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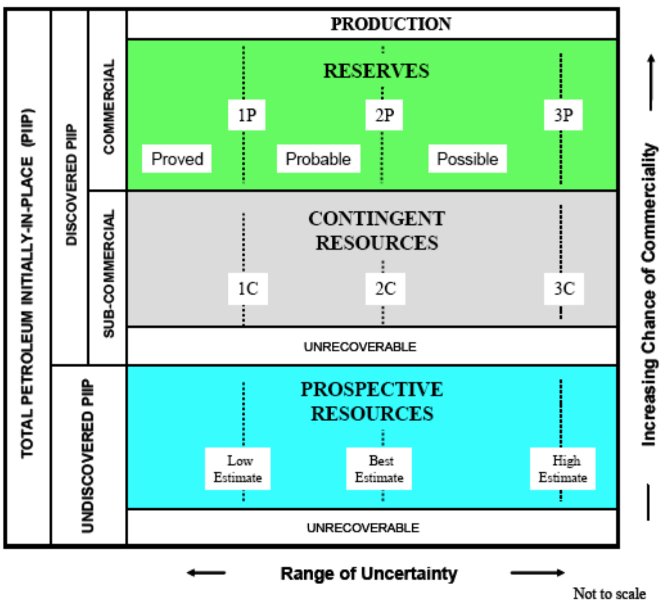
North America oil and gas resources and production

-World: US and the rest of the world

Since 1978 the SEC rules oblige oil companies listed on the US stock market to not report probable reserves but only proved reserves. The result is that US proved reserves are different from the rest of the world proven+probable reserves following the SPE/WPC/AAPG/SPEE rules.

Figure 1: SPE/WPC/AAPG/SPEE reserves definition

Figure 1-1 is a graphical representation of the SPE/WPC/AAPG/SPEE resources classification system. The system defines the major recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum.



In fact 2P seems in this graph to correspond to the **best estimate** which is badly defined and could be different from mean value, being then most likely = mode

Obviously probability is hard to explain and to define precisely what is 2P!

But it seems that operators like imprecise definitions to report what they want to promote their company!

In the 1997 SPE big change in reserves by introducing probabilistic approach 2P is defined as P50, but it is in contradiction with deterministic approach where probable is as likely as unlikely (meaning P50). Best estimate is not defined and could be the most likely (or mode) which again is different from the mean. There is a discrepancy left to show the problem. I know that well, because I was an active member of the 1997 SPE/WPC task force on reserve definition (leader: Anibal Martinez) and I obliged that 2P was associated with P50, when the proposal was that probable = P50 (http://www.oilcrisis.com/Laherrere/Com-SPE-2007.pdf).

Canada dropped US practice in 2001. The SEC is also changing, because since 2010 oil companies may report proven +probable reserves.

But past US reserves data is proved reserves, which are the remaining volume anticipated to be recovered under reasonable certainty. Proven reserves under SPE rules correspond to a 90% probability. It is scientifically wrong to add the field proved reserves to obtain the US proved reserves, or to add the country proved reserves to get the world proved reserves.

But it is what is done by all, which publish world reserves: OGJ, USDOE, BP Statistical Review SPE report mentions that this incorrect arithmetic addition is far from the correct probabilistic aggregation. This US bad practice on reporting reserves lead to the so-called reserves growth.

With time reserves growth because probable reserves turn into proved reserves.
Using 2P close to mean value, there is statistically no growth with time because the mean is the expected value. If there is statistical growth, it means that the way to estimate the mean was badly done and should be corrected.
In the SPE graph it is obvious that the mean is less than P50, close to P40!
Figure 2: Deterministic versus probabilistic aggregation

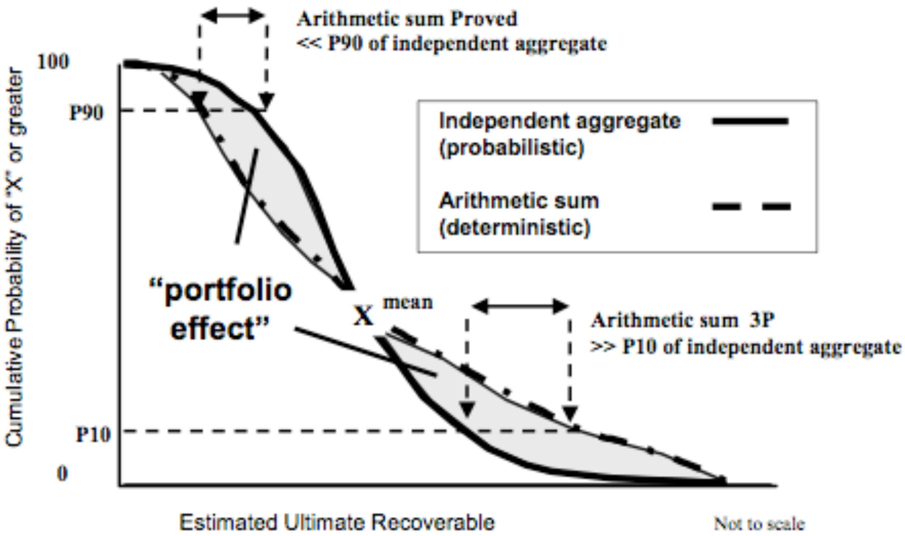
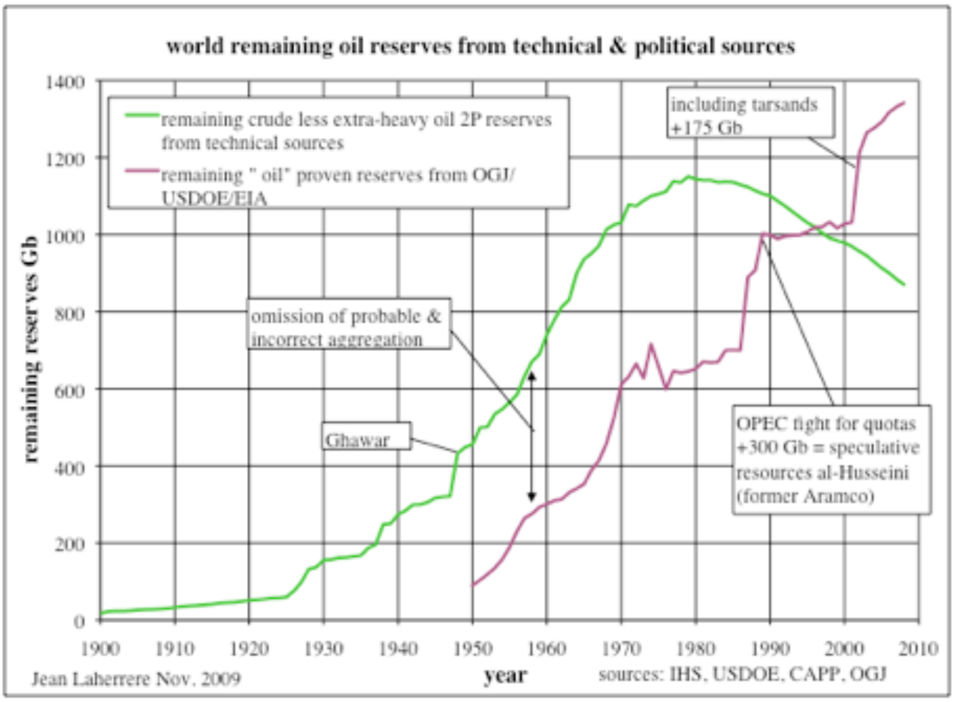


Figure 3-2: Deterministic versus Probabilistic Aggregation

The only right way to aggregate reserves is to add mean (expected) values.
Decision by the IOCs to drill a prospect is based on the Net Present Value, which is computed using mean reserves. When SEC proved reserves are just an indication for the bankers to be sure to recover their loans from some *JR Ewing* independent oil companies!

The huge difference between the technical remaining 2P backdated reserves (obtained from scout companies) and the political (OPEC) or financial (SEC) 1P current reserves is frightening.
The jump of 300 Gb in the fight of OPEC members for quotas is known recognized by Sadad al-Husseini former Aramco VP. The jump in 2002 by adding 175 Gb of tarsands
The brown curve is the only data available to economists, coming from USDOE or BP. Then, economists rely on this always climbing remaining conventional oil reserves, when in reality every explorer knows that since 1980 more oil is produced than found and the remaining reserves should decline. Adding unconventional oil reserves, as OGJ did, is changing the rules in the middle of the game. Tarsands are known for a long time.
With unconventional reserves, the size of the tank does not matter, it is the size of the tap!
Figure 3: world remaining reserves from technical & political sources



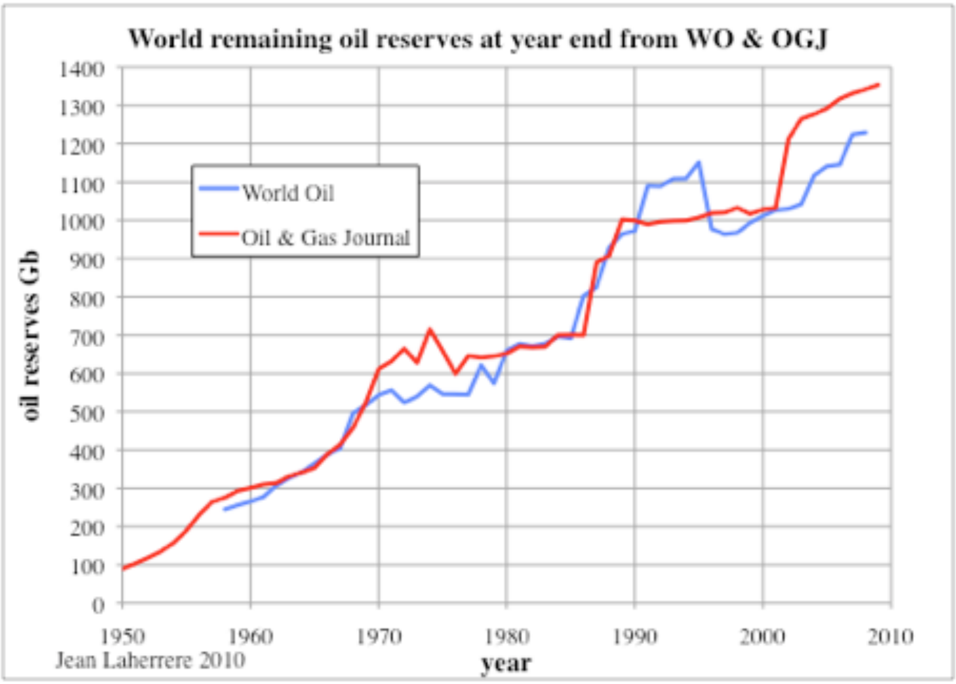
The difference between Oil & Gas Journal (reported by USDOE & BP) and World Oil is also sometimes huge

For end 2002 the oil reserves are in Gb

WO	1 029.881 0
OGJ	1 212.880 852

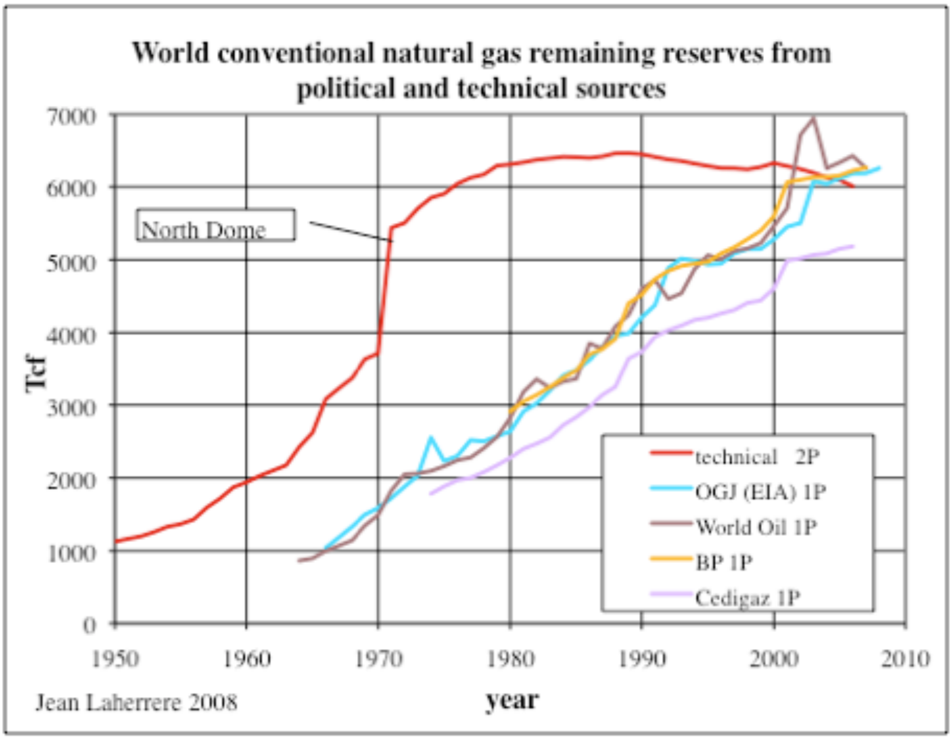
The difference between OGJ and WO reserves is about 200 Mb, when OGJ reports value down to thousand barrels with 10 significant digits: it is ridiculous !

Figure 4: world remaining oil reserves from WO and OGJ



It is the same huge difference for the remaining conventional natural gas reserves: the technical 2P backdated conventional reserves are flattening since 1980 and declining in the last years when the proved political reserves are increasing since 1950!

Figure 5: world remaining conventional natural gas reserves from technical & political sources

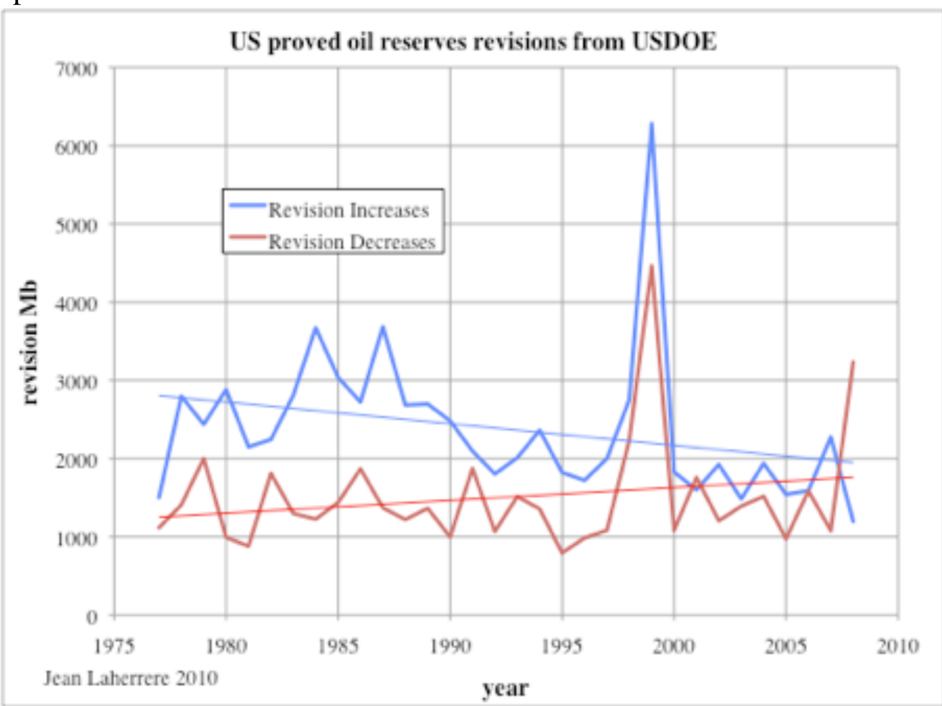


-US

-US oil

USDOE/EIA reports proved reserves revision since 1977and for oil the positive revisions declines when negative revision is on the rise.

