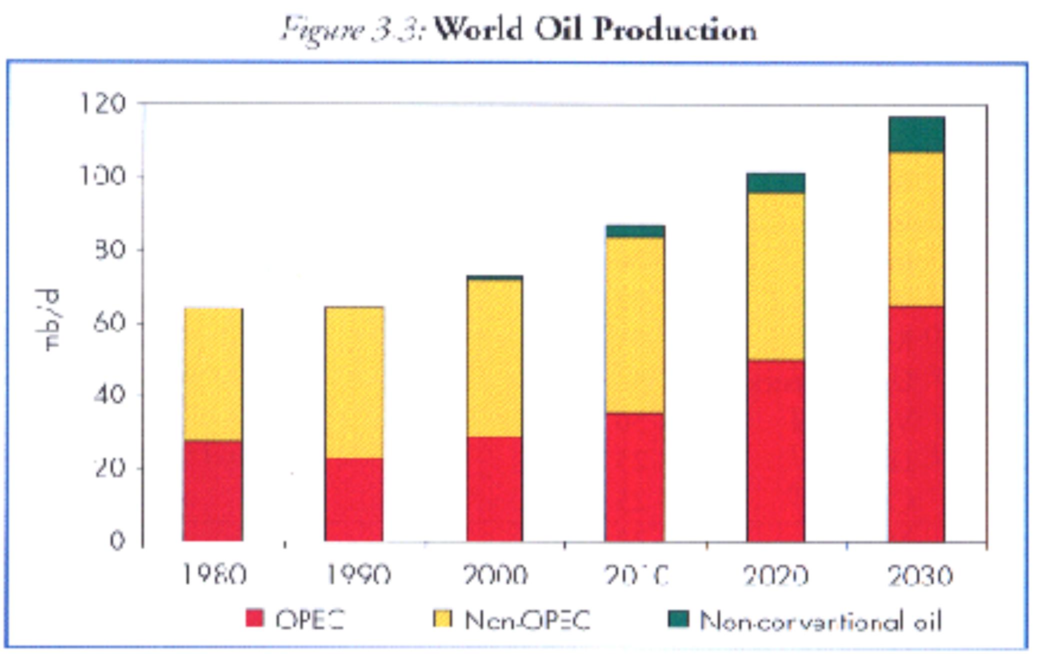
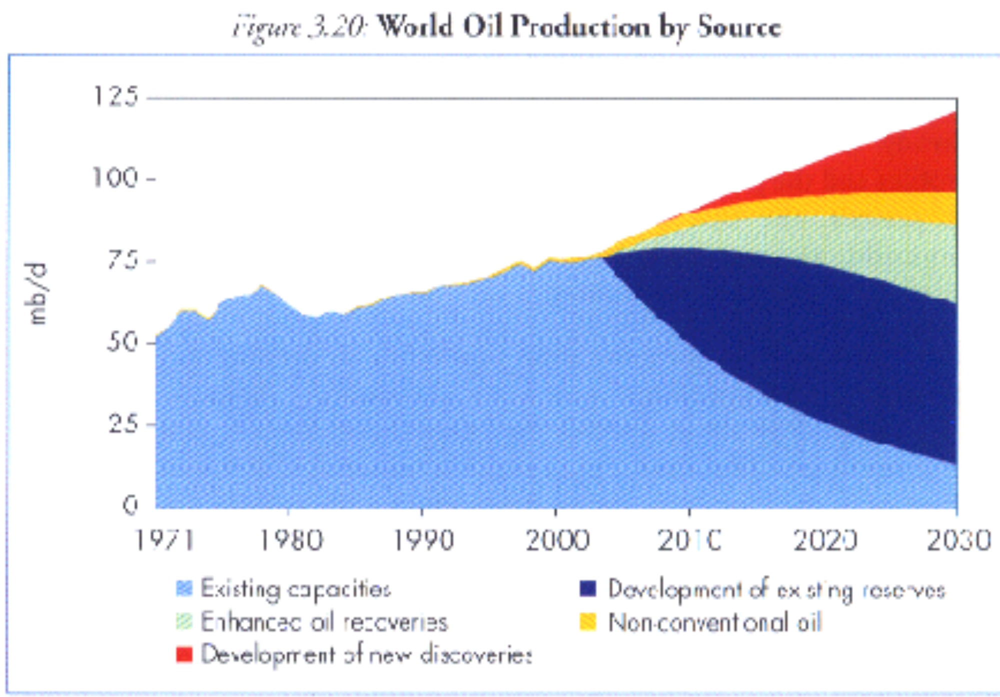


Figure 42: **IEA 2004 forecast by F.Birol: there could be problem**

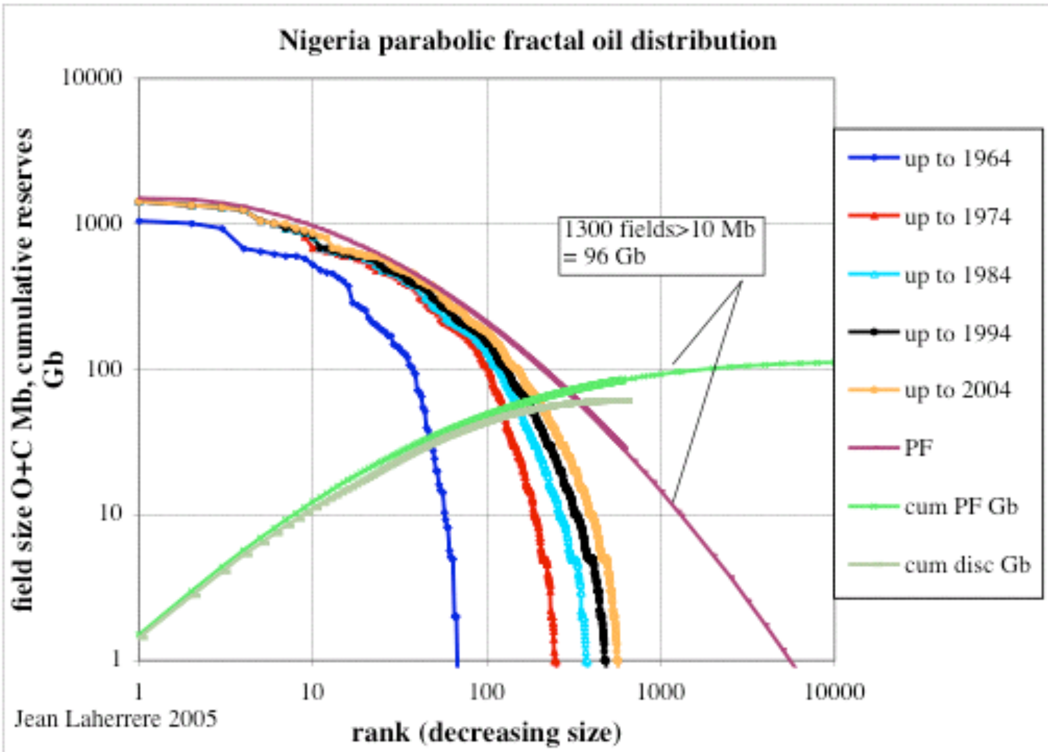


-Oil

Reserves distribution

Oil reserves gather in fields as human beings in urban agglomerations or stars in galaxies or earthquakes. It is not, in a size-rang log-log graph, a power law (straight line) as reported by many, but a parabolic fractal as shown by the distribution in the Niger delta :

Figure 43: **Nigeria parabolic fractal distribution (Niger Delta petroleum system)**

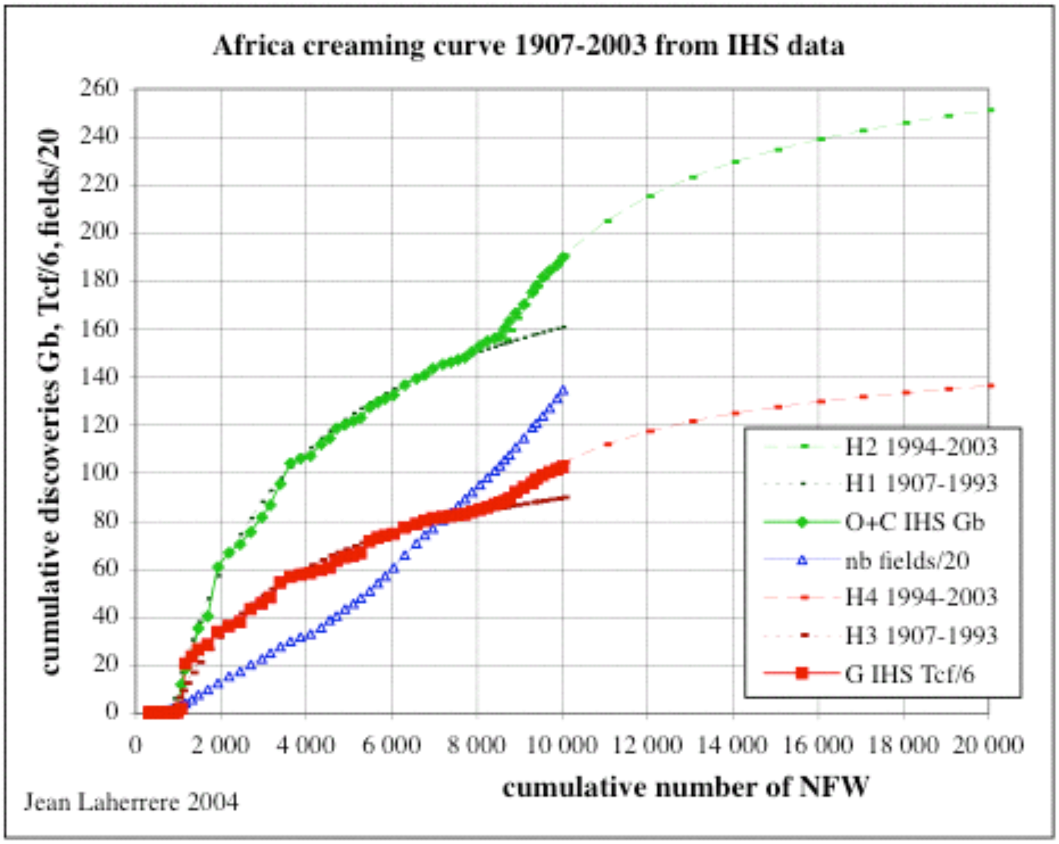


-Creaming curves

Creaming curves (= cumulative discovery versus cumulative number of pure exploratory wells = New Field Wildcat = NFW) is the best tool to estimate ultimate when the reserves are the backdated mean. Surprising it is always easily modelled with several hyperbolas, showing the known “law of diminishing returns” in mineral exploration.

Africa is a good example with a new cycle of deepwater in 1994 for oil and gas when the trend in number of discovery does not change (it did in the 1960s with better seismic with multiple coverage)

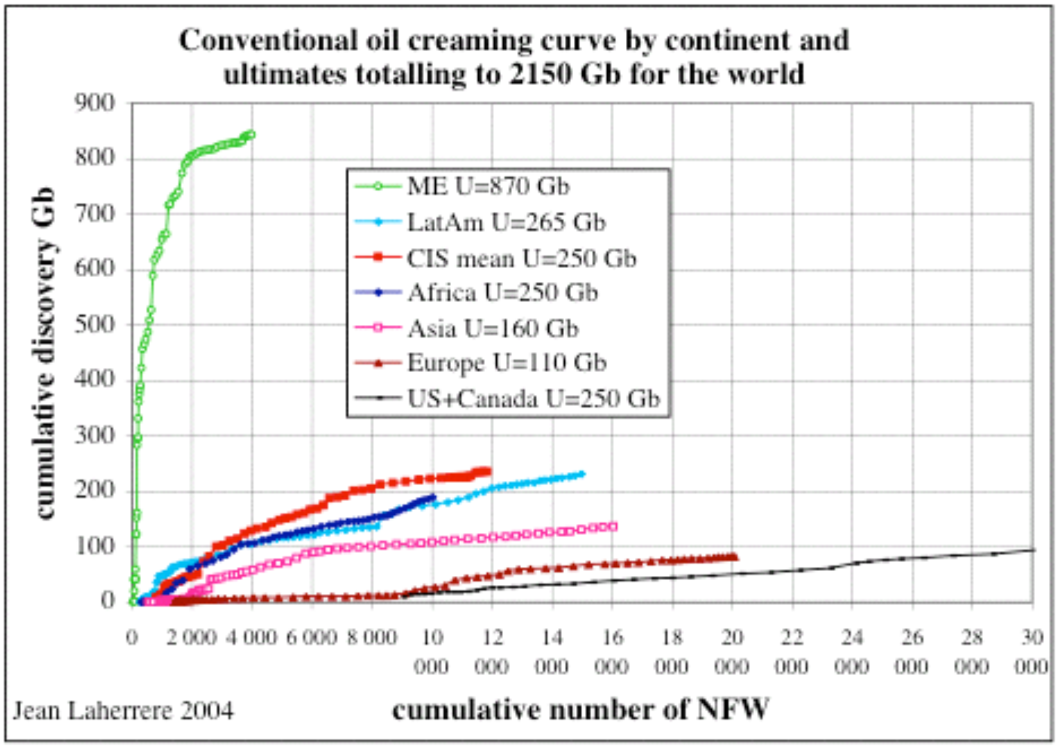
Figure 44: Africa oil creaming curve 1907-2003



The comparison of creaming curves by continent displays a wide range, meaning that continent are differently endowed with oil.

