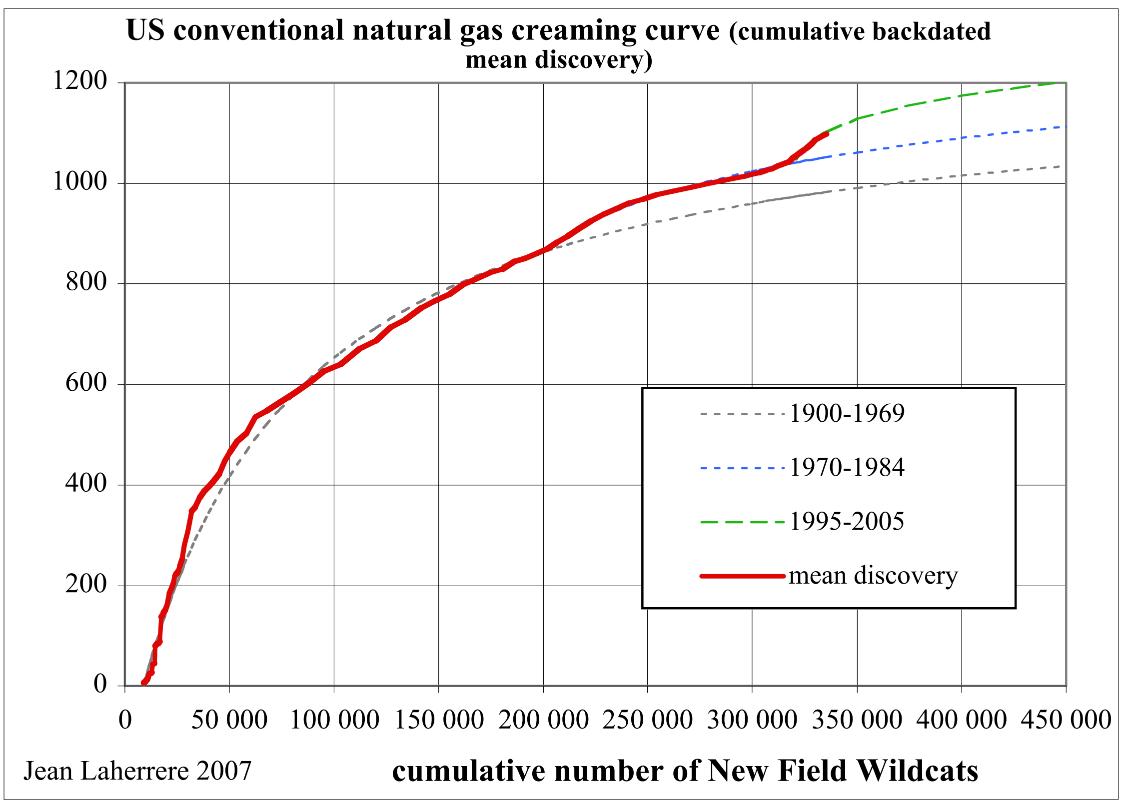
Jean Laherrere 20 August 2007

North America natural gas discovery & production

-US

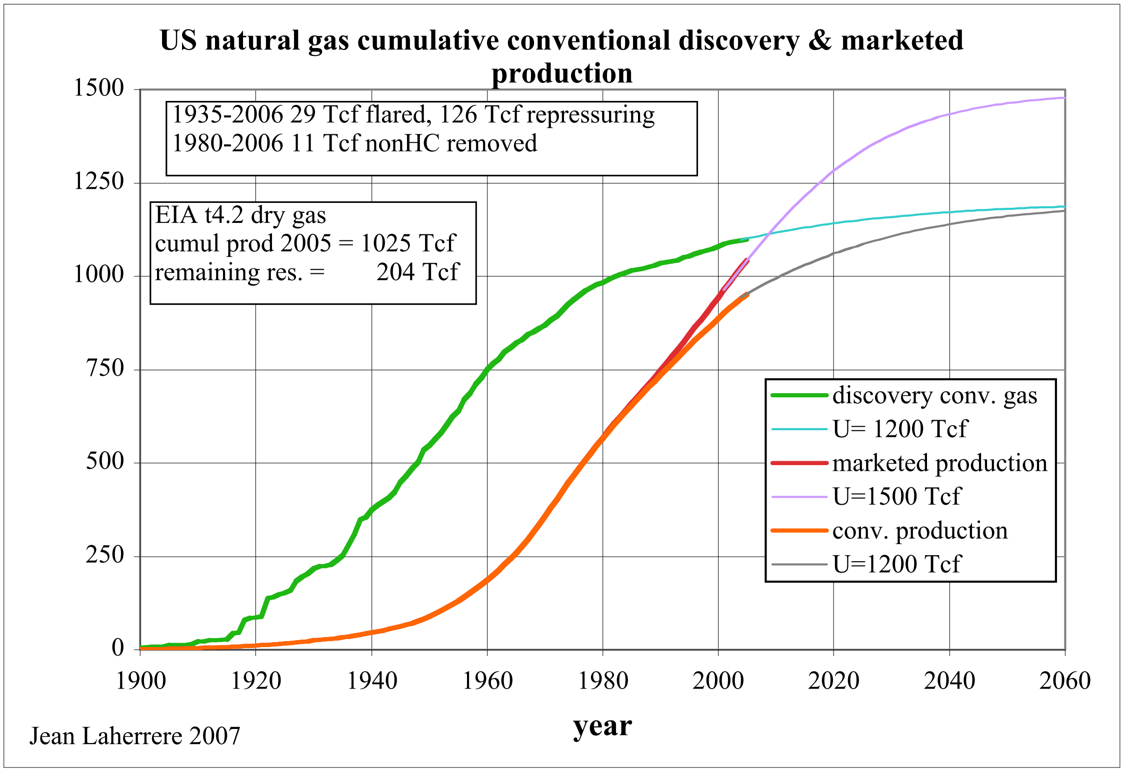
From USDOE/EIA-0534 1990 "US oil and gas reserves by year of field discovery" up to 1988 and EIA annual reports using new discovery and new reservoir in old fields after 1988, it is possible the approach the mean backdated conventional discovery (or proved plus probable) from 1900 to 2005. The plot of cumulative discovery versus cumulative number of New Field Wildcats (NFW) is called the creaming curve, which can be modelled with several hyperbolas. The first cycle 1900-1969 is Lower 48, the second cycle1970-1994 is Alaska and the third cycle 1995-2005 is deepwater. It is unlikely to have a fourth cycle. The known discoveries up to 2005 is 1100 Tcf and 1200 Tcf could be reached by drilling more than 100 000 NFW representing more than 60 years of 2005 NFW drilling (1600 NFW). We assume then that the conventional gas ultimate is 1200 Tcf

Figure 1: US conventional natural gas creaming curve 1900-2005 and models



The cumulative discovery versus time is also easily modelled with a S curve (logistic function) with an asymptote of 1200 Tcf.