Figure 6: US proved oil reserves revisions from USDOE

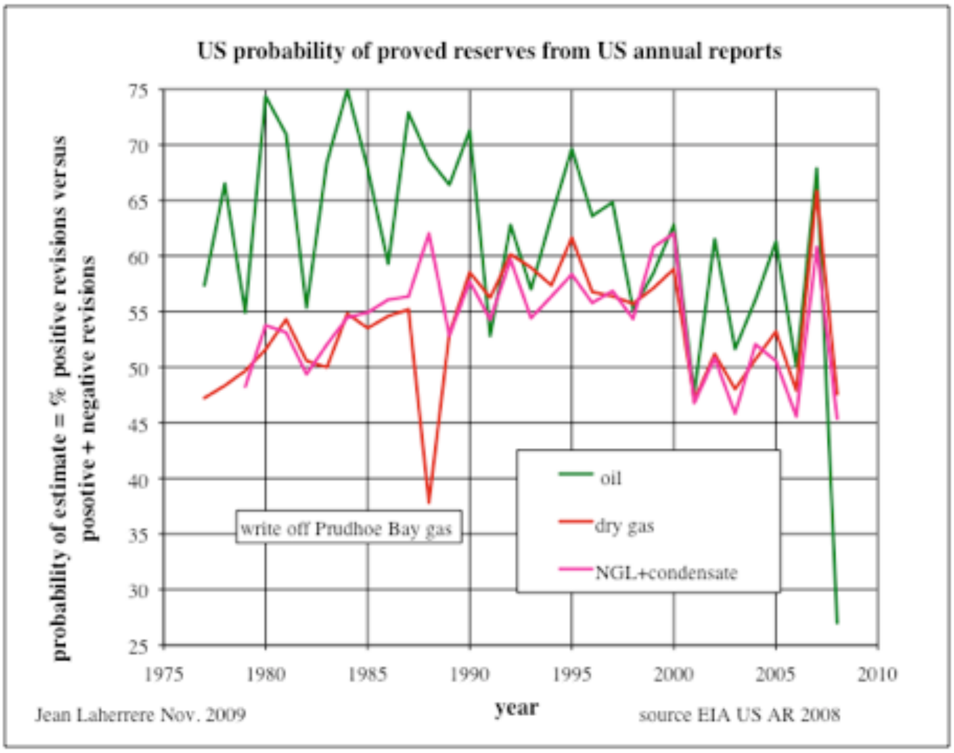


The ratio of positive revisions over the sum positive +negative revisions represents the probability of the reserves.

For oil in the 80s the probability was around 70% when in the 2000s it is around 55%, far from the assumed 90% ! For gas the ratio oscillates between 50 and 60%.

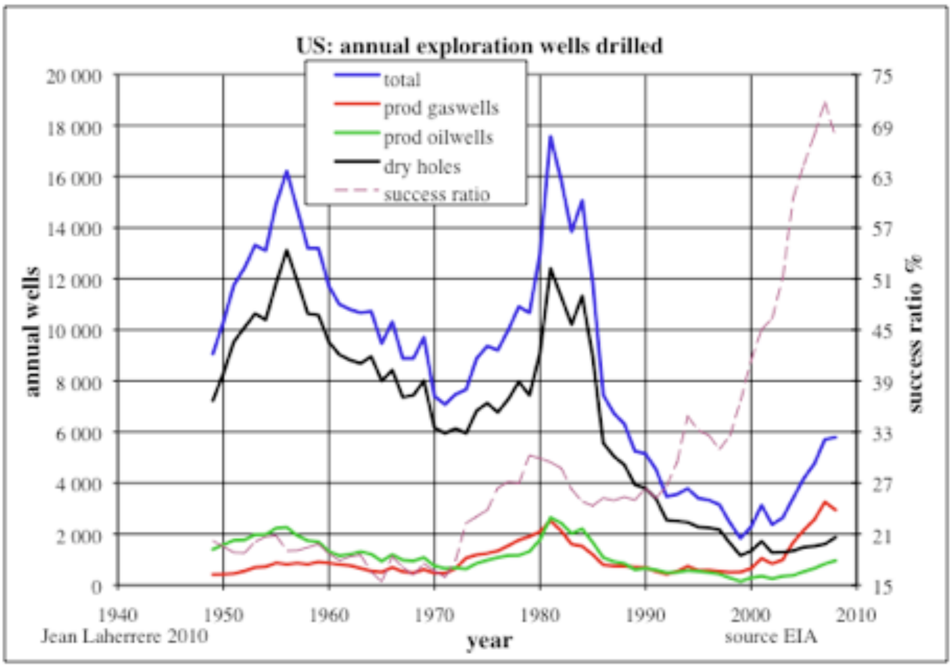
In fact the US proved reserves are moving towards the 2P rest of the world reserves!

Figure 7: US : probability of proved oil reserves revisions from USDOE



The success ratio of exploratory wells has changed drastically from around 20% in the 60s against 70% now where exploration is mainly on unconventional, defined by the USGS as continuous type accumulation, easy to find !

Figure 8: US: annual exploration wells drilled



-USL48 oil

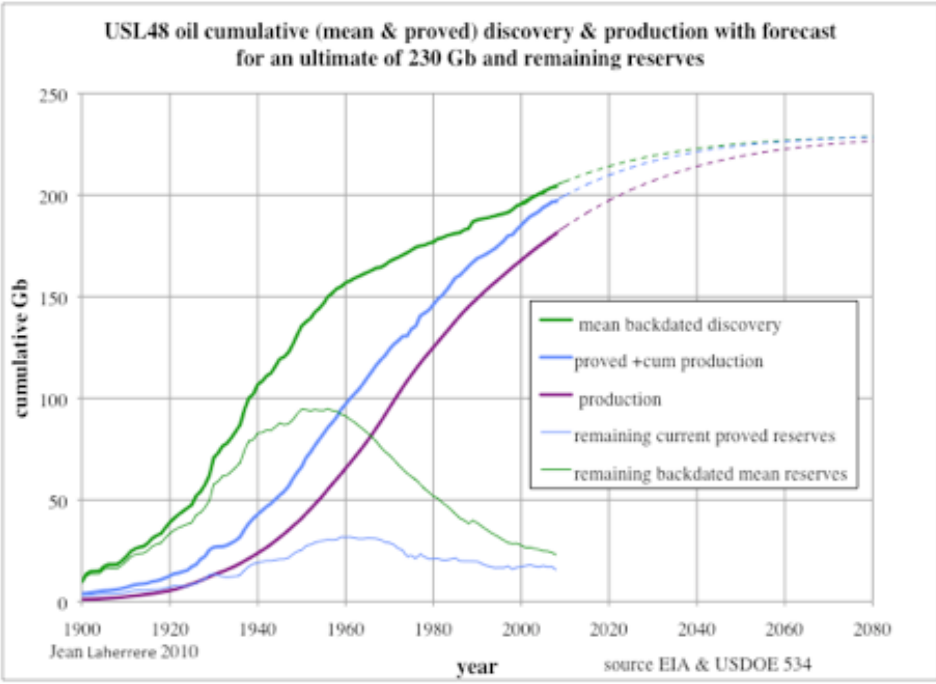
As mentioned above, it is incorrect to add the field proved reserves to obtain the proved reserves of the US, like it is done by USDOE/EIA.

Only mean field data can be aggregated to obtain US mean backdated reserves. It is very difficult to do so because the mean data is not available and the number of fields is huge.

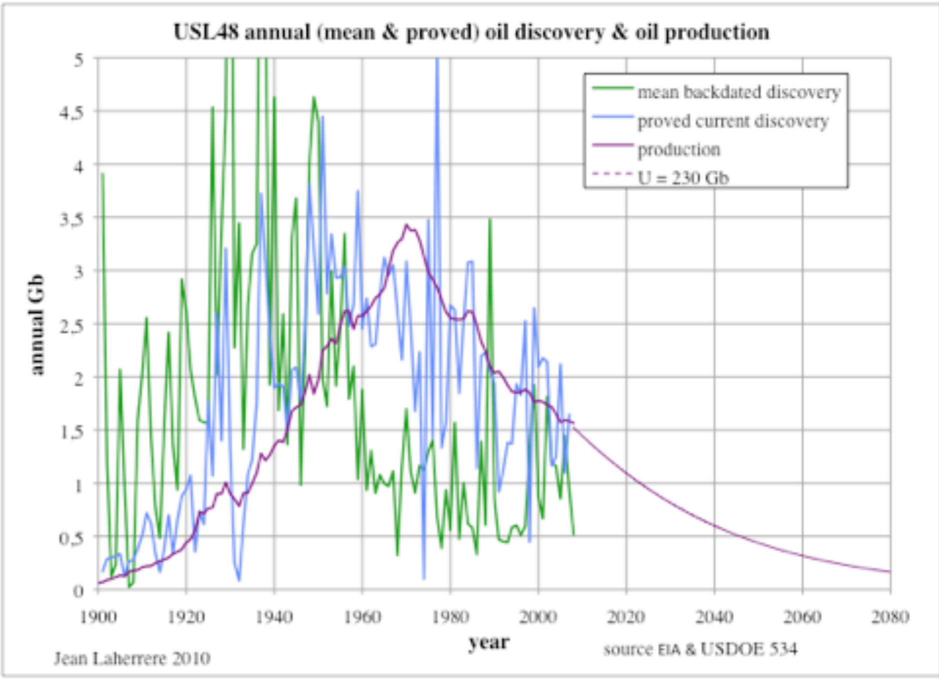
USDOE/EIA backdated US oil & gas reserves in 1990 in their open file report

-DOE/EIA-0534 1990 "US oil and gas reserves by year of field discovery" Aug. Open file

This 0534 open file cannot be found anymore on the EIA site
USDOE/EIA used this study in DOE/EIA 1992, "Geologic distributions of US oil and gas" Report-0557, which is available on microfiche. This backdating study is also described in "The enigma of oil and gas field growth" E.D.Attanasi & D.H.Root AAPG 78/3 March 1994.
It is a pity that USDOE has not updated this 0534 study because they have in house all the data.
I use this 534 report for the period 1900 to 1988, with some growth to obtain 2P, plus the annual EIA reports to obtain the new discovered reserves and new reservoirs in old fields, and also the 2P reserves scout estimates in frontier areas.
I assume that 2P is close to mean values, because these 2P scout estimates come from the operator that decides the development on the NPV based on mean reserves estimate.
The backdated 2P discovery (in green) is quite different from the proved reserves (in blue).
The proved +cumulative production is parallel with the cumulative production with a 10 years advance. It is well known that proved reserves are often estimated by multiplying ten times the annual production, leading that for the last 80 years R/P is close to 10.
This stable US R/P means that the R/P is a very poor indicator!
Remaining backdated reserves peaked in the 1950s when current proved (remaining) reserves peaked in the 1960s at a level three times less.
The cumulative discovery and production is modeled using an ultimate of 230 Gb.
Figure 9: USL48: cumulative mean & proved discovery and cumulative production for U=230 Gb



The same data is presented on an annual discovery and production
Figure 10: USL48: annual backdated mean & proved discovery and production for U= 230 Gb

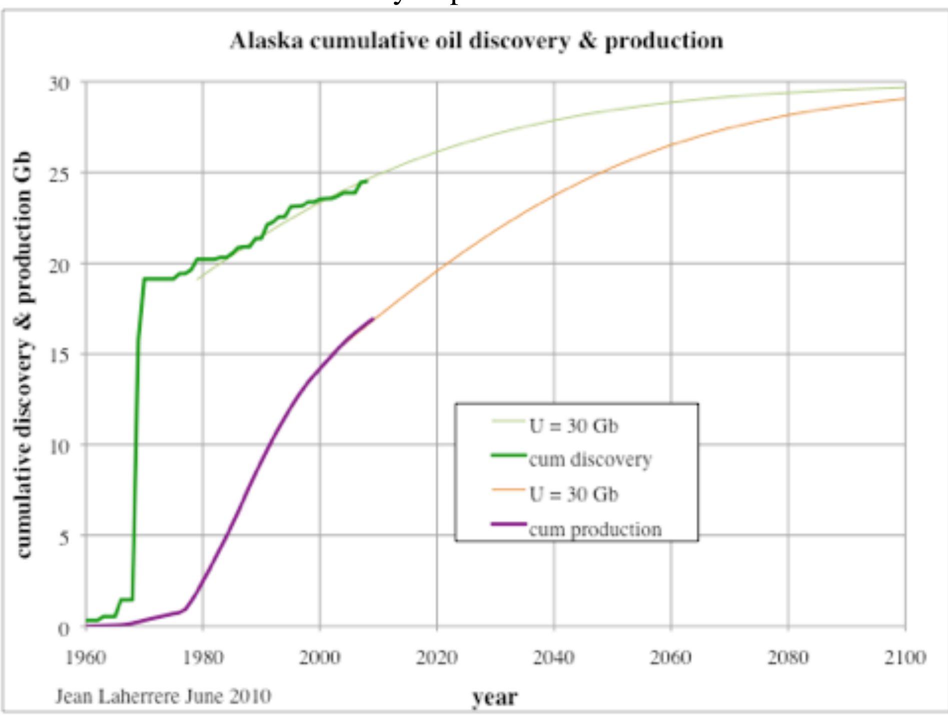


The above USL48 data includes the Gulf of Mexico. Former MMS was providing good and complete (but restricted to proved estimates) backdated reserves and production on GOM oil fields but with a large delay (now in 2010 only at end of 2006), then scout data up to 2008 was preferred.

-Alaska oil

The cumulative oil 2P discovery is modeled towards an ultimate of 30 Gb, as production.