Middle East has found 850 Gb with 4000 NFW when Europe 80 Gb with 20 000 NFW and US 210 Gb with 330 000 NFW.

Figure 45: **Conventional oil creaming curve by continent**



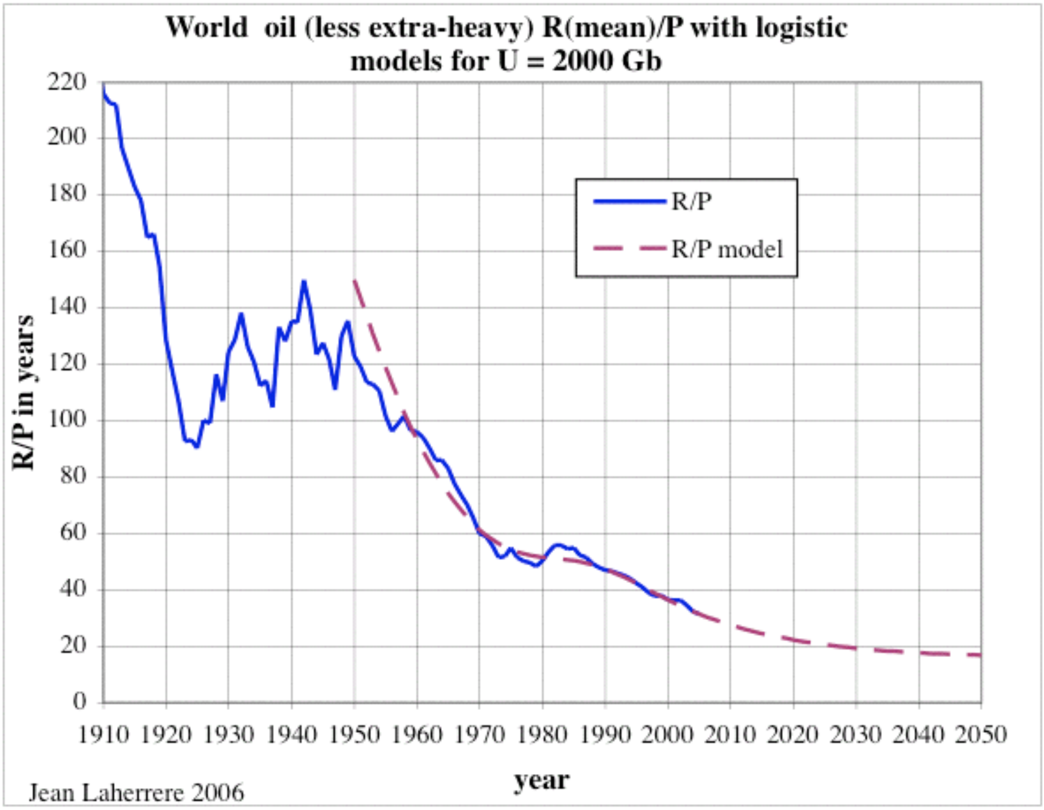
Creaming curves are rarely used in estimating ultimate because very few has the data on historical NFW. When exploration activity was not discontinuous, ultimate can be estimated by modelling cumulative mean discovery versus time using logistic curve as in figure 53.

-Oil production forecast

R/P: very often used by the medias

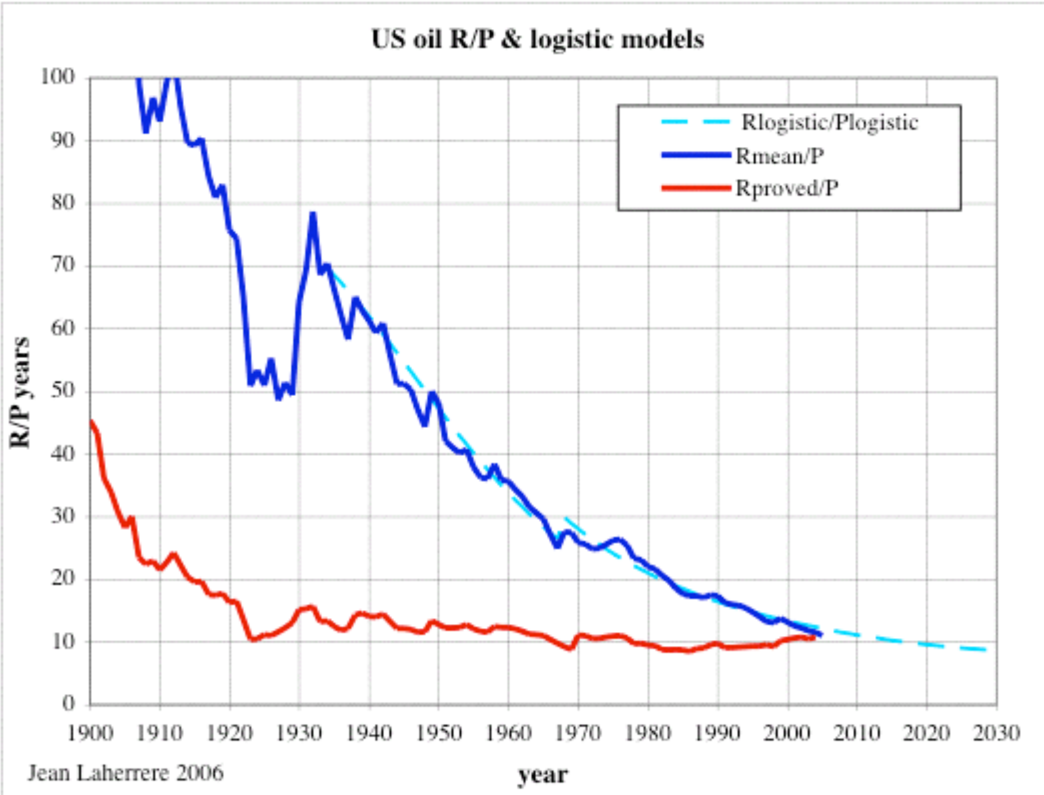
Medias and politicians claimed that there is oil for the next 40 years and gas for 60 years, but it is using proved reserves from political or financial sources. The ratio is different when using technical data (backdated mean). As mean reserves can be modelled with several logistic curves, R/P trends towards an asymptote which is related to the width of the last logistic curve, for the world about 20 years.

Figure 46: **World R/P from technical and political sources**



R/P from US proved reserves is about 10 years since the last 80 years, showing that R/P is useless for forecasting! R/P from mean discoveries decreases and trends towards also 10 years with logistic models.

Figure 47: US R/P from mean backdated reserves and from proved current as logistic model



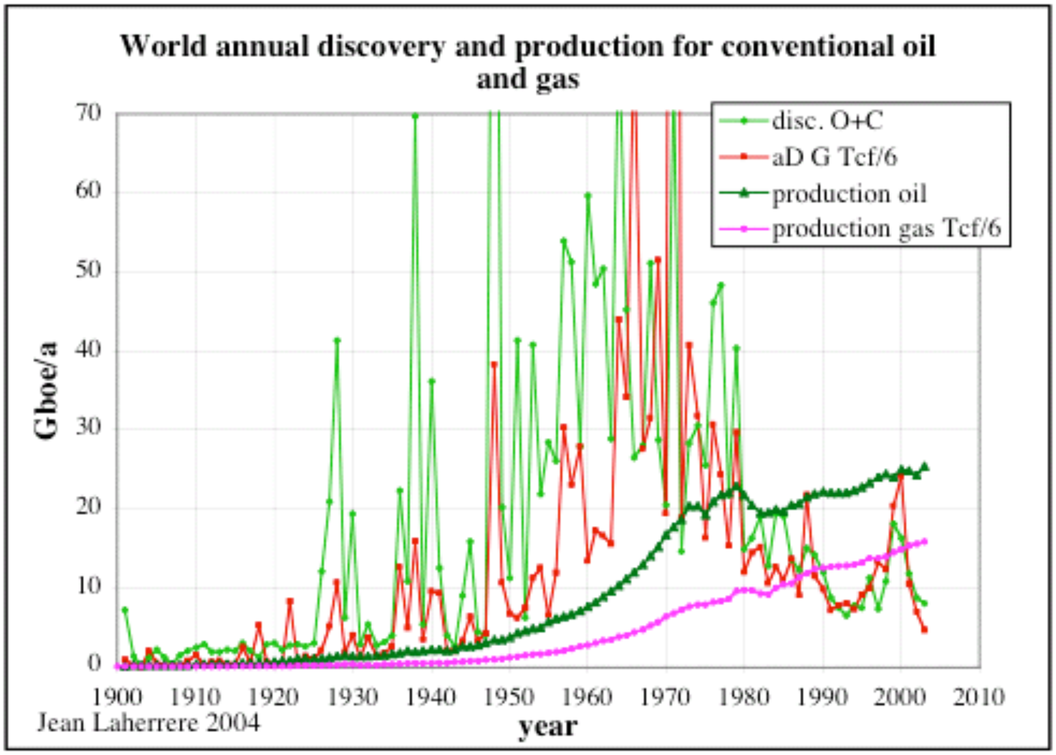
The last US barrel will be produced with still 9 barrels reserves in the ground, which will be then going back to resource status.

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

-Future production

It is necessary to well know the past to forecast the future. Any forecast showing less past than future should be rejected. The whole history has to be presented

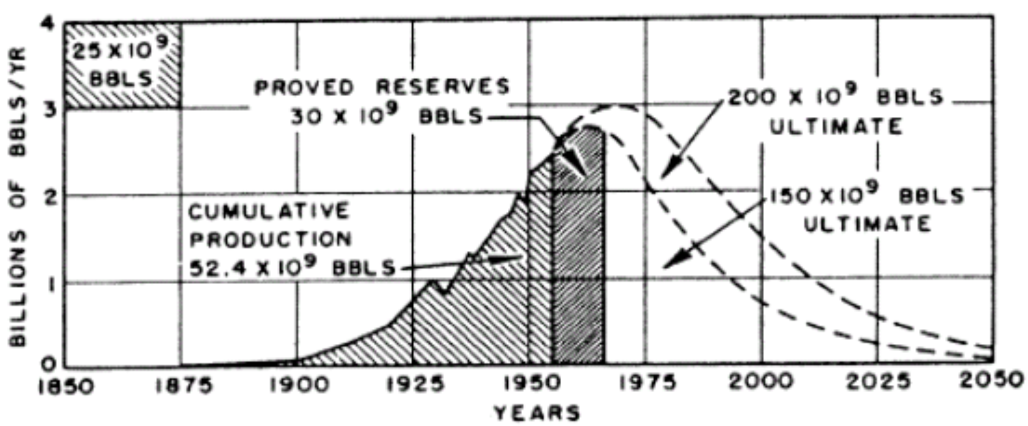
Figure 48: **World annual discovery & production for conventional oil & gas**



Since 1980, oil production is more than twice discovery (Chevron willyoujoinus.com), gas production about discovery

