Future of natural gas supply
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This paper provides many data for the web reader and only some graphs will be presented at the conference.

-World
-production of natural gas (NG)
Reliable data s 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 loss is usually hidden. Non-hydrocarbons gases are important in some fields.

Production data varies from sources for what is called marketed

World Production marketed		**2001**	**2002**
-Cedigaz marketed	G.m3	2552	2600
-OPEC	G.m3	2566	2589
-Enerdata			2623
-BP 2003	G.m3	2493	2528
-BP 2003	Tcf from G.m3	88,0	89,2
-BP 2003	Tcf	89,3	90,6
-USDOE dry Tcf		90,5	92,3
-USDOE marketed		94,7	

As any data in the indutry, 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 significant, being 8 % of the gross and this loss is rarely taken into account to estimate the remaining reserves as usually it is the dry production which is reported.

Cedigaz 2002	%	%	%	%	%	Tcf/a
		flared &	other		gross-	
Production % gross	reinjected	vented	losses	marketed	reinjected	gross
NORTH AMERICA	13	1	6	80	87	32
Canada	6	1	8	85	94	8
United States	15	0	5	79	85	24
LATIN AMERICA	18	6	10	65	82	8
EUROPE	11	1	4	85	89	12
CENTRAL EUROPE	0	0	2	98	100	1
FSU	0	1	2	97	100	27
Russia	0	0	2	98	100	21
AFRICA	32	14	5	50	68	9
MIDDLE EAST	23	3	7	67	77	12
ASIA-OCEANIA	3	2	6	89	97	11
WORLD TOTAL	11	3	5	81	89	111

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

The difference for 2001 from USDOE and Cedigaz for countries producing over 1 Tcf/a is

Tcf/a country	USDOE marketed	USDOE dry	Cedigaz marketed
world	94,7	90,5	90,1
Russia	20,5	20,5	20,5
United States	20,6	19,7	19,7
Canada	7,2	6,6	6,6
UK	3,9	3,7	3,7
Algeria	3	2,8	2,8
Netherlands	2,75	2,75	2,55
Indonesia	2,51	2,34	2,34
Iran	2,52	2,33	2,33
Uzbekistan	2,23	2,23	2,03
Norway	2,10	1,95	1,95
Saudi Arabia	2,00	1,90	1,90
Turkmenistan	1,70	1,70	1,81
Malaysia	1,83	1,66	1,66
UAE	1,54	1,39	1,39
Argentina	1,49	1,31	1,31
Mexico	1,30	1,30	1,25
Australia	1,19	1,19	1,19
Venezuela	1,34	1,12	1,12
China	1,07	1,07	1,07
Qatar	1,10	0,95	0,95
Egypt	1,01	0,87	0,87

In the US for 2002 dry production was 93 % of the gross -reinjected when marketed was 98%

2002	gross	gross-reinjected	marketed	dry production
Tcf/a	24,1	20,4	20,0	19,0
%	118	100	98	93

The volume of natural gas plants liquids (NGPL) increases with the volume of gas with an average ratio of about 27 Mb/Tcf
Figure 1: World natural gas and gas liquids production
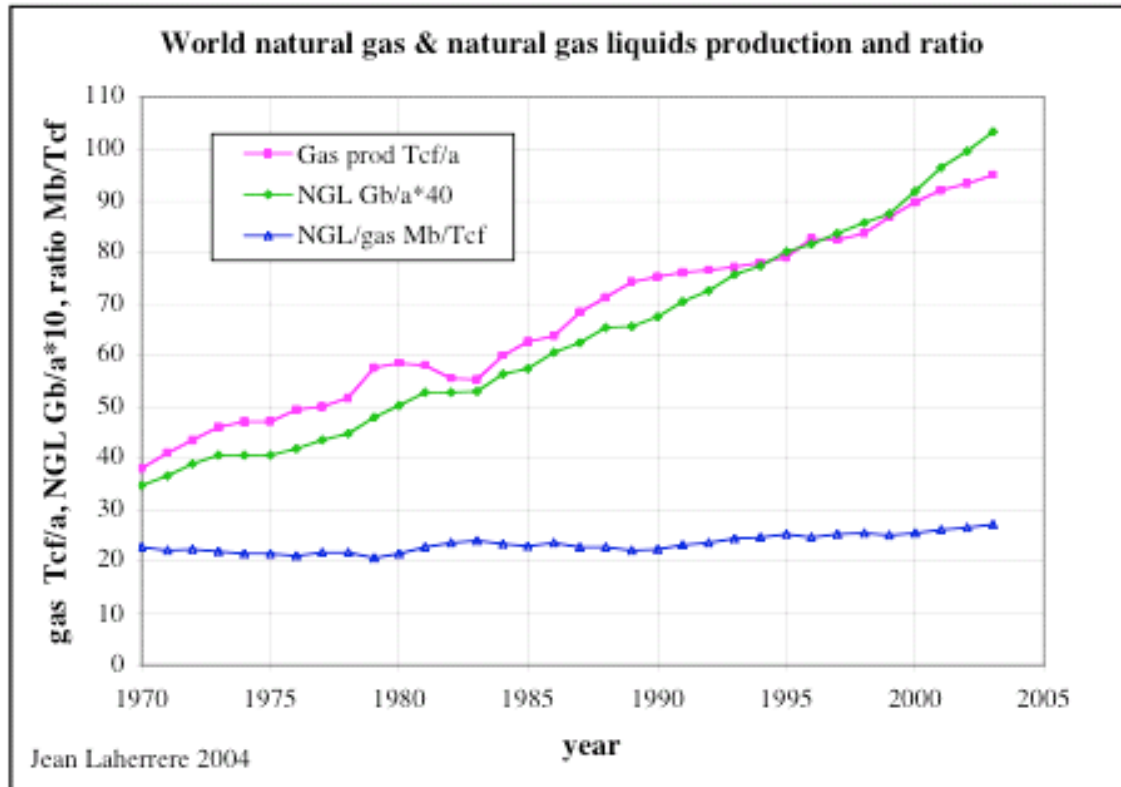
NGPL has increased strongly in OPEC countries since 1970, when flat in the US.
Figure 2: NG plants liquids production for some countries
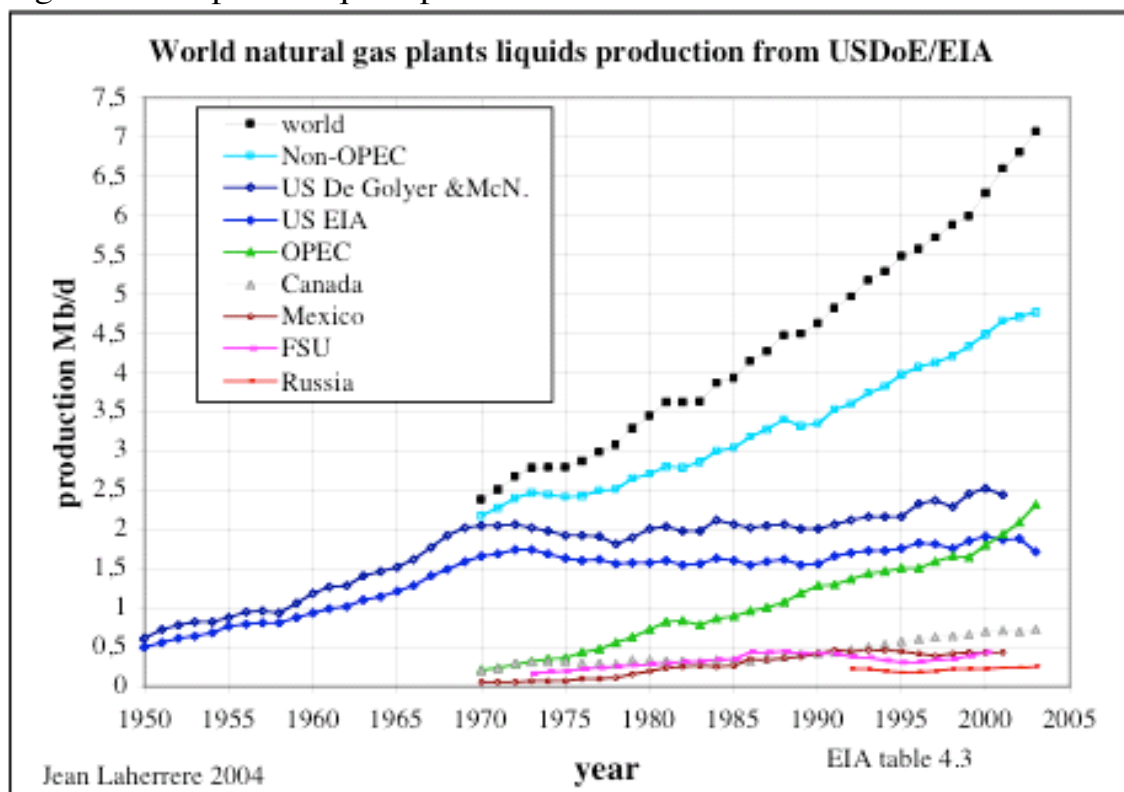
Heat content varies largely with field and country. The 2002 BTU/cf of dry production ranges from 799 in Poland to 1431 in Greece with an average for 89 countries of 1042. The 2002 main producers have the following heat content:

Producer	production Gcf/d	Btu/cf
Russia	57	1009
US	52	1027
Canada	18	1022
UK	10	1059
Algeria	8	1127
Netherlands	7	894
Indonesia	7	1090

Algeria gas is 26% more energetic than Netherlands gas.

Changing source could mean adjusting the equipment. In the US, in the past, liquids were recovered to bring a larger profit because gas was cheap, but it is now more profitable to sell the liquids with the gas and one third of the gas is not processed anymore (http://www.enn.com/news/2004-04-30/s_23344.asp) damaging consumer equipments used to receive dry gas.

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.

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 3: LNG trade from Cedigaz 2002

Figure 3 - Evolution of international LNG trade
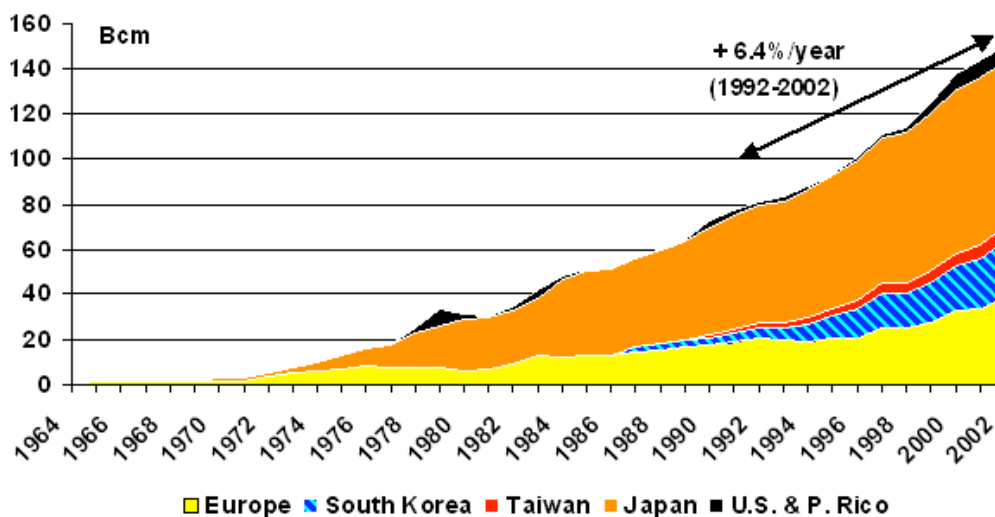
Notice the first attempt for LNG in the US in 1980

There are mainly 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
Prices from BP Review show a range and a sharp increase since 2000.
Figure 4: NG price from BP Review

Natural gas prices from BP Statistical review

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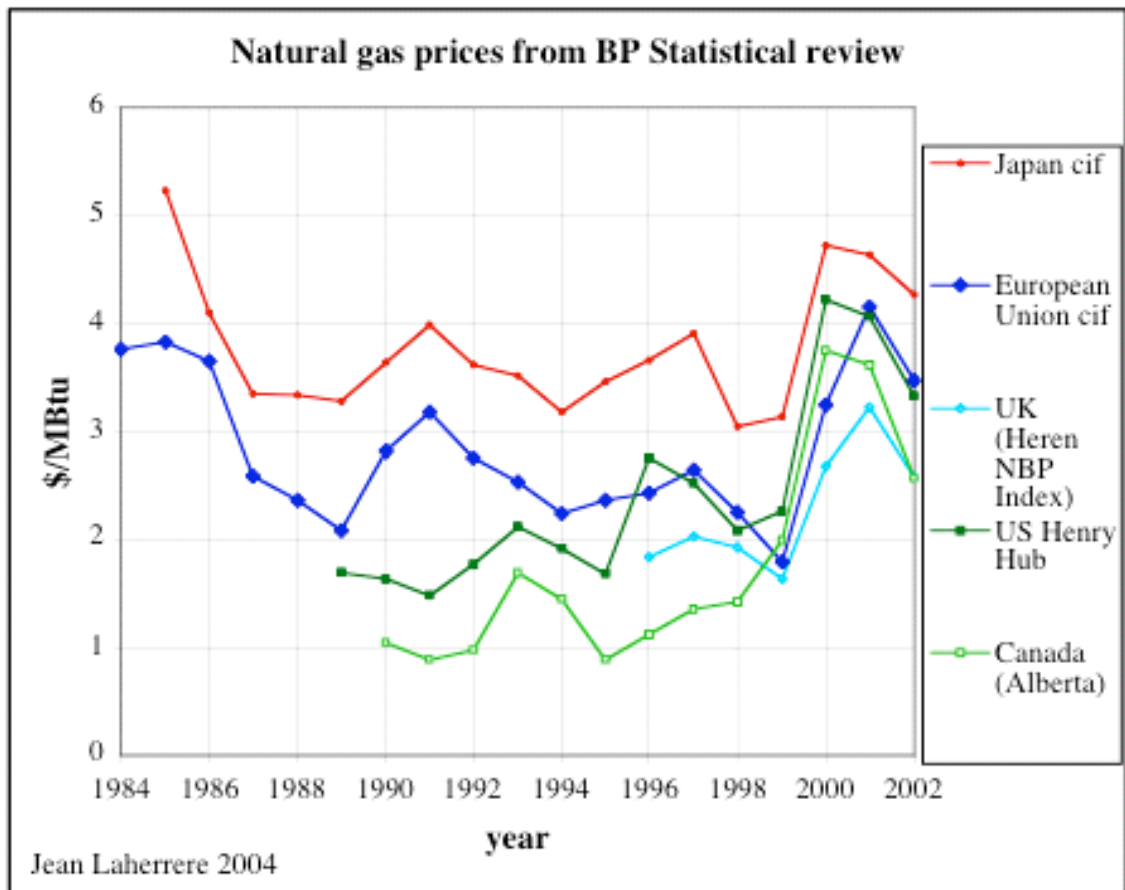
US Henry Hub are 10% higher than wellhead price
(http://www.eia.doe.gov/oiaf/analysispaper/henryhub/)
Prices from USDOE better show the difference for households, as in Japan gas was three times more expensive than in Europe and five times than in Canada
Figure 5: NG price to households
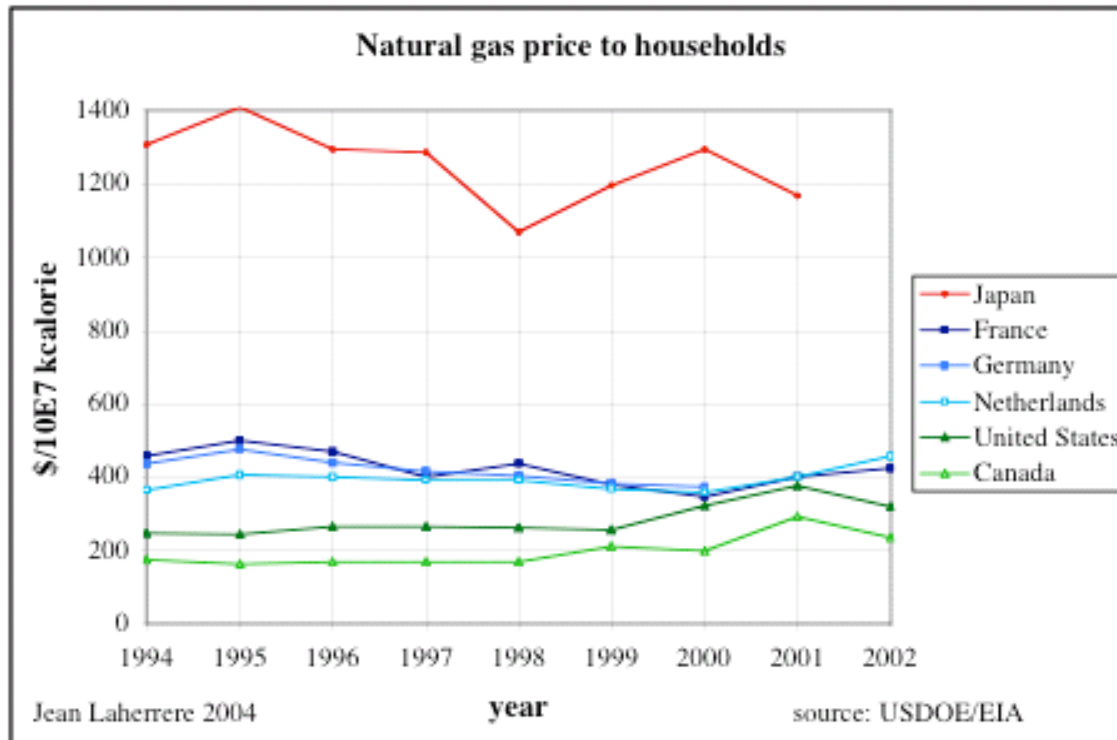
The difference is less for the industry.

Figure 6: NG price for industry
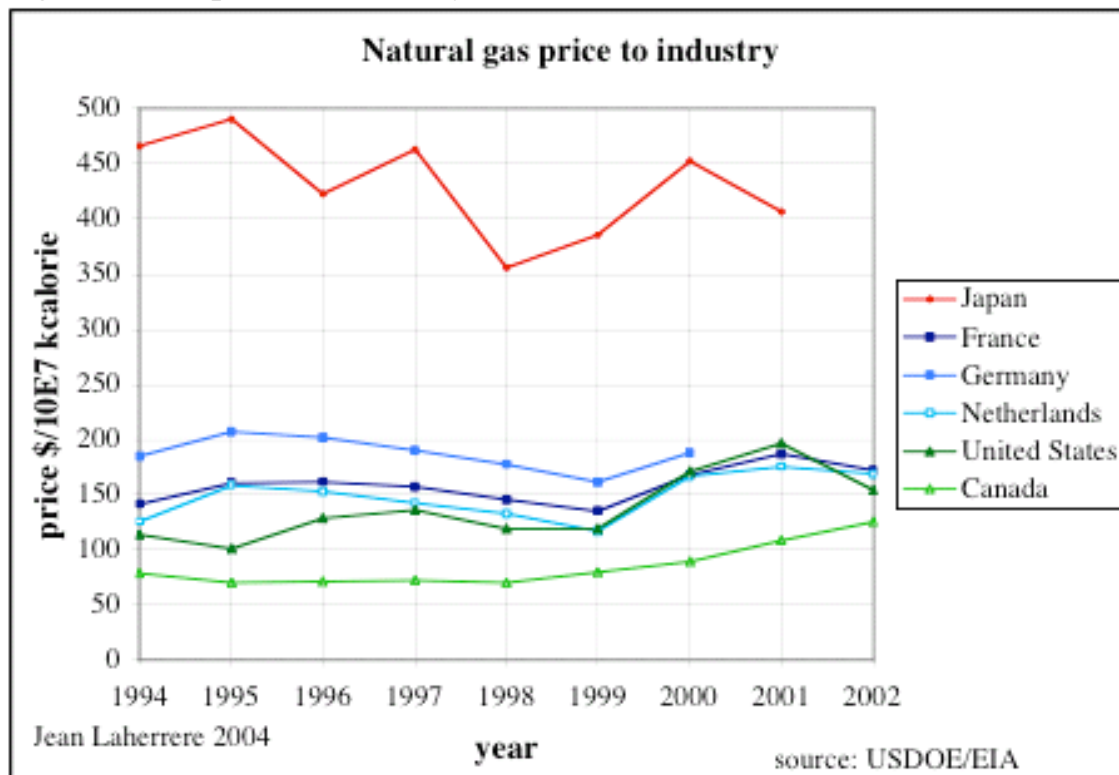
Contrary to oil where consumption and production are different by continent, NG production is close to consumption by continent

Figure 7: NG production & consumption from BP Review
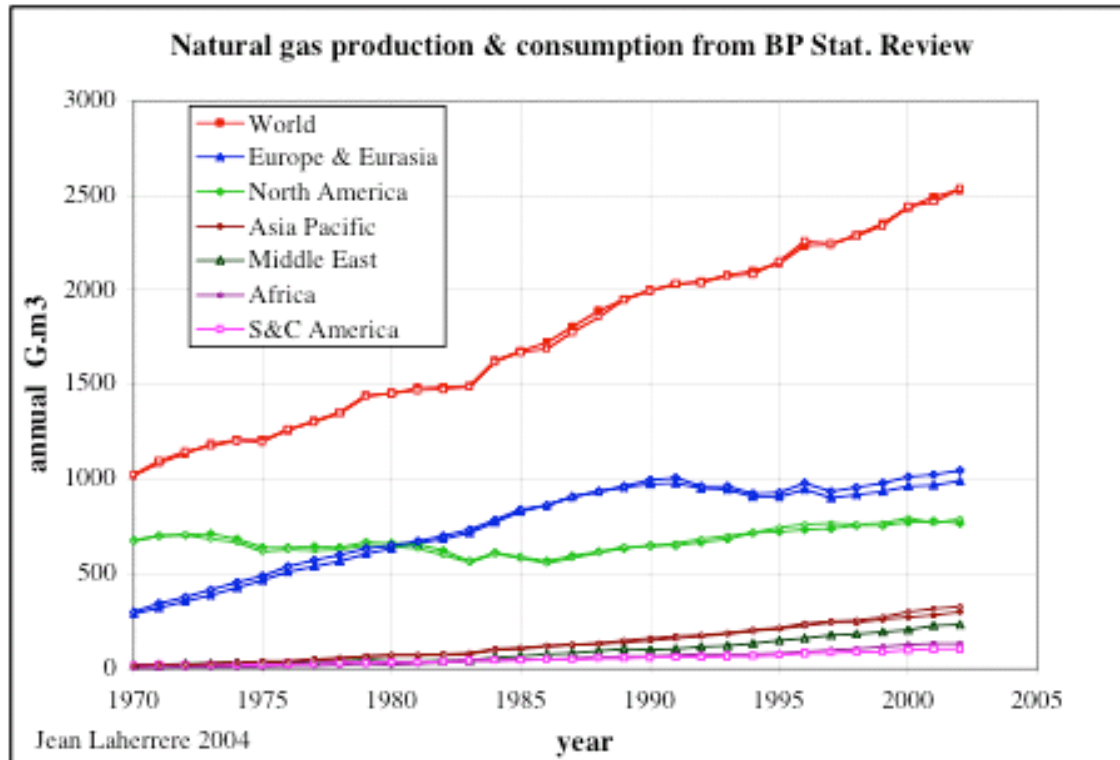
The difference is better seen on the next graph
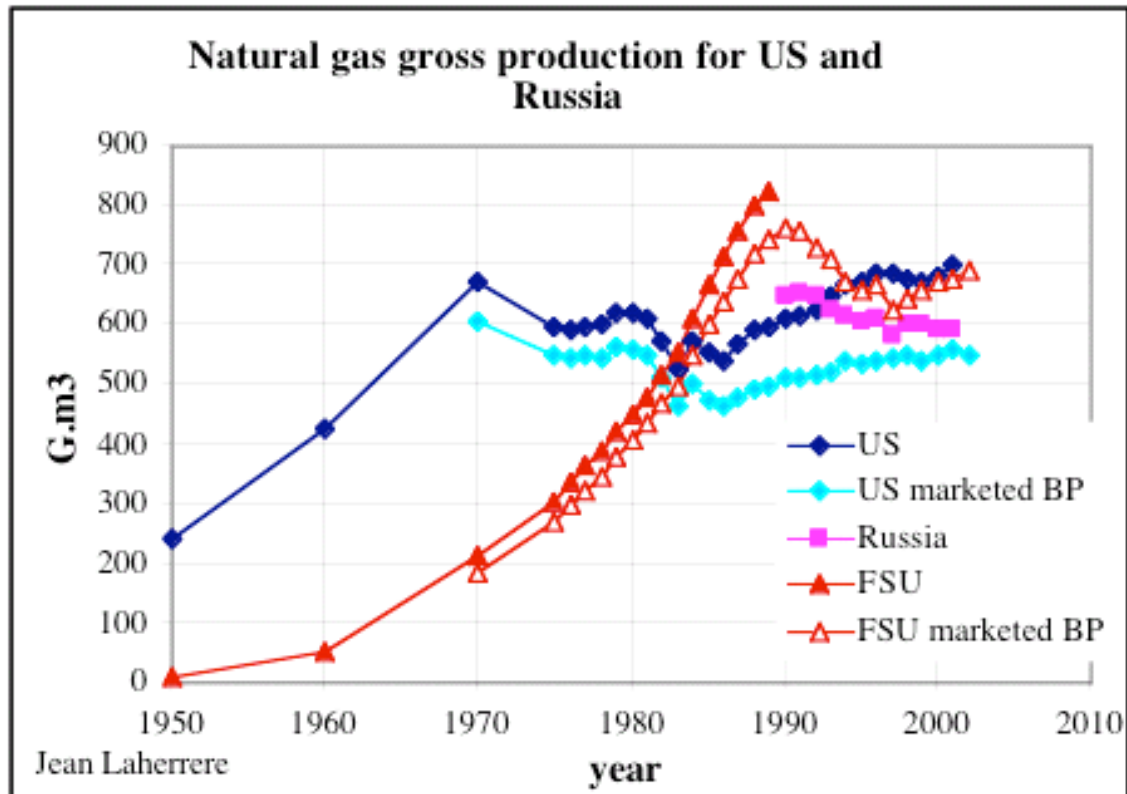Figure 8: NG production minus consumption
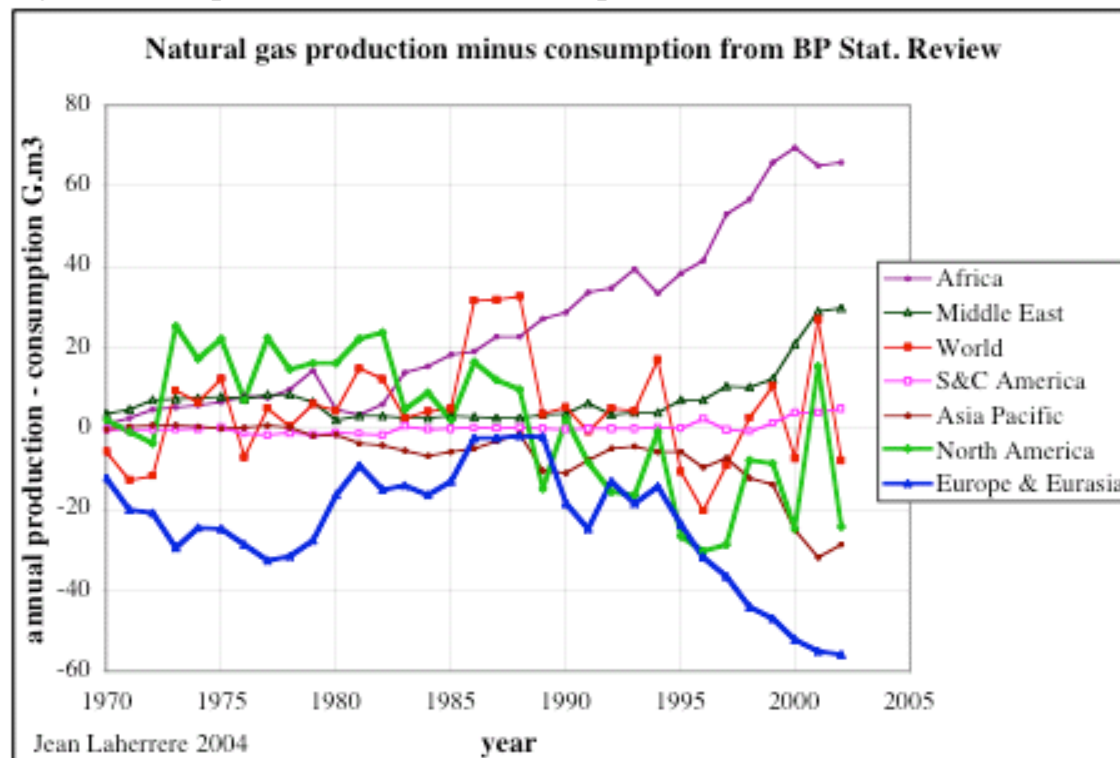
On the last decade, Africa is exporting and Europe importing

In 1970 the US were producing three times more than FSU, but since 1985 Russia markets more than the US
Figure 9: NG gross production for US and Russia

Natural gas gross production for US and Russia

But the reported (BP) proved reserves are 9 times more in Russia than in US
Figure 10: NG proved reserves from BP Review

Natural gas proved reserves from BP Stat. Review
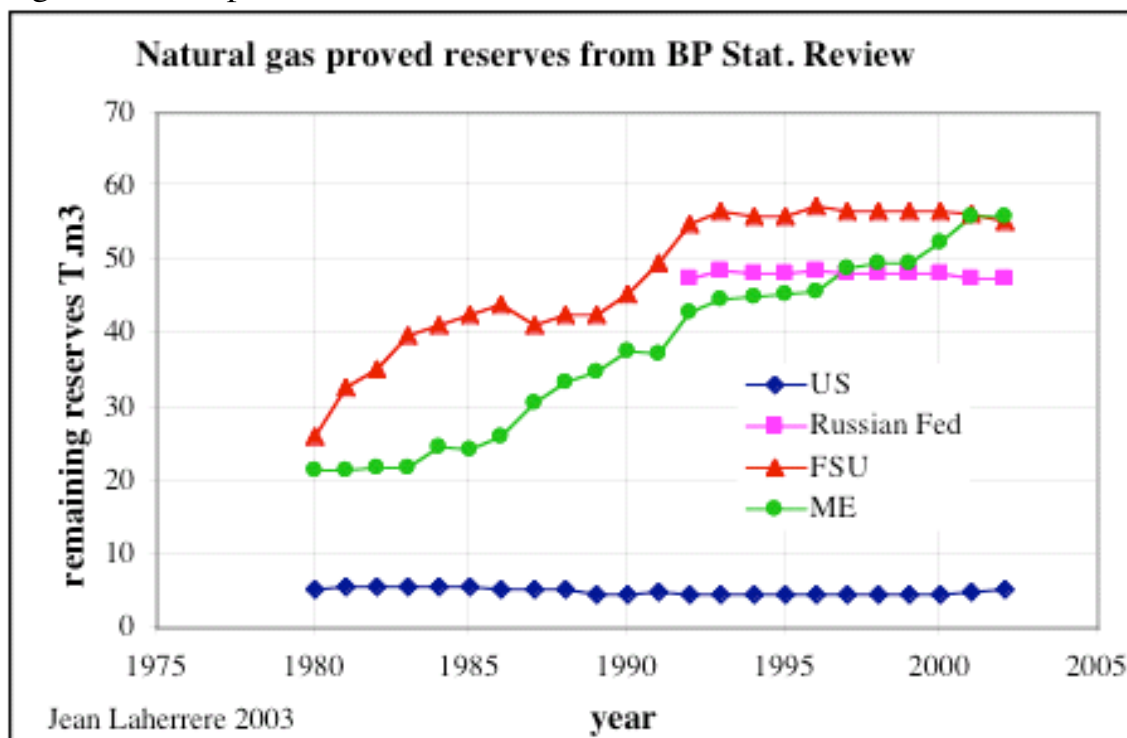
Data is unreliable for production, but it is worse for reserves. As for oil, the remaining gas reserves published by political sources (enquiries to governments done by Oil & Gas Journal (OGJ) and reproduced by BP, OPEC and World Oil (WO)) are drastically different from technical sources. Cedigaz is 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. IHS using ABC1 values (close to 3P) is higher than the mean value. Technical remaining reserves are the initial reserves minus production and can vary if production is taken as dry or gross minus reinjected.

Since 1980 the technical remaining reserves is about constant since annual discovery is close to annual production.

Figure 11: World remaining reserves from technical and political sources
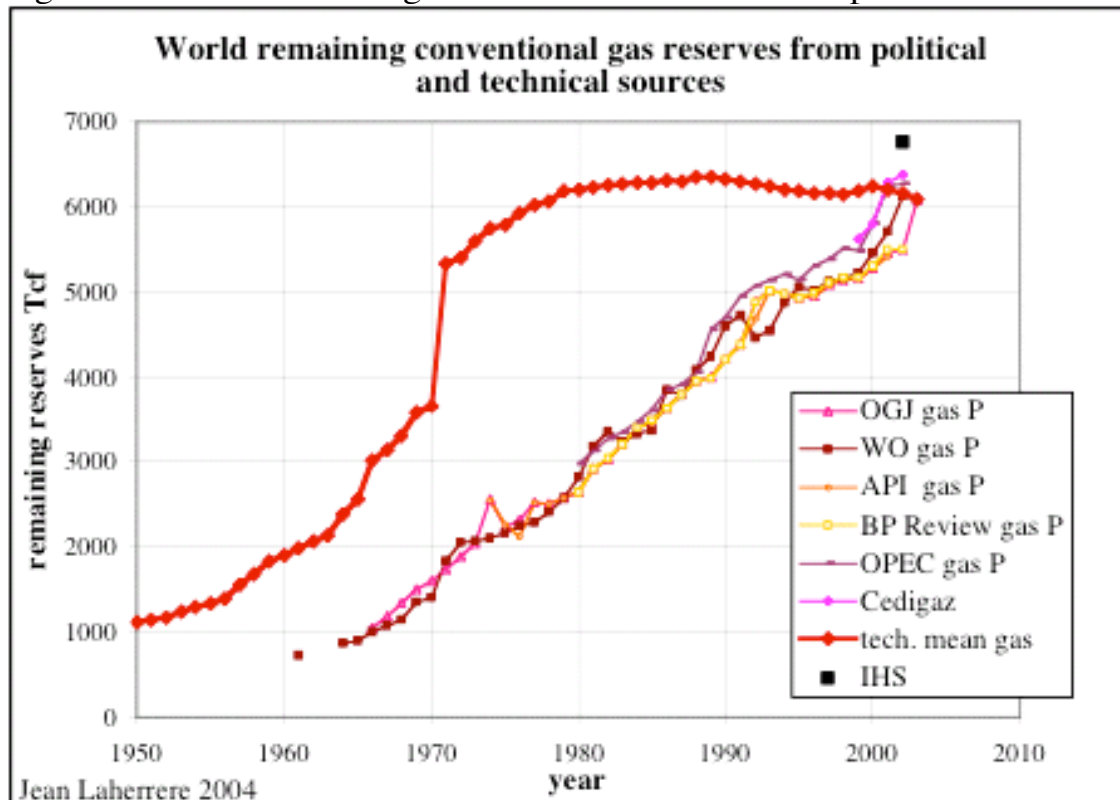
Chew (2004) notices that the OGJ reserves report Dec 22nd 2003
"Proven" gas reserves estimates for 102 countries;
76 estimates unchanged from 2002;
45 estimates unchanged from 1998;
7 estimates unchanged since 1993.

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, which is important, but the variation with time. The R/P varies drastically when using technical or political data.

Figure 12: R/P from technical and political sources

R/P from technical and political sources for oil & gas

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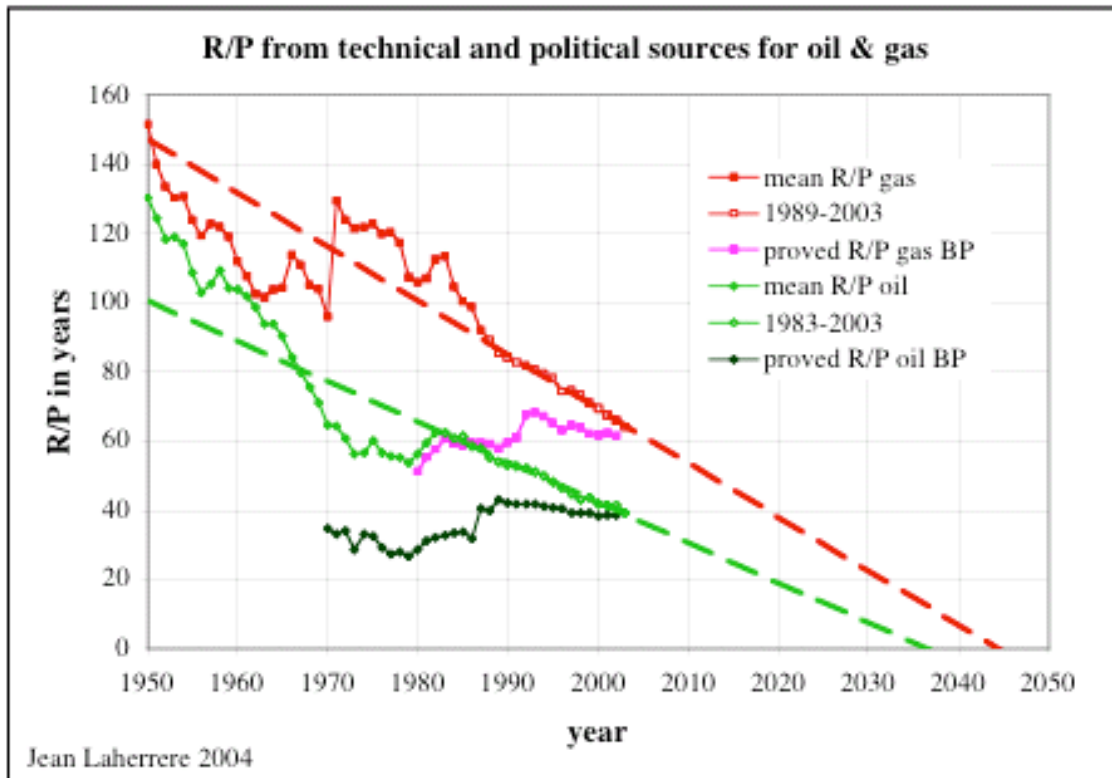
For gas since 1989 the technical trend is linear and a linear extrapolation could conclude that production will cease around 2045. But the political trend is almost horizontal leading that production will never end.

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 13: Exxon graph on annual NG discovery
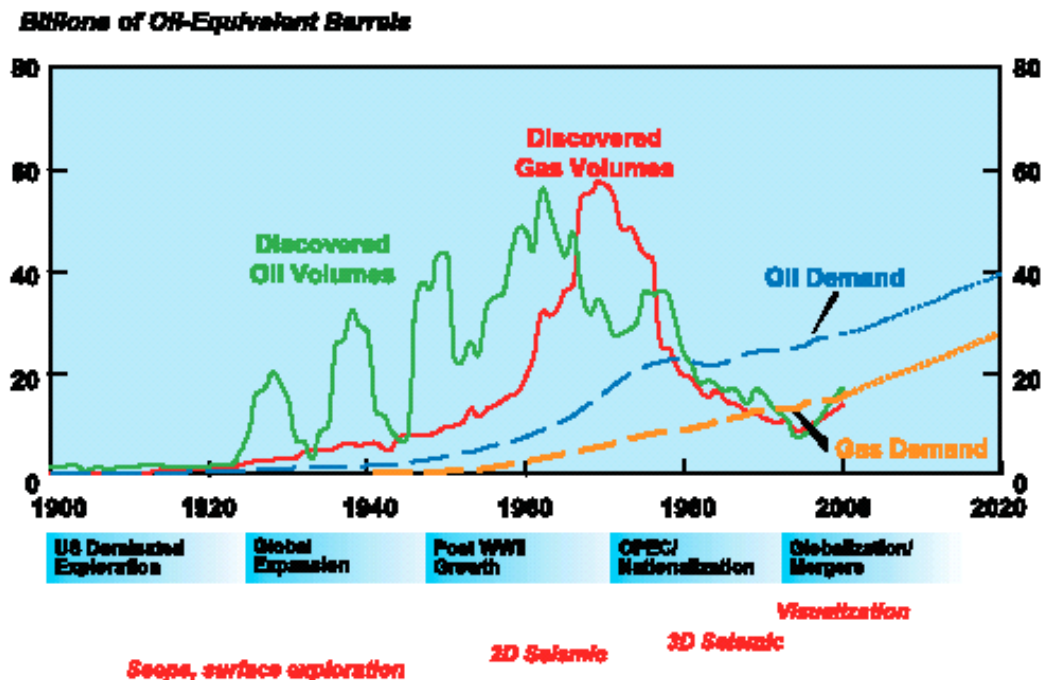
Figure 5: Gas Supply and Demand

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 the most and the unconventional gas as CBM and tight gas could not reach 40 Tcf/a in 2020 as it is about 4 Tcf presently.

Our past annual "mean" discovery is very close to Exxon-Mobil.

Figure 14: World conventional oil & gas "mean" discovery and production
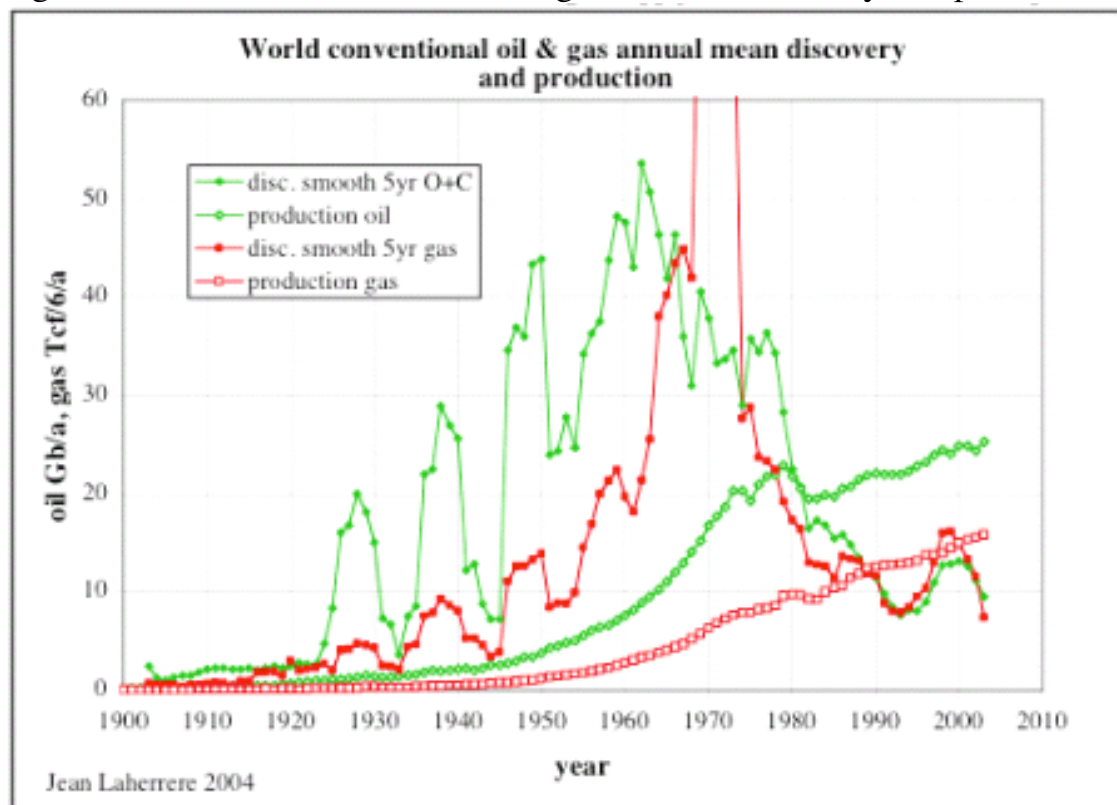
The cumulative discovery by continent shows the huge inequality of NG distribution.