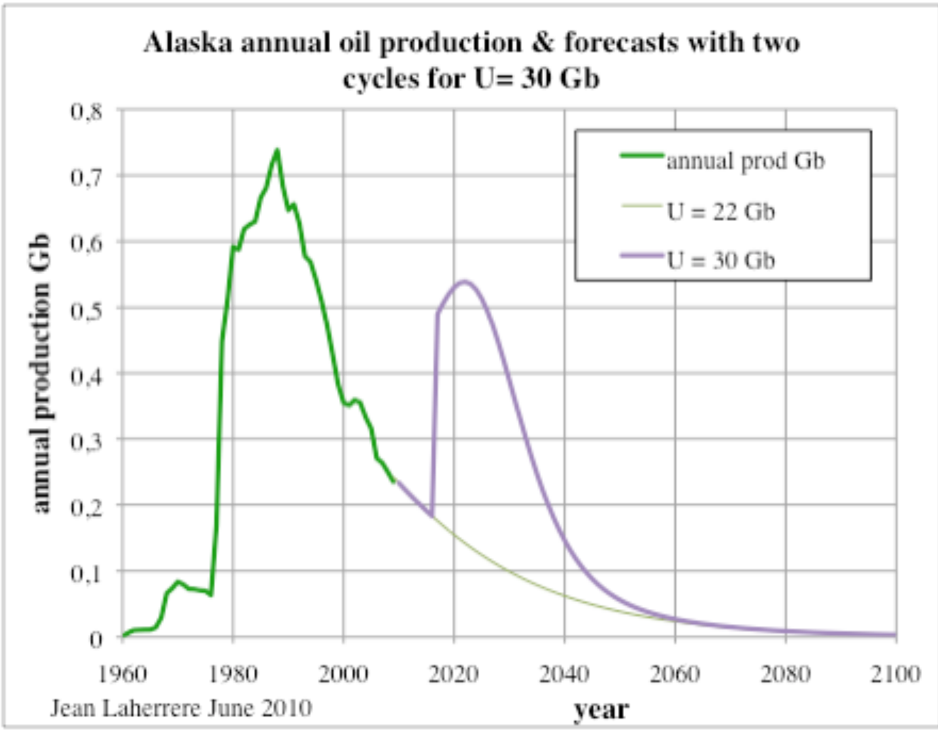
Figure 11: Alaska: cumulative oil discovery & production for U=30 Gb



Alaska annual production is in sharp decline trending towards a cumulative production of 22 Gb , less than the ultimate of 30 Gb from known discoveries.
To model the annual production with an ultimate of 30 Gb needs a second cycle coming from a huge investment leading to sharp increase in production.

It is hard to guess when this investment will be done ; the problem is that some of these reserves are heavy oil!

Figure 12: Alaska: annual oil discovery & production for U=30 Gb

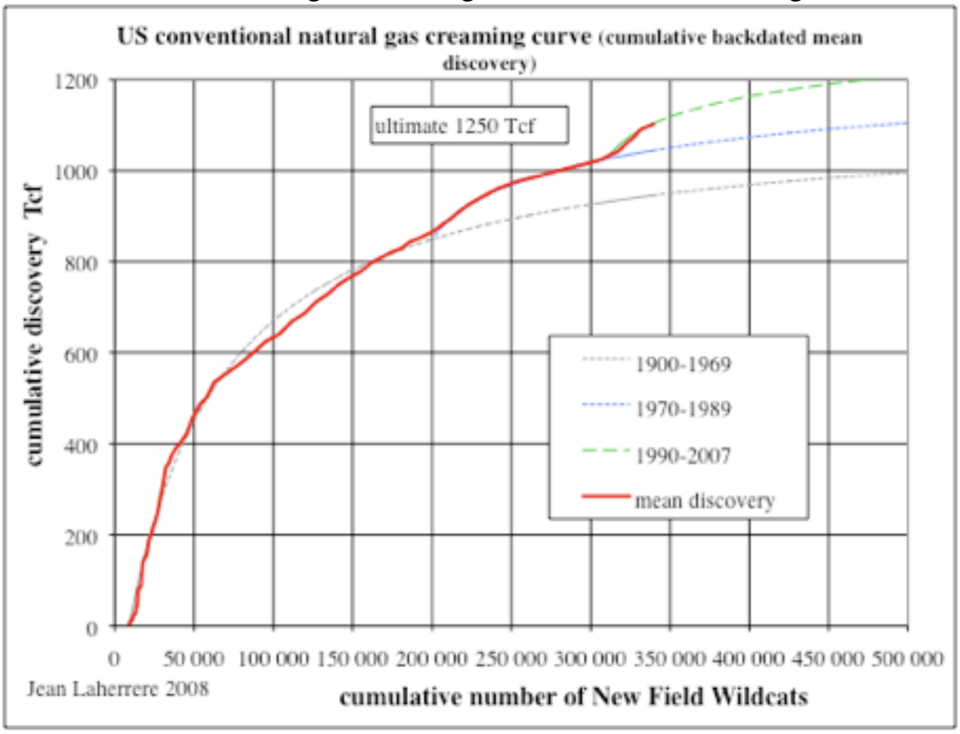


The other problem is that the Trans Alaska pipeline is already old and leaking and needs a certain volume to be economical. North Slope .

-US gas

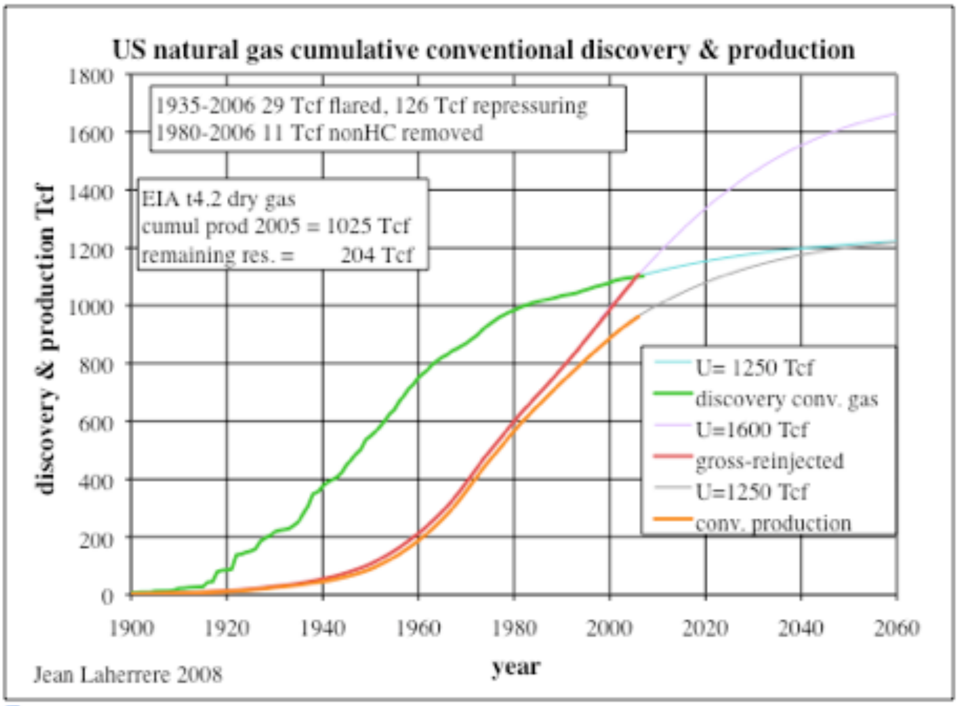
The conventional natural gas cumulative mean backdated discovery is plotted versus the cumulative number of NFW to obtain the creaming curve, which is modeled with 3 cycles towards 1250 Tcf.

Figure 13: US conventional natural gas creaming curve 1900-2007 leading to U = 1250 Tcf



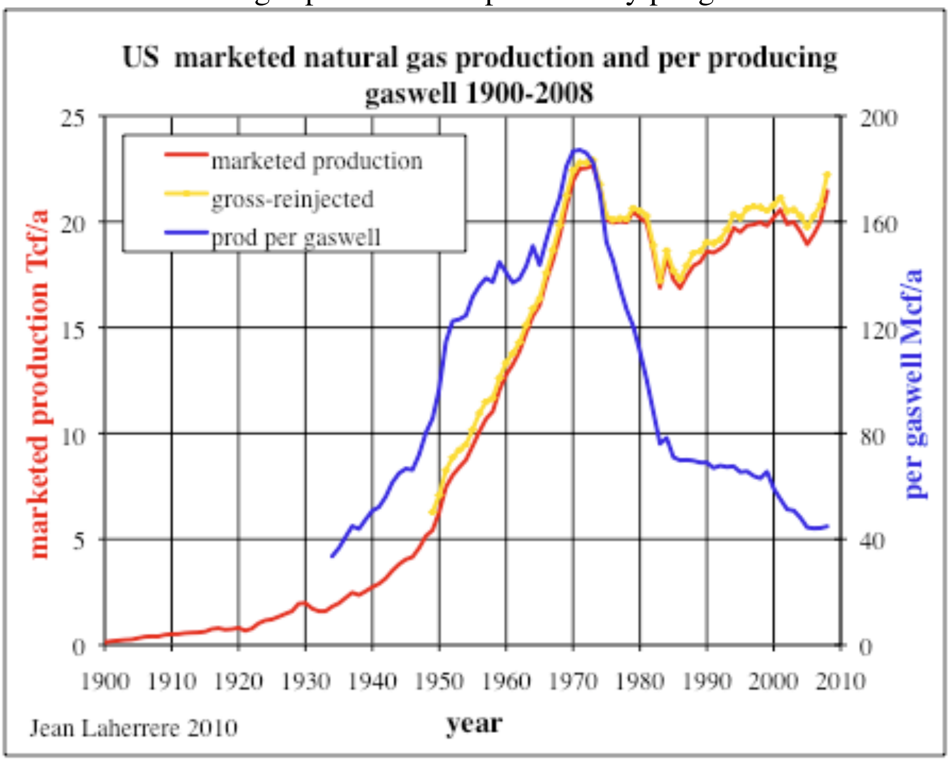
The cumulative conventional discovery and production is plotted versus time towards this 1250 Tcf ultimate.

Figure 14: US conventional natural gas cumulative discovery & production for U= 1250 Tcf



The US marketed gas production is compared to the productivity per gaswell

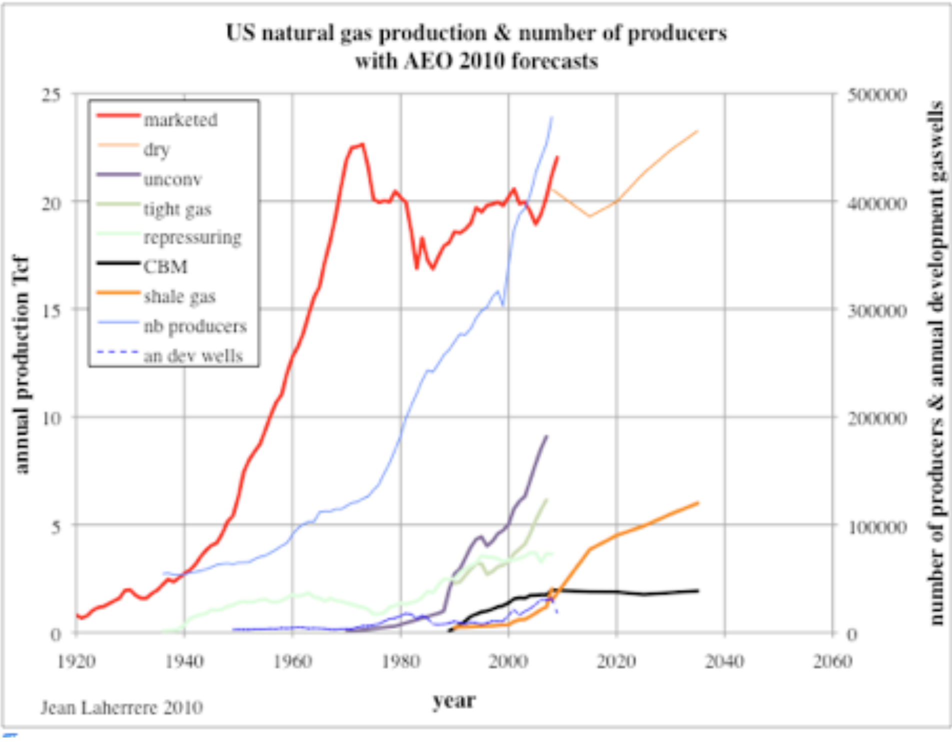
Figure 15: US marketed natural gas production & productivity par gaswell



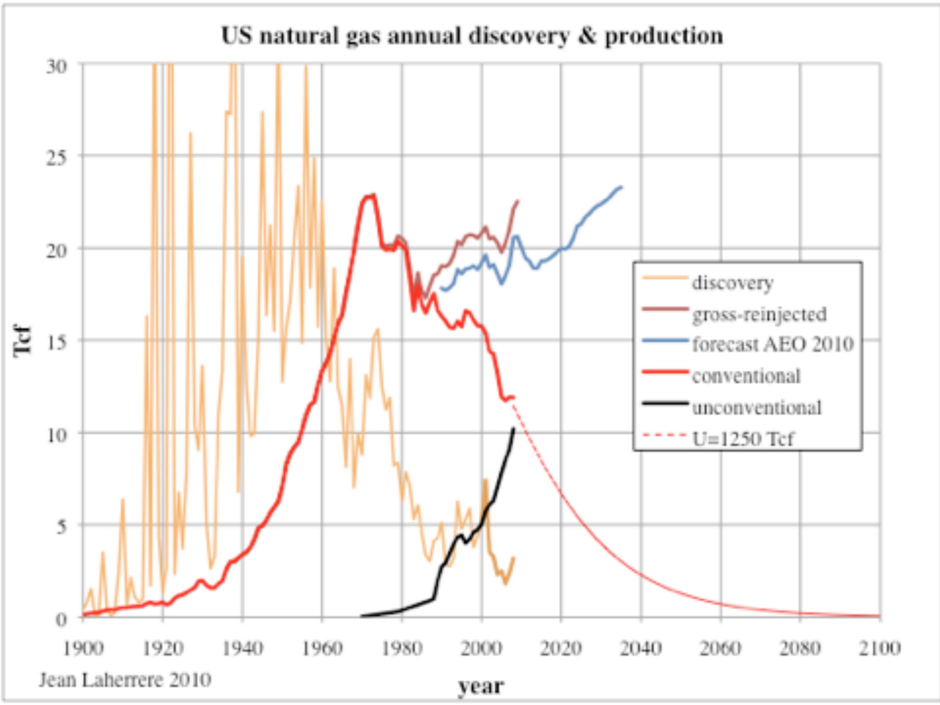
The US natural gas production is broken down into conventional and unconventional and compared to the number of producing wells.

This year, USDOE/EIA has without any explanation removed the tight gas from unconventional sources and its volume is not found anymore being gathered with conventional gas !

Figure 16: US natural gas production with AEO 2010 forecasts & number of producers



The US conventional gas production is modeled with an ultimate of 1250 Tcf showing a continuous decline since 2000 of about 5%/a.
I am unable to forecast the unconventional. The EIA/AEO 2010 (dry) forecast displays a trough in 2013 and a rise again to produce in 2035 a little over the peak of 1971!
Figure 17: US natural gas annual discovery & conventional production for U= 1250 Tcf



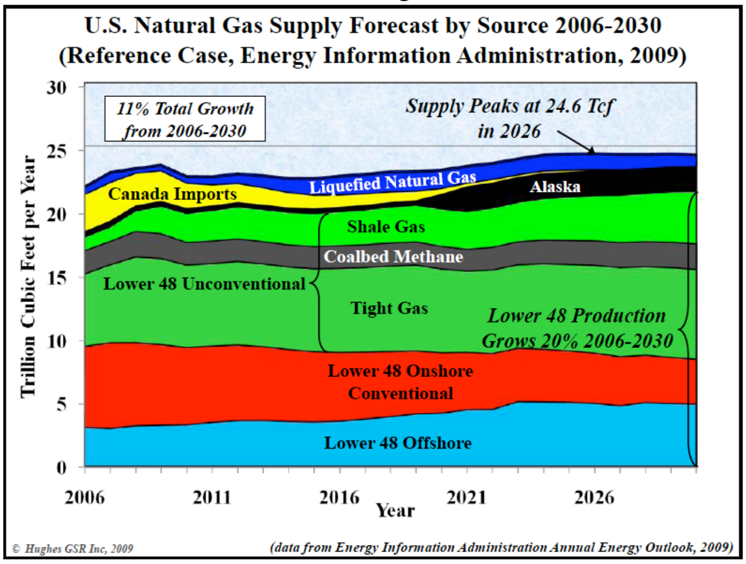
The gas reserves in Alaska North Slope are stranded as long as the gas pipe is not decided. Nobody knows when, and I will not guess either.

