Natural gas future supply

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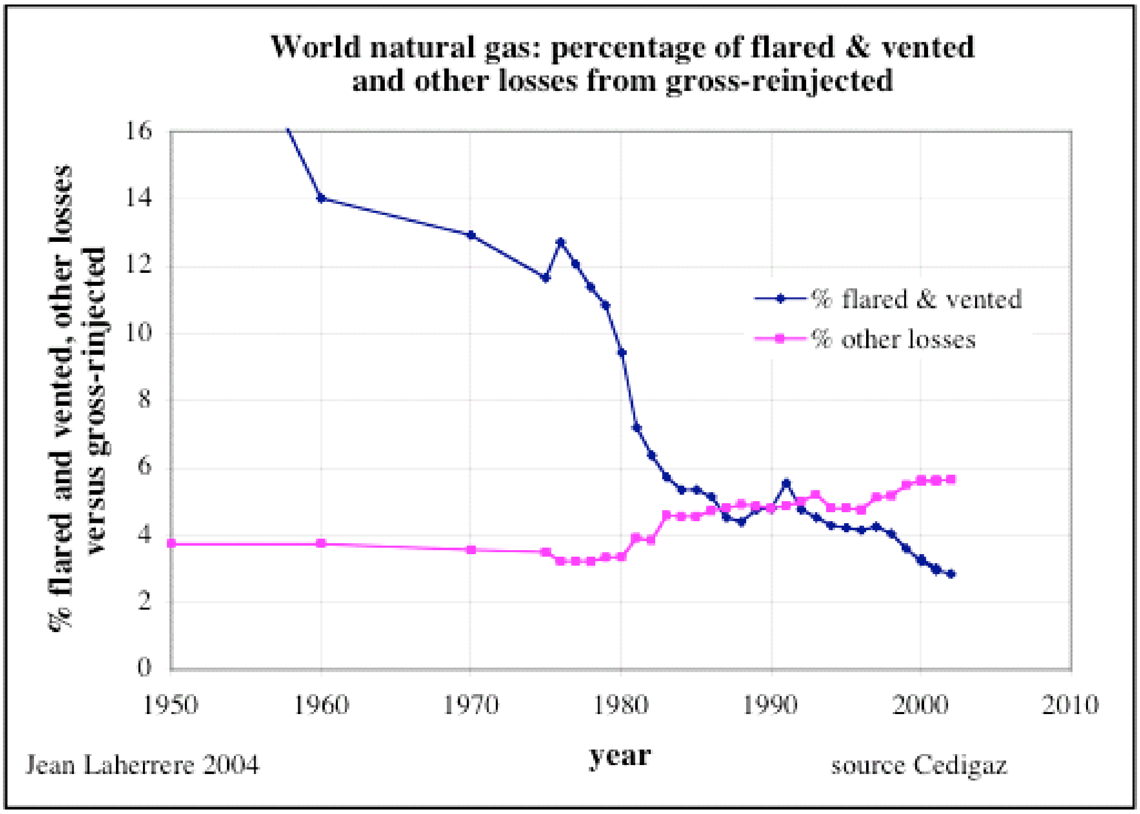
This paper provides a lot of data for the web reader, but only some graphs will be presented at the conference. More data can also be found in the paper prepared for the ASPO conference in Berlin 25 May 2004.

Warnings:
Gas (or any mineral) is produced (extracted) only:
-after it has been found
-after spending money to develop the field
-if the demand exists
Reserves are expected future production and represent only a small part of the resources, which are what is in the ground. Resources are often confused with reserves.
Constant growth has no future in a limited world
What goes up must come down.

-World

-production of natural gas (NG)

Reliable data is very difficult to get, as very often the data does not specify if it is gross or gross minus reinjected or marketed, wet or dry values. The losses are usually hidden. Non-hydrocarbons gases are important in some fields.
As for any data in the oil & gas industry, the accuracy is not better than 5%.
From Cedigaz, out of the 111 Tcf gross produced in 2002, 11% is reinjected, 3% is lost and 5% flared or vented, leaving only 81% for marketing. The US market only 79% when Russia markets 98 % of the gross production.
The total loss is still significant, being over 8 % of the gross (flared & vented on decline , other losses on rise), but globally in decline as it was 27 % in 1950 and 16% in 1970. This loss is rarely taken into account to estimate the remaining reserves as usually it is the dry production which is reported.
Figure 1: World NG; percentage of flared & vented, other losses versus gross-reinjected



Marketed is assumed to be larger than dry as some liquids may be removed.
What is called «marketed» by Cedigaz seems to be called «dry gas» by USDOE, which calls marketed the "wet" marketed as it is shown for 2001 in Tcf/a for the world

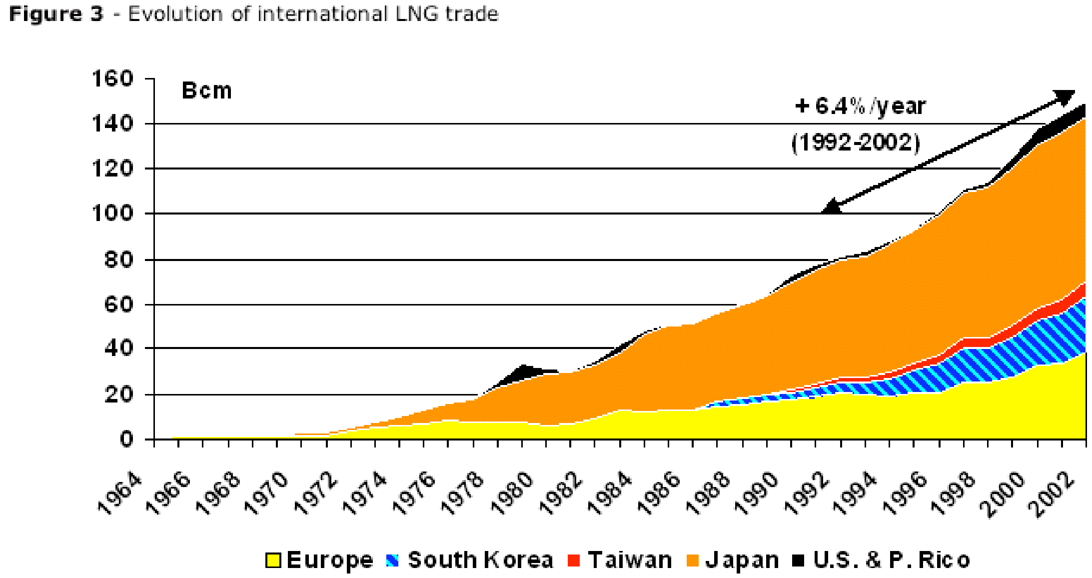
World	Gross	Vented, Flared	Reinjected	Marketed	Dry	other losses
USDOE	110,5	2,7	12,6	94,7	90,5	?
Cedigaz	111,2	2,9	12,7	90,1	?	5,6

Heat content varies largely with field and country. The 2002 BTU/cf of dry production ranges from 799 in Poland to 1431 in Greece, with an average for 89 countries of 1042 Btu/cf, when for LNG the content is from 1075 to 1150 Btu/cf.

In 2002 the gas trade totals 700 G.m3 (25 Tcf or about 25% of the world production), being 20% by LNG and 80% by pipeline. Liquefaction leads to an average loss of 12% of the original gas.
International trade in 2002 (not including intra-FSU) in %

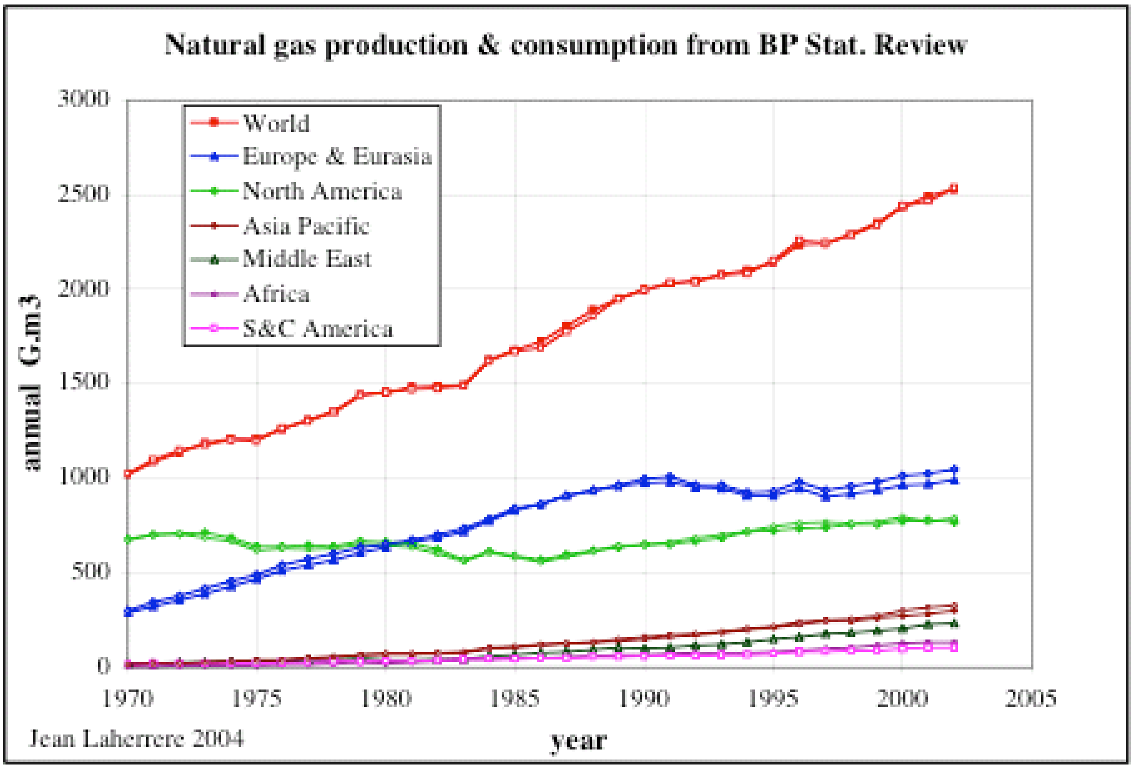
Russia	21.8
Canada	18.5
Norway	10.4
Algeria	9.8
Netherlands	7.2
Indonesia	6.1
Malaysia	3.5
Qatar	3.2
Others	19.6

LNG trade has been increasing in the last 10 years at a rate of 6.4 %/a, in 2003 about 11%.
Figure 2: LNG trade from Cedigaz 2002



Notice the first attempt for LNG in the US in 1980

Contrary to oil where consumption and production are quite different by continent, NG production is close to consumption by continent.
Figure 3: NG production & consumption from BP Review

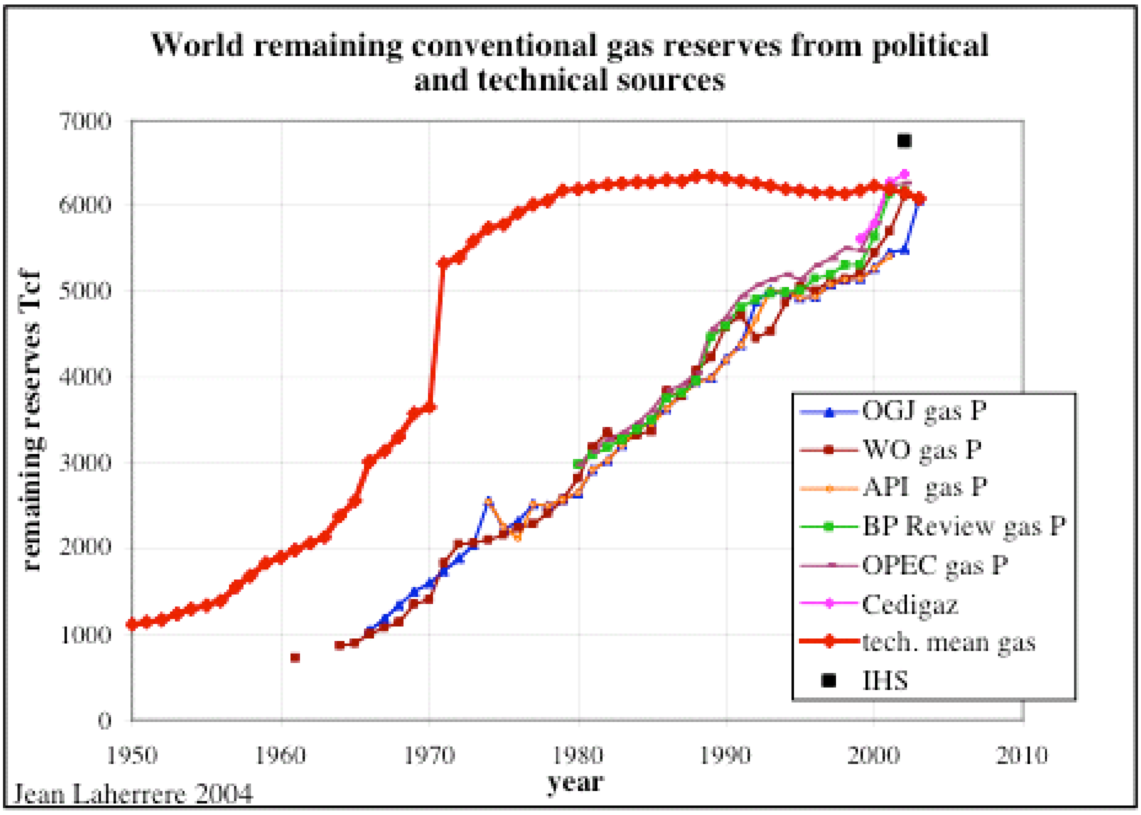


On the last decade, Africa is exporting and Europe importing

Oil market is global as cheap to transpmort and oil is sold mainly on the spot market. Natural gas is expensive to transport and needs long term contracts (mainly take-or-pay) and is marketed mainly on three markets:

-Europe with exporters Russia, Norway; Netherlands and Algeria
-North America with exporters Canada and US
-Asia pacific (Japan, S.Korea and Taiwan) with exporters Indonesia, Malaysia and Brunei
A new market is opening up in South America

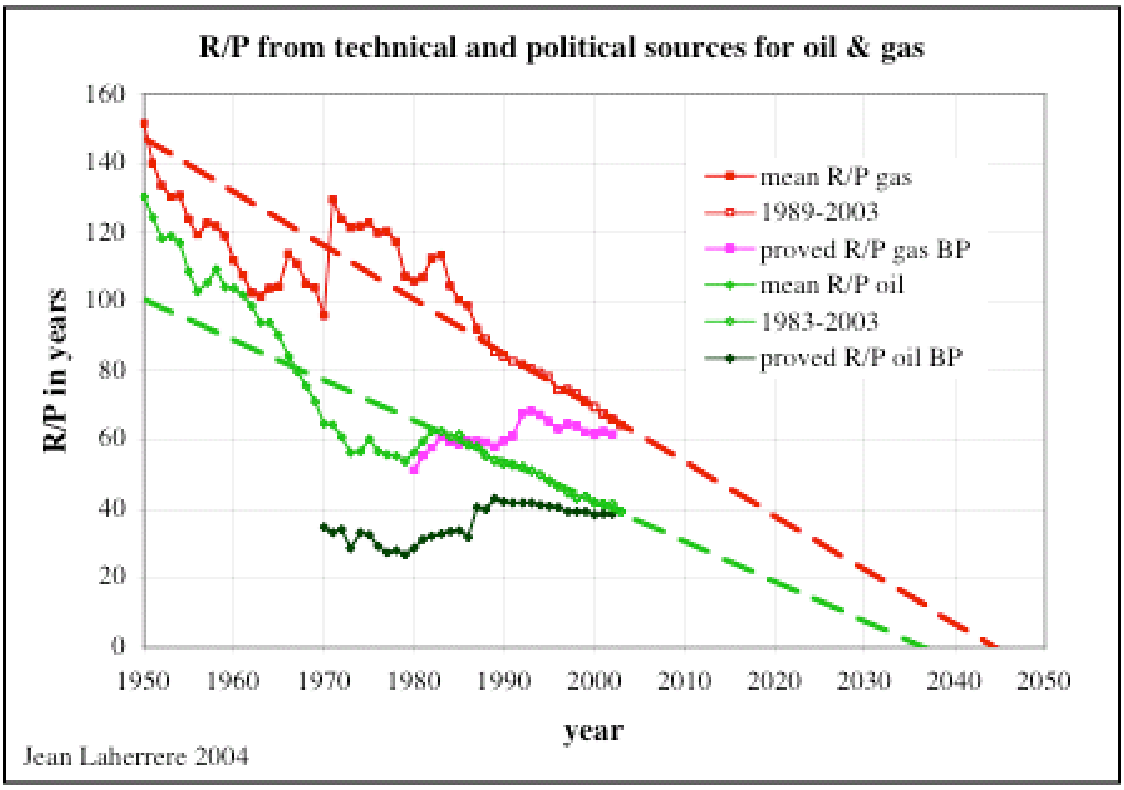
Data is unreliable for production, but it is worse for reserves. As for oil, the remaining gas reserves published by political sources (enquiries to governments done by Oil & Gas Journal (OGJ) and reproduced by BP, OPEC and World Oil (WO)) are drastically different from technical sources. Cedigaz is also getting data from governments. American medias report proved reserves to please the SEC, despite that many countries report proven+probable reserves, such as UK. The current proved data is designed to provide growth and most annual additions are revisions of past estimates. The technical data represents the mean value (or expected value) and the estimate is backdated to the year of discovery. HIS, using for FSU ABC1 values (close to 3P), is higher than the mean value. Technical remaining reserves are the initial reserves minus cumulative production and can vary if production is taken as dry or gross minus reinjected. Wood Mackenzie (WM) data is not available worldwide, but only for most countries.
Since 1980 the technical remaining reserves has been constant because annual discovery is close to annual production.
Figure 4: World remaining reserves from technical and political sources



Chew (2004) notices that the Dec 22nd 2003 OGJ reserves reports “Proven” gas reserves estimates for 102 countries;
76 estimates unchanged from 2002;
45 estimates unchanged from 1998;

7 estimates unchanged since 1993.

R/P is usually wrongly given to describe the life of the remaining reserves, omitting that production is also assumed to continue to grow. It is not the number of years today, that is important, but the variation with time. The R/P varies drastically when using technical or political data.
Figure 5: R/P from technical and political sources



For gas, since 1989 the technical trend is linear and a linear extrapolation could conclude that production would cease around 2045 (in fact the trend will not be linear when close to extinction). But the political trend is almost horizontal, implying that production will never end.

Technical remaining reserves have been flat since 1980 because the annual discovery roughly matches the annual production, as shown by Exxon-Mobil (Longwell 2002), since we both backdate the discoveries and we use mean values, when the political data uses current proved reserves.
Figure 6: Exxon graph on annual NG discovery

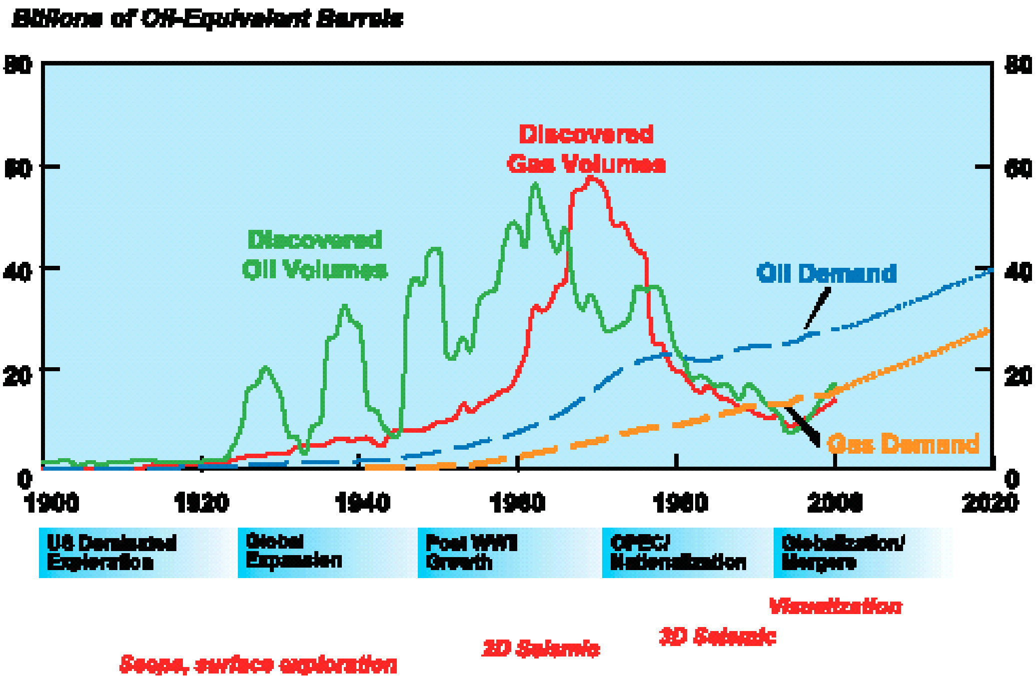
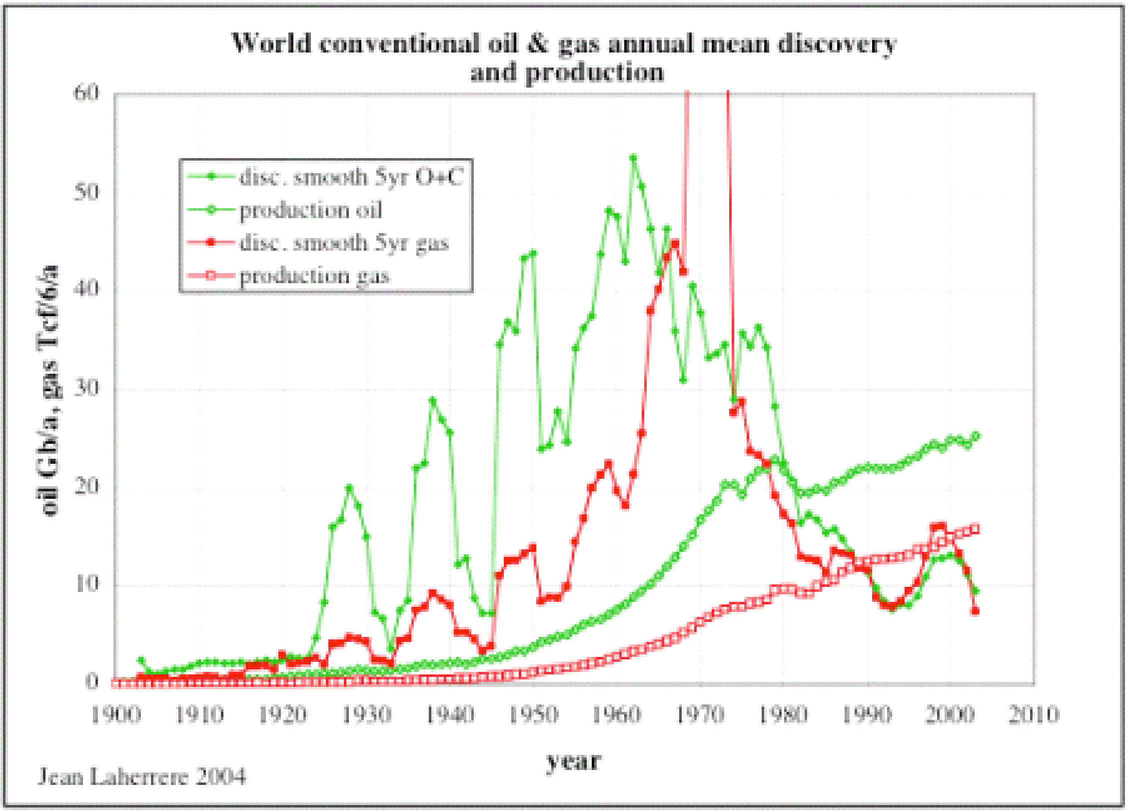
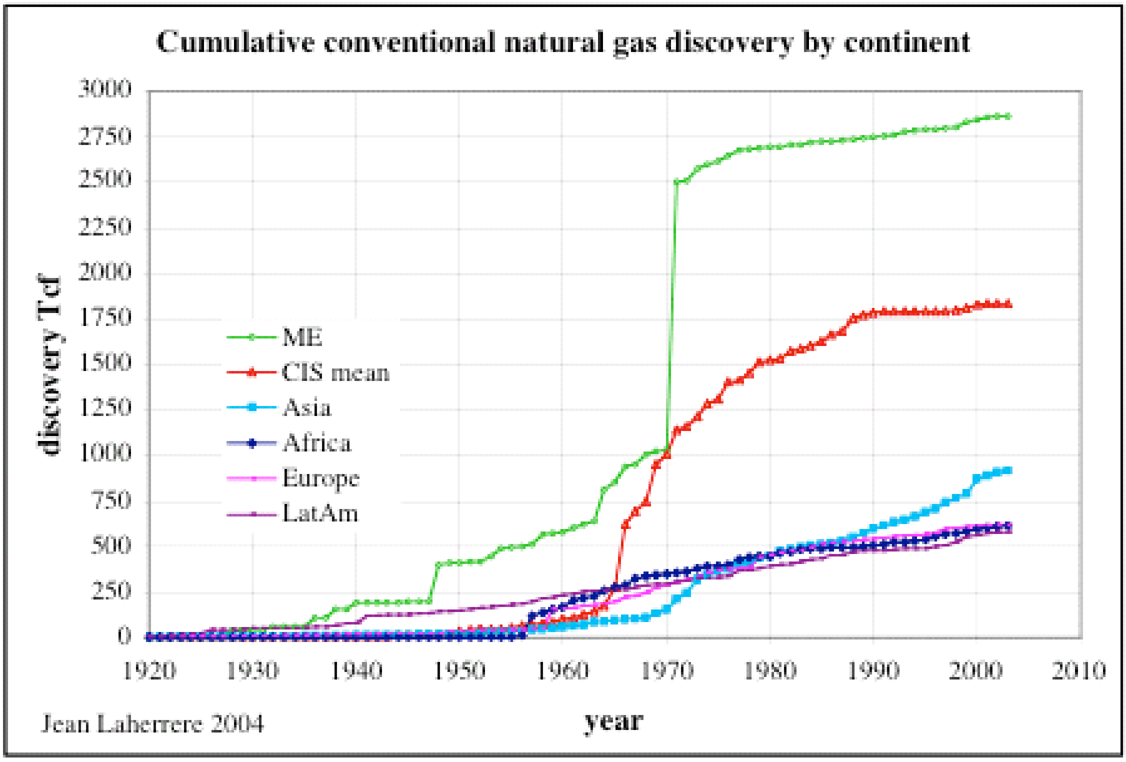


Figure 5: Gas Supply and Demand

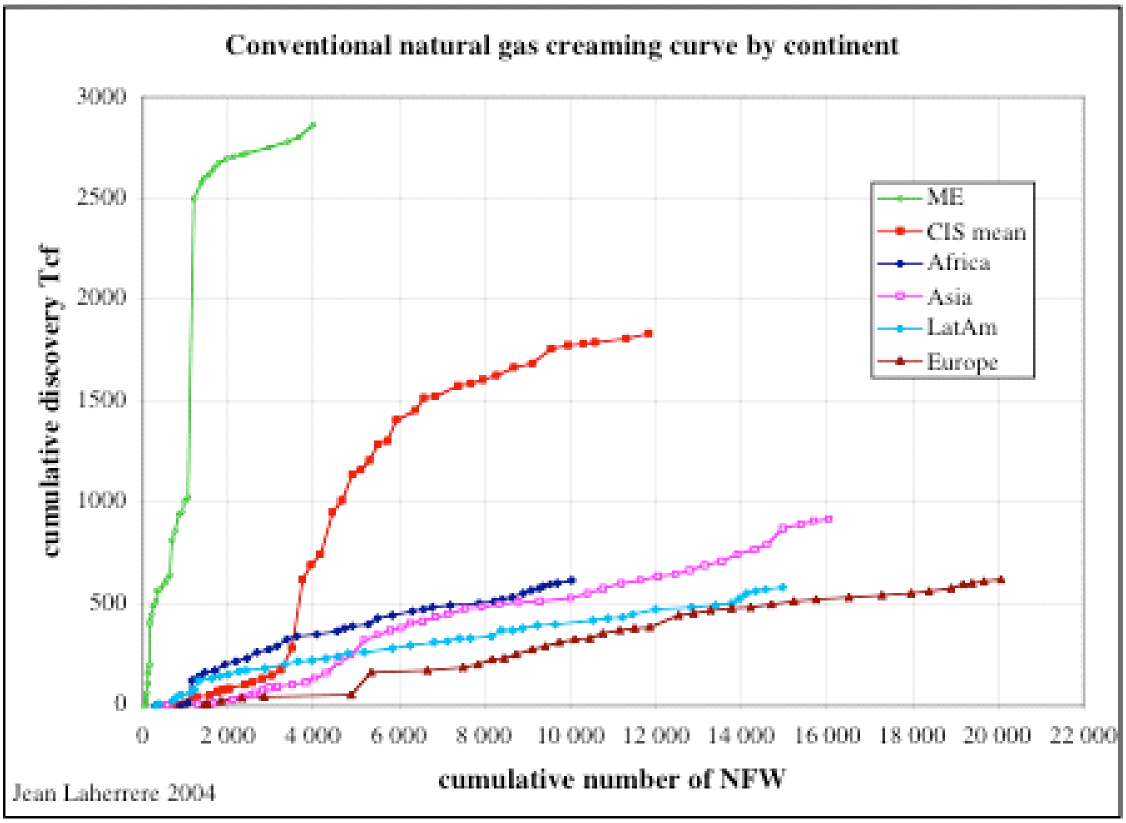
The Exxon demand in 2020 is about 27 Gboe/a or 160 Tcf/a. Our forecast for conventional gas in 2020 is about 120 Tcf/a at most and the unconventional gas, such as CBM and tight gas could not reach 40 Tcf/a in 2020, for it is about 4 Tcf presently.
Our past annual "mean" discovery (after correcting several files) is very close to Exxon-Mobil's.
Figure 7: World conventional oil & gas "mean" discovery and production