Figure 2: US natural gas cumulative conventional discovery and marketed production and models



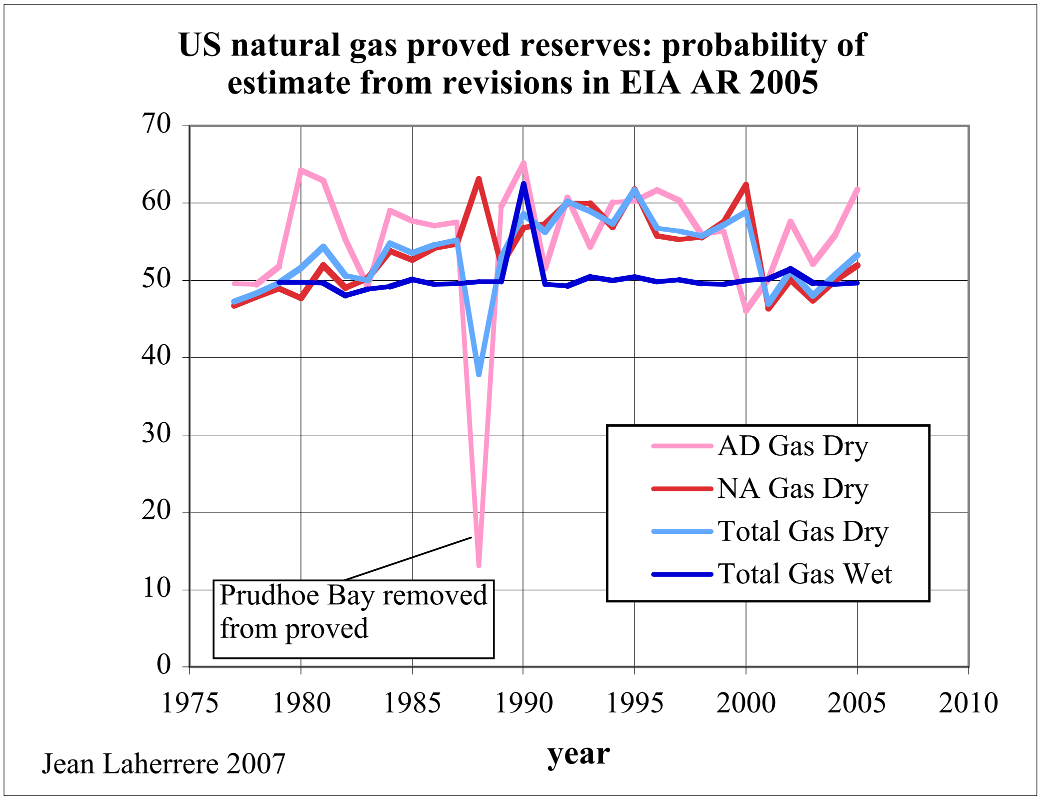
The cumulative marketed gas production is plotted up to 1040 Tcf in 2005, and conventional gas up to 950 Tcf compared a 1025 Tcf reported as cumulative dry gas production (Table 4.2 Crude Oil and Natural Gas Cumulative Production, Proved Reserves, and Proved Ultimate Recovery,1977-2005).

Conventional discovery is modelled with an ultimate of 1200 Tcf when marketed production with an ultimate of 1500 Tcf, as conventional production also with an ultimate of 1200 Tcf.

The 1100 Tcf conventional discovered up to 2005, with a cumulative production of 950 Tcf, leaves about 150 Tcf remaining to be compared to the 200 Tcf estimated by EIA as proved remaining reserves including unconventional gas (tight reservoirs, shale gas and CBM)?

But flared, vented (29 Tcf from 1935 to 2006), as nonHC gasses removed (11 Tcf from 1980 to 2006) are not counted. Assuming 50 Tcf for the total cumulative flared, vented and nonHC gases removed and that is not counted towards the initial discovery, it decreases the EIA remaining proved reserves down to 150 Tcf, equal to our estimate for mean. But the so called proved reserves assumed to represent a 90% probability is in fact displays a much lower probability when looking at EIA annual reports for positive and negative revisions.

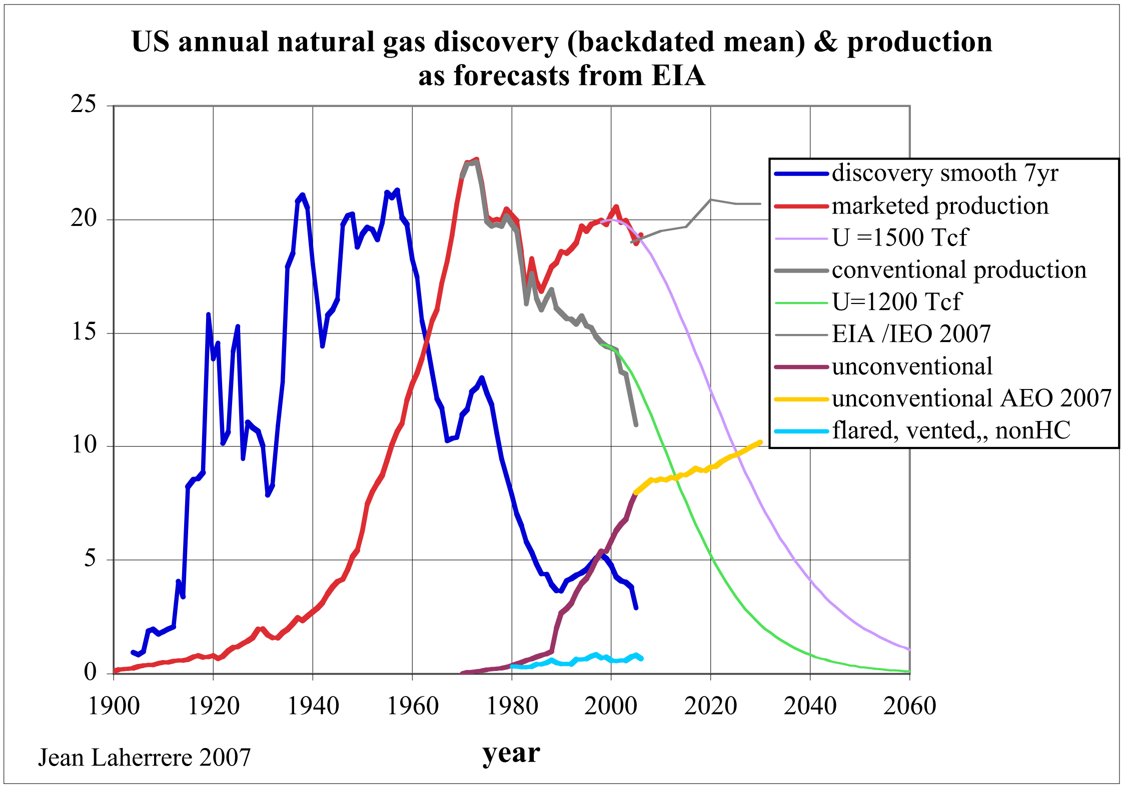
Figure 3: US natural gas proved reserves : probability of estimate from revisions in EIA AR2005



it appears that the average probability of US NG estimates is close to 50% which is the SPE definition of proved plus probable.