Figure 15: Cumulative conventional NG discovery by continent

Cumulative conventional natural gas discovery by continent
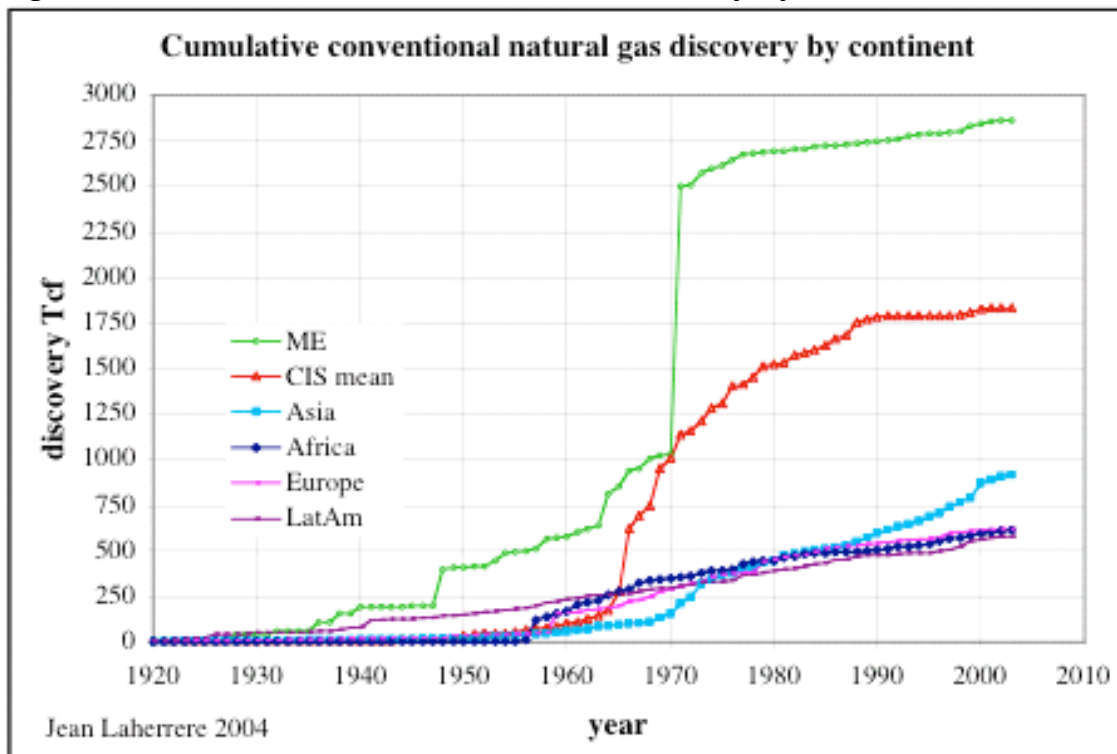
It is more striking to compare the creaming curve (cumulative discovery versus cumulative number of New Field Wildcats NFW)

Figure 16: Conventional NG creaming curve

Conventional natural gas creaming curve by continent
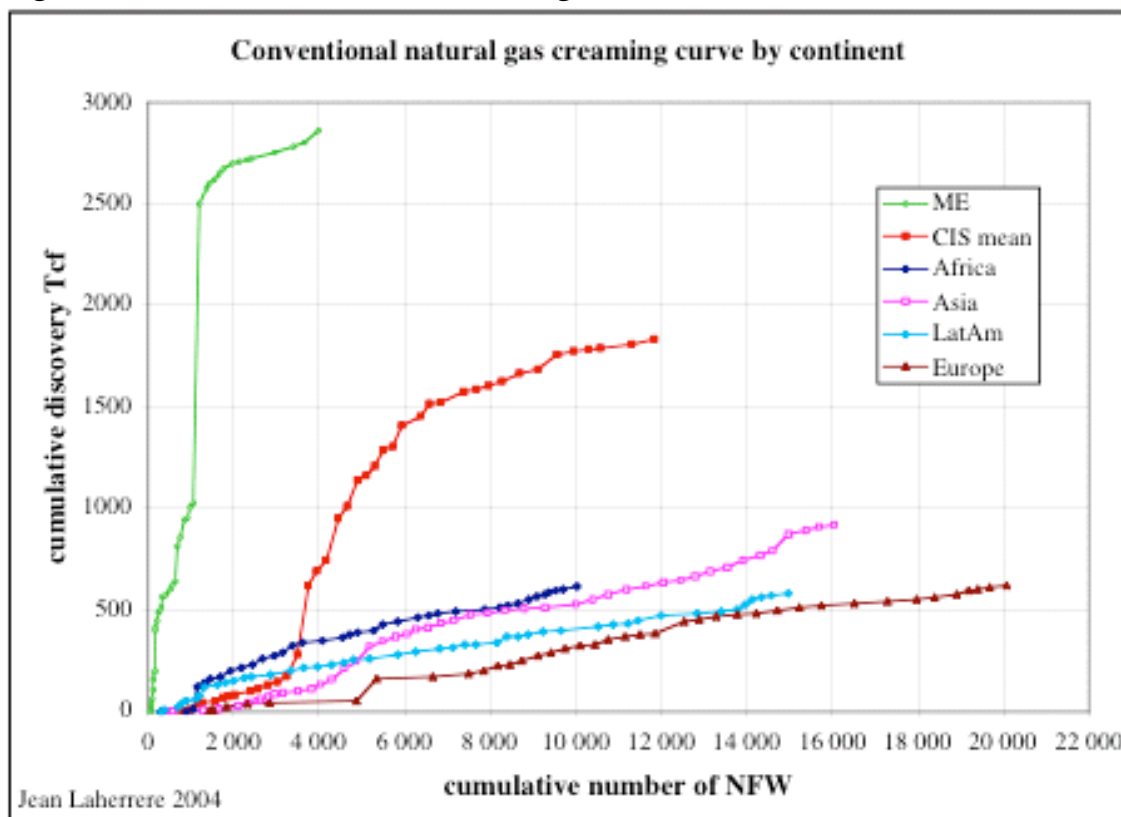
The Middle East has discovered 2800 Tcf with less than 4000 NFW, when FSU (CIS) has discovered only 1800 Tcf with 12 000 NFW and Europe 700 Tcf with 20 000 NFW.

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	Tcf
Middle East	3 000
CIS	2 000
US	1 250
Asia	1 150
Africa	800
Latin America	800
Europe	800
Canada	250
total	10 000 Tcf = 10 Pcf

It is comforting to find that the world ultimate of conventional gas is still 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 17: World NG production annual/cumulative versus cumulative
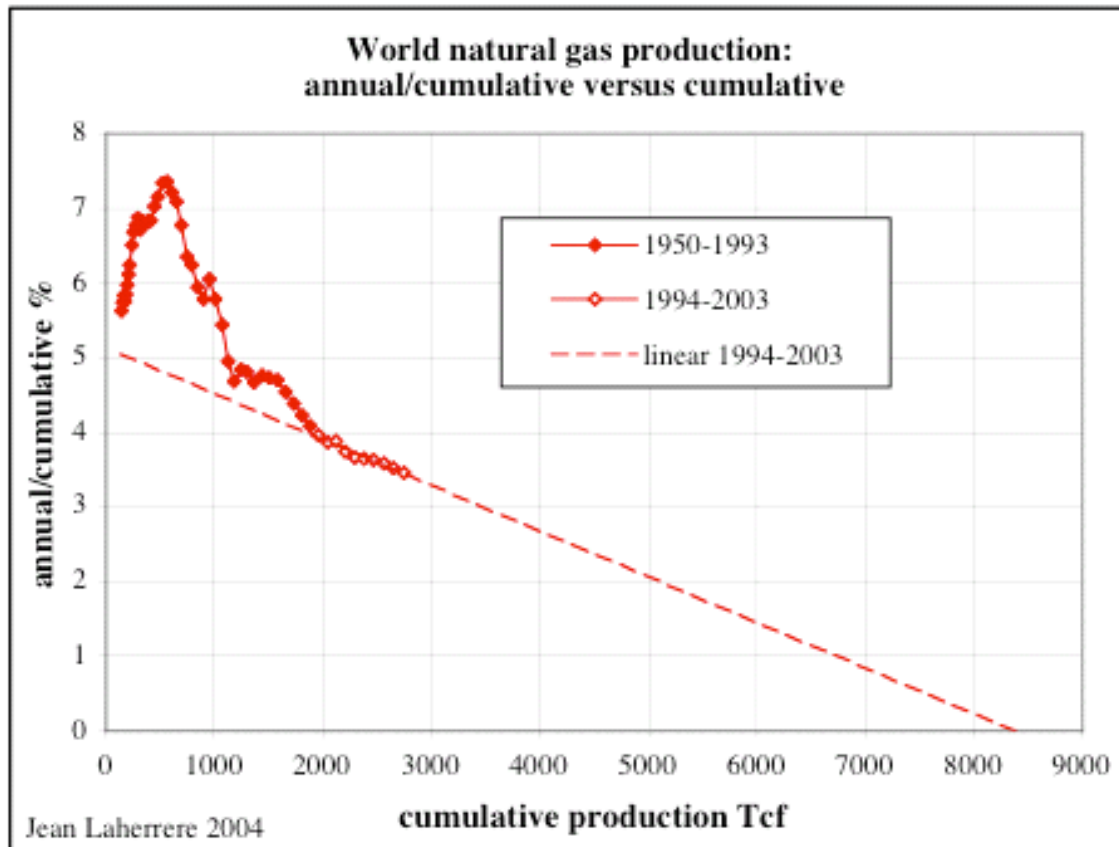
The trend is linear from 1994 to 2003 and goes toward an ultimate of 8500 Tcf, but stranded gas does not contribute to this trend and is therefore excluded from the ultimate. This indicates that the stranded gas is presently about 1500 Tcf.

The cumulative world gas discovery displays a curve close to a logistic curve, except the huge jump in 1971 by 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 18: World conventional NG cumulative discovery & production with logistic models

World conventional gas cumulative discovery and production with logistic models
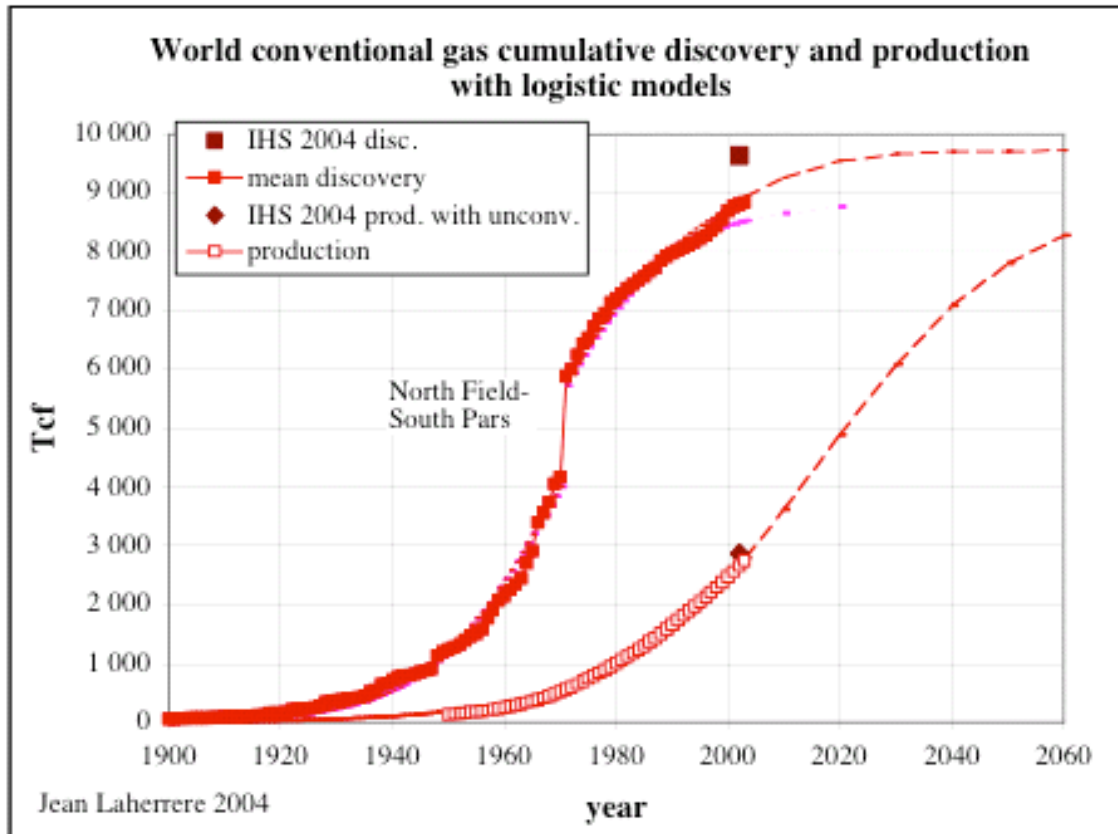
A 12 Pcf ultimate is used to model the annual all (conventional and unconventional) production with a derivative of the logistic (Hubbert curve) and compared to USDOE (EIA/IEO 2003) and WETO (Brussels) 2003 forecasts which in fact are plain forecasts of the demand without bothering to know if the supply will be there.

Figure 19: World NG annual production & forecasts

World natural gas production & forecasts
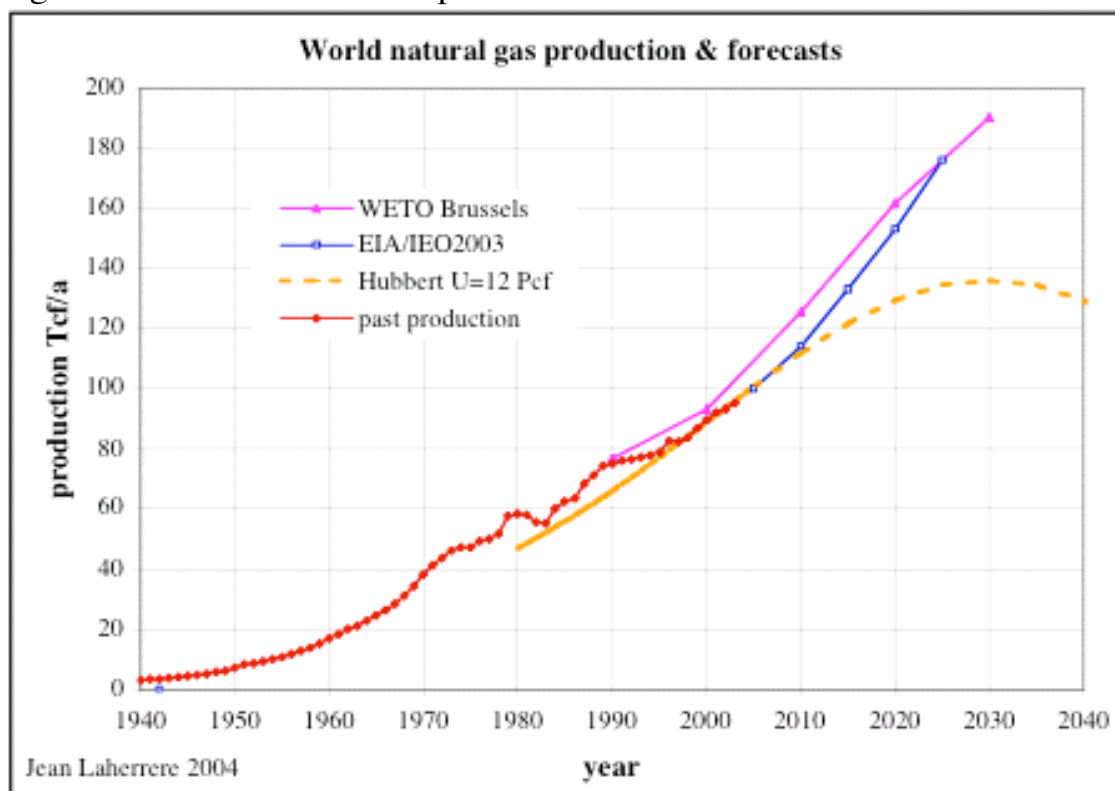
In 2025 USDOE and WETO forecast 180 Tcf/a when our forecast is about 140 Tcf
WETO forecasts a peak in W.Europe and Asia in 2010 and in North America in 2020,
Figure 20: WETO (European Union) NG production forecast
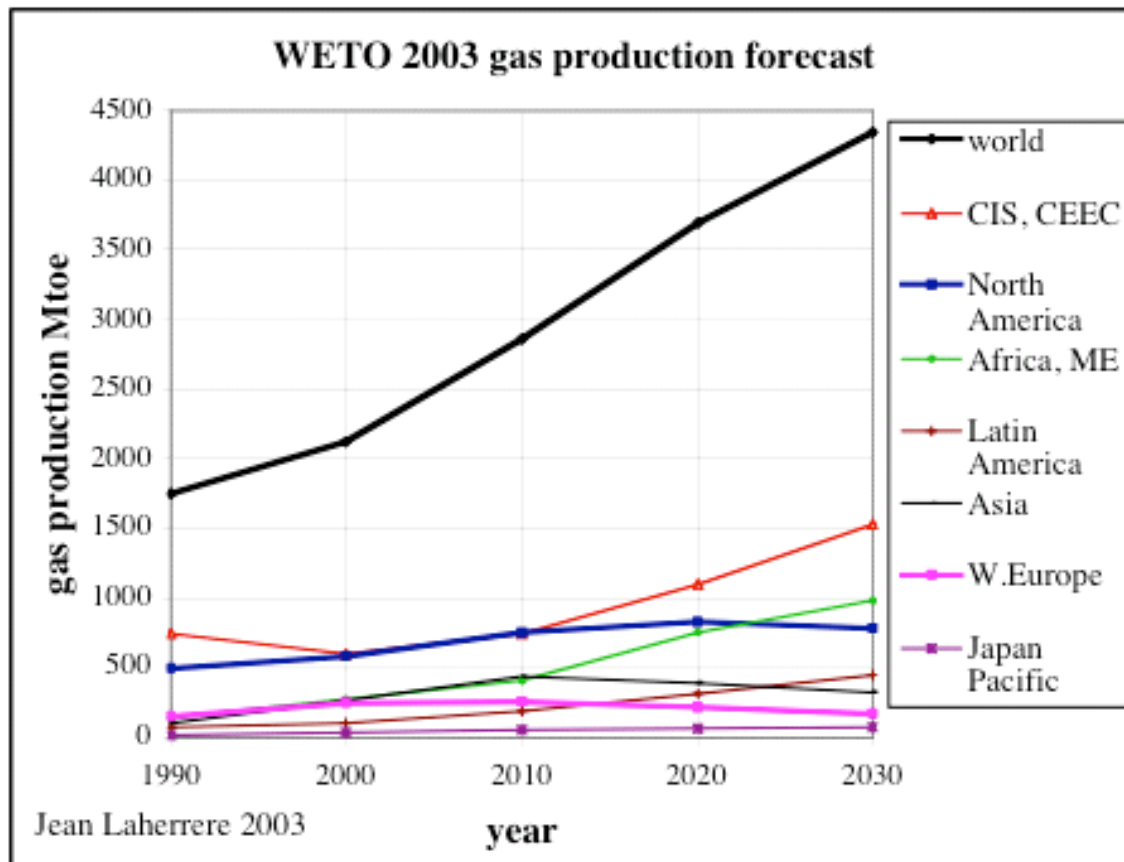
The study by country and continent displays different curves in order to foresee the future
production. The problem is that contrary to oil, which is usually quickly put into production
after discovery, there are many places where gas is stranded and production does not imitate
discovery.

-**Netherlands**
The remaining reserves vary with sources, the political being OGJ, BP, WO and Cedigaz
giving the proved values as reported by governments. Technical data is from IHS and WM.
The National Applied Geosciences (TNO) reports the expected values (as well the proven
values), still underestimated by about 10 Tcf compared to the backdated technical values.
Out of the 393 discovered gasfields only 228 have been developed, representing 148 Tcf out
of the 160 Tcf discovered, explaining the difference between TNO and the technical value.
Figure 21: Netherlands NG remaining reserves from technical & political sources
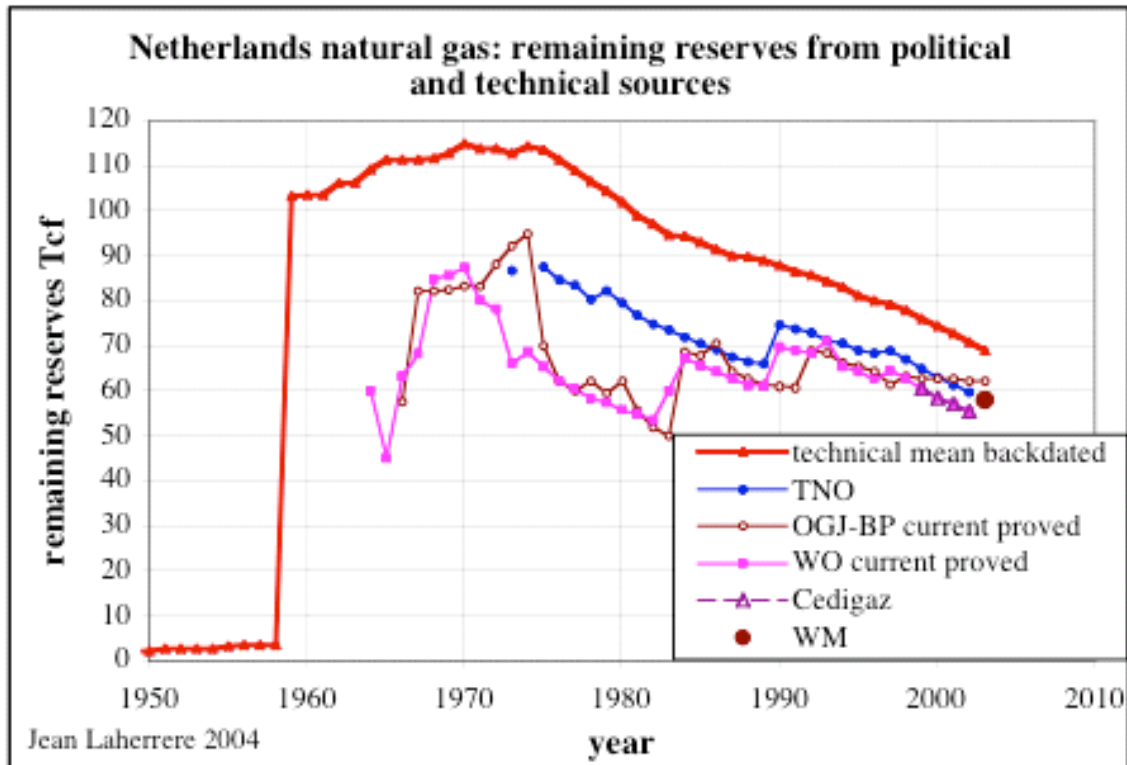
Groningen is used as a swing producer and is reported as 100 Tcf in the technical database, but its ultimate could be lower. In fact Zittel (2003) reports an ultimate of 95 Tcf for Exxon; 59 Tcf for Gasunie and 64 Tcf for LBST. However TNO annual reports give the values for the remaining reserves in Tcf:

	Proved	expected
End 2001	37	40
End 2002	36	39

As the cumulative production of Groningen is about 60 Tcf as of end 2001, this estimate gives an initial reserves figure of about 100 Tcf.

The annual versus cumulative production plot displays a chaotic decline, as Groningen is not only a swing gas producer but is used also as storage, and it is not produced at full capacity. It is difficult to rely on the past decline to estimate its ultimate.

Figure 22: Groningen decline
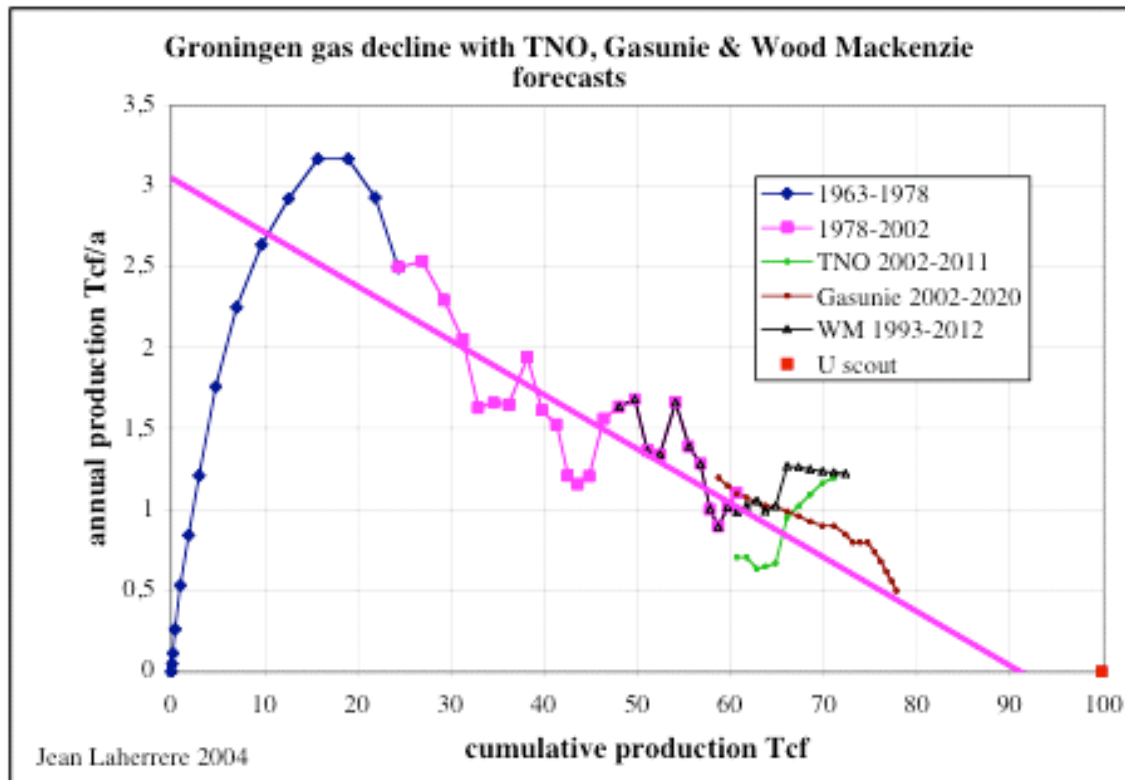
Gasunie uses Groningen as a swing producer in order to produce the small fields first at full capacity (in light green) when Groningen (dark green) oscillates with the demand
Figure 23: Gasunie small fields policy with Groningen as swinger
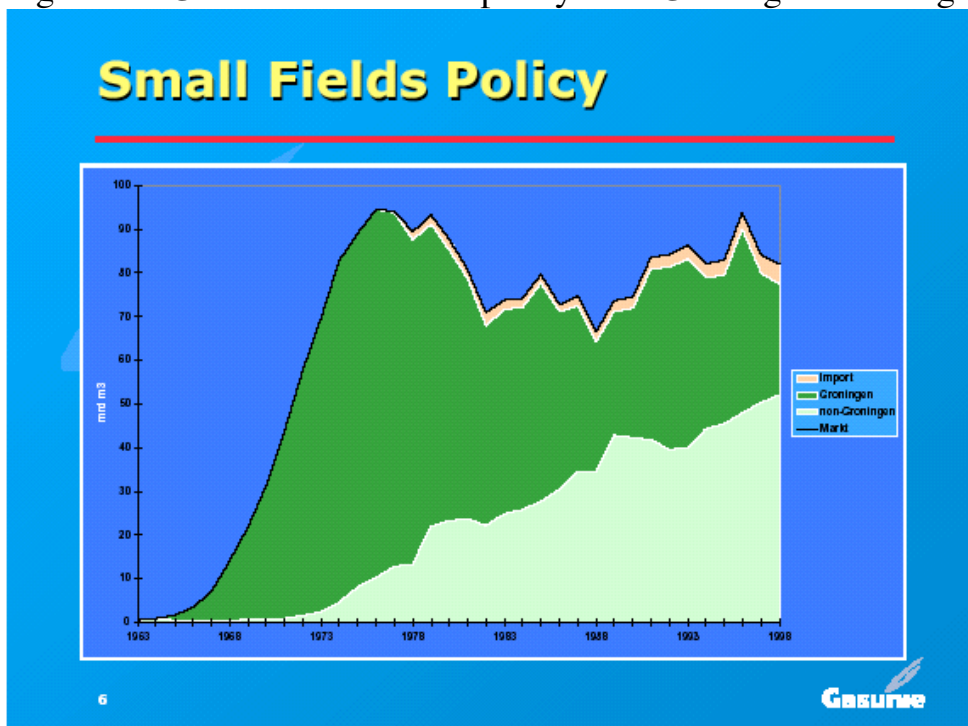
NITG-TNO 2002 has a forecast Groningen from 2002 to 2011 where the decline continues until 2004 and then with compression the production increases.
Figure 24: TNO forecast
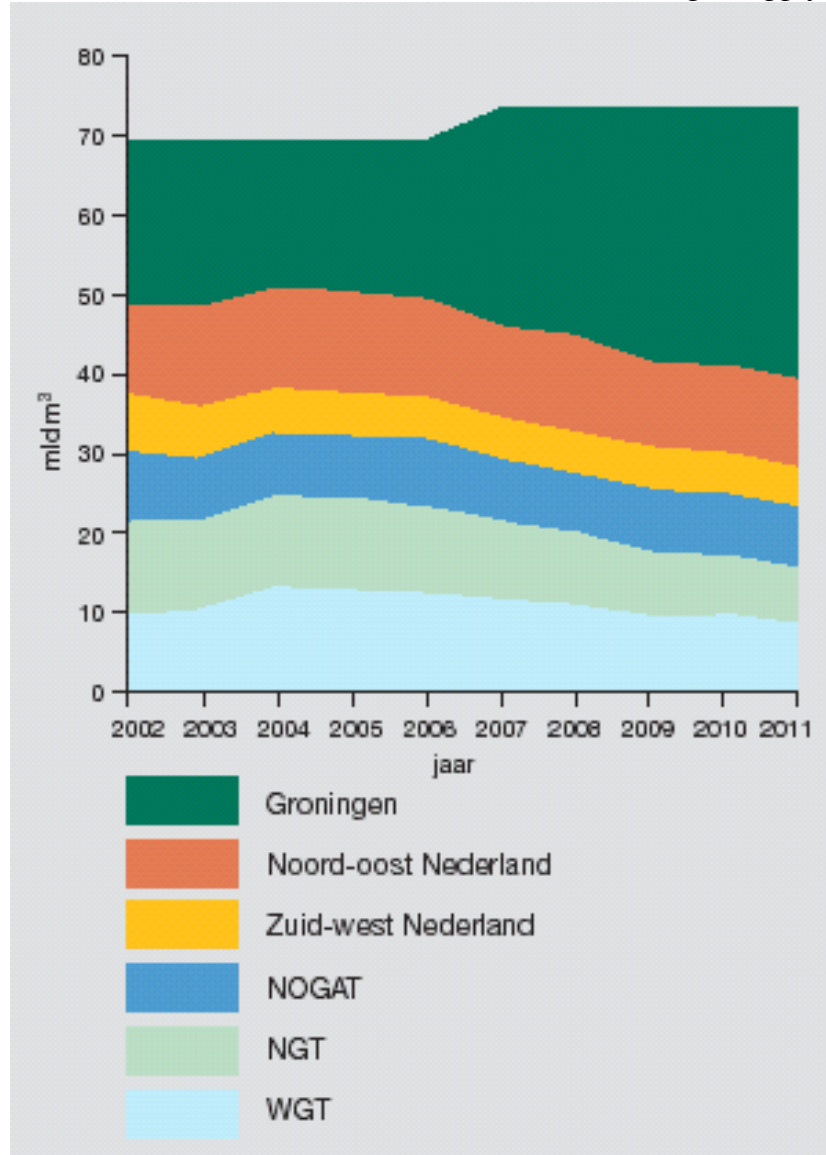
Gasunie (Bensdorp 2001) in his 2002-2020 forecast, distinguishes Groningen finishing around 2010 and Compression Groningen starting in 2002. Both productions give a slight decline until 2010 and a higher decline after. The graph is titled "conceptual" but I guess that the values are Gasunie values.

Figure 25: Groningen compression project
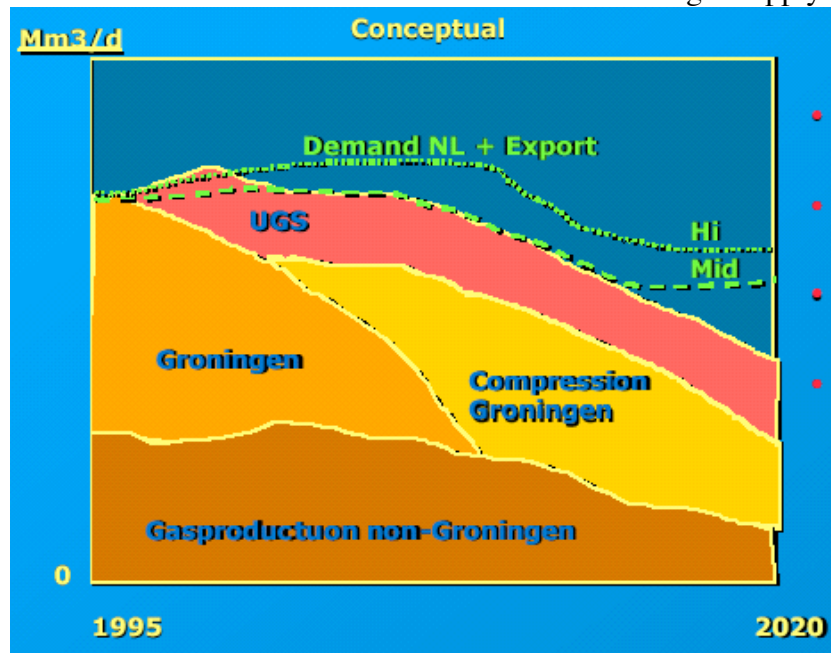
The gas creaming curve is difficult to model because Groningen is a King, which disturbs the gas plot. Even when excluding Groningen the curve does not display the typical hyperbolic plot, as it includes a small part of a large Petroleum System covering mainly the offshore (the Palaeozoic gas system of the Anglo-Dutch basin (including also Germany see Laherrere, Perrodon & Campbell 1996) where the full Gas System was estimated with an ultimate of 260 Tcf (with 760 gasfields discovered up to1996).

The creaming curve is modelled with 4 cycles, and if there is not a new cycle (where could it be?), the ultimate will be around 170 Gb

Figure 26: Netherlands creaming curve
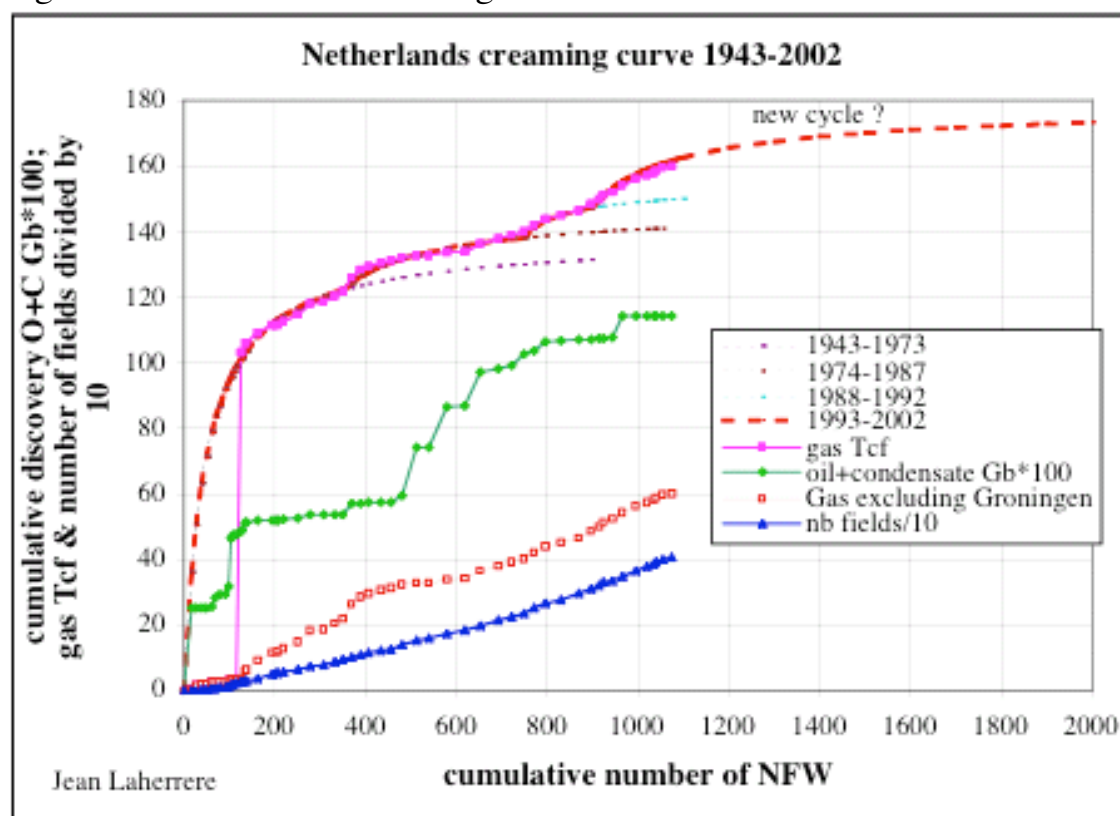
The cumulative discovery and production versus time can be modelled with 2 logistic curves plus adding 100 Tcf (Groningen) in 1959 for an ultimate of 170 Tcf.

Figure 27: Netherlands NG cumulative discovery & production
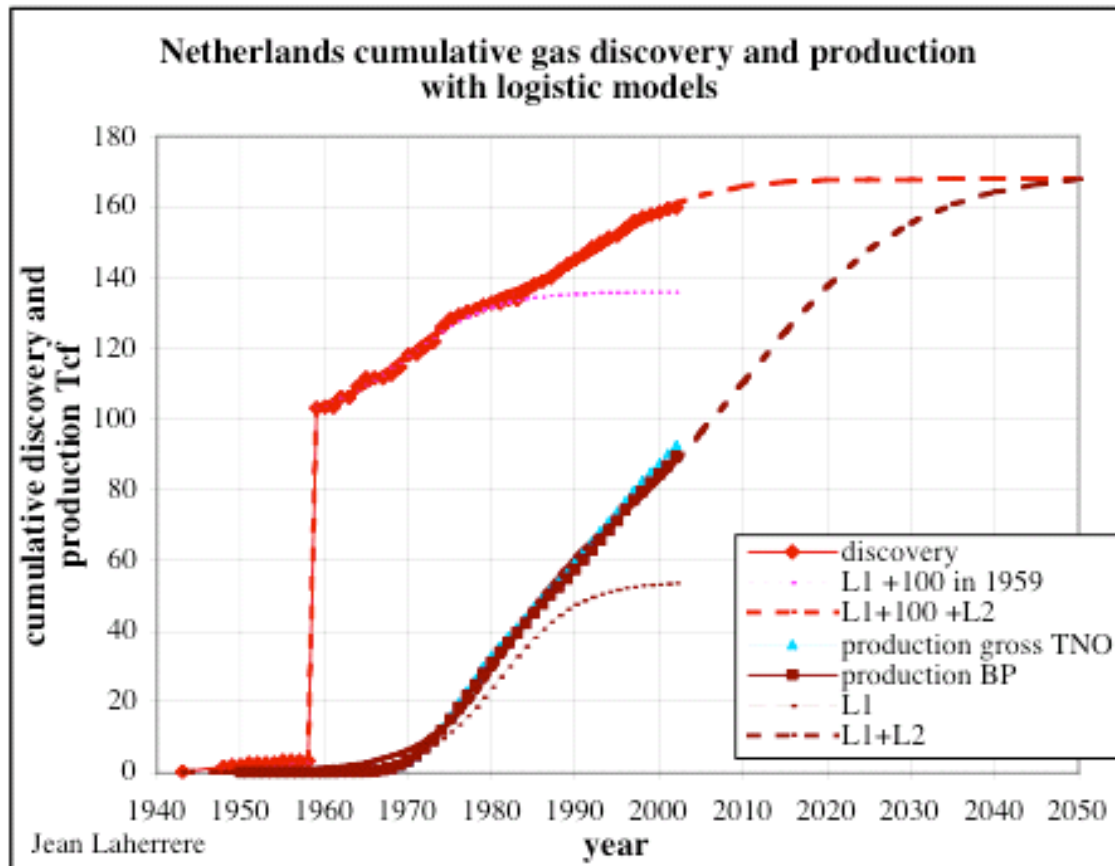
The reported data gives an ultimate of 170 Tcf, assuming that Groningen is about 100 Tcf, but it could be lower. Two future curves were drawn: one for 170 Tcf (considered as high) and the other for 150 Tcf (low).

As the discovery displays 3 cycles, the production is also modelled with 3 cycles of about same width.

Figure 28: Netherlands NG annual discovery & production

Netherlands natural gas discovery & production with model of 3 cycles

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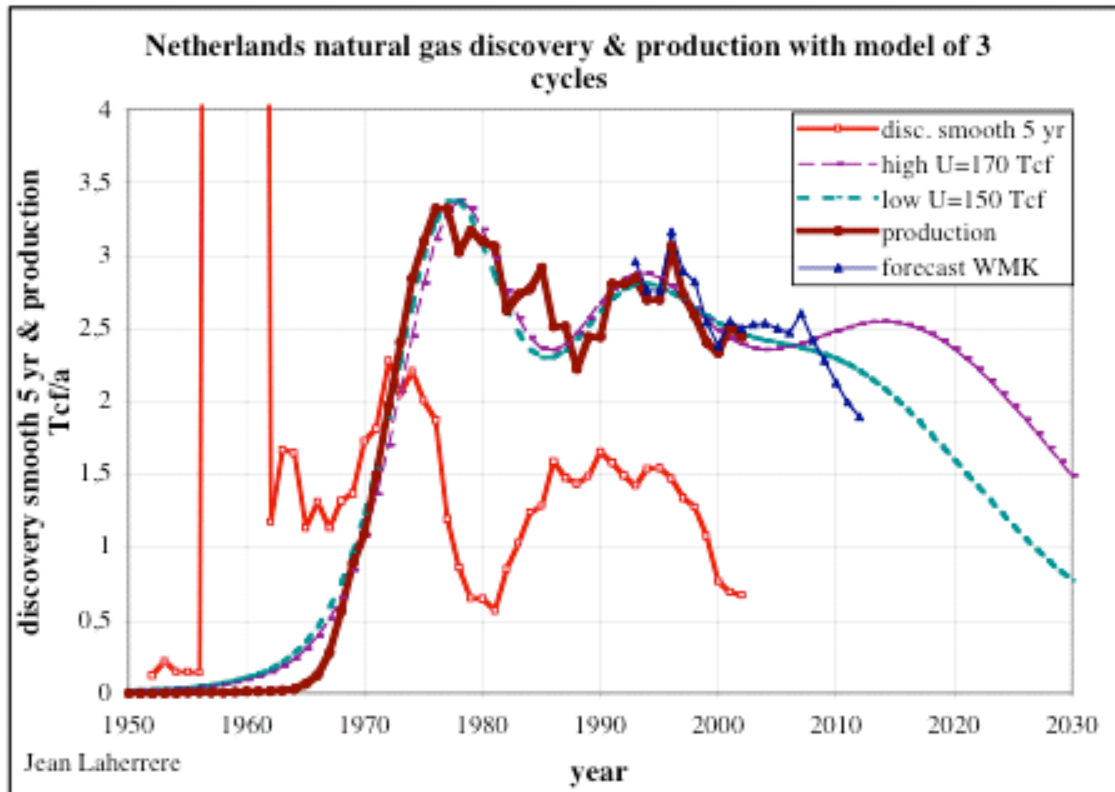
Zittel has a more pessimistic forecast because in his estimate of Groningen, his optimistic forecast (flat Groningen until 2020) is about our low one. His optimistic forecast for 2020 is 38 G.m3 or 1.3 Tcf to be compared to our forecast between 1.6 and 2.3 Tcf.
His most likely (declining Groningen) forecast is about 22 G.m3 (0.8 Tcf) in 2020.
It is important to check with Gasunie and TNO their contradictory forecasts.