The cumulative discovery by continent shows the huge inequality of NG distribution.
Figure 8: Cumulative conventional NG discovery by continent



It is more striking to compare the creaming curve (cumulative discovery versus cumulative number of New Field Wildcats NFW), which deletes all the stops and goes of exploration in time
Figure 9: Conventional NG creaming curves

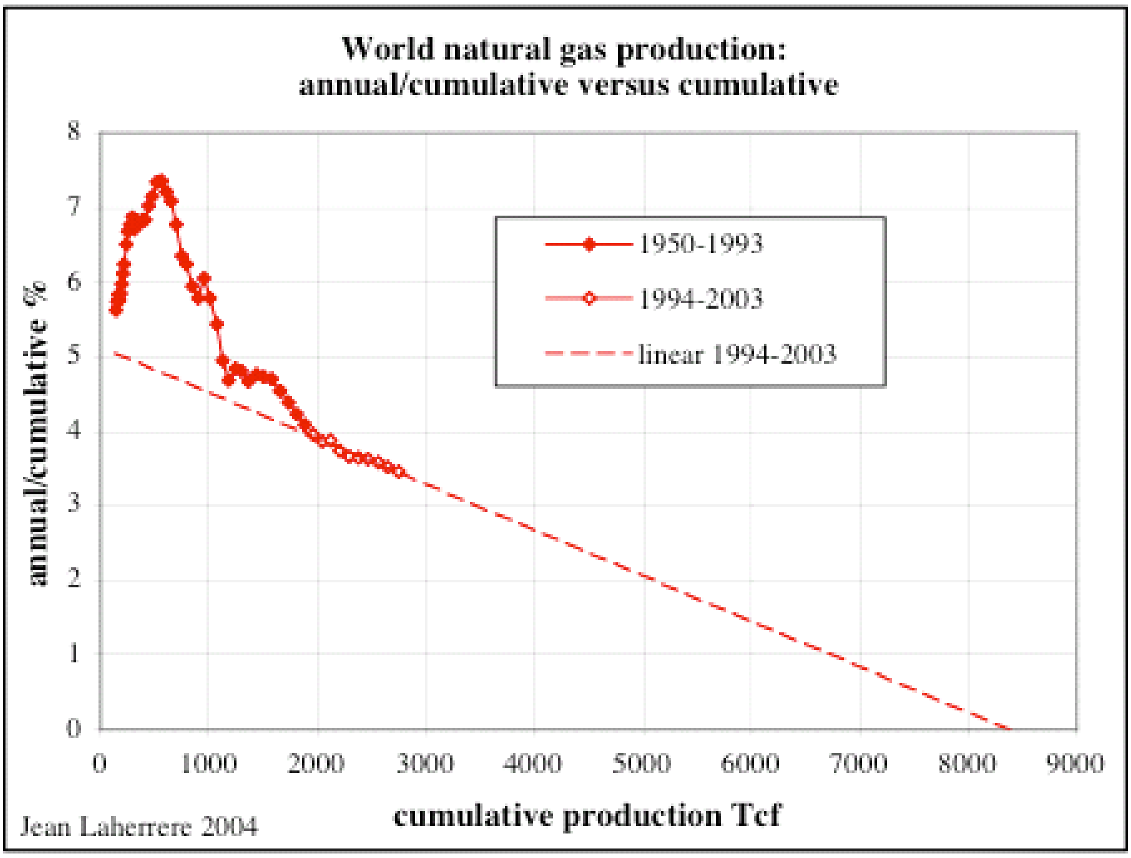


The Middle East has discovered 2800 Tcf with less than 4000 NFW, when FSU (CIS) has discovered only 1800 Tcf with 12 000 NFW and Europe 700 Tcf with 20 000 NFW.
Creaming curves are easily modelled with several hyperbolas (several cycles) and the ultimate is estimated for a cumulative number of NFW double of the present number.
The conventional gas ultimate from the creaming curves of mean values is in Tcf

	ultimate	found	produced	remaining reserves
Middle East	3 000	2 860	200	2 660
CIS	2 000	1 830	700	1 100
US	1 250	1 200	960	240
Asia	1 150	920	180	740
Africa	800	620	100	520
Latin America	800	580	150	430
Europe	800	620	300	320
Canada	250	215	155	60
World	10 000	8 800	2 700	6 100
OPEC	3 600	3 500	400	3 100

It is comforting to find that the world ultimate of conventional gas is still 10 000 Tcf=10 Pcf, which was already the value of our reports:
-Laherrère J.H., A.Perrodon, C.J.Campbell 1996 “The world’s gas potential”
-Perrodon A., Laherrère J.H., C.J.Campbell 1998 “The world’s non-conventional oil and gas”
Each time better data and more detailed studies confirm our previous estimate.
However these studies were based on 2P field values from IHS corrected for FSU, and the comparison with the other field database from Wood Mackenzie (despite being incomplete) shows that IHS is much higher than WM about 20% for oil and from 10% (Europe) to 100% (Middle east) for gas, since WM reports only economical fields, stranded gas is therefore not reported.
So our estimate has to be considered as optimistic.
In these reports we estimate the conventional and unconventional ultimate at 12.5 Pcf.
IHS (Chew 2004) reports an ultimate of 14.7 Pcf, accepting USGS reserve growth and undiscovered estimates.

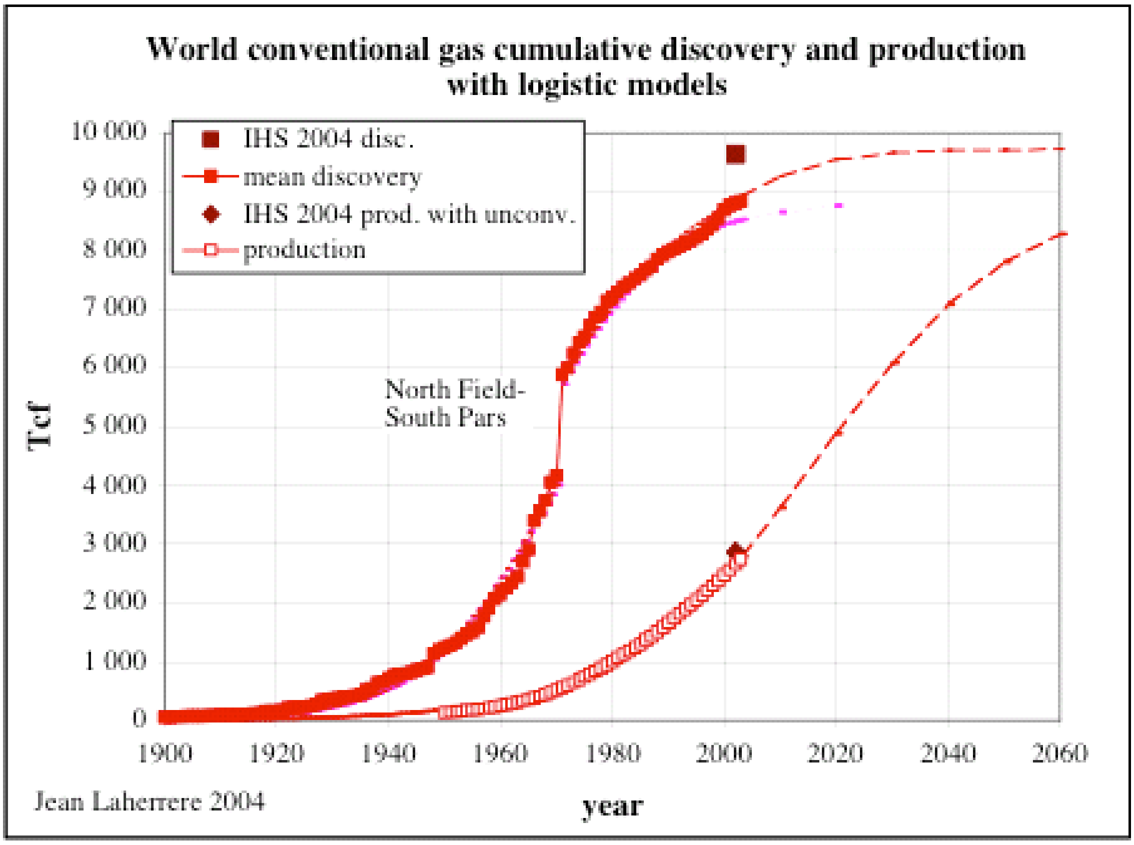
Our estimate of conventional and unconventional gas ultimate was 12.5 Pcf in 1998 and I do not see any reason to change it, as any change will be under the inaccuracy range.
Another quick way to estimate ultimate is from past production to extrapolate the annual/cumulative percentage versus the cumulative production. A linear trend means that the curve fits a logistic curve.
Figure 10: World NG production annual/cumulative versus cumulative



The trend is linear from 1994 to 2003 and goes toward an ultimate of 8500 Tcf, but stranded gas does not contribute to this trend and is therefore excluded from the ultimate. This indicates that the present stranded gas ultimate is about 1500 Tcf. But stranded gas status is changing rapidly with new LNG plants (Nigeria, Trinidad).

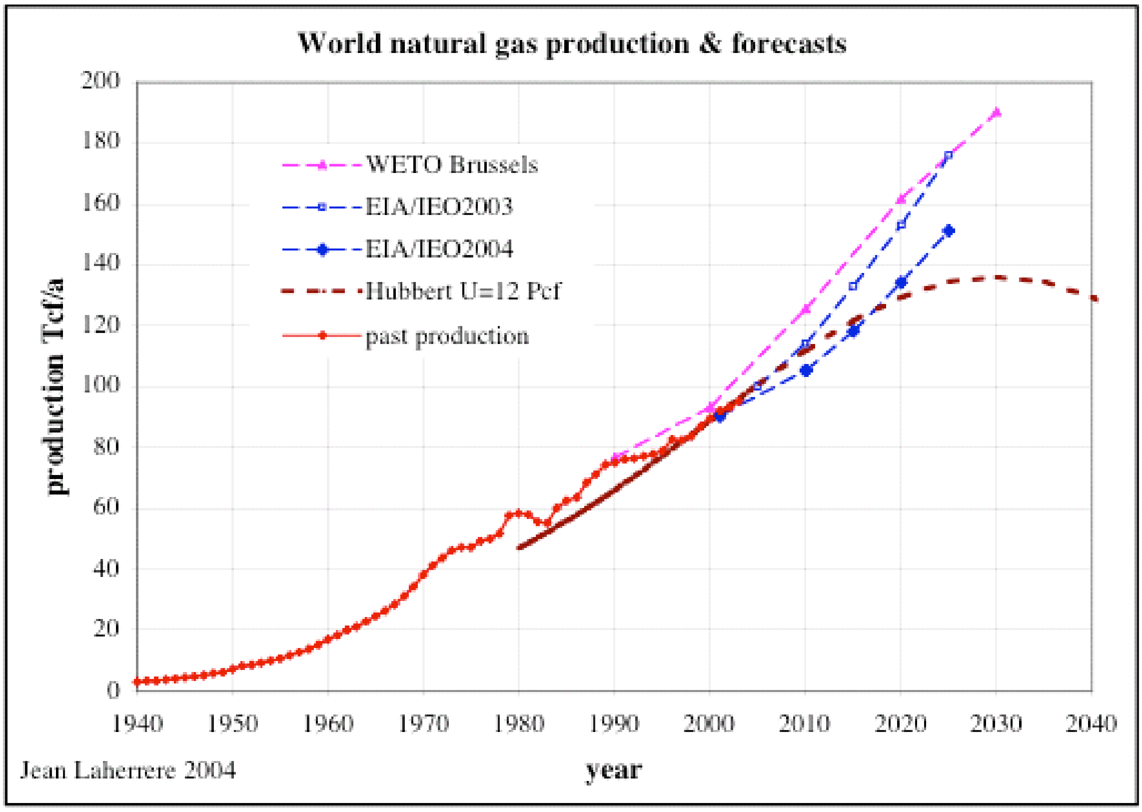
The cumulative world gas discovery displays a curve close to a logistic curve, except the huge jump in 1971 due to the discovery of North field (Qatar)-South Pars (Iran). This huge field is 5 to 6 time larger than Urengoy, which was considered recently (and still by some) as the largest gasfield in the world. This field represents 15% of the ultimate, when the largest oilfield, Ghawar, represents only about 6% of the conventional oil ultimate. The cumulative production perfectly fits a logistic curve with a 10 Pcf ultimate.

Figure 11: World conventional NG cumulative discovery & production with logistic models



A 12 Pcf ultimate is used to model the annual all (conventional and unconventional) production with a derivative of the logistic (Hubbert curve) and compared to USDOE (EIA/IEO 2003 & 2004) and WETO (Brussels) 2003 forecasts which in fact are plain forecasts of the demand without bothering to know if the supply will be there. But EIA 2004 is drastically lower than EIA 2003, close to our values up to 2020.

Figure 12: World NG annual production & forecasts from USDOE/EIA and European Union

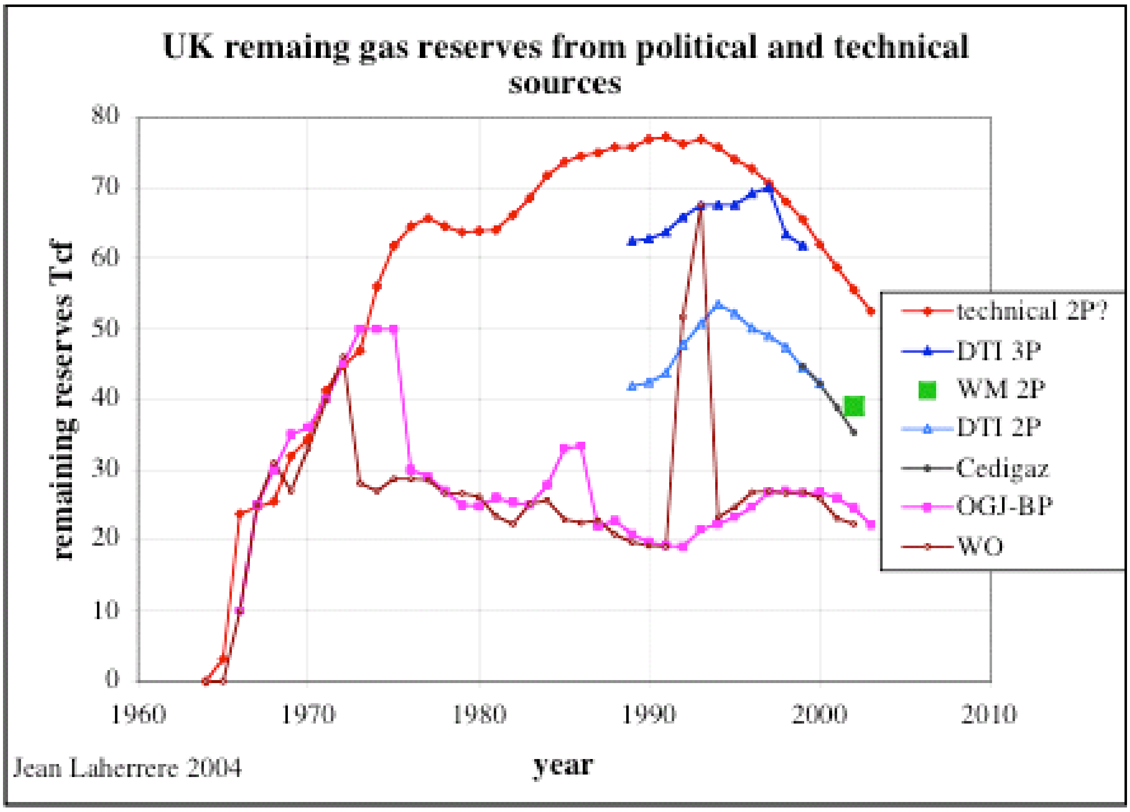


The study by country and continent displays different curves in order to foresee the future production. The problem is that contrary to oil, which is usually quickly put into production after discovery, there are many places where gas is stranded and production does not mimic discovery as well.

-UK

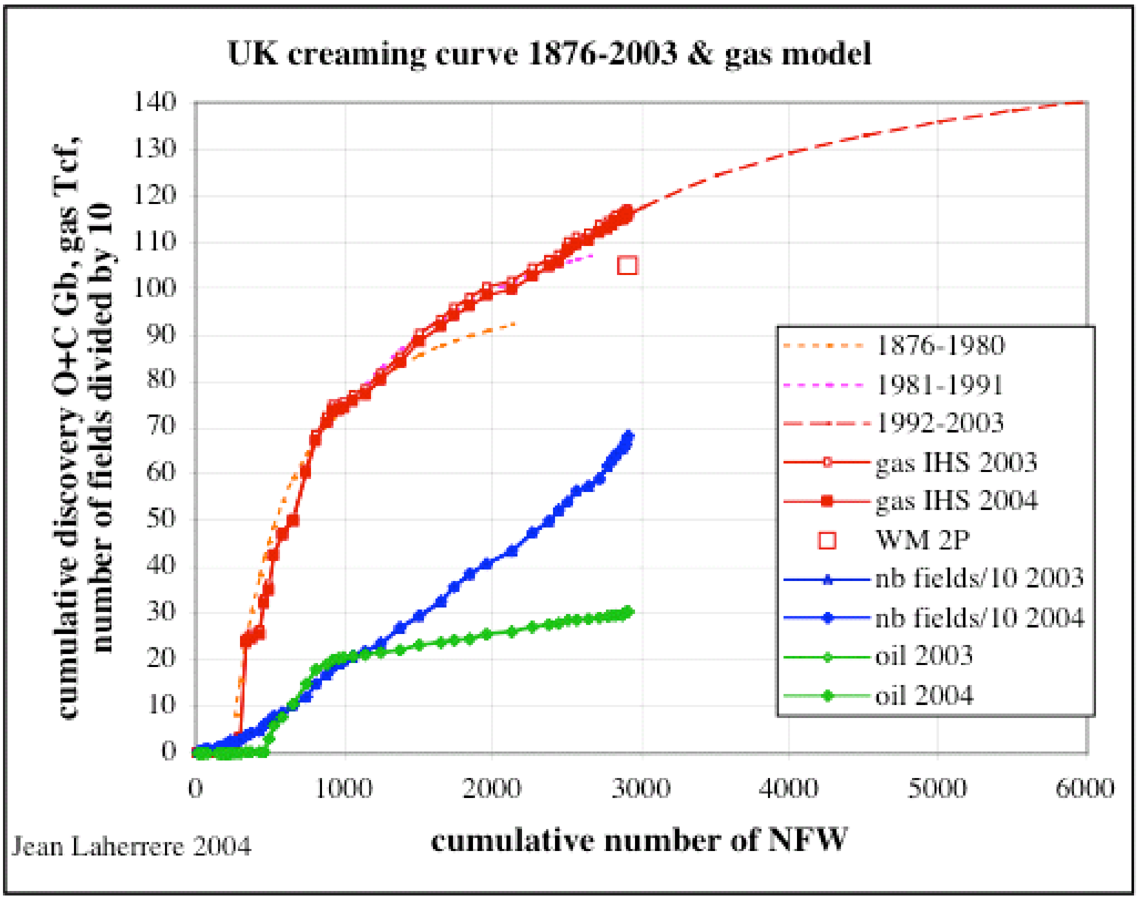
Despite that DTI reports reserves for each field as P, 2P and 3P, political data is chaotic with World Oil moving from 1P to 3P and back to 1P. It shows that the world reserves reported by the media are very poor. IHS data corresponds to the 3P as they include every discovery (300 discoveries are still waiting to be developed). WM 2P is close to DTI 2P and 20 Tcf lower than IHS P50.

Figure 13: UK NG remaining reserves from technical & political sources.



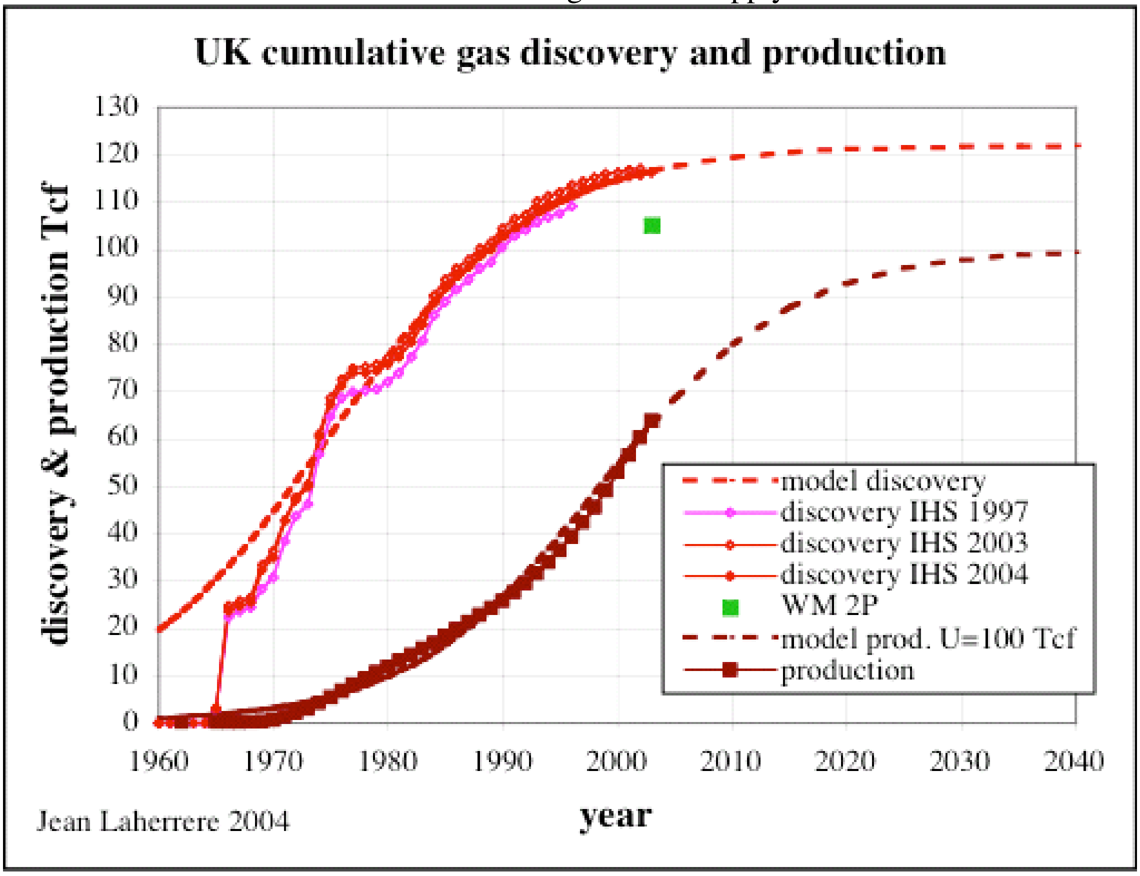
UK NG creaming curve (from IHS) is easily modelled with only one hyperbola. The cumulative gas discovery is lower in IHS 2004 than from IHS 2003, showing that the reserve growth is now negative.

Figure 14: UK creaming curve



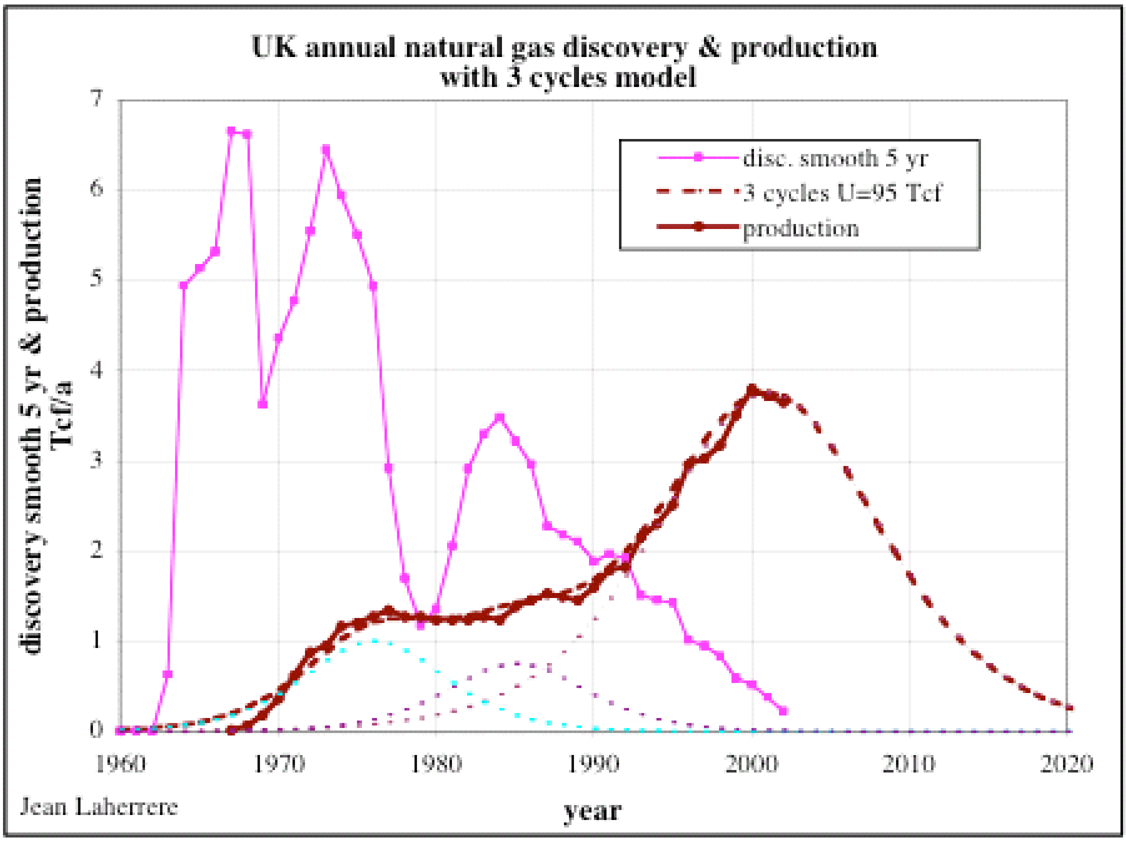
The cumulative discovery versus time is not as easy to model because the stop and go of exploration up to 1980, but trends toward 125 Tcf. The production is modelled with a lower ultimate (to fit WM 2P)

Figure 15: UK NG cumulative discovery & production



The annual production is modelled with an ultimate of 95 Tcf.

Figure 16: UK NG annual discovery & production

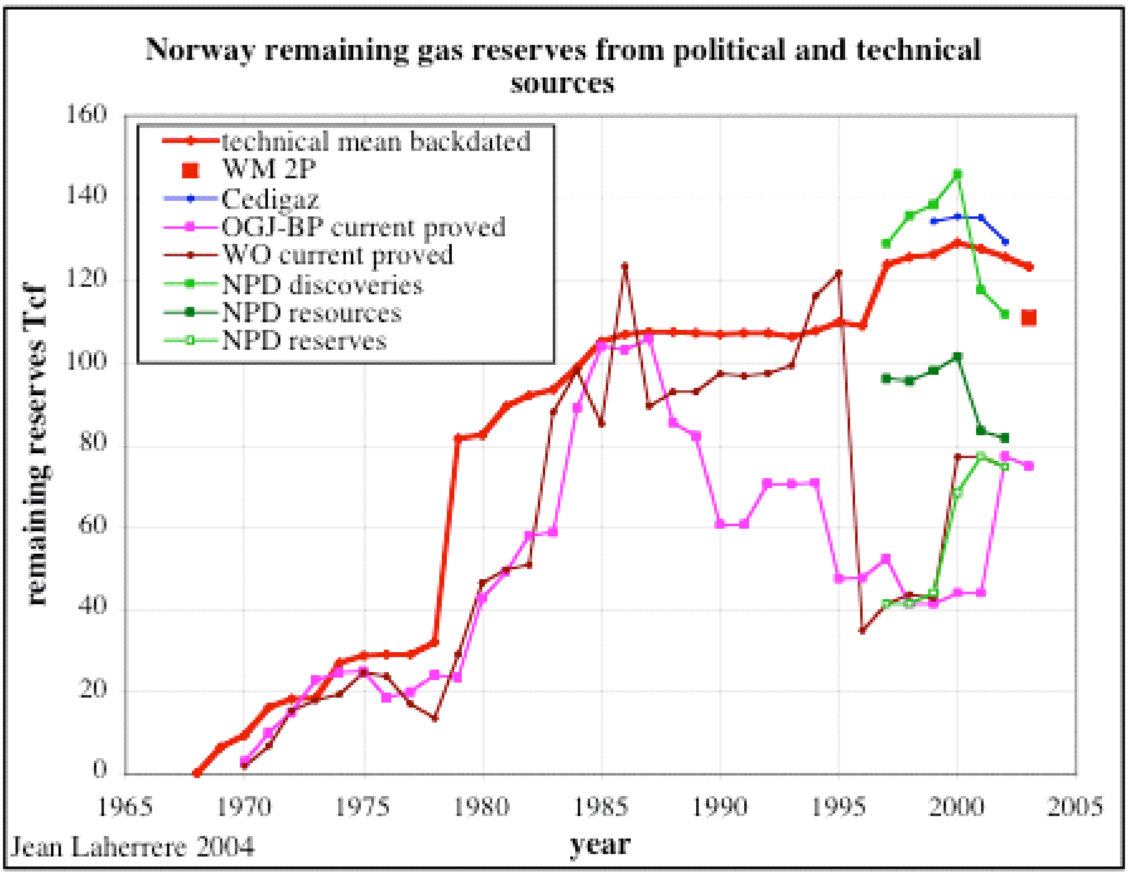


The UK NG production has peaked and will decline towards extinction after 2025.