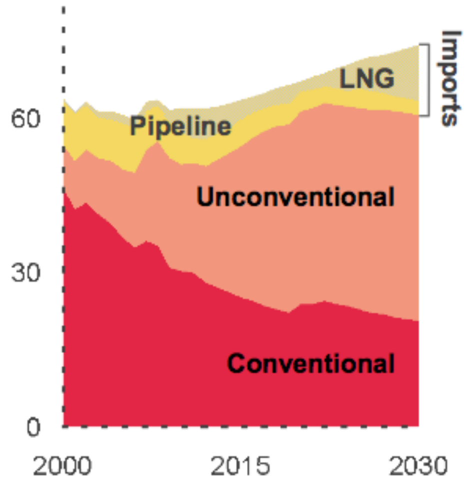
-US unconventional gas

There is too must hype on shale gas production that it is difficult to forecast long-term production.

Shale gas is found in source-rock with poor reservoir quality, but it not new. The first US gas production was in 1820 at Fredonia in New York State from Marcellus shale gas. But shale gas was abandoned when conventional, easy, cheap gas was found. It is back with new technology!
Shale gas production was busted by horizontal wells and fracturing, promoted by small independent when gas price went up to more than 10$/kcf. The area of the basins with shale gas is huge (area of the source-rock) and gas is found everywhere in this continuous-type accumulations, but the quality of the reservoir is heterogeneous. Yet most operators assume that good quality reservoir (sweet spot) will prevail in most of the basin, though it is likely not to be the case. Now with horizontal drilling and hydraulic fracturing, higher initial production occurs (the cost is also higher), but the decline is also sharper. But the US gas price went down from 12 $/kcf to 3 $/kcf and the number of shale gas rigs was reduced by half. There is disagreement on the economic threshold of shale gas.

The US gas supply forecasts differ largely between J.D. Hughes («Natural gas in North America: a panacea to replace imported oil?» Sept 2009) displaying the forecast of EIA AEO 2009 and Exxon-Mobil Eizember 2010 «The outlook for energy: a view to 2030»
Figure 18: US natural gas forecast to 2030
from AEO 2009 via Hughes in Tcf   from Exxon-Mobil 2010 in Gcf/d

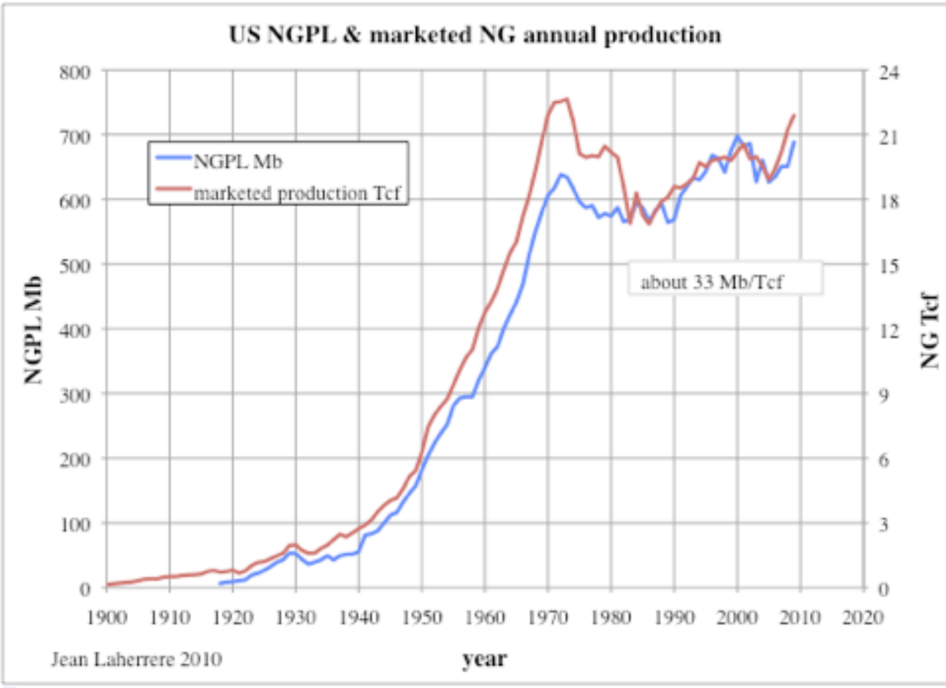




In 2030 the increase in US shale gas could be less than the inaccuracy on the conventional gas forecast decrease. Tight gas, formerly included in unconventional by EIA, is now conventional in AEO 2010, when some gather together tight gas and shale gas! It appears that transparency is not the goal of many! Confusion helps promotion!
There is large disagreement on the life of the shale gas wells. Chesapeake claims several decades when some (Berman) only a few years. Shale gas real production started few years ago and more than ten years production is needed to have enough data to judge the long-term behavior of shale gas wells. Some believes that shale gas behaves after few years as CBM where methane comes from fracture and from adsorption after dewaterization..
We have to wait a few years to know more about shale gas potential. We have to remember the hopes on CBM potential (now flat) in the 90s, on dissolved gas in geopressured aquifers in the 80s (little production despite resources up to 50 000 Tcf BGR 2003), and tomorrow on the hydrates!
But the main problem of shale gas is the possible pollution of the large injected volume of water with toxic (confidential) products (biocides) in deep aquifers, which can move from faulty (or simply old) wells into shallow drinking aquifers, but it will take some time! There is already a blow out in Pennsylvania. New York State forbids shale gas drilling.
NIMA (Not In My Aquifer) soon could be as strong as NIMBY!
Injecting high-pressured water volume may also lead to earthquake, as happened in Switzerland for the dry rock geothermal pilot, now stopped.

-US Natural gas plant liquids

Because in the US, condensate at the wellhead is measured together with the crude oil, natural gas plant liquids (NGPL) of course exclude condensate. But in many countries condensate is reported in natural gas liquids (NGL) creating confusions, in particular with IEA.
NGPL is connected with NG marketed production and the correlation in the last decades is about 33 Mb per Tcf
Figure 19: US NGPL & marketed gas production



NGPL forecast has to be correlated with NG forecast with such ratio of 33 Mb/Tcf

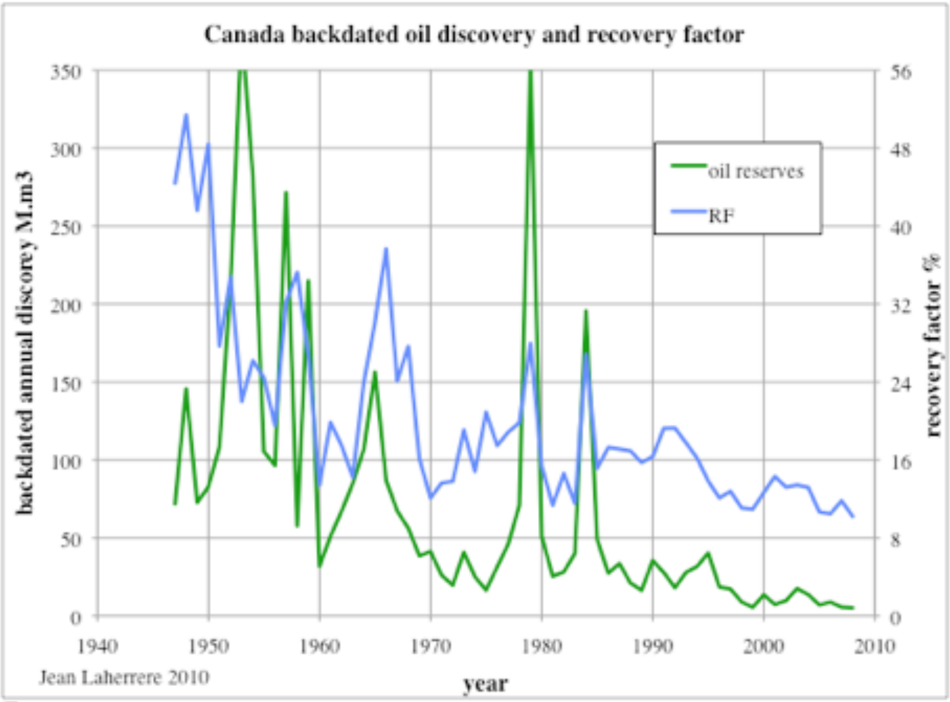
-Canada

Since 2001(National Instrument 51-101) Canada has abandoned the poor US practice to report only proved reserves and allows to report probable, 2P being the best estimate. But the definition used by the industry is still loose, as usual to allow more freedom in reporting! For CAPP **Established is proved +half probable**, being less than 2P! But some Canadian companies report 2P for established reserves!
But again I assume that, what operator reports as established, is the mean value used in estimating the NPV; if not, arithmetic aggregation is wrong!
Definitions of reserves COGEH and N1 51-101:
http://www.spee.org/images/PDFs/ReferencesResources/Defininitions%20O&G%20Resources%20and%20Reserves%20per%20COGEH%20Vol%201.pdf
Revisions to proved + probable reserves estimates should generally be neutral as new information becomes available
It could be translated by saying: it is the mean = expected value.
Study on field growth (Drummond 1995) shows that field growth stops 10 years after discovery, in contrary with the US where it is much longer!
Backdating data for fields older than 10 years reports the mean value.
The Canadian Association of Petroleum Producers publishes an annual handbook giving all necessary data, in particular backdated *established* reserves since 1947.
The missing item is the number of fields (and pools) discovered annually.
The US should take example on Canadian oil & gas practices in reporting oil & gas data, as also in reporting units. The USDOE being a federal agency should report SI units, as they are obliged since 1993 (The Omnibus Trade and Competitiveness Act of 1988 (Pub. L. 100–418, section 5164).

-Canada oil

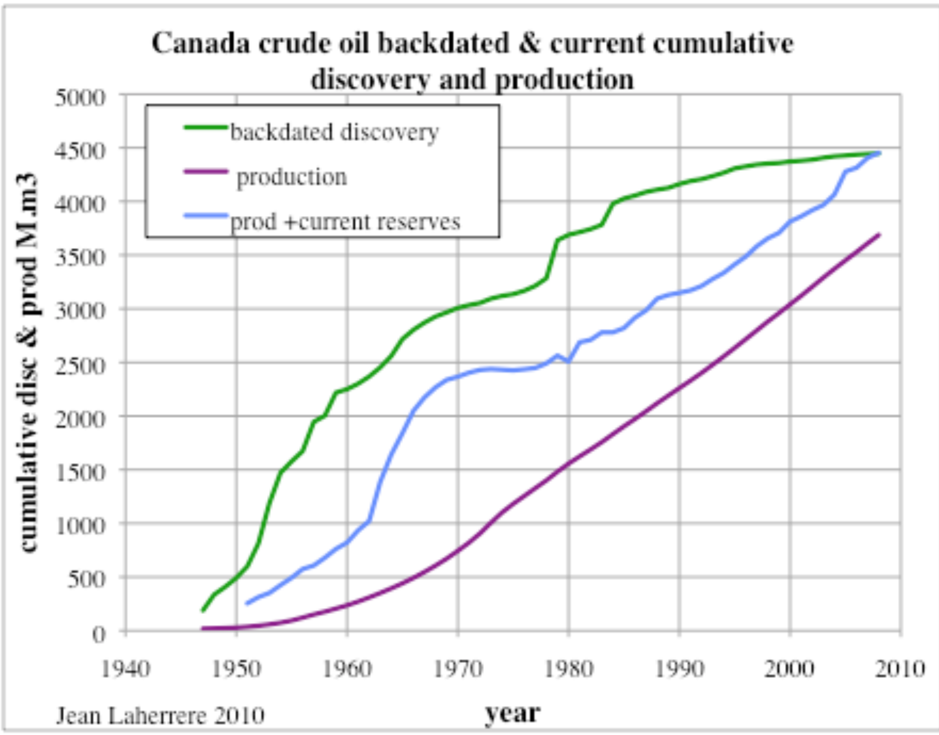
The annual oil discovery displays an erratic curve but in decline, as the recovery factor which over 40% in the 50s is now about 10% !

Figure 20: Canada backdated oil established discovery and recovery factor

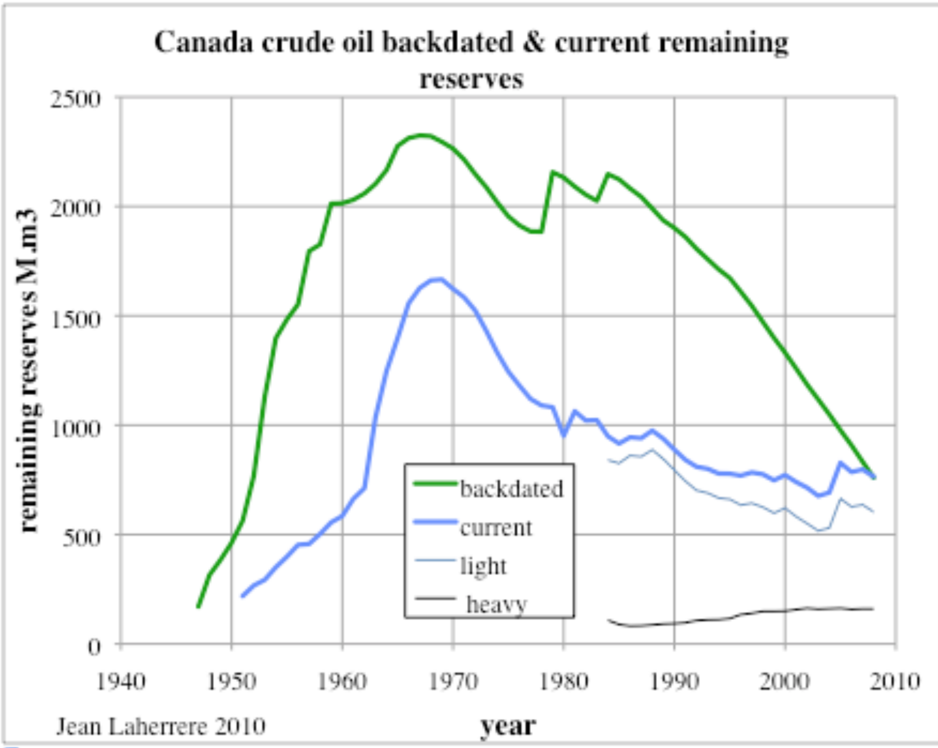


The cumulative discovery from backdated initial established reserves in green is really different as it is in the US with the current proved reserves +cumulative production in blue. The backdated discovery is flattening when current proved displays the same slope since 1980, parallel to the cumulative production.