Figure 3 is converted from cumulative into annual. The forecasted marketed production decline is sharp but about parallel to the decline of conventional discovery with a lag of about 30 years

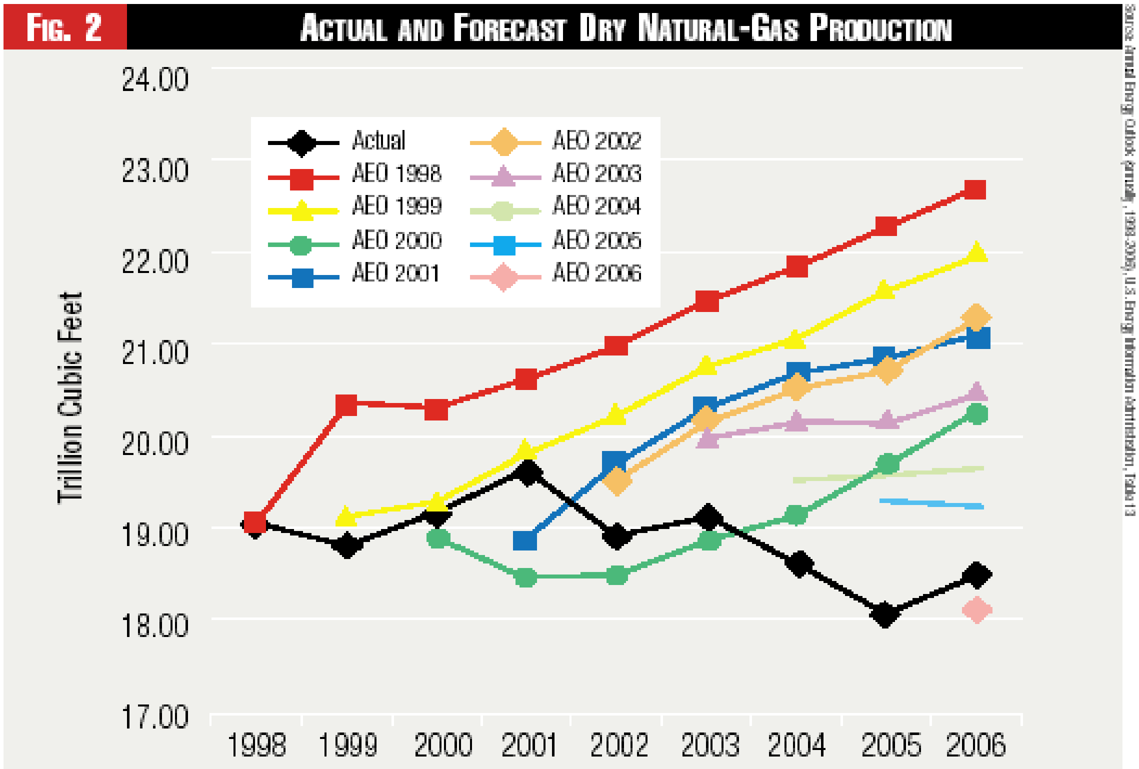
Figure 4: US annual natural gas discovery (backdated mean) and production, as EIA forecasts



The EIA IEO 2007 forecast sees an increase from now to 2030 at 21 Tcf when our forecast is about 10 Tcf less than half ! But EIA forecasts have been always too optimistic in the past.

Considine T, Clemente F 2007 “Gas-market forecasts –betting on bad numbers” public Utilities fortnightly July p53-59 compiles past forecasts

Figure 5: US natural gas production: compilation of EIA forecasts



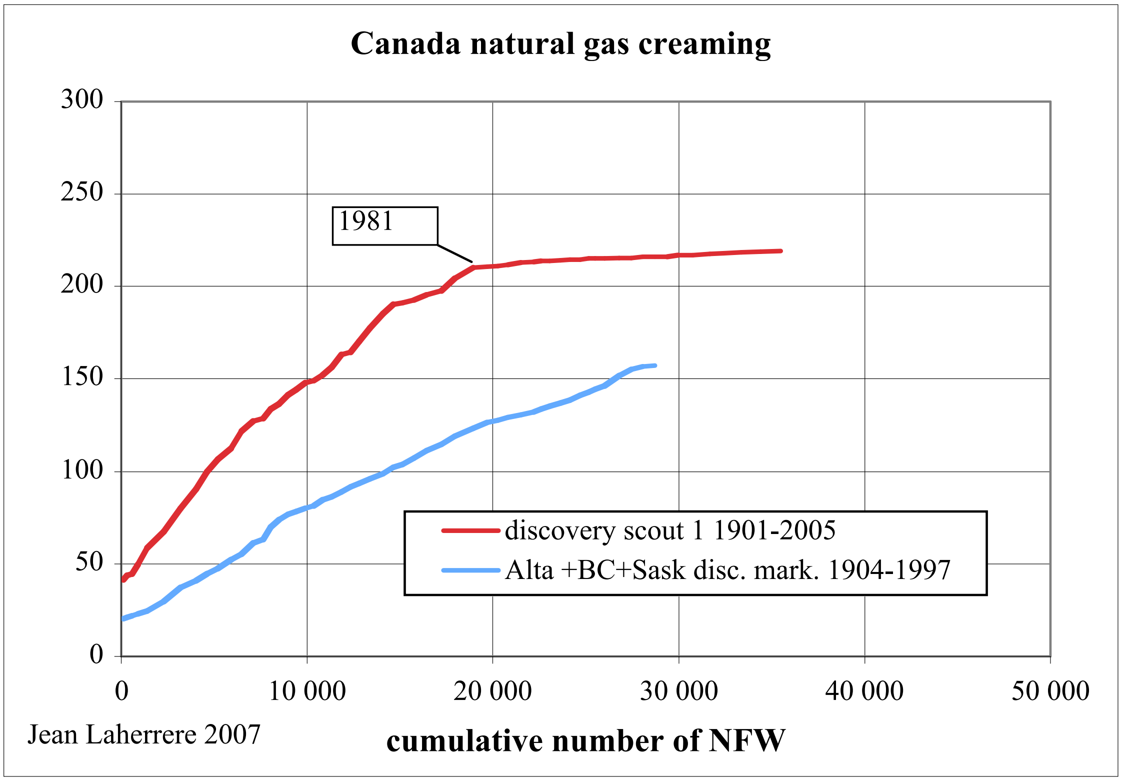
-Canada

The same approach is carried out for Canada. All data are public but they are not found on the web and data is for pools, not for fields, making creaming curve more difficult. The number of NFW is not available on the complete series. I was in charge of exploration for Total Canada from 1966 to 1971, exploring the Western Canadian Sedimentary Basin, but also the Arctic, Labrador (finding gas in Bjarni), as Michigan.