-Norway

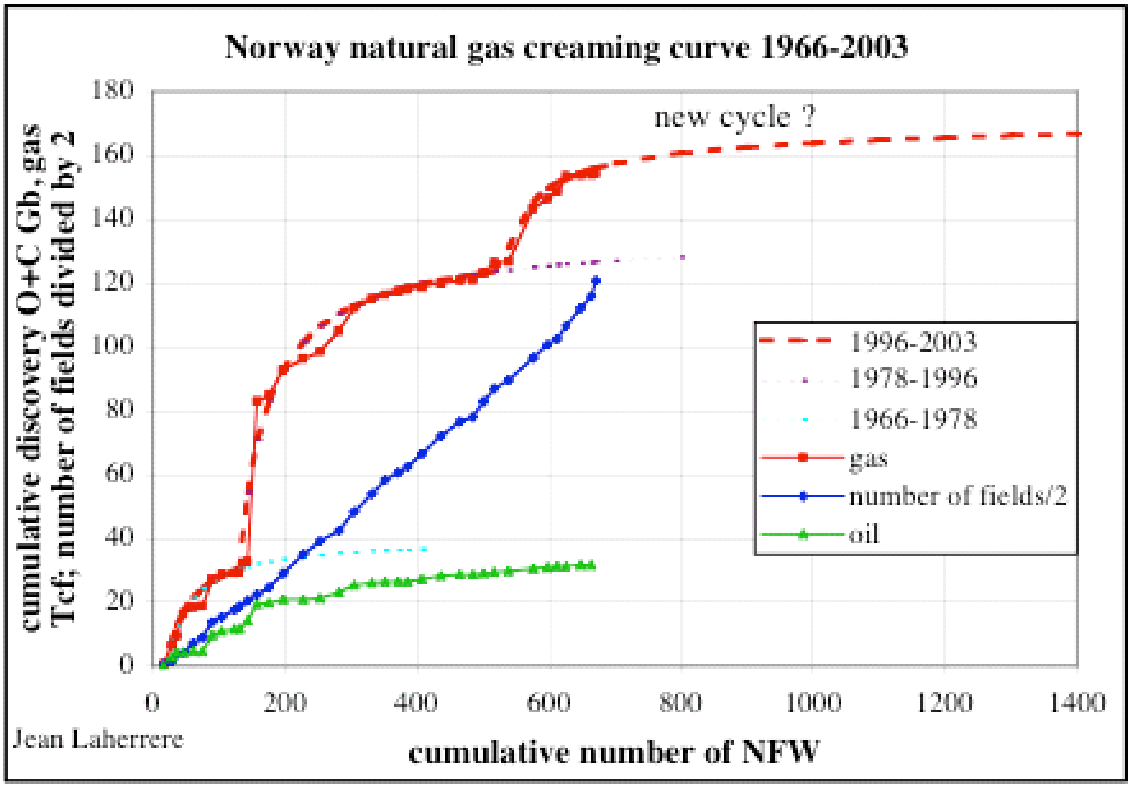
Again Norway is the best country for reserve classification and publishes field reserves, discarding the proved values, however political values are chaotic between OGJ and WO. WM is 15 Tcf lower than IHS.

Figure 17: Norway NG remaining reserves from technical & political sources



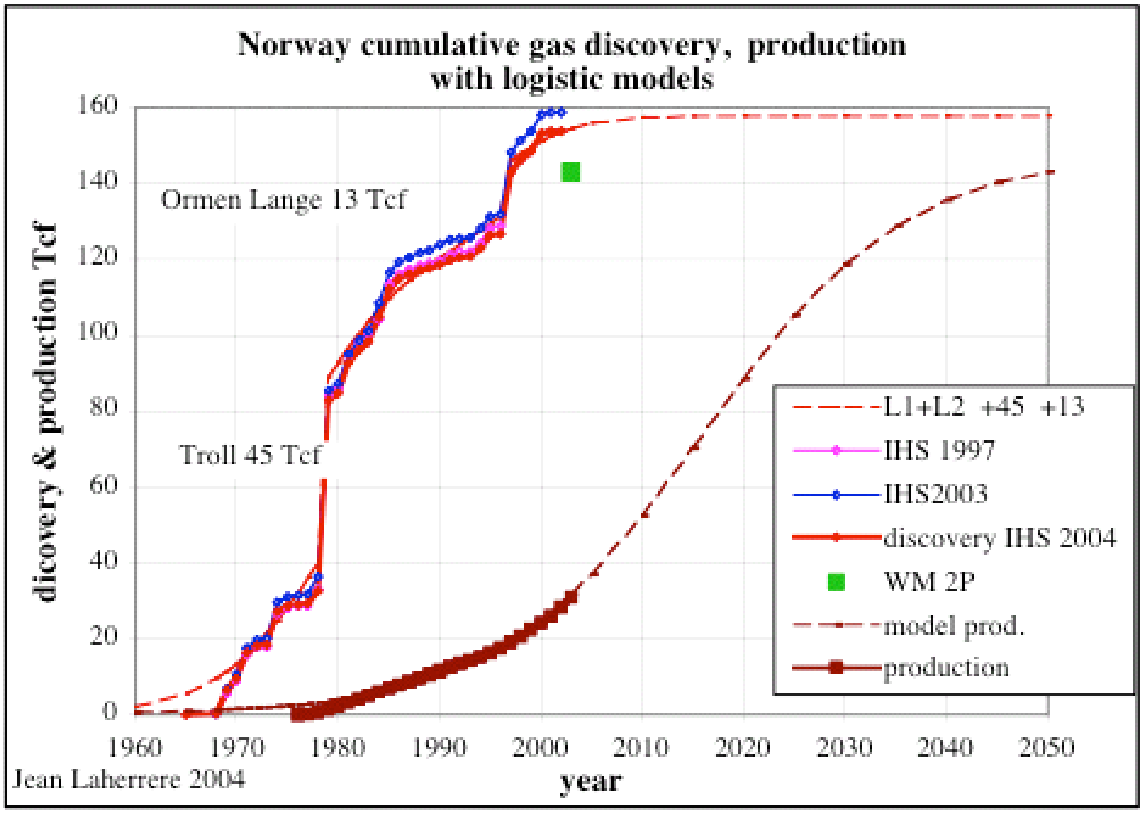
The creaming curve can be modelled with 3 cycles and a new cycle could exist (Barentz sea?). The ultimate is about 170 Tcf.

Figure 18: Norway NG creaming curve



The cumulative discovery versus time is, as usual, not as easy to model as the creaming curve. As for UK the 2004 IHS values are lower than the 2003 values, showing a negative reserve growth, confirmzed by a lower WM value.

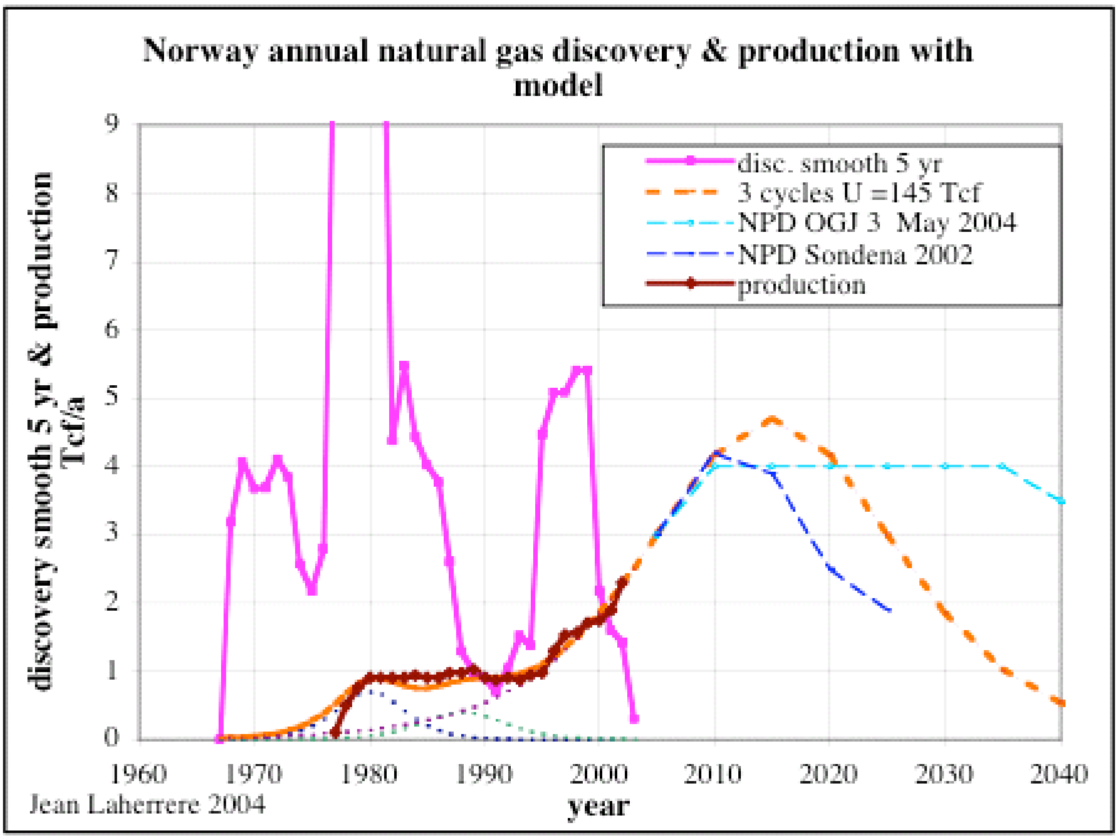
Figure 19: Norway NG cumulative discovery & production



The annual production is modelled with an ultimate of 145 Tcf (lower than the ultimate from IHS values) and will peak around 2015 at 5 Tcf/a. The NPD forecasts vary (OGJ 3 May

2004) with a plateau at 4 Tcf/a from 2010 to 2035, but Sondena (2002) was estimating a peak in 2010 at 4 Tcf/a.

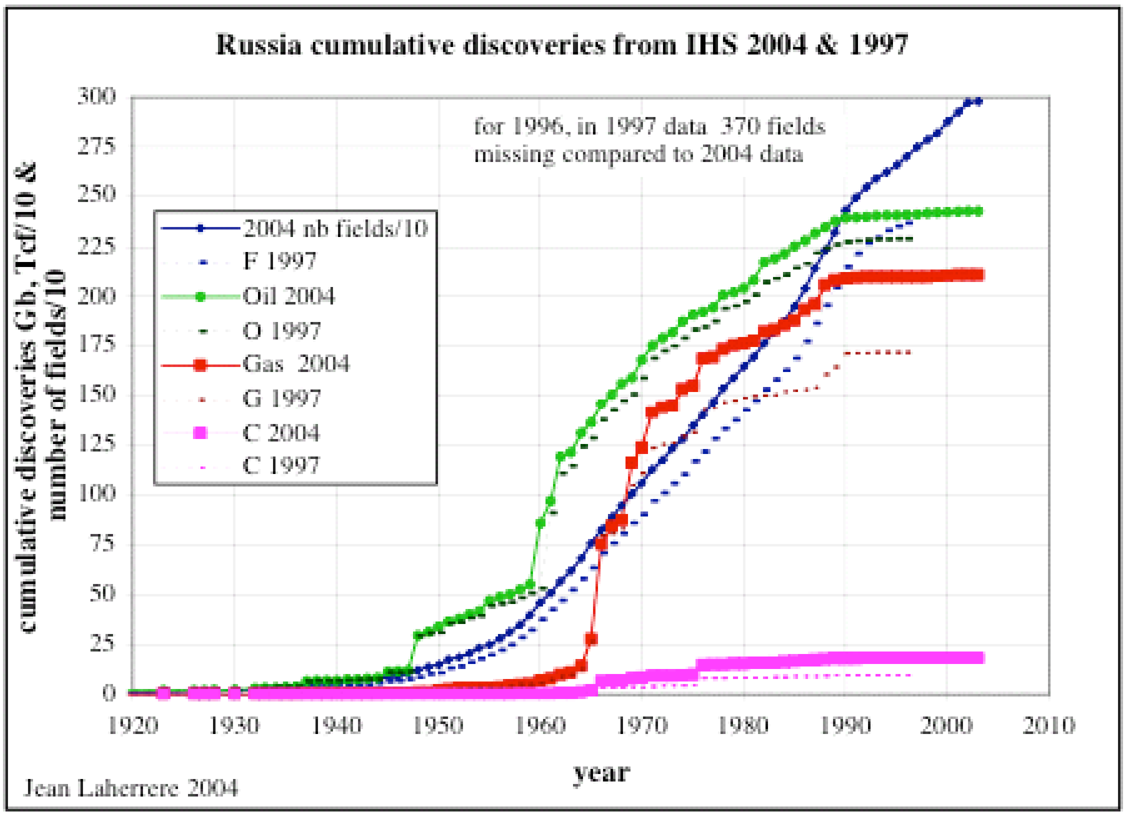
Figure 20: Norway NG annual discovery & production



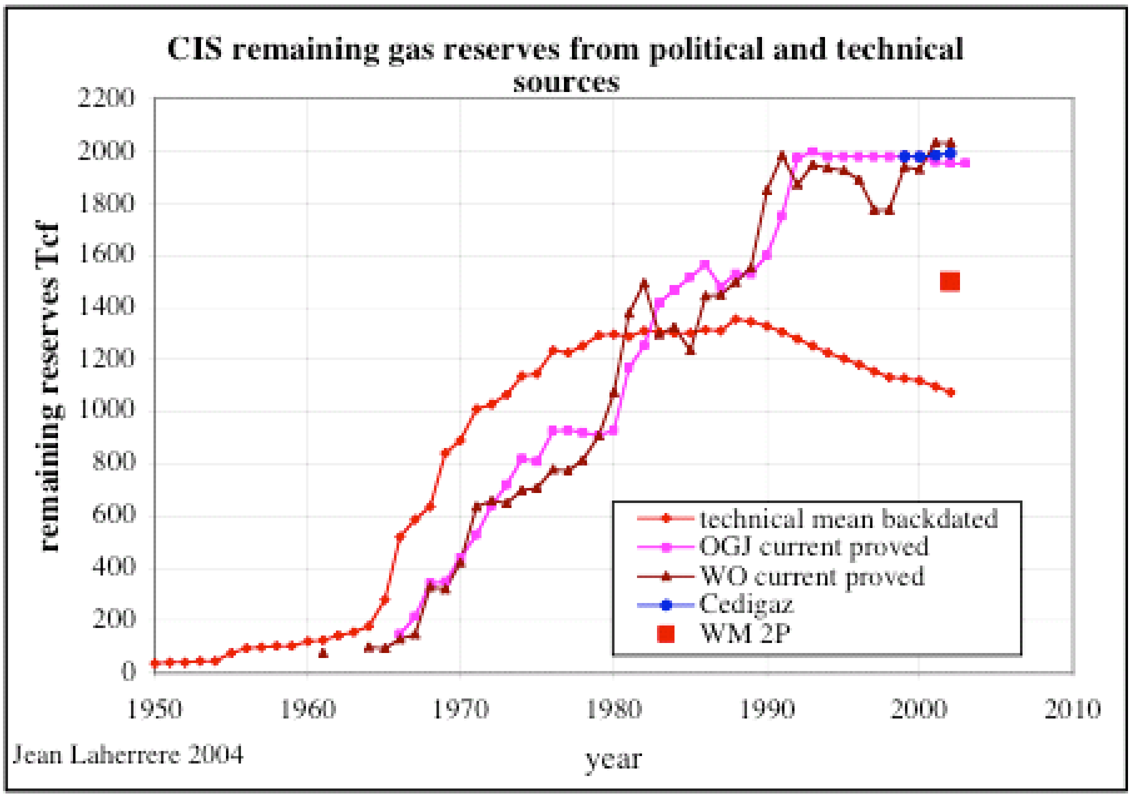
-CIS

IHS reserve inventory as end of 1996 were on the 1997 values, missing 370 fields and 50 Tcf compared to the values reported in 2004. In 1997 many fields were not yet recorded in IHS computers, being still on paper and untranslated. This kind of reserve growth is mainly due to incomplete records.

Figure 21: Russia cumulative discoveries from IHS 1997 & 2004

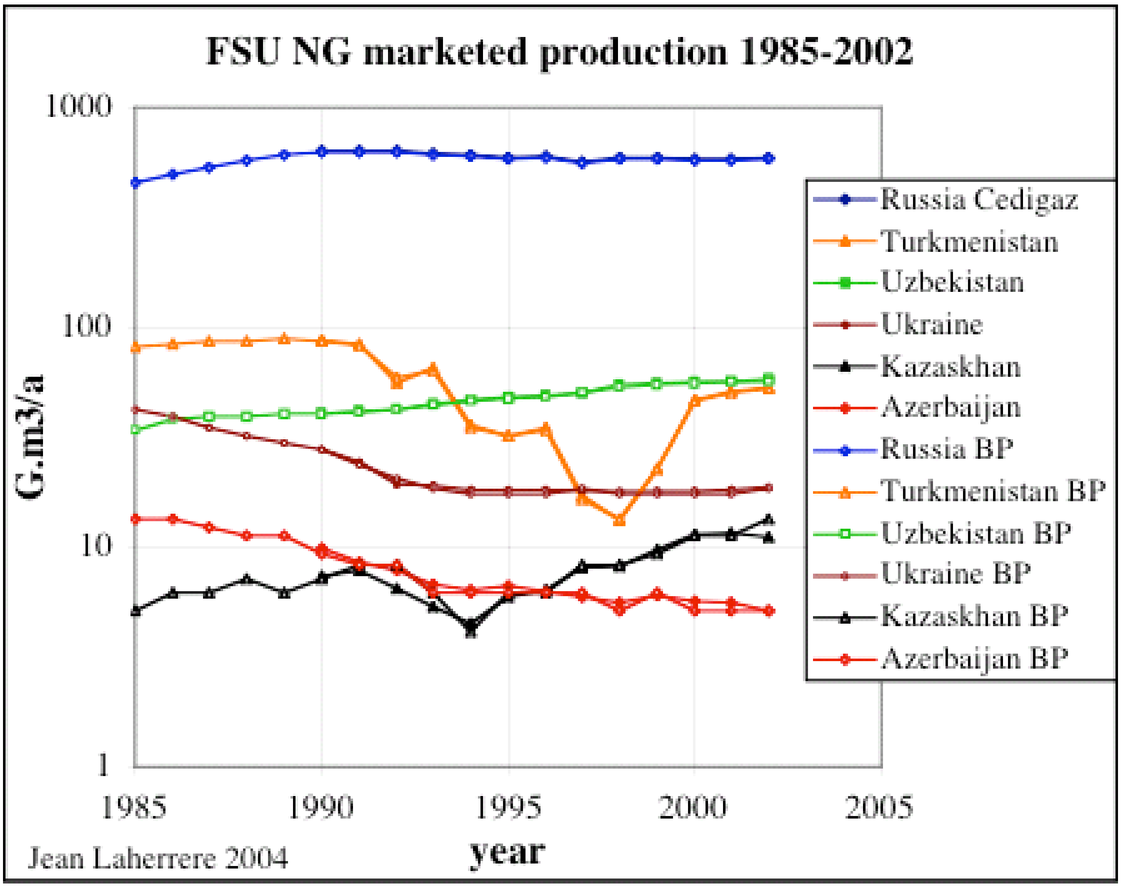


The problem with Russian reserves under their 1979 classification (stated as grossly exaggerated by Khalimov in 1993, despite that he presented this classification in WPC 1979 as the best system) is that ABC1 corresponds to 3P (maximum theoretical recovery) and should be corrected to get the mean value (2P) by reducing it by 30%.
Our technical mean data is obtained after reducing the ABC1 values by 30%.
WM seems to rely on ABC1 values.
The political reserves as of end 2003 are about 2000 Tcf against 1100 Tcf for the technical reserves. WM reports about 1500 Tcf and IHS about 1800 Tcf.
More studies are needed to obtain the true mean values of FSU fields. Russia has asked the UN to get a new reserve definition and the UN Framework Classification has just issued a new definition with the goal to homogenize the reserve definition for oil and gas, coal and uranium. Unfortunately the last draft to be approved is a poor compromise (rejecting the probabilistic approach), which, as the previous text, will be discarded by the operators.
Figure 22: CIS NG remaining reserves from technical & political sources



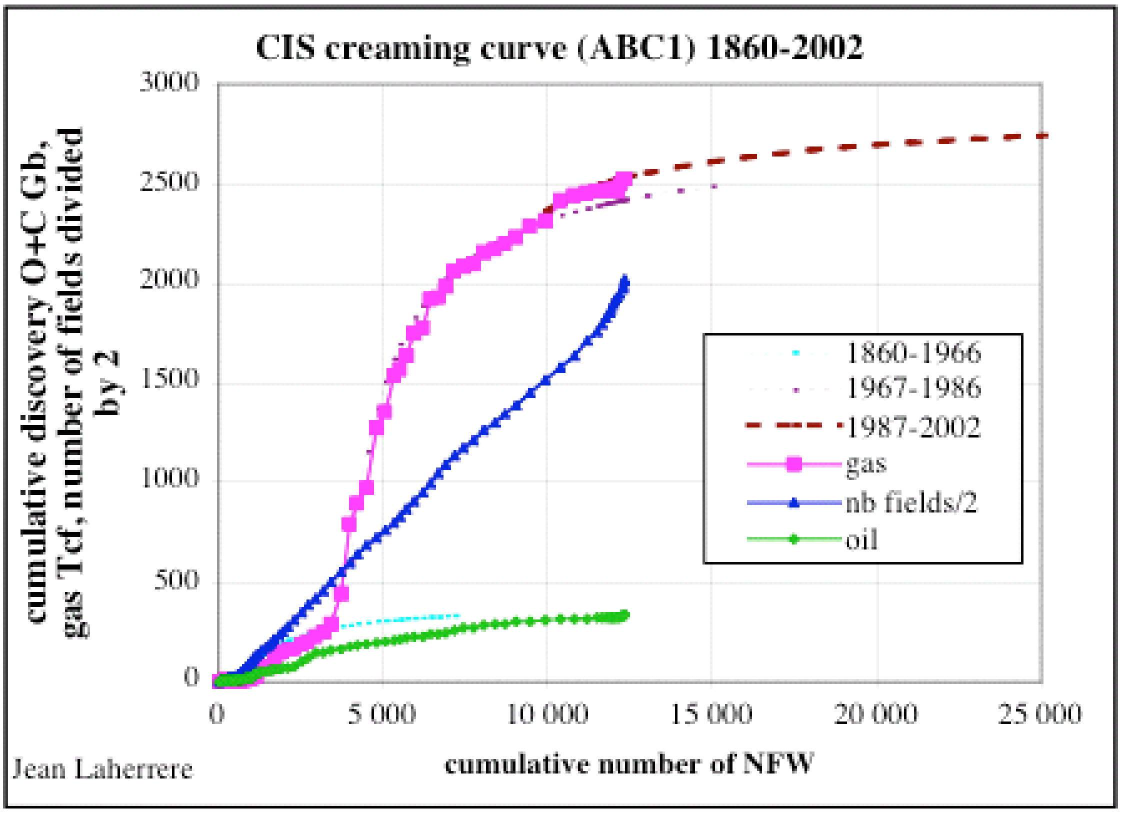
BP Review and Cedigaz production data are very close. Russian production has remained flat since 1990 when Turkmenistan fell from 1991 to 1998.

Figure 23: FSU gas production from BP Review and Cedigaz



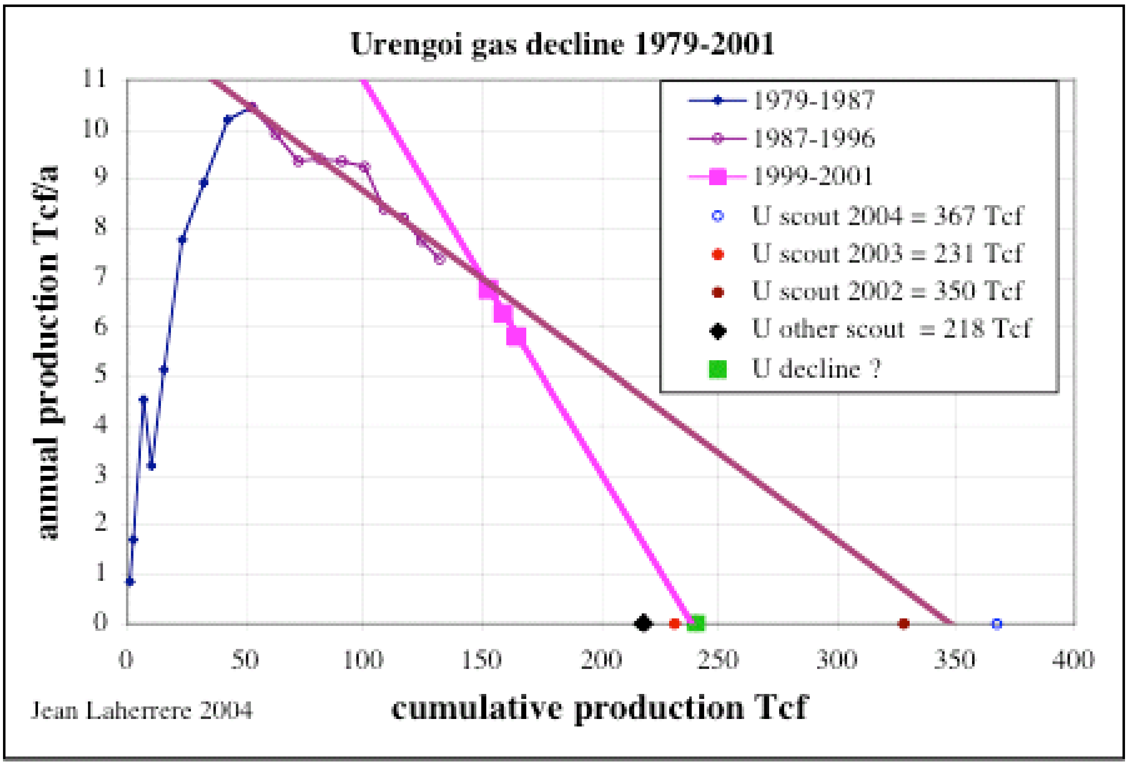
The ABC1 creaming curve is modelled with 3 hyperbolas trending towards 2800 Tcf, despite a strong increase in the number of discoveries.

Figure 24: CIS creaming curve (ABC1) 1860-2002

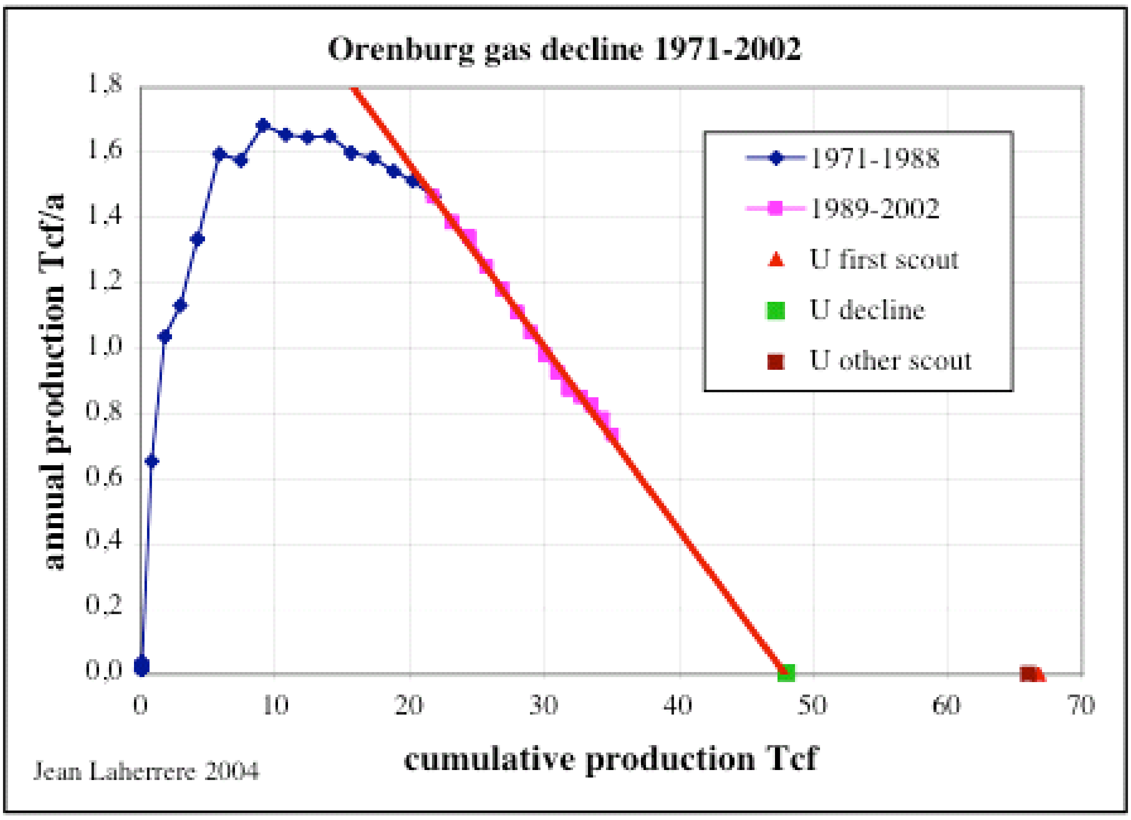


The largest Russian gasfield, Urengoi, has just been reduced from 382 Tcf in 2000 to 328 Tcf in 2002 (in line with the decline from 1987 to 1996, only data available), then to 231 Tcf in 2003 (in line with the last decline from 1999 to 2001), but raised again to 367 Tcf in 2004 (without any reason?), when Urengoi oil and condensate reserves did not change at all. But the last known decline is trending towards 240 Tcf. But WM estimate is 218 Tcf when Zittel reports 250 Tcf. It seems that the past decline from 1987 to 1996 was due to overproduction, meaning that the decline from this period is unreliable. Unfortunately recent production values are unavailable.