Forecasting using ultimate

Figure 49: **King Hubbert forecast the US oil production in 1956**

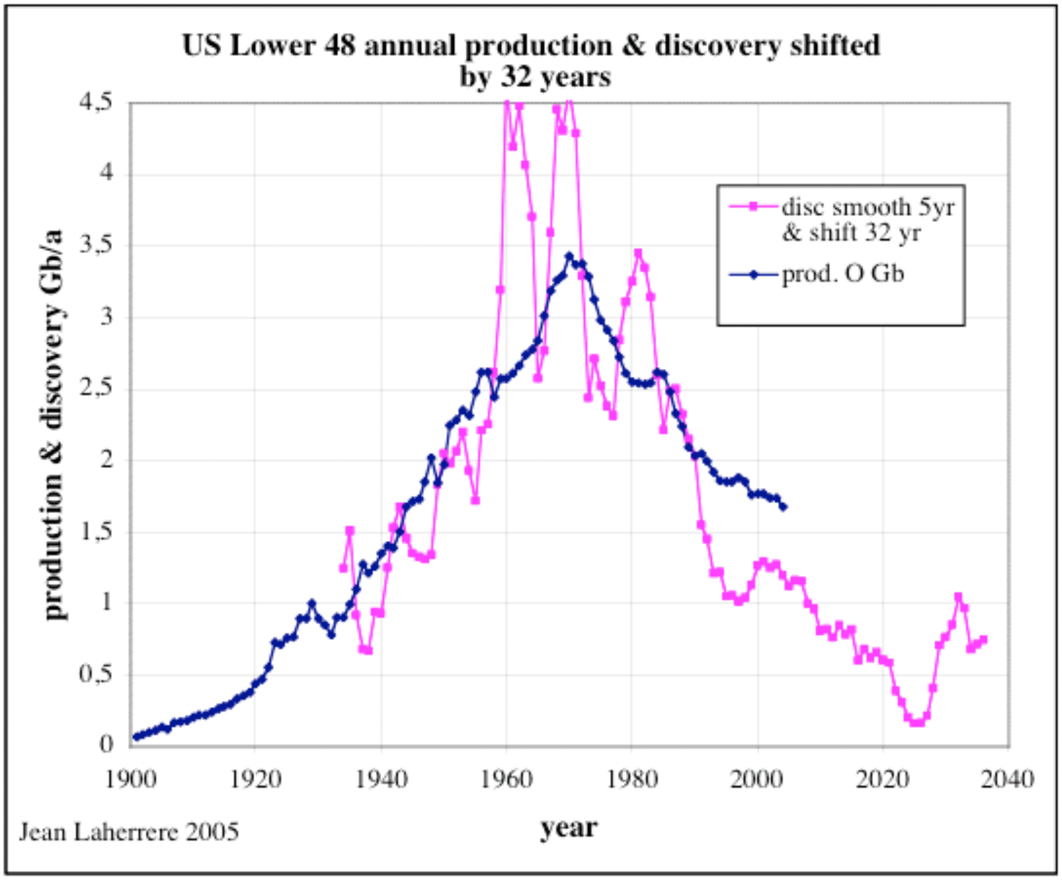


Hubbert forecasted in 1956 from his hand plot (area below the curve = ultimate U) that US oil production will peak in 1965 for U=150 Gb = his estimate or 1970 for U=200 Gb (highest value of Delphi survey)

Nerhing (2006) claims that Hubbert's method is to use the ultimate from the discovery curve, and Nerhing for San Joaquin and Permian basin uses for ultimates (EUR) the proved data at different years, saying later that these EUR were wrong.

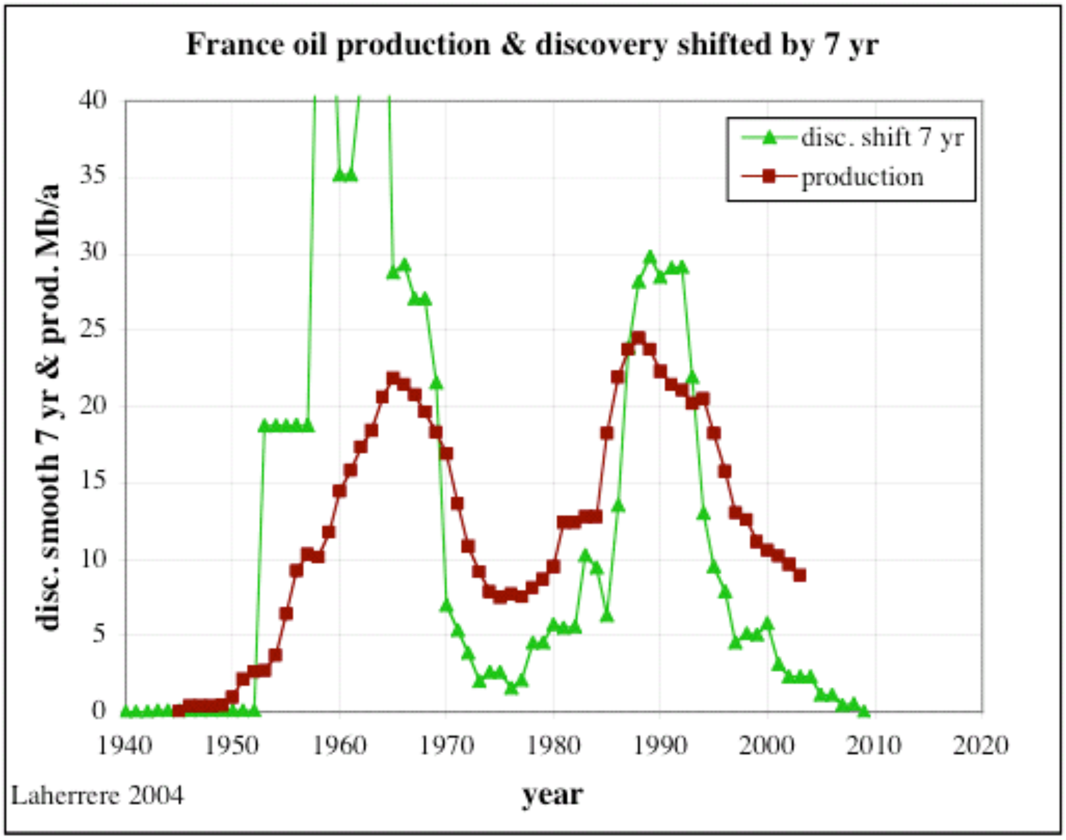
It is using proved reserves data which is wrong, because proved data is for banker use and should not be used for forecasting. Hubbert did not use the proved cumulative so-called discovery being in 1956 as 52+30= 82 Gb, but the geological estimates of 150 Gb and 200 Gb. It is why Hubbert's forecast was right. Using an ultimate of 82 Gb as Nehring is doing for his examples will change completely the oil peak forecast. Nehring should use ultimate estimated by geologists and not financial one. What Nerhing calls discovery is in fact political addition! He should backdate the field reserves to get a good ultimate with creaming curves, as he has his own field database (used in 1992 by USDOE/EIA for his report 0557 "Geologic distributions of US oil and gas"). In 1990 the USDOE published the only report backdating US fields: EIA-0534 "US oil and gas reserves by year of field discovery" that I use to get the US *mean* discovery. Unfortunately Deffeyes is doing the same error, but it is because he has only current proved data, which is not the case of Nerhing!
US (excluding Alaska which joined only in 1959) production peaked in 1970 as the ultimate is close to 200 Gb and random behaviour (normal curve) can be expected as there are over 20 000 independent producers (central limit theorem)

Figure 50: **US Lower 48 annual production and *mean* discovery shifted by 32 years**



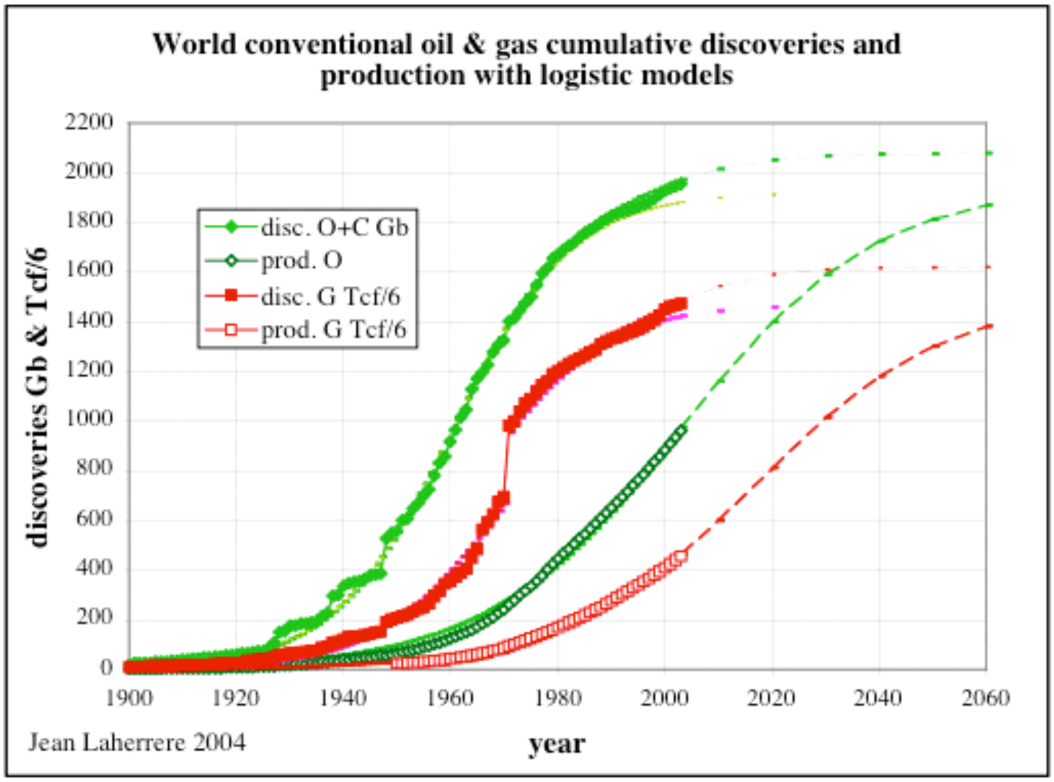
Production mimics discovery.

Figure 51: **France oil production and shifted discovery: 2 discovery cycles & 2 production cycles**



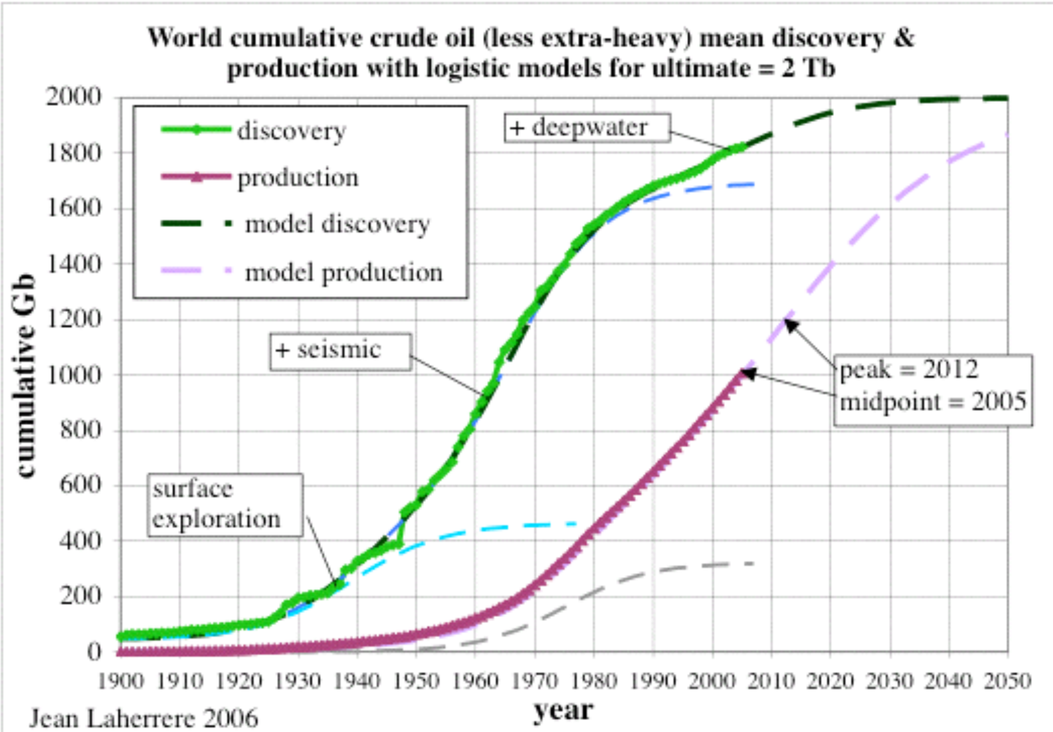
Most countries display several peaks for discovery, as production.