I presented a paper in 1999 in Calgary "Assessing the oil and gas future production and the end of cheap oil ?" CSEG Calgary April 6 http://dieoff.com/page179.htm, where I compiled the Provincial reserves books. But it is difficult to update as estimates are reported by pools and there are over 30 000 pools. Furthermore the Canadian Geological Survey stopped by lack of staff carrying out inventory open to public to be done by private companies.

18 gasfields were discovered in the Mackenzie Delta and 21 gas fields in the Beaufort Sea with a range mini 7 Tcf ; mean 9 Tcf and maxi 12 Tcf. It is why a pipeline is not yet built !

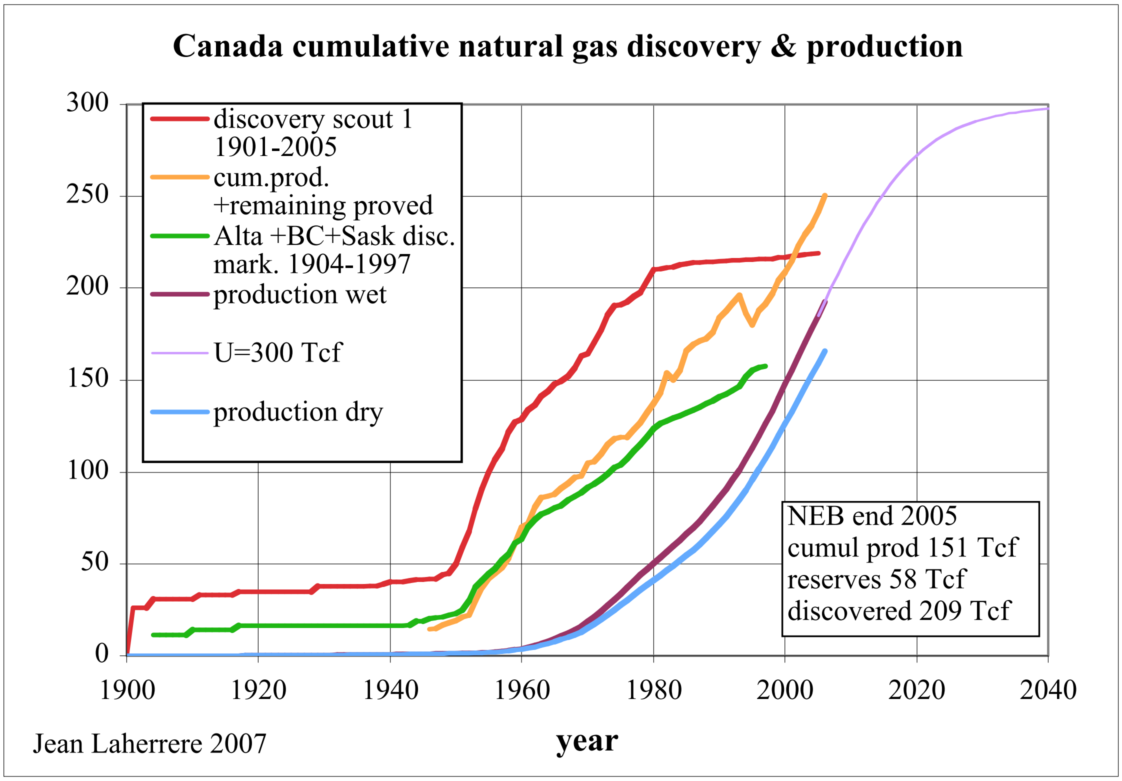
Figure 6: Canada natural gas creaming curve



So data is unreliable and varies and it is difficult to estimate an ultimate. We have chosen 300 Tcf, which seems reasonable, as fitting well the cumulative production and the various discovery data. Of course the cumulative production plus remaining proved reserves is showing a continuous reserve growth due to the omission of probable. But since 2003 Canada has abandoned the SEC rules and allows company to report probable (National Instrument NI 51-101 – Standards of Disclosure for Oil and Gas Activities). So past discoveries have to be corrected, this inventory is not available for the whole Canada and should be reported by fields and not by pools..

Discovery was high at the beginning of the century with the discovery of the largest gasfield Medecine Hat, flattened and started again after 1945. The break is not visible on the creaming curve.