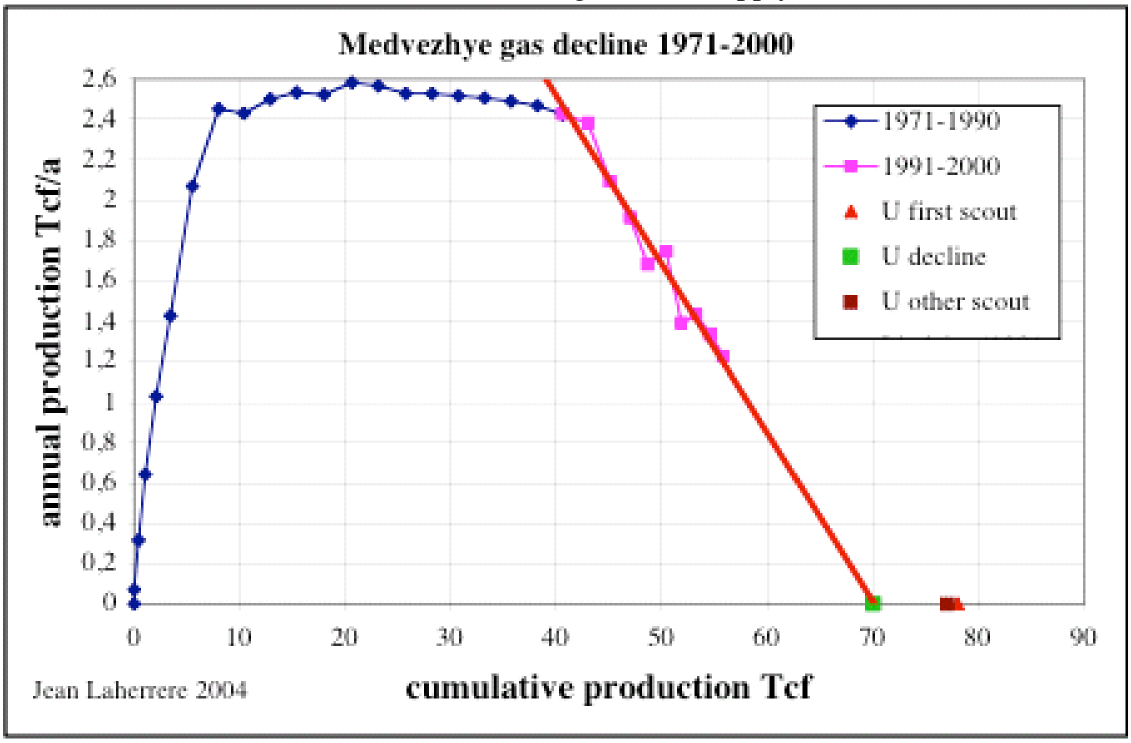
Figure 25: Urengoi gas decline



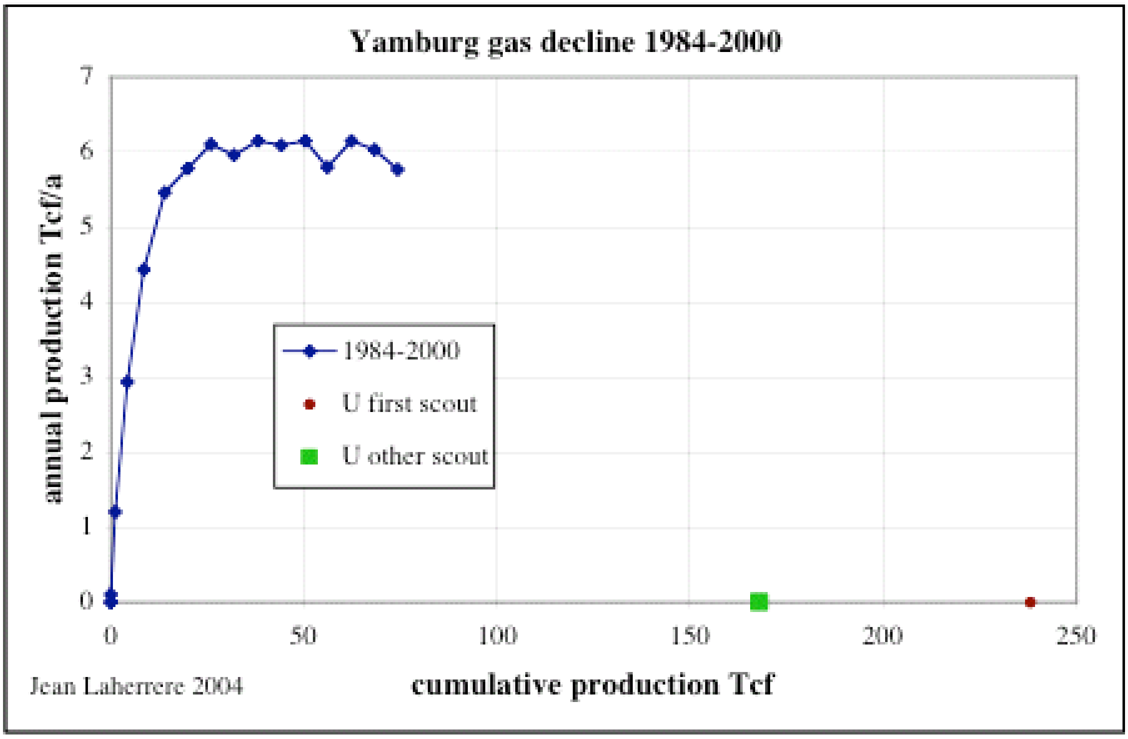
Orenburg is overestimated by IHS and WM (both using ABC1) by 40% with 68 Tcf when decline is about 48 Tcf.
Figure 26: Orenburg gas decline



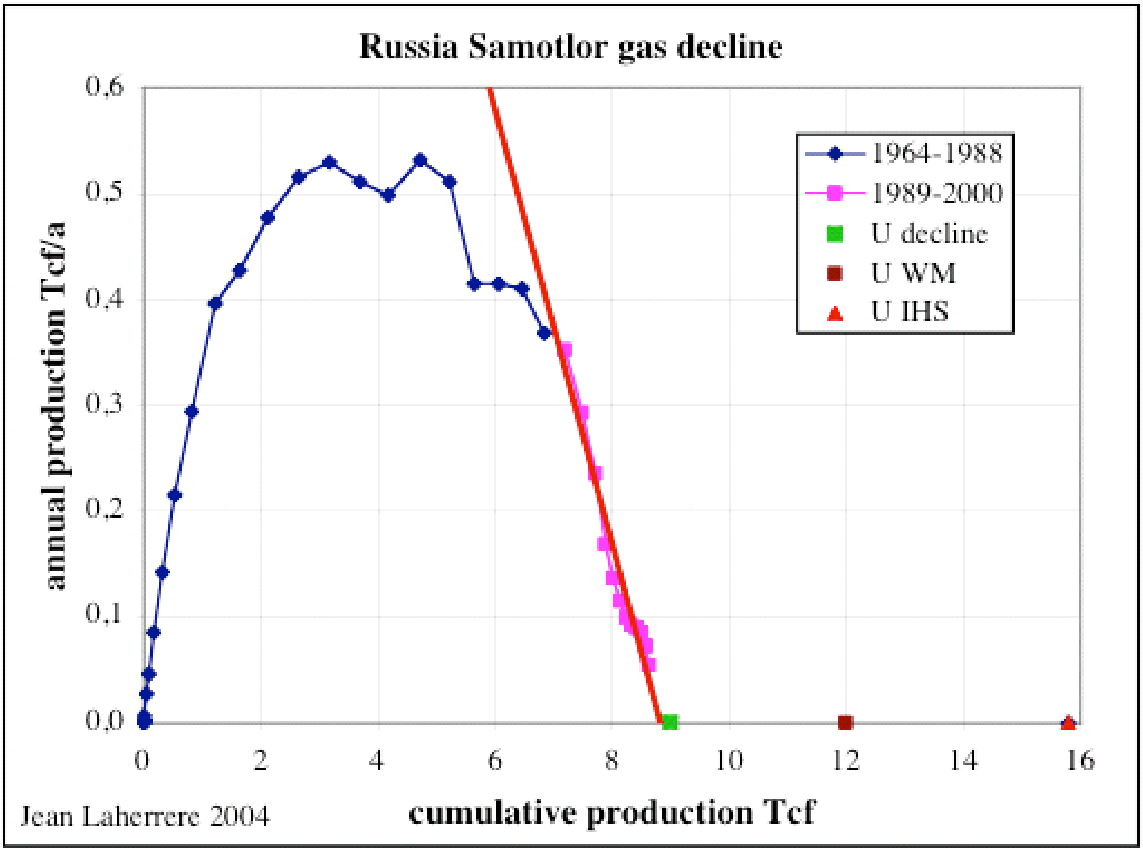
Medvezhye is also overestimated by both IHS and WM, but only by 10%
Figure 27: Medvezhye gas decline



Yamburg has not declined significantly yet, but the two scouts diverge
Figure 28: Yamburg gas decline

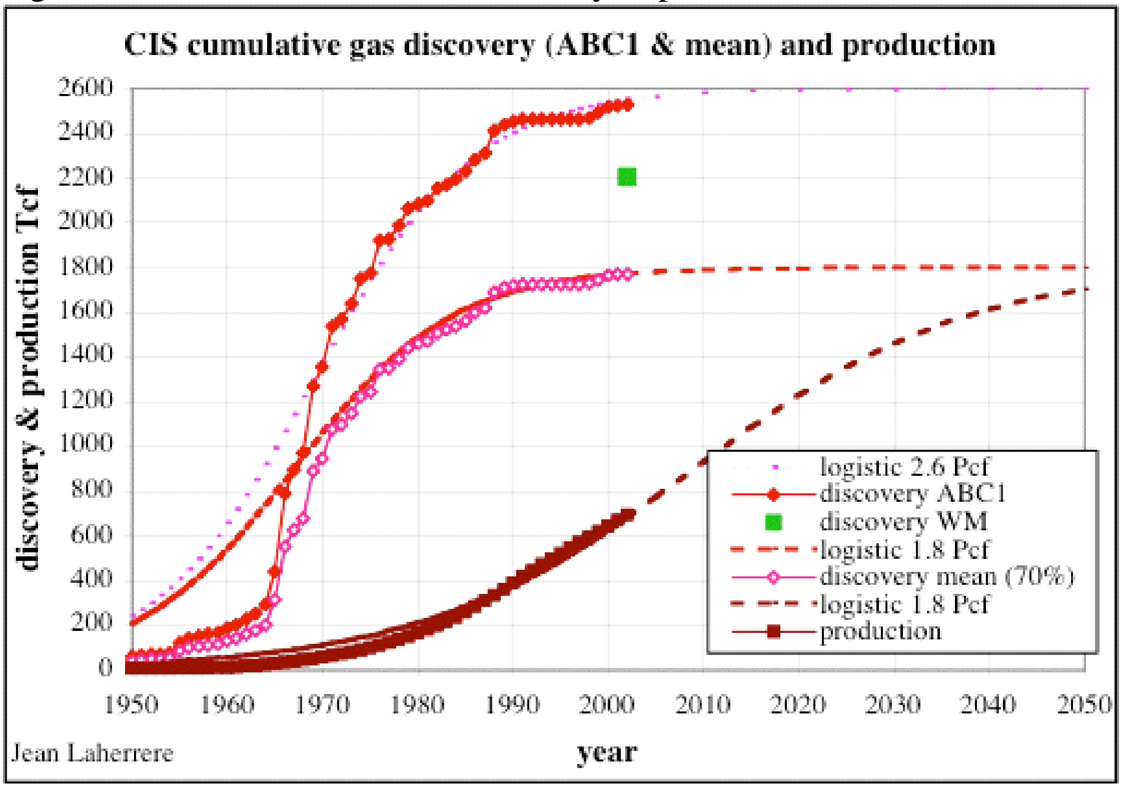


The NG production from Samotlor is close to the end, with an ultimate of 9 Tcf against 16 Tcf for IHS and 12 Tcf for WM.
Figure 29: Samotlor gas decline

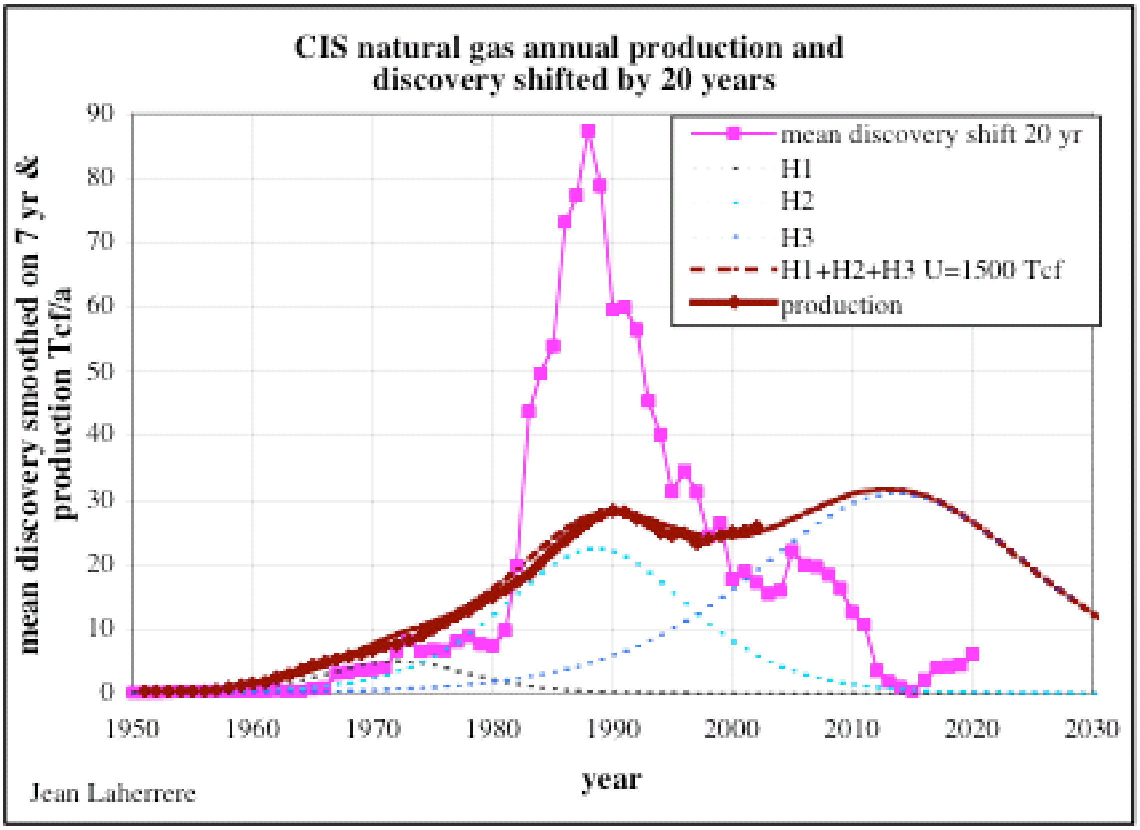


Applying a 30% reduction for gas (as for oil), to get the mean gas reserves indicates from the creaming curve an ultimate of about 1800 Tcf and the cumulative production fits a logistic curve with such ultimate.

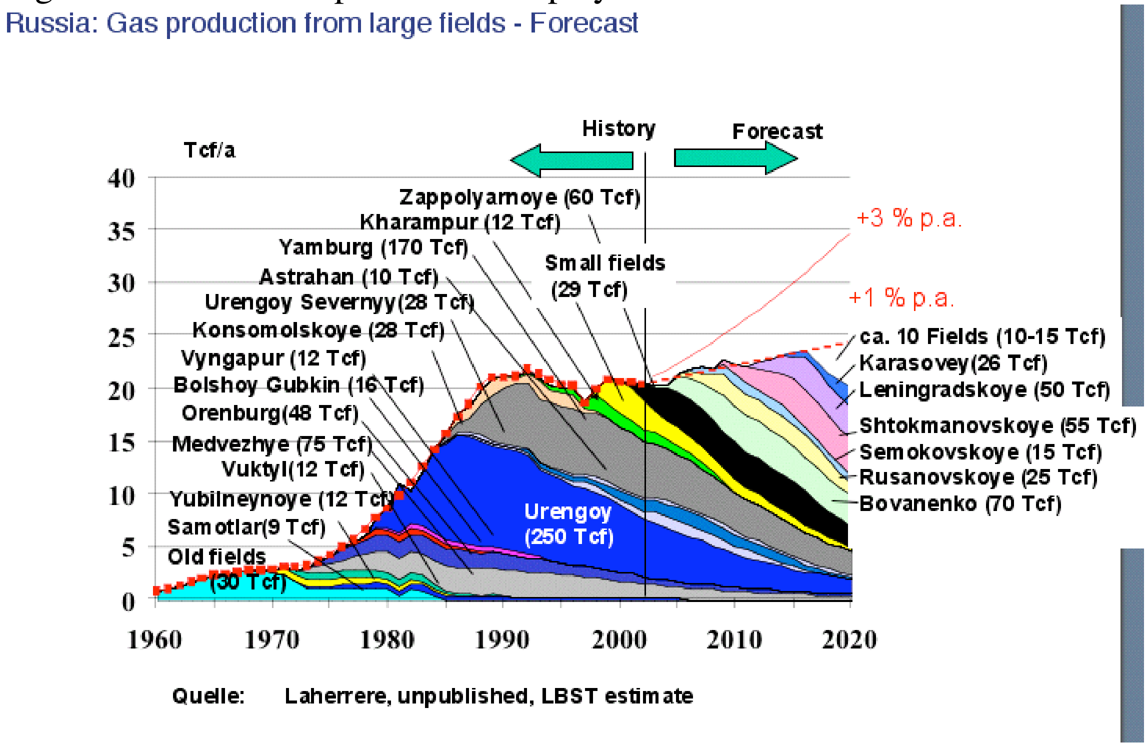
Figure 30: CIS NG cumulative discovery & production



We have plotted the future annual production for an ultimate of 1500 Tcf
FSU NG production will peak about 2012 with 30 Tcf/a, only 4 Tcf/a above the present level.
Figure 31: CIS NG annual discovery & production



Zittel seems to be similar when adding all the known fields and projects.
Figure 32: Zittel field production display

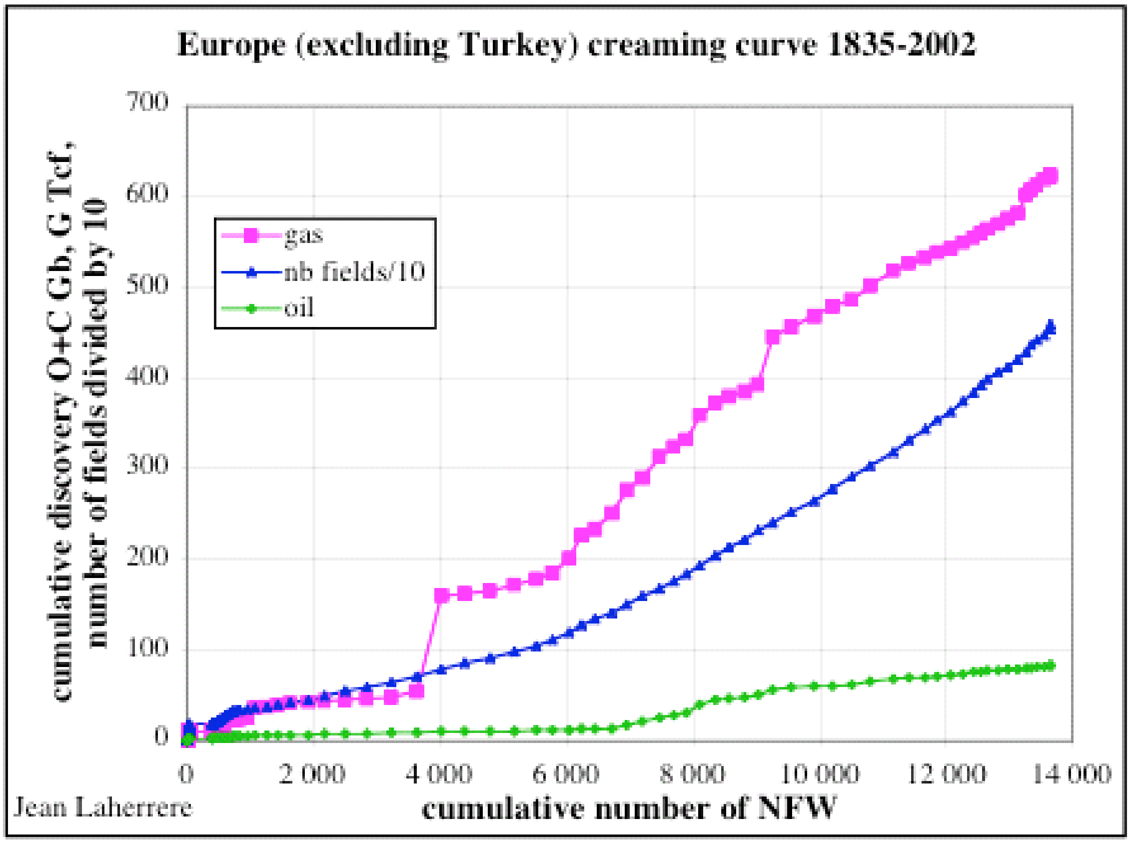


FSU can hardly answer the Europe future needs

-Europe

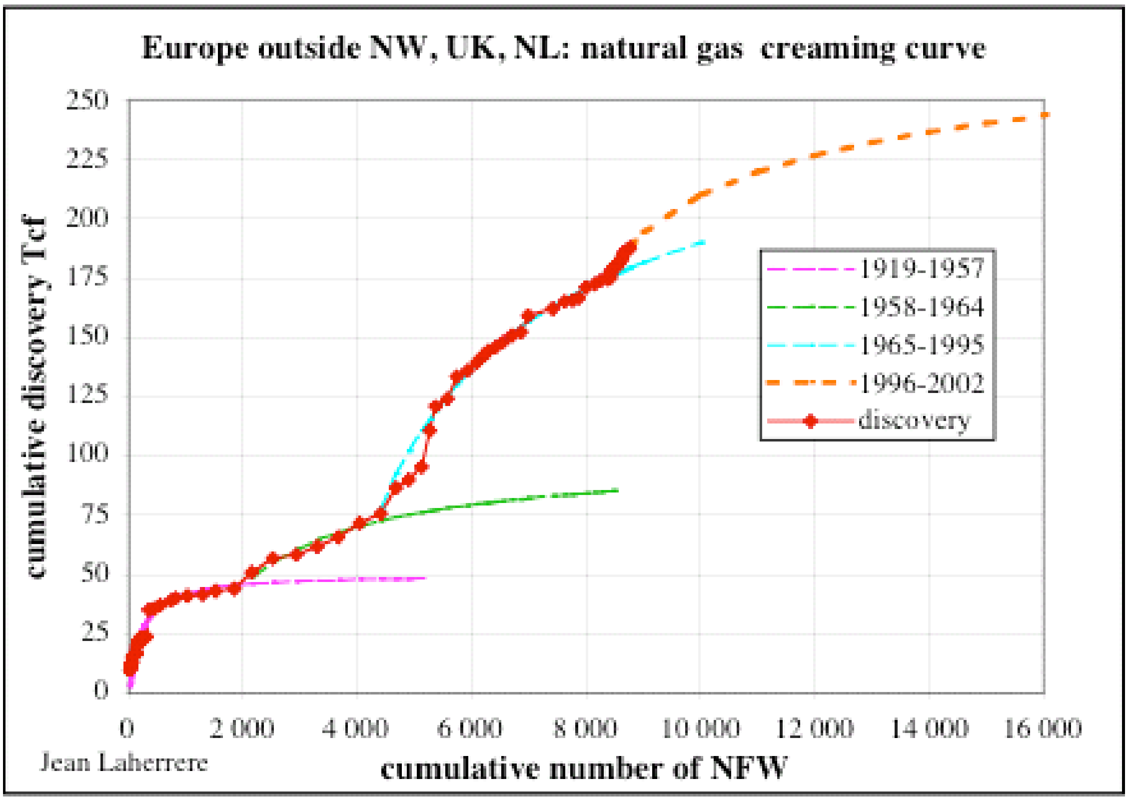
Europe is taken without Turkey, which is reported in our reserves file within Middle East. The creaming curve gathering too many different Petroleum Systems has no good pattern.

Figure 33: Europe creaming curve



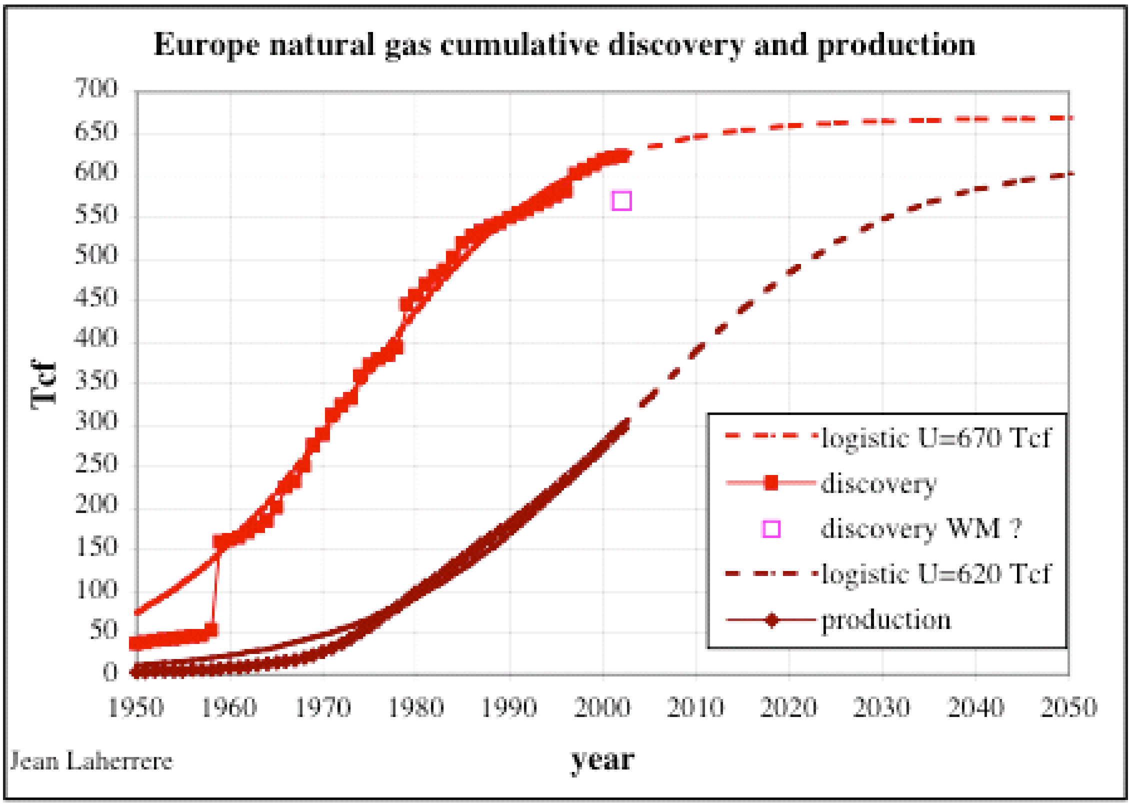
The Europe outside Norway, UK and Netherlands has an easier to model creaming curve, with an ultimate of 240 Tcf.