Figure 52: **2004 forecast: World conventional oil & gas discoveries and production with logistic models**



same approach in 2006 for oil with minor changes in ultimate (reduced after correction due to WM and rounded to 2 Tb)

Figure 53: **2006 forecast: World conventional cumulative oil discoveries and production with logistic models at U = 2000 Gb = 2 Tb**

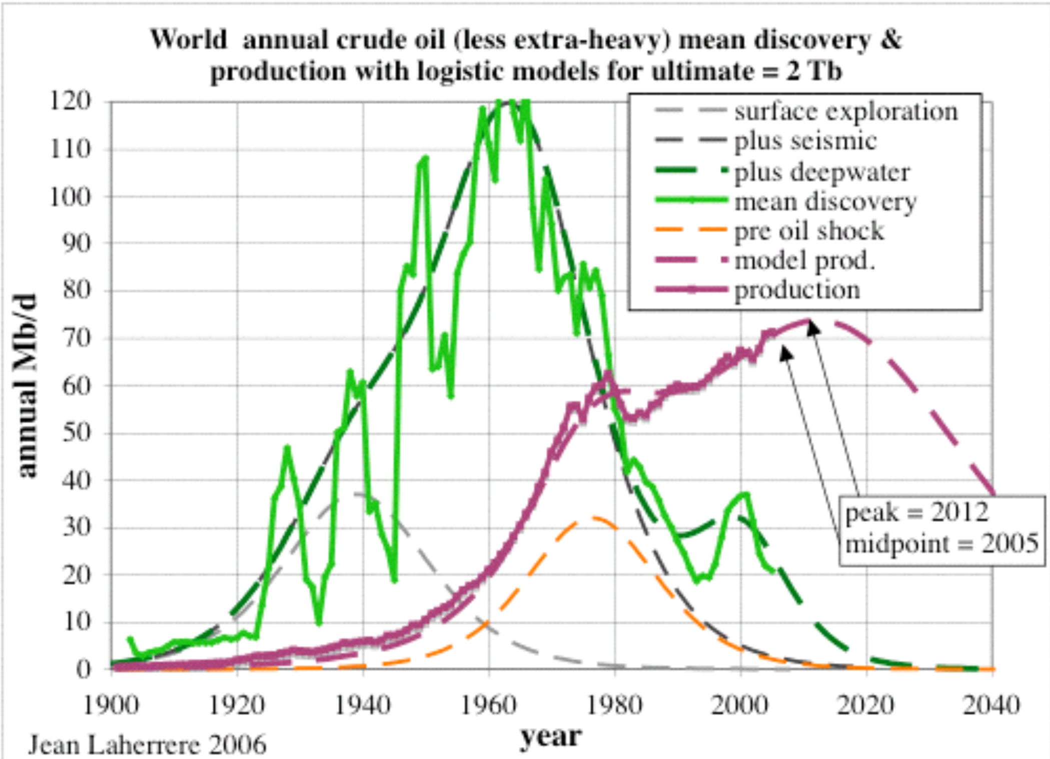


Most of cumulative discoveries and productions can be easily modelled with several logistic curves. When several cycles, oil peak does not coincide with mid-point.

It is not a rule, but a fact. I am still looking for one real data, which cannot be modelled with several logistic curves.

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 constraint.

Figure 54: World annual crude less extra-heavy oil mean discovery and production with logistic model for U = 2000 Gb

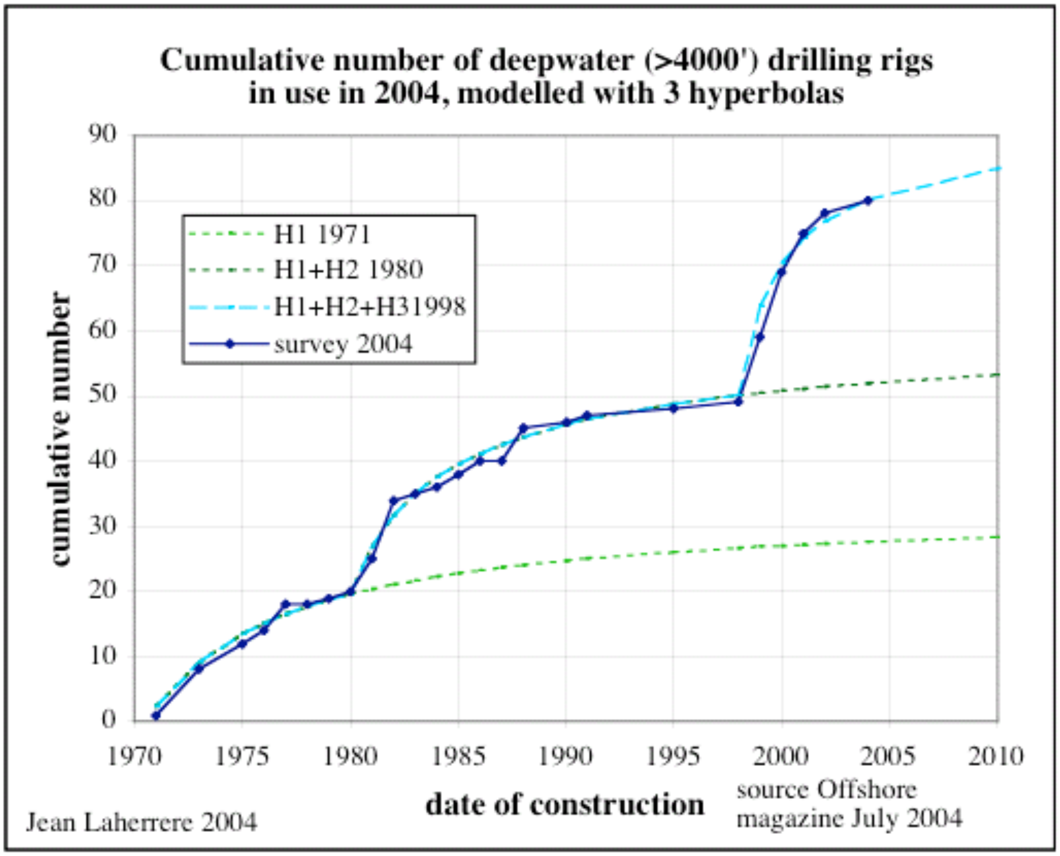


The last minor oil discovery peak in 2000 was due to deepwater. Oil peak (2012) does not coincide with mid)point (2005)

-Deepwater

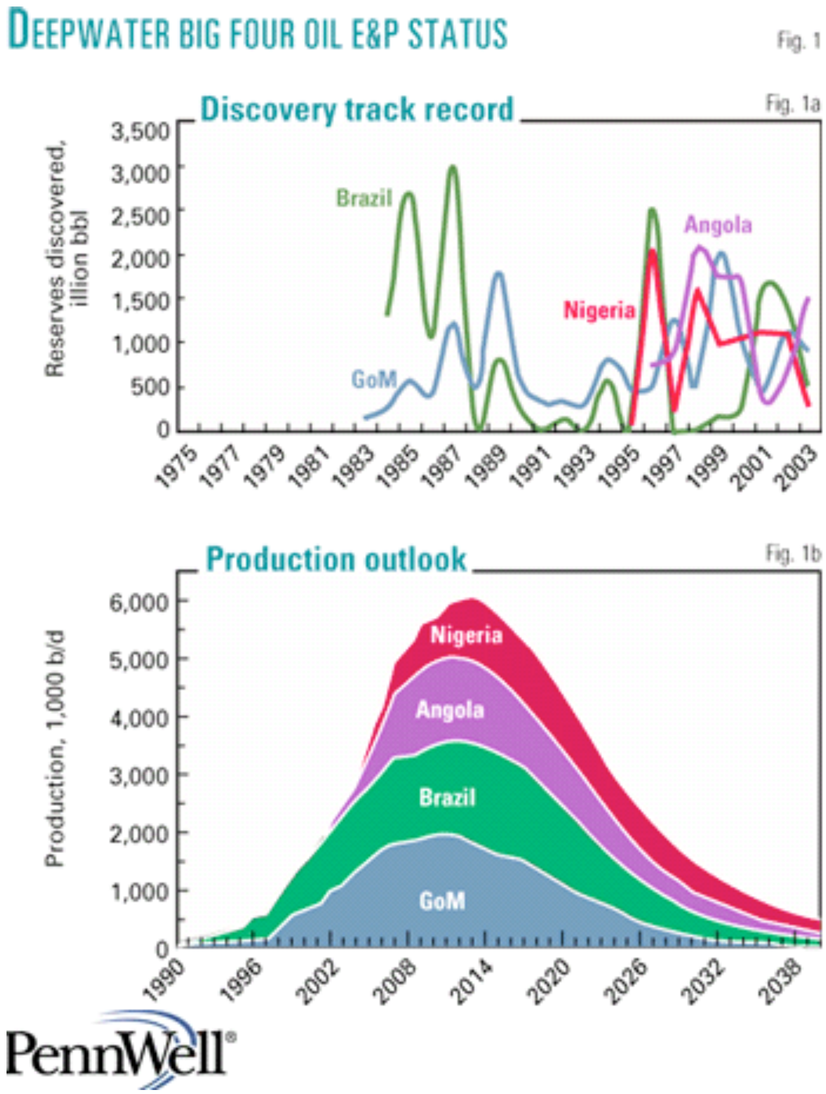
Deepwater is not a new project. The first drilling rig (dynamic positioning drillship) was in 1971 for oil (the first one was for the recovery by the US of a Russian submarine).

Figure 55: **Cumulative number of deepwater drilling rigs in use in 2004, modelled with 3 hyperbolas**



Already 3 cycles of deepwater exploration= 1971, 1980, 1998! Deepwater exploration is not new!

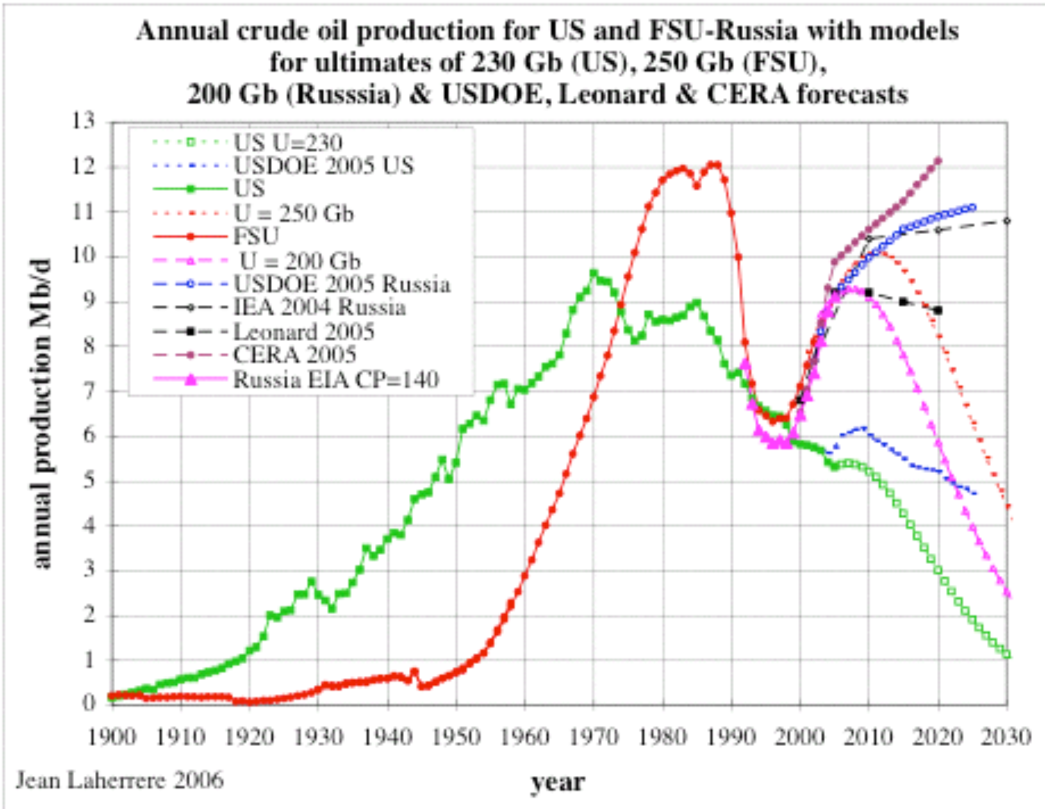
Figure 56: **Deepwater oil discovery and production**



Two peaks for discovery but likely one peak for production as there are no large finds outside Gulf of Mexico, Brazil, Angola and Nigeria (all in turbiditic reservoirs in diapyric tectonic)