-**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).
Figure 29:!UK NG remaining reserves from technical & political sources. As WM is 20 Tcf lower than IHS the cumulative.
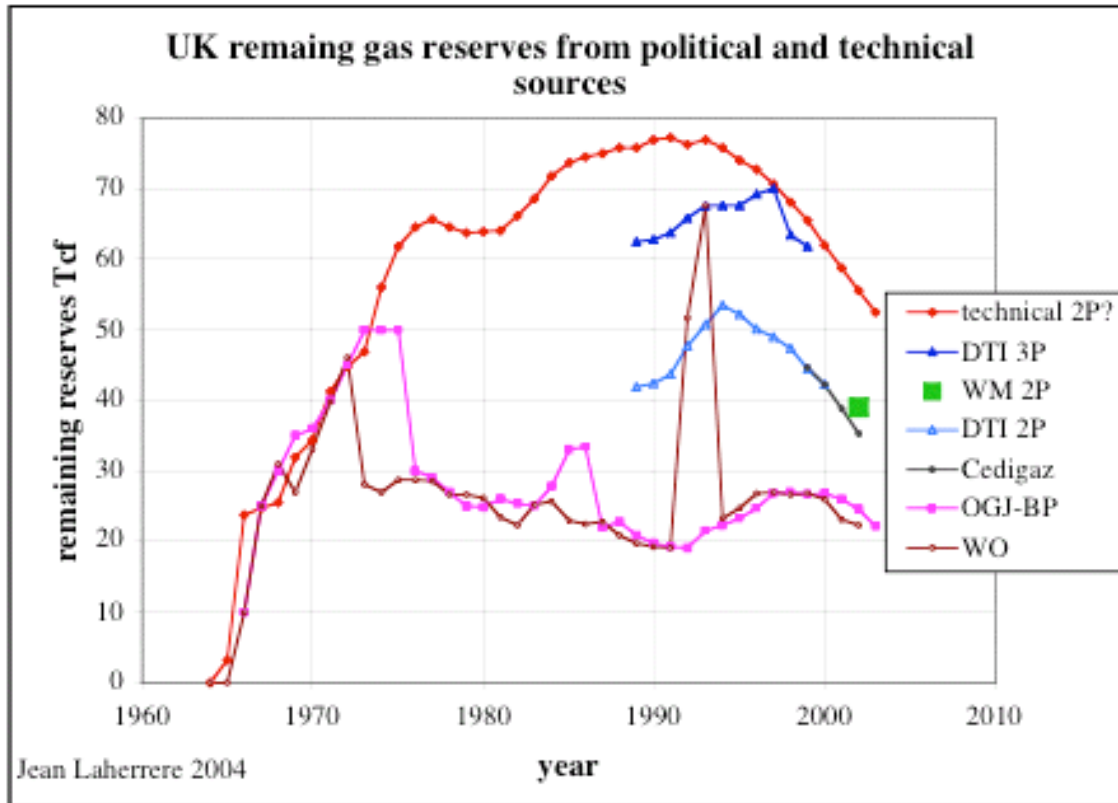
UK NG creaming curve is easily modelled with only one hyperbola.
Figure 30: UK creaming curve
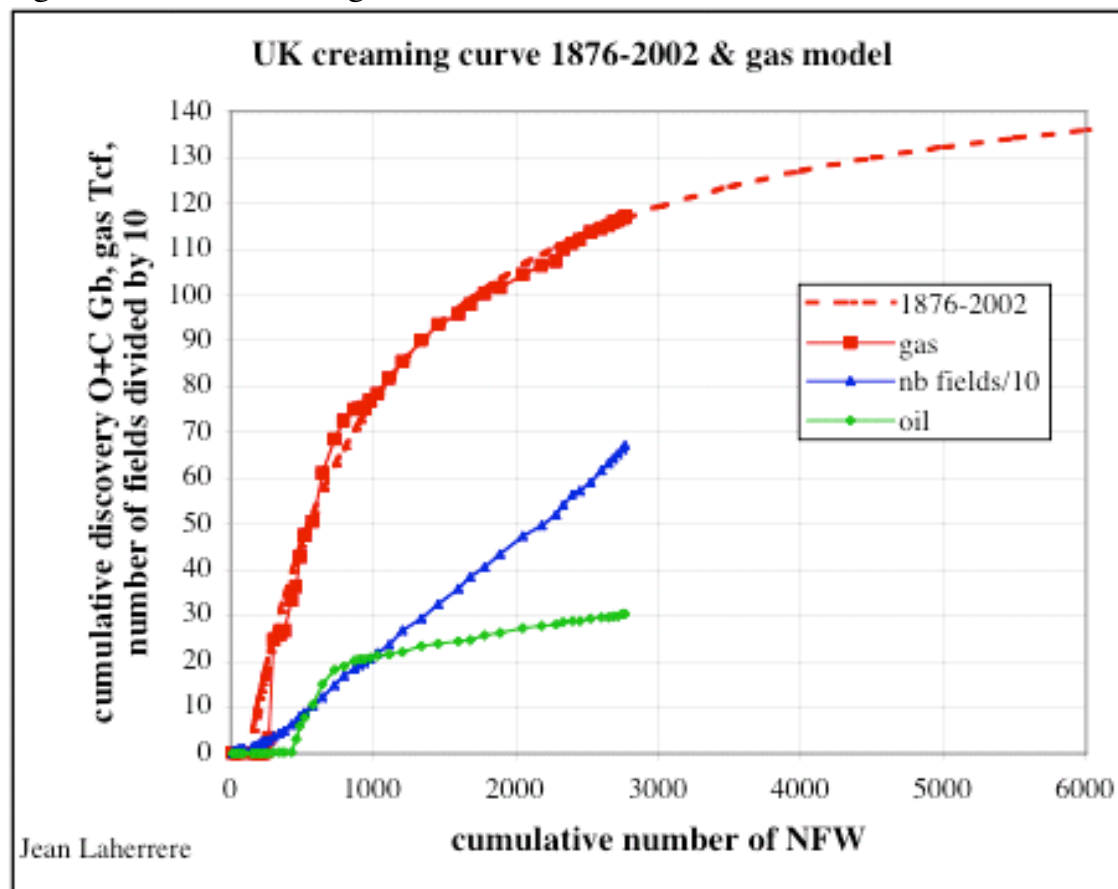
The cumulative discovery is not as easy to model because the stop and go of exploration up to 1980, but trends toward 125 Tcf.

Figure 31: UK NG cumulative discovery & production
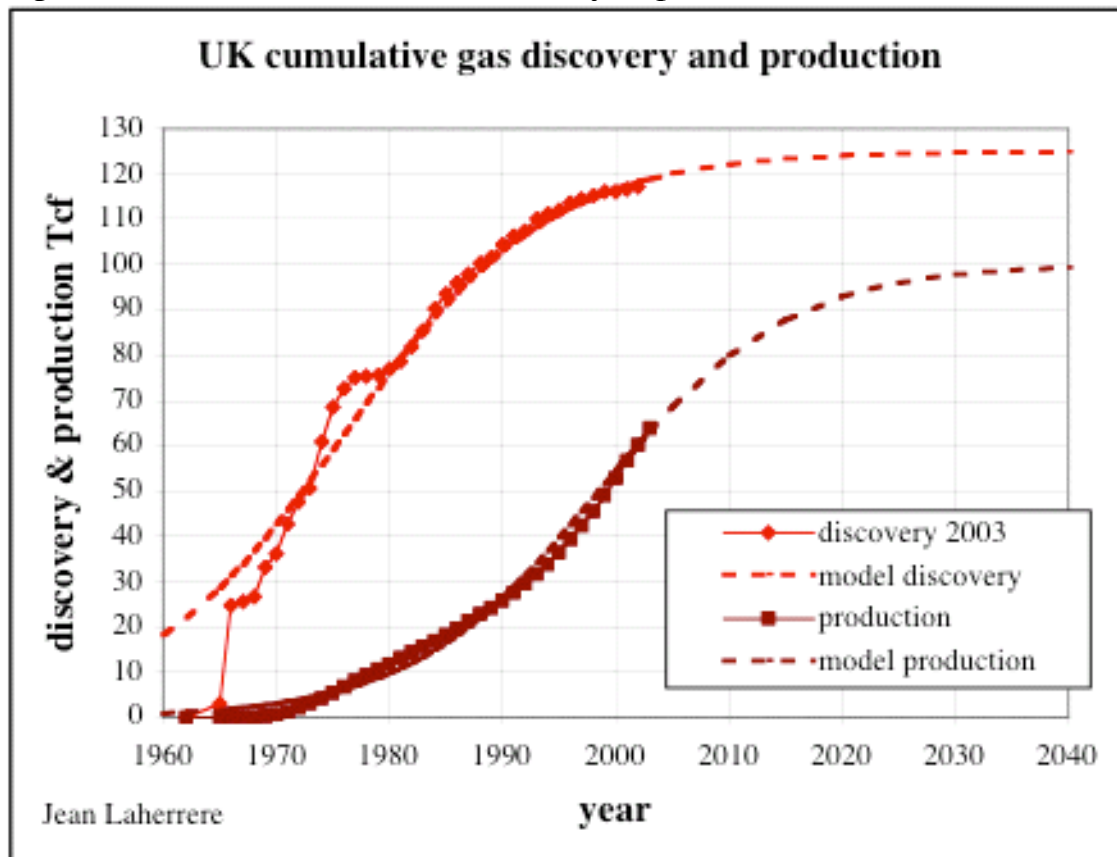
As for Netherlands, the IHS gas reserves seem to have been overestimated (close to the 3P from DTI), our forecast is 100 Tcf when the creaming curve gives about 125 Tcf, since WM total discovery is 20 Tcf lower.
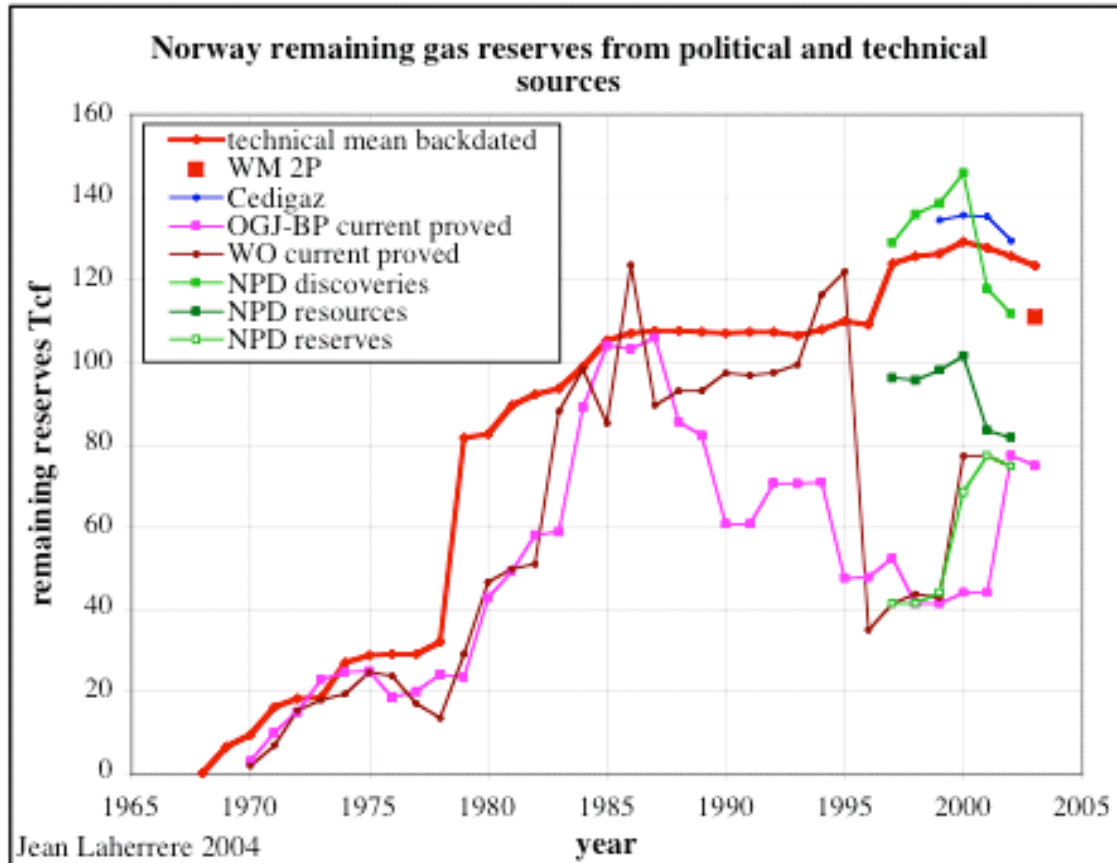
Figure 32: UK NG annual discovery & production
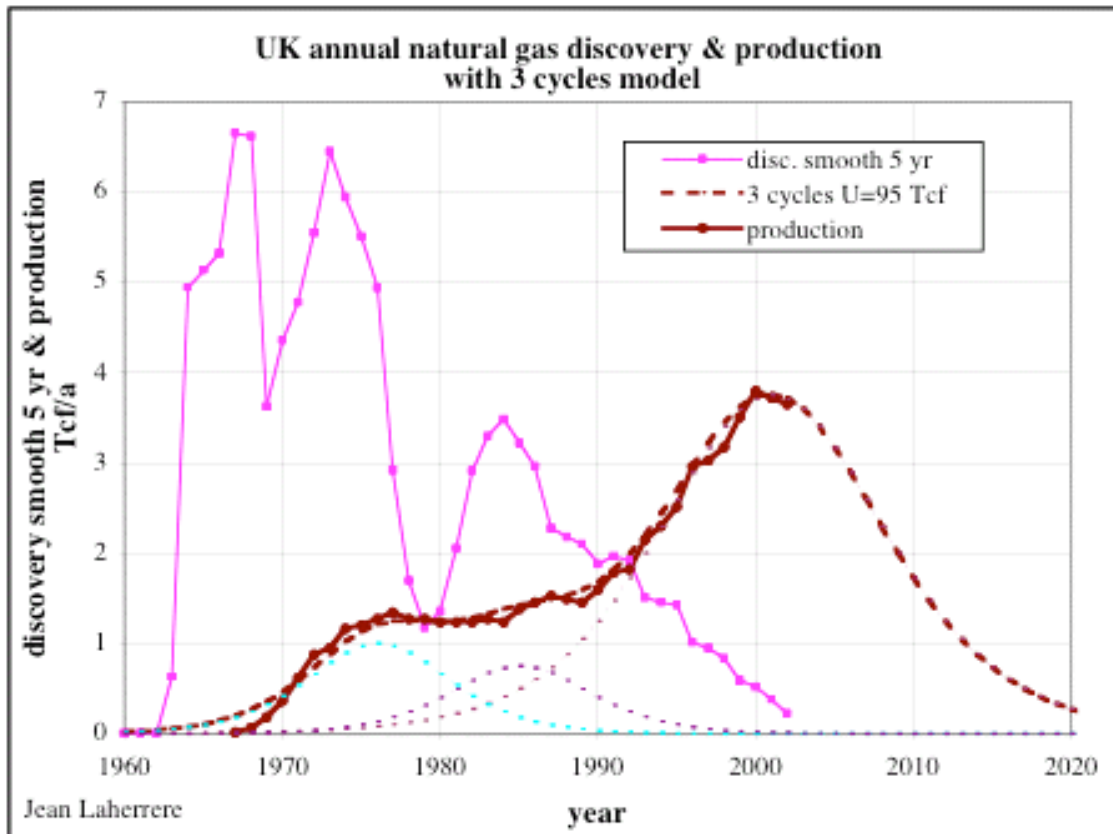
-Norway
Again Norway is the best country for reserve classification and publishes field reserves, discarding the proved values, however political values are chaotic between OGJ and WO. WM is 15 Tcf lower than IHS.
Figure 33: Norway NG remaining reserves from technical & political sources

Creaming curve can be modelled with 3 cycles and a new cycle could be left (Barentz sea?).
The ultimate is about 170 Tcf.
Figure 34: Norway NG creaming curve
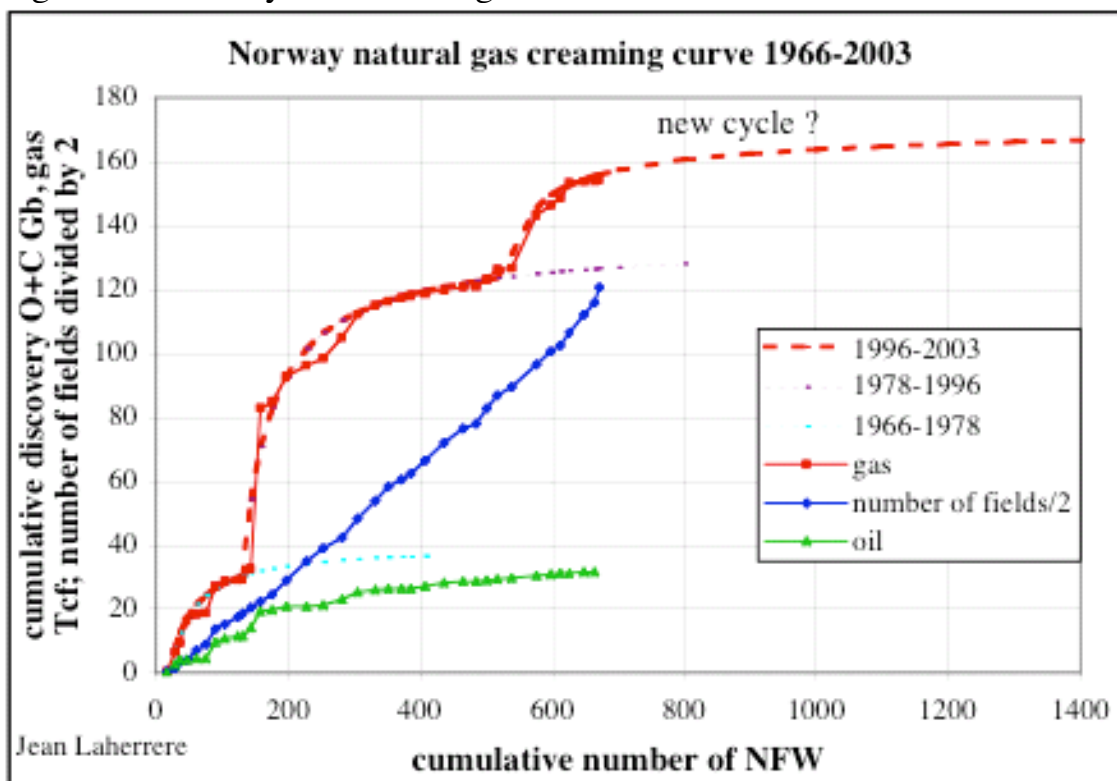
The cumulative discovery versus time is, as usual, not as easy to model as the creaming curve.

Figure 35: Norway NG cumulative discovery & production
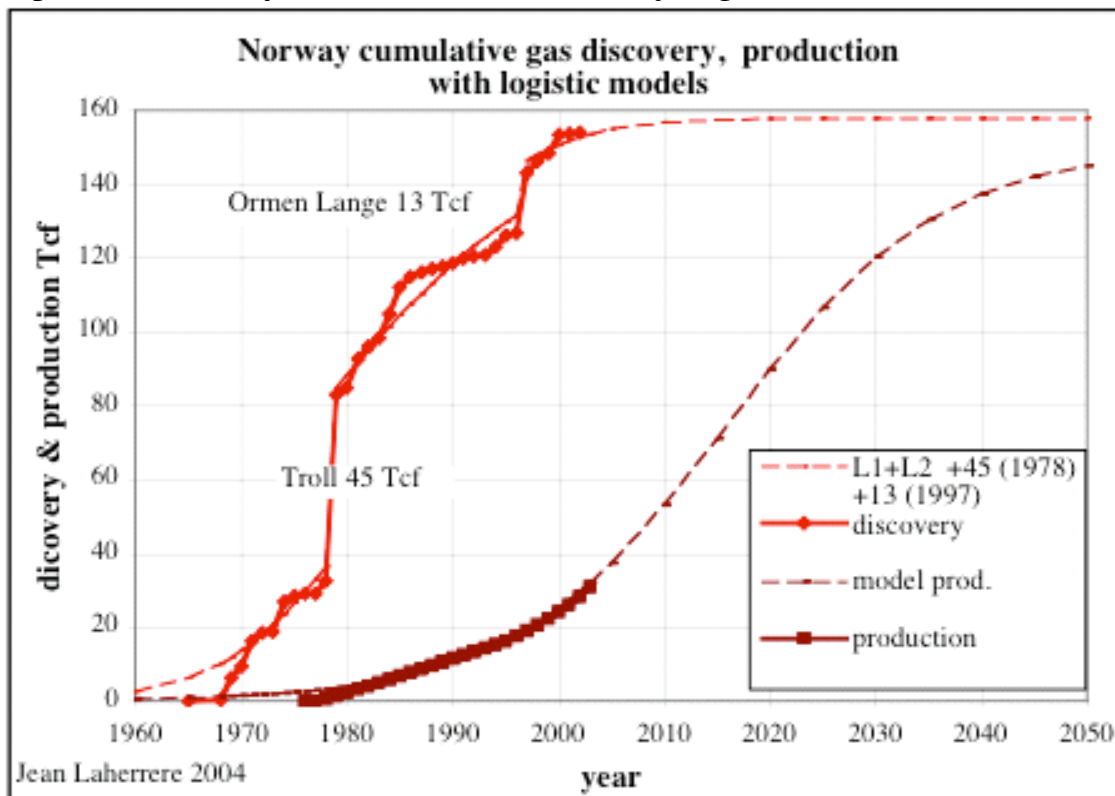
The annual production is modelled with an ultimate of 150 Tcf (lower than the ultimate from IHS values) and will peak around 2015 at 5 Tcf/a. The NPD forecasts vary (OGJ 3 May 2004) with a plateau at 4 Tcf/a from 2010 to 2035, but Sondena (2002) was estimating a peak in 2010 at 4 Tcf/a.

Figure 36: Norway NG annual discovery & production
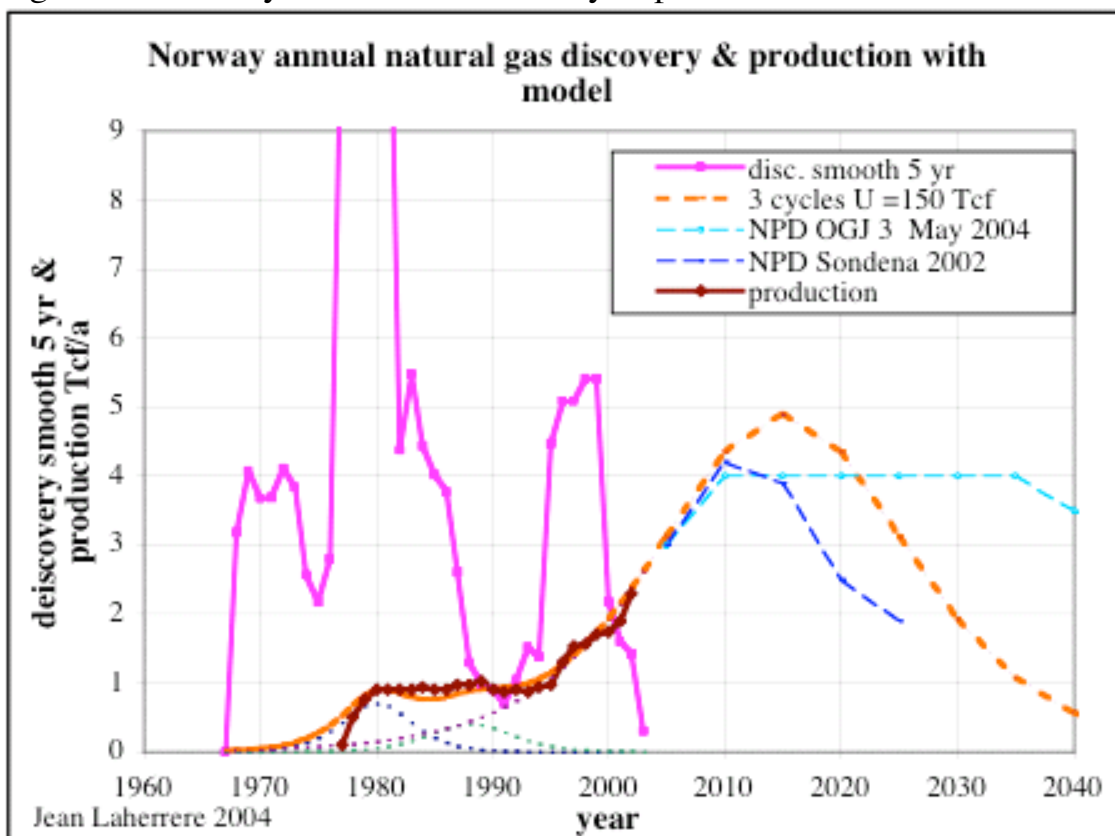
-**Germany**
Again chaotic political current proved remaining reserves, and WM is 4 Tcf lower than IHS.
Figure 37:!Germany NG remaining reserves from technical & political sources
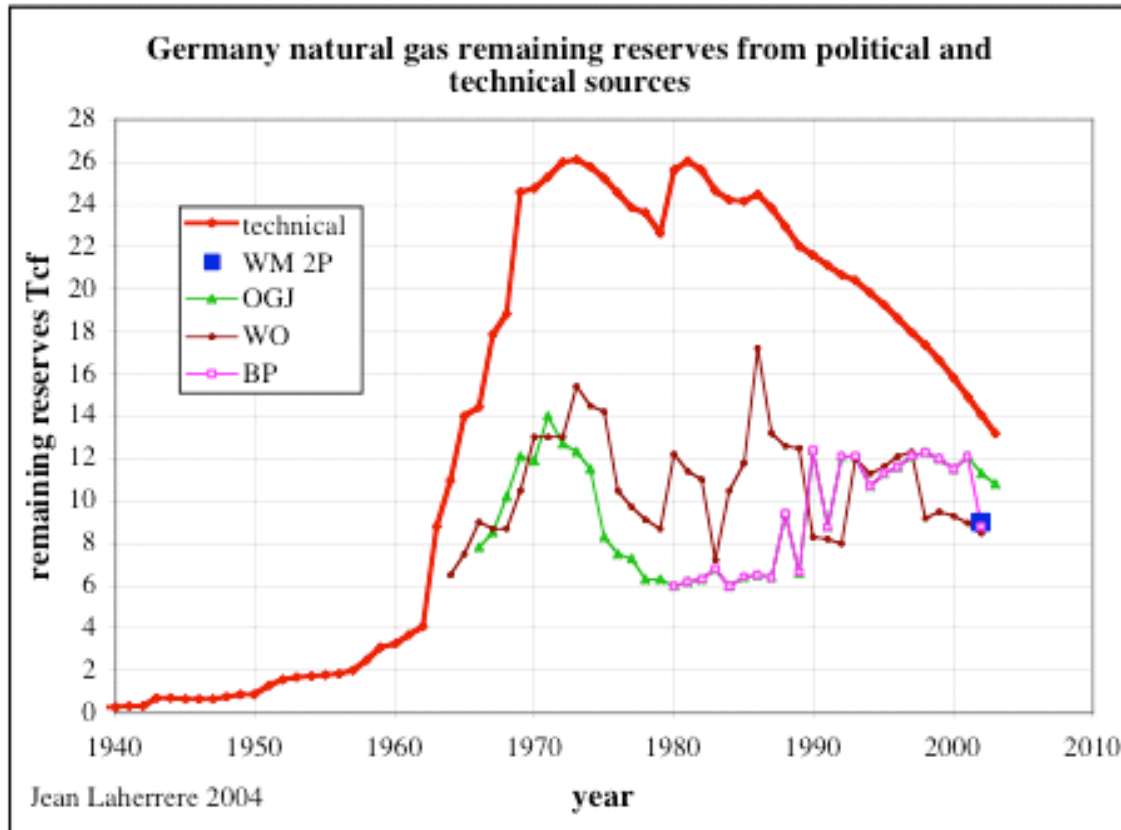
The NG creaming curve from 1856 to 2003 is modelled with 3 cycles for an ultimate of 50 Tcf.
Figure 38: Germany creaming curve
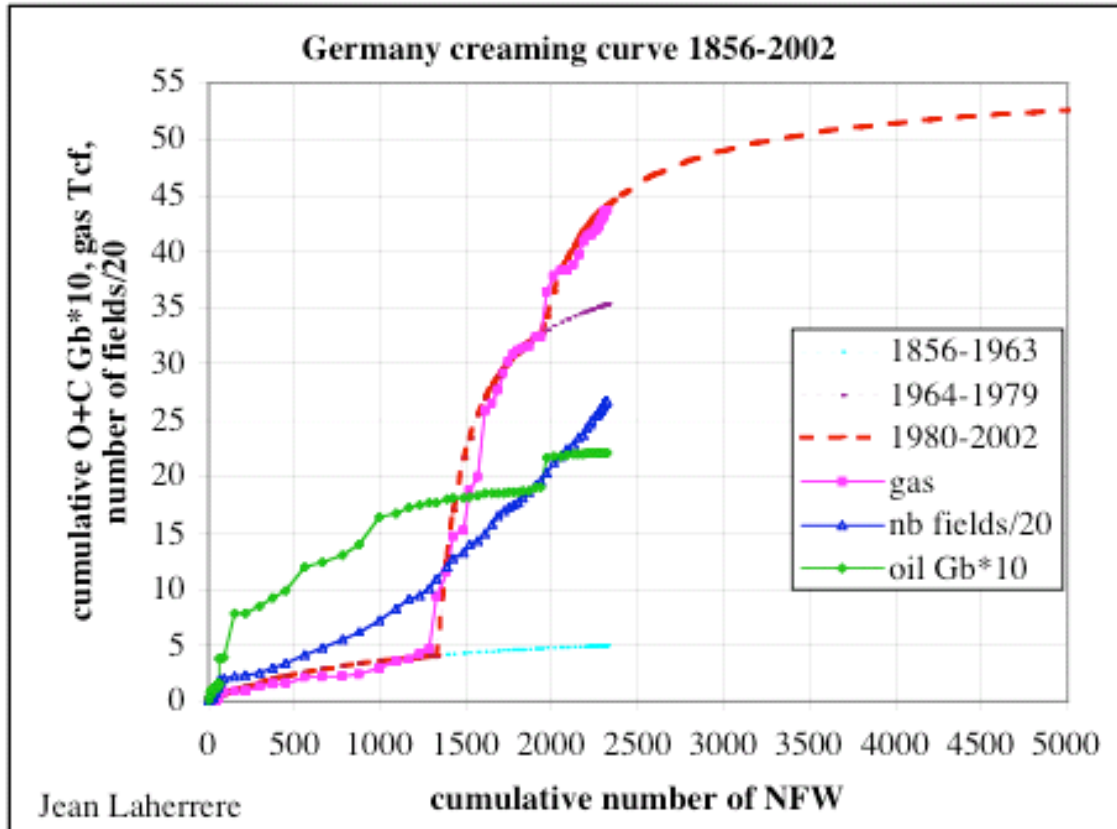
The cumulative discovery versus time is more flat towards about 45 Tcf and the production is modelled with an ultimate of 40 Tcf
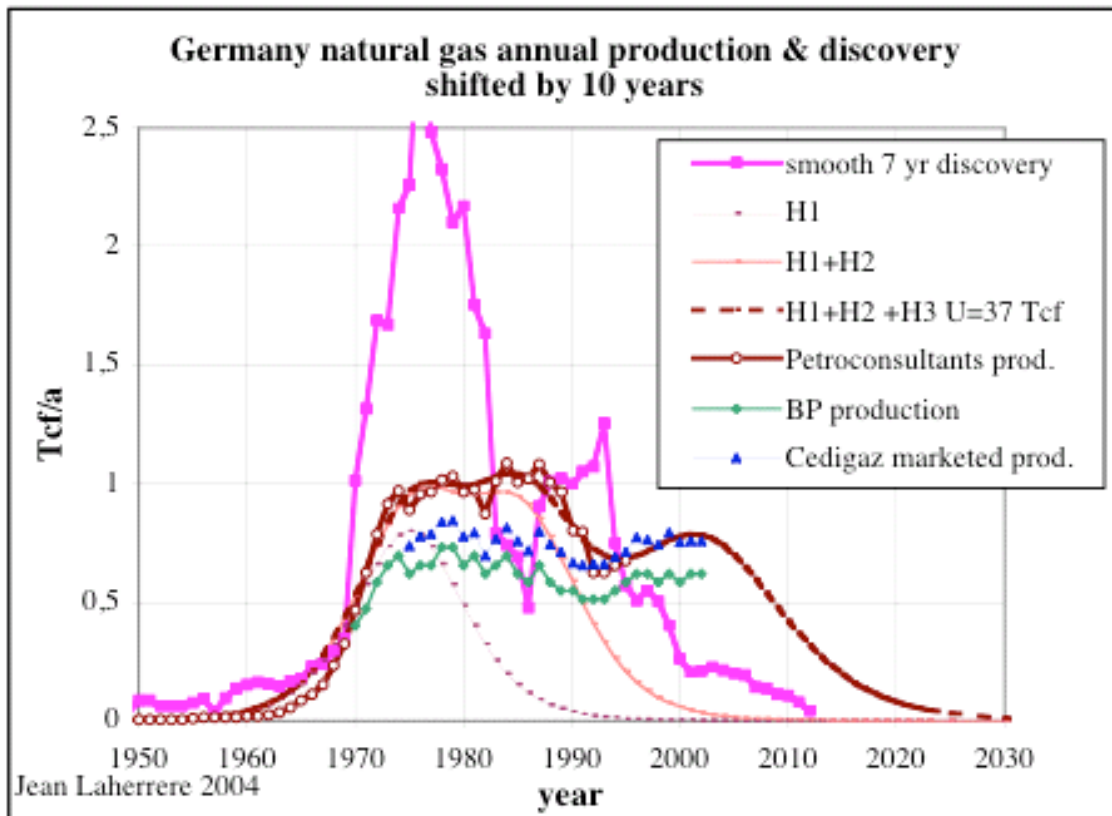
Figure 39: Germany NG cumulative discovery & production
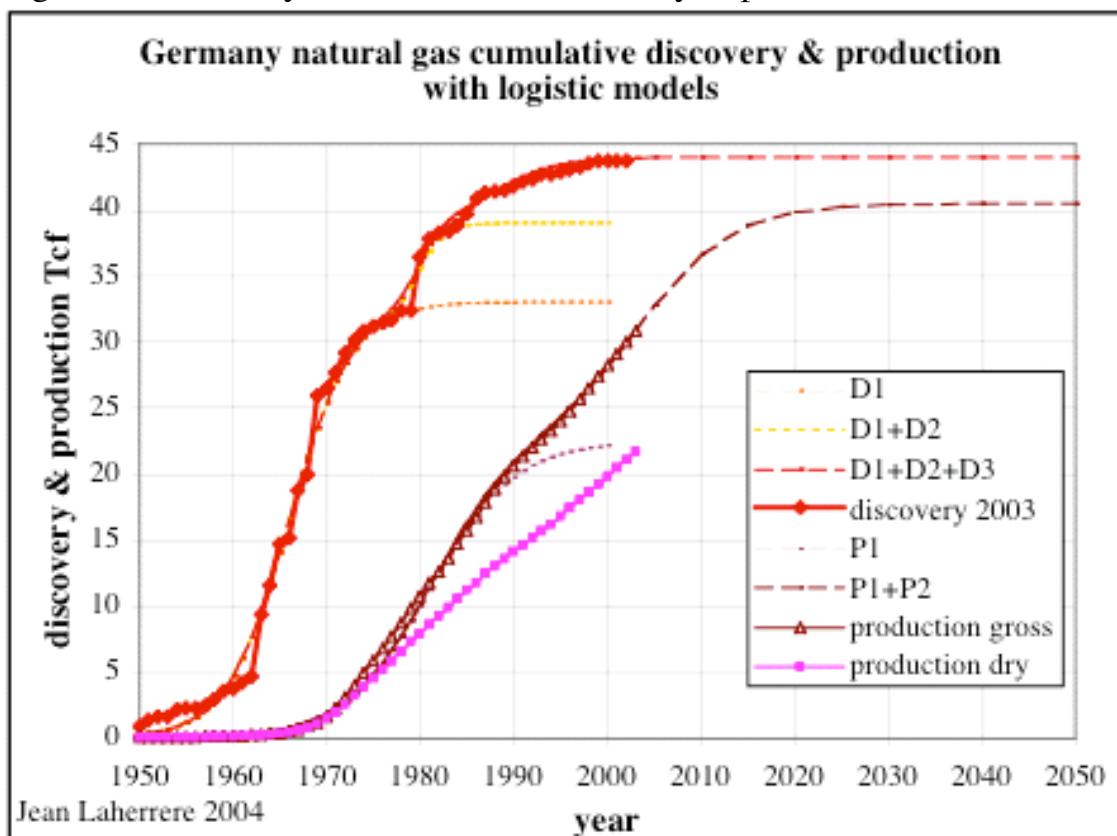
The annual production displays a discrepancy between Cedigaz and Petroconsultants data. The forecast is for a peak now and a sharp decline coming.
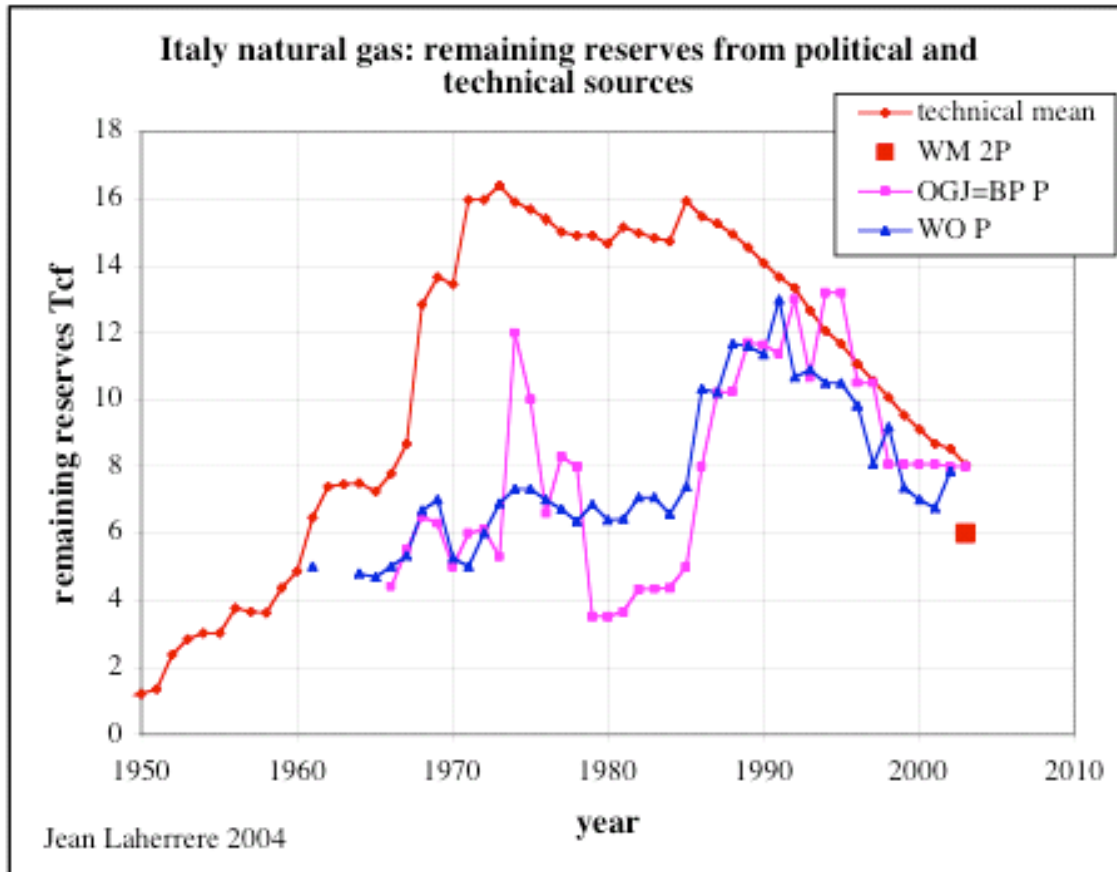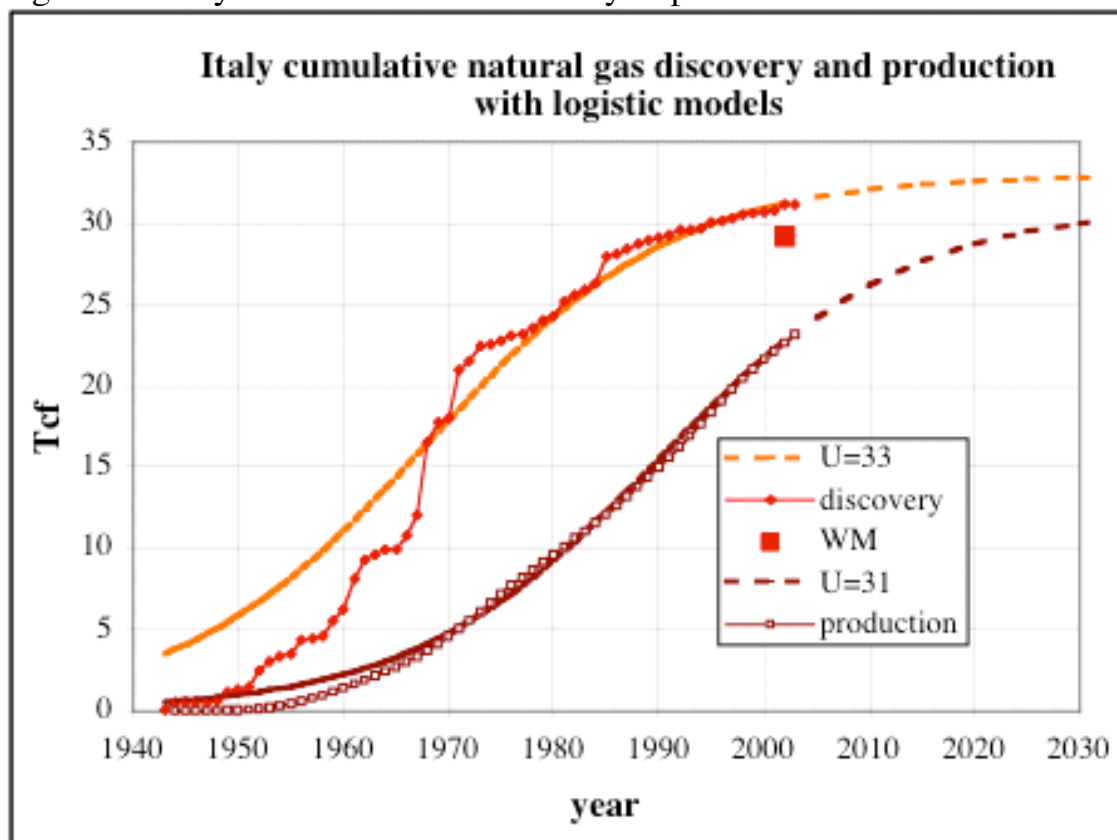
Figure 40: Germany NG annual discovery & production