Figure 34: Europe outside Norway, UK, Netherlands creaming curve



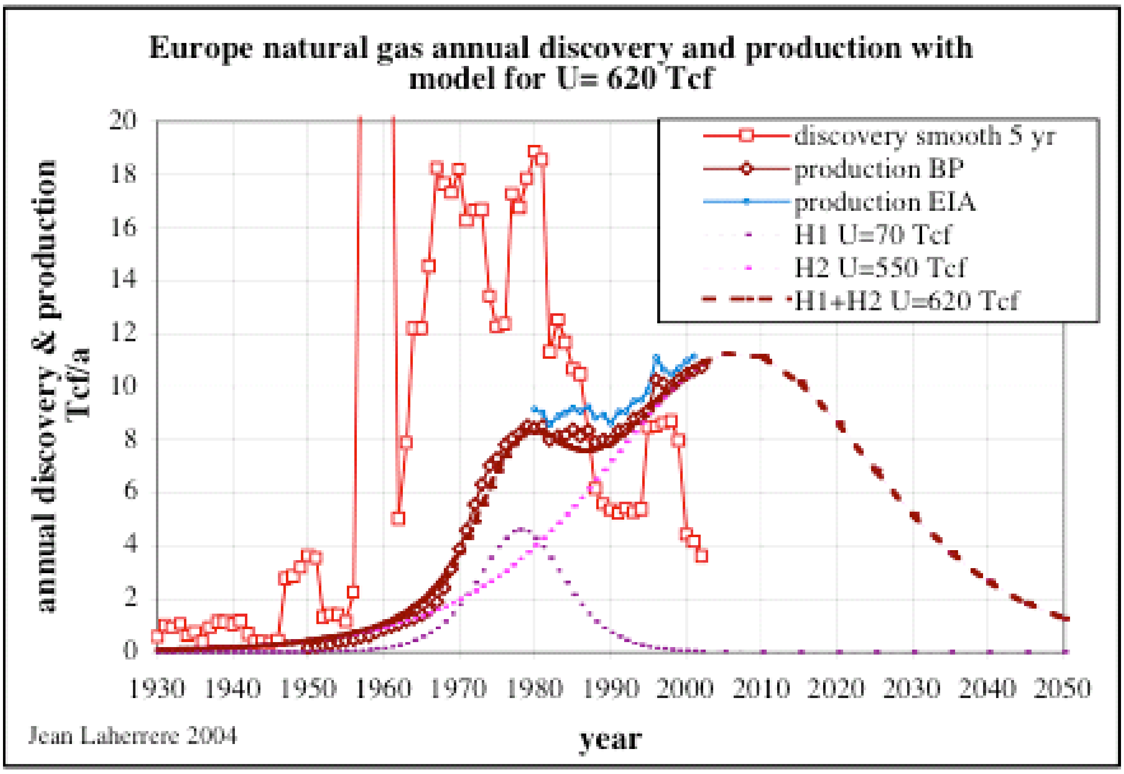
The Europe Cumulative discovery versus time may be modelled (past the Groningen discovery) with one logistic curve with an ultimate of 670 TCF. The cumulative production is modelled with an ultimate of 620 Tcf to adjust to WM value.

Figure 35: Europe NG cumulative discovery & production



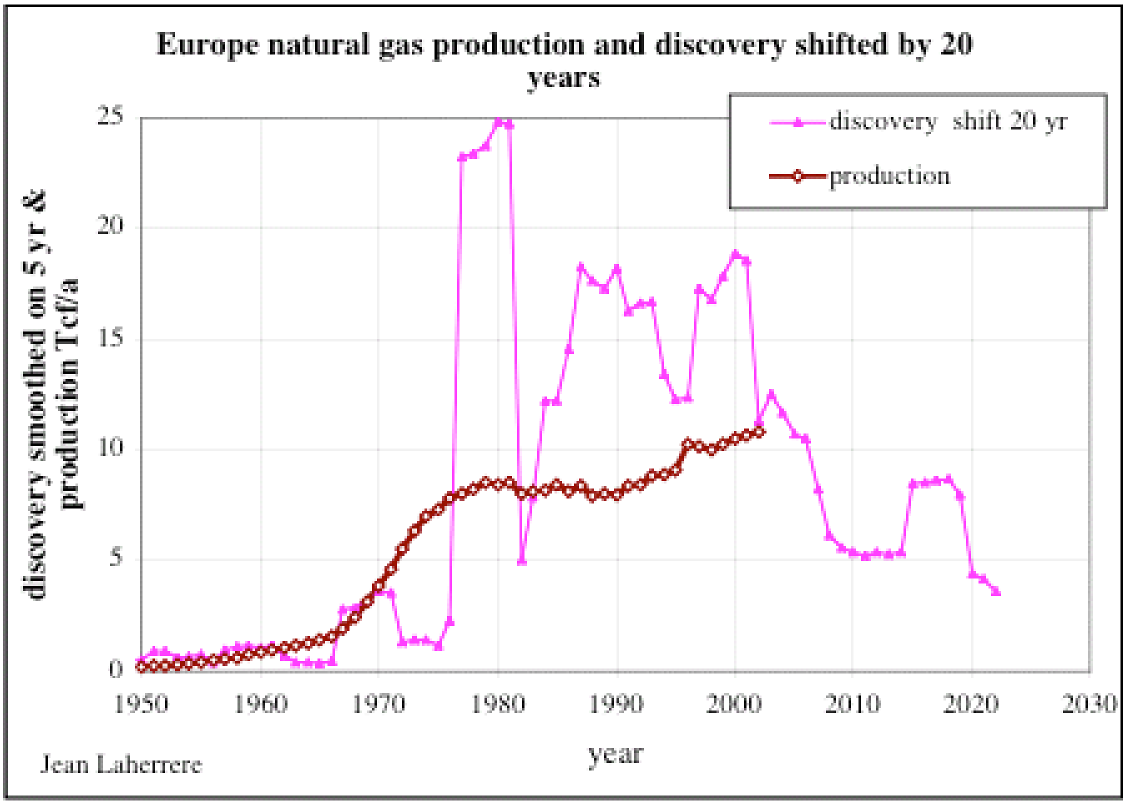
The annual production is modelled with the 620 Tcf ultimate, giving a peak in 2005 at 11 Tcf/a

Figure 36: Europe NG annual discovery & production



Europe will peak soon; another way to forecast future production is to correlate past production with shifted discovery. A shift of 20 years provides a fair correlation where discovery is in sharp decline after 2000, in agreement with the previous graph.

Figure 37: Europe NG production & shifted discovery



Europe production is peaking now and will decline at a rate of 0.3 Tcf/a. More imports will be needed (Algeria and FSU) but if FSU production is forecast (figure 61) to peak around

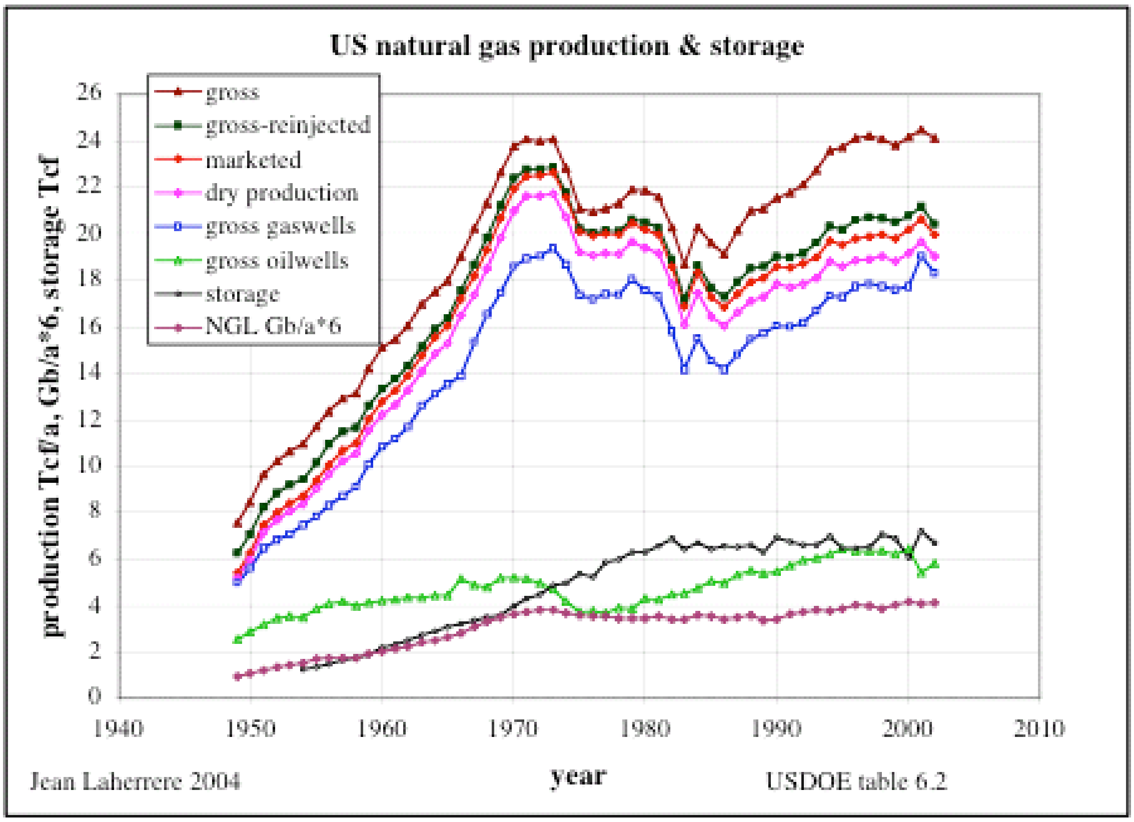
2012 at a volume of only 4 Tcf/a above the present production. Will the demand be satisfied? Will Europe compete with North America on LNG?

-US

The US is the best place to get data as every number gathered by federal agencies (USDOE and USDOI/MMS) is available freely on the web. USDOE/EIA also provides international data on long periods.

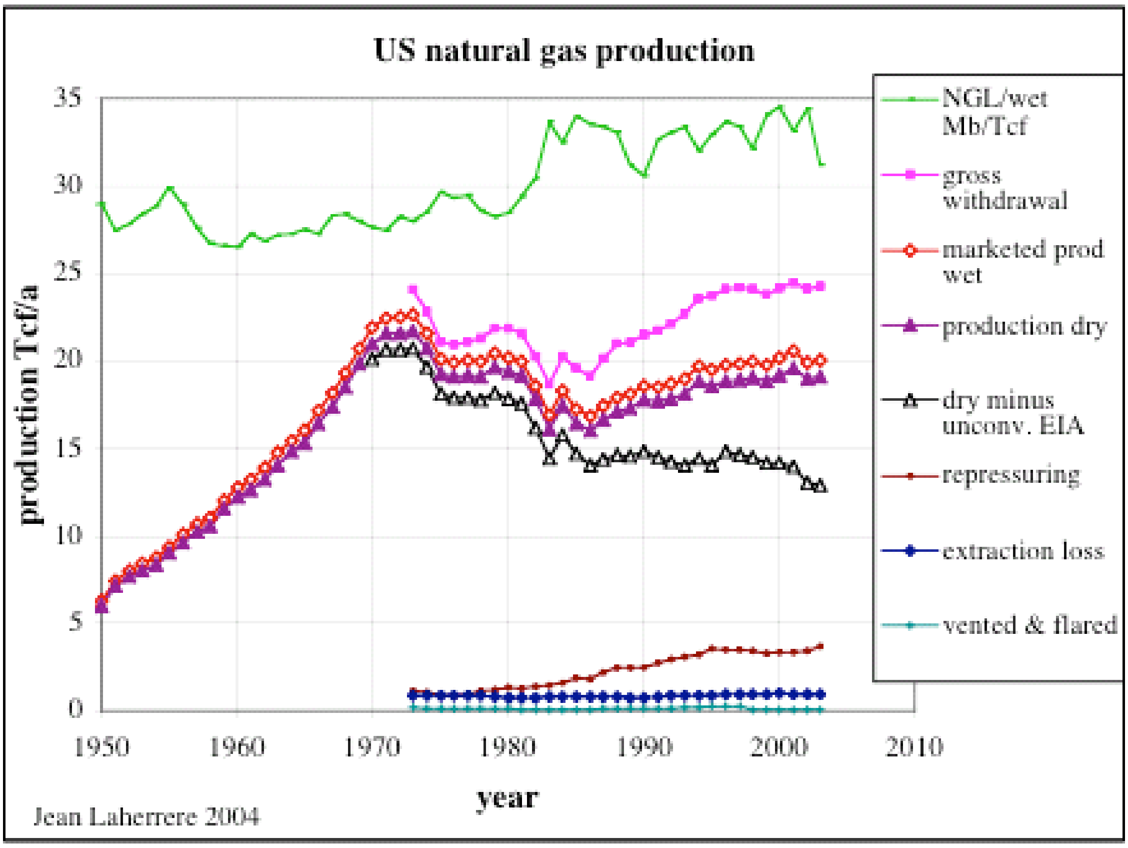
The NG volume that is extracted, lost, reinjected, stored, flared and vented is shown on the next graph. Because the high price pf NGL compared to gas, the recovery of these NGL was pushed to the maximum, giving a dry production much lower than the wet production.

Figure 38: US NG production & storage 1949-2002



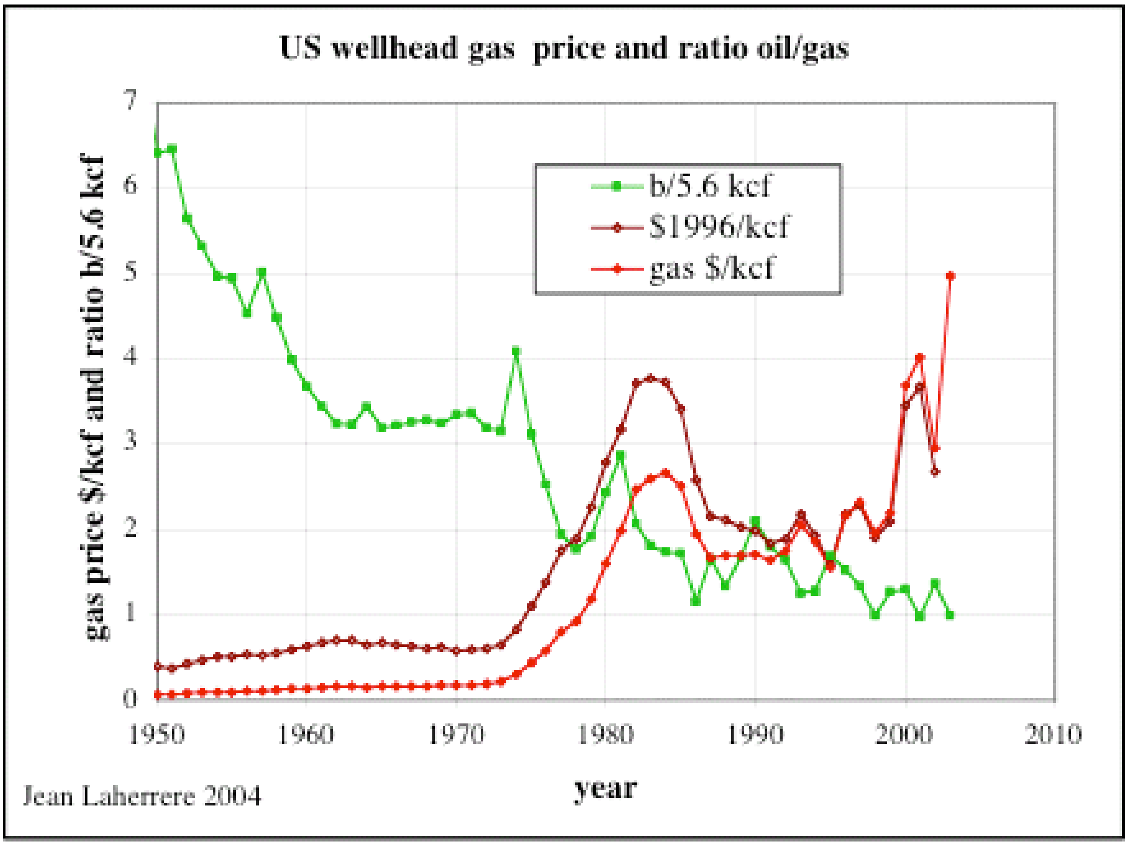
Though the marketed production, which already peaked in 1973, has been increasing since 1986, it is now flattening. The dry conventional (black triangles) has in fact declined since1973; the ratio of NGL versus the wet gas production is about 32 Mb per Tcf (compared to 25 Mb/Tcf for the world).

Figure 39: US NG production 1950-2003 with NGL/wet production



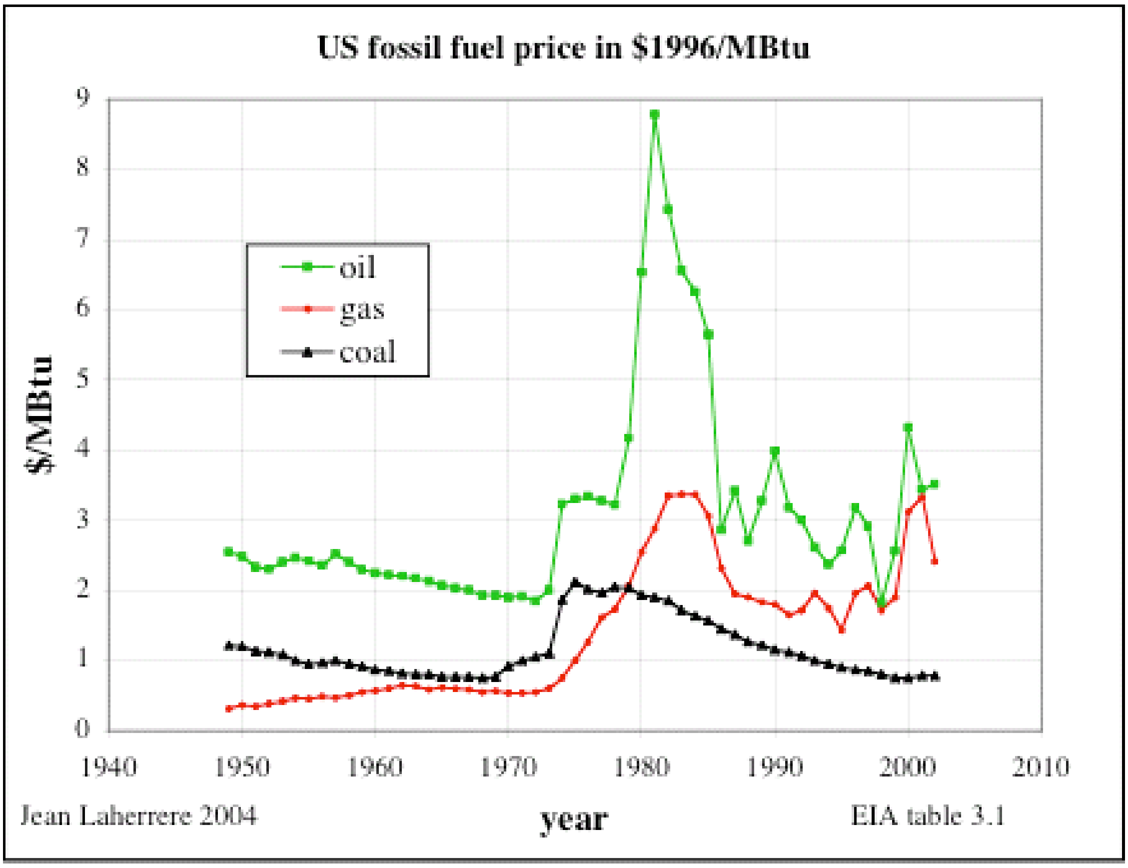
The US price for oil and gas shows that the ratio barrel versus 5.6 kcf (calorific equivalent) was more than 6 in the 1950s, 3 in the1960s, and 2 around 1990, and now close to 1 or even less on a monthly basis.

Figure 40: US NG wellhead price and ratio oil/gas



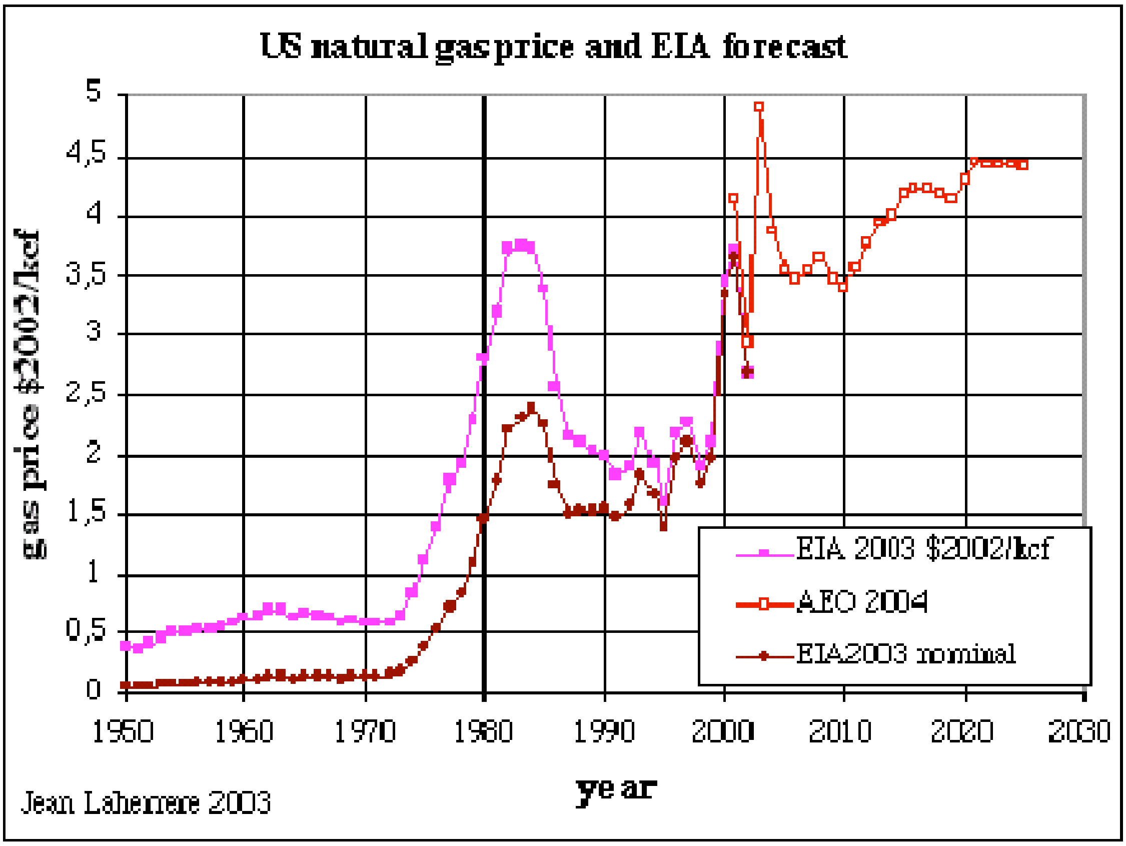
The price of oil and gas in $/Mbtu is compared to coal which is presently one third

Figure 41: US fossil fuels price in $/MBtu

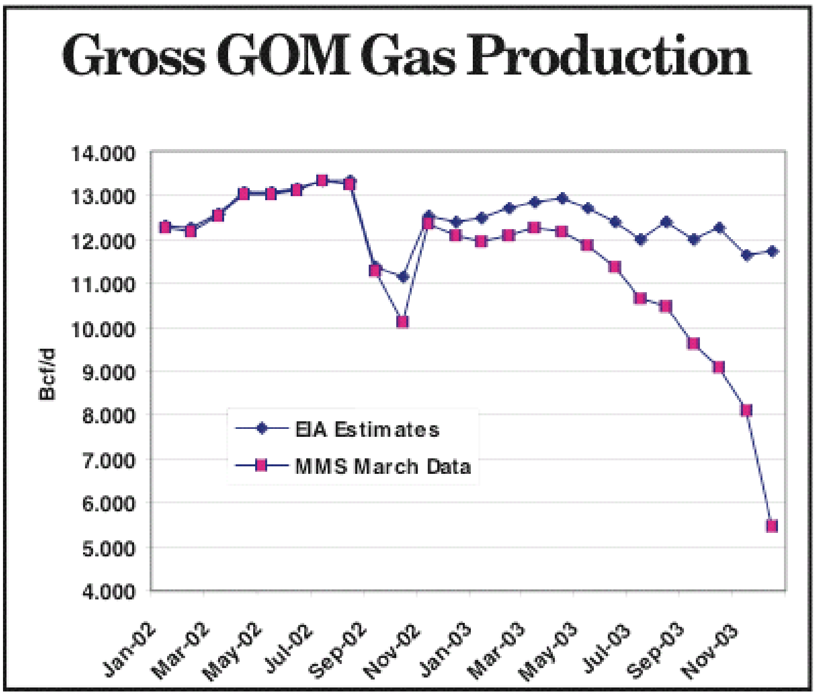


USDOE forecast (AEO 2004) is a mild increase in 2002$ up to 2030 to go to 4.5 $/kcf

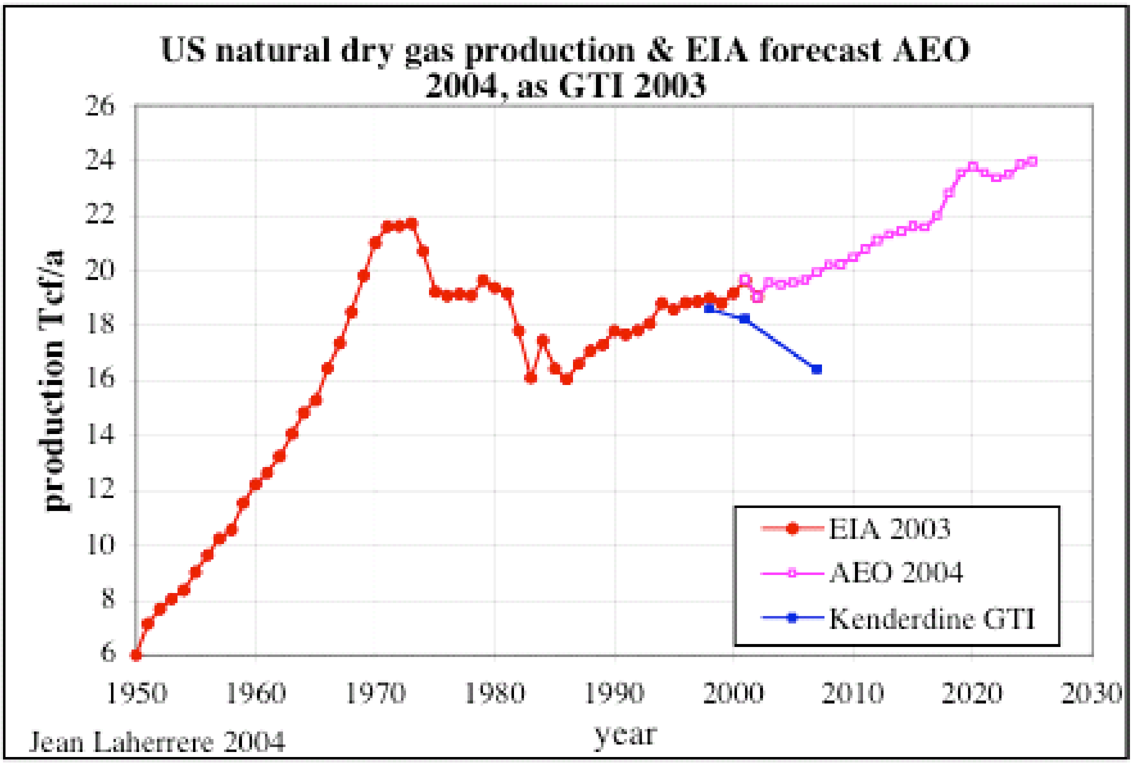
Figure 42: US NG price and EIA forecast



Though much data is available, it is not very reliable when published and needs several revisions, since agencies ask only a small part of operators to report. The gas production reported by MMS in the Gulf of Mexico for the last months is estimated by the USDOE to be only half of the truth for the end of 2003. It means that the accuracy is worse than 50%.
Figure 43: Gulf of Mexico production from MMS & EIA

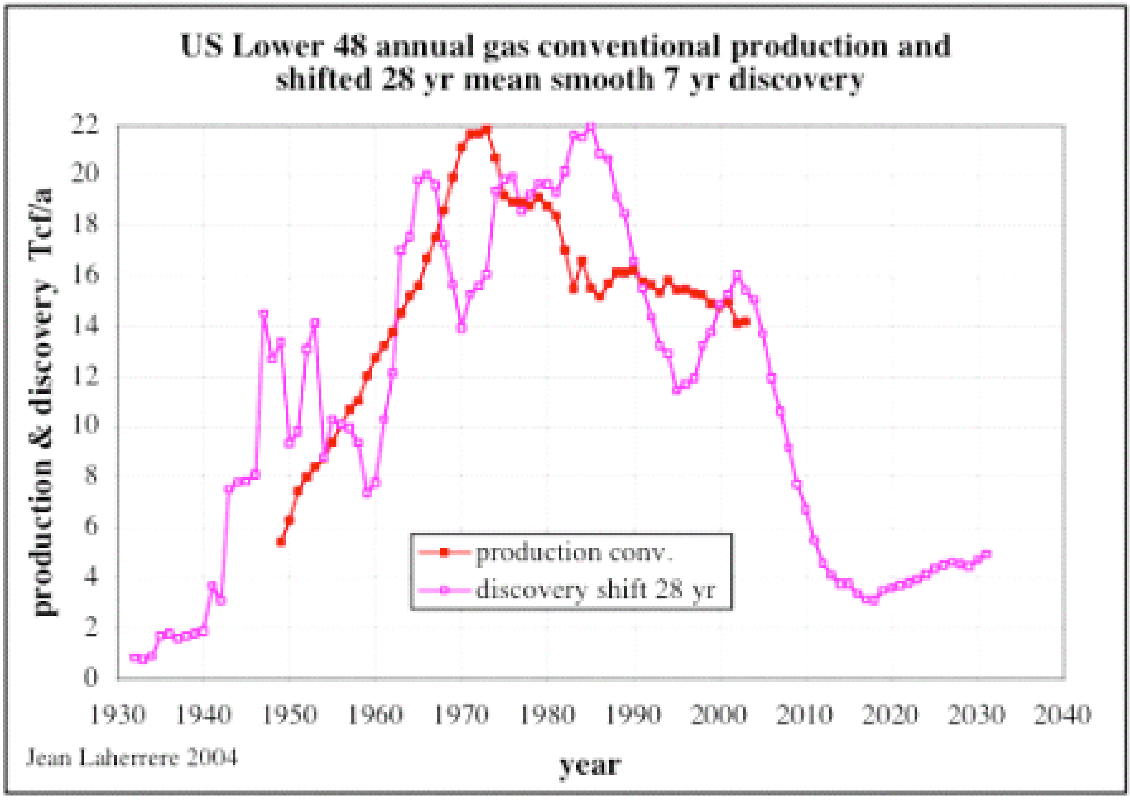


USDOE (AEO 2004) forecasts an increase of the NG production up to 2025, being in contrary to Gas Technology Institute (Kenderdine 2003), which forecasts 16,4 Tcf in 2007 (45 Gcf/d) against 20 Tcf for EIA
Figure 44: US NG production & EIA forecast



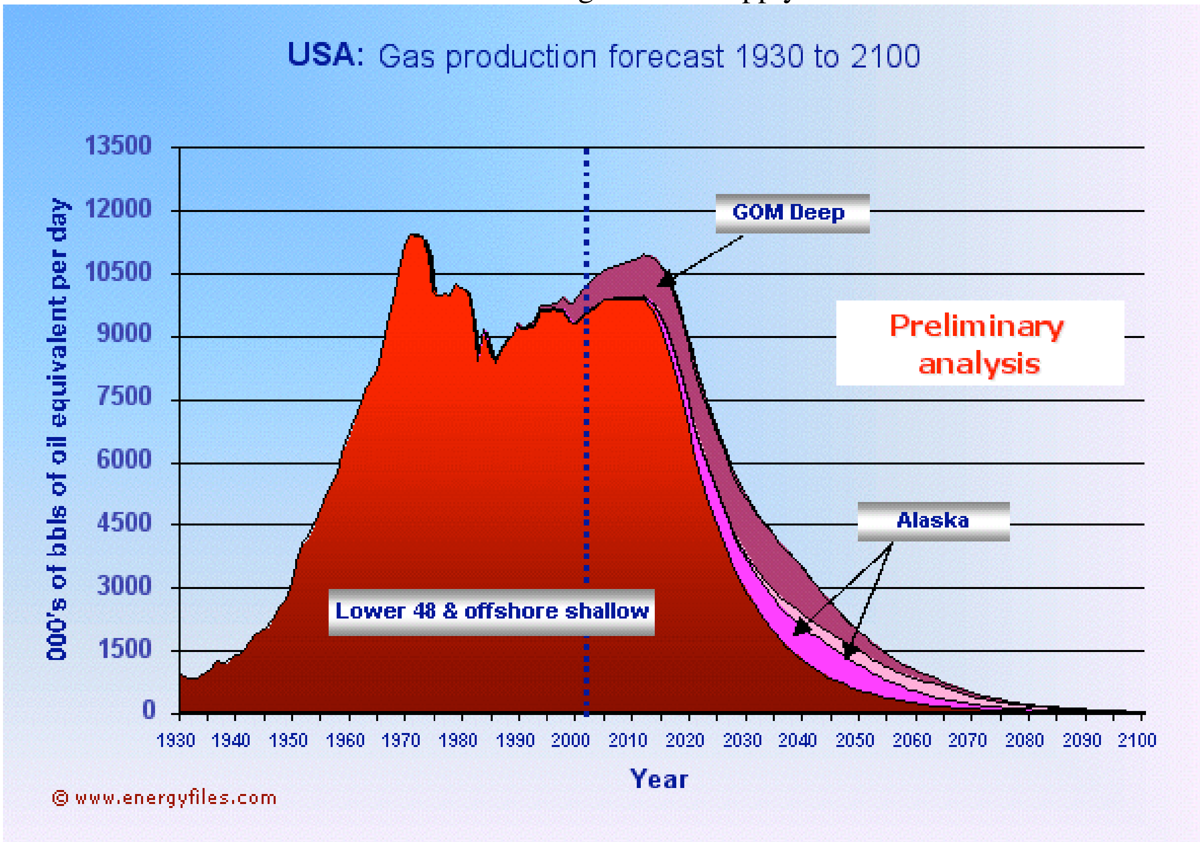
Our best forecast is to correlate the mean backdated reserves (from EIA 90-534 and later annual reports on new discoveries) to conventional production after shifting the discovery by 28 years. It seems obvious to most viewers that the future production will decline in a cliff (called a waterfall by Simmons 2004) in the near future and the unconventional will not be able to compensate for this sharp decline.