-US-FSU

Figure 57: US & FSU annual oil production and forecasts



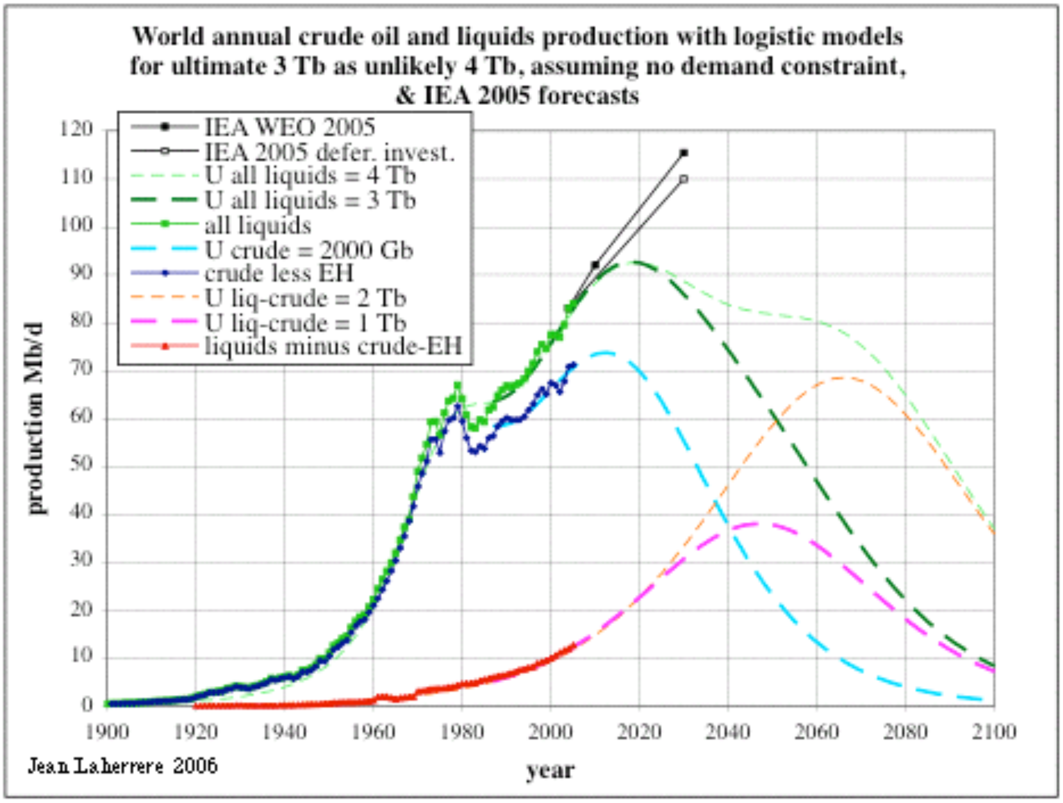
-World oil production

In our 1998 Scientific American we (Campbell and myself) were considering only conventional oil and we realize later that our forecast was far from the oil demand. As already stated, world oil demand is not filled only by oil and natural gas from wells, but also by synthetic oils (upgraded bitumen from mining, GTL, CTL(coal) and BTL(biomass)). 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. 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.

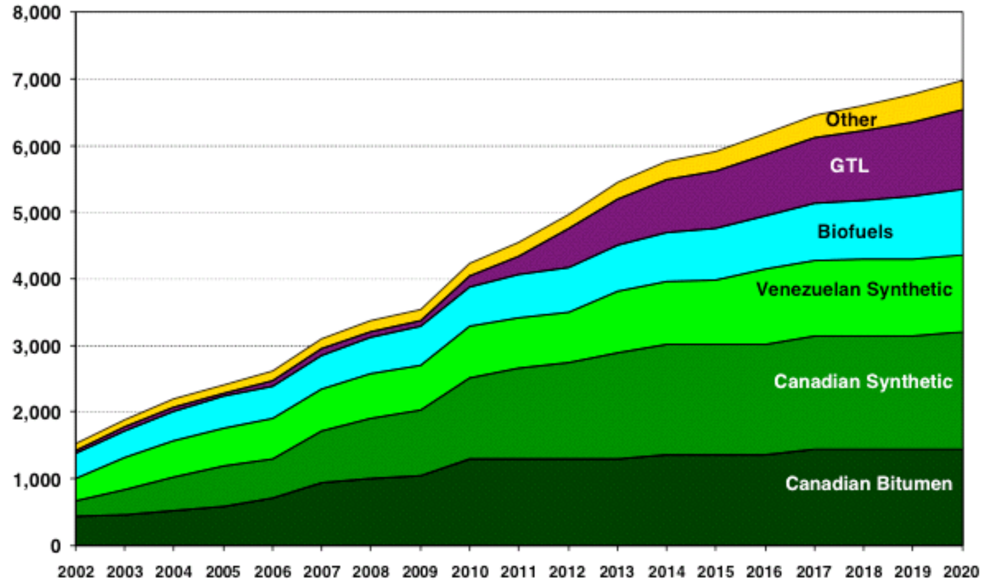
The forecast is then the previous forecast for cheap oil = crude oil less extra-heavy oil with an ultimate of 2000 Gb plus adding the expensive oil with an ultimate of 1000 Gb which will peak (to fit with the past production in value and slope) around 2050 at less than 40 Mb/d (against 12 today). The liquids peak will be in the 2010s, if there is no demand constraint. But the likely coming economic crisis (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 58: **World liquids production** (no demand constraint)



-Comparison of different oil forecasts
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
Figure 59: Non-conventional oil production 2002-2020 by OIES

Figure 23: Total unconventional oil supply 2000-2020



Source: OIES estimates.

OIES forecast of 7 Mb/d in 2020 should be compared with our forecast for expensive oil by adding of natural gas liquids plus refinery gains, which is over 12 Mb/d.

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 60: BGR oil projection peaking around 2015 at 4.7 Gt = 93 Mb/d

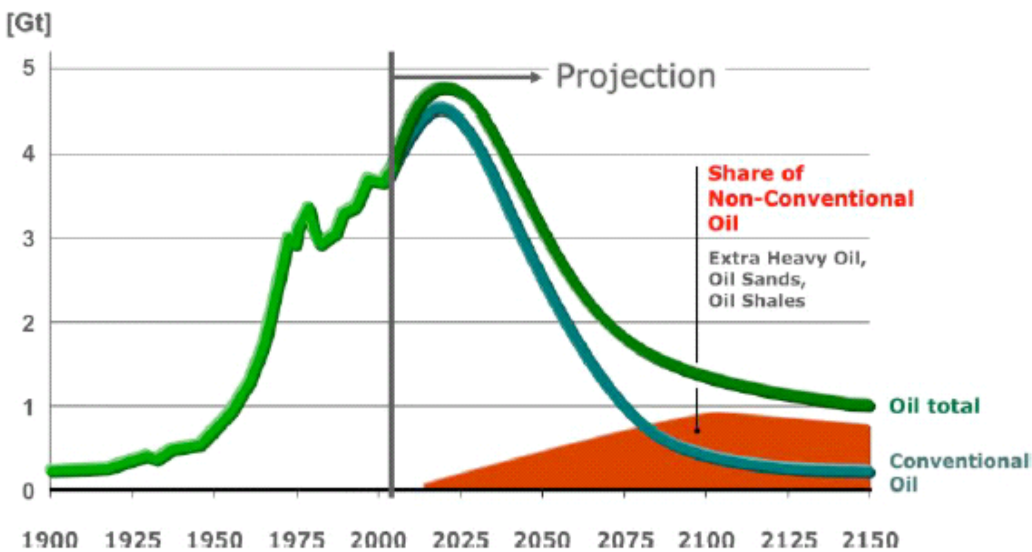
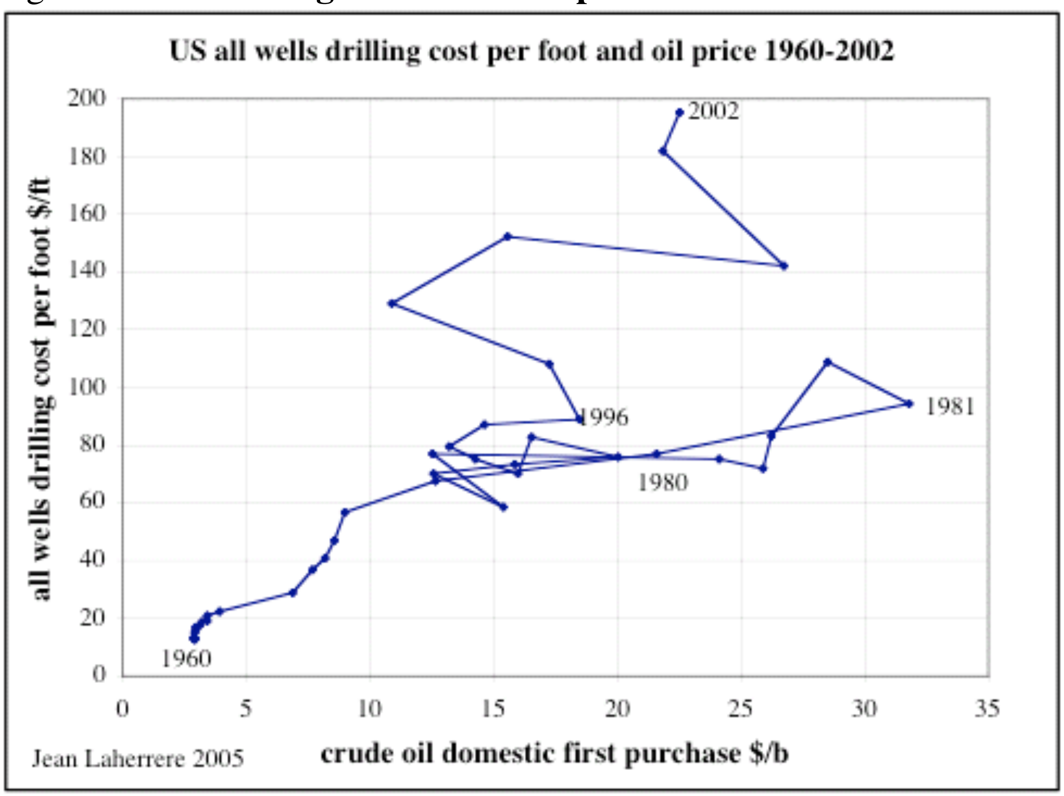


Fig. 17: Worldwide oil production from 1900 until 2150 – Historical development and attempt of an outlook.

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.

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)

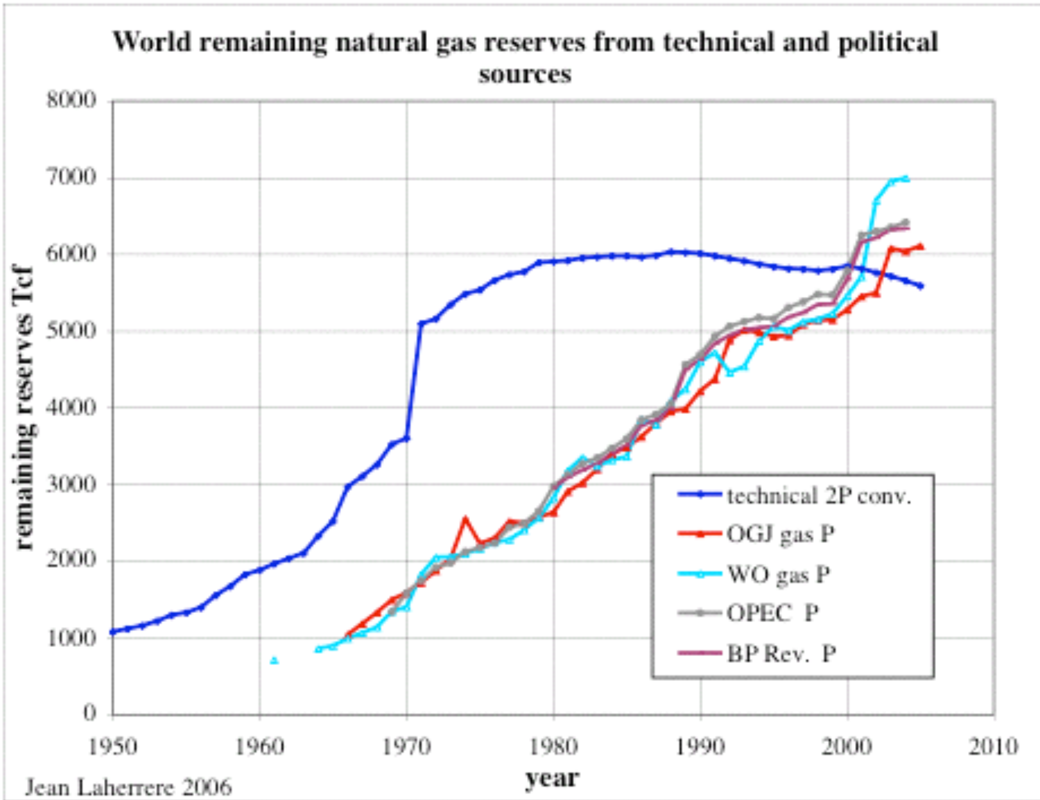
-Finding or operating cost and reality
Some claim that costs are down with technology, but facts are different. Drilling cost depends upon oil price and location of drilling. Deepwater is very expensive, drillship daily rate is now at 0.5 M$/d. The US drilling cost in $ per foot versus the crude oil domestic first purchase shows from 1960 to 1996 a strong linear relationship, despite all the technological improvement. Since 1996 drilling cost has increased sharply because the increase of deepwater drilling.
Figure 61: **US drilling cost versus oil price**