-Italy
Chaotic and different political values from OGJ and WO. WM is 2 Tcf lower.
Figure 41: Italy NG remaining reserves from technical & political sources

Cumulative discovery versus time trends to 33 Tcf and production towards 31 Tcf
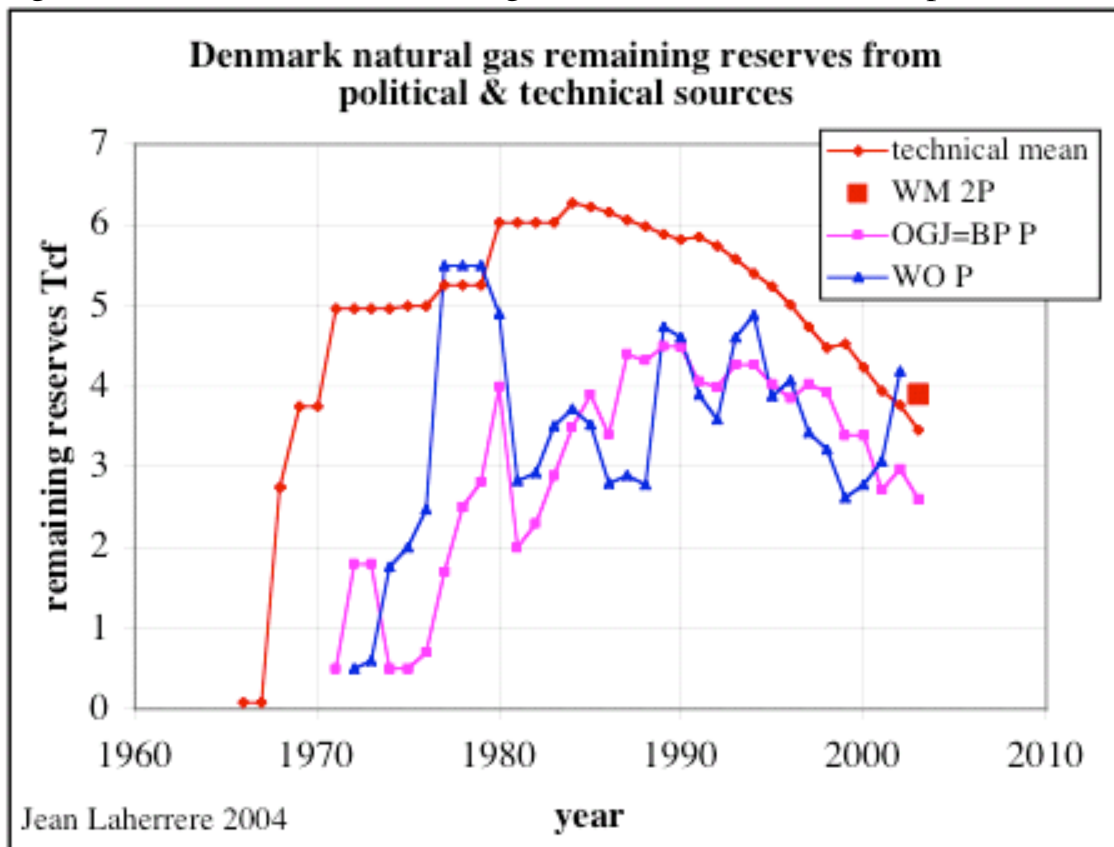Figure 42: Italy NG cumulative discovery & production

The annual production peaked in1995 and will continue to decline.
Figure 43: Italy NG annual discovery & production

Italy natural gas annual discovery & production
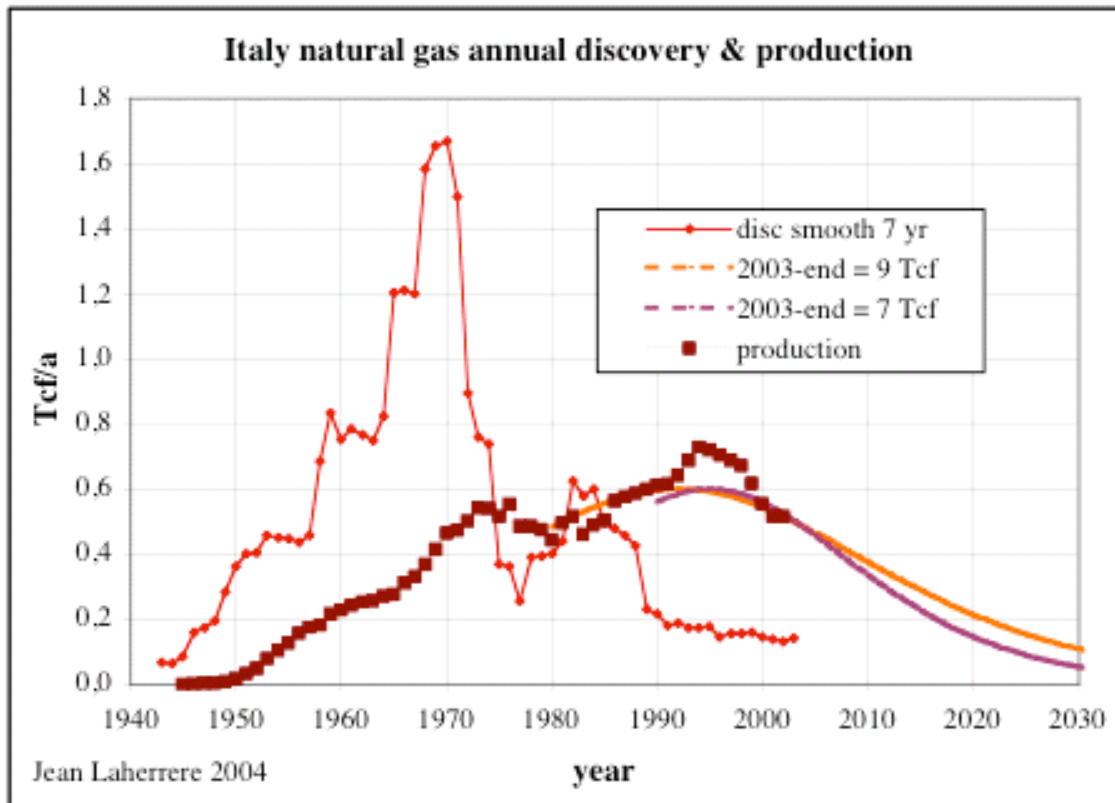
-**Denmark**
OGJ and WO are chaotic as usual, but for once WM is higher than IHS
Figure 44: Denmark NG remaining reserves from technical & political sources
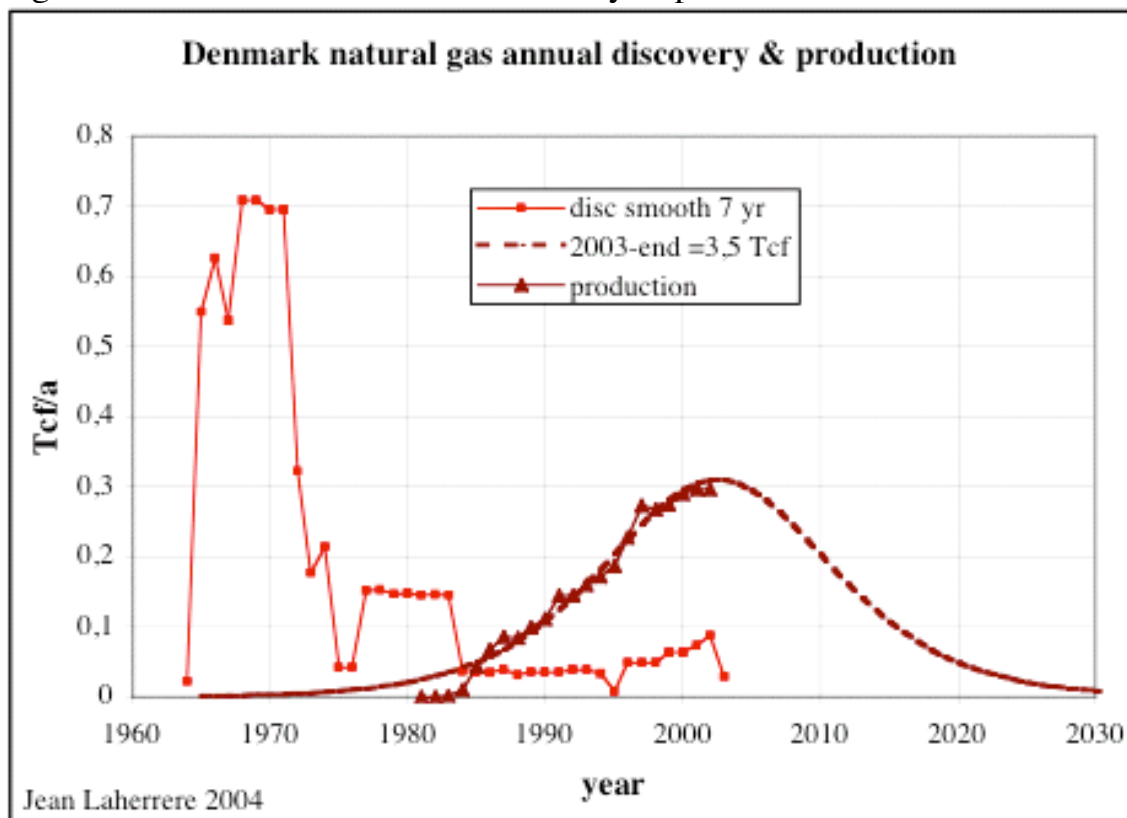

Denmark natural gas remaining reserves from political & technical sources

Cumulative discovery is close to an ultimate of around 7 Tcf.

Figure 45: Denmark NG cumulative discovery & production
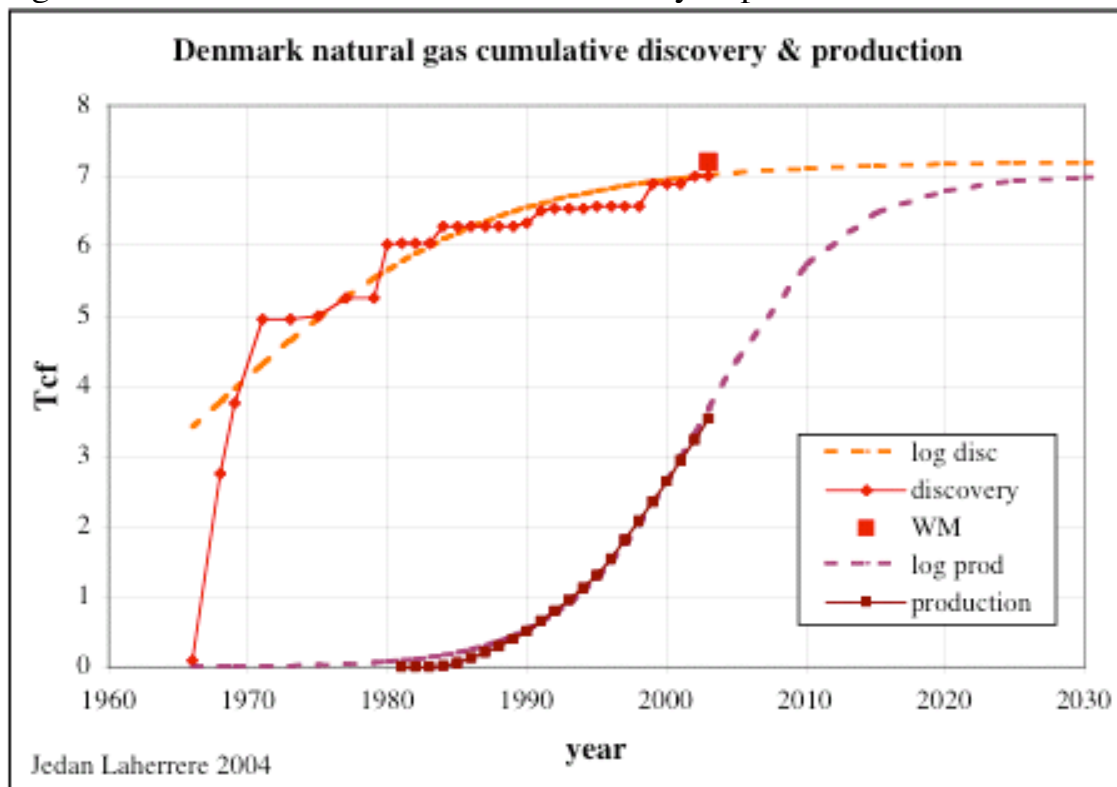
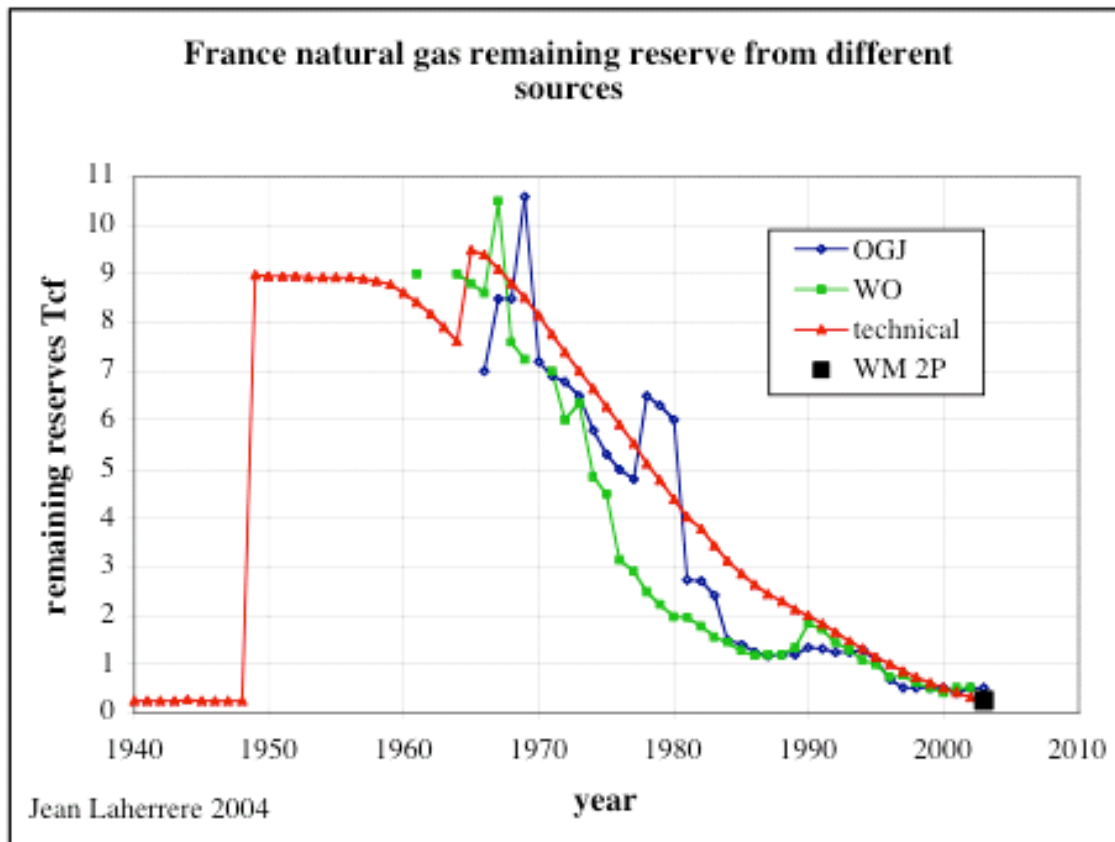Denmark NG production is peaking now and will decline slowly just like it rose

Figure 46: Denmark NG annual discovery & production
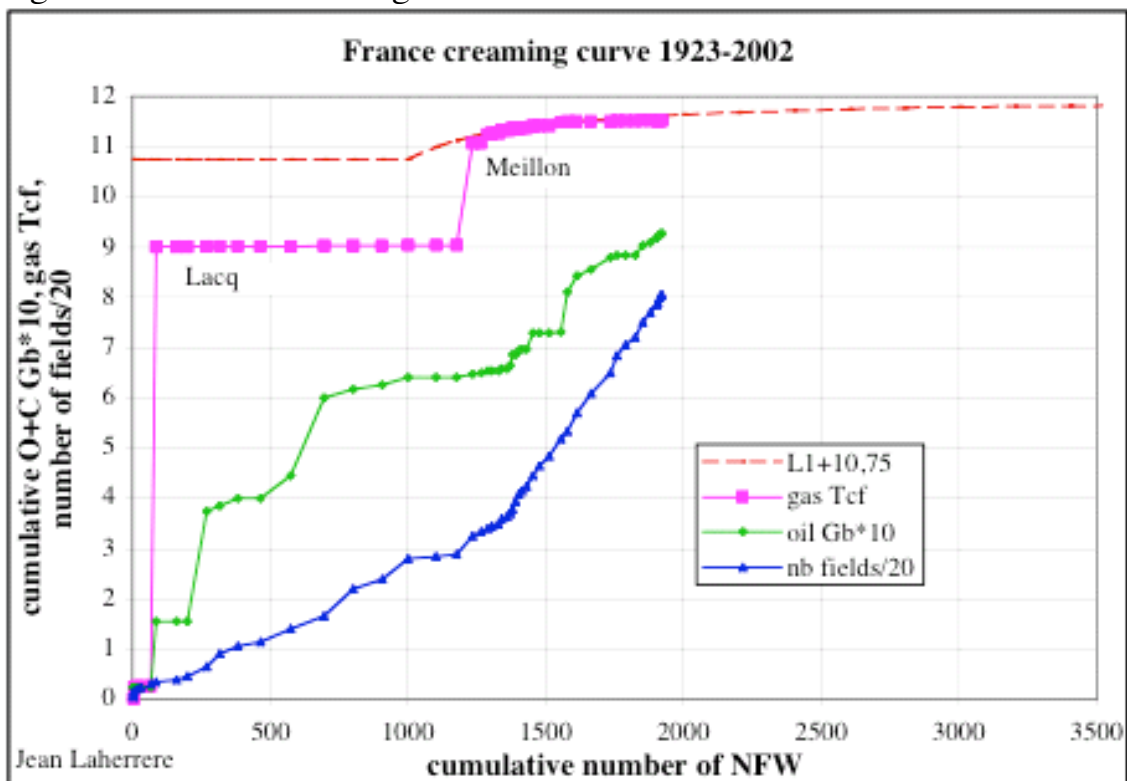

-**France**

France NG remaining reserves are trending to zero, and political and technical data agree on it.

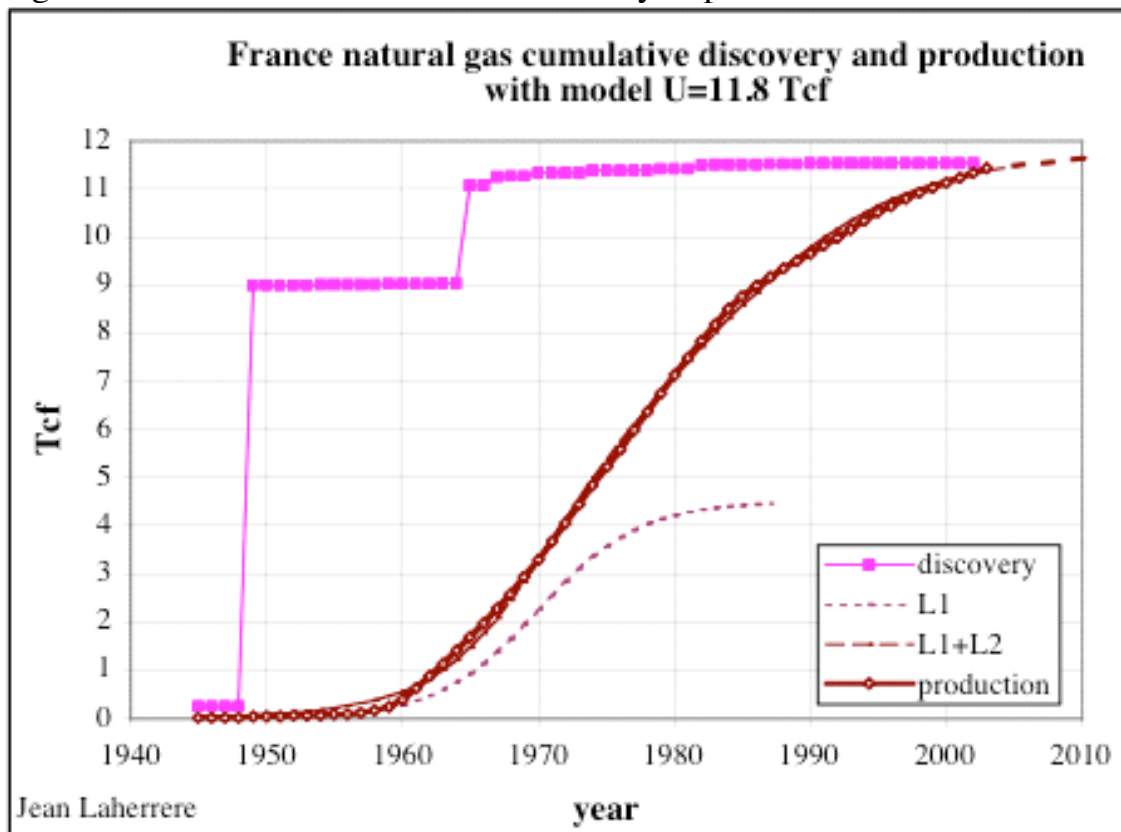Figure 47: France NG remaining reserves from technical & political sources

The creaming curve is disturbed with two large gasfields Lacq and Meillon

Figure 48: France creaming curve

Cumulative production is close to cumulative discovery.

Figure 49: France NG cumulative discovery & production

France is a good example of an almost depleted gas producer. Last month coal reserves went down to nil as the last coal mine was closed down.

Annual discovery displays two peaks when annual production can be modelled with 5 cycles.

Figure 50: France NG annual discovery & production
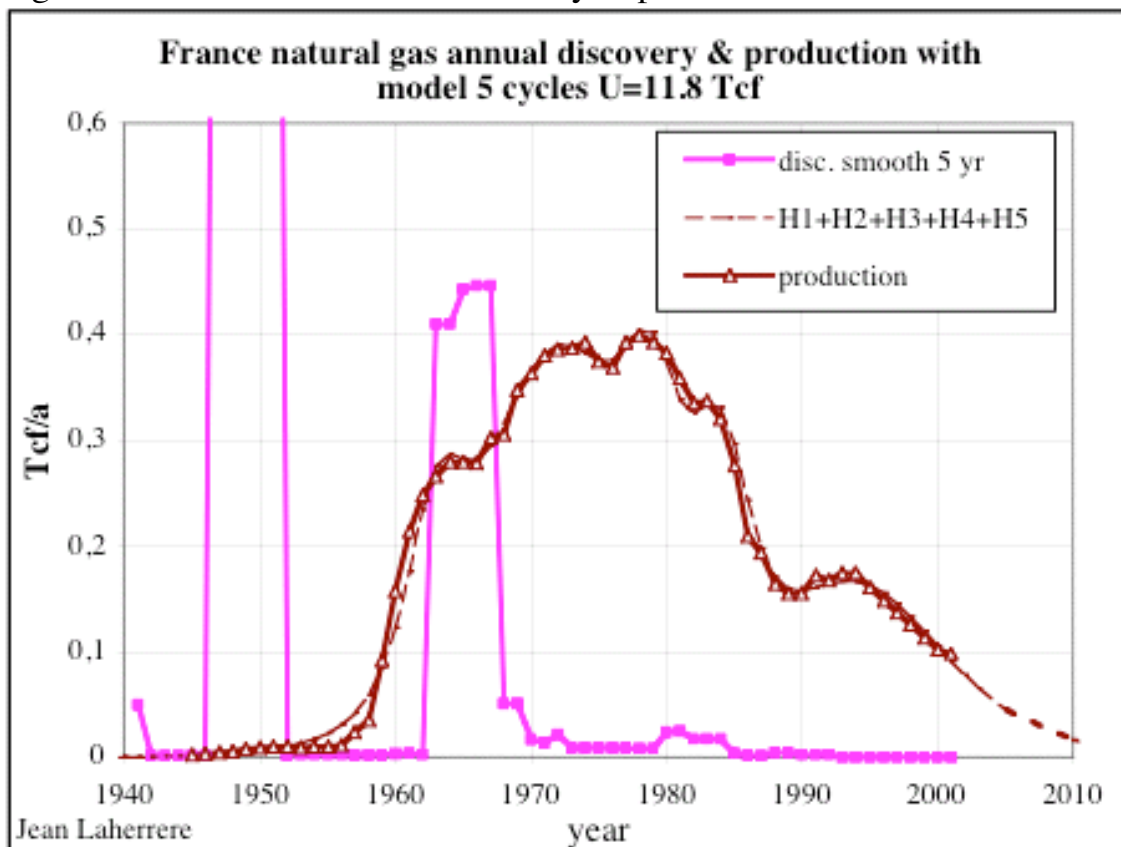
EIA for France reports gas production at 0,067 Tcf for 2001 as being for gross and dry (http://www.eia.doe.gov/emeu/world/country/cntry_FR.html) but Cedigaz reports a gross production of 0,098 Tcf and a marketed production of 0,067 Tcf, the difference being losses other than flaring & vented and recycling. In this total coalbed methane seems to be included. The French government (DGEMP) forecasts a gas consumption in 2020 of 220 % the 2001 consumption, giving an increase much larger than the world forecast, which is only 160% when my forecast is 150%.

Figure 51: DGEMP NG consumption forecast
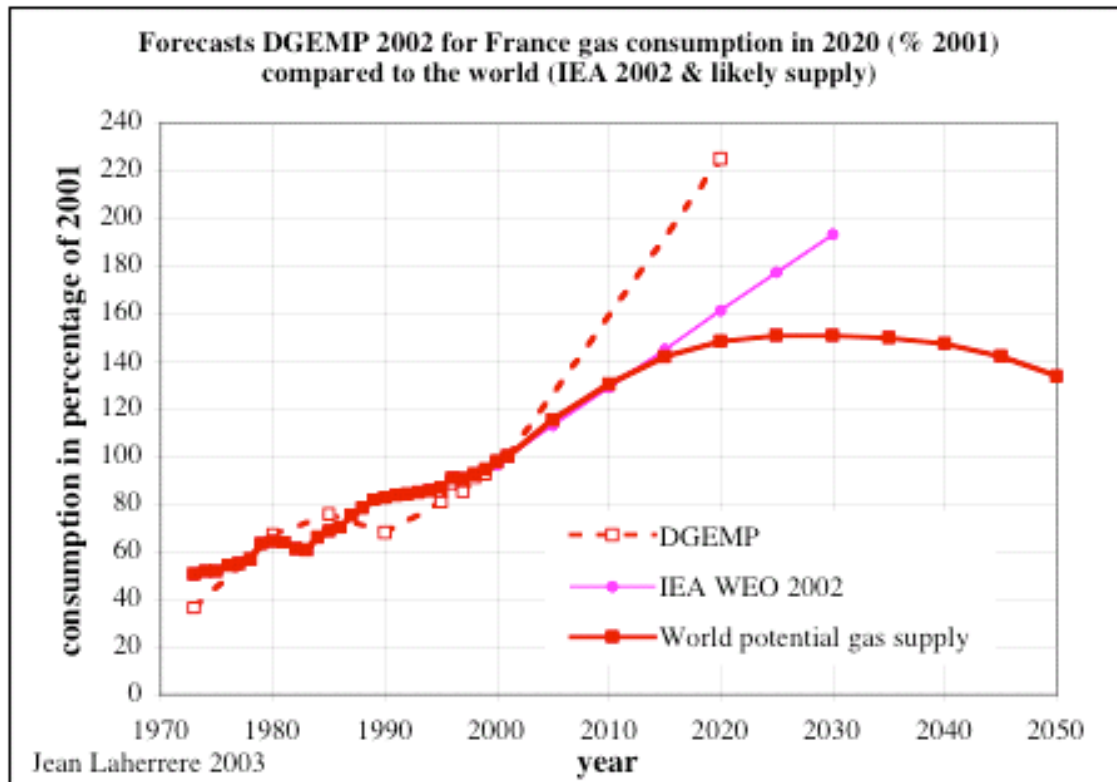
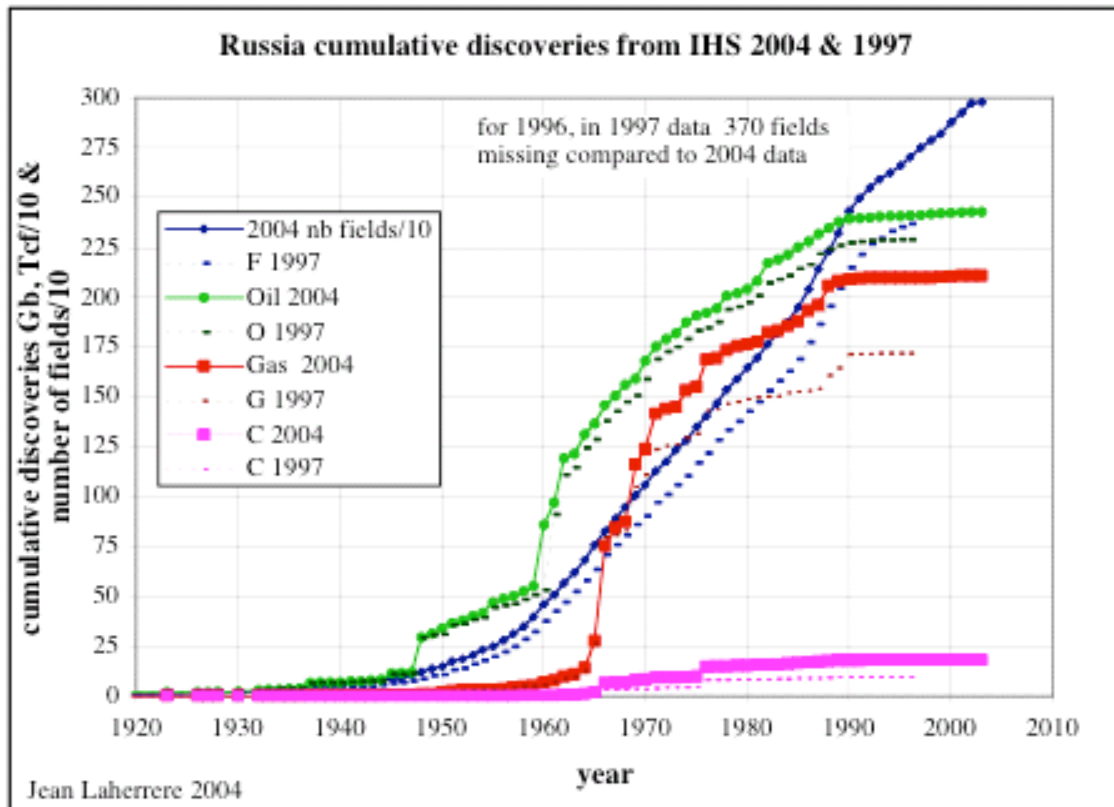-**CIS**

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 their computers, being still on paper and untranslated. This kind of reserve growth is mainly due to incomplete records.

Figure 52: Russia cumulative discoveries from IHS 1997 & 2004

Russia cumulative discoveries from IHS 2004 & 1997

for 1996, in 1997 data 370 fields missing compared to 2004 data

Jean Laherrere 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 are about 2000 Tcf against 1100 Tcf for the technical reserves. WM reports about 1500 Tcf and HIS 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 53: CIS NG remaining reserves from technical & political sources
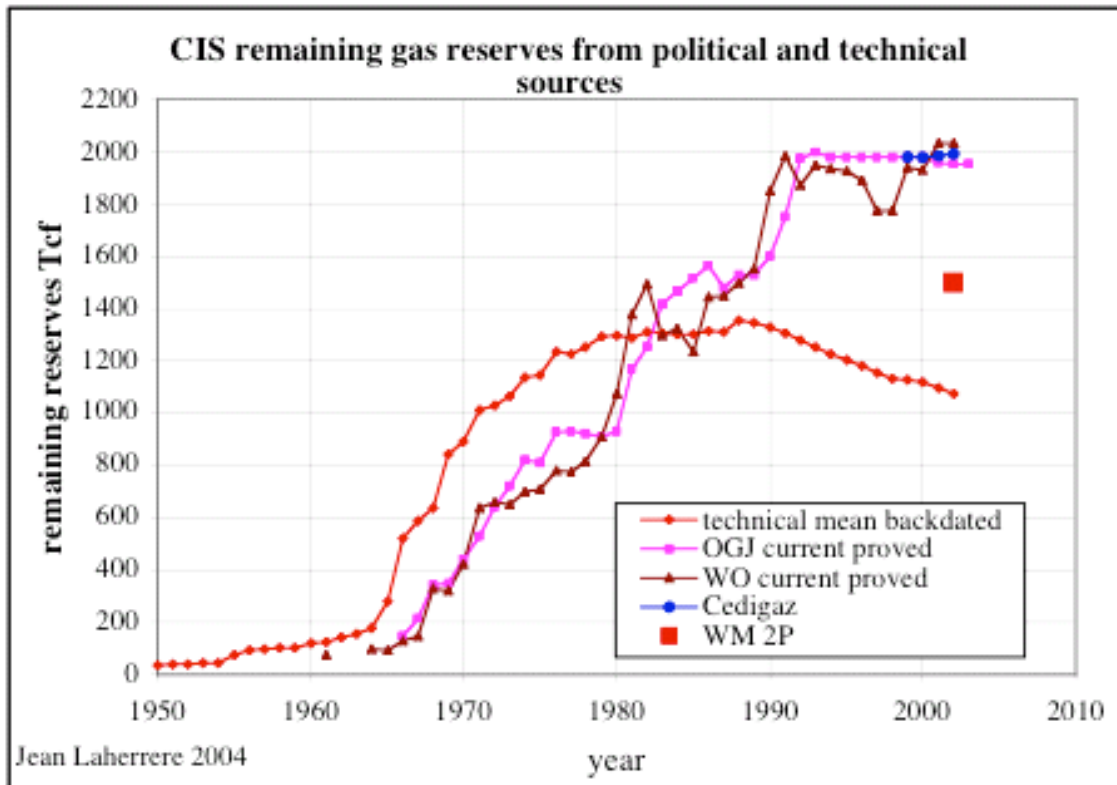
BP Review and Cedigaz production data are very close. Russian production has remained flat since 1990 when Turkmenistan fell from 1991 to 1998.

Figure 54: FSU gas production from BP Review and Cedigaz
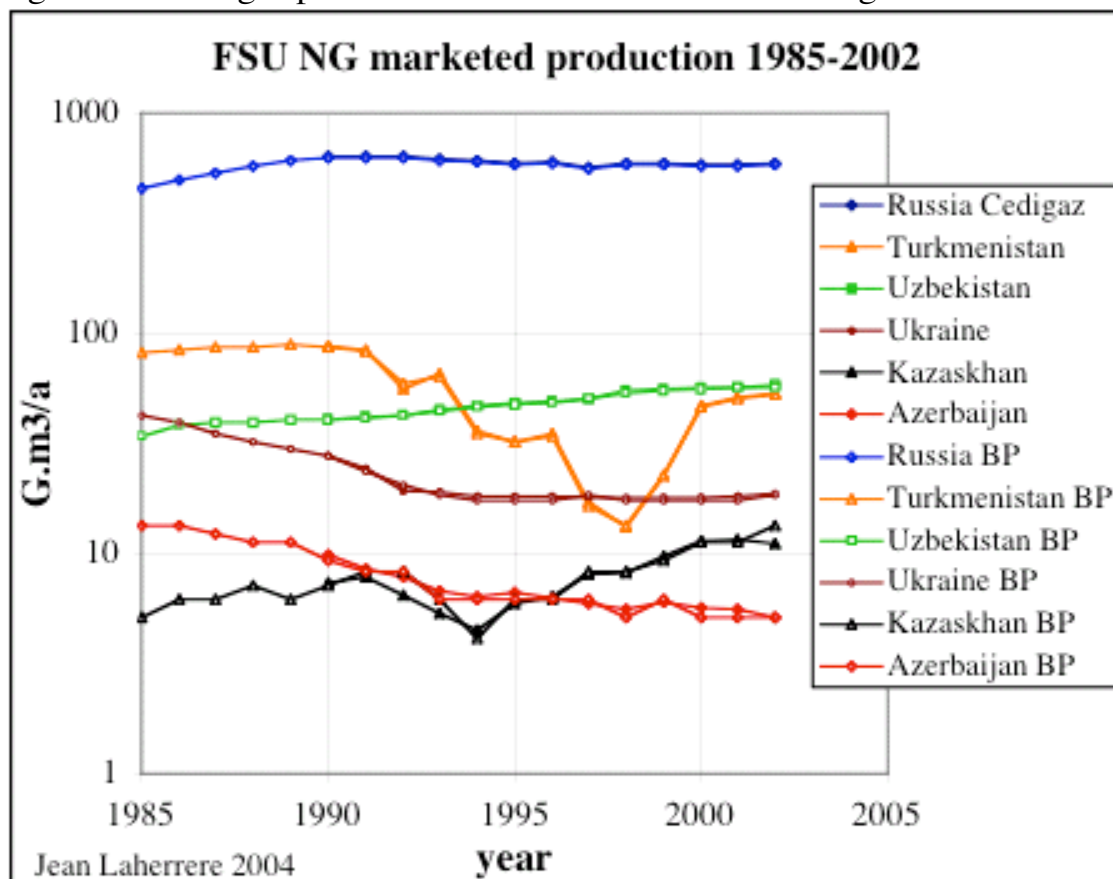
The ABC1 creaming curve is modelled with 3 hyperbolas trending towards 2800 Tcf, despite a strong increase in the number of discoveries.