Figure 45: US 48 states NG conventional production and shifted discovery



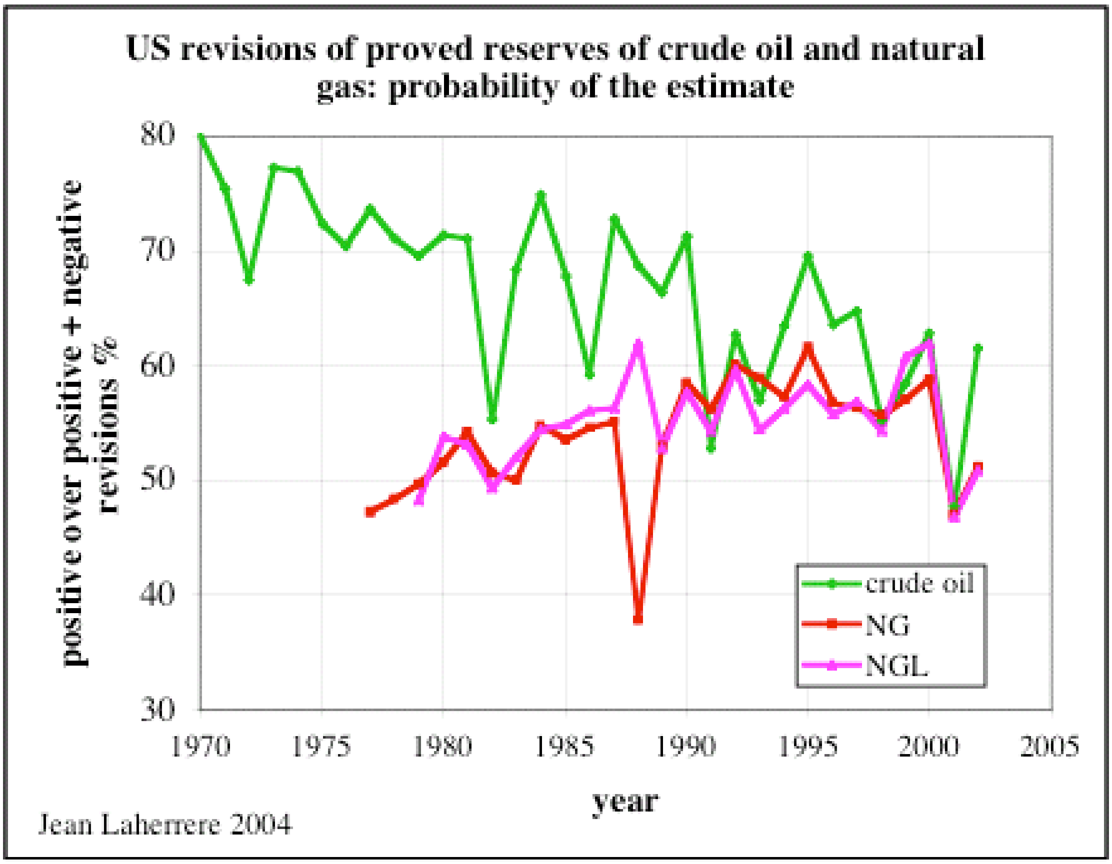
Michael Smith (energyfiles.com) is also showing a sharp decline but starting later

Figure 46; US NG production forecast from Michael Smith



The USDOE annual reports since1977 give the revisions of the past estimates as positive and negative values, allowing to compute the probability of the estimates.

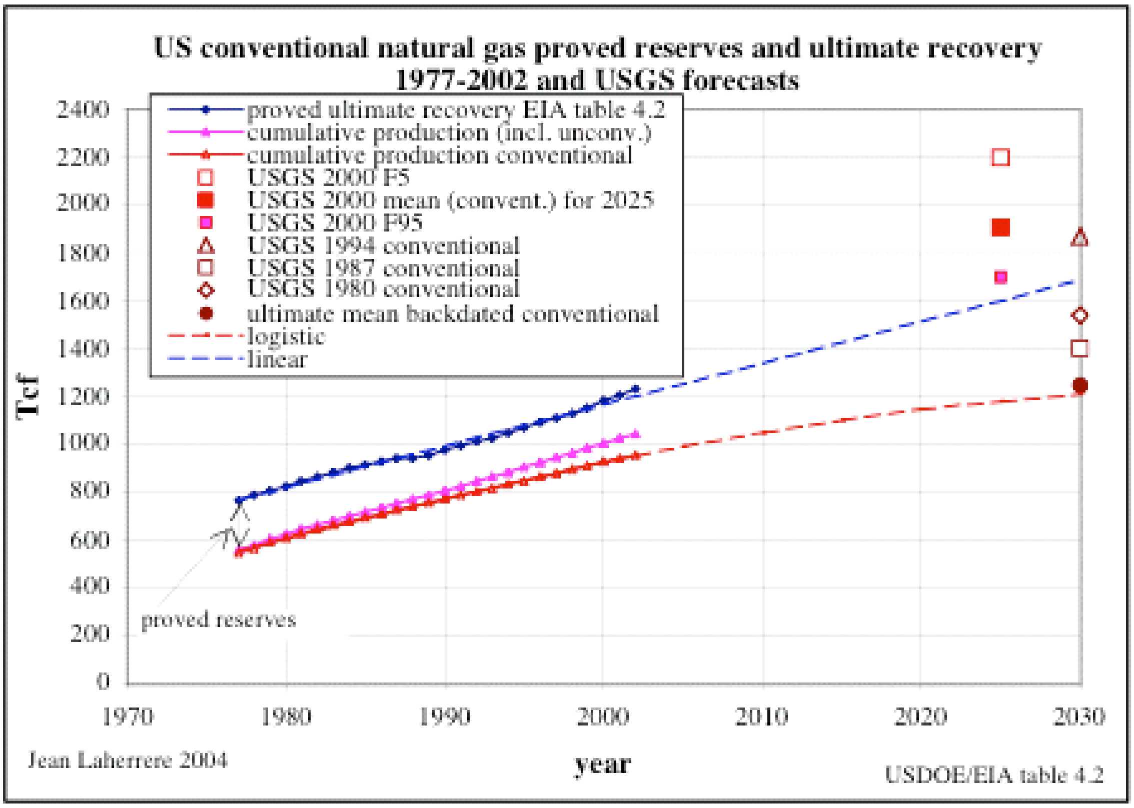
Figure 47: US revisions of the proved reserves giving the probability of the estimate for oil, NG and NGL



This graph is very important as it shows that the probability of the so-called proved reserves is not 90% as required by the SPE/WPC rules but presently about 55% for oil as NG and NGL. But in 1980 the probability was about 70 % for oil but 50% for NG

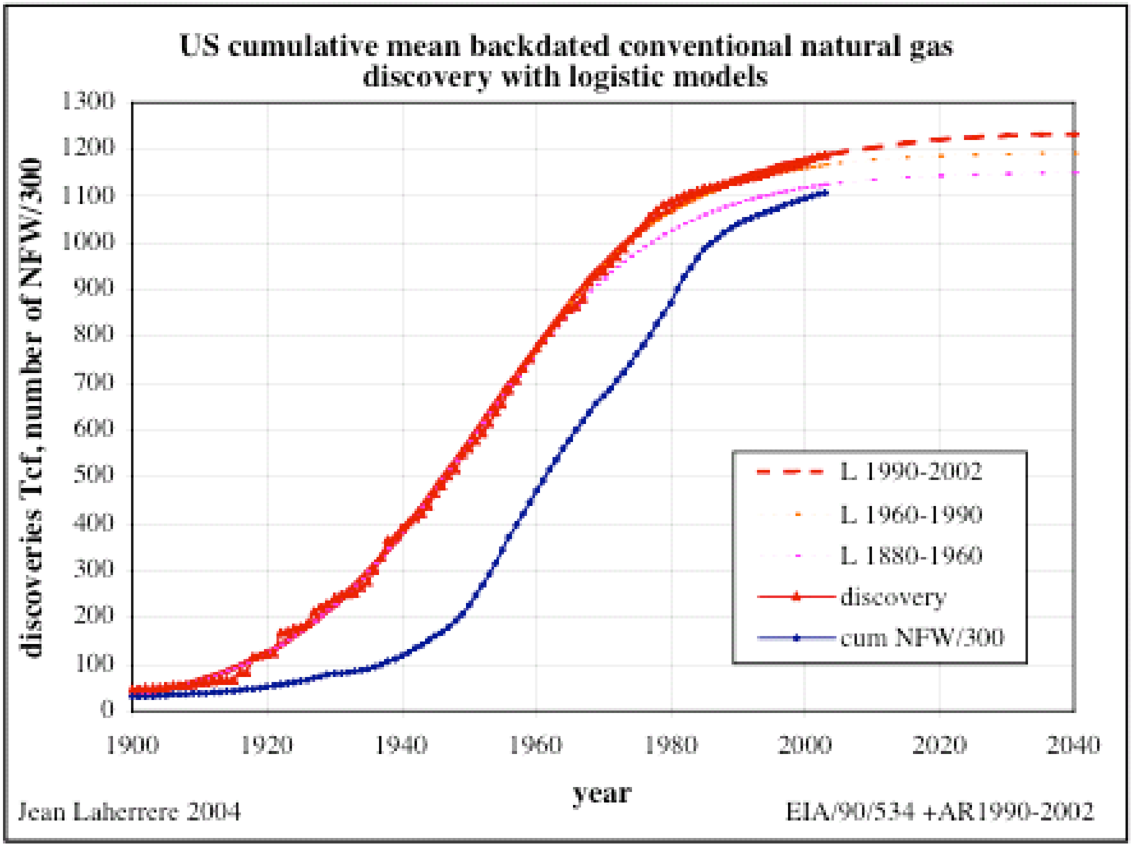
The USGS 2000 estimate of an ultimate around 1900 Tcf for 2025 is far from the extrapolation of the present cumulative production with a logistic model or even of the linear extrapolation of the ultimate recovery as reported by EIA from 1977 to 2002. The previous USGS estimates in 1984, 1987 and 1994 of the NG ultimate seem more realistic, especially the 1987 one.

Figure 48: USGS 2000 forecast for US NG and extrapolation of past production



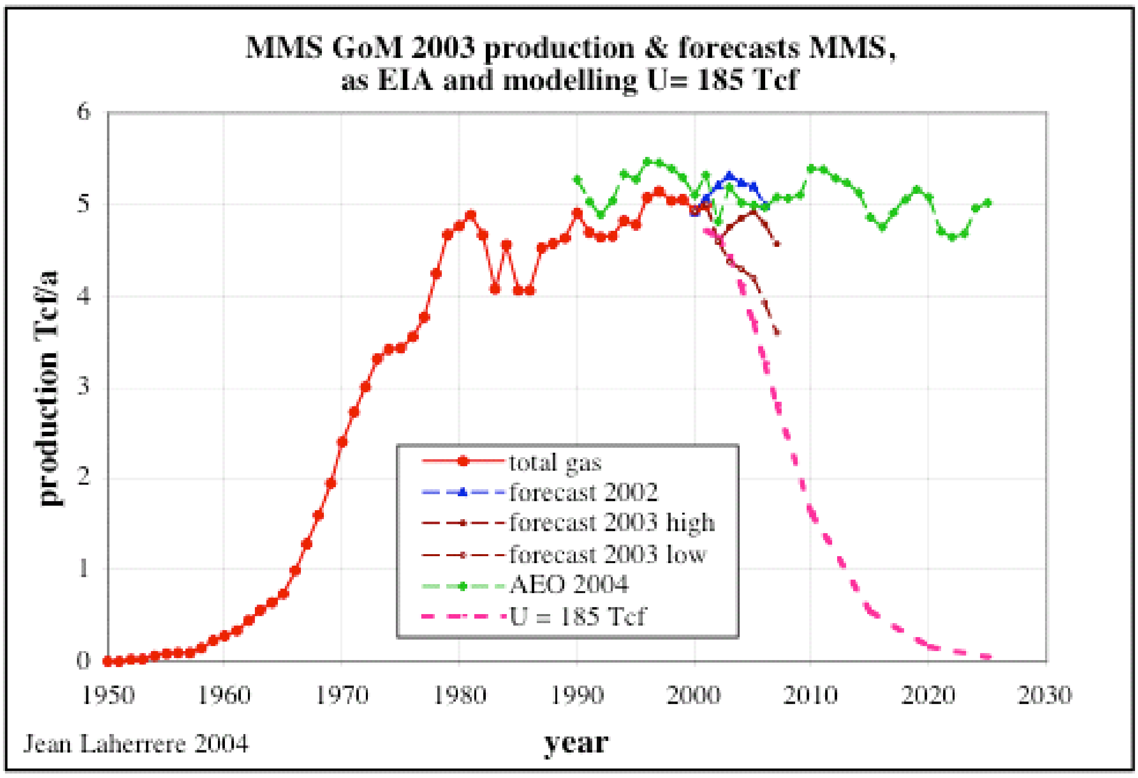
The US cumulative mean backdated discovery is close to one single logistic model, with an ultimate of 1200 Tcf. The number of NFW displays also a good logistic curve with an ultimate of 350 000 wildcats.

Figure 49: US conventional NG cumulative mean discovery & production



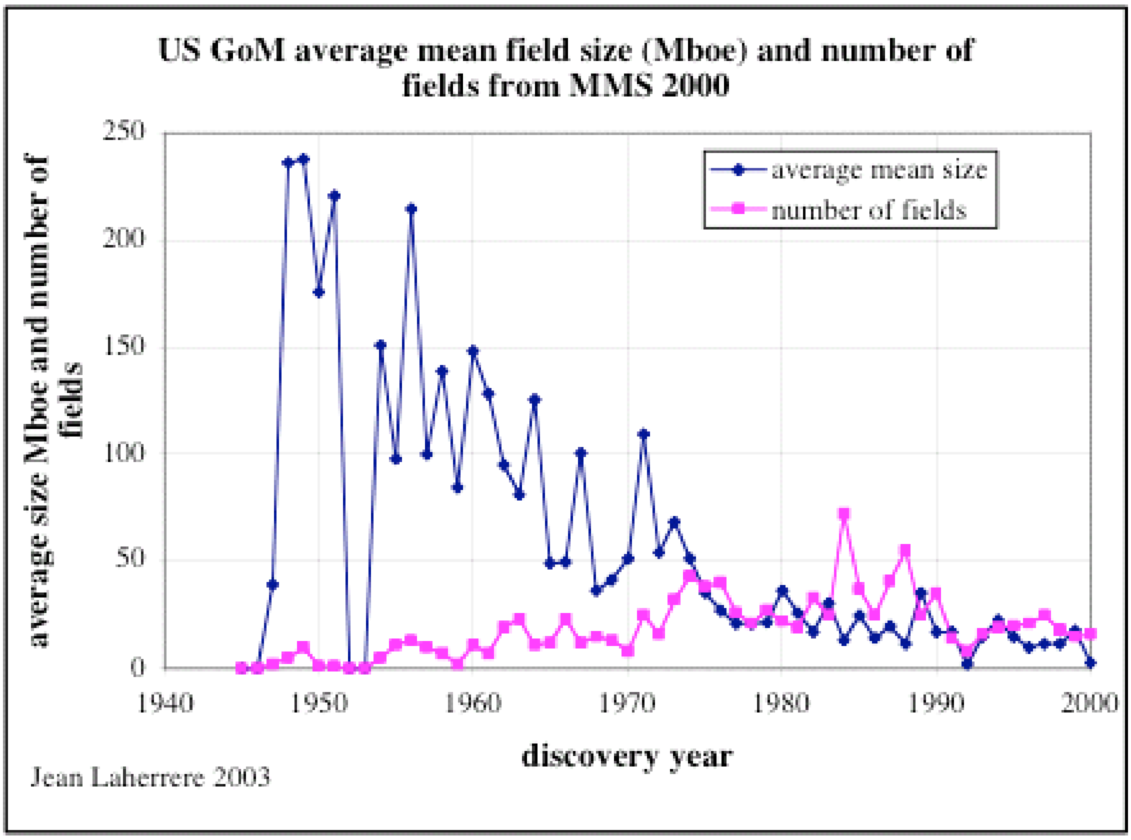
For the Gulf of Mexico the NG production is shown as the MMS 2002 (higher) & 2003 forecasts as the model for an ultimate of 185 Tcf. All these forecasts display a sharp decline in the coming years, but USDOE in contrary forecasts an increase and 5 Tcf/a in 2025 compared to almost nil in my model.

Figure 50; GoM NG production and MMS forecasts & model for U=185 Tcf compared to USDOE/EIA forecast



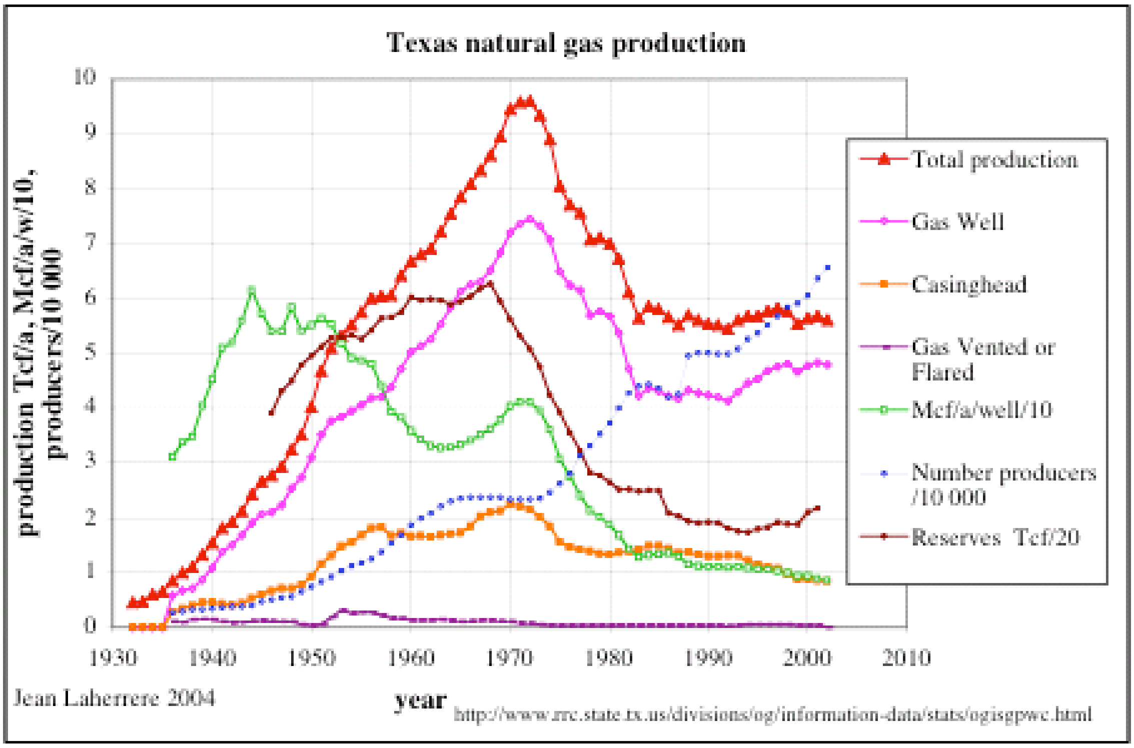
The number of fields from MMS 2000 shows a peak in the 1980s, but the average size has been declining since 1960.

Figure 51: US GoM average size and number of fields from 1945 to 2000



The Texas NG production peaked in 1970 but has been flat since 1980, as the number of producing wells has increased sharply by 30 000 in the last 20 years. But the production per well has declined and is now less than 10 Mcf/a/w from about 60 in 1945

Figure 52: Texas NG production

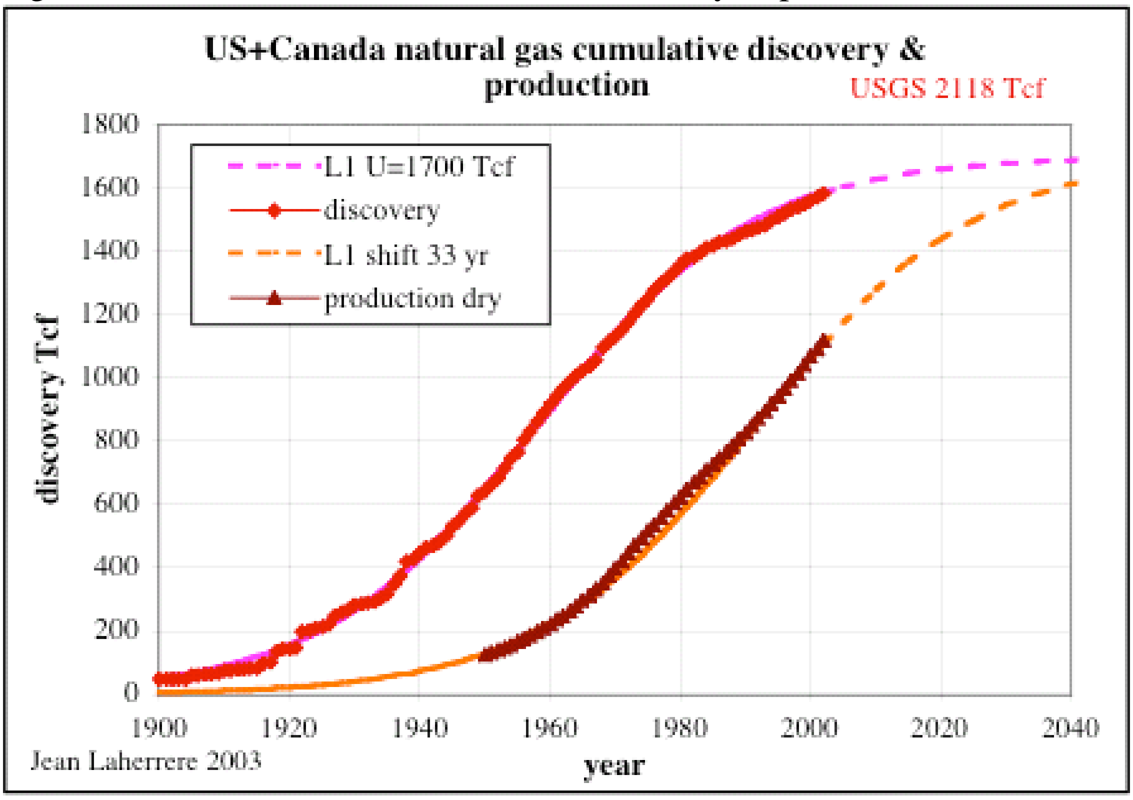


-US+Canada+Mexico

North America (US+Canada+Mexico) is one local market (and the largest), as outside imports (LNG) are small

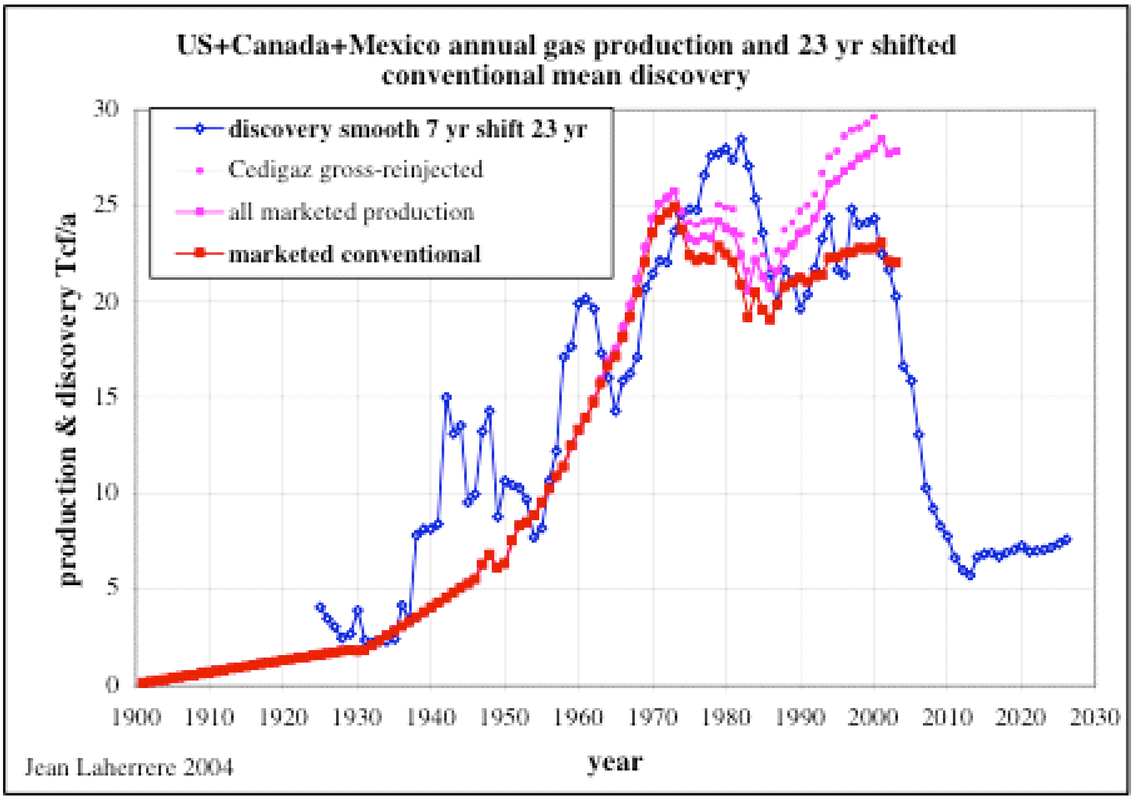
The cumulative discovery is easily fitted with one logistic model trend going toward an ultimate of 1700 Tcf, when USGS 2000 estimates for 2025 an ultimate of 2118 Tcf

Figure 53: US+Canada NG cumulative discovery & production



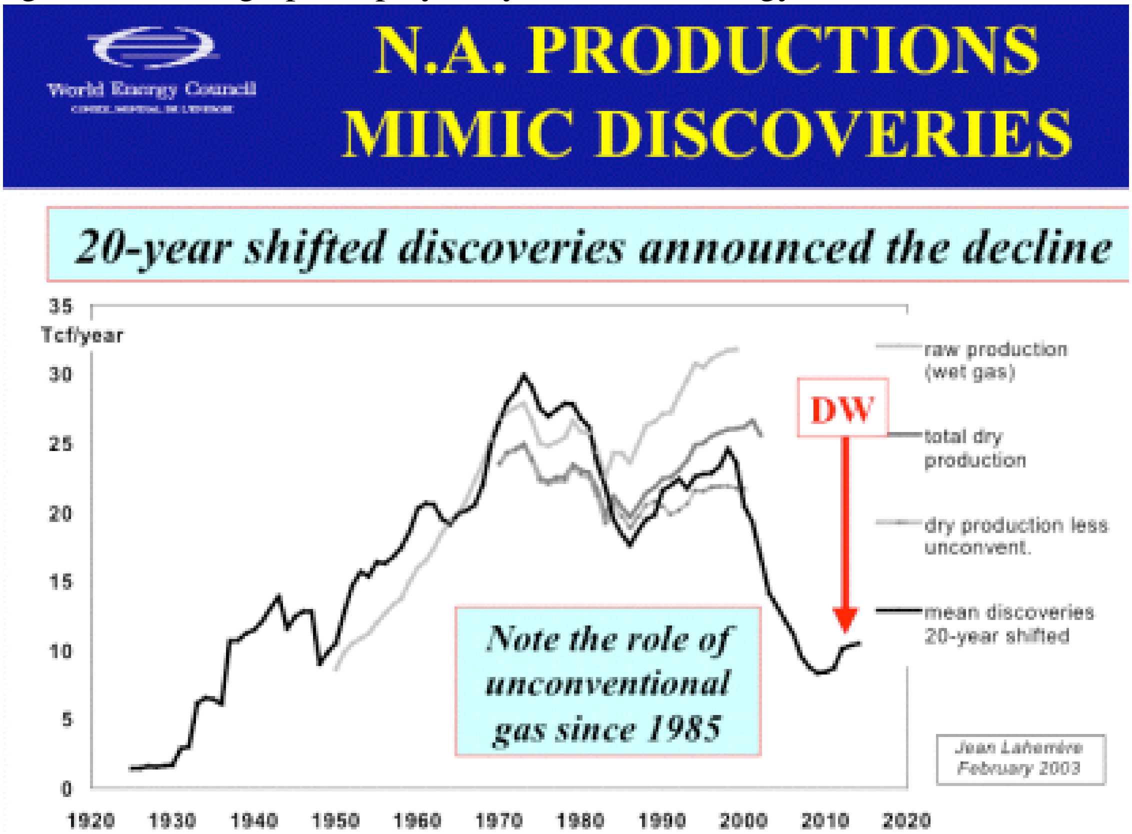
Instead of modelling the annual production, it is better to compare the past conventional production (red curve) with the conventional mean discovery (from EIA90/534 report) (blue curve) shifted by 23 years. Most readers will be inclined to forecast a sharp decline.