Some states that finding cost are around 7 $/b for IOCs and less than 1 $/b in Saudi Arabia.
Finding or operating cost on an annual base has little meaning because it should be done by field and on the entire life, and it forgets many items as dry exploration, overhead, finance and administration, royalties, .
Break-even point from companies in 2004: 25 $/b for Shell, 21 $/b for Total.
For Saudi Arabia, nation which main business is selling oil, the break even point is the one giving a zero deficit, which is about 20 $/b.
Only data on development in $/b/d are reliable because short period and known price and known maximum capacity. The range in $/b/d was about 1 000 easy, 5 000 offshore, 10 000 deepwater, 30 000 extra-heavy oil (but much longer plateau), 50 000 GTL, CTL.
But prices are going up with oil price, rigs and labour shortage.
The myth of reducing cost with technology is still present with IEA WEO 2005 and IFP, when it is obvious that cost are exploding with the oil price, Overruns occur everywhere, rising to high investments as Kashagan = 30 G$, Sakhaline II = 20 G$, Athabasca tarsands (Suncor).

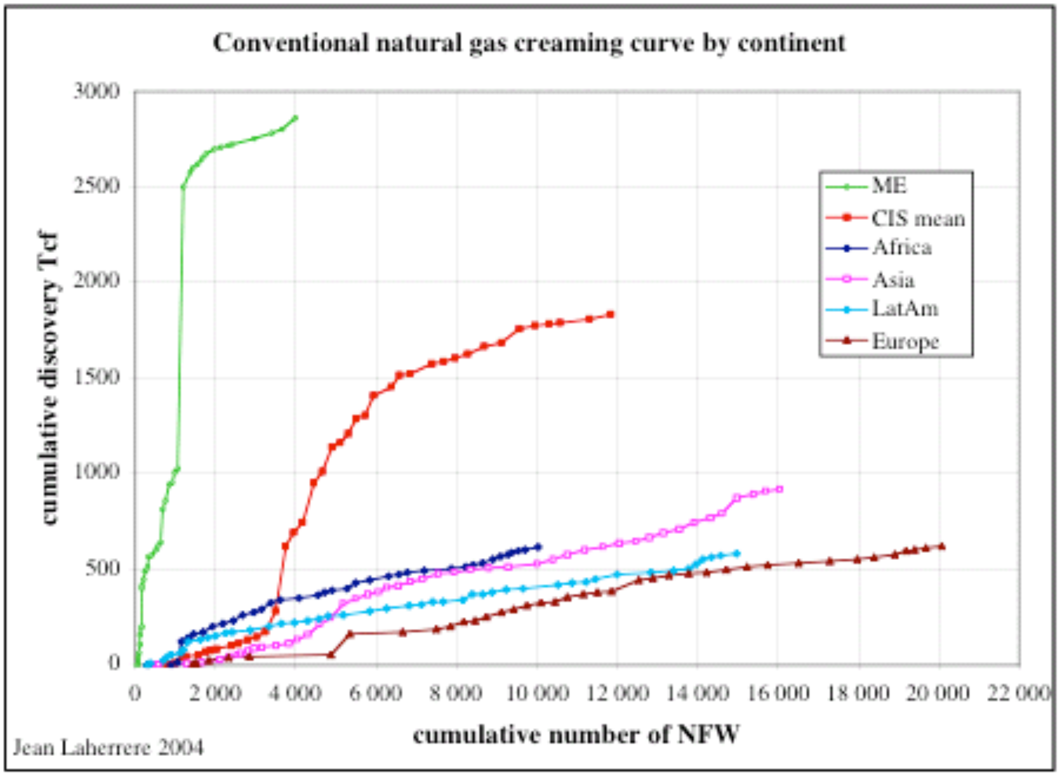
-**Natural gas**

if there is only one oil market, because natural gas (NG) cost 10 times more to transport, there are three NG markets: North American, Europe and Asia Pacific. A fourth one is occurring with South America.
There are still a large number of field where gas is flared or reinjected or stranded.
Recovery factor is much higher for NG than for oil, so there is less gas left in the ground.
NG reserves are also badly reported as the rules are the same as oil. Political (or financial) sources report a world rising remaining reserves since 1950 but technical sources report a flattening level since 1980, slightly decreasing since 2000.
Figure 62: world remaining NG reserves from different sources.



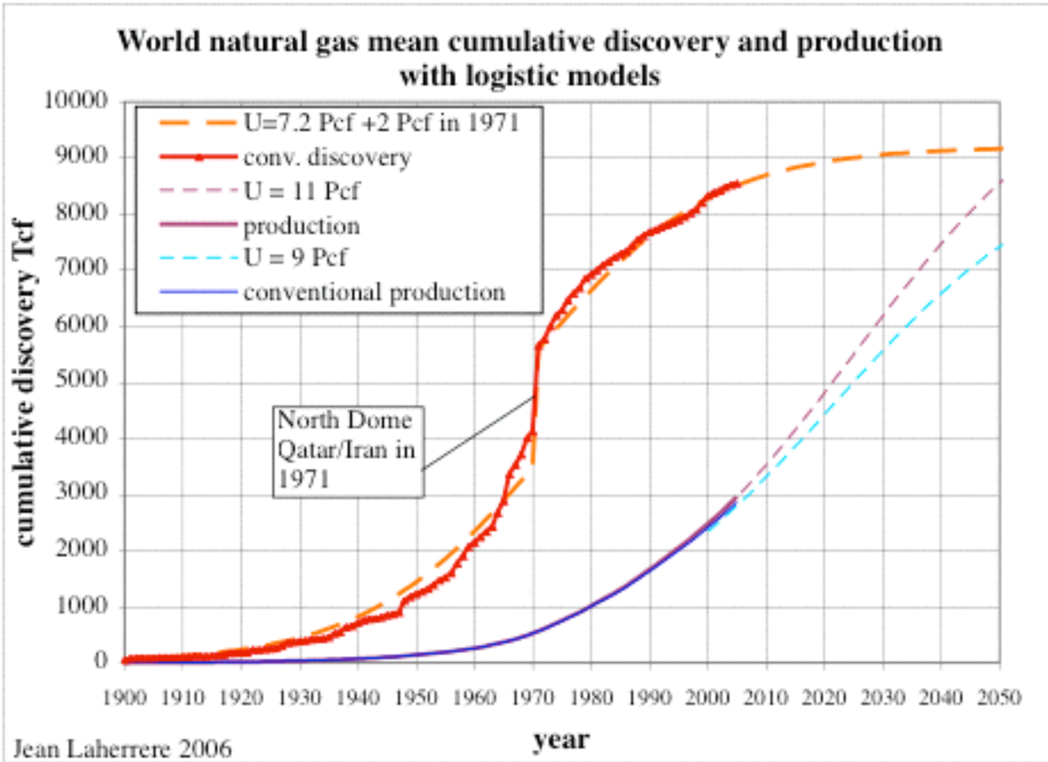
Creaming curves by continent show that again ME is endowed far more than the others but FSU is also above the rest

Figure 63: **Conventional gas creaming curve by continent**



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) represents about 15 % of the ultimate (Ghawar represents only 6%) and upsets the curve, so it is separated from the curve

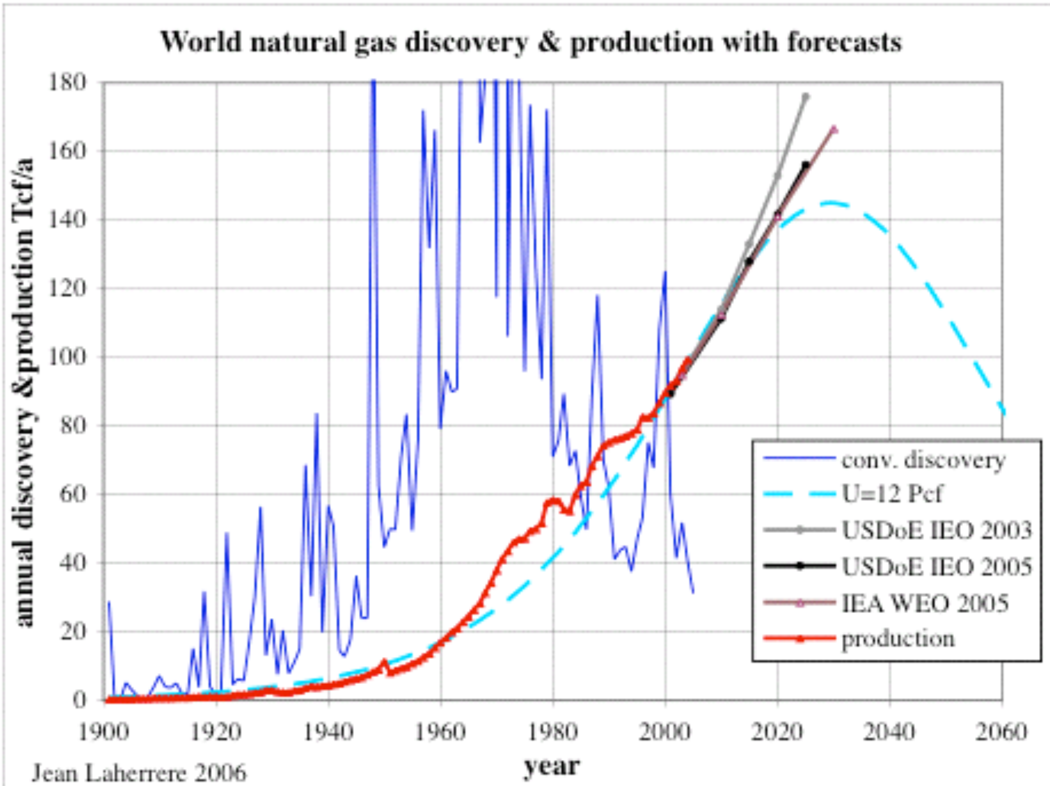
Figure 64: **2006 forecast: World conventional cumulative gas conventional discoveries and production with logistic models**



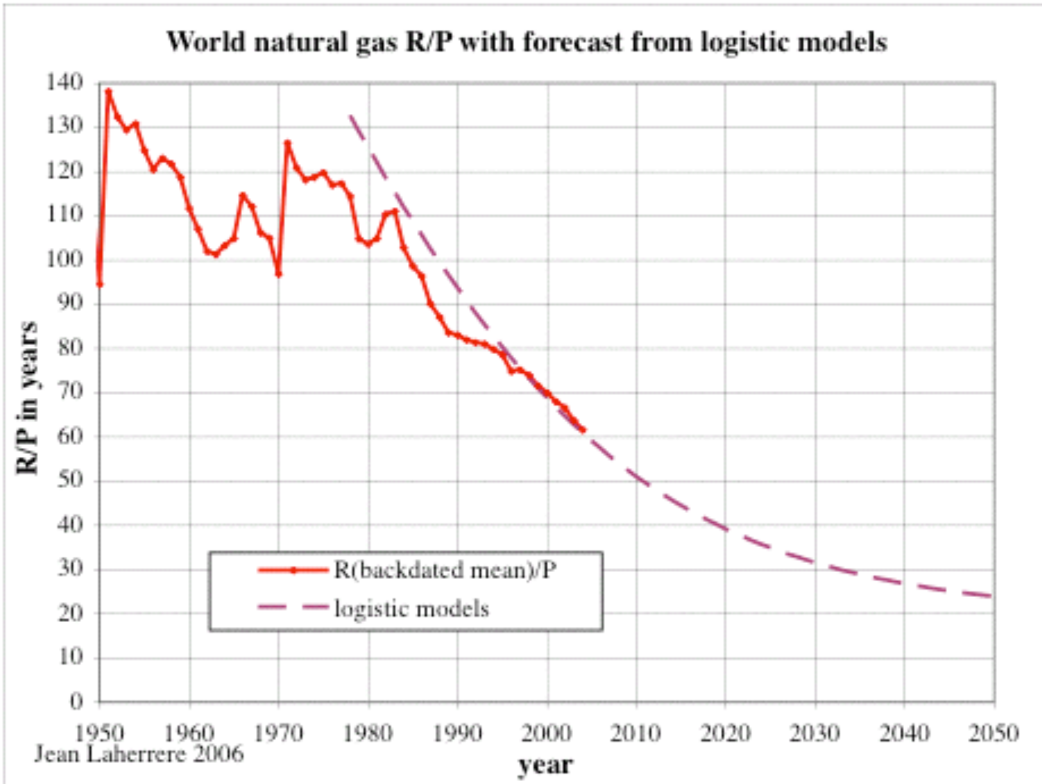
The ultimate NG was estimated at 10 000 Tcf (10 Pcf) 10 years ago (Laherrere, Perrodon, Campbell 1996) for conventional and 12 Pcf including non-conventional. We keep these values, as updated data confirm these round values