Figure 7: Canada natural gas cumulative discovery & production

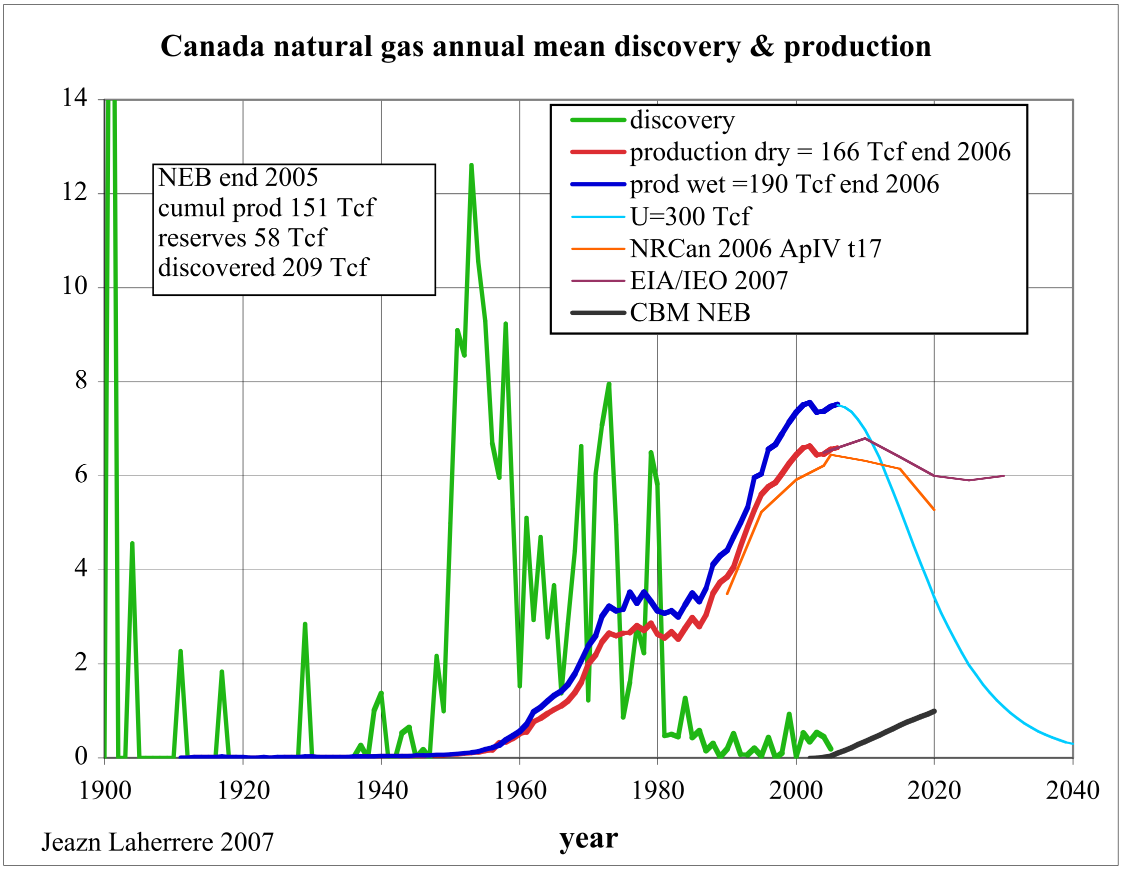


Another problem is to estimate the past production. Pools reserve estimates reports everything as in place, producible and marketable. But production is reported as marketed or also dry or wet (assumed to be marketed). Marketed (wet ?) annual production as officially reported gives a cumulative up to end 2005 at 185 Tcf, when Natural Resources Canada reports in «Canadian natural gas Review of 2005 and outlook to 2020 » 58 Tcf of remaining proved reserves at end 2005 with a cumulative production of 151 Tcf or 209 Tcf discovered (close to the cumulative discovery reported by a scout company as plotted in our creaming curve. As Canadian reserves are reported as initial reserves and remaining by subtracting cumulative production, if cumulative production is underestimated by 34 Tcf (185 -151), remaining reserves are overestimated by 34 Tcf. Furthermore, as for US, past flared and vented has to be checked as having correctly evaluated in the initial reserve estimate (difference between producible and marketable as done for each pool).

Another reason to feel that 300 Tcf ultimate is a fair estimate because all the hopes in the Arctic seems to be too optimistic. Resources (what is in the ground) should not confused with reserves (what will be produced).

Annual discovery and production shows that present production is at the peak and should decline fairly steeply (similar to the discovery). NRCanada forecasts also a peak now, when EIA forecasts a peak in 2010, being as usual optimistic. CBM is forecasted by NEB to reach 1 Tcf in 2020, not much, but being one third of the total production !

Figure 8: Canada natural gas annual discovery & production

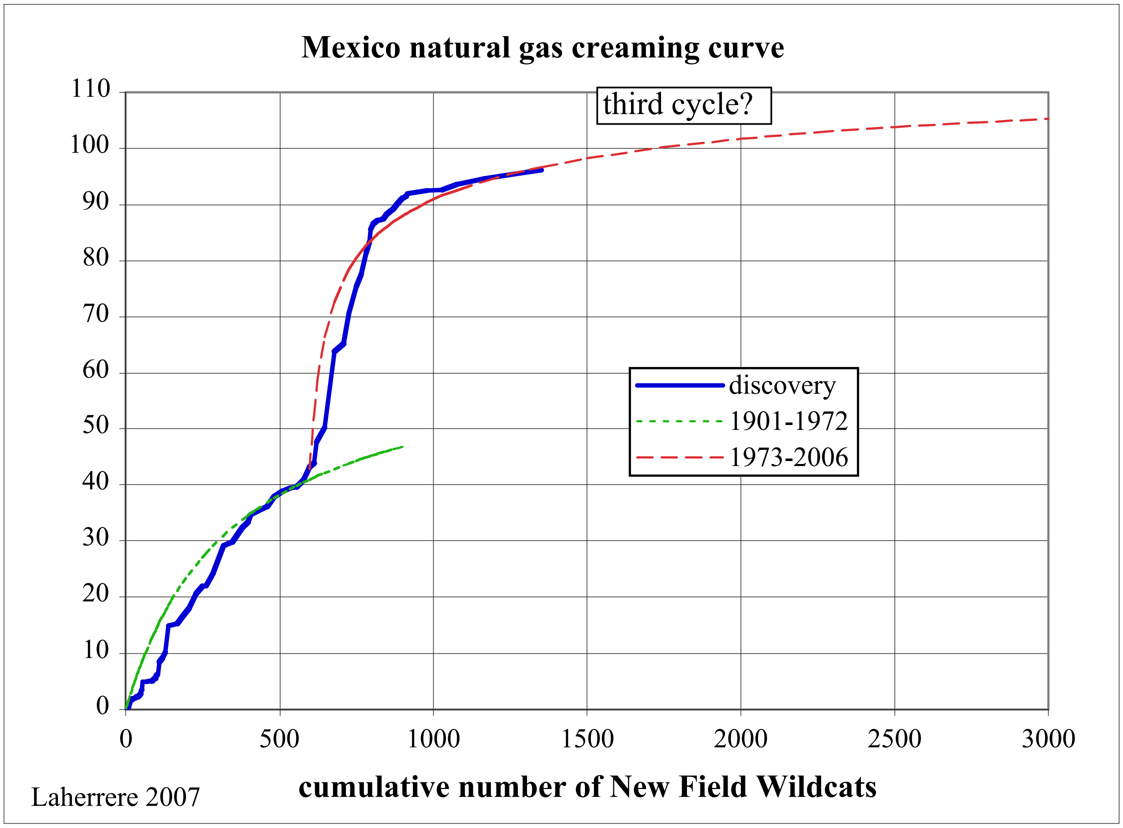


-Mexico

There is better discovery data, the creaming curve displays two cycles first 1901-1972 and second 1973-2006. Is it a possible third cycle, maybe in deepwater, but the first wells found heavy oil.