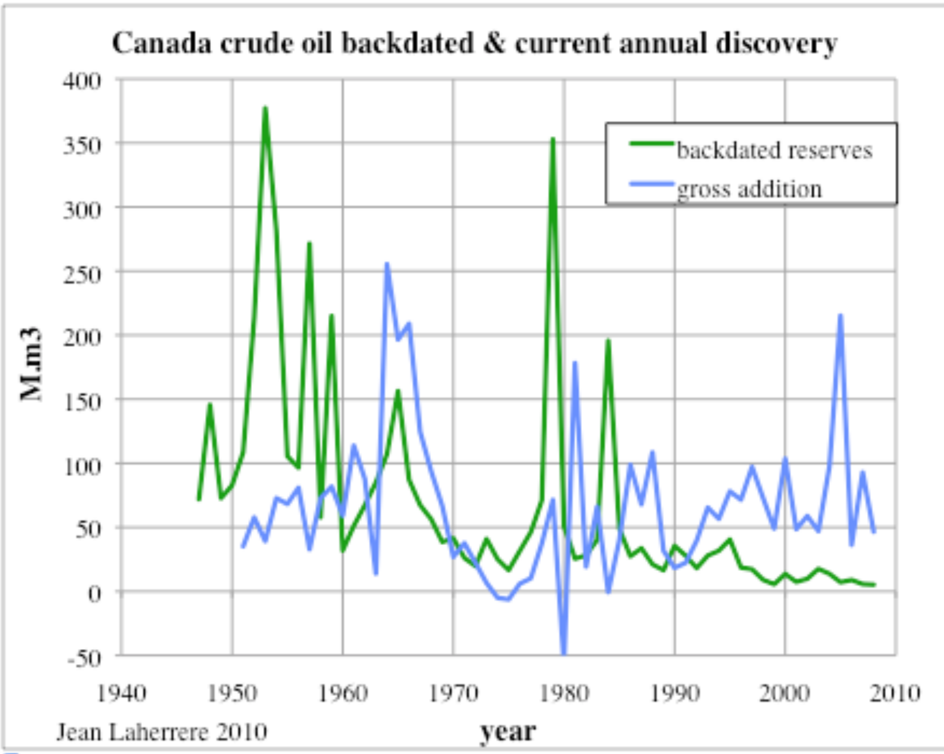
Figure 21: Canada crude oil: backdated & current cumulative discovery & production



The remaining reserves from backdated (in green) and current (in blue) confirm the large difference.
Figure 22: Canada crude oil backdated & current remaining reserves

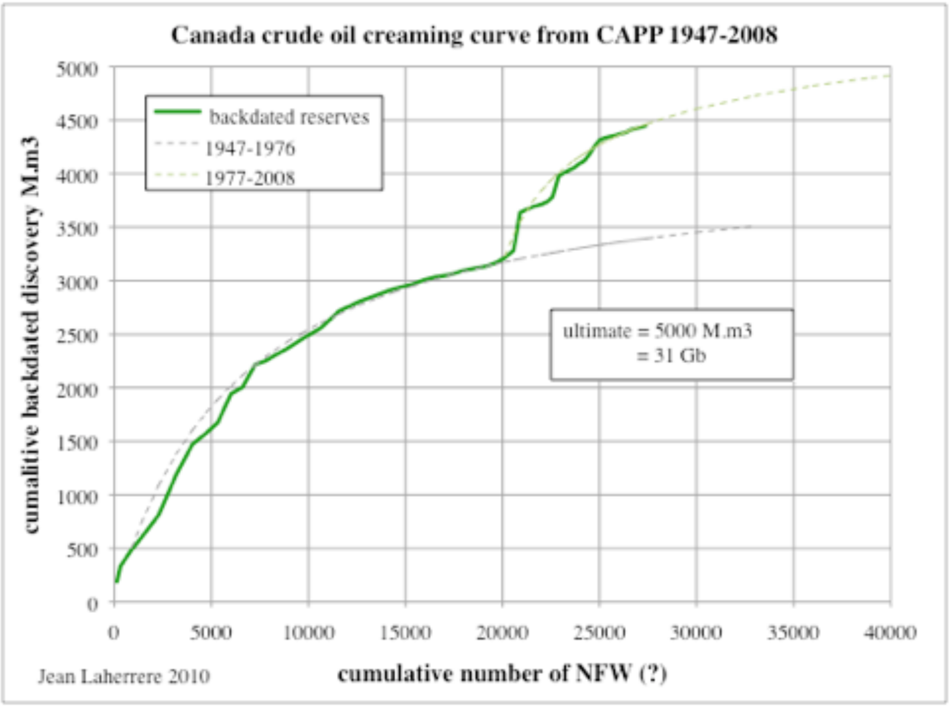


Same data displayed for annual discovery shows that large old discoveries were underestimated and recent additions display a poorly overestimated image of the recent discoveries.
Figure 23: Canada crude oil backdated & current annual discovery



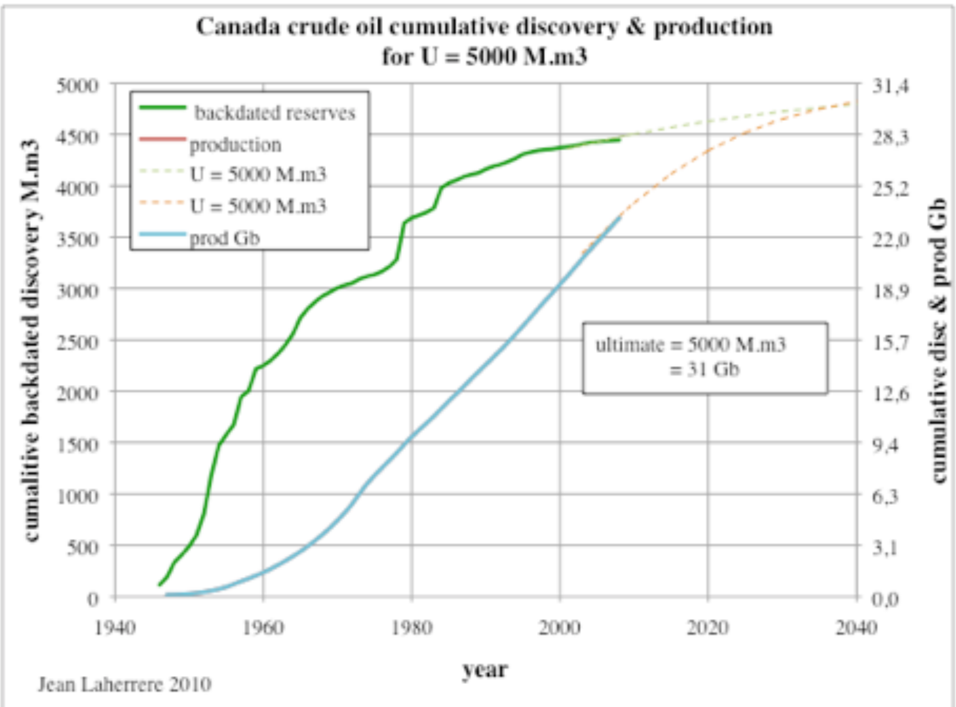
It is obvious that extrapolation of backdated data will provide better extrapolation towards the ultimate. The crude less extra-heavy oil creaming curve displays two main cycles with the break in 1976. A large third cycle seems unlikely. The ultimate seems to be 5000 M.m3 or 31 Gb.

Figure 24: Canada crude less XH oil creaming curve from backdated CAPP reserves 1947-2008 towards U=31 Gb



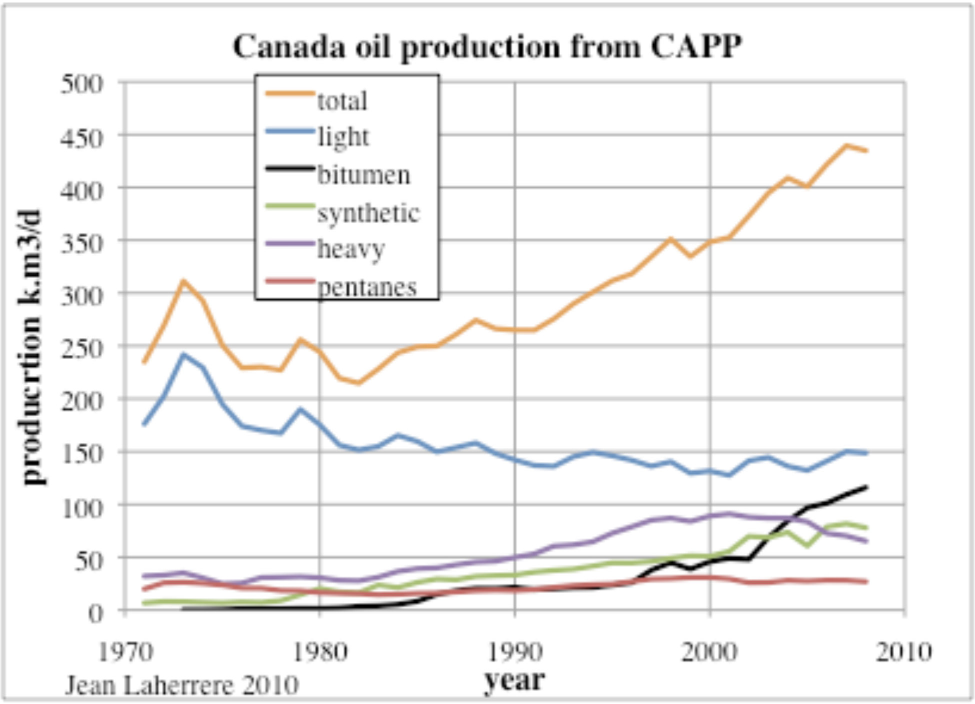
The same crude oil (excl XH) cumulative discovery versus time and cumulative production are modeled towards the ultimate of 31 Gb

Figure 25: Canada crude oil cumulative discovery & production from CAPP

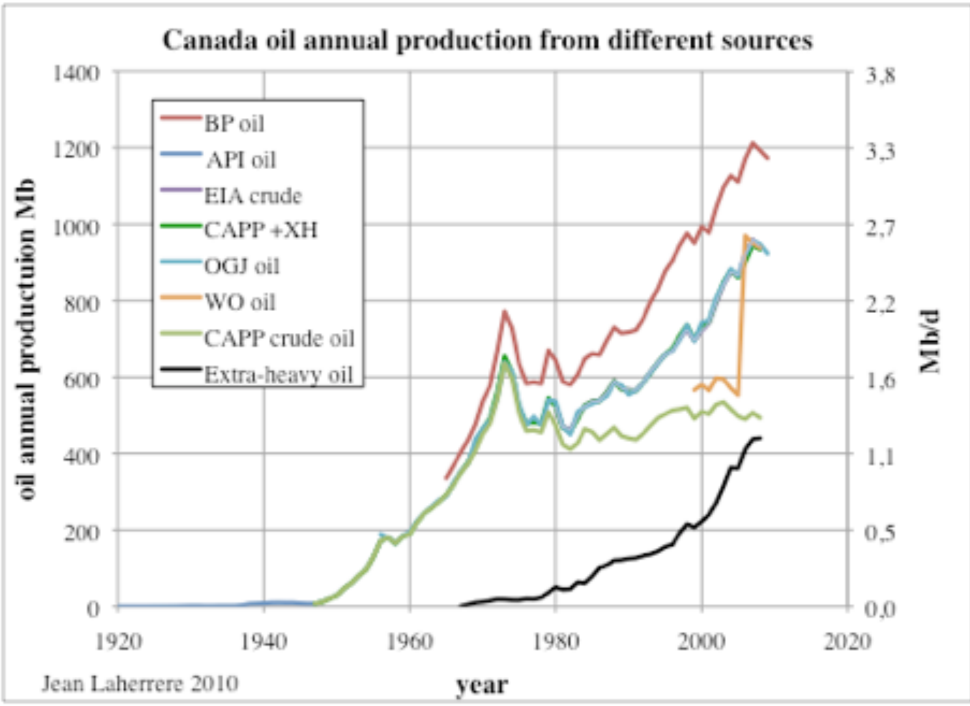


CAPP reports the oil production with the breakdown into light, heavy, bitumen, synthetic and pentanes.

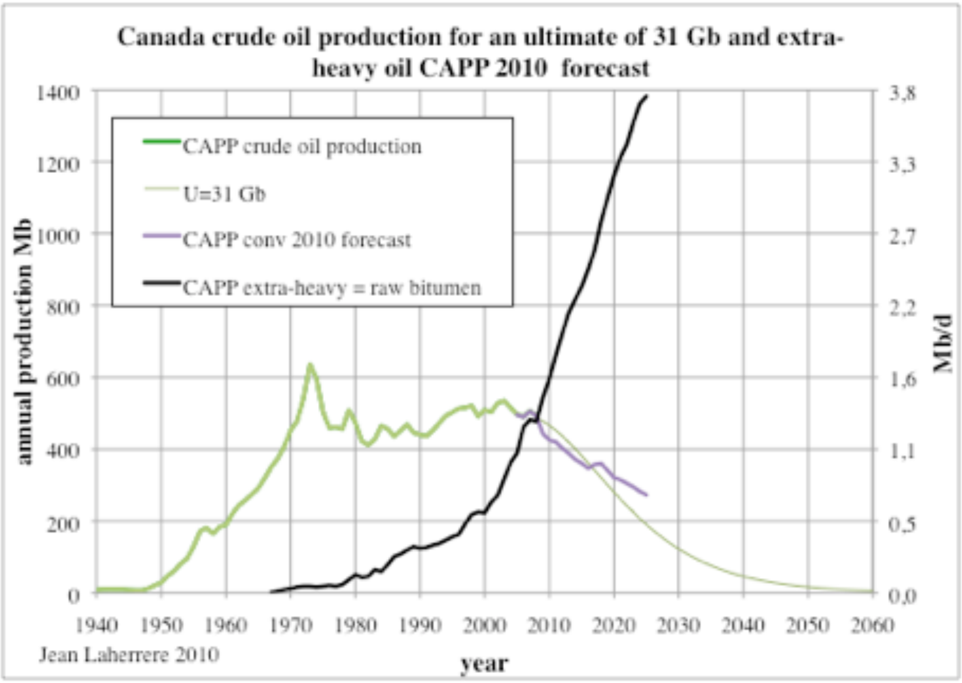
Figure 26: Canada annual oil production from CAPP