Figure 55: CIS creaming curve (ABC1) 1860-2002
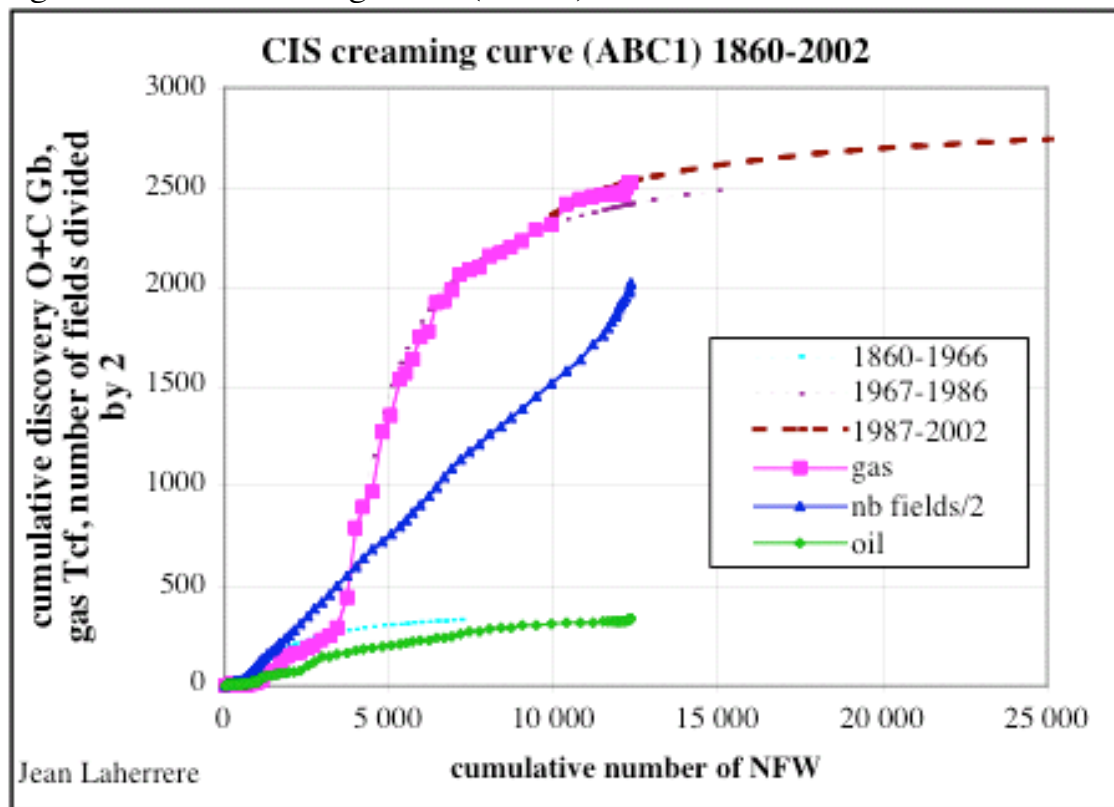
The largest Russian gasfield, Urengoi, has just been reduced from 382 Tcf in 2000 to 328 Tcf in 2002 (in line with the decline from 1987 to 1996, only data available), then to 231 Tcf in 2003 (in line with the last decline from 1999 to 2001), but raised again to 367 Tcf in 2004 (without any reason?), 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 56: Urengoy gas decline

Figure: Urengoi gas decline 1979-2001
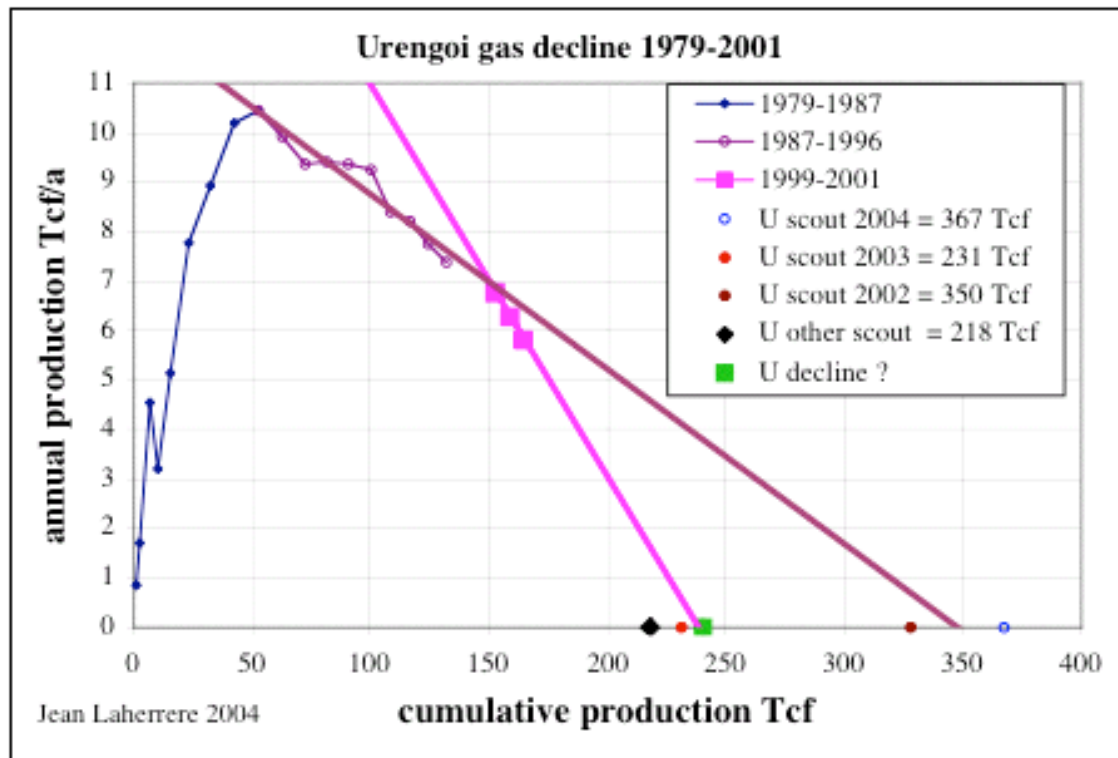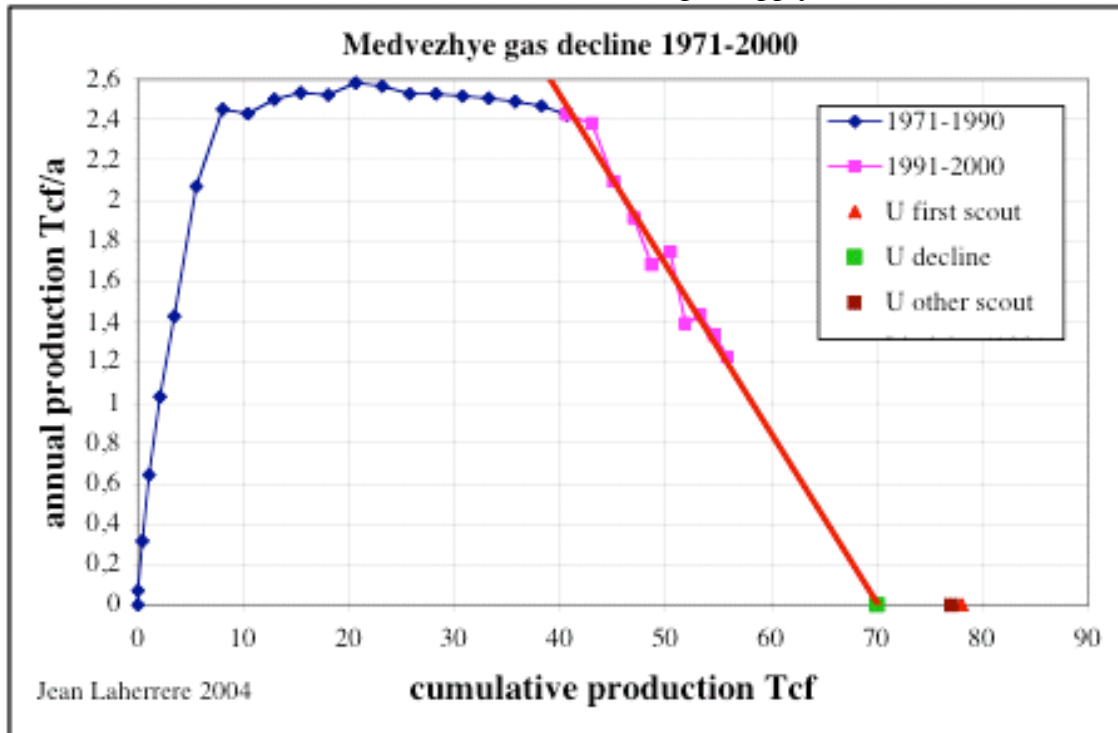
Orenburg is overestimated by IHS and WM (both using ABC1?) by 40% with 68 Tcf when decline is about 48 Tcf.
Figure 57: Orenburg gas decline

Figure: Orenburg gas decline 1971-2002
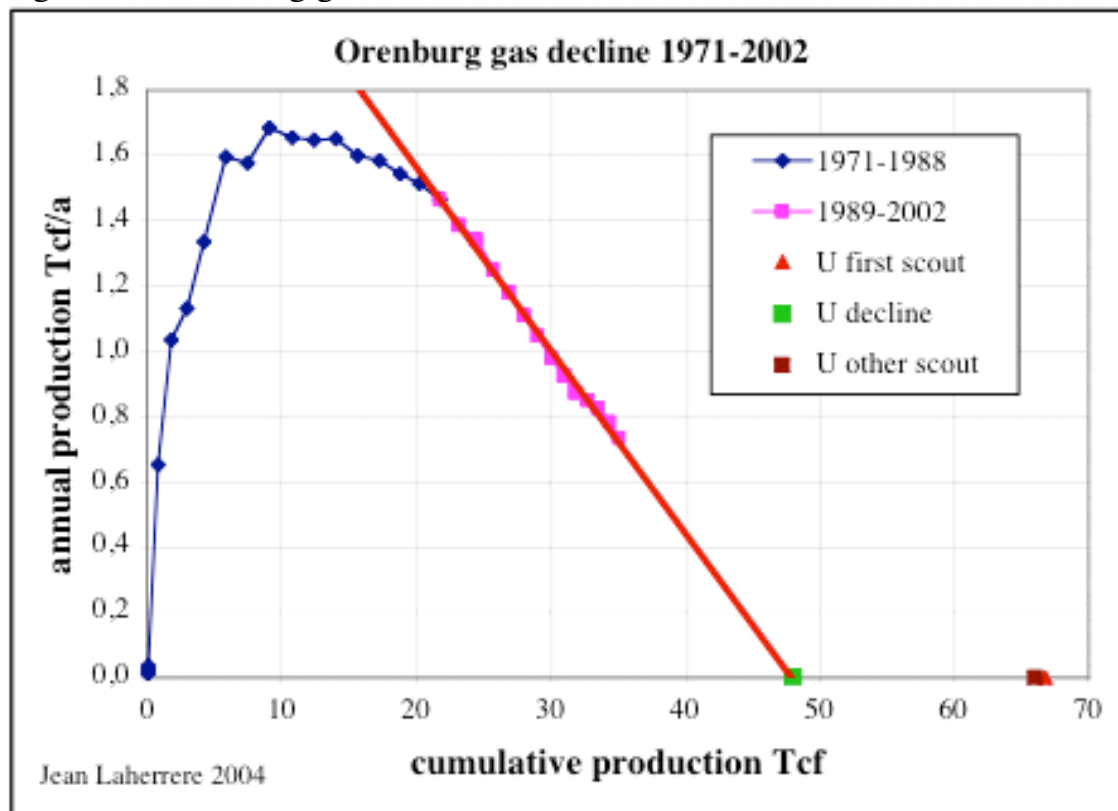
Medvezhye is also overestimated by IHS and WM but only by 10%
Figure 58:!Medvezhye gas decline

Yamburg has not declined significantly yet, but the two scouts diverge
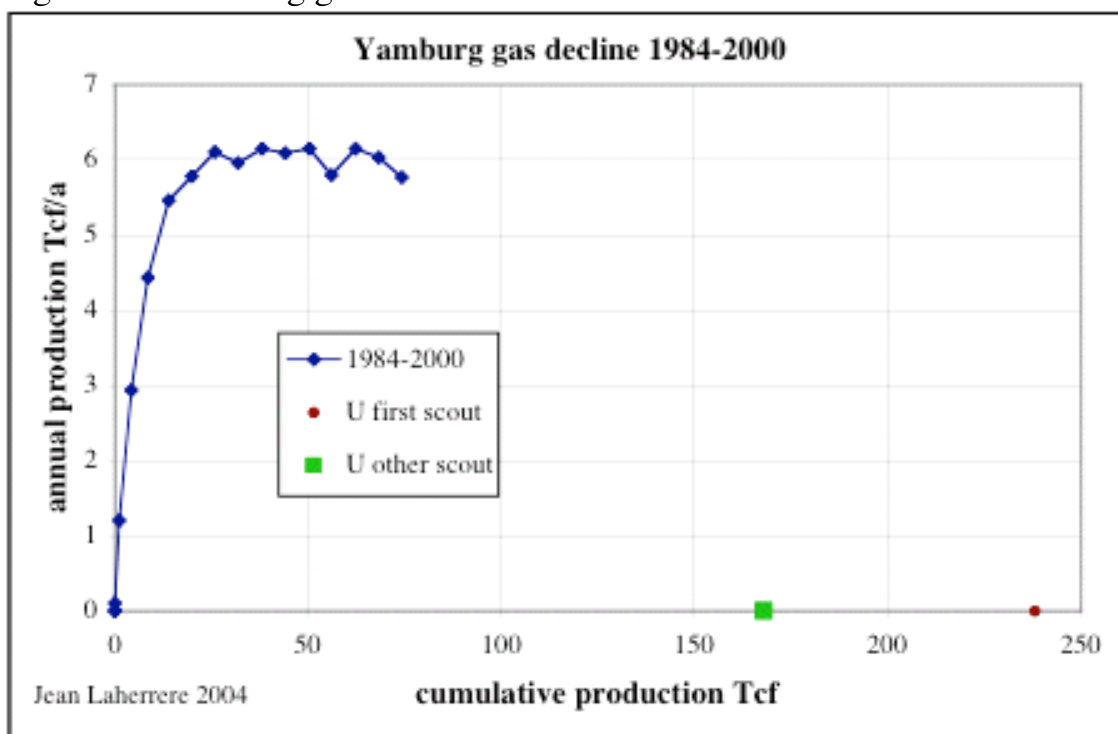
Figure 59: Yamburg gas decline

Figure 60:

Jean Laherrere 2004
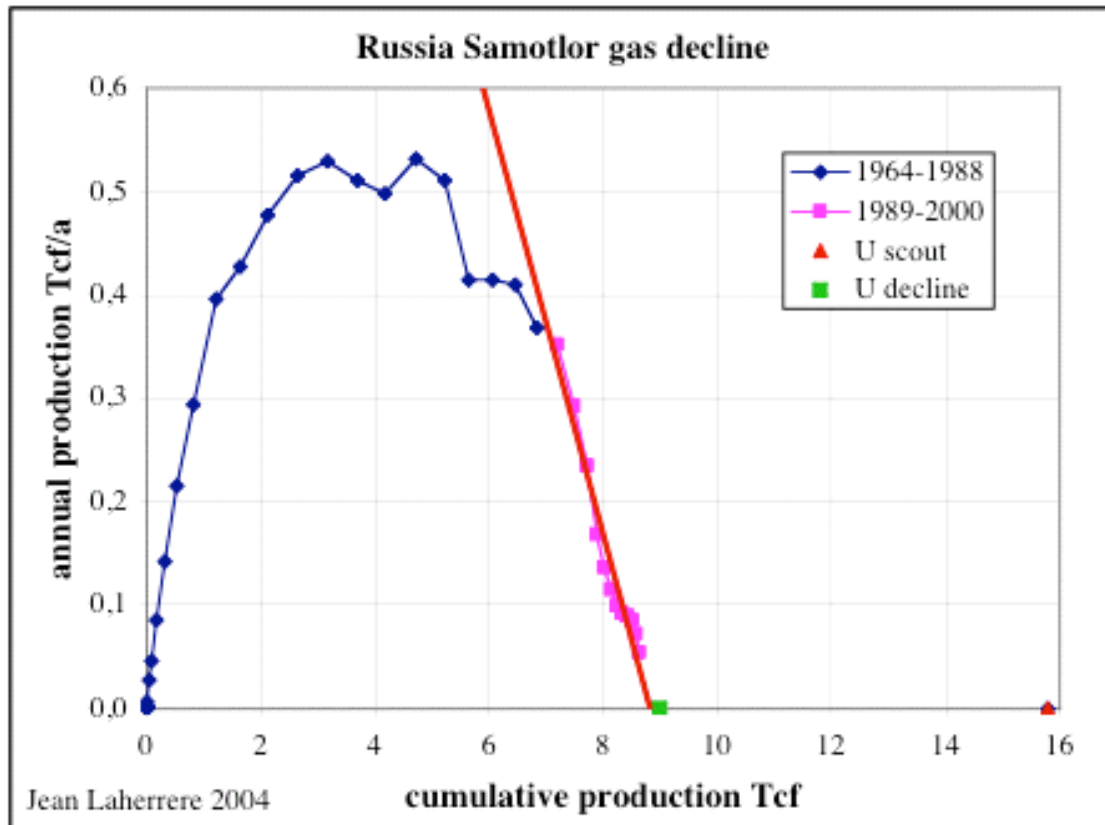
Applying a 30% reduction for gas (as for oil), to get the mean gas reserves indicates from the creaming curve an ultimate of about 1800 Tcf.

Figure 61: CIS NG cumulative discovery & production

Jean Laherrere
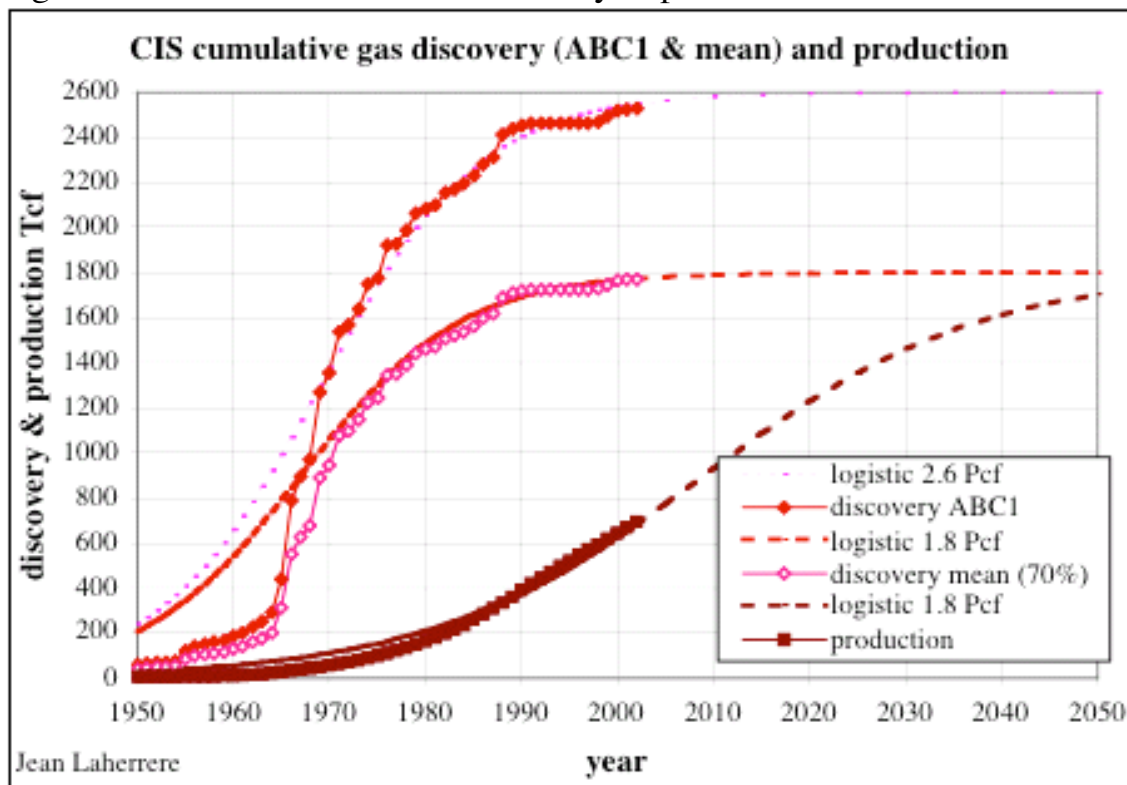
We have plotted the future annual production for an ultimate of 1500 Tcf

FSU NG production will peak about 2012 with 30 Tcf/a, only 4 Tcf/a above the present level.

Figure 62: CIS NG annual discovery & production
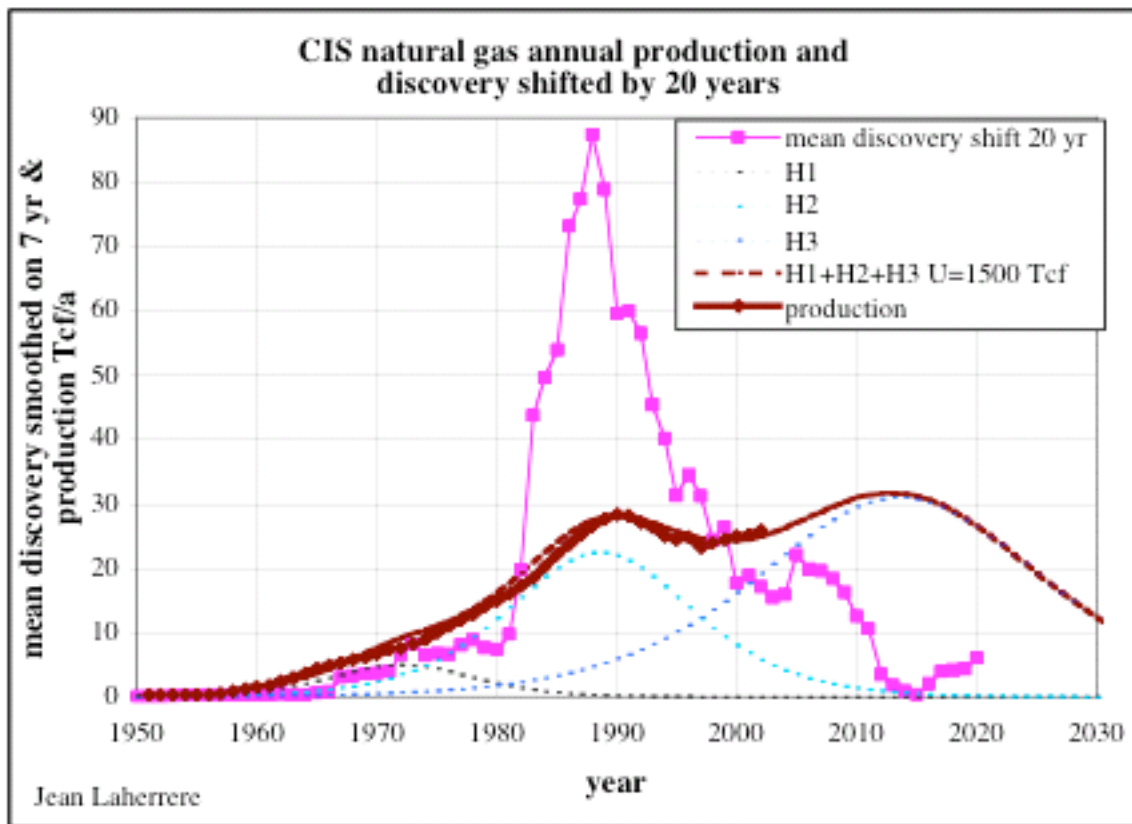
Zittel seems to be similar when adding all the known fields and projects.

Figure 63: Zittel field production display
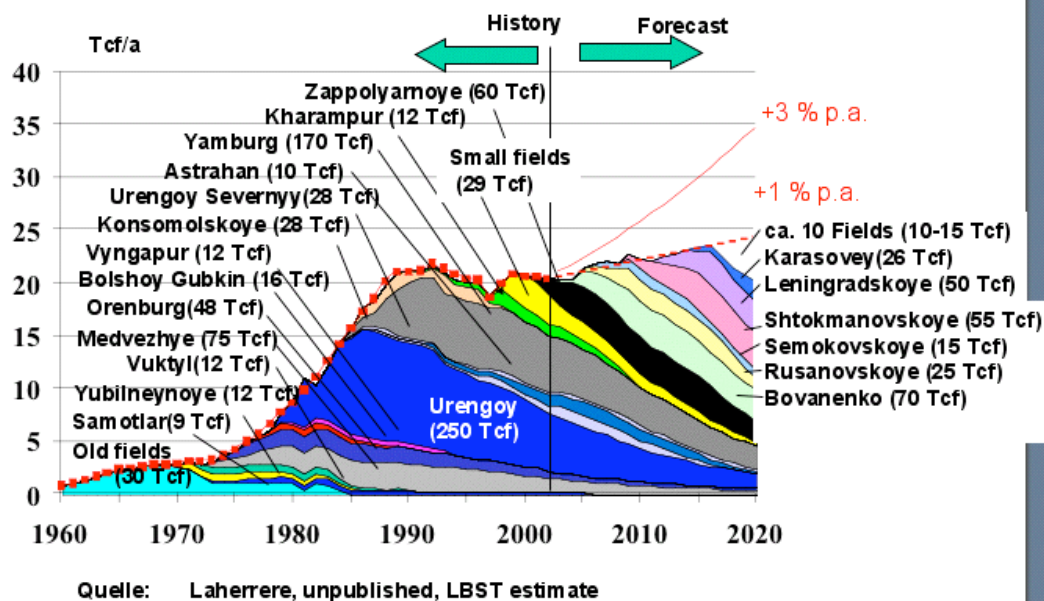
-**Europe**

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 64: Europe creaming curve
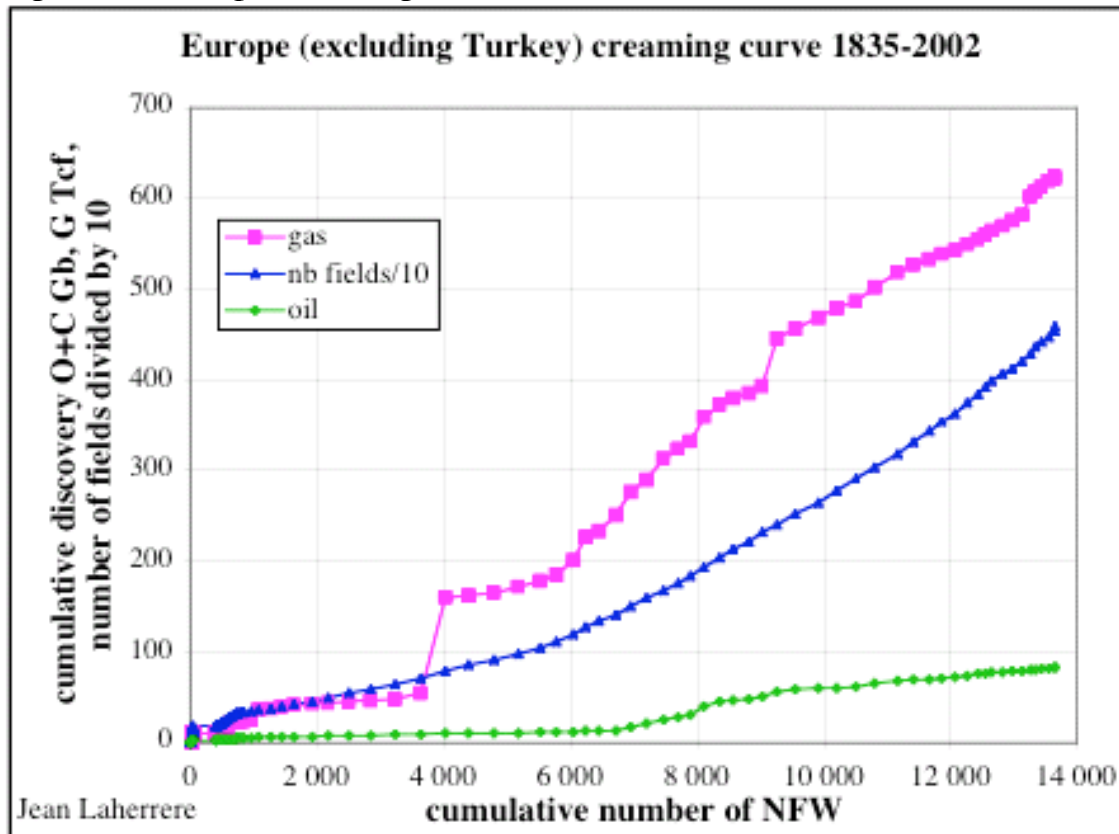
The Europe outside Norway, UK and Netherlands has an easier to model creaming curve,
with an ultimate of 240 Tcf.
Figure 65!: Europe outside Norway, UK, Netherlands creaming curve
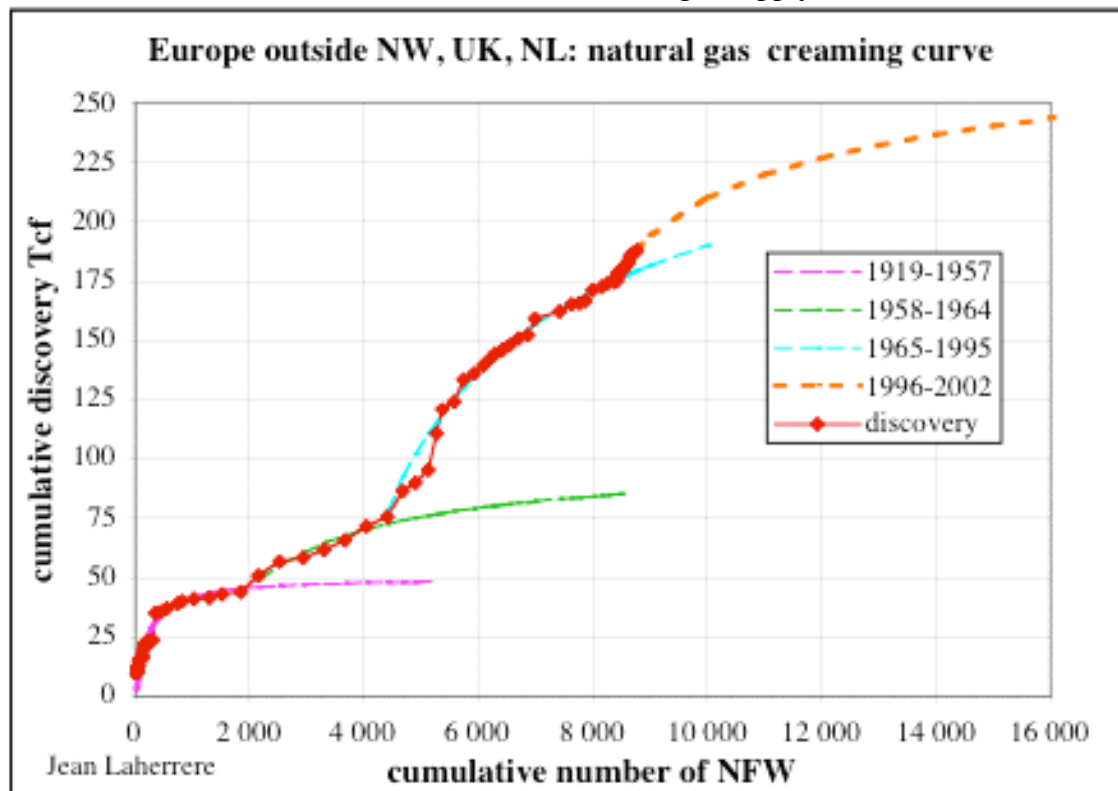
The Europe Cumulative discovery versus time may be modelled (past the Groningen discovery) with one logistic curve with an ultimate of 670 TCF. The cumulative production is modelled with an ultimate of 620 Tcf to adjust to WM value.

Figure 66: Europe NG cumulative discovery & production
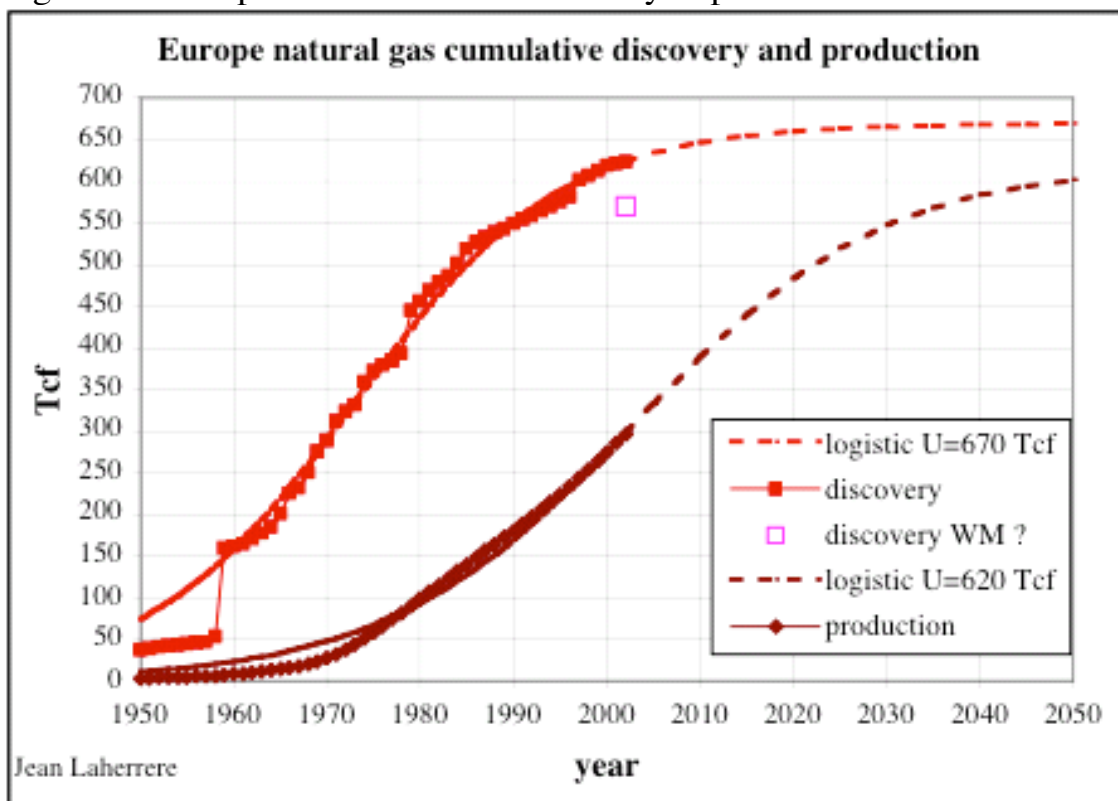
The annual production is modelled with the 620 Tcf ultimate, giving a peak in 2005 at 11 Tcf/a

Figure 67: Europe NG annual discovery & production
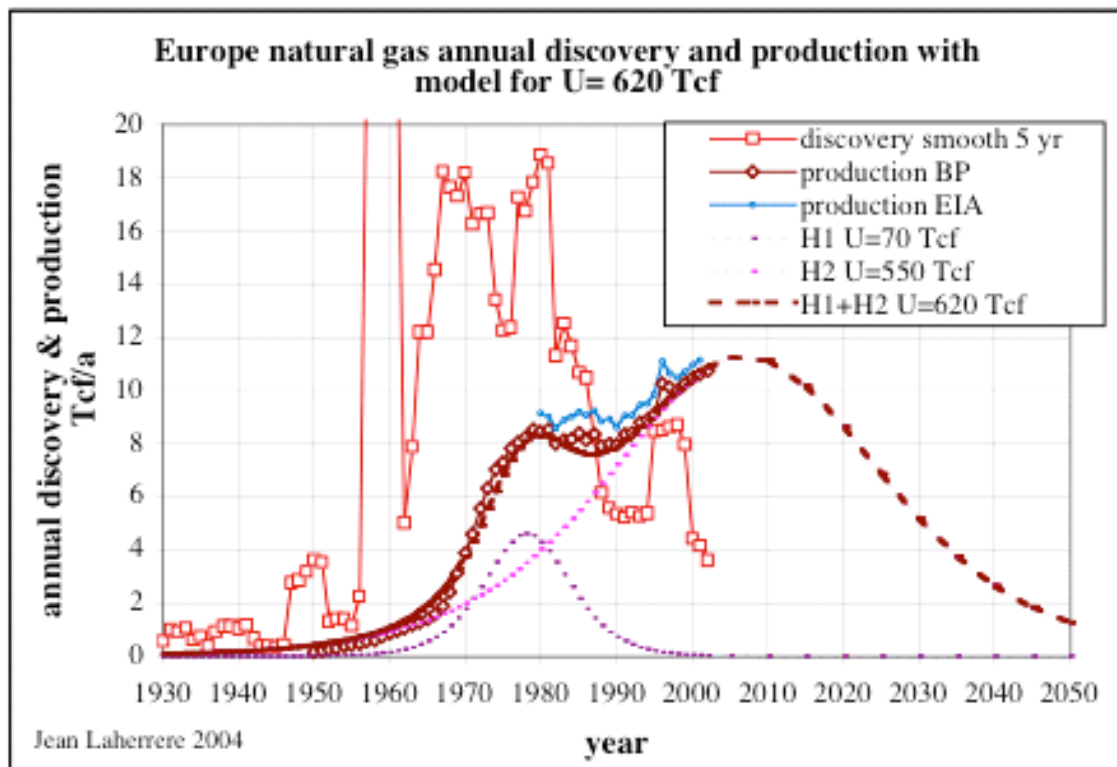
Europe will peak soon, another way to forecast future production is to correlate past production with shifted discovery. A shift of 20 years provides a fair correlation where discovery is in sharp decline after 2000, in agreement with the previous graph.

Figure 68: Europe NG production & shifted discovery
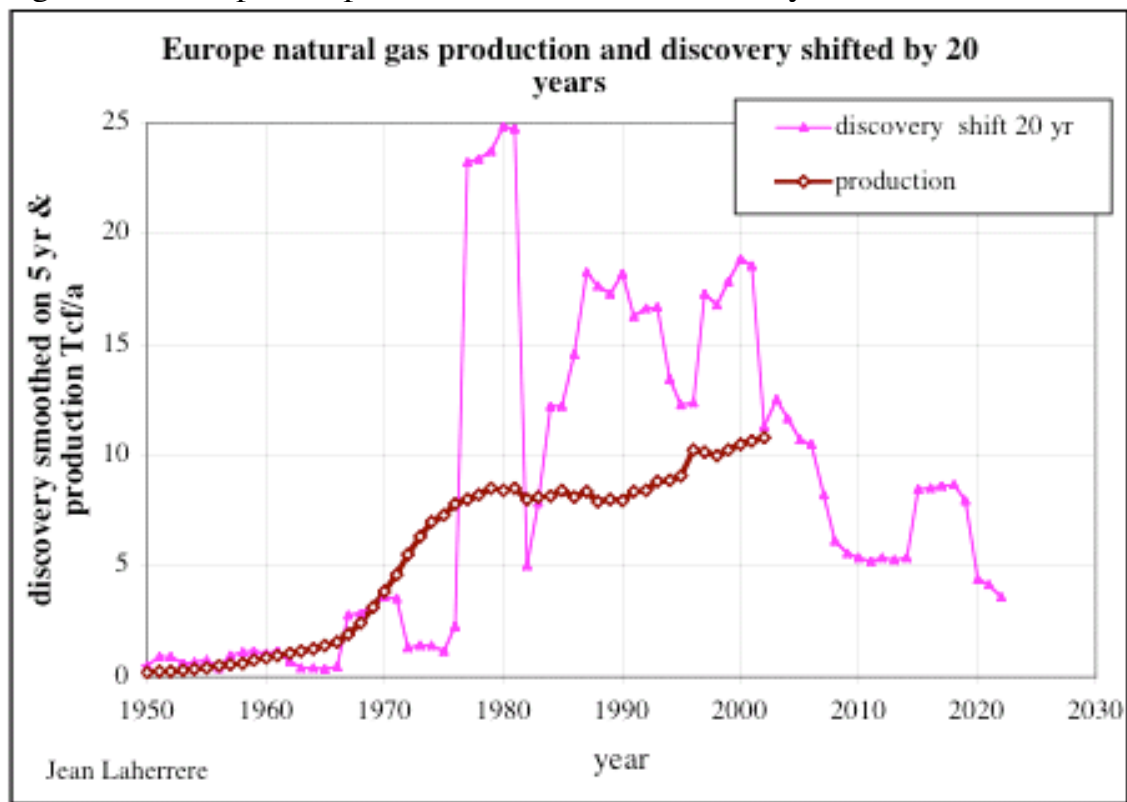
The modelling of figure 66 for Europe is compared to the addition of the models for the seven largest producers: UK, Netherlands, Norway, Germany, Italy, Denmark and France as shown before.

The total is different as Europe includes more than these 7 countries, but the trend is very similar

Figure 69; Europe NG forecast and addition of the seven countries above
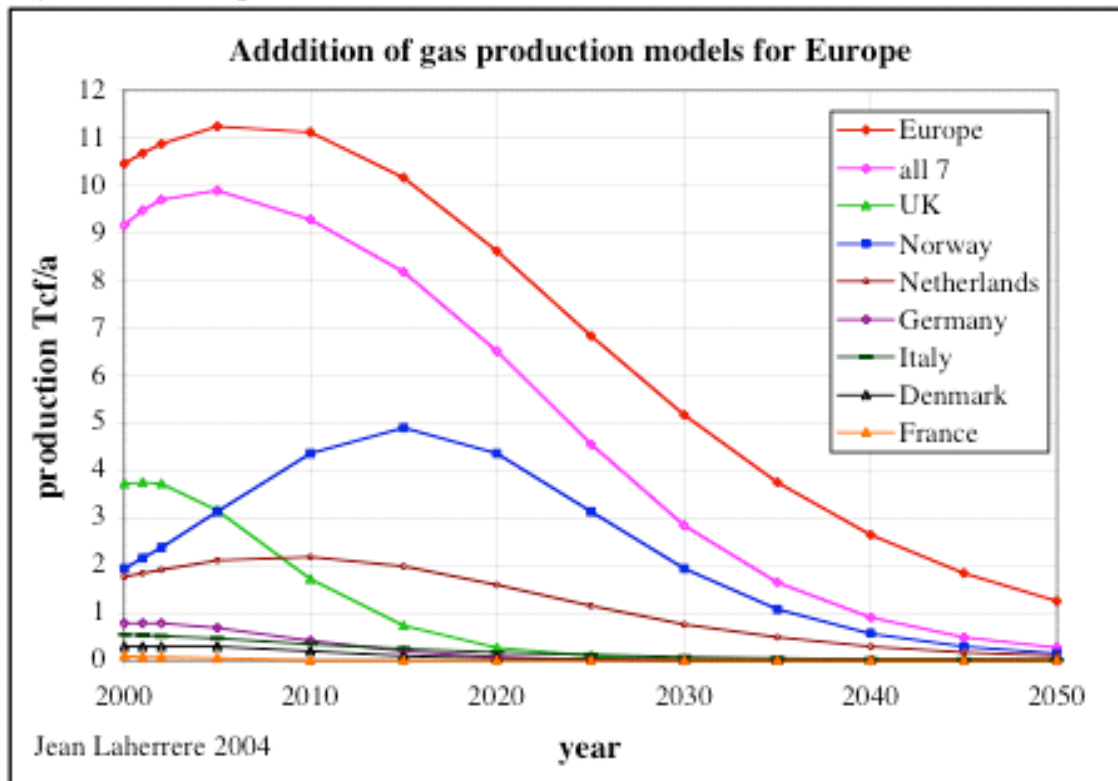
Europe production will peak around 2005 and will decline at a rate of 0.3 Tcf/a. More imports will be needed (Algeria and FSU) but is FSU production is forecast (figure 61) to peak around 2012 at a volume of only 4 Tcf/a above the present production. Will the demand be satisfied?

-**US**

The US is the best place to get data as every number gathered by a federal agencies (USDOE in particular), which is available freely on the web. USDOE/EIA also provides international data on long periods.

The NG volume 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 70: US NG production & storage 1949-2002
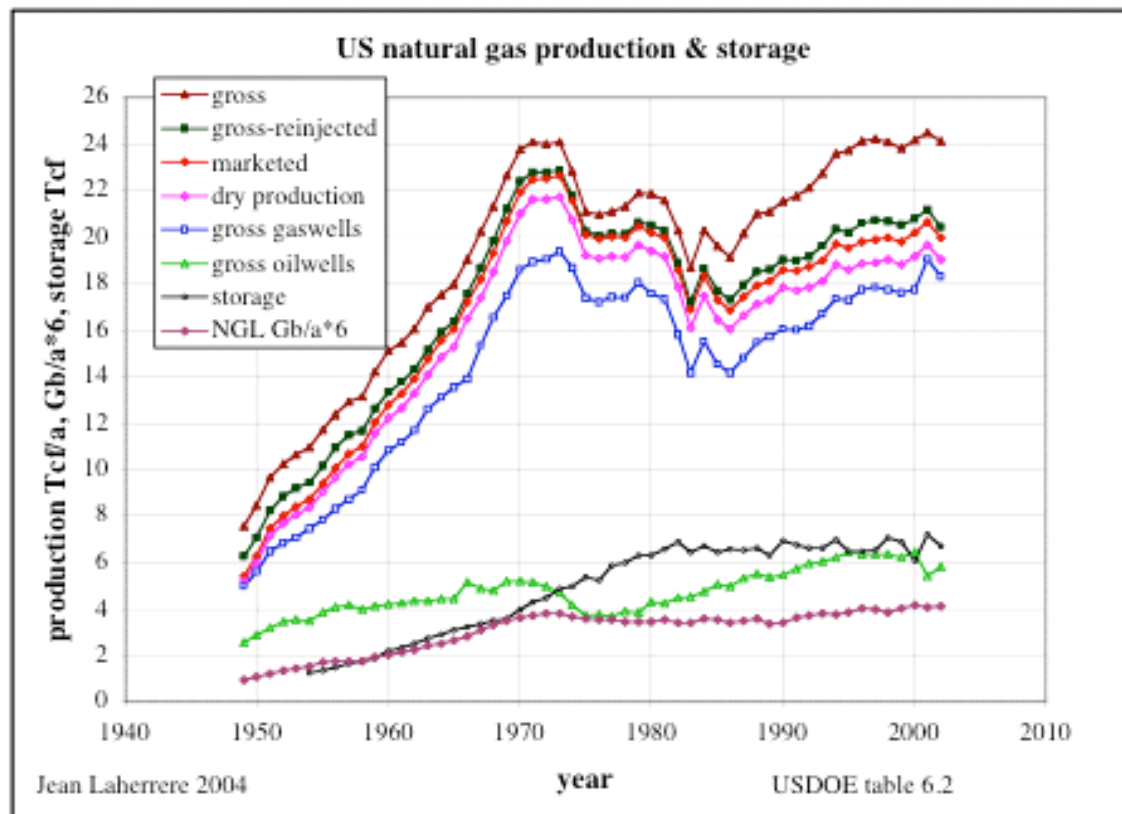
Though the marketed production, which already peaked in 1973, has been increasing since 1986, it is now flattening. The dry conventional (black triangles) has in fact declined since1973, the ratio of NGL versus the wet gas production is about 32 Mb per Tcf (compared to 25 Mb/Tcf for the world).