The world NG production will peak in 2030 about 140 Tcf/a when USDOE and IEA forecasts 165 Tcf/a and rising

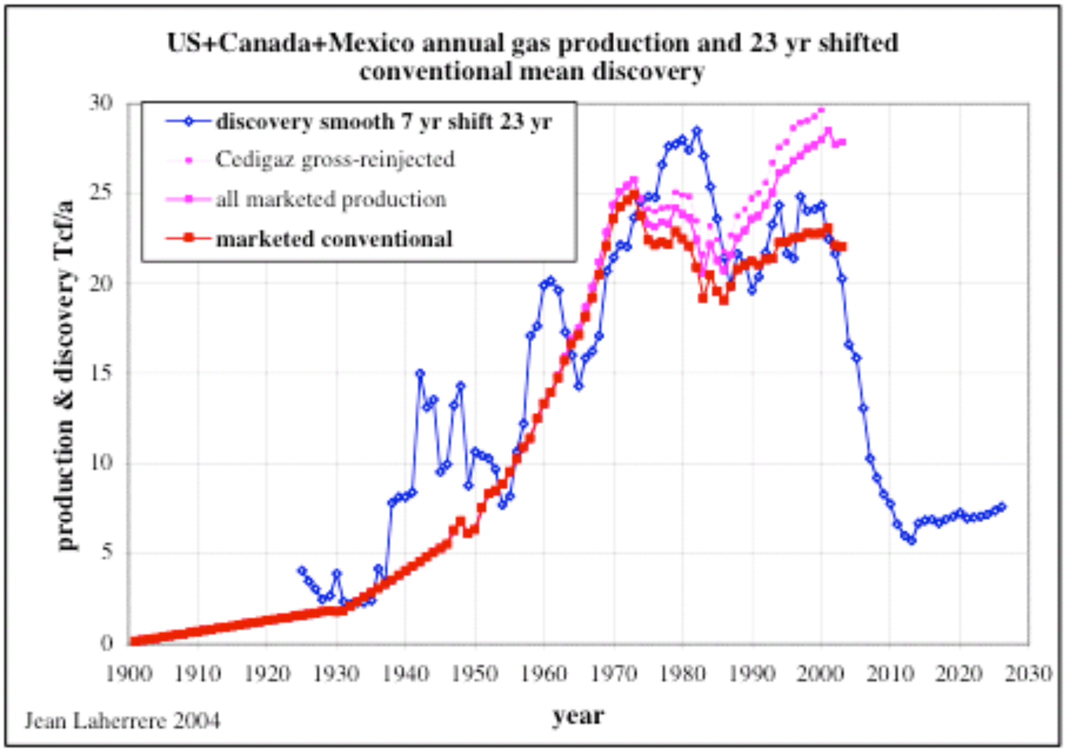
Figure 65: **World annual gas discovery & production as forecasts**



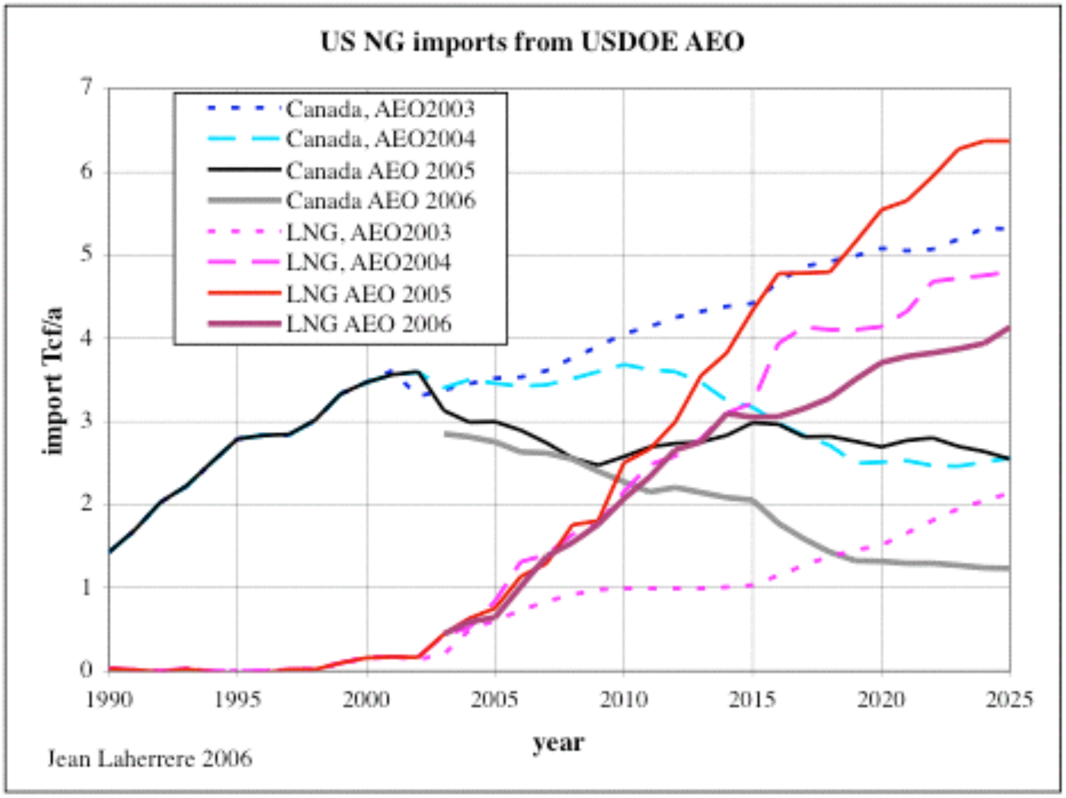
The R/P has decreased from 140 years in 1950 to 60 years in 2005 and trends towards an asymptote of 20 years (as for oil).
Figure 66: World natural gas R/P with forecasts from logistic models



North America demand is filled by local supply, which has started to decline
Figure 67: **US + Canada + Mexico annual conventional gas production and shifted discovery**

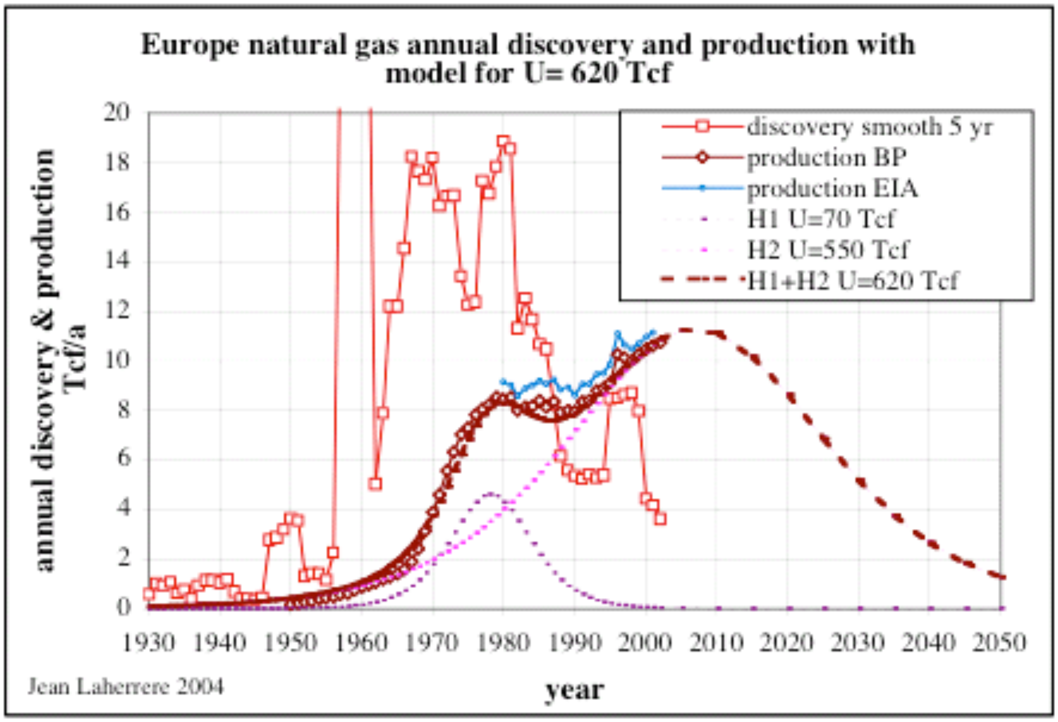


North America gas production is peaking and will decline sharply following the correlation between production and mean discovery shifted by 23 years.
USDOE changed drastically their forecasts on imports from Canada and LNG from 2003 to 2006
Figure 68: **US gas imports from Canada and from NGL with USDOE forecasts from 2003 to 2006**

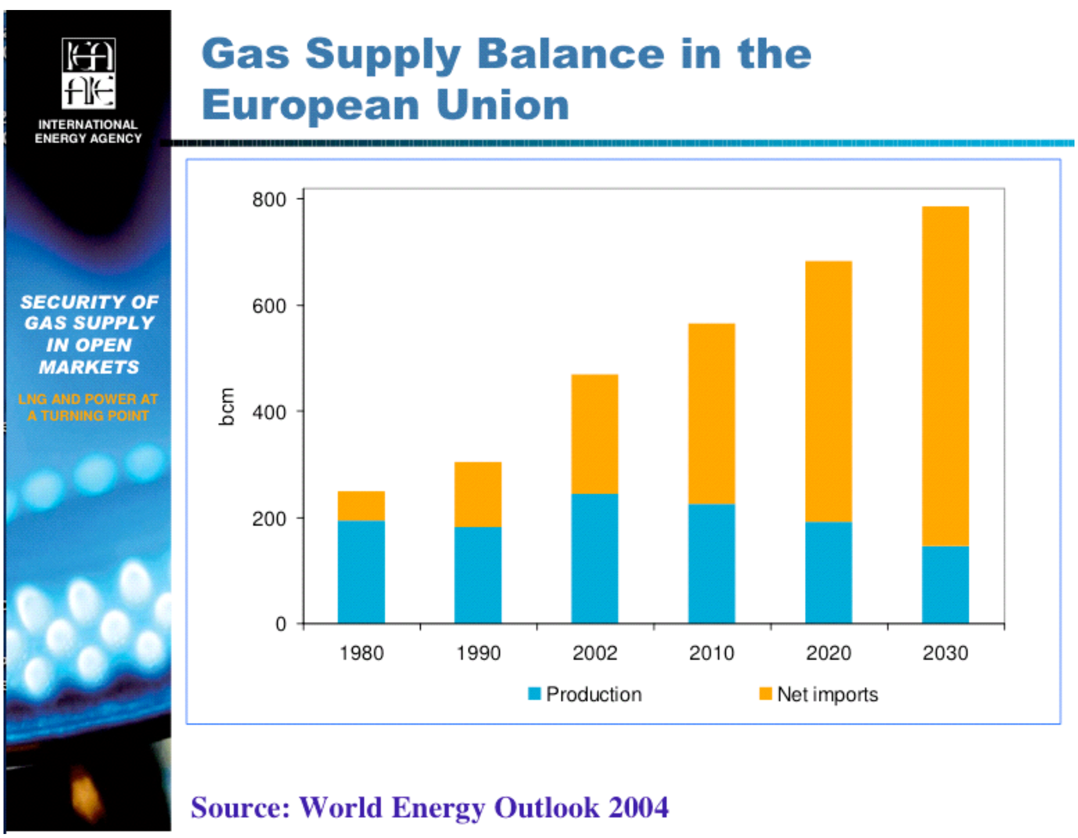


There is a rush to build new LNG terminals in the US, but as the NG price has increased sharply since 1995, the demand is falling because shifting to other fuel and closing fertilizer plants