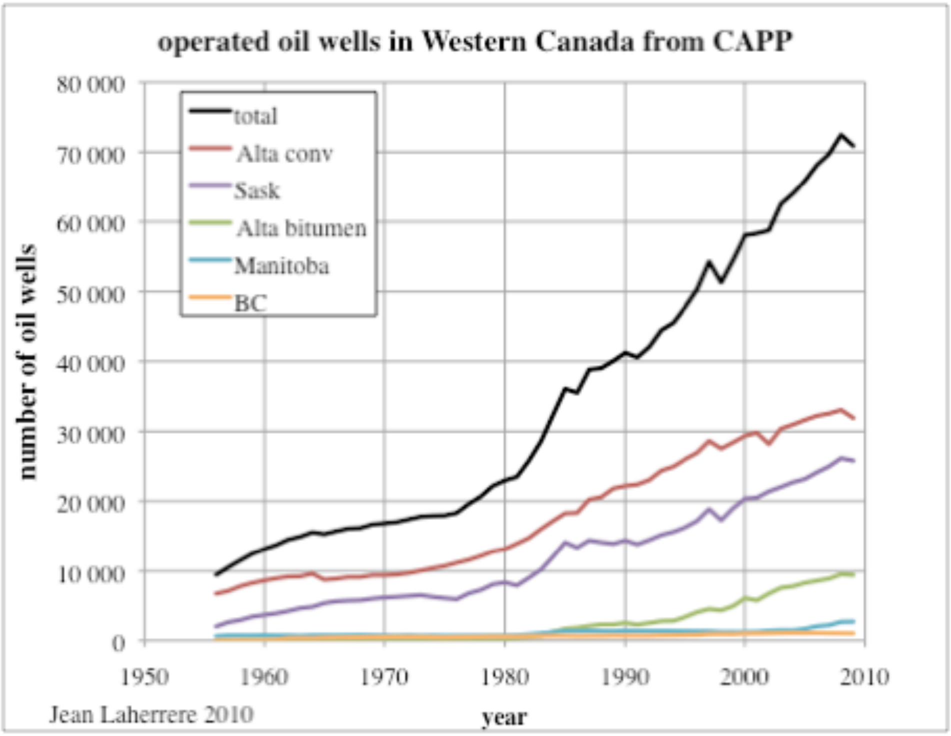
Because the importance of extra-heavy and the difference in heat content, Canada oil production is reported from different sources with large difference between BP, OGJ & WO, despite that Canadian agencies reports precise data, but the interpretation differs from magazines !
This difference shows that precise data does not leads necessarily to homogeneous reporting !
Figure 27: Canada annual oil production from different sources



The annual crude oil (excl XH) production is modeled with an ultimate of 31 Gb and the extra-heavy (raw bitumen) is reported with CAPP forecast up to 2025.
As any unconventional resources the important is not the size of the tank but the size of the tap. Oil sands development depends upon investments and other constraints as pollution, water & steam supply.
Figure 28: Canada annual crude oil production for U=31 Gb & bitumen CAPP forecast

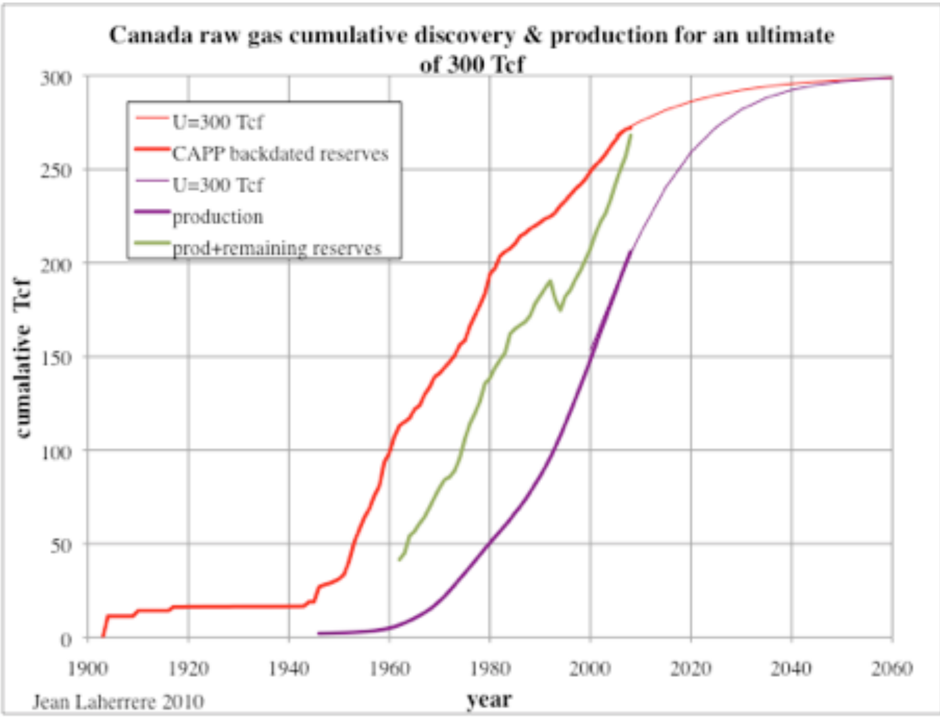


In Western Canada there are over 70 000 operated oilwells with 30 000 within Alberta.
Figure 29: Canada operated oilwells in Western Canada from CAPP

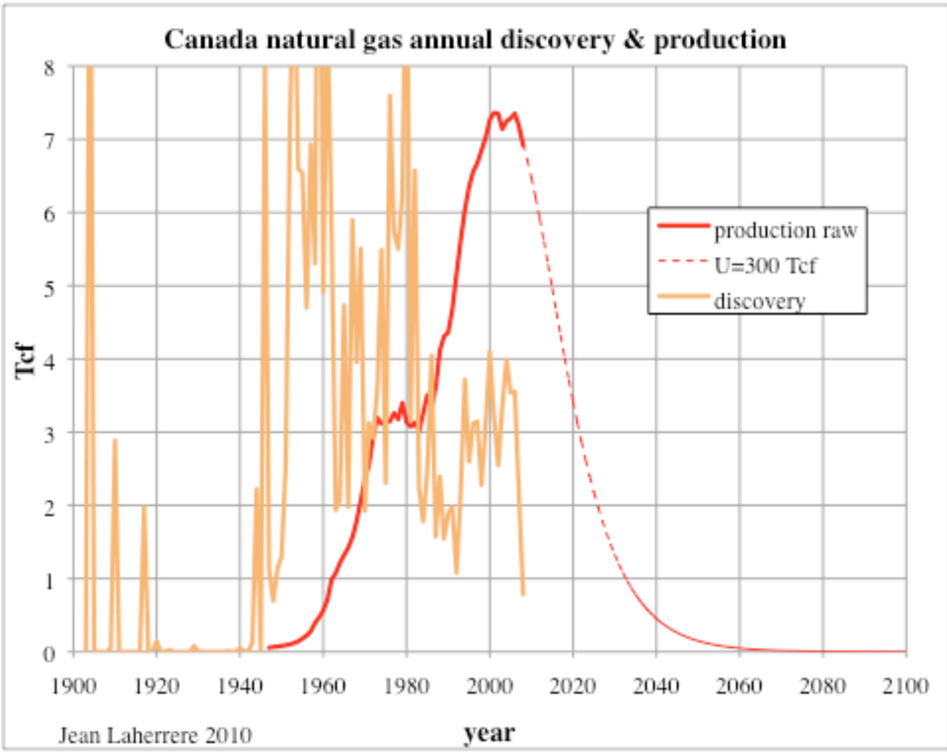


-Canada natural gas

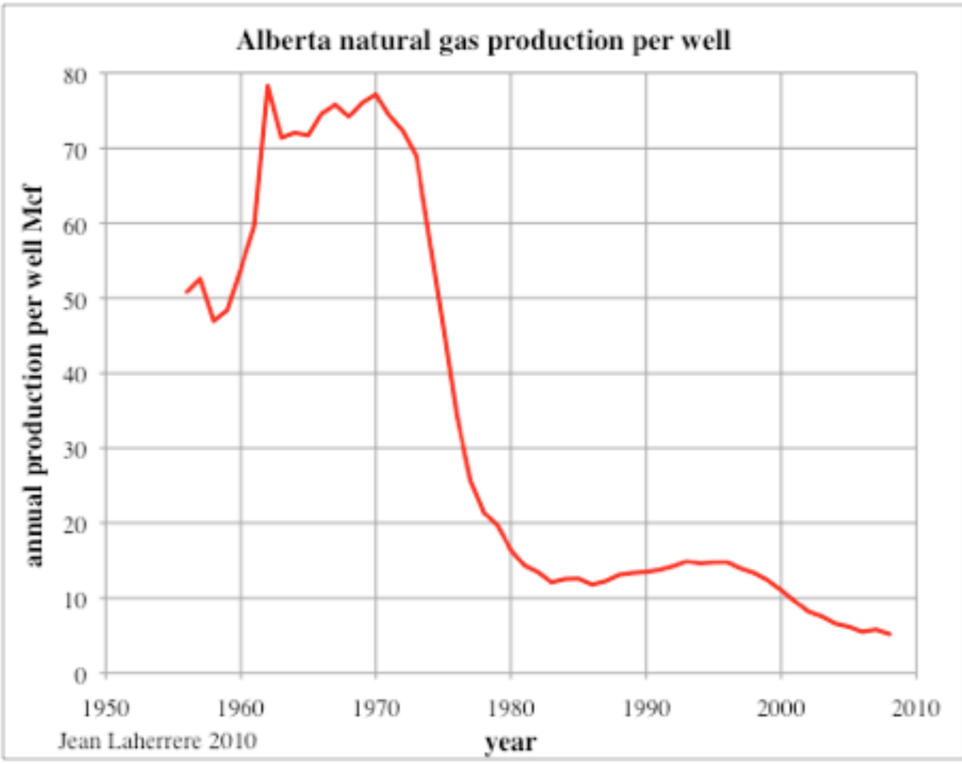
CAPP data on natural gas provides the same display and large difference between backdated initial established reserves and current data. The backdated cumulative discovery is extrapolated towards 300 Tcf as the cumulative production.
Figure 30: Canada raw gas cumulative discovery & production for U = 300 Tcf



The annual discovery peaked in the 1950s, with a new peak in the 80s and the annual production seems to decline after a peak around 2000.
Figure 31: Canada raw gas annual production for U= 300 Tcf

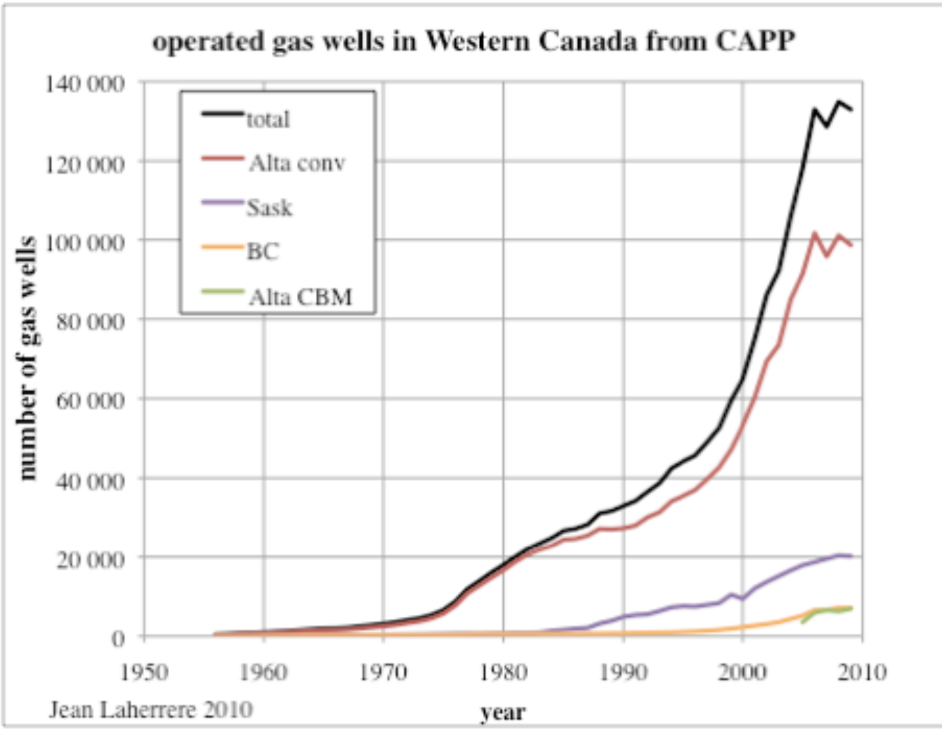


Alberta production per gaswell, excluding CBM gaswells (6% of conventional in 2008), displays a drastic decline around 1975 and now is slowly declining.
Figure 32: Alberta natural gas (excluding CBM) production per well



The number of gaswells in Western Canada has increased sharply between 1995 and 2005. Alberta CBM flattens !

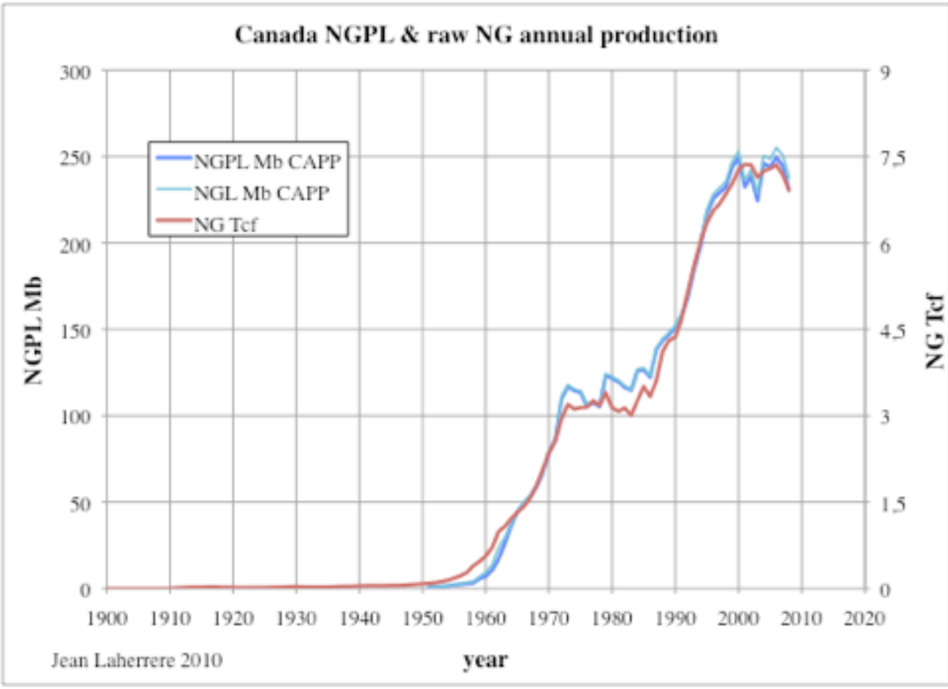
Figure 33: Western Canada: number of operated gas wells from CAPP



-Canada NGPL

Canada NGPL acts exactly like in the US with the same ratio with NG production of about 33 Mb/Tcf. But in Canada condensate production is reported, but it is negligible compared to NGPL.