Figure 54: US + Canada + Mexico NG annual production and discovery shifted by 23 years



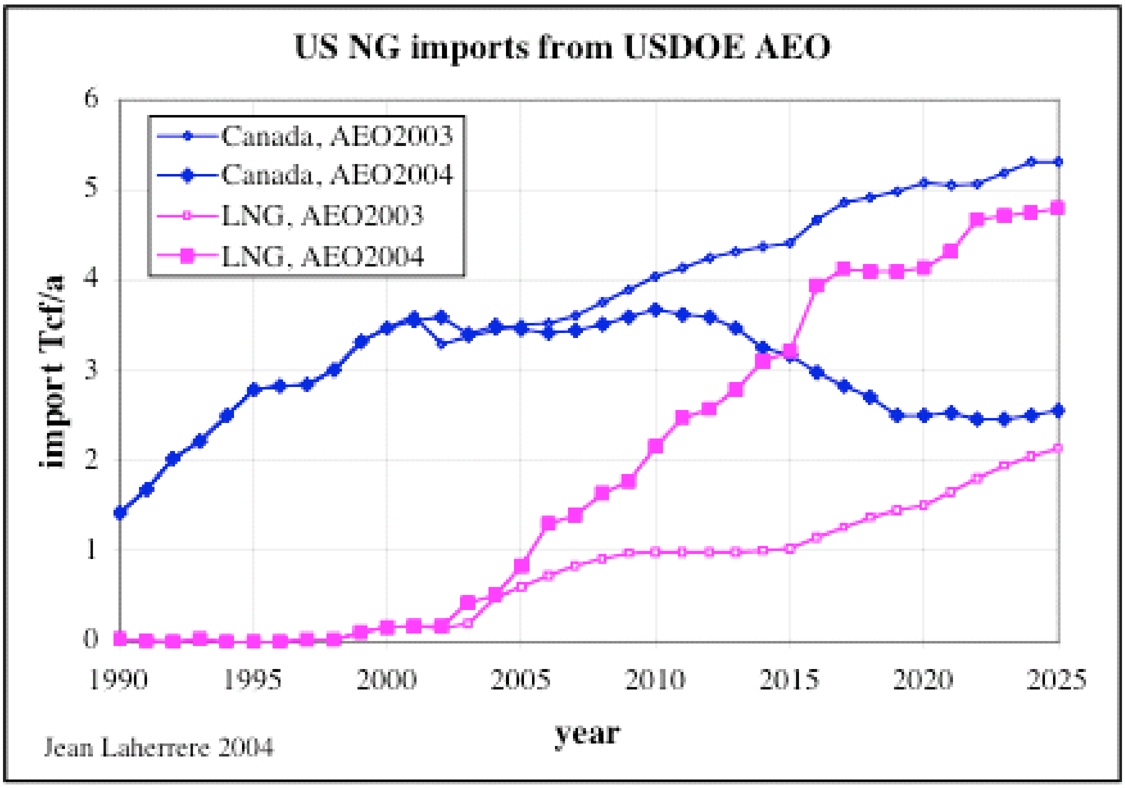
The World Energy Council has adopted my curve in their 2003 report "Drivers of the energy scene"

Figure 55: same graph displayed by the World Energy Council



USDOE must have just realized that Canada will decline as the AEO 2004 forecast is drastically different from AEO 2003, as for the import from Canada (in 2025 2.5 Tcf instead of 5.5 Tcf) and for LNG import (in 2025 5 Tcf instead of 2 Tcf

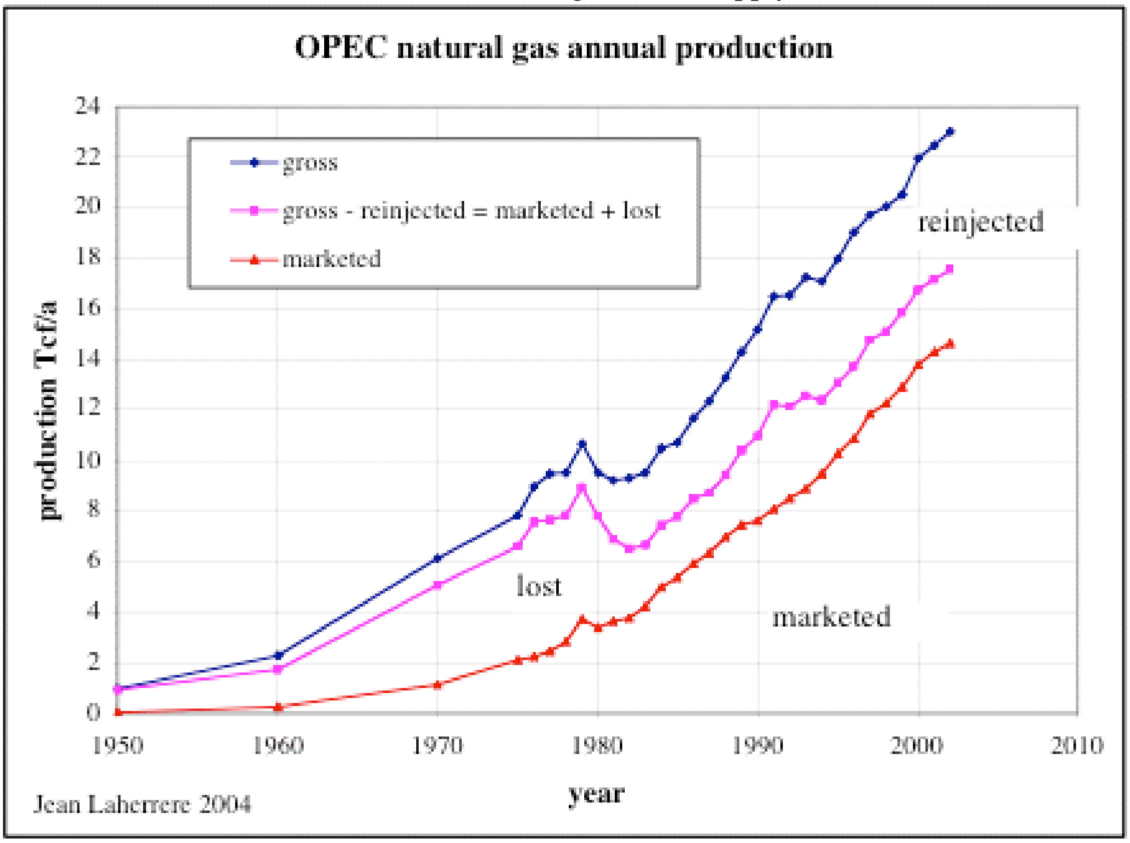
Figure 56: USDOE forecast in 2003 and 2004 on import from Canada and LNG



-OPEC

Cedigaz production data shows that the lost gas was important up to 1983.

Figure 57: OPEC NG production



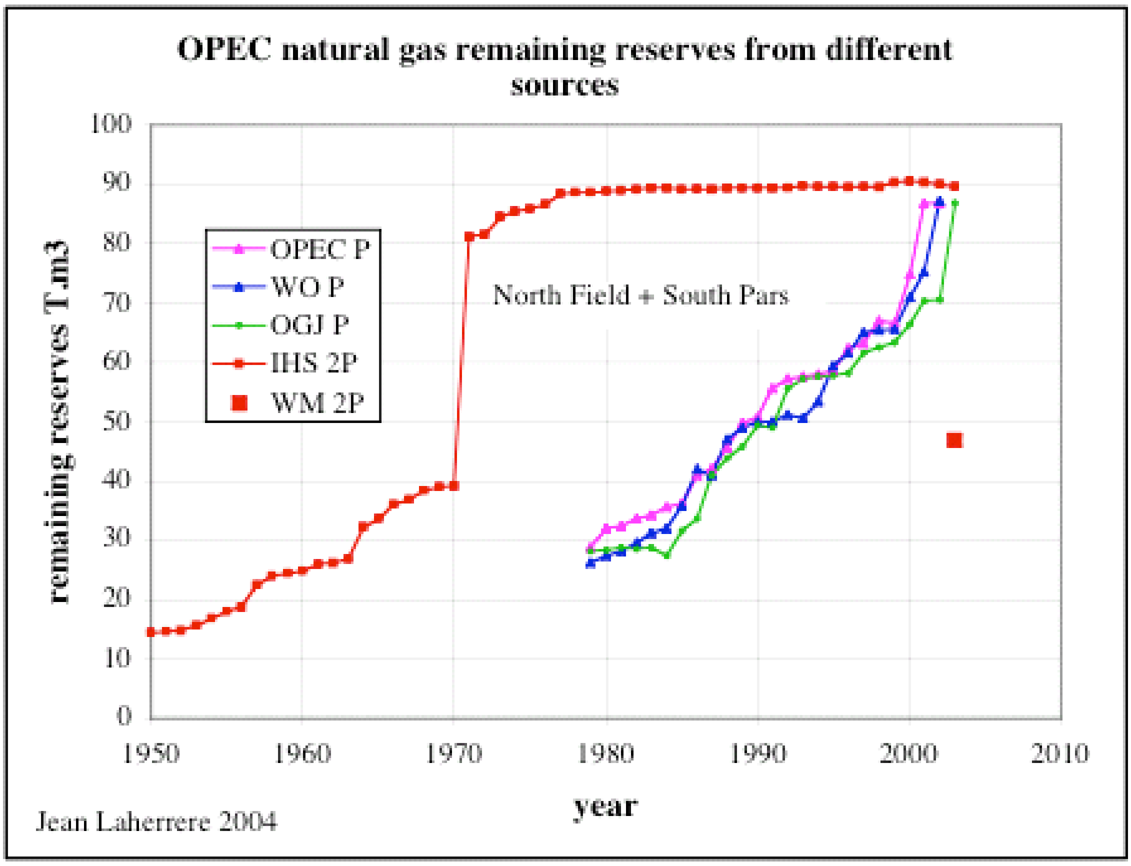
From OPEC AR 2002, production in G.m3:

OPEC	gross	reinjected	marketed	% mark/gross-reinjected
1997	565	140	344	81
1998	575	141	355	82
1999	588	132	372	81
2000	634	157	389	82
2001	647	158	412	84
2002	663	165	420	84

The percentage of marketed to the gross minus reinjected is about 84%.

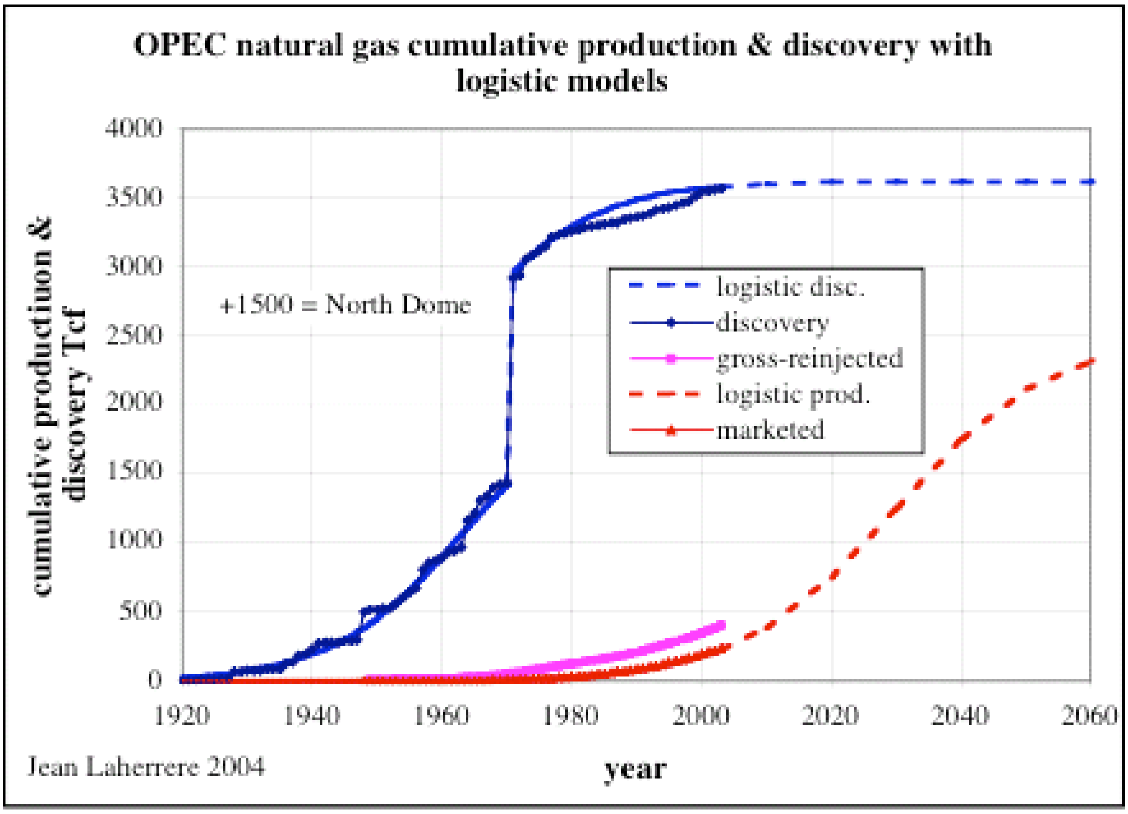
The NG remaining reserves is reported as growing sharply since 1980 by the political sources when the technical data (HIS) has practically remained flat since 1975. WM reports only developed reserves which are about half of IHS value.

Figure 58: OPEC NG remaining reserves from technical & political sources



As indicated before, the discovery of North Dome in 1971 = North Field + South Pars (Qatar-Iran) upsets the curve which seems to trend towards 3600 Tcf. The production (marketed when gross-reinjected should be better) is difficult to extrapolate.

Figure 59: OPEC NG cumulative discovery & production



-Reserves growth

Gas recovery factor is about twice the oil recovery, as gas molecules are tiny and can move easily. In fact there is no impermeable seal except evaporites, and many gasfields are leaking some gas. So there are fewer possibilities to increase gas recovery factor, reserve growth is less than for oil. Of course if reserve estimates are the proved value which is assumed to be the minimum, the possibility of increase is there, but in fact in the US the probability of proved gas reserves for the last 25 years as shown in figure 47 is around 55%, as negative revisions were about the same level as positive revisions.

The USGS 2000 report estimated the conventional NG reserve growth at 355 Tcf for the US where reserves are proved and 3305 Tcf for the rest of the world where reserves are proven+probable. For the US figure 48 shows that the last trend does not confirm such value and for the rest of the world there is no justification, just wishful thinking.

The Russian gas reserves are also overestimated as shown by the estimate for Urengoi (fig.25), Orenburg (fig.26), Medvezhye (fig.27) and Samotlor (fig28). .

Many other examples of negative reserve growth, as Maui in New Zealand, Sable Islands in Canada, Frigg in North Sea.

The Australian government (Geoscience Australia 2002) has used the USGS reserve growth function to fit their reserves change. It fits during 10 to 30 years after discovery, but after 30 years the growth is trending to zero.

Figure 60: Reserve growth from Geoscience Australia

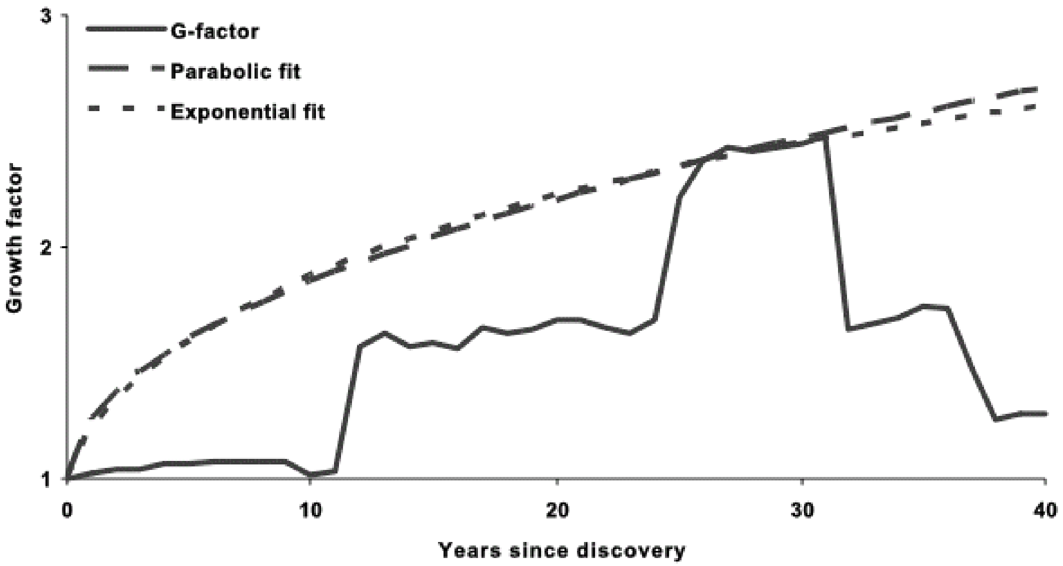
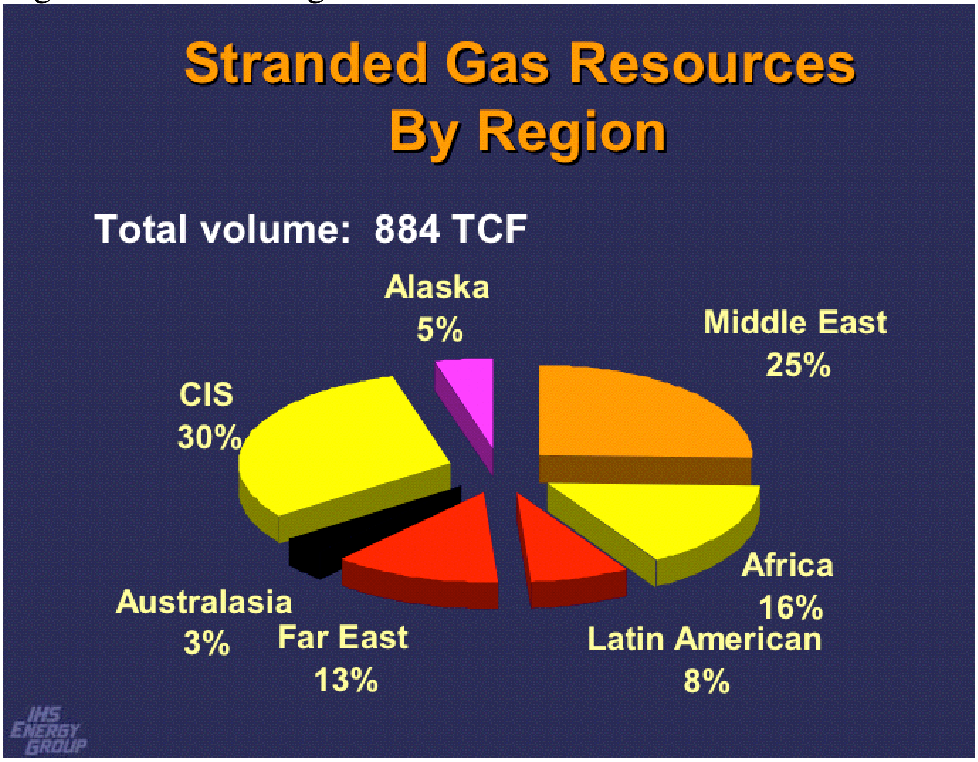


Figure 2.8 Reserves growth for Australian gas fields

There is no striking positive reserve growth example from gasfields, like Ekofisk for oilfield (due to compaction of the chalk reservoir). North Dome reserves have grown but it is mainly because Qatar did not bother to report the right value. The area of the structure did not change since the discovery, neither did the net pay.

-Stranded gas

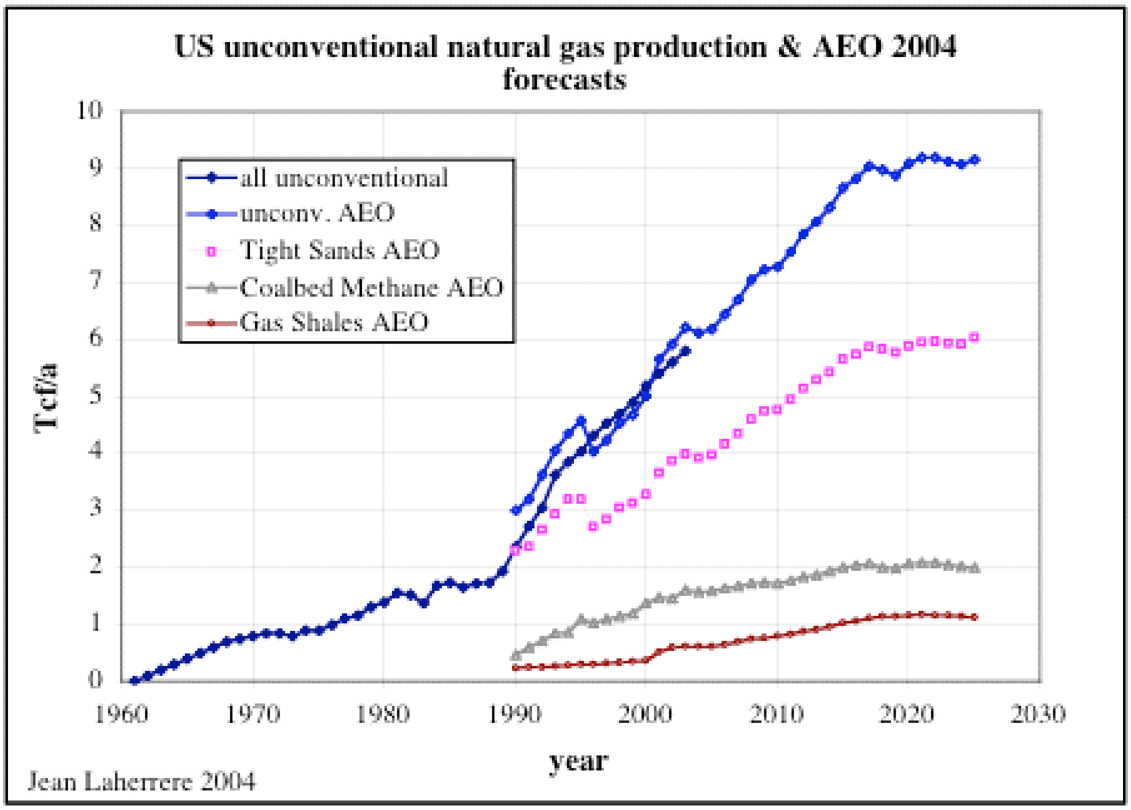
The definition of stranded is confusing and may represent undeveloped gas in a producing area because it is uneconomical or in non-producing area by lack of transport. The status is changing with new LNG and pipeline projects.
Most papers report for stranded gas that the volume is about half of the remaining reserves (about 2500 Tcf) without making any real study. But IHS from its field database has estimated the volume at 884 Tcf.(Stark 2001).
Figure 61: Stranded gas reserve estimates from IHS



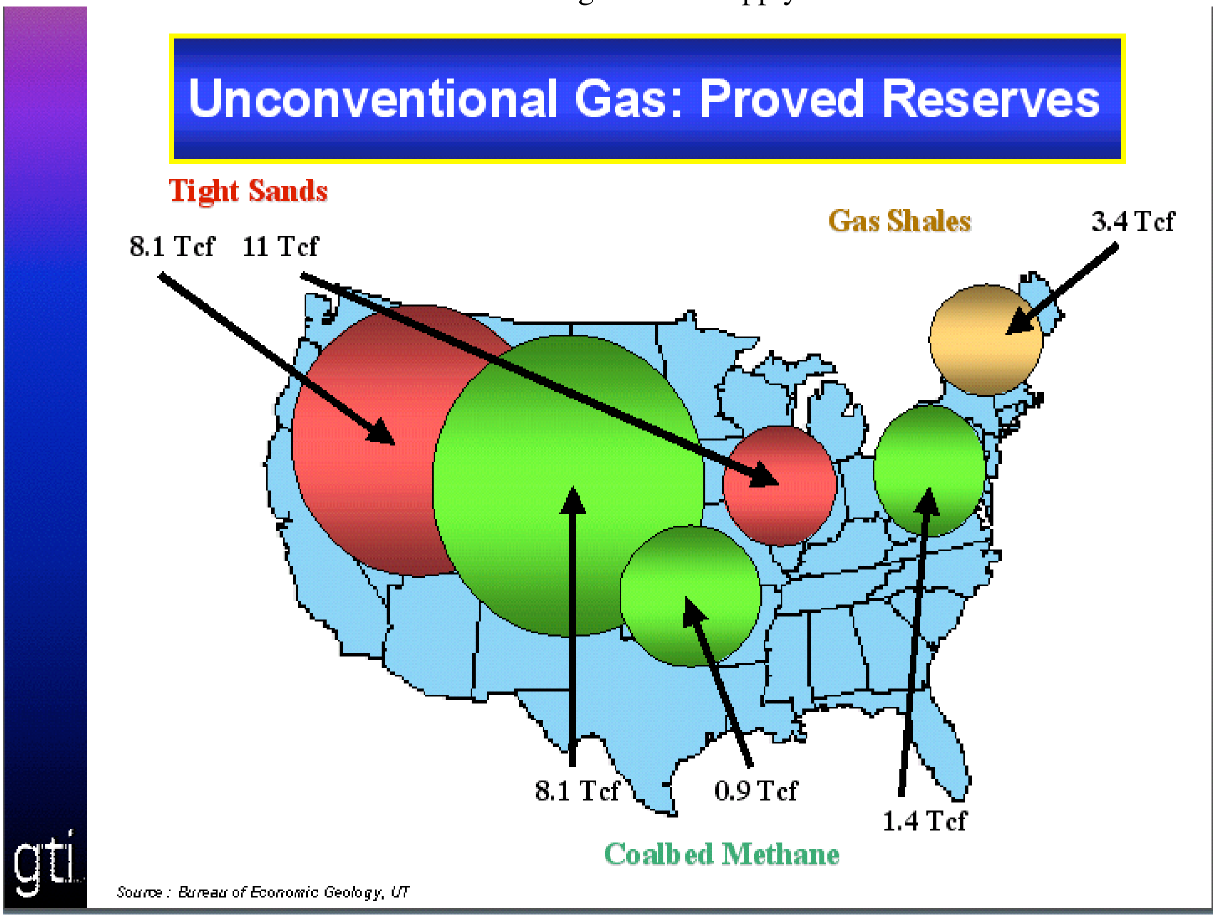
-Unconventional gas

-US

The US unconventional gas production is in 2002 about 6 Tcf/a and USDOE (AEO 2004) forecasts a peak at 9 Tcf/a in 2020. The US tight gas from tight reservoirs and shales is about twice the production of coalbed methane.
Figure 62: US unconventional NG production & USDOE forecast



USDOE AEO forecasts a production from 2004 to 2025 of 178 Tcf. They report unconventional NG proved reserves as 76 Tcf (51 Tcf tight sands, 19 Tcf CBM and 5 Tcf gas shales) and 475 Tcf of undeveloped resources (342 Tcf tight sands, 79 Tcf CBM and 54 Tcf gas shales).
However the Gas Technology Institute (GTI) (Kenderdine 2003) reports proved reserves as 10 Tcf for CBM, 19 Tcf for tight sands and 3 Tcf for gas shales totalling 32 Tcf
Figure 63: US unconventional reserves from GTI = 32 Tcf



-rest of the world

-CBM

From the USDOE forecast on CBM production (AEO 2004) peaking in 2020 around 2 Tcf/a, it is possible to estimate the US CBM ultimate at about 100 Tcf. As the US reserves in coal is estimated by the BGR to be about one third of the world's coal reserves, it could be estimated that the world CBM ultimate is about 300 Tcf.
More optimistic estimates can be found (Kelafant et al 1992), being resources (and not potential reserves), and may be compared to the coal reserves estimate by BGR 2002

estimate	resources 1992 Tcf	our guess reserves	BGR Coal reserves Gtoe
China	1 000 -1 200		57
Russia	600 –4 000		76
Canada	200 –2 700		2
Australia	300 - 500		45
US	100 – 400	100	145
World	?	300-400	423

CBM has just started to be produced in Canada

-Tight reservoirs

Tight reservoirs have a low permeability of around 0.1 mD or less, low porosity of 7 to 12 %, low saturation of 50 % or less and low productivity in the range of 2 000 to 20 000 m3/d/w
The deep syncline of Alberta covering 67 000 km2 was claimed to contain 500 Tcf of potential reserves after the discovery of Elmworth (Masters1980) where tight sands with gas

occur below porous sands with water. But the 1980-claimed 440 Tcf Elmworth/Wapiti field is now estimated by Hayes to contain only 5 Tcf.
Tight formations potential is reported by the UN in FSU, Middle East, North America, and China.