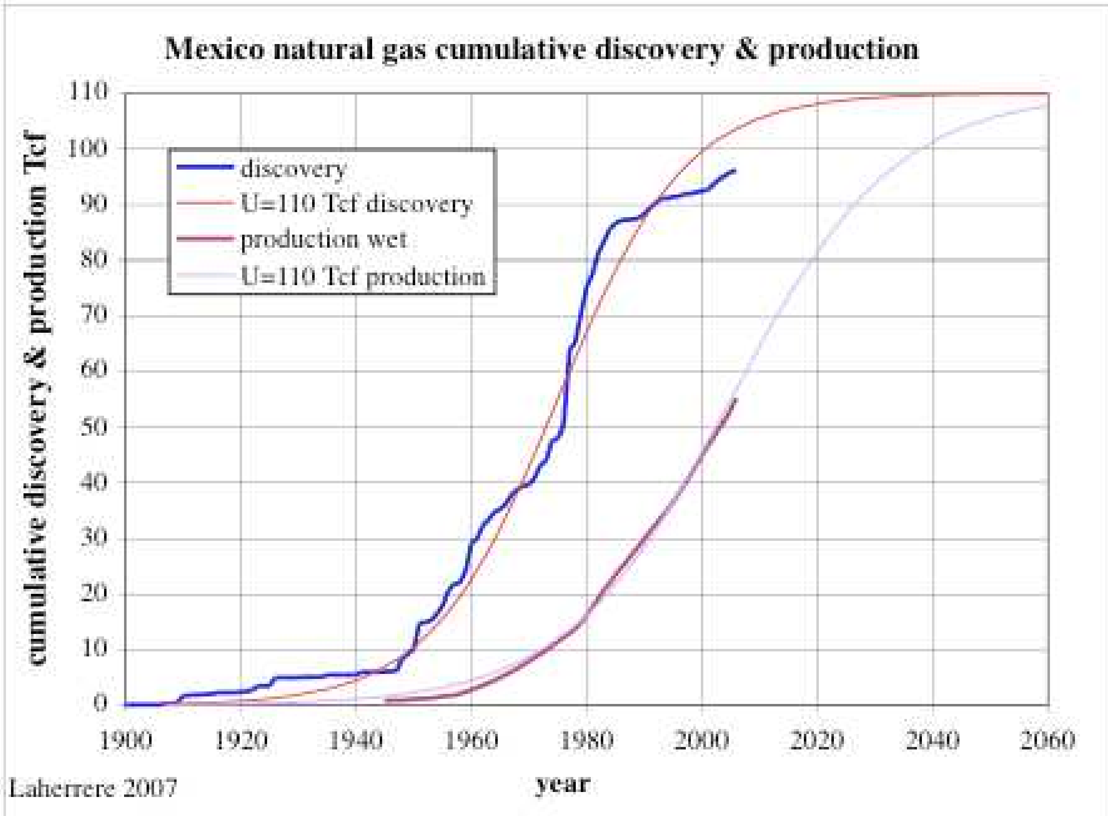
Then we estimate an ultimate of 110 Tcf

Figure 9: Mexico natural gas creaming curve

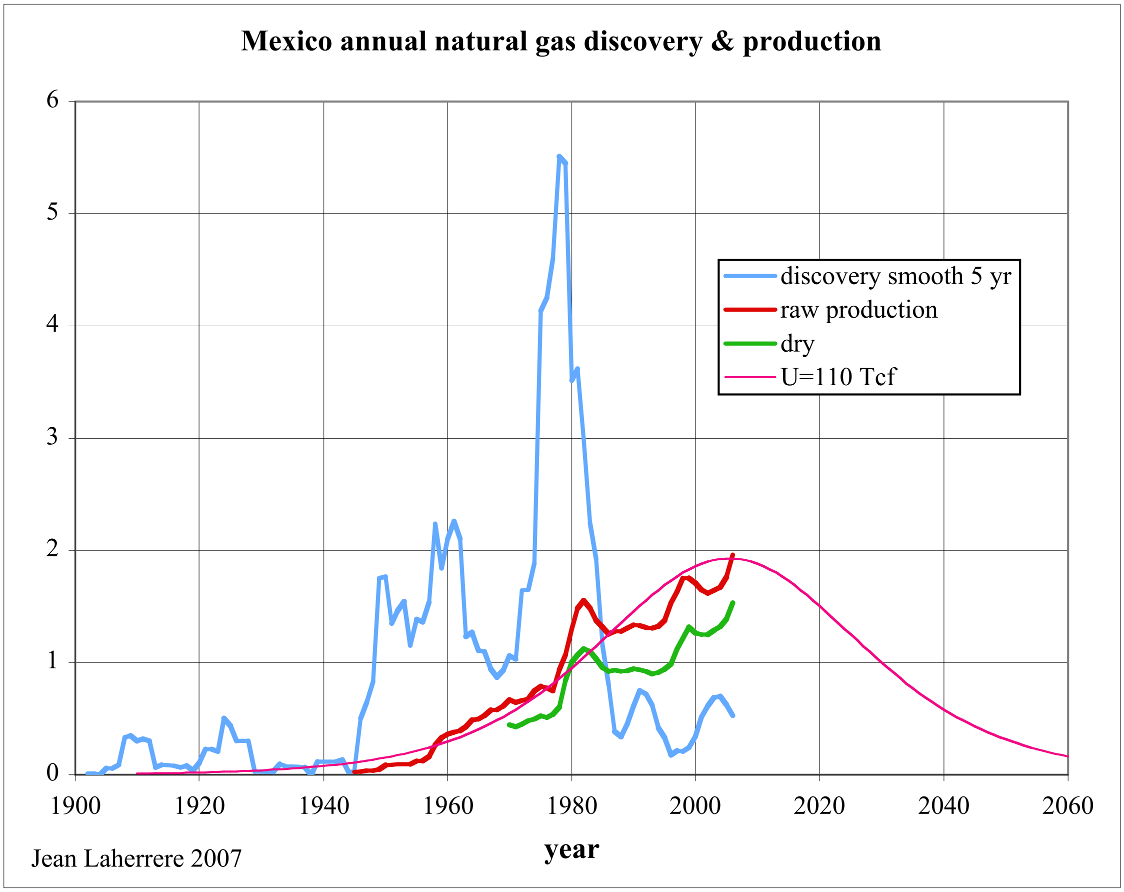


Despite the two cycles, the cumulative discovery versus time is easily globally modelled with an ultimate of 110 Tcf as the annual production.

Figure 10: Mexico natural gas cumulative discovery & production

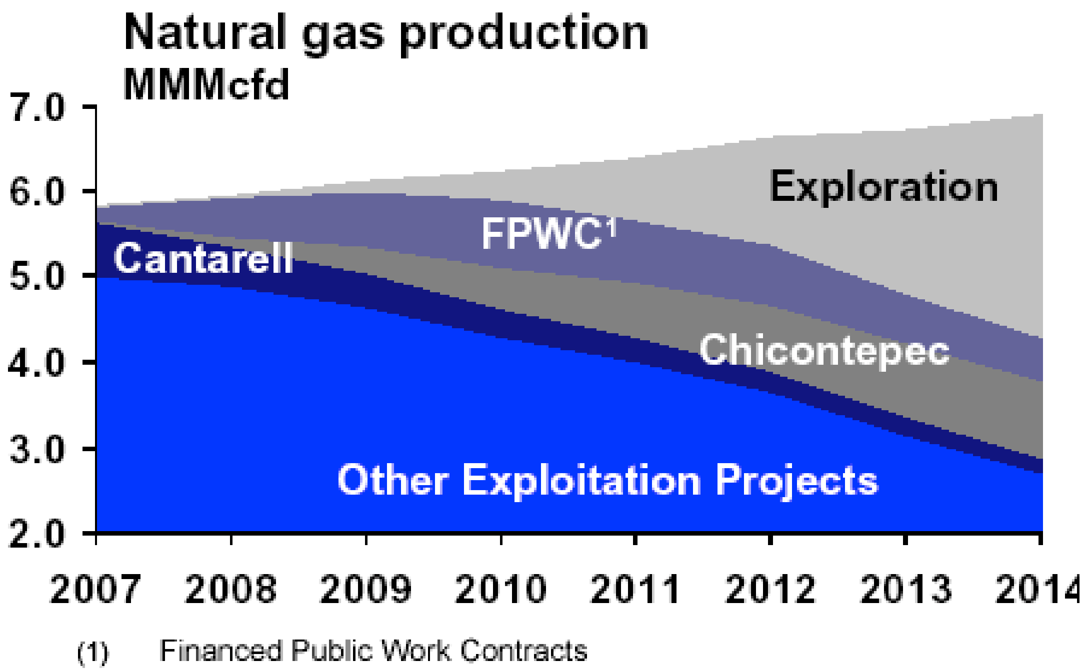


The annual production shows for an ultimate of 110 Tcf a peak now.
Figure 11: Mexico natural gas annual discovery & production