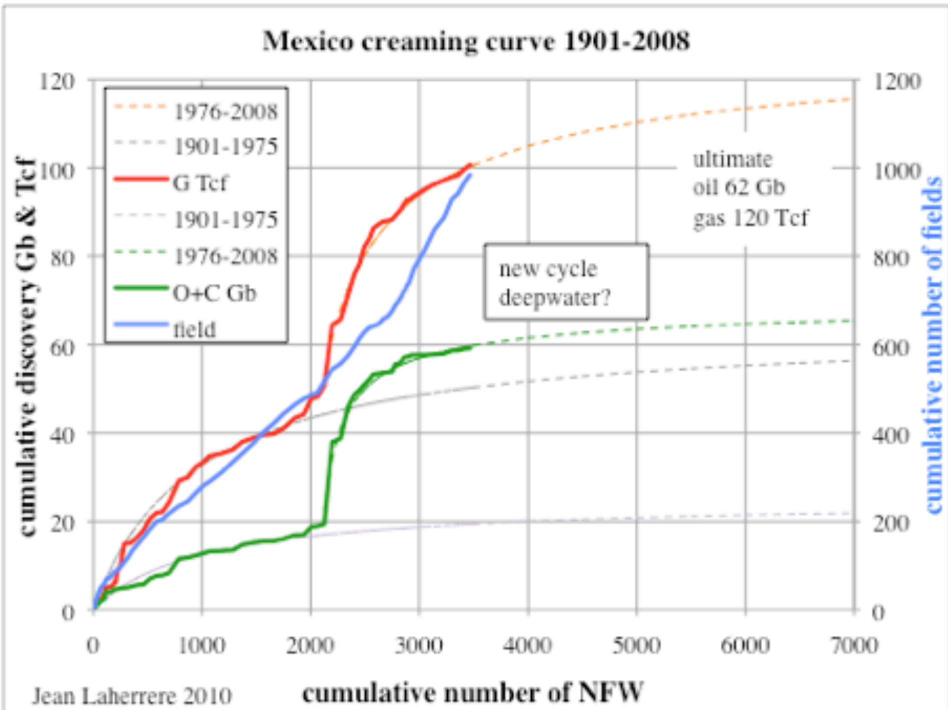
Figure 34: Canada NGPL and NG production



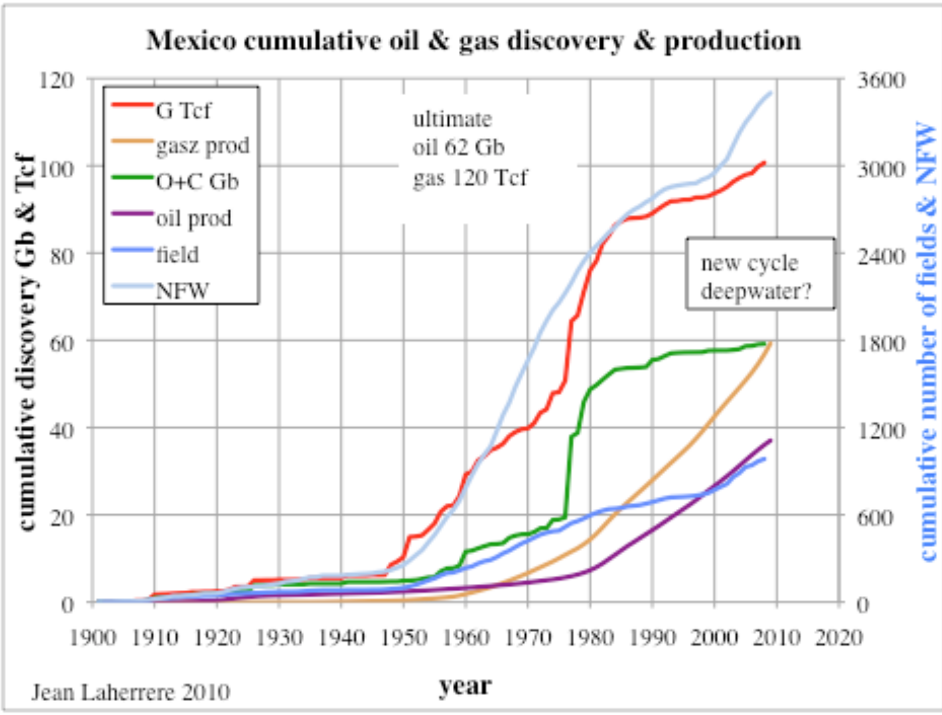
Canada NGPL production forecast has to be correlated to NG production forecast using a ratio of 33 Mb/TCF

-Mexico

Pemex publishes good discovery and production data but only for the recent years.
Mexico reserves are reported as backdated 2P and the creaming curve display both for oil and gas two cycles. A third cycle (being deepwater which is not explored) is likely.
The ultimate is 62 Gb for oil and 120 Tcf for gas.
Figure 35: Mexico creaming curve 1901-2008 towards 62 Gb & 120 Tcf



The cumulative discovery is displayed now versus time for oil and gas, as the production.
Figure 36: Mexico cumulative oil & gas discovery and production



At end 2009 cumulative oil production at end 2009 is 39 Gb, leaving 21 Gb as remaining reserves when Pemex 2009 annual reports gives 28 Gb pour 2P (proved = 14 Gb, probable = 14.2 Gb, possible = 14.8 Gb) ! Chicontepec is overestimated !
Chicontepec oil is mainly unconventional!
The breakdown into onshore and offshore discovery is reported up to end 2007, offshore with 33 Gb and 24 Tcf, onshore with 26 Gb and 75 Tcf
Figure 37: Mexico offshore cumulative oil & gas discovery

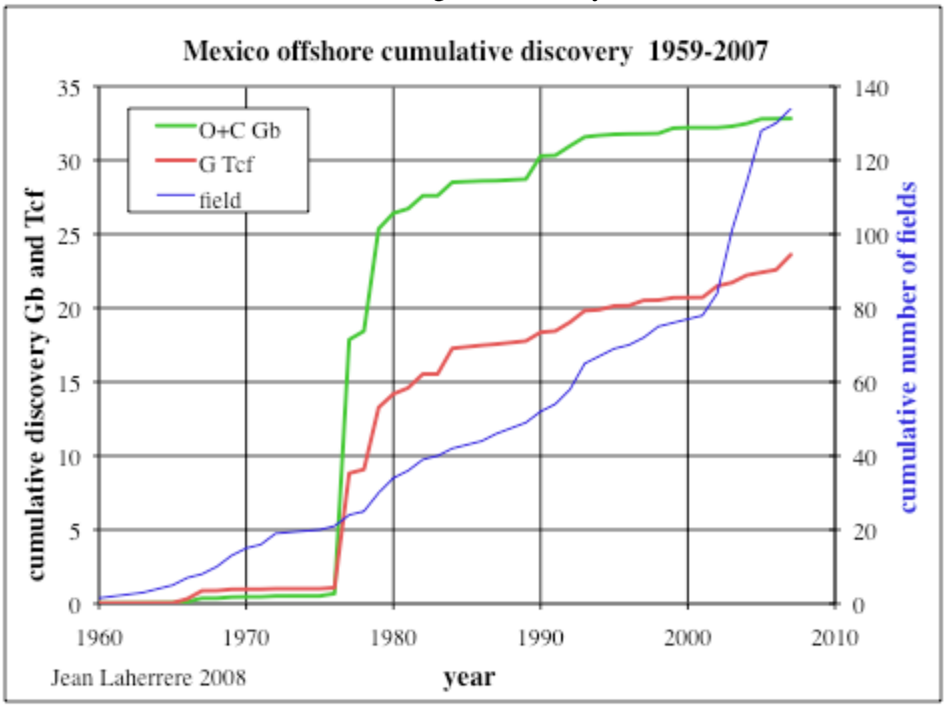
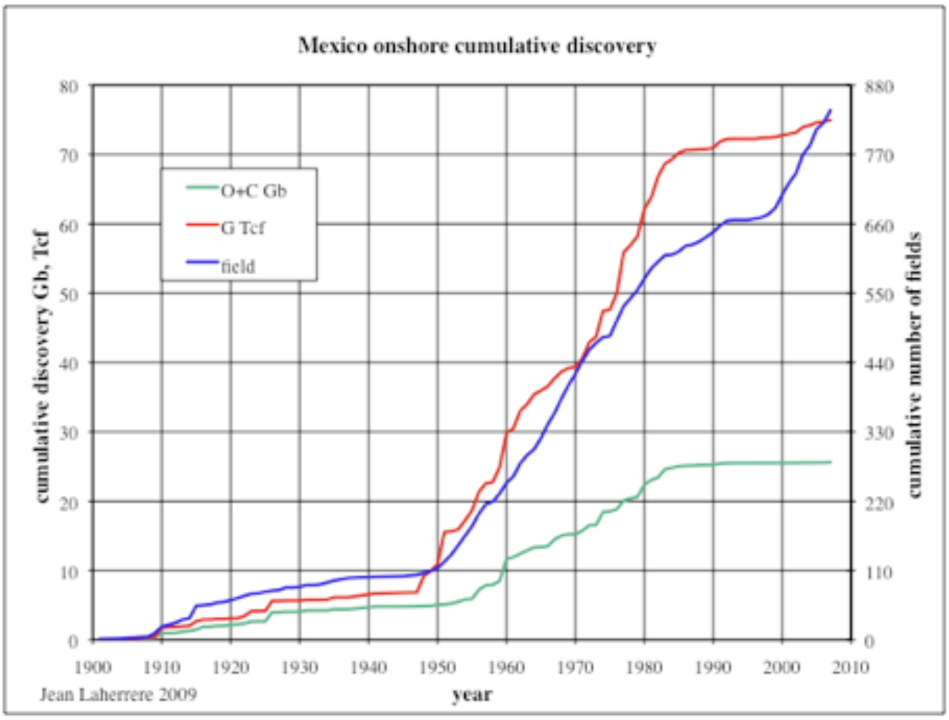
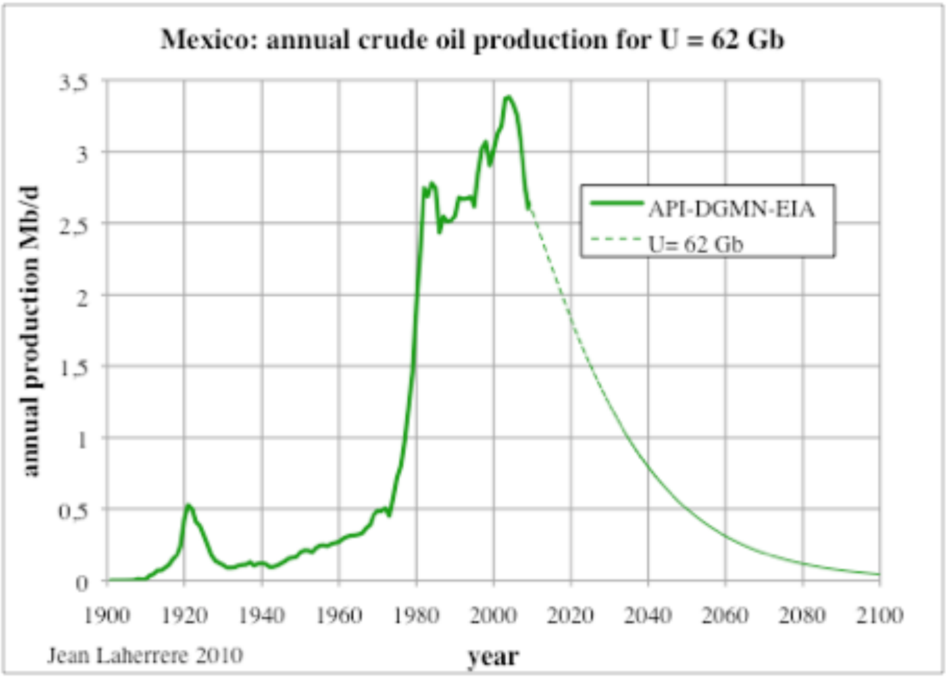


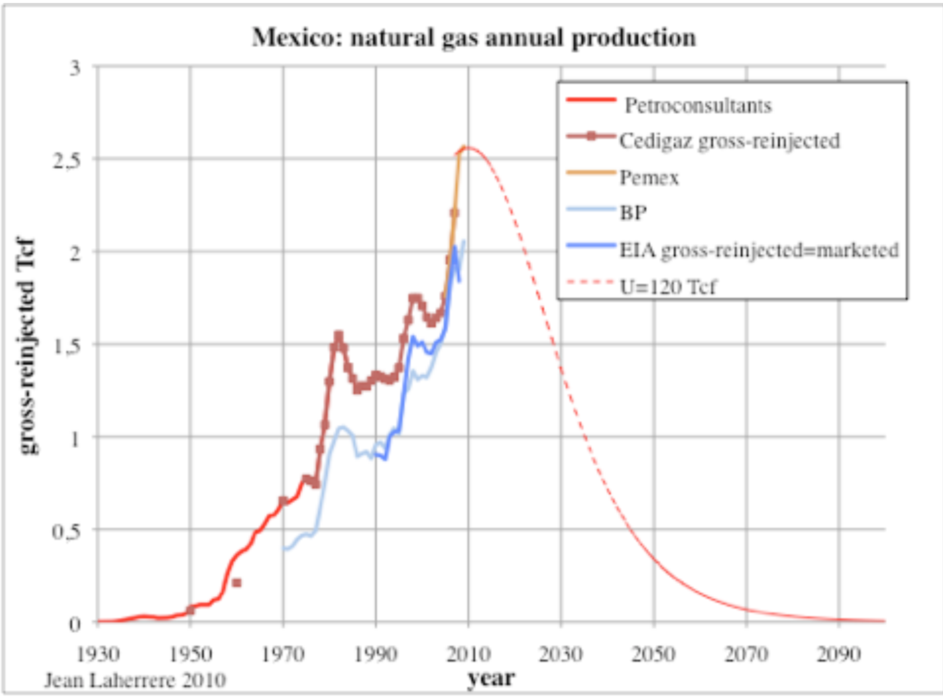
Figure 38: Mexico onshore cumulative oil & gas discovery



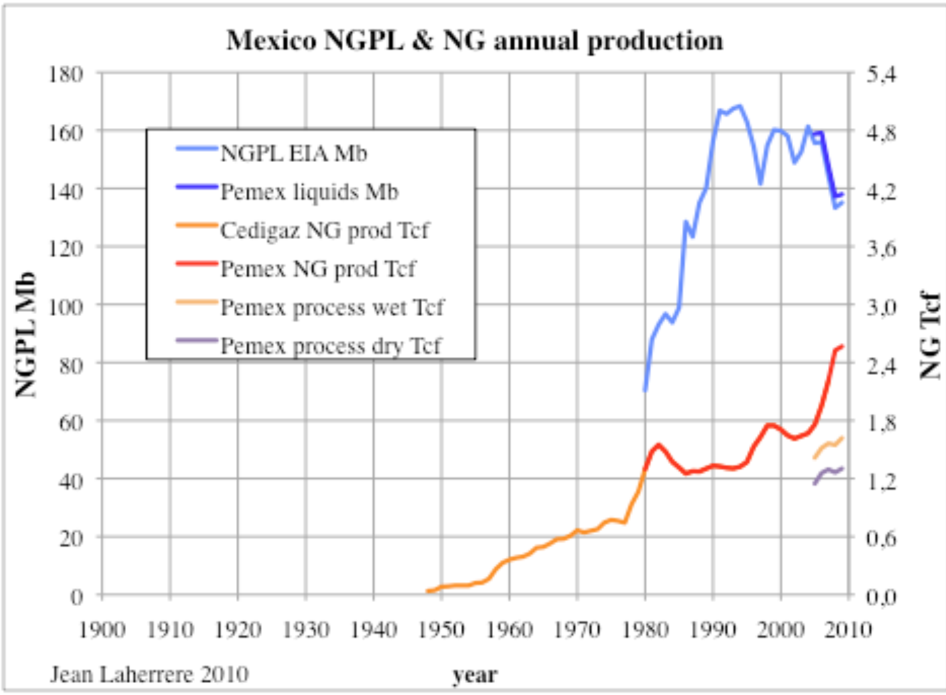
Annual oil production is modeled for U = 62 Gb, showing a peak in 2004.
Figure 39: Mexico annual oil production for U = 62 Gb