Figure 71: US NG production 1950-2003 with NGL/wet production
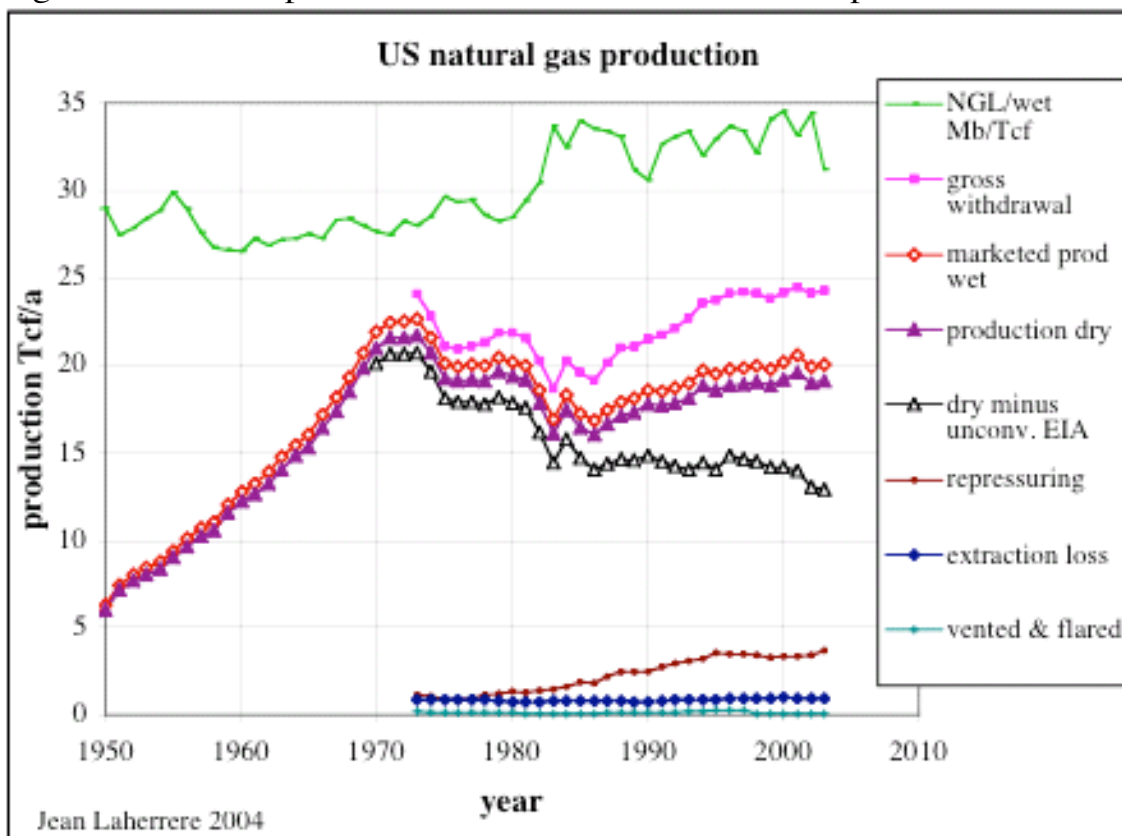
The US price for oil and gas shows that the ratio barrel versus 5.6 kcf (calorific equivalent) was more than 6 in the 1950s, 3 in the1960s, 2 around 1990, and now close to 1 or even less on the monthly basis.

Figure 72: US NG wellhead price and ratio oil/gas
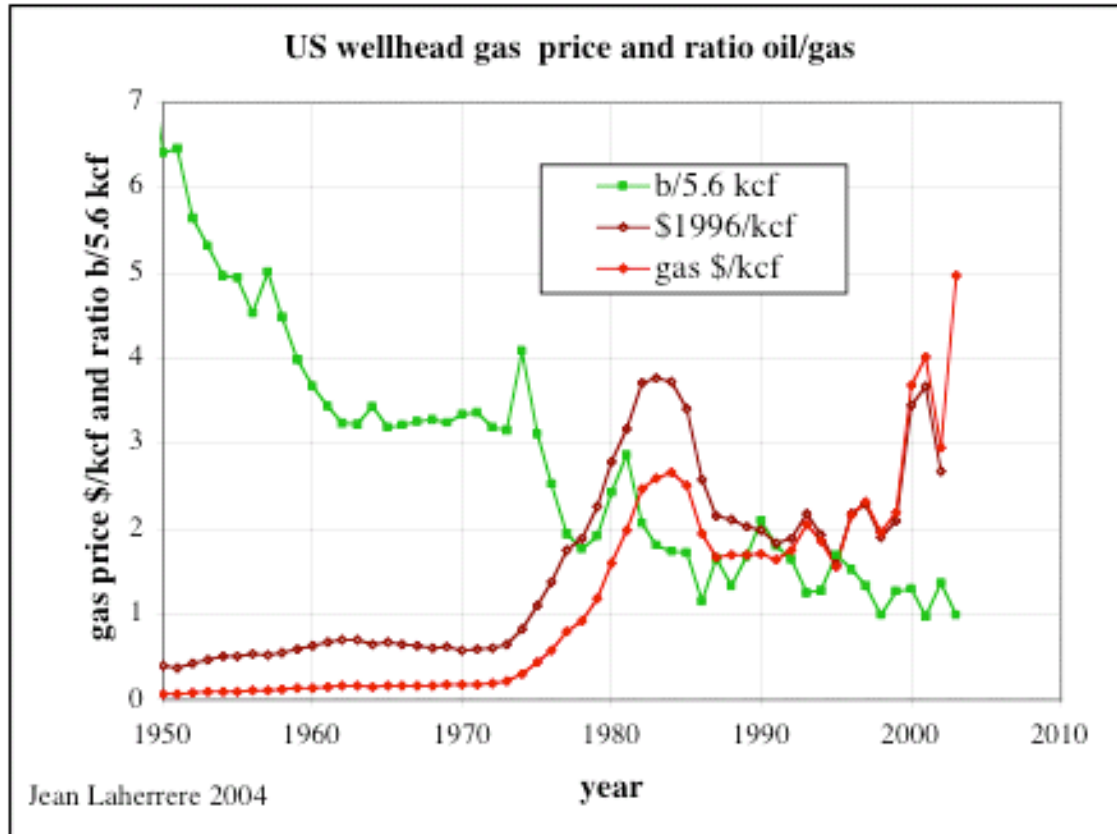
The price of oil and gas in $/Mbtu is compared to coal which is presently one third

Figure 73: US fossil fuels price in $/MBtu
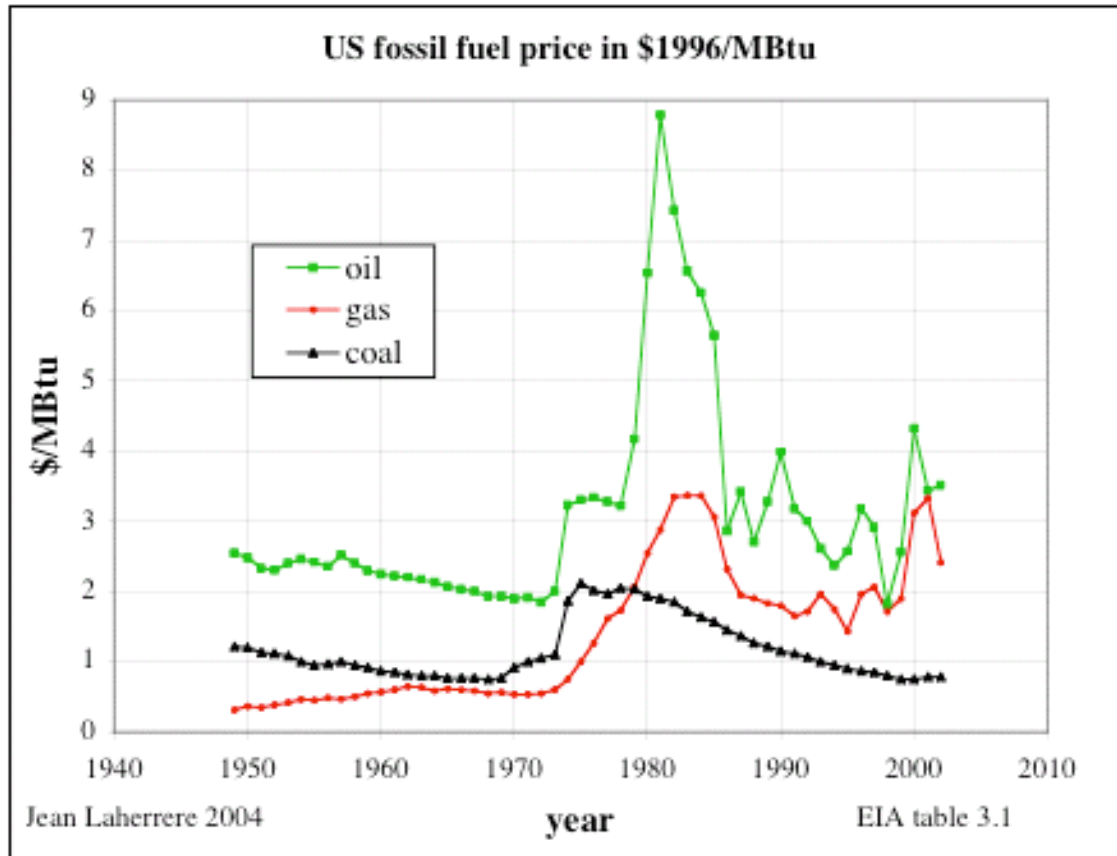
USDOE forecast (AEO 2004) is a mild increase in 2002$ up to 2030 to got to 4.5 $/kcf
Figure 74: US NG price and EIA forecast
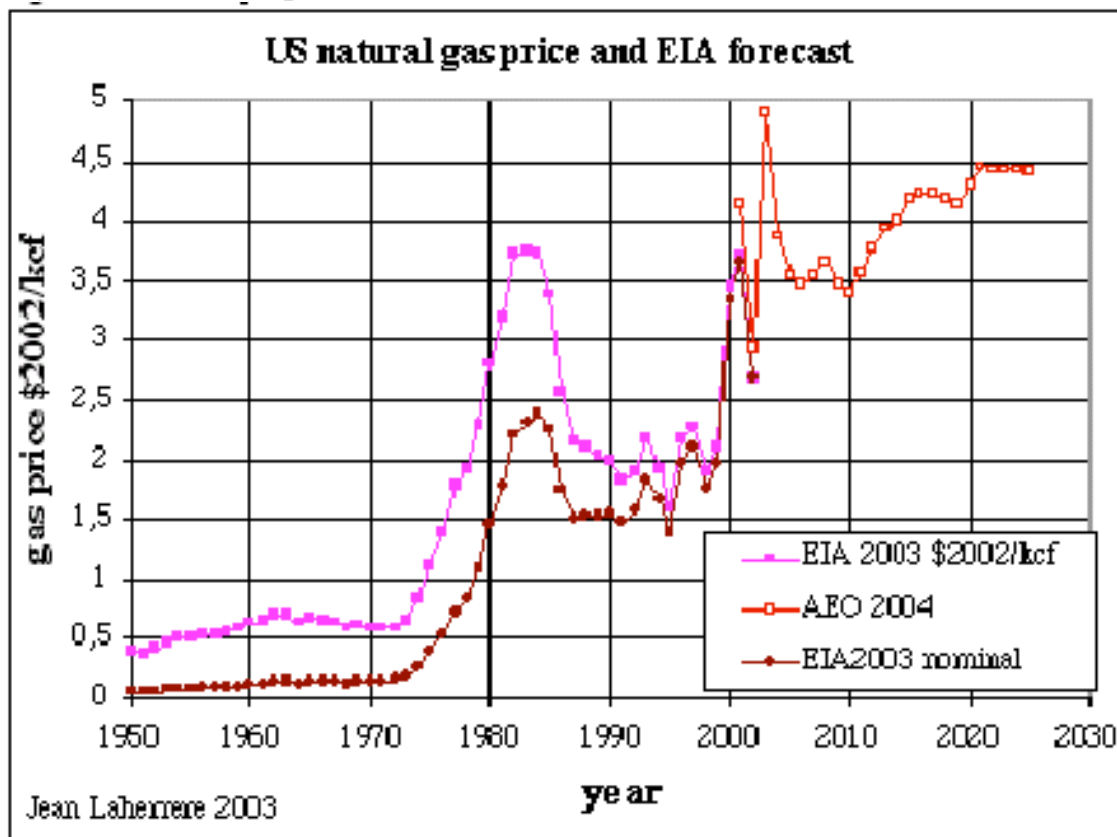
Though much data is available, it is not very reliable when published and needs several revisions, since agencies ask only a small part of operators to report. The gas production

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 75: Gulf of Mexico production from MMS & EIA
GOM production: very large contradictory data between MMS and EIA
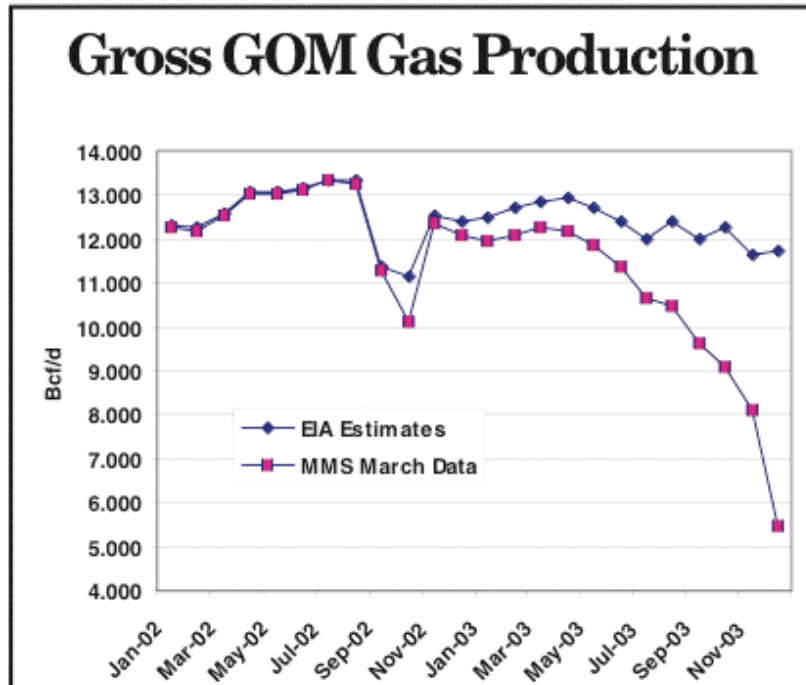
USDOE (AEO 2004) forecasts an increase of the NG production up to 2025, but Kenderdine (GTI 2003) forecasts 16,4 Tcf in 2007 (45 Gcf/d) against 20 Tcf for EIA
Figure 76: US NG production & EIA forecast
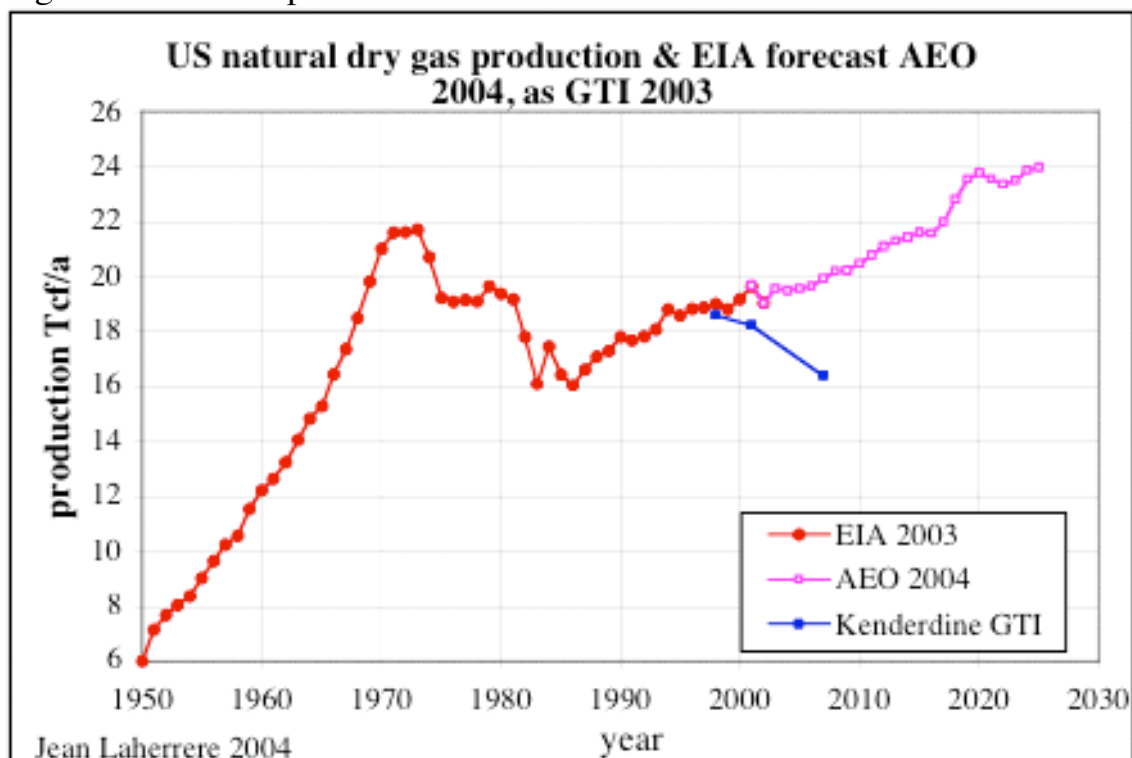
Our best forecast is to correlate the mean backdated reserves (from EIA 90-534 and later annual reports on new discoveries) to conventional production after shifting the discovery by 28 years. It seems obvious to most viewers that the future production will decline in a cliff in the near future and the unconventional will not be able to compensate for this sharp decline.
Figure 77: US 48 states NG conventional production and shifted discovery
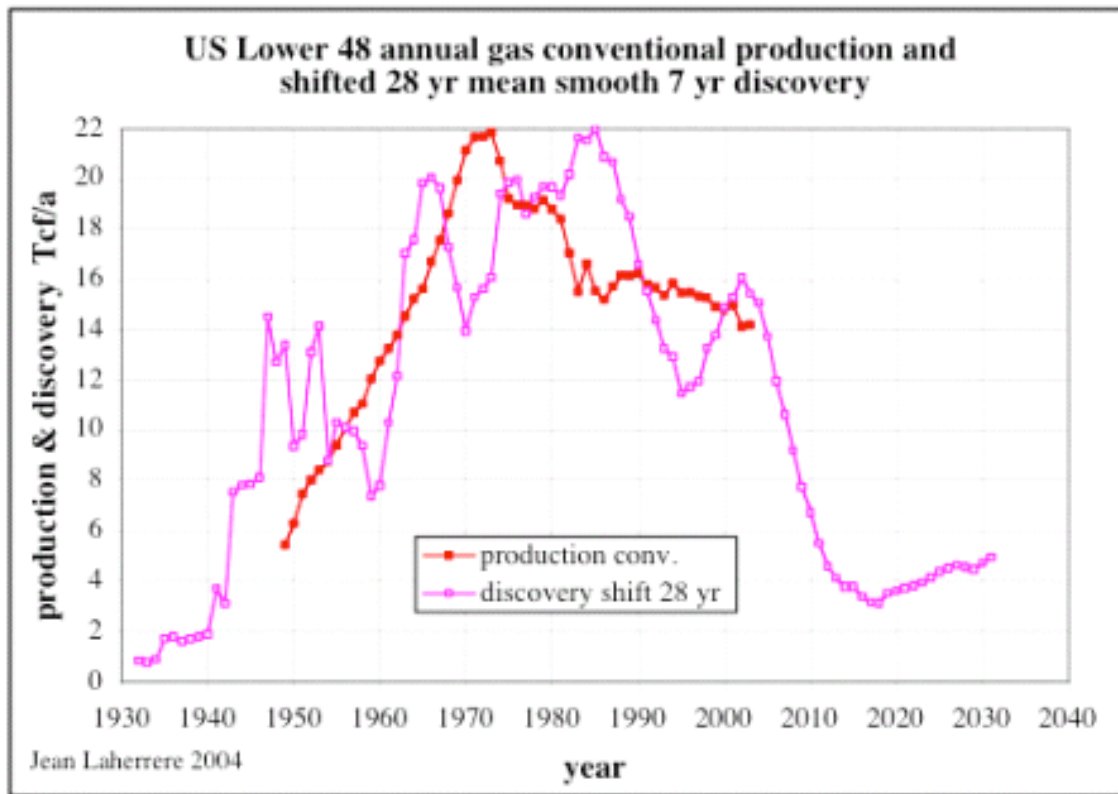
Michael Smith (energyfiles.com) is also showing a sharp decline but starting later
Figure 78; US NG production forecast from Michael Smith
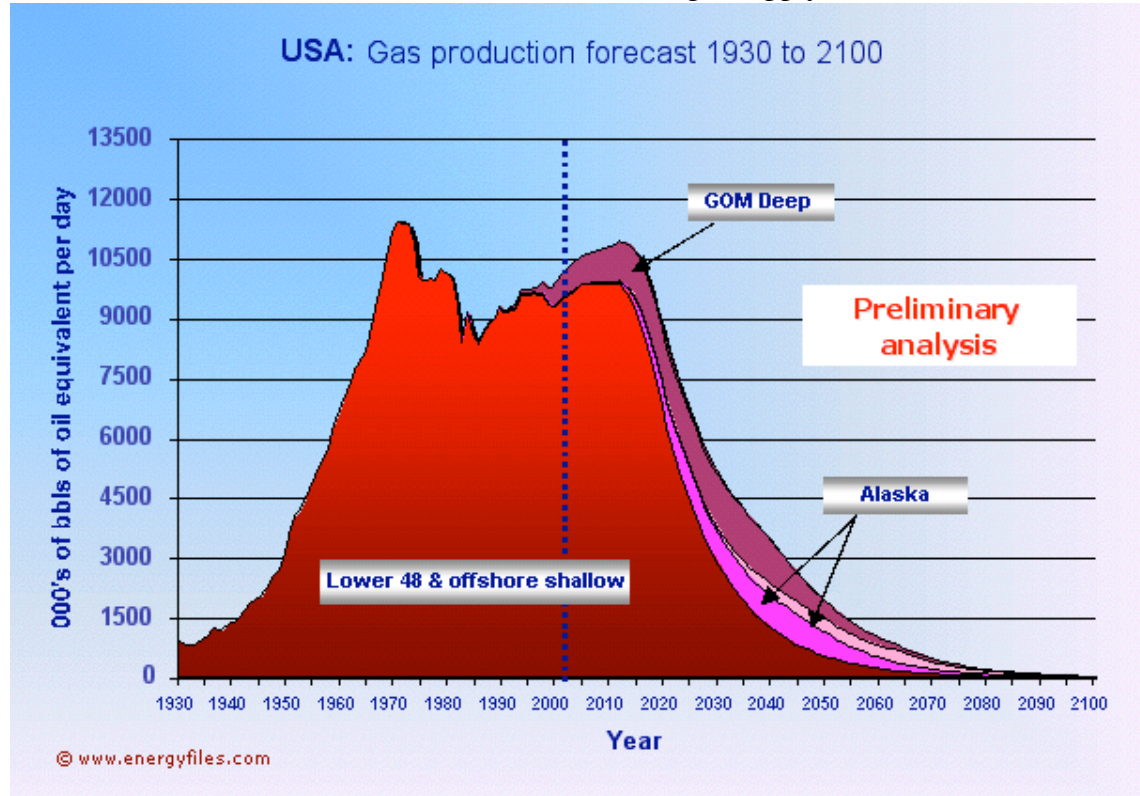
The USDOE 1985 report has published a (poor) graph (on a 20 yr time scale from 1900 to 2100) showing several forecasts from Hubbert, USGS and PGC

Figure 79: USDOE 1985 graph comparing Hubbert 1980, USGS 1981 and PGC 1983
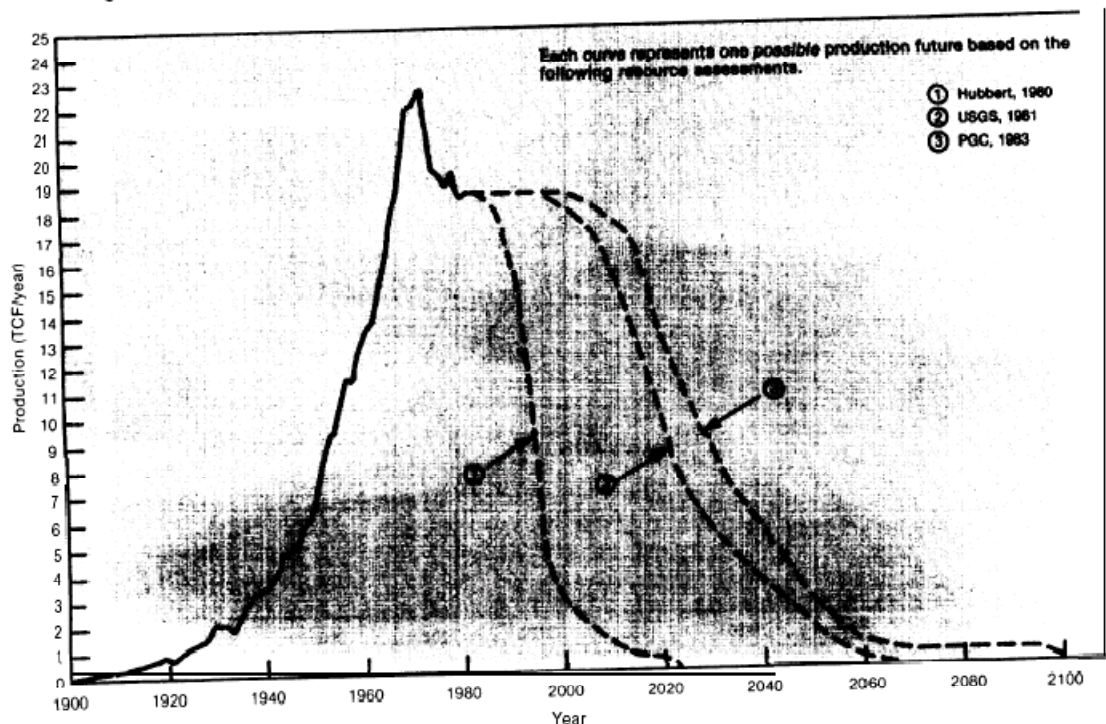
Hubbert was forecasting a sharp decline starting in 1990 when USGS and PGC forecasted a sharp decline too but starting in 2010.

This 1985 report gives the following forecasts (made around 1980) in Tcf/a

	1985	1990	1995	2000
Hubbert 1980	18	16	10	3,5
USGS 1981	18,5	18,5	18,5	18,5
PGC 1983	18,5	18,5	18,5	18,5
Riva 1983	16,1-16,8	14,5-15,1	13,5-14,5	12,6-13,3
Gulf	19.4	18,6	16,7	13,8
Texaco	18,9	16,1	14	13
Chevron	18,2	18	16,5	14
Exxon		14,6		14,1
Conoco	19	18		14,6
Union	18,5	17,7	16,5	15,5
GRI	17,9	15,1	12,8	11,6
IEA/OECD	16,5-18	14,0-17		11-15
Average 20 forecasts	18,1	16,6	15,3	14,3
-**Real value**	**15,5**	**16,2**	**15,5**	**14,8**

It is amazing to see that the forecasts were all completely wrong for 1985 (year of the publication), when the forecasts are not too wrong for 2000.

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

Figure 80: US revisions of the proved reserves giving the probability of the estimate for oil, NG and NGL
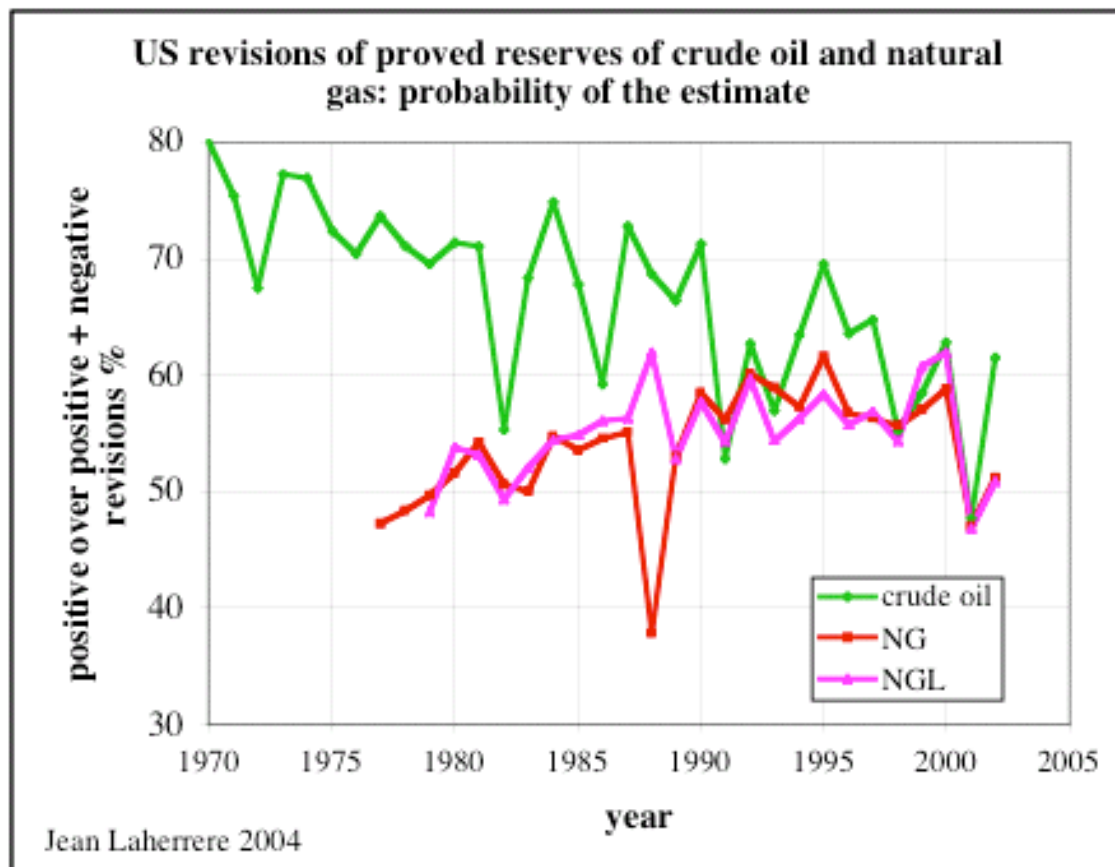
This graph is very important as it shows that the probability of the so-called proved reserves is being not 90% as required by the SPE/WPC rules but presently about 55% for oil as NG and NGL. But in 1980 the probability was about 70 % for oil but 50% for NG

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 81: USGS 2000 forecast for US NG and extrapolation of past production
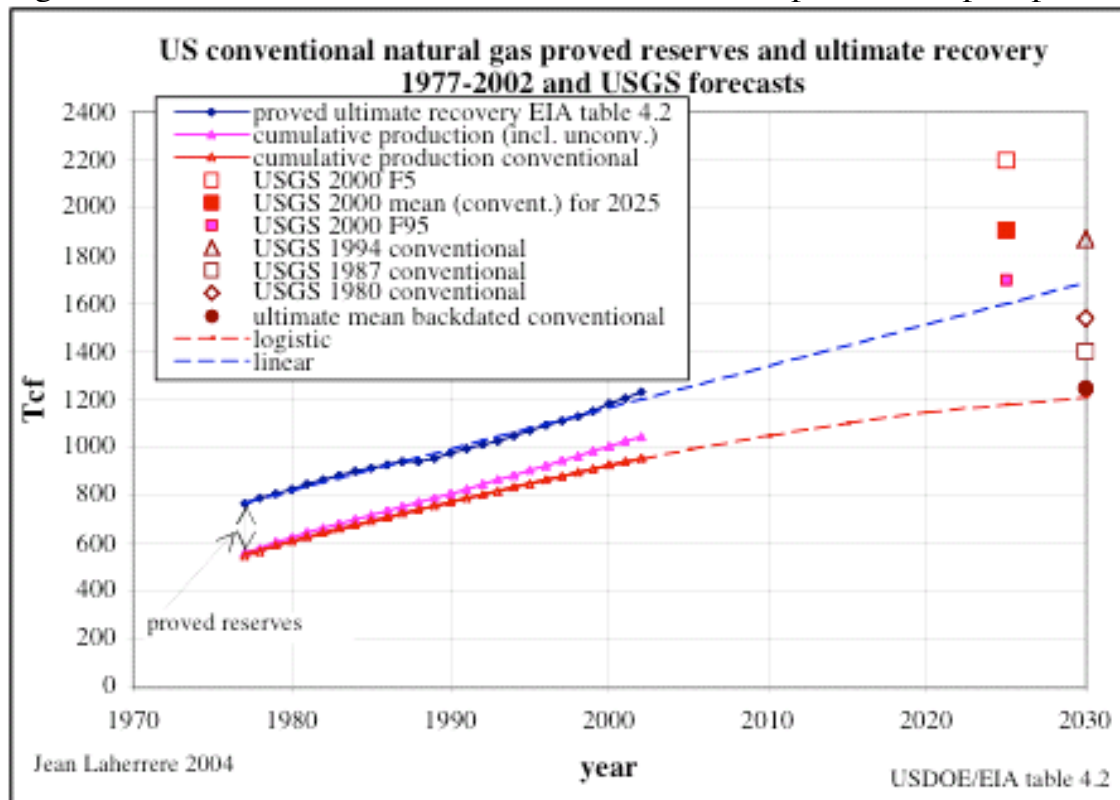
The US cumulative mean backdated discovery is close to one single logistic model, with an ultimate of 1200 Tcf

Figure 82: US conventional NG cumulative mean discovery & production

US cumulative mean backdated conventional natural gas discovery with logistic models
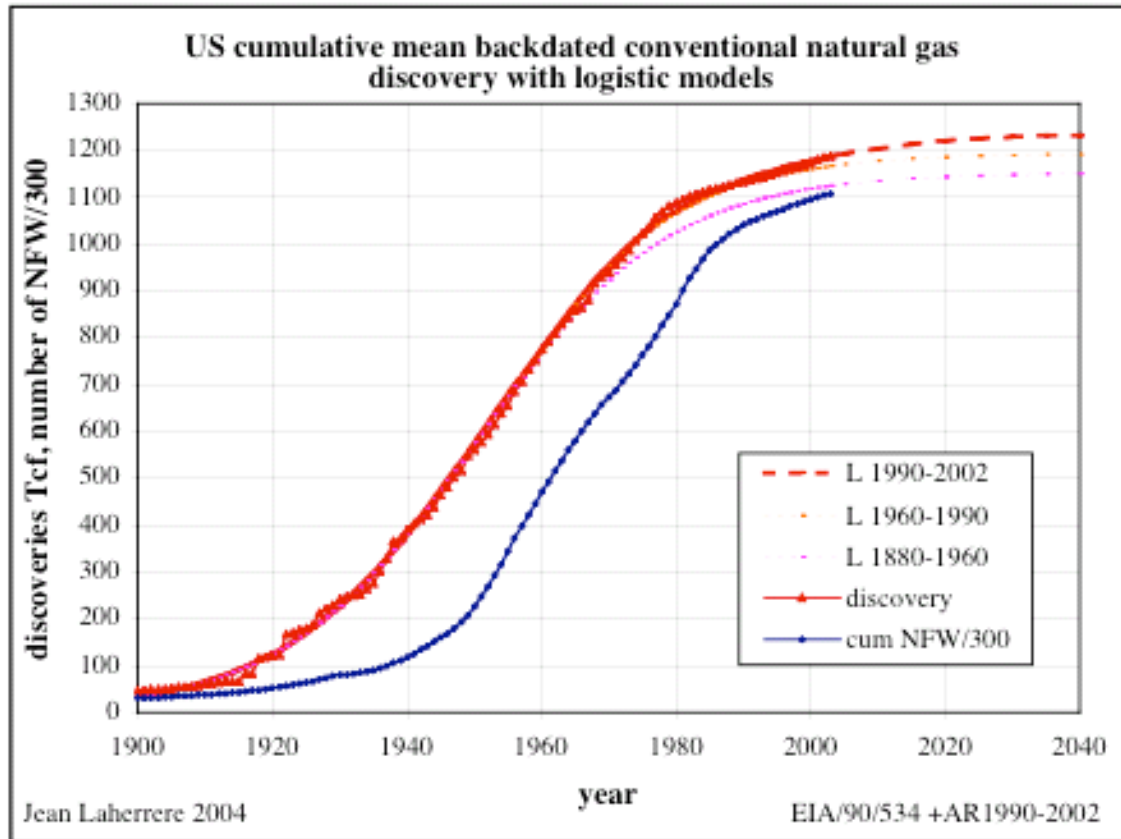
For the Gulf of Mexico the NG production is shown as the MMS 2002 (higher) & 2003 forecasts as the forecast for an ultimate of 185 Tcf. All these forecasts display a sharp decline in the coming years.

Figure 83; GoM NG production and MMS forecasts& model for U=185 Tcf

MMS GoM 2003 production & forecasts as modelling U= 185 Tcf
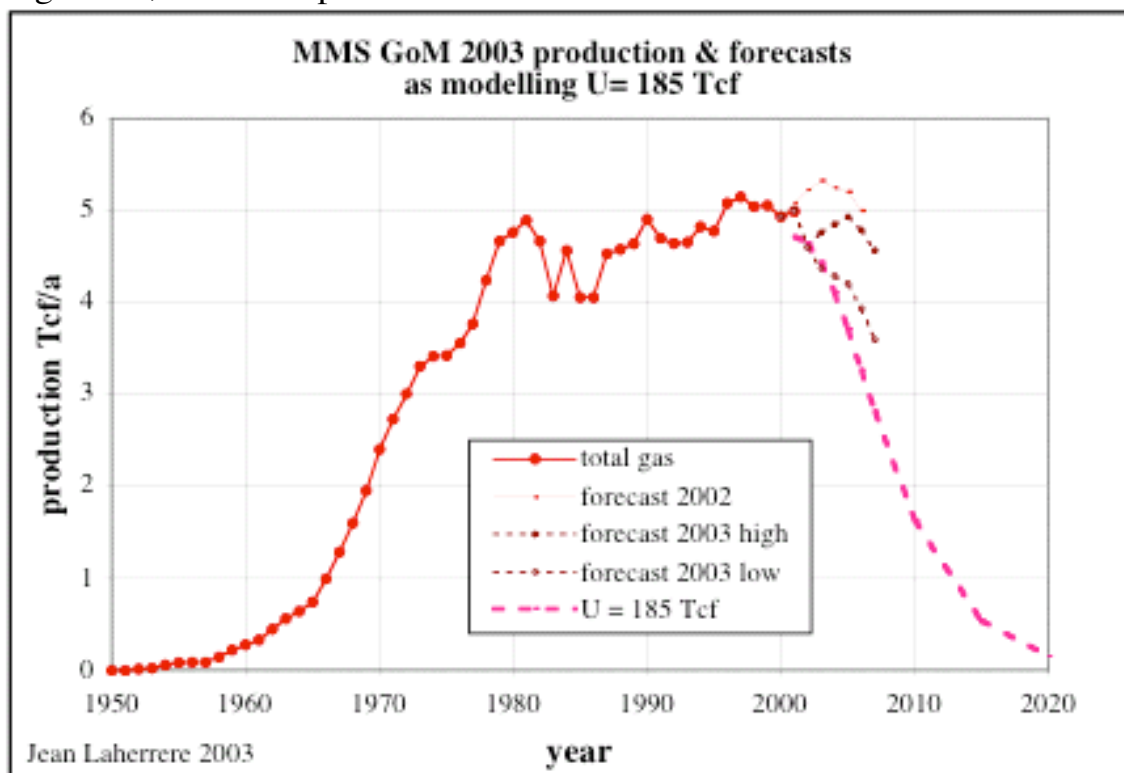
USDoE has a different forecast for the Gulf of Mexico than MMS in their last forecast
AEO 2004 without any steep decline

Figure 84: GoM NG production & USDOE/EIA forecast
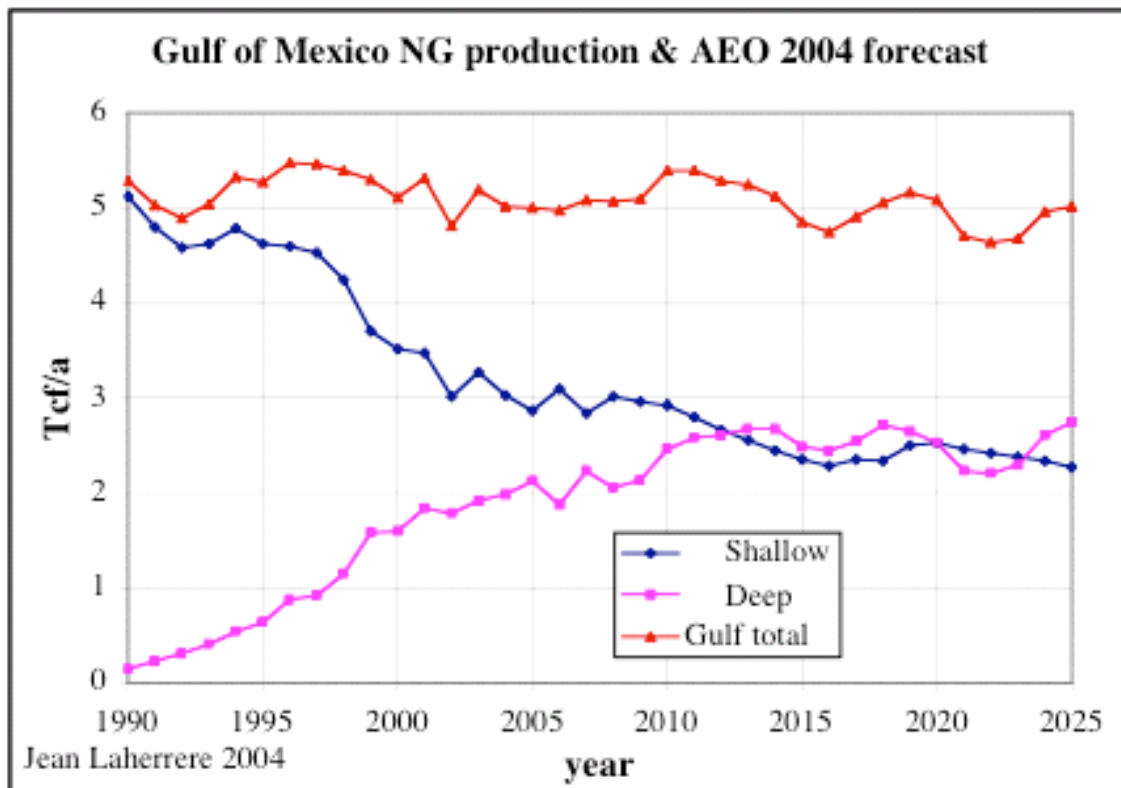
The number of fields from MMS 2000 shows a peak in the 1980s, but the average size has
been declining since 1960.