Europe NG production is peaking
Figure 69: **Europe annual gas production and discovery**



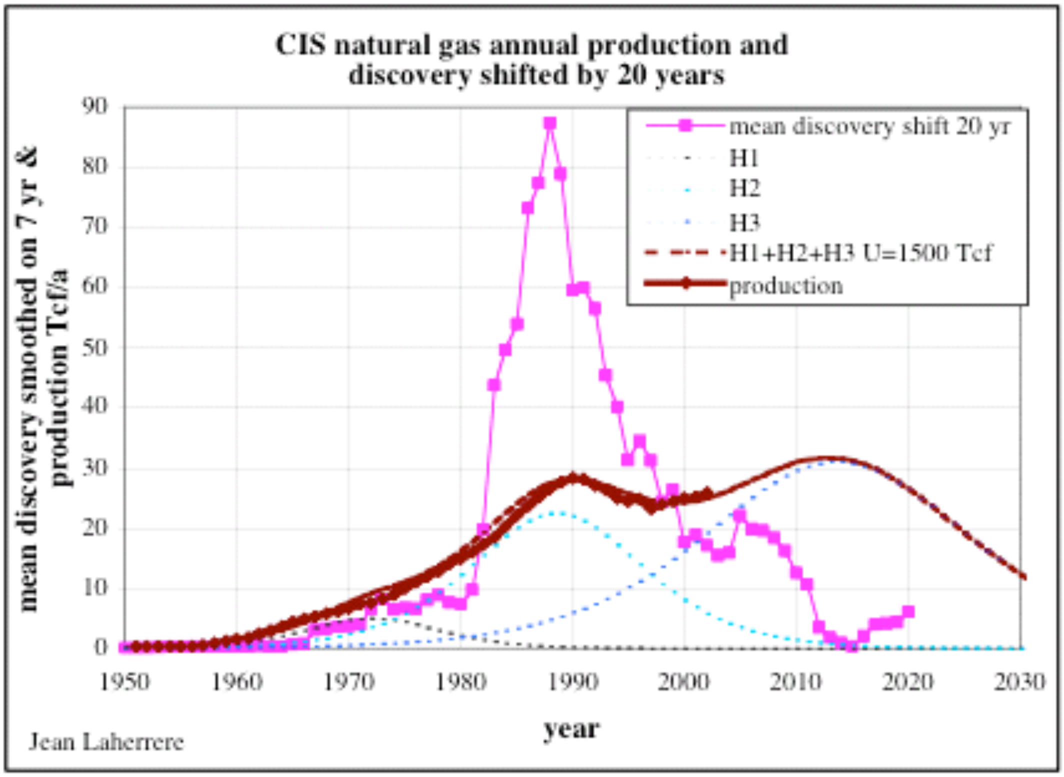
Europe gas production will peak soon as reported by the IEA for European Union
Figure 70: Gas supply balance in the European Union 1980-2030



Source: World Energy Outlook 2004

Europe is counting too much on Russian gas supply, which is overestimated from the Russian definitions (3P)

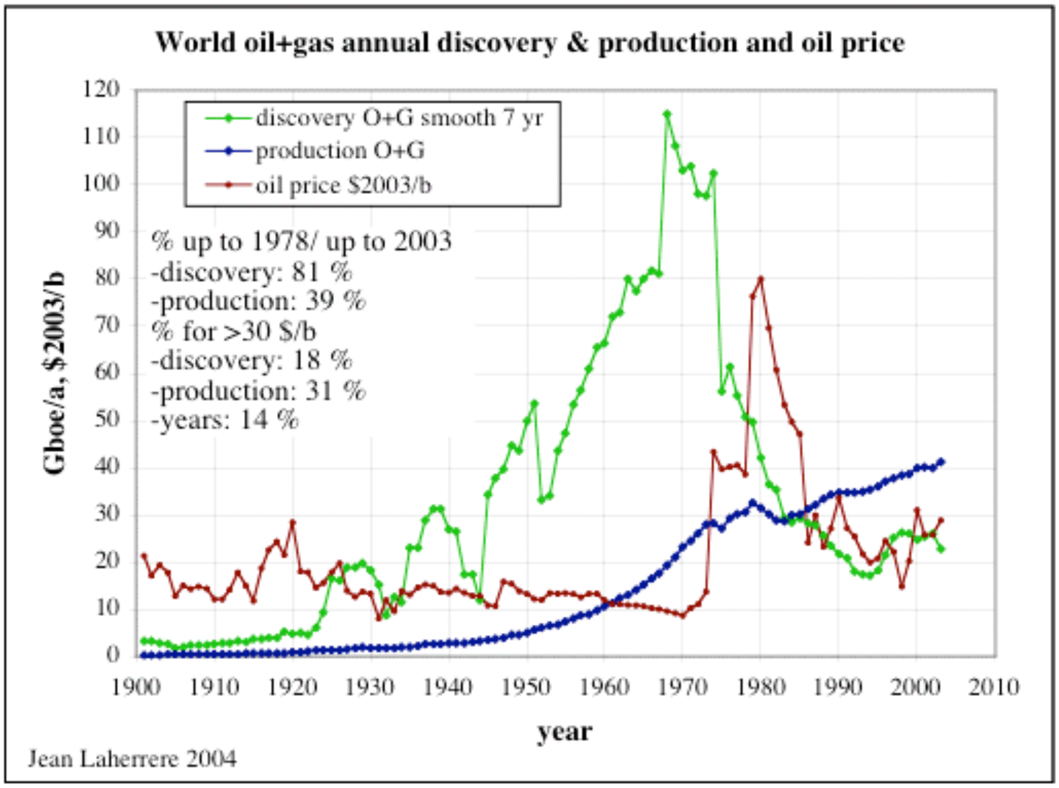
Figure 71: **FSU gas production and shifted discovery**



Russia gas production will peak soon and will not provide Europe needs!

-Discovery does not increase with oil price

Figure 72: **World oil+gas production & discovery and oil price**



Oil price increase did not increase discovery, in contrary, it only decreased production for a while!

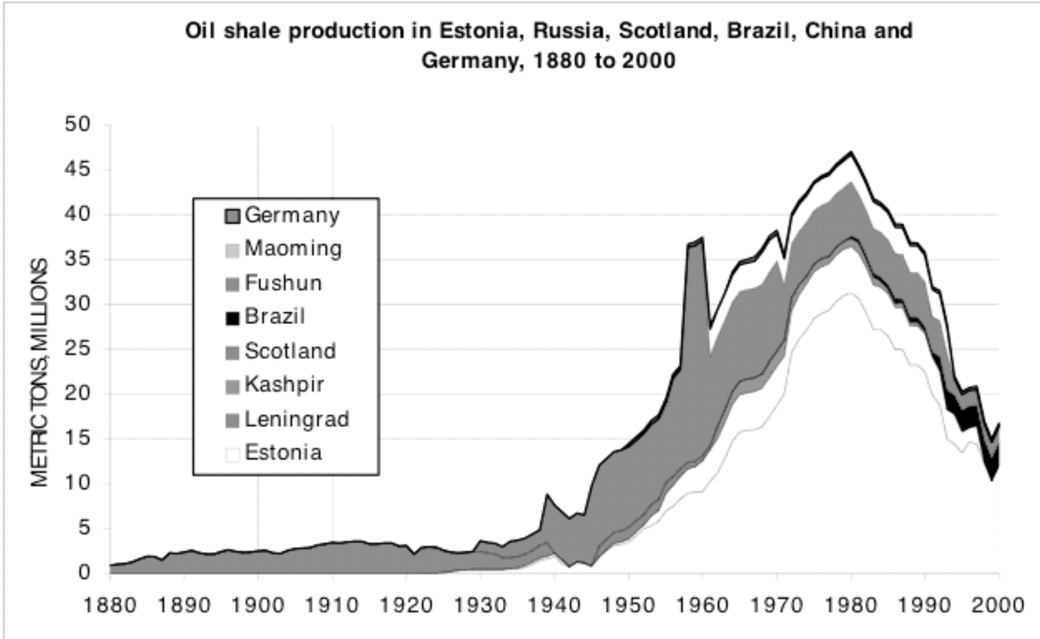
-Oil shales

Oil shales are in fact immature kerogen, which are classified with lignite for BGR and WEC!

Oil shale can be burnt directly or pyrolysed into oil.

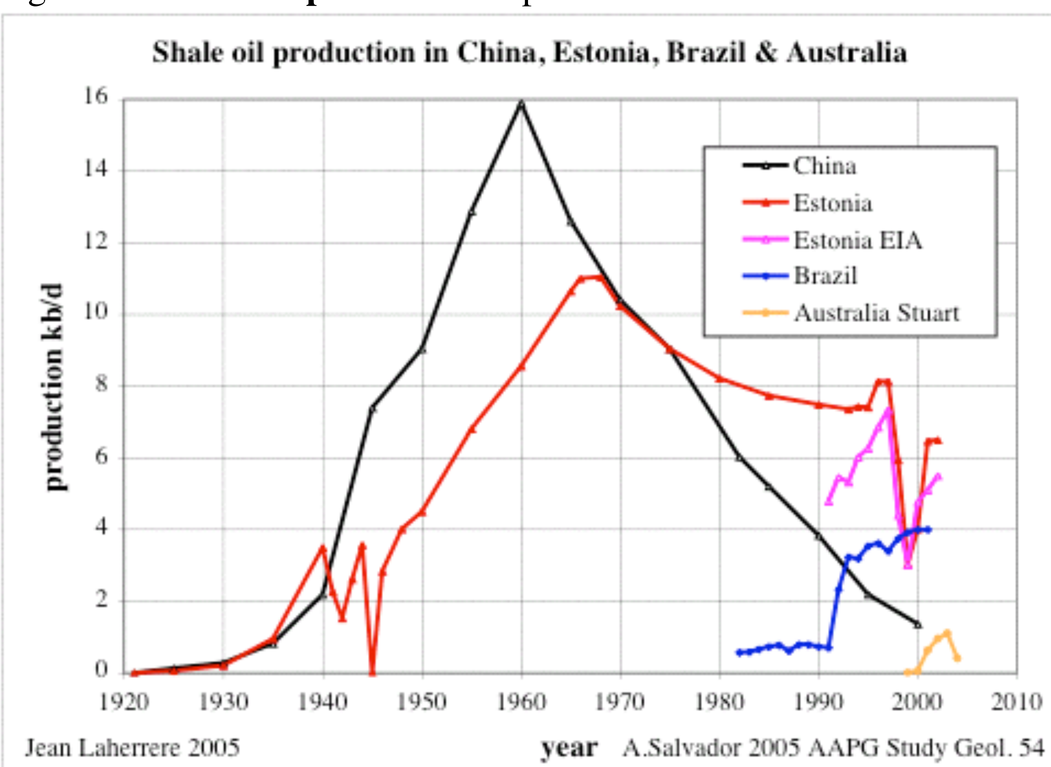
Oil shale production started in 1837 in France (schistes d'Autun), then Scotland and Germany. It peaked in 1980

Figure 73: **Oil shale production**



source: Illustration #21 from paper: Origin and resources of some world oil shale deposits, by John R. Dyni, U.S. Geological Survey, Denver, CO, USA, presented at the Estonian Oil Shale Symposium, Tallinn, Nov. 18-20, 2002.

To enter into European Union, Estonia was obliged to reduce its future oil shale production to decrease pollution!
Shale oil is produced from mined shale oil by pyrolisis at 700°C (retorting)
Figure 74: **Shale oil production** = peak in 1960



If extra-heavy oil production increases with oil price, it is not the case for shale oil. In 2002, world shale oil production <12 kb/d = 0,015 % of world oil production. Mining is considered as impossible with environment, only Shell has a pilot in the US where oil shale is heated slowly with electric radiators in shallow holes and sediments around are frozen to prevent water to come. Shell produces 10 b/d with 2000 $/d electric bill! Shell hopes to decide in 2012 if the process is commercially viable.