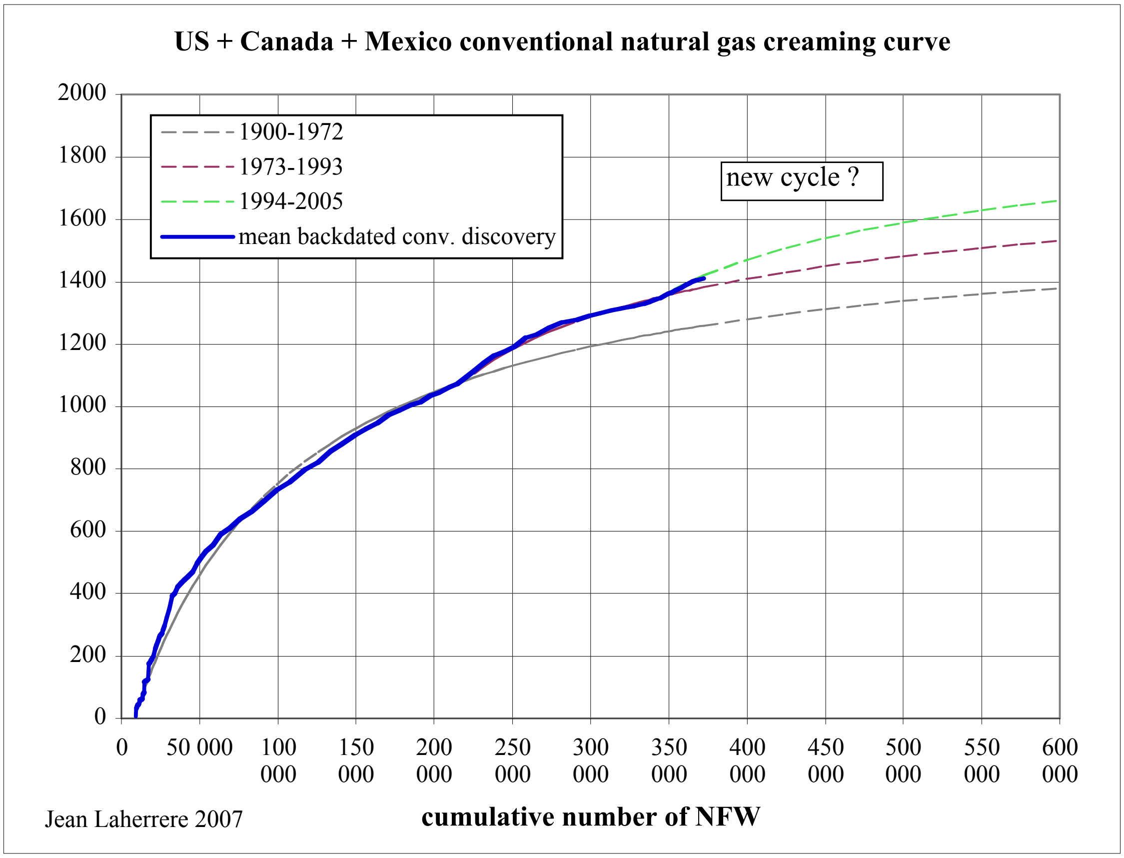


Pemex AR2006 forecasts a peak for gas production around 2009 if forgetting the exploration which is not very successful, but because financial problems Pemex is not too active in exploring the deepwater. If success occurs in deepwater the production will come well after the peak, delaying only the decline. Chicontepec paleocanyon is producing small amount of oil for decades with many wells and was the subject of a fight between Pemex and USGS on oil reserves in the 90s. I doubt that Chicontepec gas production will reach 1 Tcf/a in 2013 !

Figure 12: Mexico natural gas annual production forecasted by Pemex

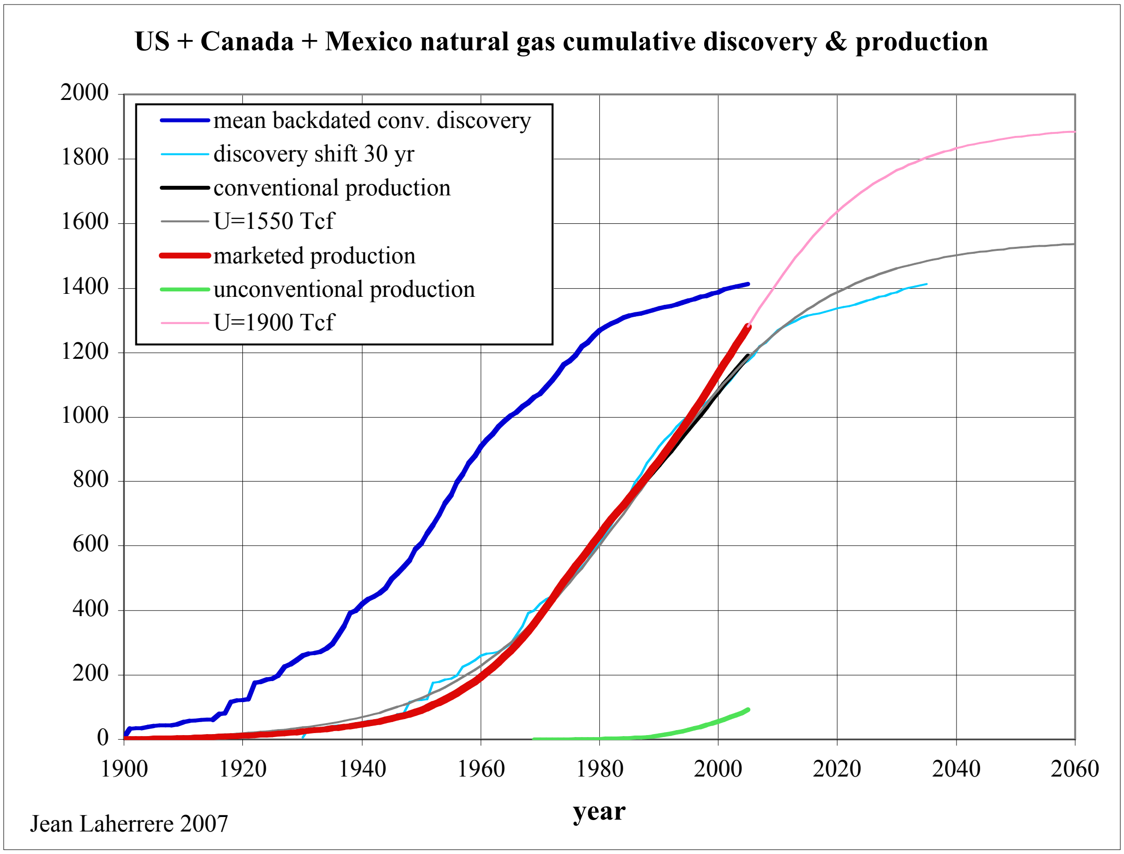


-North America
Adding the 3 countries gives a creaming curve easily modelled with 3 cycles ; 1900-1972, 1973-1993, 1994-2005 which forecasts an ultimate at 1600 Tcf for conventional gas for an additional drilling of more than 120 000 NFW.
Figure 13: North America natural gas creaming curve



The cumulative conventional production versus time is modelled with an ultimate of 1550 Tcf and the marketed production (including unconventional gas) with an ultimate of 1900 Tcf.