Figure 85: US GoM average size and number of fields from 1945 to 2000

US GoM average mean field size (Mboe) and number of fields from MMS 2000

Jean Laherrere 2003
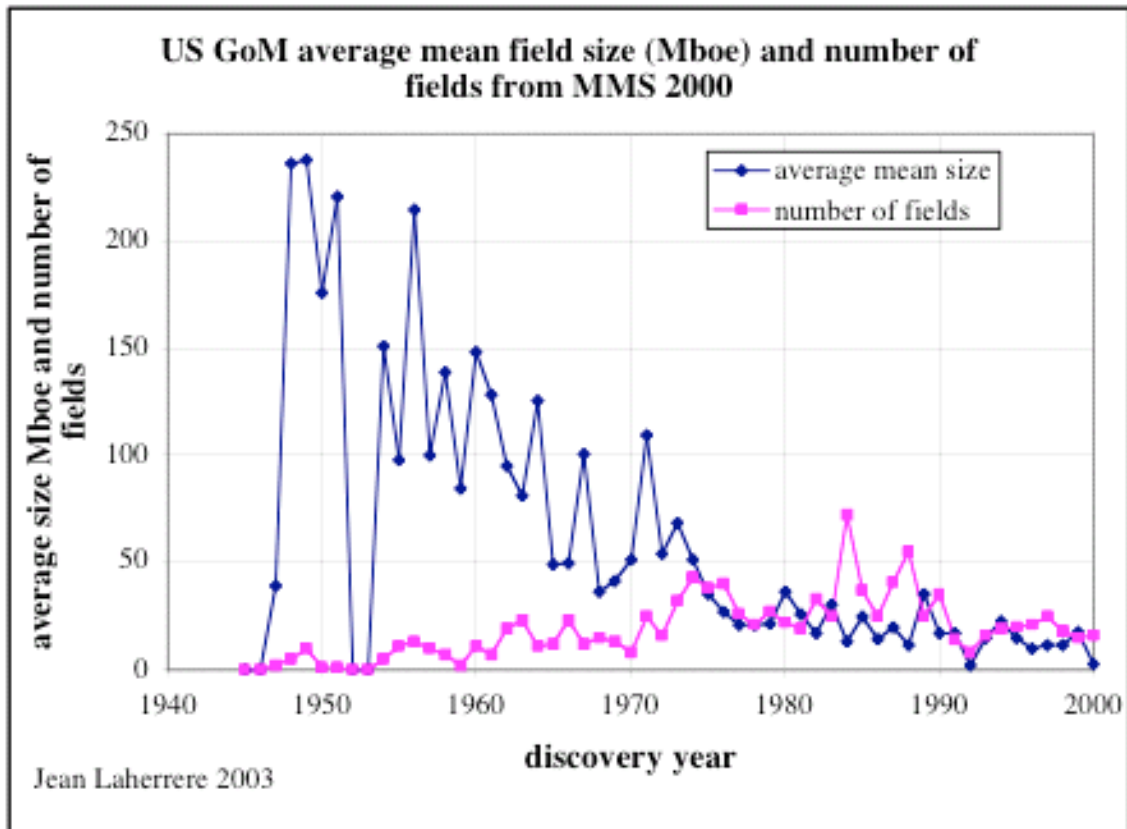
The GoM cumulative discovery is still increasing, but less than production, since 1990.
Figure 86: MMS GoM cumulative discovery & production

MMS GoM cumulative discoveries & production and number of fields

Jean Laherrere 2003
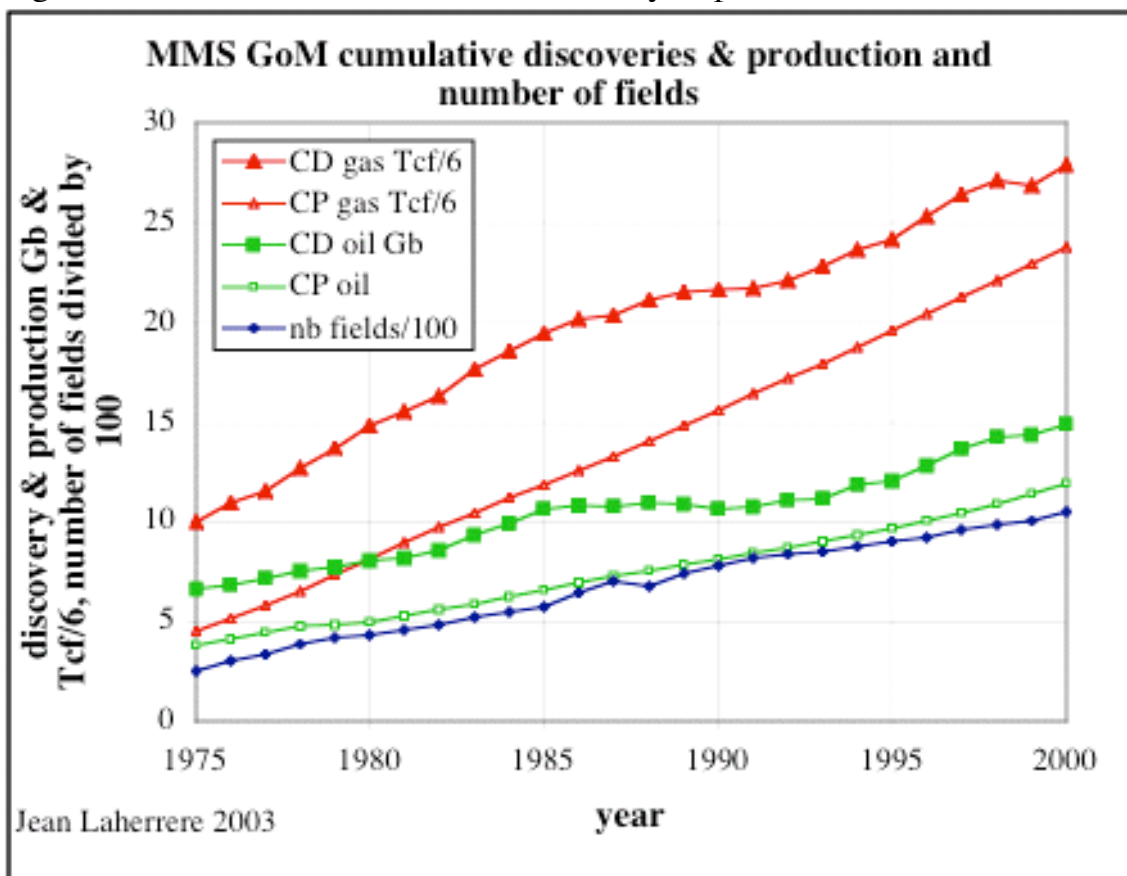
The Texas NG production peaked in 1970 but is flat since 1980, as the number of producers has increased sharply by 30 000 in the last 20 years. But the production per well has declined and is now less than 10 Mcf/a/w

Figure 87: Texas NG production
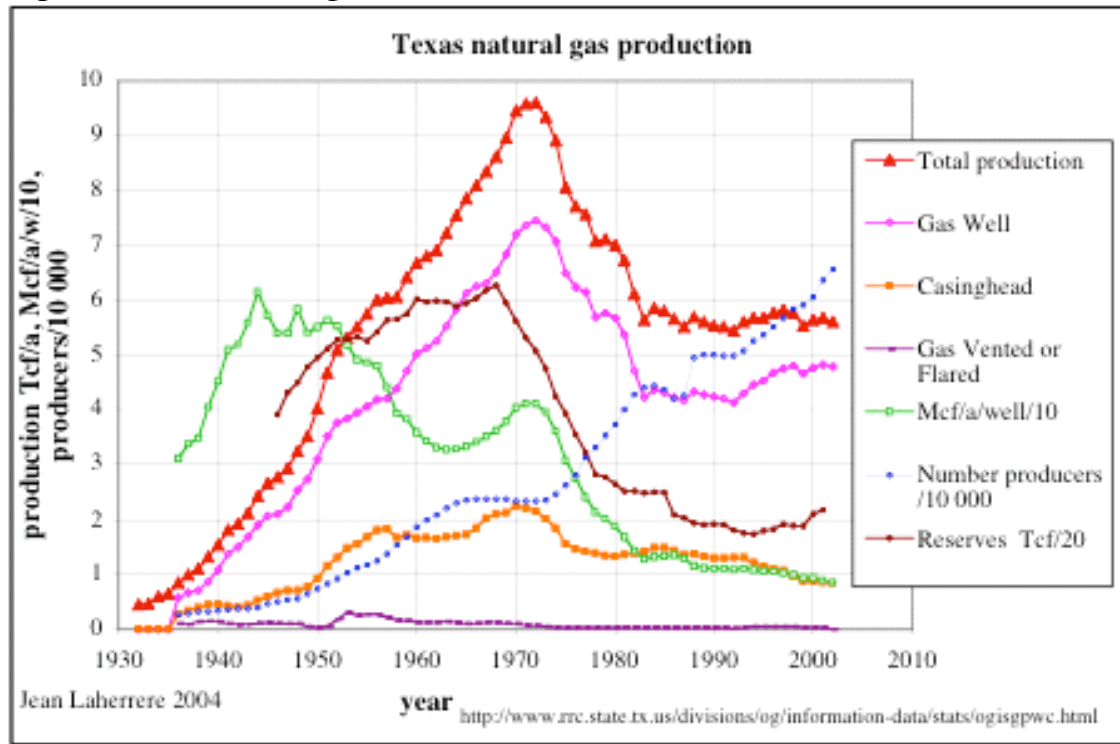
-**US+Canada+Mexico**

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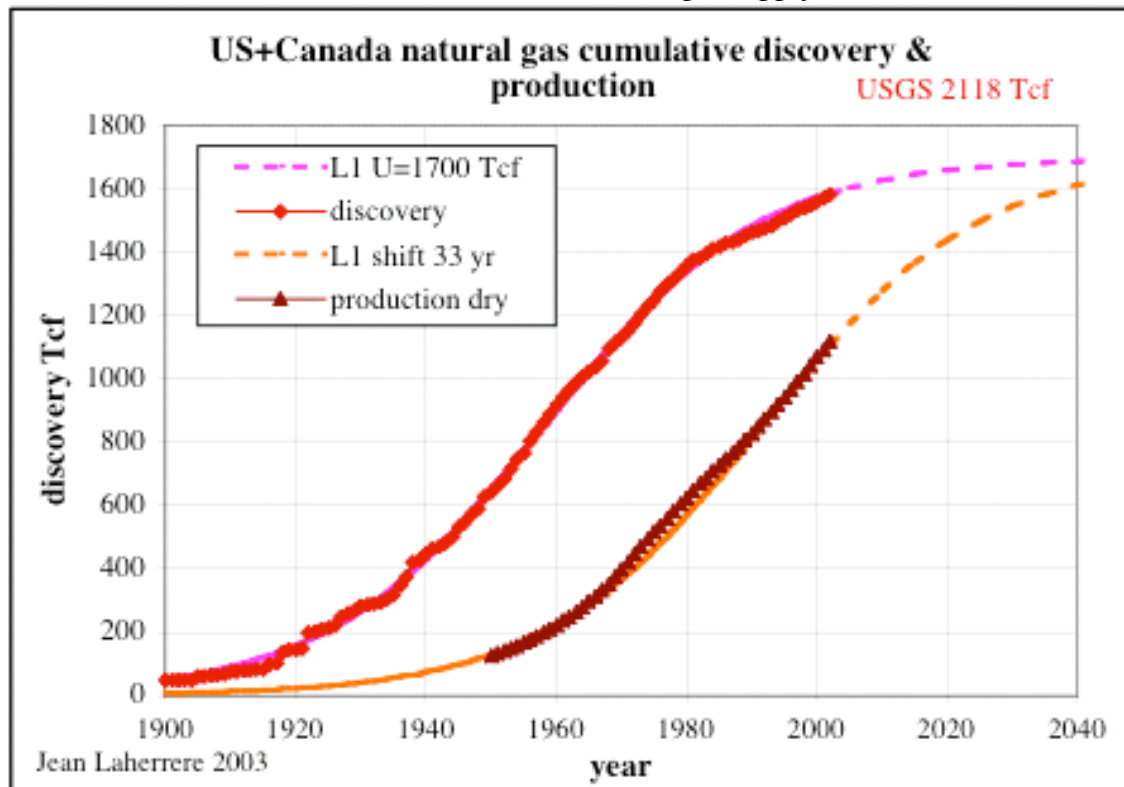
Instead of modelling the annual production, it is better to compare the past conventional production (red curve) with the conventional mean discovery (from EIA90/534 report) (blue curve) shifted by 23 years. Most readers will be inclined to forecast a sharp decline.

Figure 89: US + Canada + Mexico NG annual production and discovery shifted by 23 years
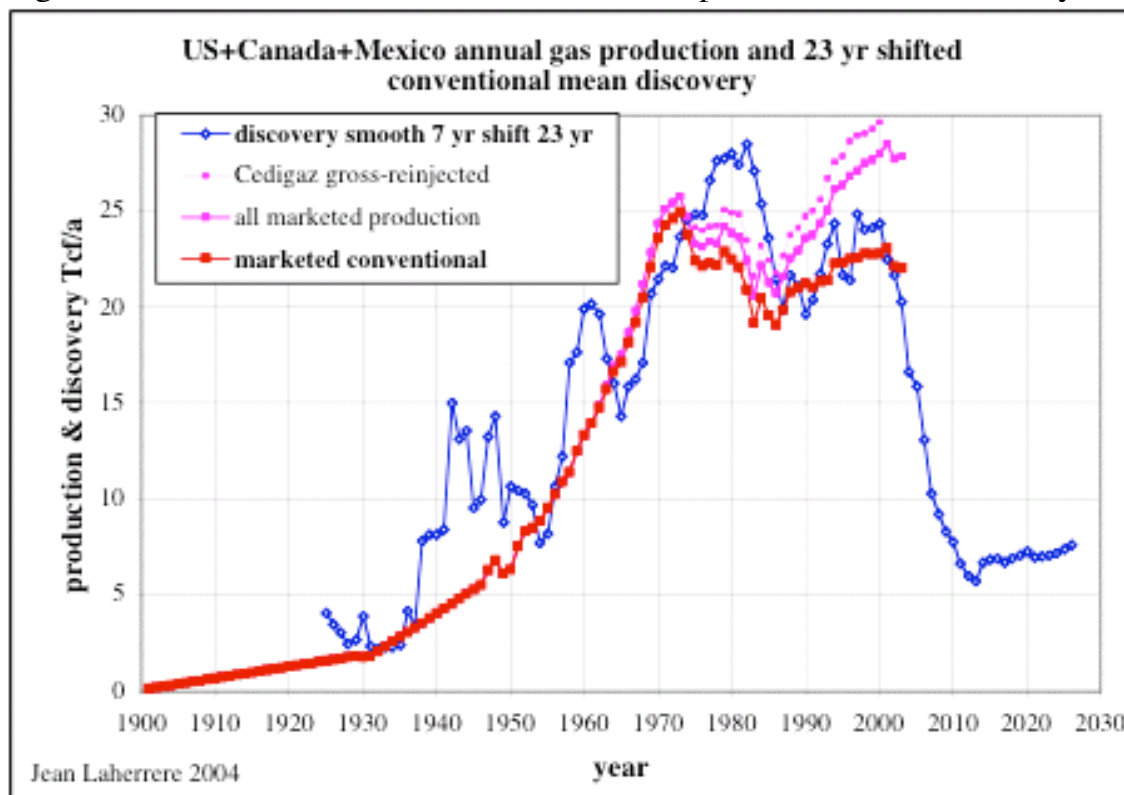
The World Energy Council has adopted my curve in their 2003 report. " Drivers of the energy scene"

Figure 90: same graph displayed by the World Energy Council
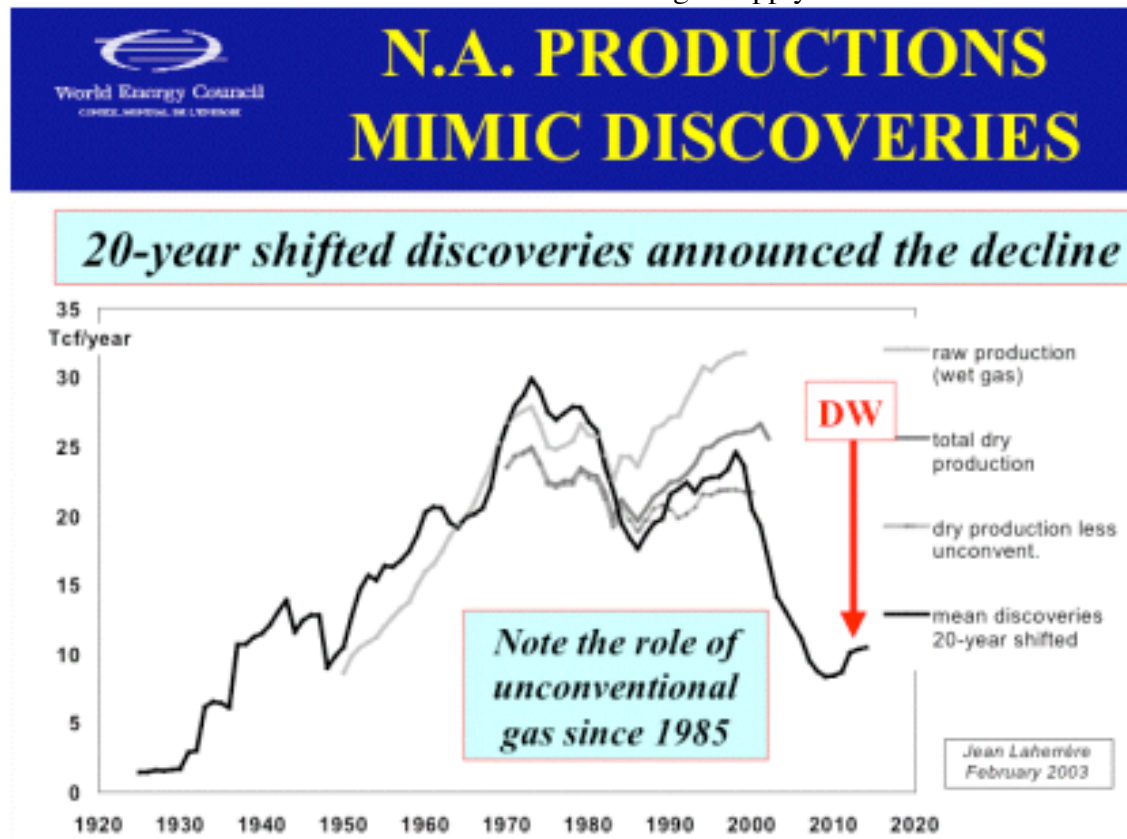
USDOE must have just realized that Canada will decline as the AEO 2004 forecast is drastically different from AEO 2003 as for the import from Canada (in 2025 2.5 Tcf instead of 5.5 Tcf) and for LNG import (in 2025 5 Tcf instead of 2 Tcf

Figure 91: USDOE forecast in 2003 and 2004 on import from Canada and LNG
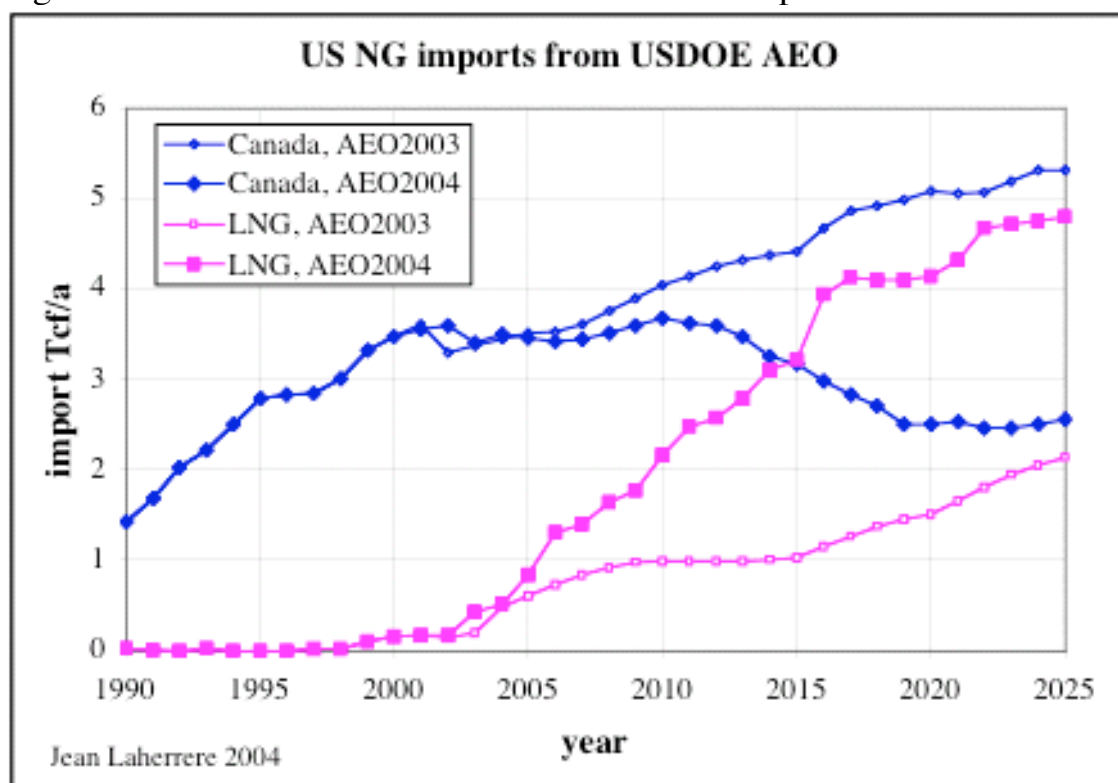
-**OPEC**

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

Figure 92: OPEC NG production
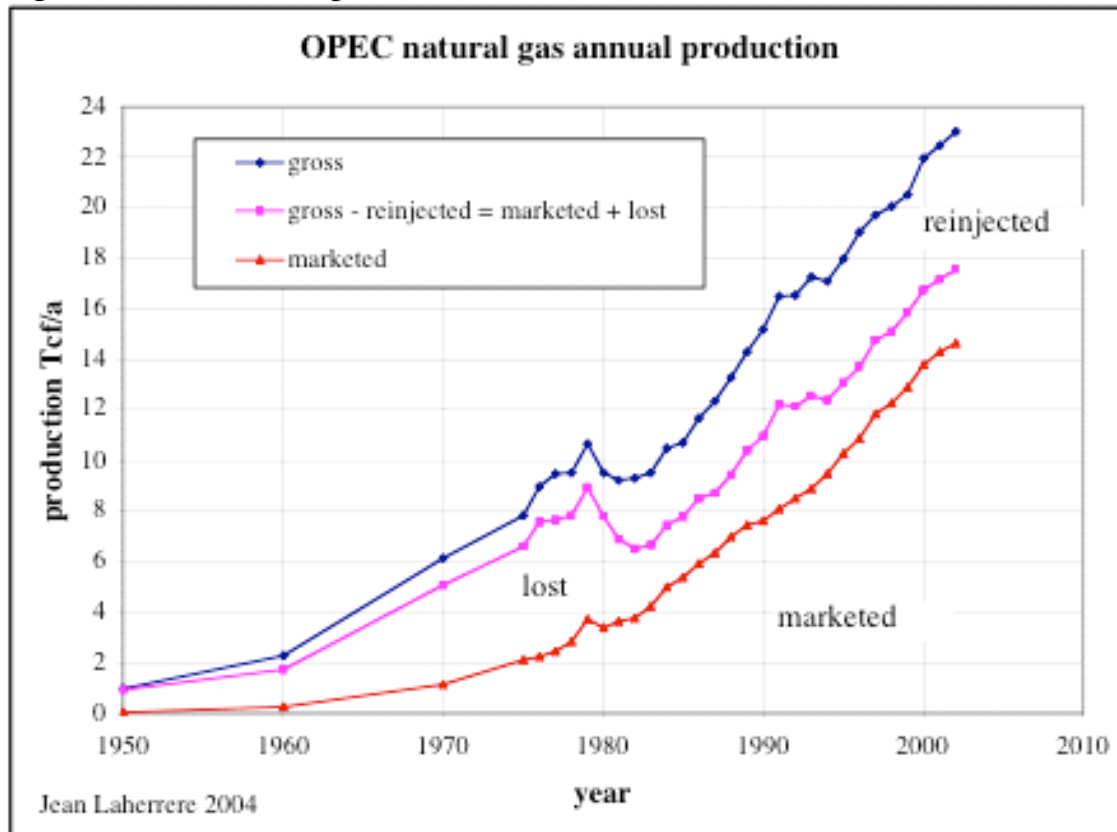
From OPEC AR 2002, production in G.m3:

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 93: OPEC NG remaining reserves from technical & political sources
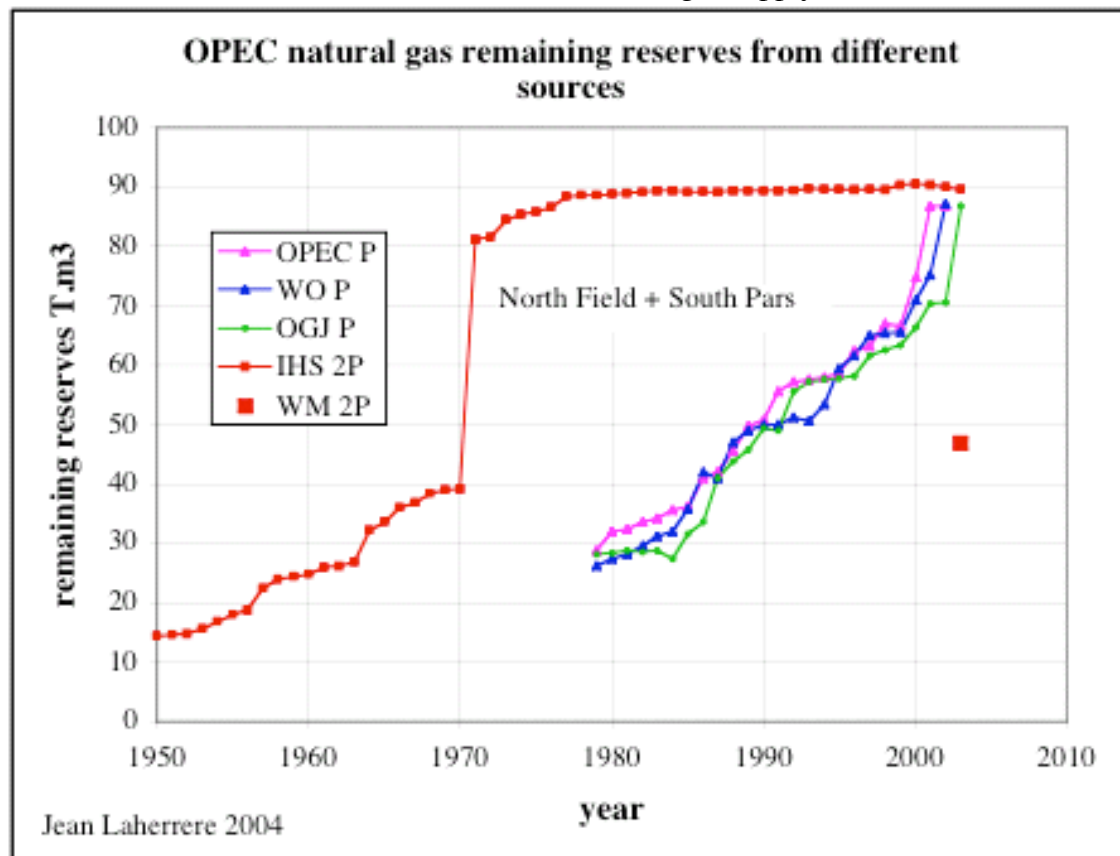
As indicated before, the discovery of North Dome in 1971 = North Field + South Pars (Qatar-Iran) upsets the curve which seems to trend towards 3600 Tcf. The production (marketed when gross-reinjected should be better) is difficult to extrapolate.

Figure 94: OPEC NG cumulative discovery & production
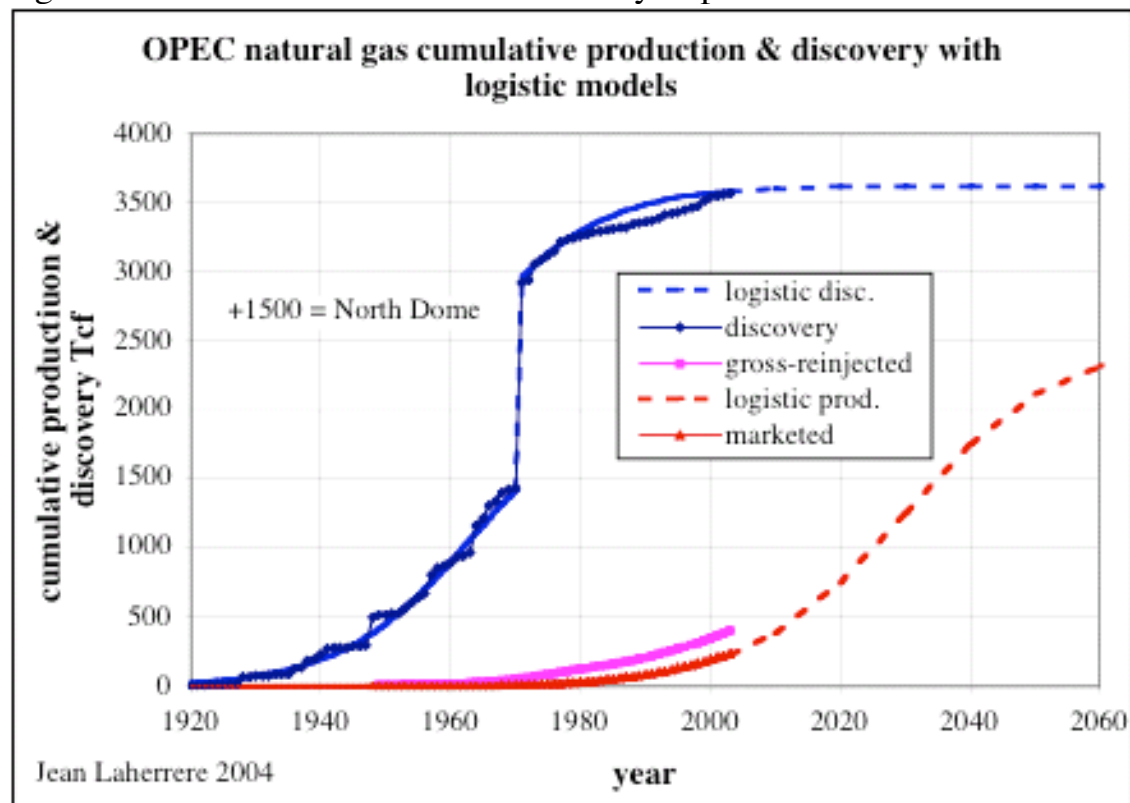
-**Indonesia**
The remaining NG reserves are chaotic when taken from OGJ, WO and OPEC which has changed drastically the values from 1999 to 2002. WM value is over 40 Tcf lower than IHS.
Figure 95: Indonesia NG remaining reserves from technical & political sources
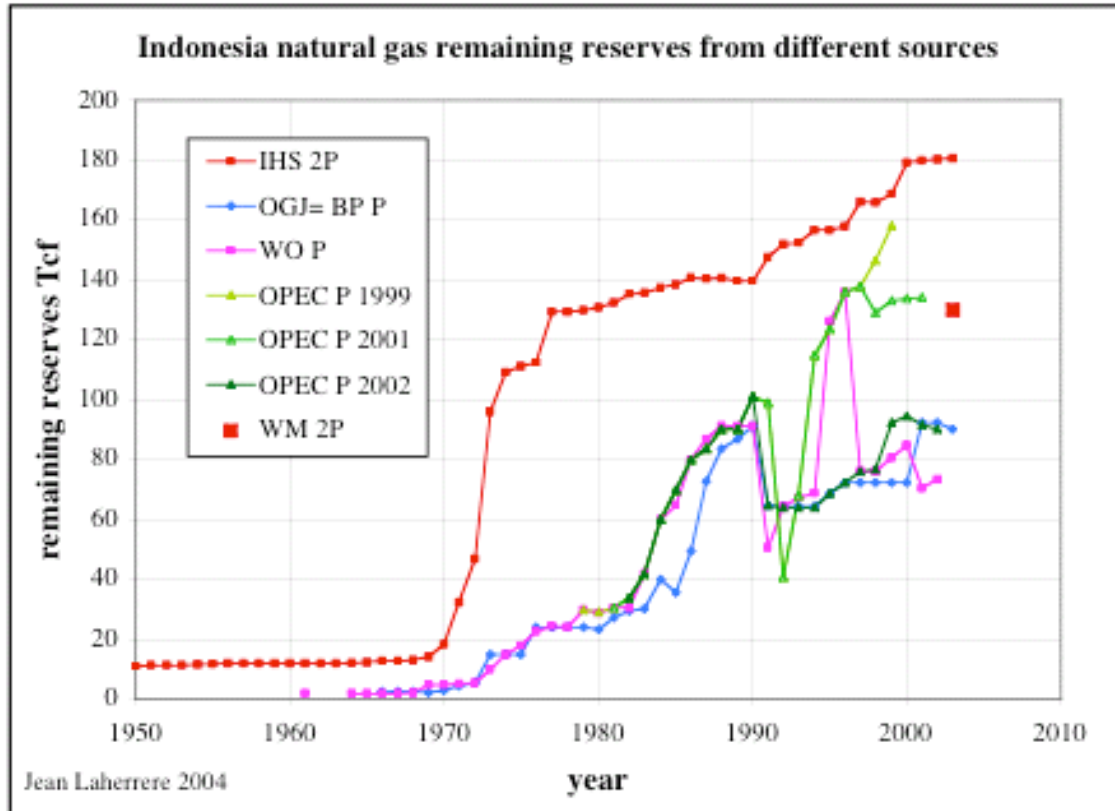
The creaming curve is modelled with 4 hyperbolas trending towards 280 Tcf
Figure 96: Indonesia NG creaming curve

Indonesia natural gas creaming curve

Jean Laherrere 2004
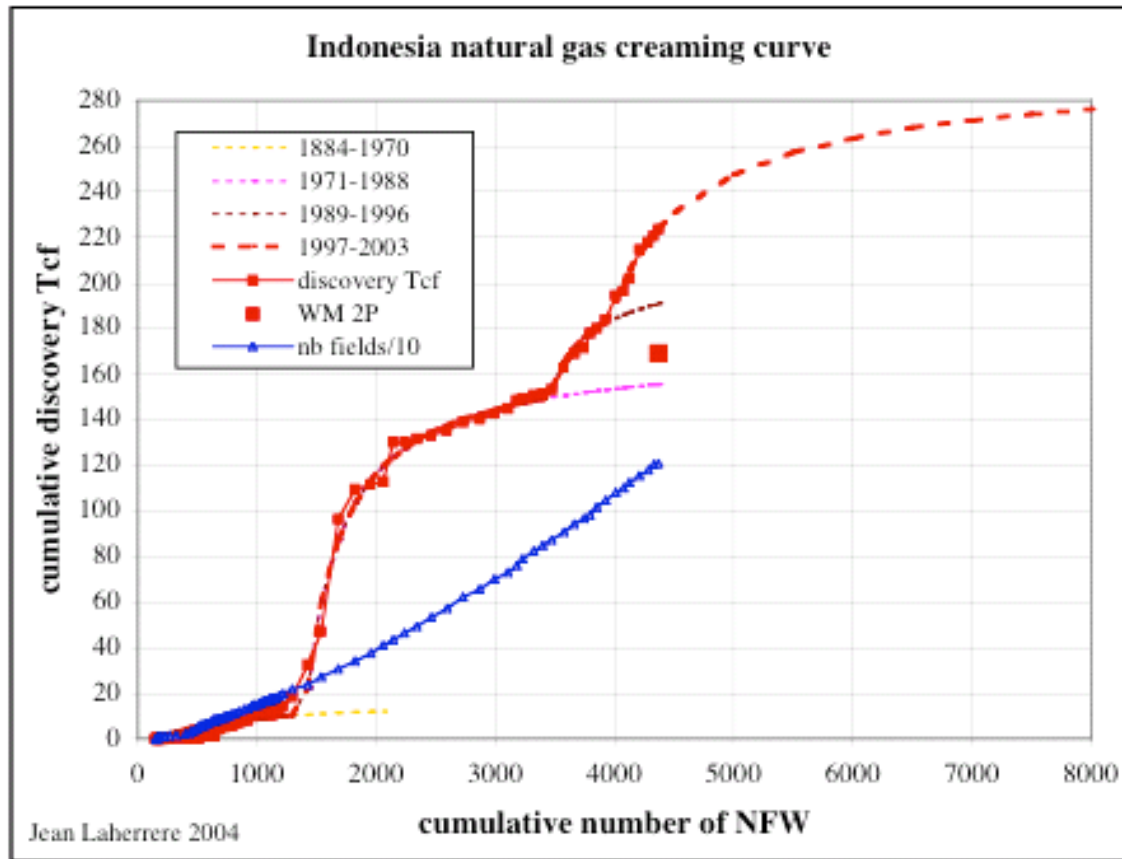
The cumulative discovery versus time is more difficult to model, but the marketed production could be modelled with an ultimate of 210 Tcf.

Figure 97: Indonesia NG cumulative discovery & production

Indonesia natural gas cumulative production & discovery with logistic models

Jean Laherrere 2004
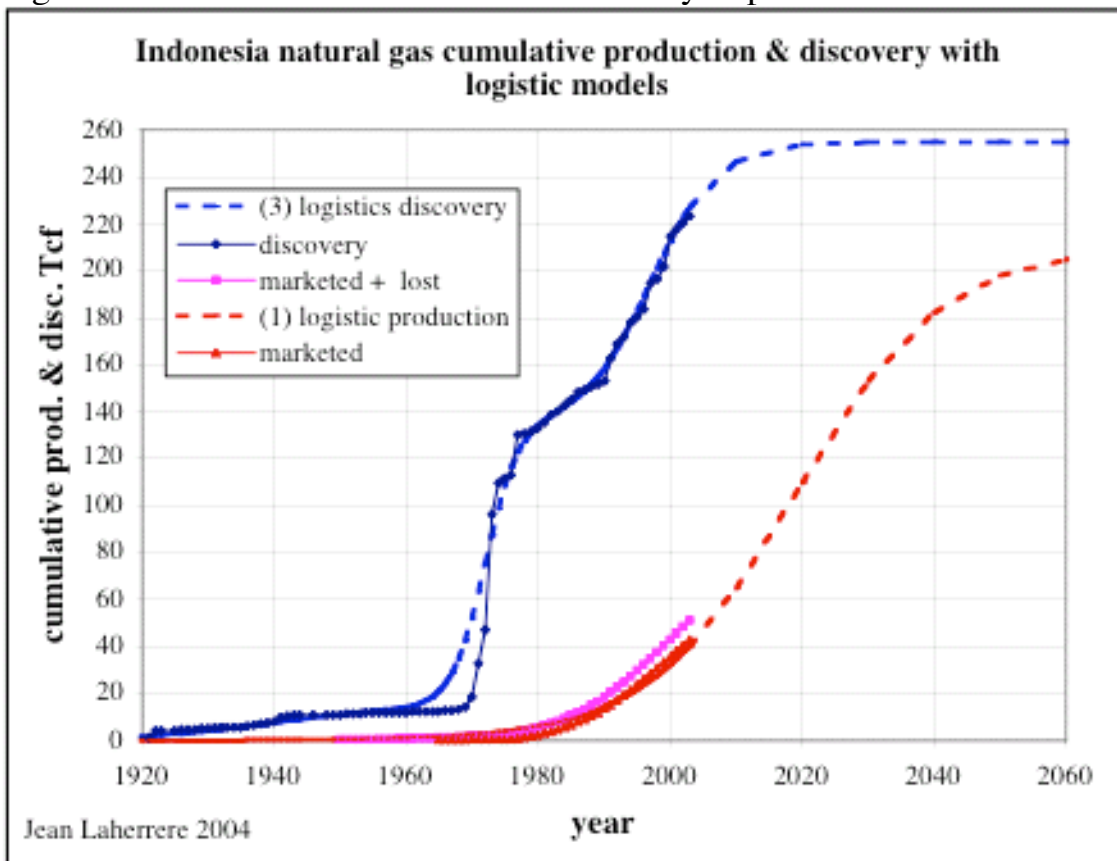
The annual production is modelled with 2 cycles (correlated to the 2 discovery shifted by 25 years) and will peak in 2025 at about 3.5 Tcf/a, 1 Tcf/a higher than now.

Figure 98: Indonesia NG annual discovery & production
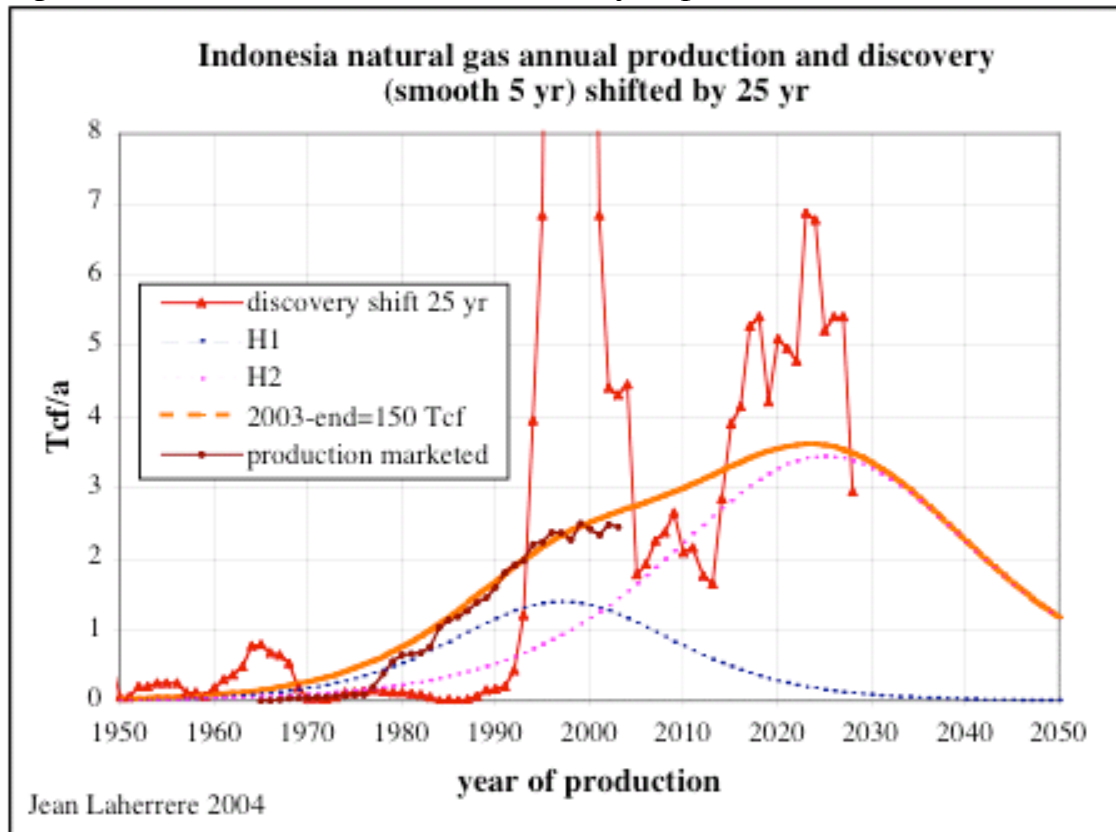
-**Saudi Arabia**

Saudi Arabia is pushing the gas production for its own use and bringing in international companies to explore.

The remaining NG reserves have grown since 1965 according to OGJ and WO when the technical data has remained flat since 1967.