-Gas shales

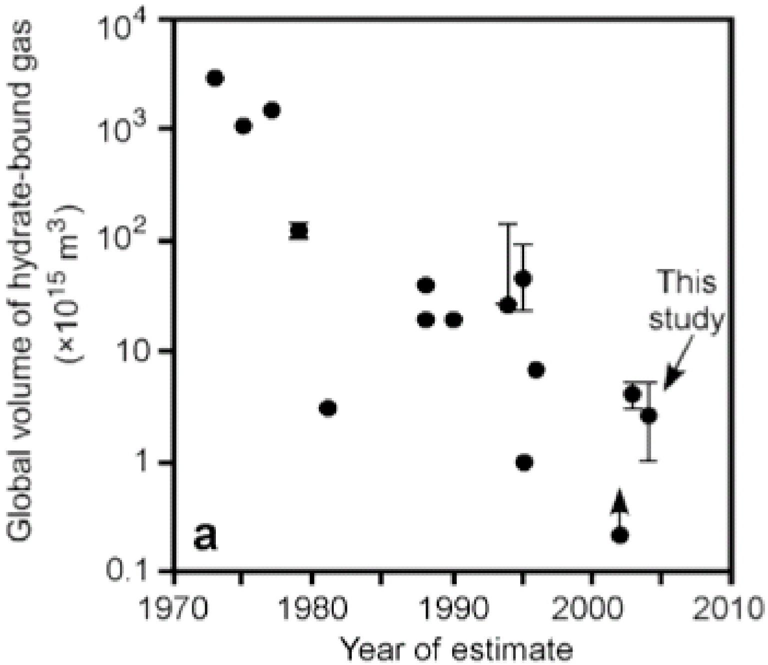
As for the CBM, most of the gas is adsorbed in the organic matter and clay mineral, and can be produced commercially only in areas where there are open natural fracture systems.
The world gas shale resources is badly estimated, but could amount to 1 000 Tcf.

-Gas in geo-pressured aquifers

The solubility in sediments of methane dissolved in water which is around 20 cf/b at 10 000 ft depth is about 120 cf/b at 20 000 ft (Bonham 1978) which is 6 times more, and it is 30 times more when the pressure increases from 200 to 10 000 psi. Russian studies report that the amount of gas dissolved in brines is around 35 000 Tcf for both West Siberia and Caspian. Bonham 1982 estimated 5 000 Tcf for the Gulf Coast. However a small percentage (5%) is recoverable, but plants in the 70s were found uneconomical with plugging and environmental problems.

-Hydrates

Many papers mention that oceanic hydrates contains more carbon than fossil fuels (coal, oil and gas). The unconventional gas white paper by Schlumberger states (page 8): <<*Rough estimates of hydrates resources exceed 60 million Tcf or almost 5000 times the conventional gas resources*<< USGS reports 336 000 Tcf in the US.
It seems strange to believe that methane in oceanic sediments deposited in the last few millions years (in unconsolidated formations, being lighter than water, and without any cover as now the hydrate stability zone is not anymore considered as a seal) can represent a larger quantity than all fossil fuels accumulated in the last 600 millions years. But a recent estimate by Soloviev (1999, 2004) divides this volume by 100 times and estimates that hydrate accumulations contain about the same volume than the conventional gas (5000 Tcf). But this low estimate assumes that two third of the oceanic sediments are covered with hydrates, which seems optimistic (Laherrere 2002).
Milkow (ESR 2004) has plotted the decline of hydrates resource estimate with time. From 1970, the volume has been divided by one thousand or more. If the trend continues, little will be left!
Figure 64: Evolution of Hydrate volume from Milkov 2004



OPD legs 164 (Blake Ridge) and 204 (Hydrate ridge) find only low concentration of hydrate. In the thousand holes drilled by Joides-ODP only three holes have found massive hydrate thicker than 15 cm. Most occurrences are reported not from evidence of hydrate core, but by proxy evidence such as seismic (BSR) or chloride concentration, and they are just speculations. It is now known that BSR is not related to hydrate but to free gas, which is present below the hydrate stability zone. Japan, eager to find gas, has drilled a hydrate well in Nankai trough in 1999 at 920 meter water depth followed by 5 appraisal wells around. It was first reported (http://www.aapg.org/datasystems/abstract/13annual_/8458/8458.htm) that massive gas hydrates were identified. But now it is stated that <<*no hydrate was observed in the core samples. However, distortion of the sediment (from gas flow and dewatering), the large amounts of gas contained in the sediment, the low temperature of the sample, and the low chloride-ion content of the pore water infer the presence of gas hydrates. Gas hydrate formed 20 percent of the bulk volume and 80% of the pore space. Volume of the hydrate is calculated to be 525 million cubic meters per square kilometer, and it is estimated that up to 50 trillion cubic meters of methane may be present in the Nankai Trough.*<<
(http://www.netl.doe.gov/scng/hydrate/about-hydrates/nankai-trough.htm)
In 2000 Japan, in search of hydrate core, drilled onshore a well “Mallik” in the Mackenzie delta in Canada, where permafrost hydrate was recognized on log 30 years ago. They cored hydrate at depths previously shown on log. In 2002 they produced a tiny amount of gas from Mallik by injecting hot water and depressuring. The amount of gas (1500 m3/d) has to be considered as uneconomical in this remote area and many dry wells have tested more gas than the Mallik test. But permafrost hydrate has nothing to compare with oceanic hydrate. In permafrost the hydrate accumulation comes from what was a free gas accumulation few million years before. When glaciations came two millions years ago, this gas accumulation now in the permafrost was changed into hydrates. Hydrate in permafrost is not of great interest presently as gas is stranded. There were great hopes for large reserves when looking at the seismic. But one of the best locations was drilled last year at Hot ice n°1 in the North

Slope by Anadarko with funds from USDOE. The well was completed last march and did not find any hydrate.
In 2004 Japan intends to drill 10 to 20 wells in methane hydrate beds along the Nankai Trough. Not one production system is known to work with hydrates. By 2011, Japan hopes to determine whether commercial methane hydrate mining is economically feasible and, if so, begin doing it four years later.
We consider that oceanic hydrates are too dispersed to be produced economically and we do not assign any reserves to hydrates.

-ultimates

The BGR 2002 report « Reserves, resources and availability of energy resources 2002 » estimates the world unconventional reserves at 70 Tcf and resources at 50 000 Tcf

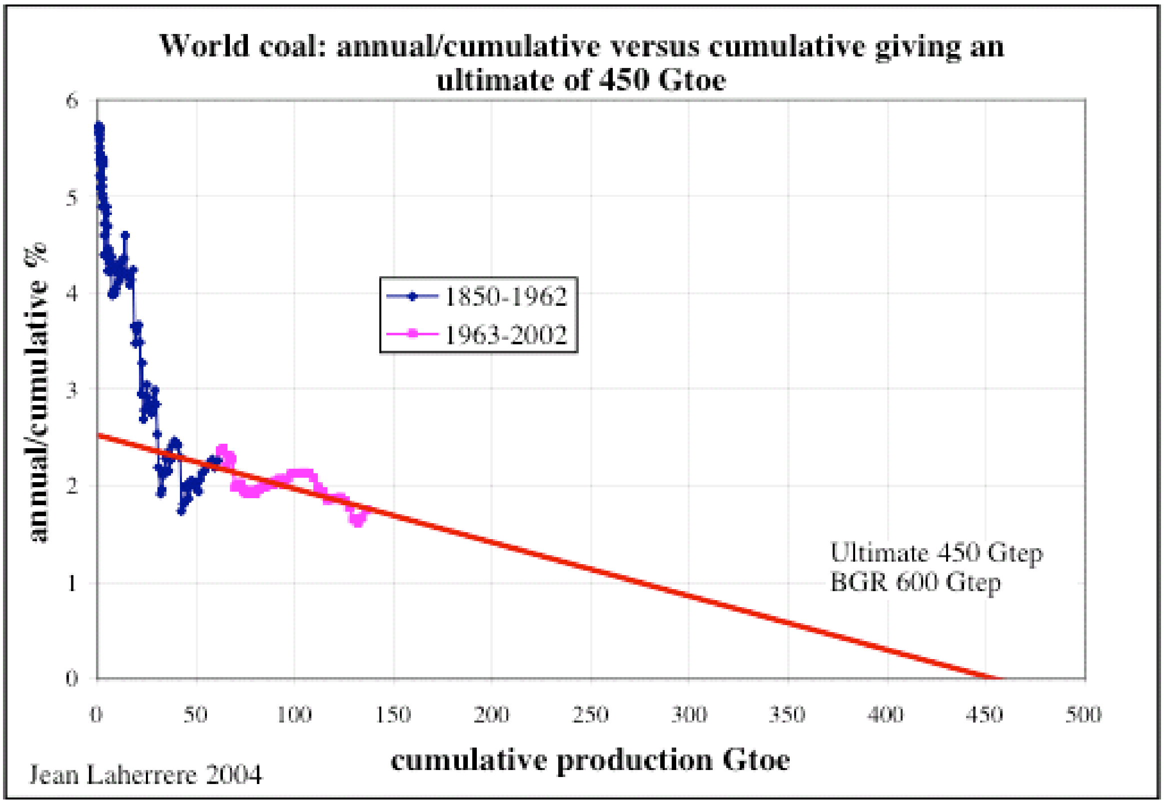
BGR 2002 t.3 Tcf	**reserves**		**resources**	
Year estimate	1997	2001	1997	2001
-tight gas	35	35	3 700	3 000
-CBM	70	35	2 800	4 700
-aquifer gas	0	0	50 000	26 000
-gas hydrates	0	0	51 000	16 000
-non-conventional gas	100	70	110 000	50 000

In table 3 unconventional gas is given as 63 EJ for reserves and 48 633 EJ for resources which is 772 times more, but in the text, unconventional gas is reported as 2 T.m3 (70 Tcf) for reserves and 220 T.m3 (8 000 Tcf) for resources, which is only 110 times more, as hydrates and aquifers are excluded, considered as too unlikely.
It is difficult inside this huge BGR range (70-8 000 Tcf) to select an ultimate.

Our 1998 report (Perrodon, Laherrere & Campbell) estimated the non-conventional gas ultimate at 2 500 Tcf. Six years later, I do not find any reason to change this estimate, keeping a global natural gas ultimate of 12 Pcf used to model the world NG production in figure xx.

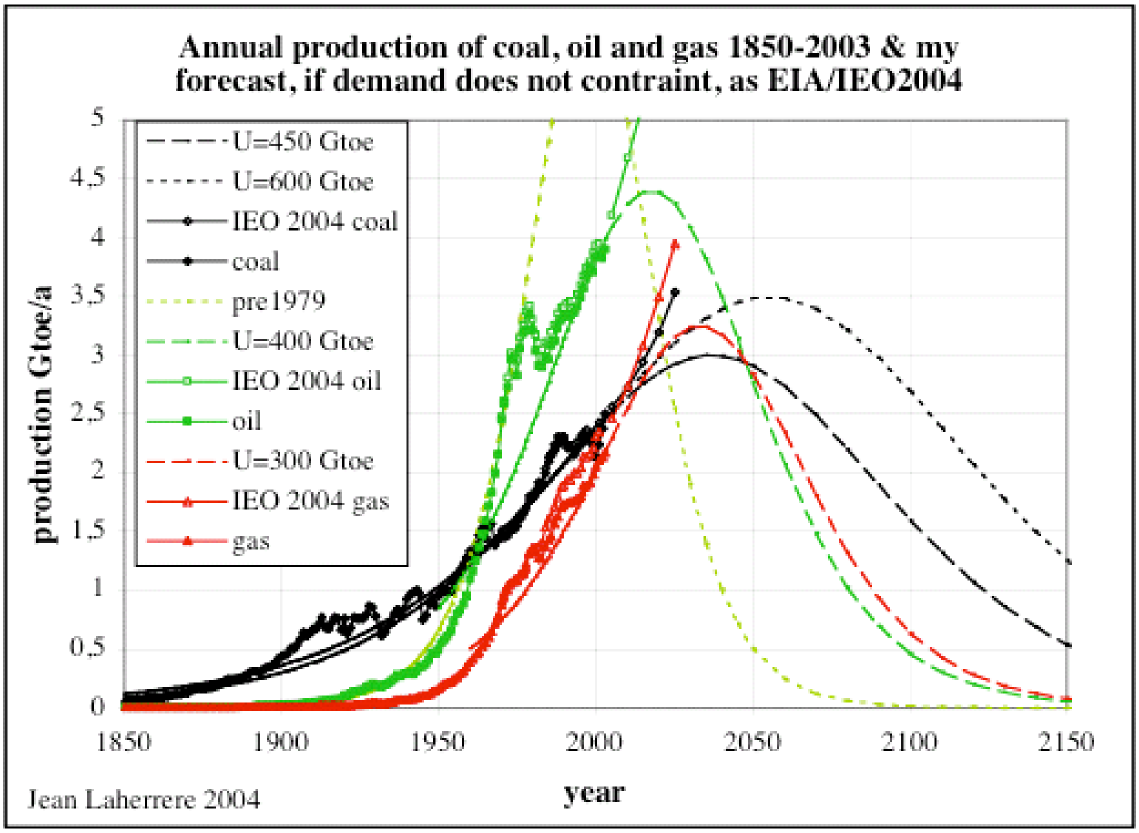
-**Modelling fossil fuel production**

It is interesting to compare the forecast of the different fossil fuels. Oil production is modelled with a 400 Gt liquids ultimate (Laherrere Copenhagen 2003 used 3 Tb all liquids ultimate), natural gas production with 300 Gtoe (close to 12 Pcf = 2 Tboe) and coal production with two ultimates (450 and 600 Gtoe). BGR 2001 inventory reports a coal ultimate of 600 Gtoe but the extrapolation of past production on a graph annual/cumulative versus cumulative production gives only 450 Gtoe
Figure 65: World coal: annual/cumulative versus cumulative



Hubbert curve is used as being the simplest curve showing an area below the curve equal to the ultimate (constant growth followed by constant decline displays an angular peak), supply would likely follow the Hubbert curve if there is no demand constraint (and a large number of independent producers to get random effect). In case of demand constraint (economic recession or depression) the production will be below the Hubbert model and the peak will be delayed, but keeping the same area below the real curve.

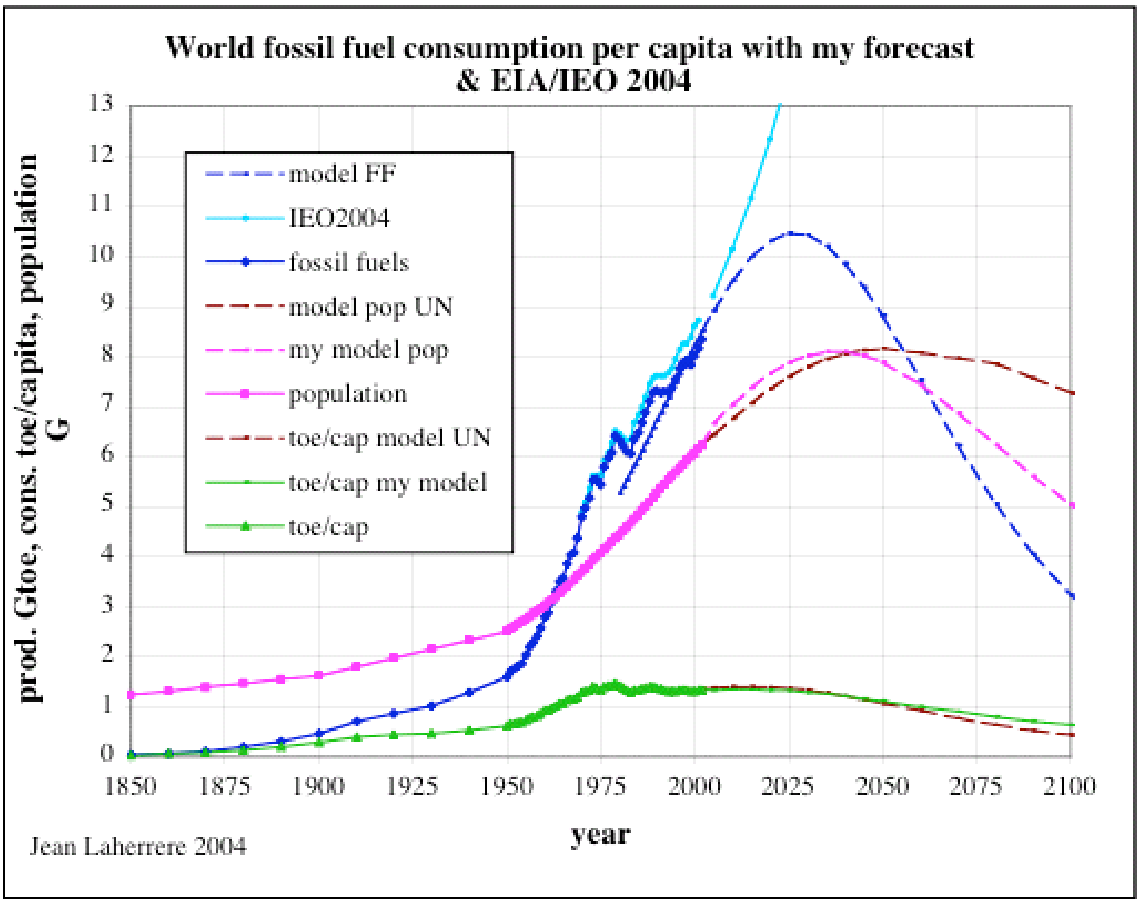
Figure 66: Past production for coal, oil and gas 1850-2003 with models up to 2150



With such ultimates and no demand constraint, oil will peak around 2015, gas around 2030 and coal around 2050, and the three fossil fuels around 2025. But EIA/IEO 2004 values up to 2025 show a larger rise.

The fossil fuels consumption will peak around 2025 at 10 Gtoe, but EIA/IEO 2004 forecasts a steep rise to over 13 Gtoe. We add the population forecasts (mine and UN) to get the consumption per capita.

Figure 67: World fossil fuels production per capita



It appears that the fossil fuels consumption per capita stays around 1.3 toe/cap since 1975 to 2025 and declines to only 1.1 toe/cap in 2050. The help from the renewables can arrive slowly.

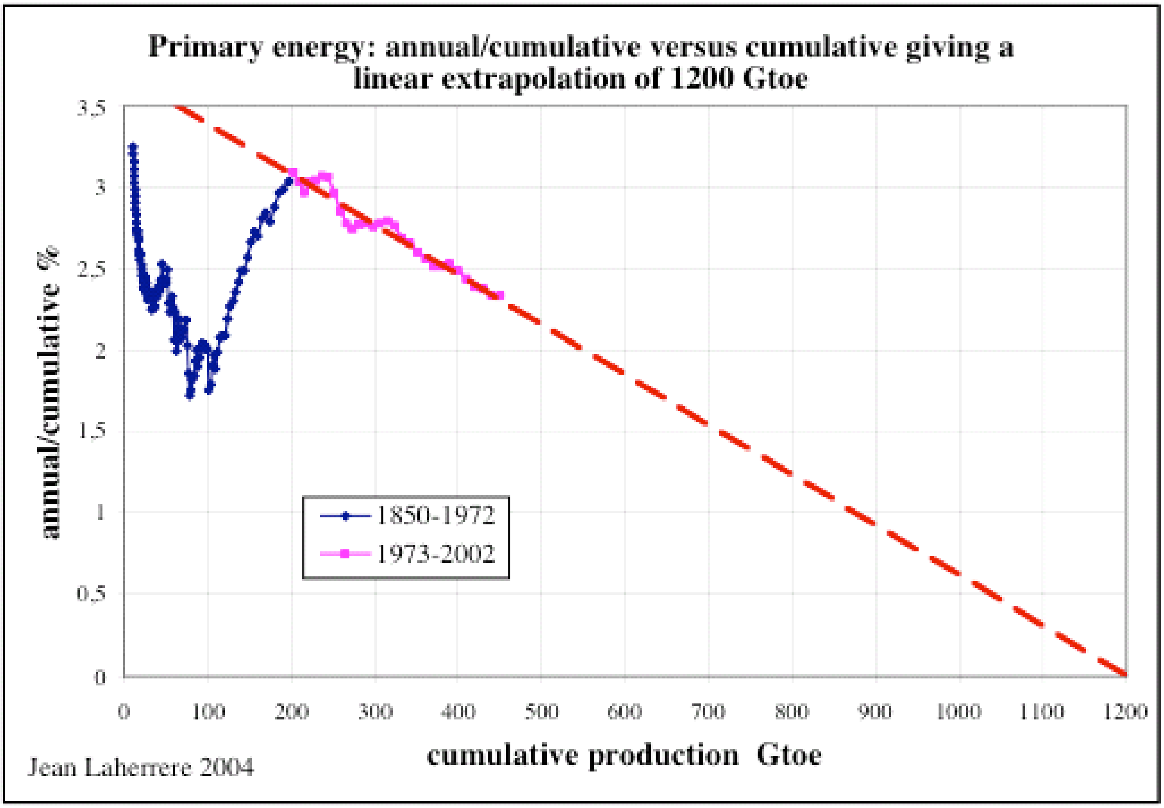
It is obvious that with energy savings the world population will have enough energy to cover the elementary needs.

-Energy modelling

The past primary energy can be extrapolated with either a logistic curve (with renewables the energy can be kept constant in long term) or a derivative (the renewables are limited by the earth limits and population goes towards extinction with a fertility rate below replacement for educated populations).

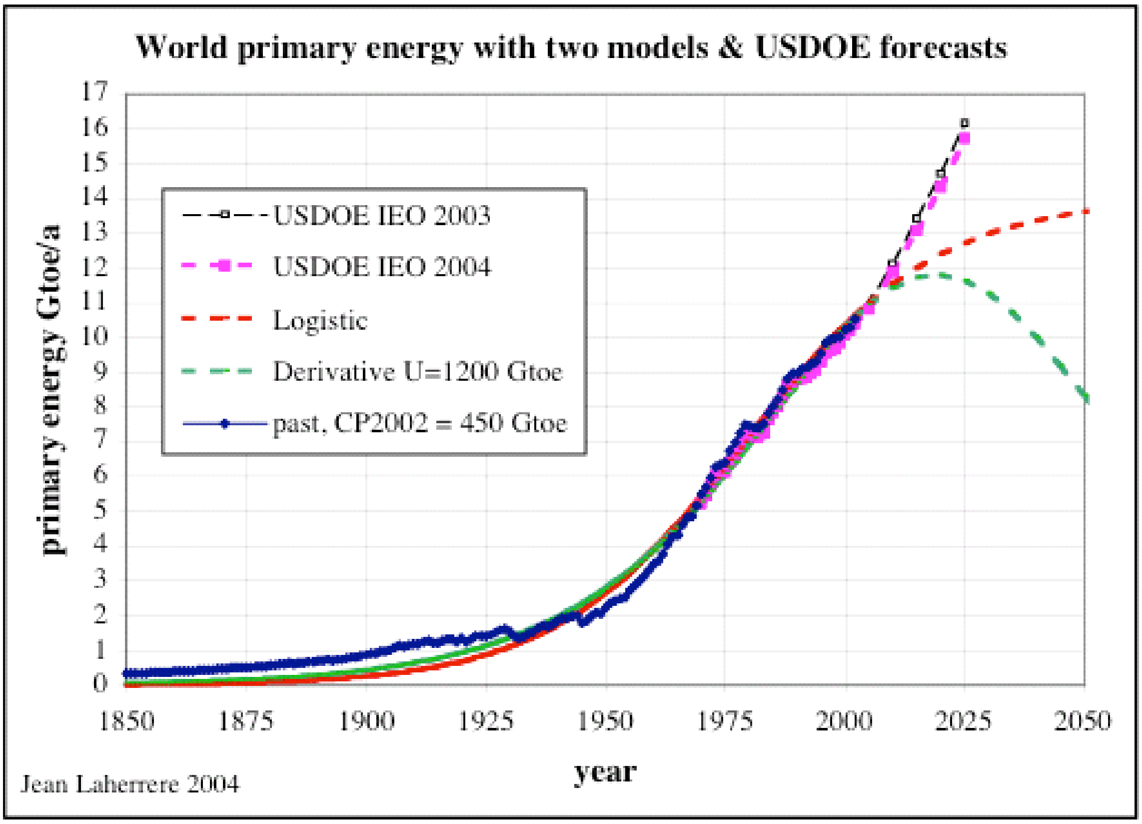
The past data on primary energy displayed as annual/cumulative versus cumulative can be extrapolated towards an ultimate of 1200 Gtoe; which is used to model the logistic derivative (Hubbert curve). But it means that the linear trend since 1973 will continue, which is unlikely as oil and gas peak will imply changes for the other energies.

Figure 68: world primary energy annual/cumulative versus cumulative production



The logistic is modelled toward an asymptote 14 Gtoe and the derivative is modelled for an ultimate of 1200 Gtoe peaking around 2025 but which is the peak of fossil fuels above, implying that the other energy will not add much, which is unlikely. It appears that both gives identical values for the next 15 years and diverge strongly only after 2025.

Figure 69: World primary energy modelling



USDOE IEO 2003 & 2004 forecasts for 2025 a much higher value, which seems unlikely to me. It is likely that the real values will be within this huge range, but no one knows as it depends mainly upon the economy, which can show some surprises.

-**Conclusions**

NG production data is poor (even in the US), the product is badly defined, and countries sometimes omit losses. Field reserves are lousy and in complete in most countries. Country reserves are reported as political data and display chaotic patterns. Technical data is confidential and scout companies report divergent figures.
Better and complete production data is needed to provide better forecasts.
For the last 20 years discovery was about the same as production but the balance has been declining for the last 3 years.
The world natural gas ultimate is about 12 000 Tcf for all and 10 000 Tcf for conventional.
Gas production will peak around 2030 at less than 140 Tcf/a (compared to 180 Tcf/a for official forecasts), but economy depression or high gas price may cause the demand to fall and the decline to be postponed.
But since gas is quite expensive to transport and requires long and very expensive investments, as long term contracts, most continents consume what they produce within the continent and there are three different gas markets.
North America gas production will decline drastically from now on and NGL will be needed soon in larger quantities if high prices do not lead to demand destruction as they did for fertilizer plants, NIMBY constraints may lead to LNG terminals delays.
Europe gas production will peak within few years at less than 12 Tcf/a
FSU gas production will peak in 2015 at 30 Tcf/a
In brief, local gas shortage may occur much sooner than global oil shortage
However, fossil fuels production per capita has been flat for the last 25 years and will stay at the same level for the next 25 years.
USDOE 2004 forecasts display lower values than in 2003, but seem still too high.
It is very difficult to foresee gas price, but cheap prices are gone except for short periods when poor investments are badly timed.
Energy savings are the best hope to solve future energy problems and high energy prices are the best way to change human behavior, when energy is recognized as the most important factor of life.

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