Figure 14: North America natural gas cumulative discovery and production



The annual conventional production is compared to the annual conventional discovery shifted by 30 years. The sharp decline of future conventional production for an ultimate of 1550 Tcf agrees well with the shifted discovery. The decline of future marketed production for an ultimate of 1900 Tcf agrees fairly well up to 2020 with ExxoMobil forecast in their annual report 2006. But EIA IEO 2007 forecast of plateau production up to 2030 is contrary to the previous forecasts.

Figure 15: North America natural gas annual discovery and production

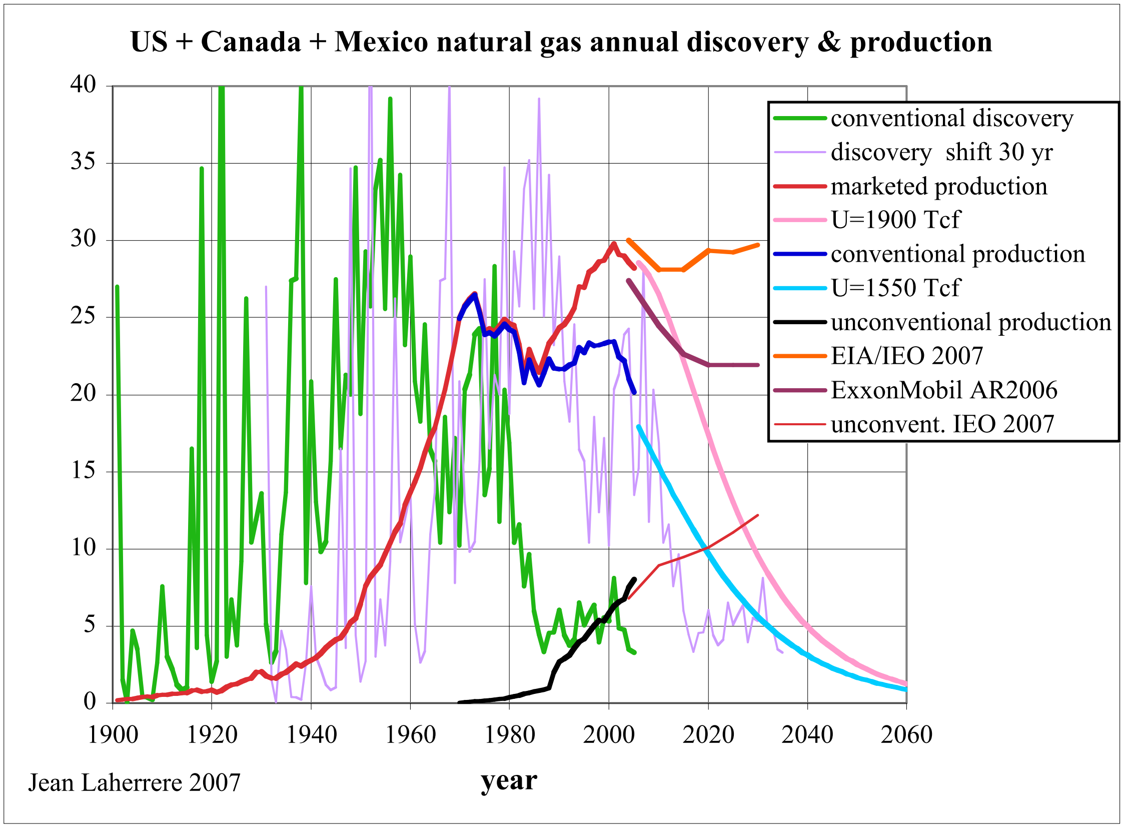
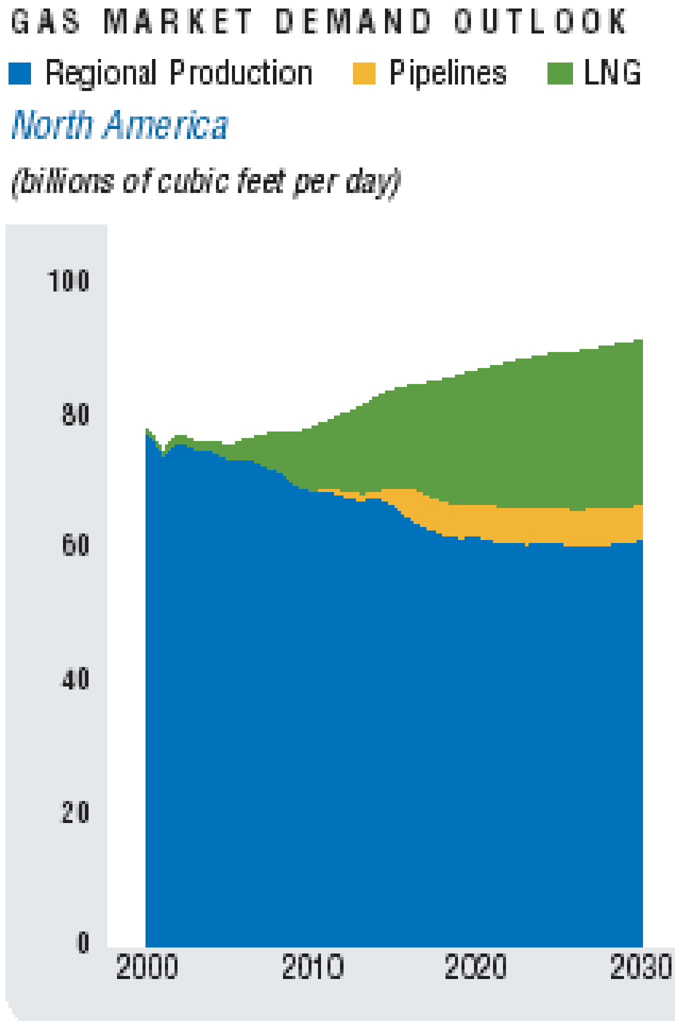


Figure 16: North America natural gas annual production and demand by Exxon-Mobil AR2006



-Conclusions

North America natural gas is heading towards a large lack of production to fill the demand, missed by EIA forecasts but not by Exxon Mobil.

LNG could have problems to fill the gap except if an economy crisis solves the case.