Figure 99: Saudi Arabia NG remaining reserves from technical & political sources

Saudi Arabia natural gas remaining reserves from technical & political sources
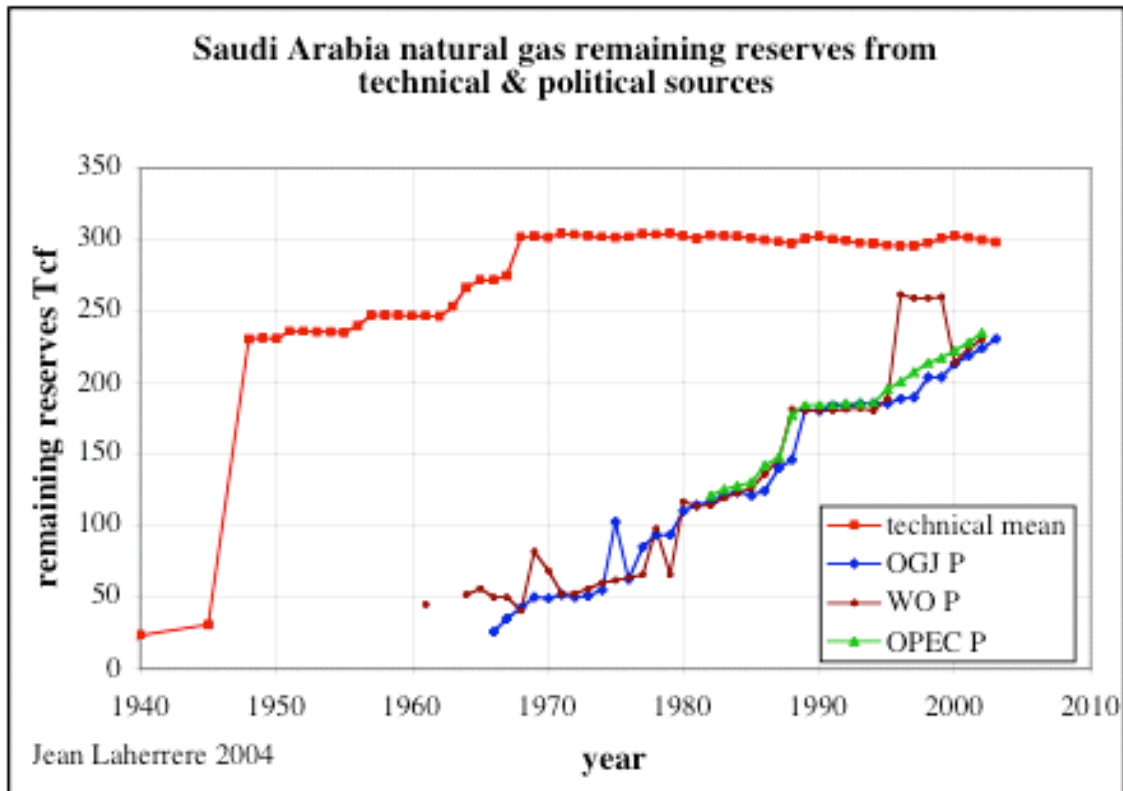
The creaming curve is using IHS data, which reports 200 Tcf for Ghawar reserves. Comparing to the oil estimates for 2P total discoveries being 391 Gb from Saudi Aramco 2004 (but 230 Tcf for Aramco 1980) , 313 Gb for IHS and 236 Gb from WM, it is likely that these gas estimates are optimistic

Figure 100: Saudi Arabia creaming curve

Saudi Arabia creaming curve 1935-2003
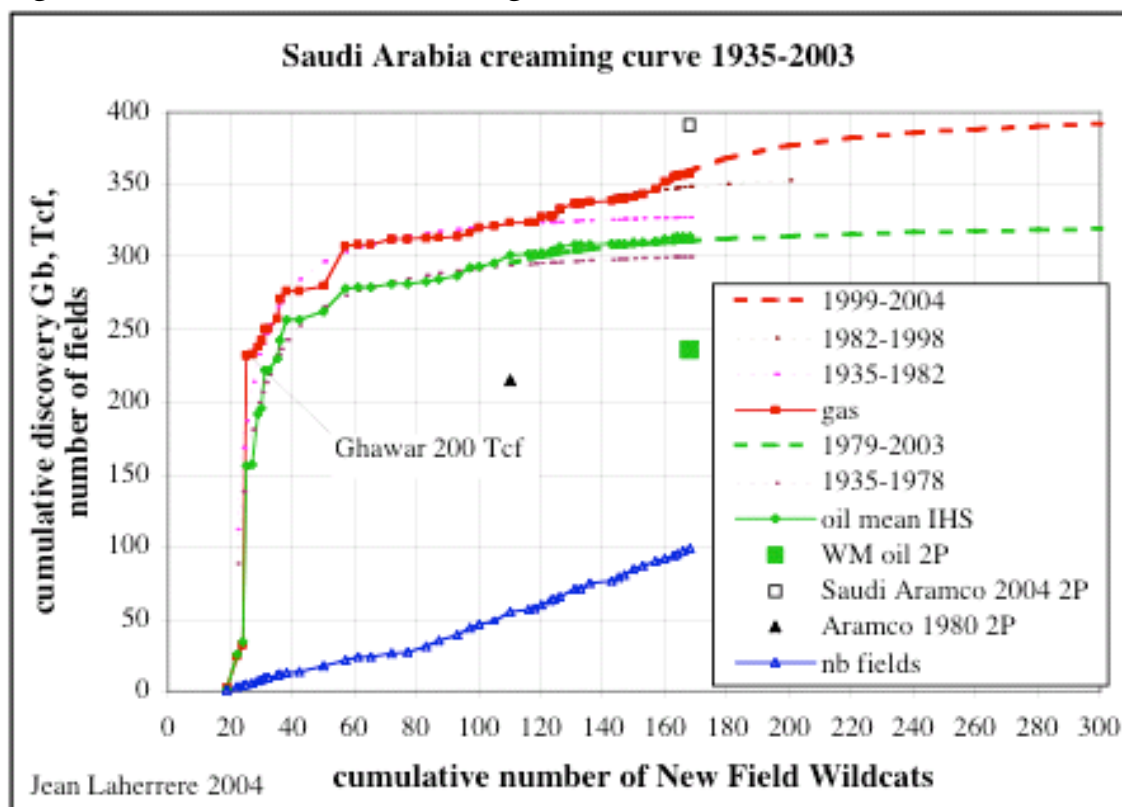
The cumulative NG discovery trends towards 400 Tcf
Figure 101: Saudi Arabia NG cumulative discovery & production
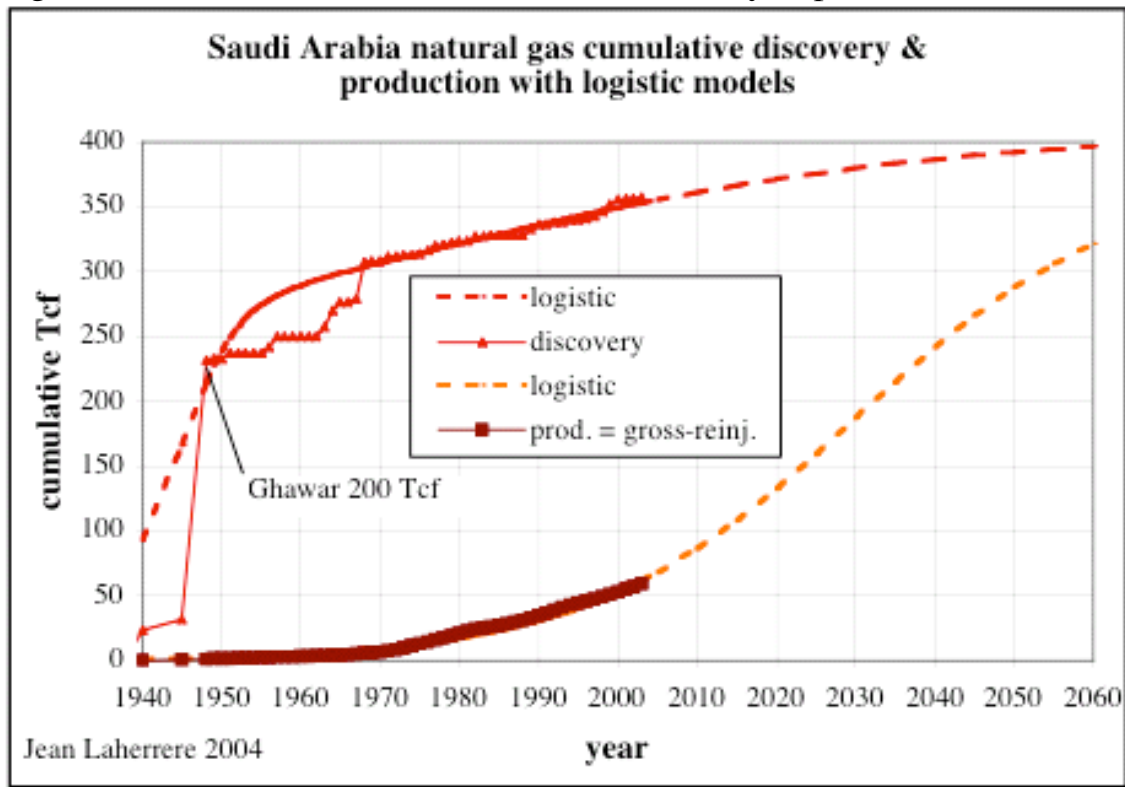
The annual production is forecast to peak around 2035 at 6 Tcf/a compared to 2 Tcf/a now
Figure 102: Saudi Arabia NF annual discovery & production
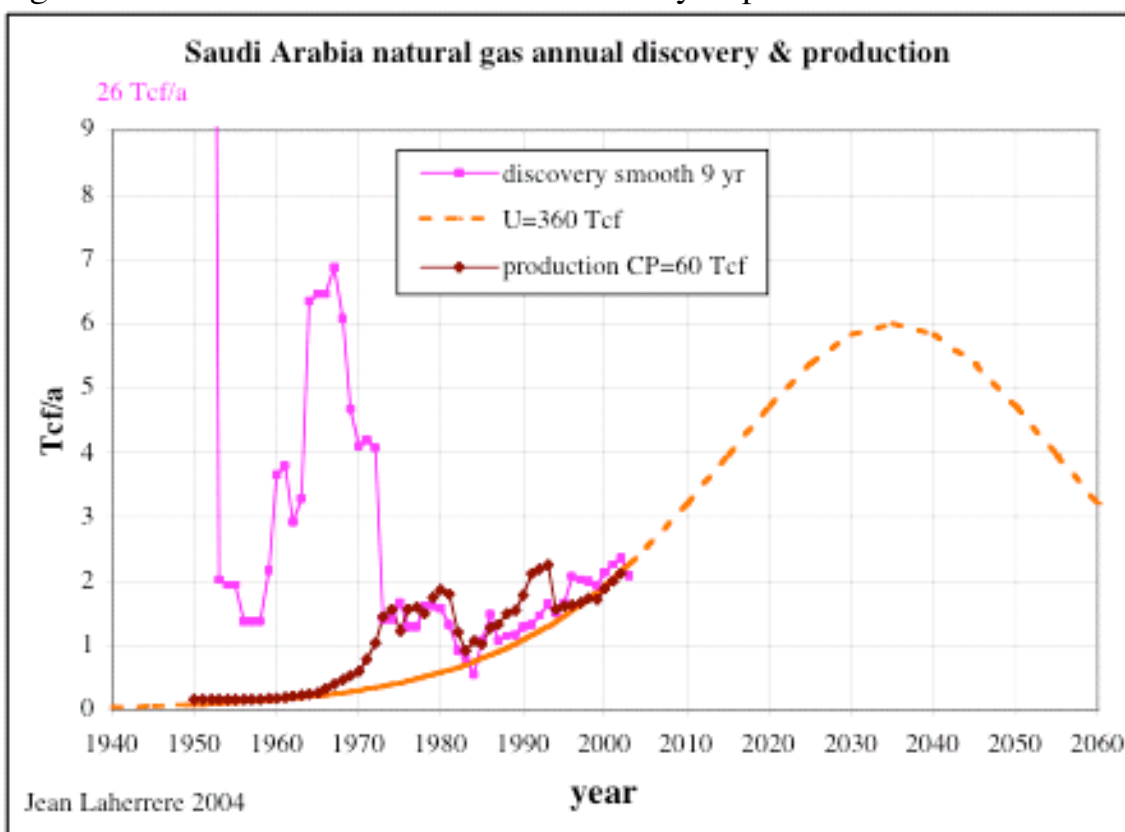
-**New Zealand**
New Zealand will be the first country to experience gas shortage.
IHS data is poor in this country as they report Kauri as 200 Mb when it is reported by the government, grouped with Rimu (IHS 6.8 Mb), as only 10.7 Mb
Figure 103: New Zealand NG remaining reserves from technical & political sources
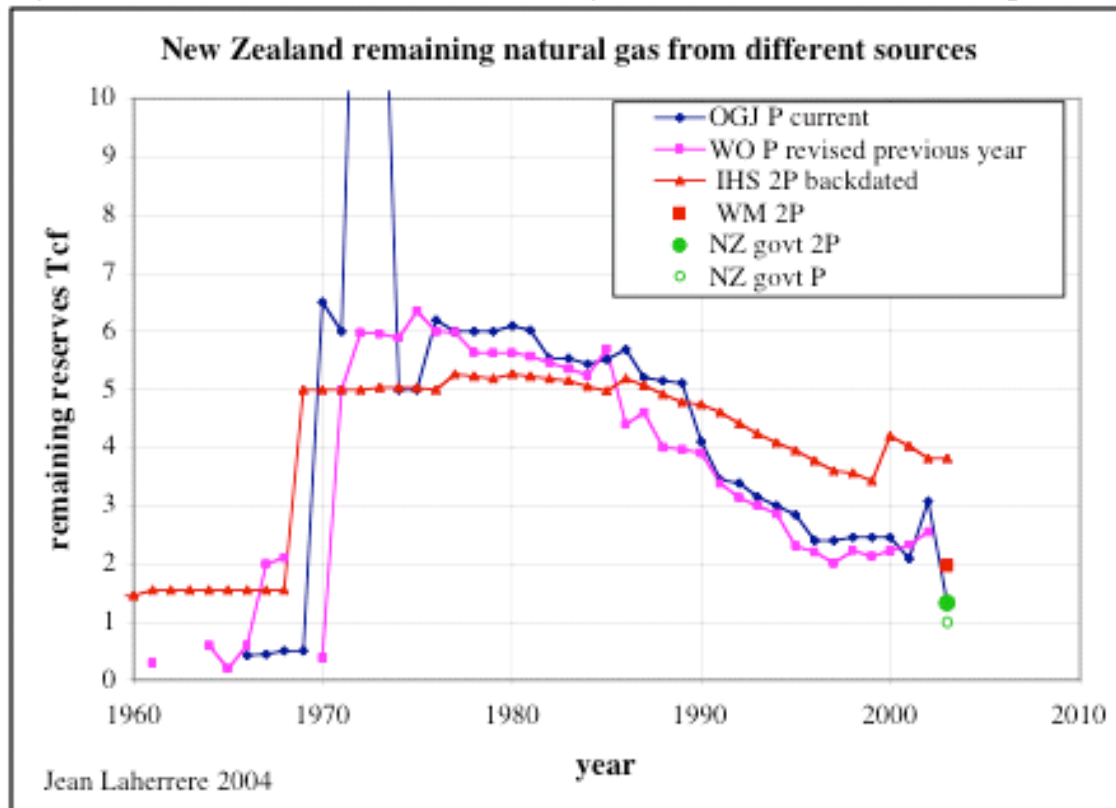
Maui, discovered in 1969 by Shell, produced in 1979 original reserves of 5500 PJ contract 4060 PJ= 4200 Gcf, in 1985 3930 PJ, 3800 in 2001 and 3562 PJ in 2003. But overproducing in 2001 twice over contract. Condensate is 3-4 times more profitable on a GJ base.
NZ government reports Maui original reserves first at 3.83 Tcf, in 2003 at 3,45 Tcf, but the decline gives less..
Figure 104: Maui gas decline
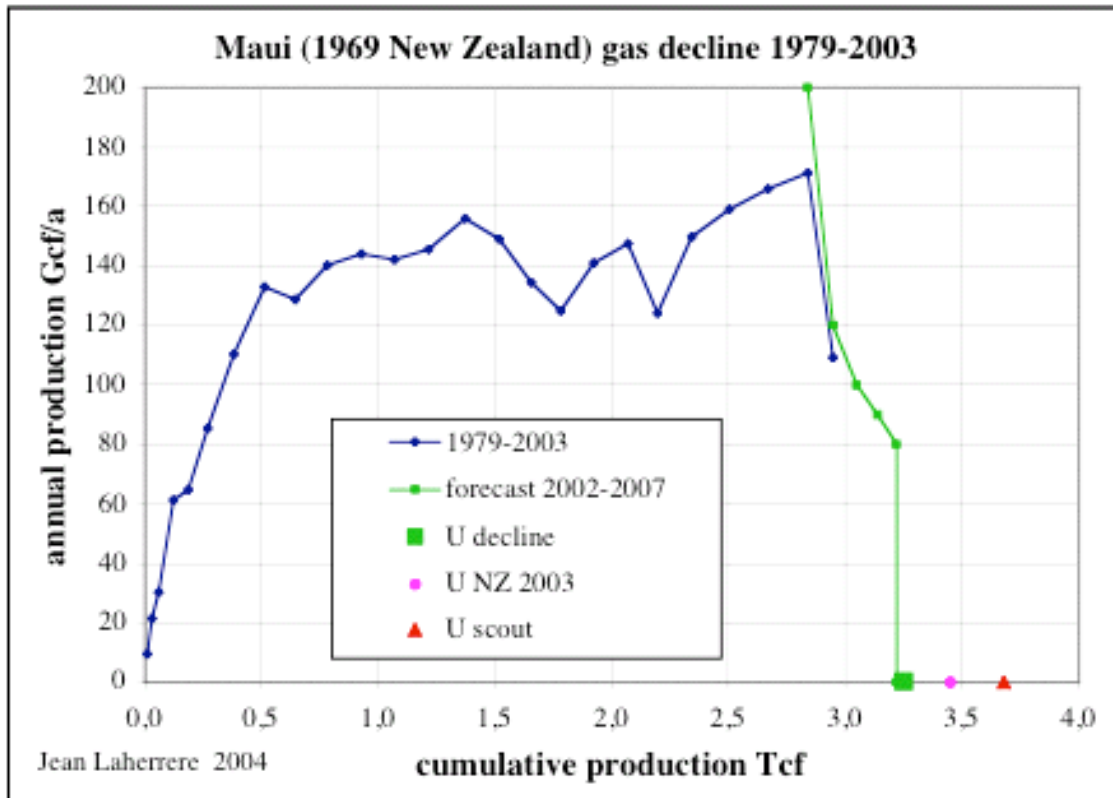
"Good practice" seems now to produce as much as possible and entail sharp decline. Shell has signed a contract with given volumes up to 2009 and will cease production in 2007 despite the contract.

Figure 105: New Zealand NG cumulative discovery & production
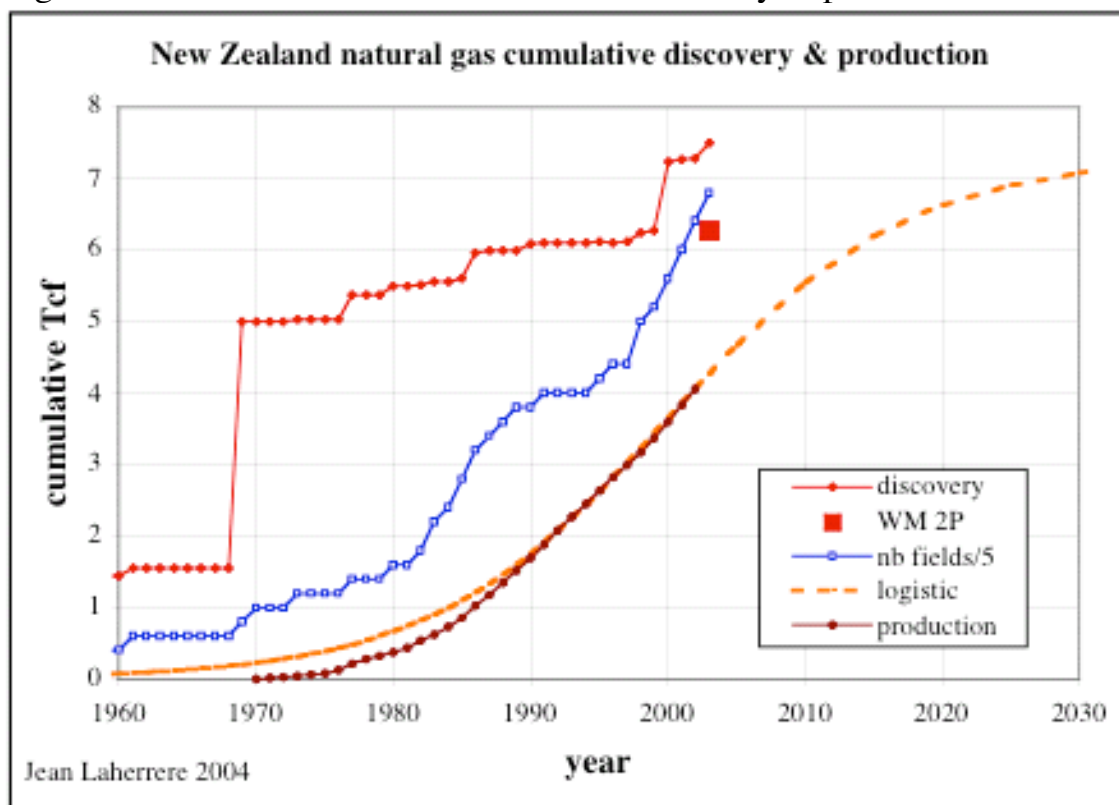
-**Turkey**

Turkey is a bad example of poor planning because they contracted as "take-or-pay" more than they now forecast their gas demand. (OGJ August 18 2003).

Figure 106: Turkey NG production, consumption with forecasts and take-or–pay contracts
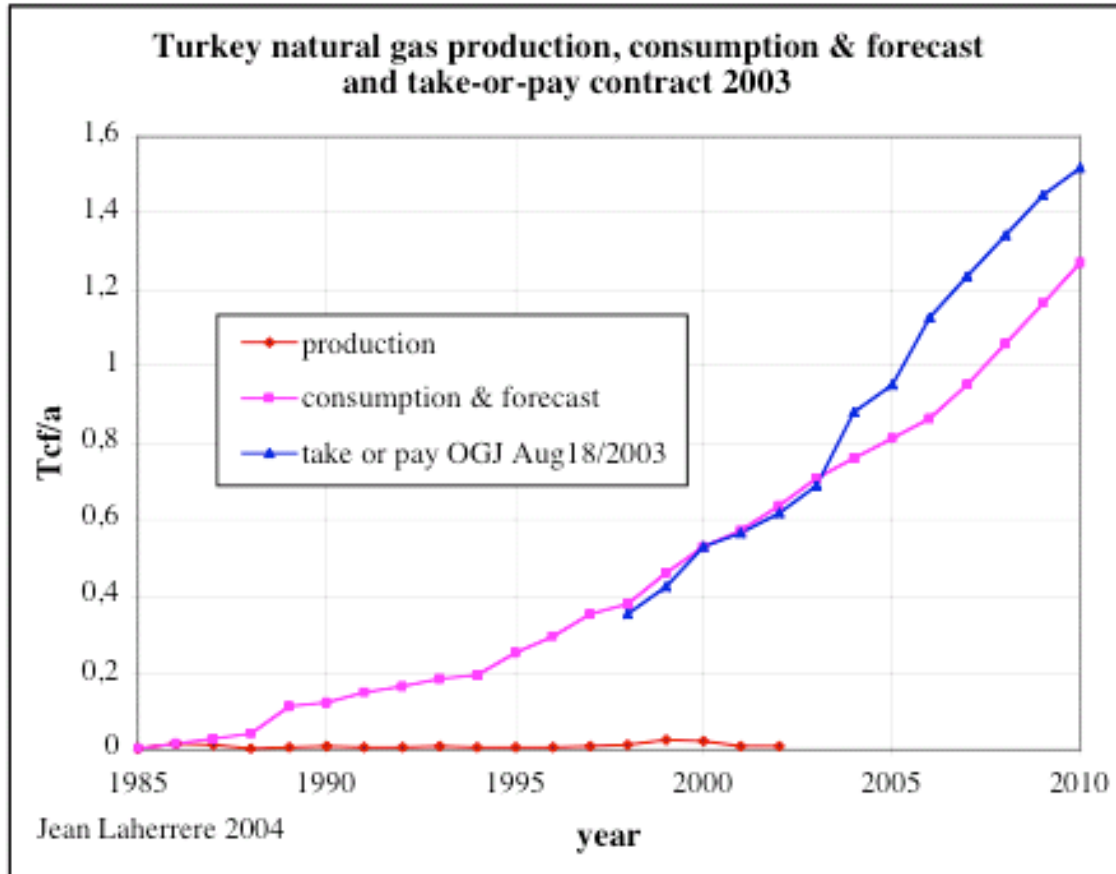
Their production is very small, however the remaining reserves were badly reported by OGJ and WO, and IHS has a value three times that of WM!

Figure 107: Turkey NG remaining reserves from technical & political sources
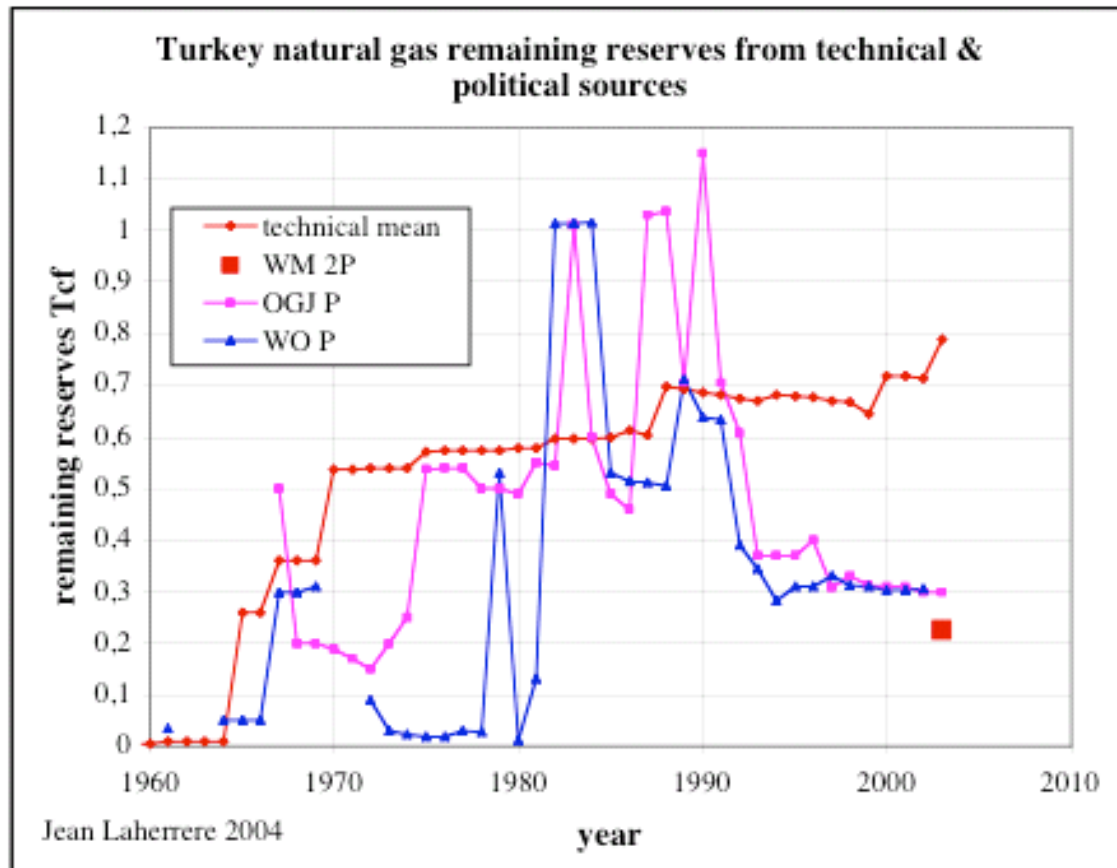
-**Reserves growth**
Gas recovery factor is about twice the oil recovery, as gas molecules are tiny and can move easily. In fact there is no impermeable seal except evaporites, and many gasfields are leaking some gas. So there are fewer possibilities to increase gas recovery factor and reserve growth 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 80 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 81 shows that the last trend does not confirm such value and for the rest of the world there is no justification, just a wishful thinking.
The Russian gas reserves are also overestimated as shown by the estimate for Urengoi (fig.56), Orenburg (fig.57) and even Medvezhye (fig.58).
Many other examples of negative reserve growth, as Maui (fig.104), Sable Islands, Frigg.
The Australian government (Geoscience Australia 2002) has used the USGS reserve growth function to fit their reserves change. It fits at the beginning but after 30 years the growth is trending to zero.
Figure 108: Reserve growth from Geoscience Australia
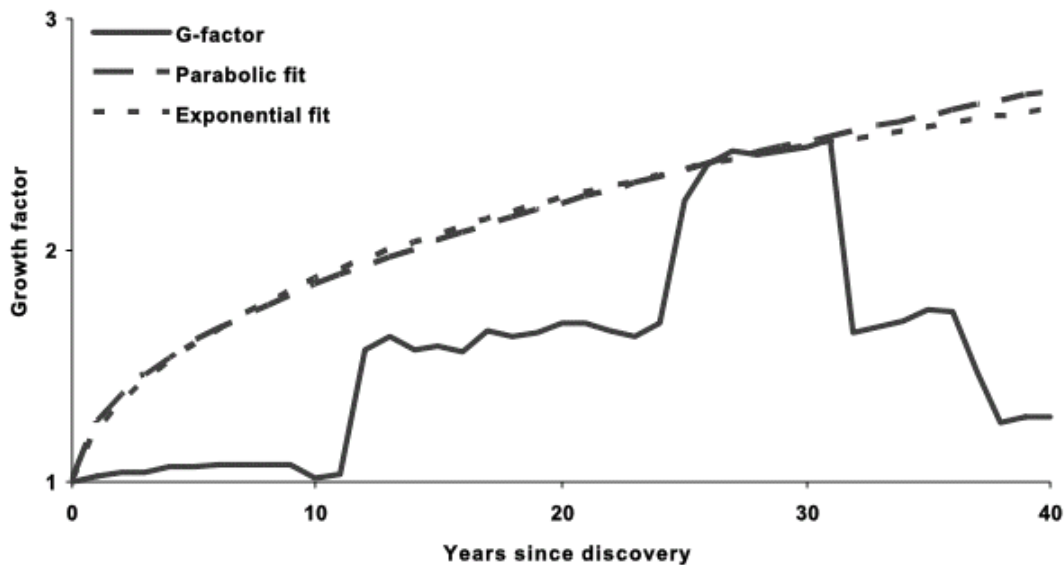
Figure 2.8 Reserves growth for Australian gas fields

There is no striking positive reserve growth example from gasfields, like Ekofisk for oilfield (due to compaction of the chalk reservoir).

-**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 109: Stranded gas reserve estimates from IHS
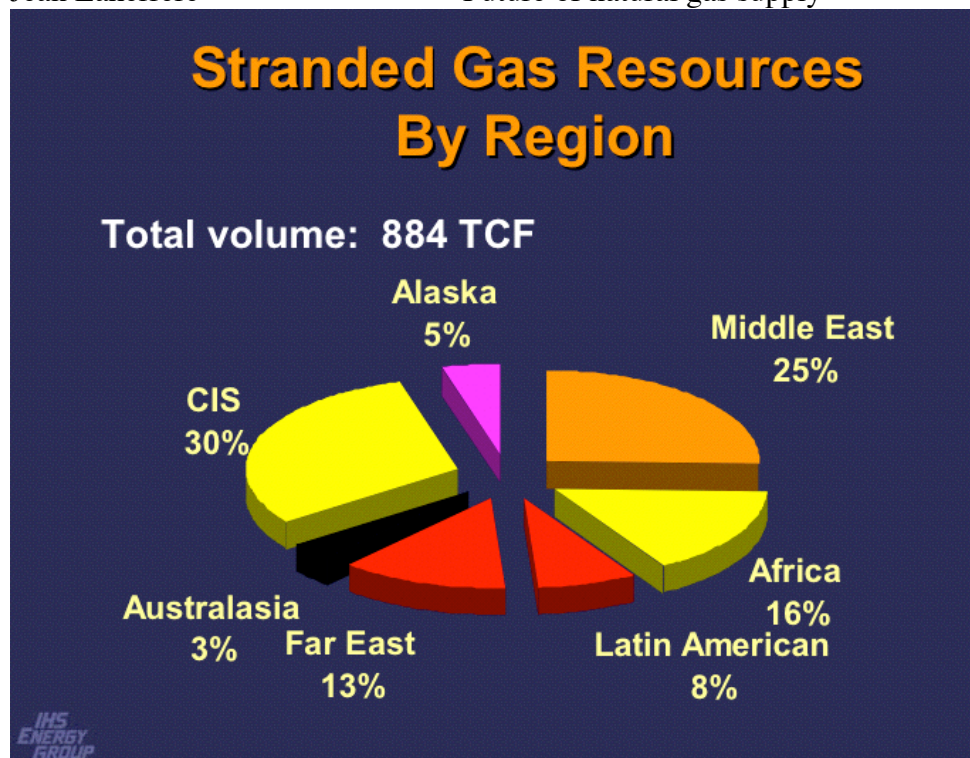
-**Unconventional gas**
   -**US**
The US unconventional gas production is in 2002 about 6 Tcf/a and USDOE (AEO 2004) forecasts a peak at 9 Tcf/a in 2020. The US tight gas from tight reservoirs and shales is about twice the production of coalbed methane.
Figure 110: US unconventional NG production & USDOE forecast
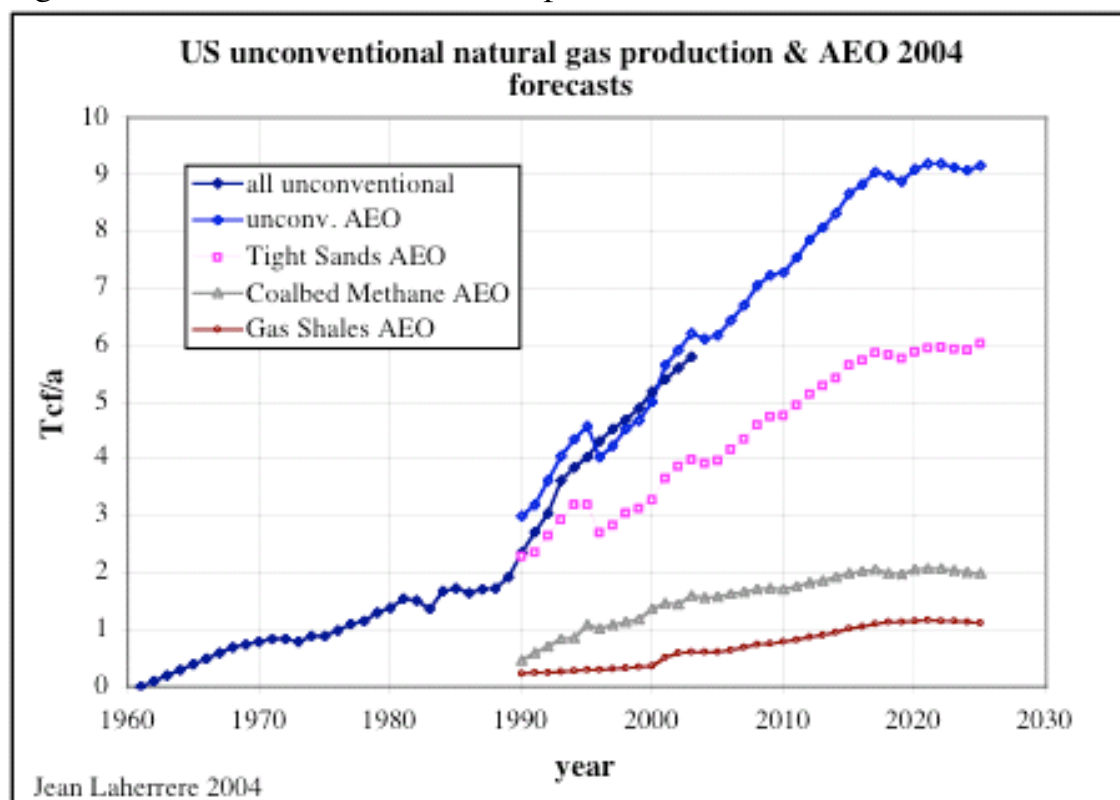
USDOE AEO forecasts a production from 2004 to 2025 of 178 Tcf. They report unconventional NG proved reserves as 76 Tcf (51 Tcf tight sands, 19 Tcf CBM and 5 Tcf gas shales) and 475 Tcf of undeveloped resources (342 Tcf tight sands, 79 Tcf CBM and 54 Tcf gas shales).

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 111: US unconventional reserves from GTI = 32 Tcf
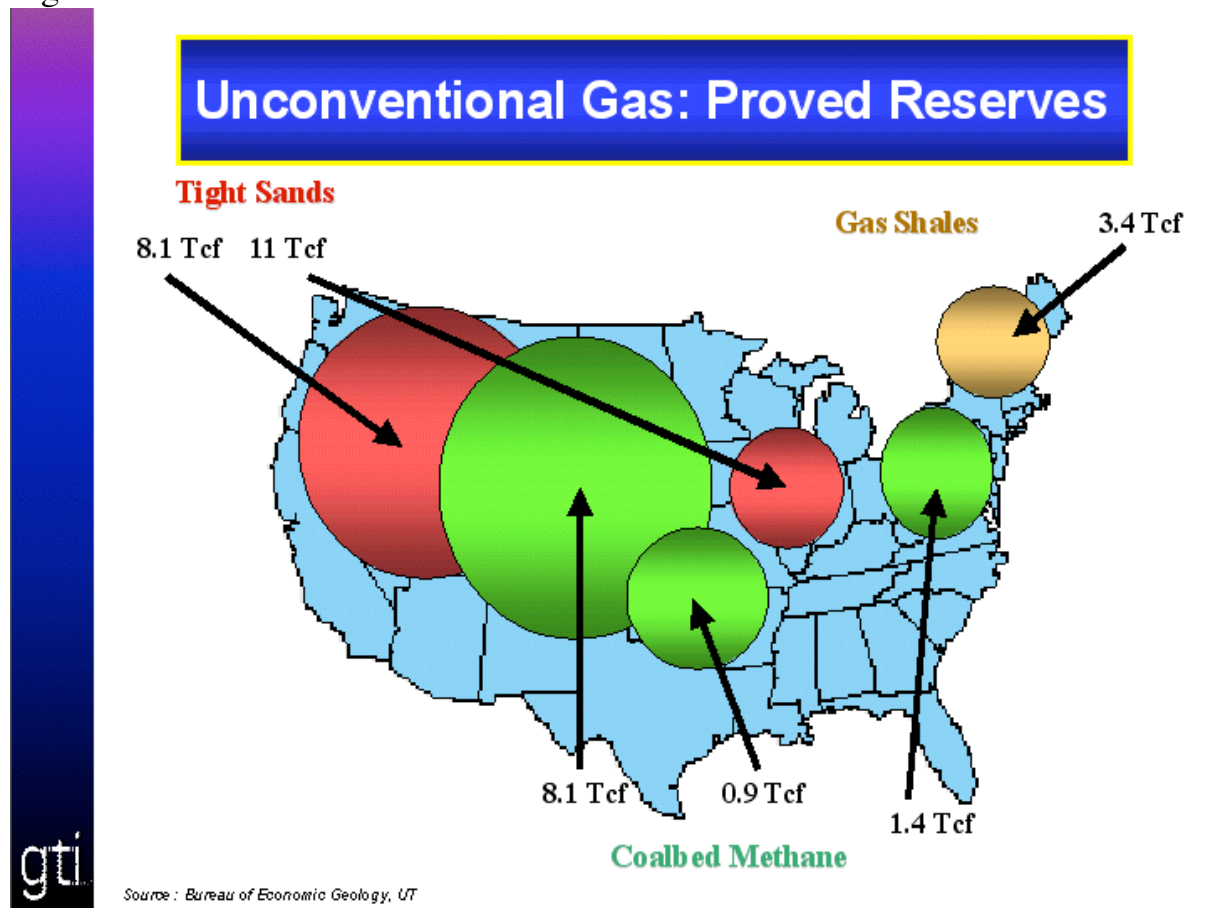
-**rest of the world**
        -**CBM**
From the USDOE forecast on CBM production (AEO 2004) peaking in 2020 around 2 Tcf/a, it is possible to estimate the US CBM ultimate at about 100 Tcf. As the US reserves in coal is estimated by the BGR to be about one third of the world's coal reserves, it could 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 the amount of oceanic hydrates contains carbon more than in 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 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 112: Evolution of Hydrate volume from Milkov 2004
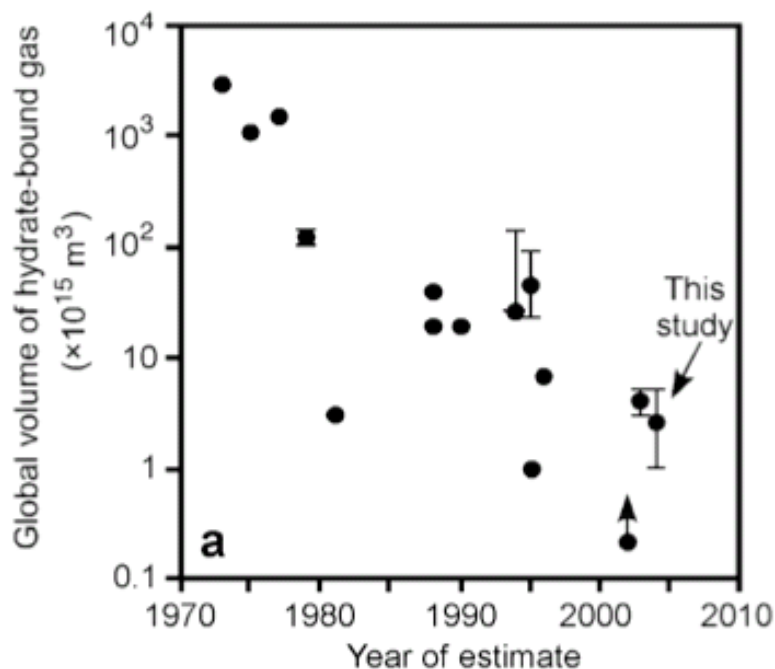
OPD legs 164 (Blake Ridge) and 204 (Hydrate ridge) find only low concentration of hydrate. In the thousand holes drilled by Joides-ODP only three holes have found massive hydrate thicker than 15 cm. Most occurrences are reported not from evidence of hydrate core, but by proxy evidence as seismic (BSR) or chloride concentration, 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 (http://www.netl.doe.gov/scng/hydrate/about-hydrates/nankai-trough.htm) *<<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.<<*
In 2000 Japan in search of hydrate core drilled 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 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.

-**Conclusions**
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 than140 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, most continents consume what they produce and there are three different gas markets.
New Zealand is the first country that will experience gas shortage.

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

OPEC gas production will peak around 2030-2040

In brief local gas shortage may occur much sooner than global oil shortage

It is very difficult to foresee gas price, but cheap prices are gone except for short periods when poor investments are badly timed.

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