Annual gas production is modeled for U = 120 Tcf, showing a peak about now !
Figure 40: Mexico annual natural gas production for U = 120 Tcf



Mexico NGPL production is found on EIA since 1980 and on the last Pemex reports and they agree. But we have seen that NG production varies from sources. Furthermore the volume of gas processed (wet or dry) is different from gas produced. Lately NG production has increased when NGPL has decreased.
Contrary to US and Canada the ratio of 33 Mb/Tcf is not found and we have lost for making forecast!
Figure 41: Mexico NGPL & NG annual production



-North America

-oil

The sum of the previous graphs for US, Canada and Mexico, leads for North America graphs
Figure 42: USL48 annual crude oil discovery & production for U = 230 Gb

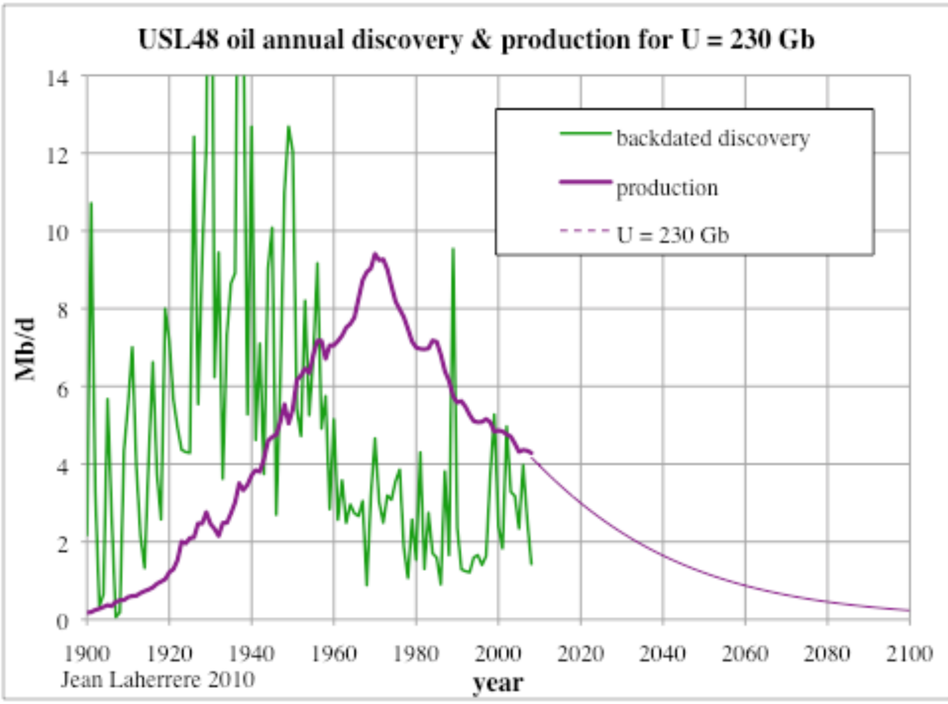


Figure 43: Alaska annual crude oil discovery & production for U = 30 Gb

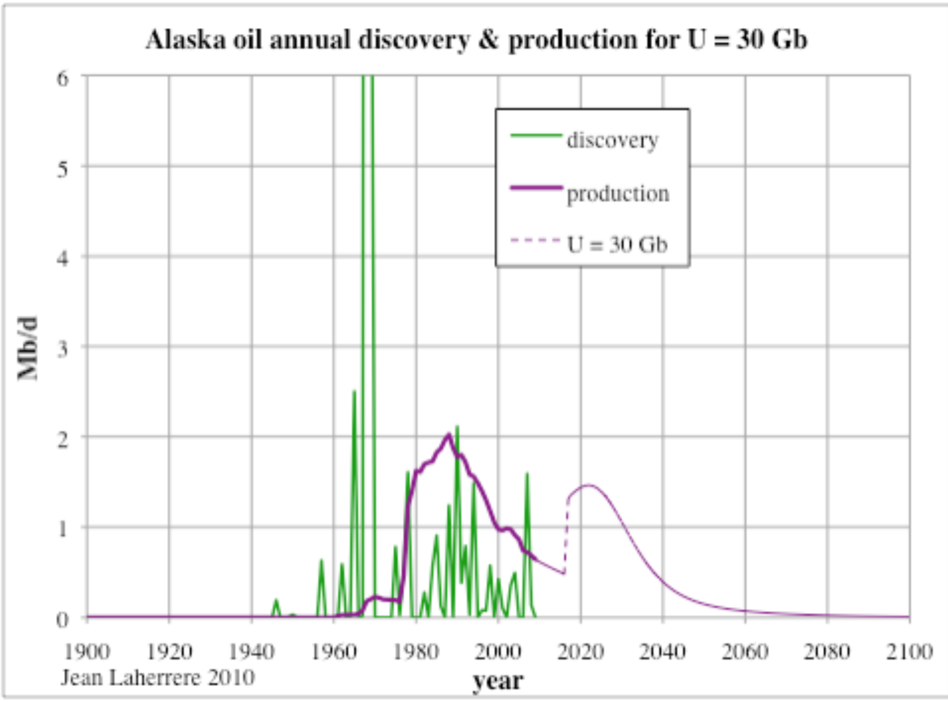


Figure 44: Canada annual crude (excl XH) oil discovery & production for U = 31 Gb

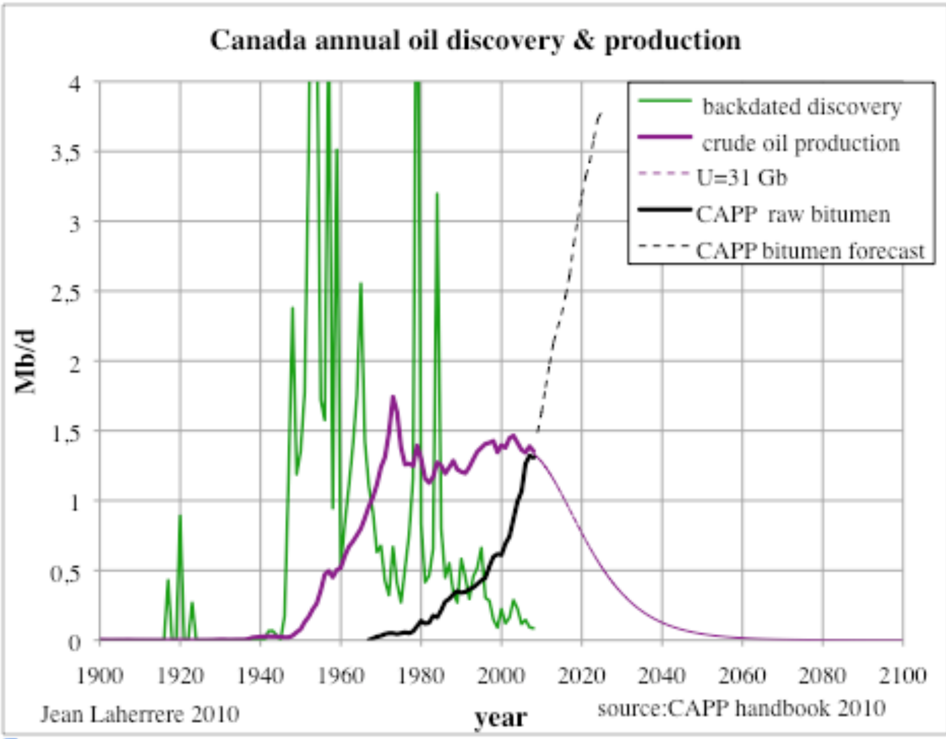
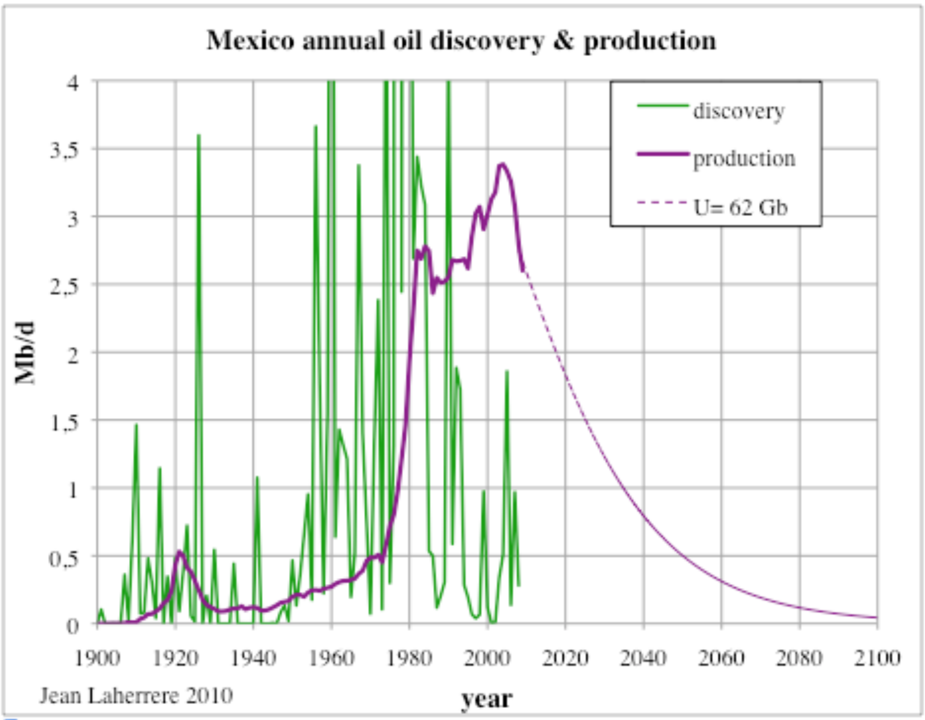
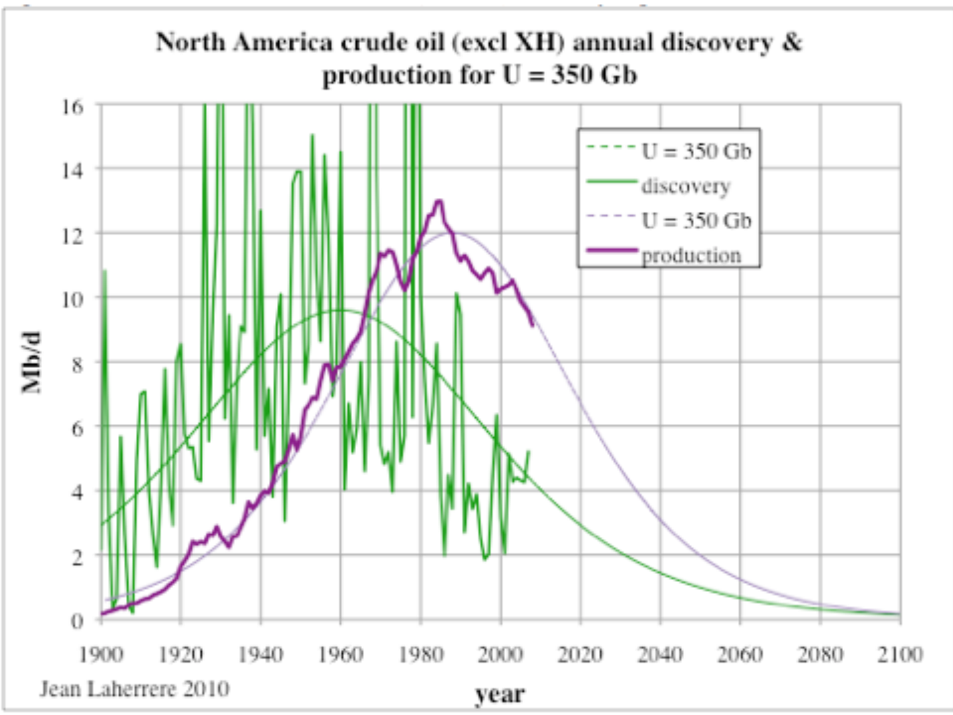


Figure 45: Mexico annual crude oil discovery & production for U = 62 Gb



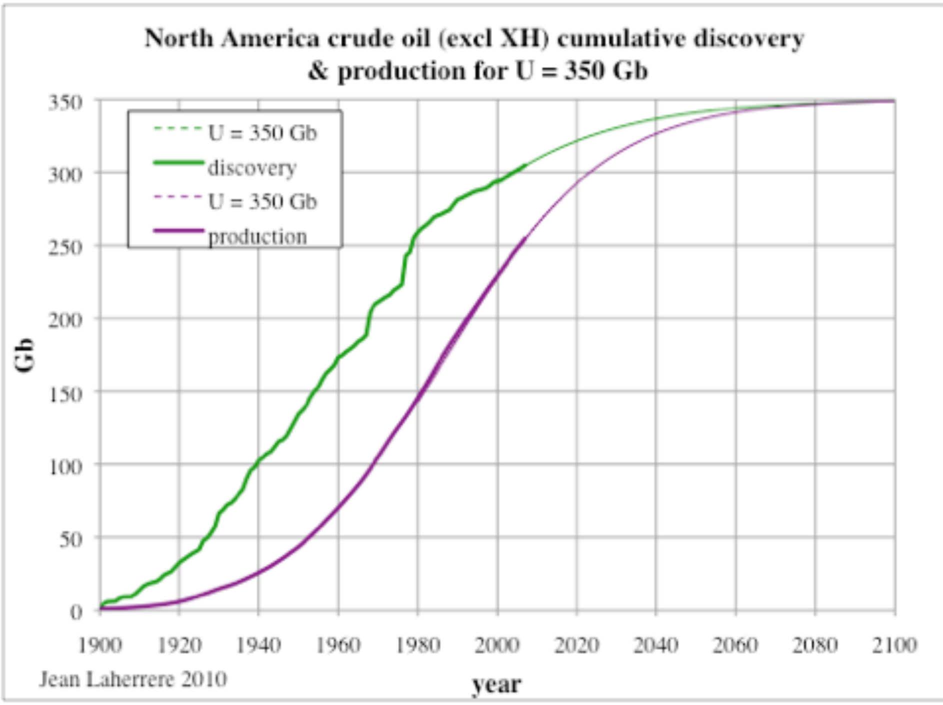
North America annual conventional oil production has peaked in 1985 and the present decline seems a little less than the rise with an ultimate of 350 Gb

Figure 46: North America annual crude oil (excl XH) discovery & production for U = 350 Gb



The cumulative oil discovery looks parallel to the production with a lag of about 25 years

Figure 47: North America cumulative crude oil (excl XH) discovery & production for U = 350 Gb



- **-natural gas**

Addition for conventional natural gas gives an ultimate of around 1700 Tcf for North America

Figure 48: US annual crude natural gas discovery & production for U = 1250 Tcf

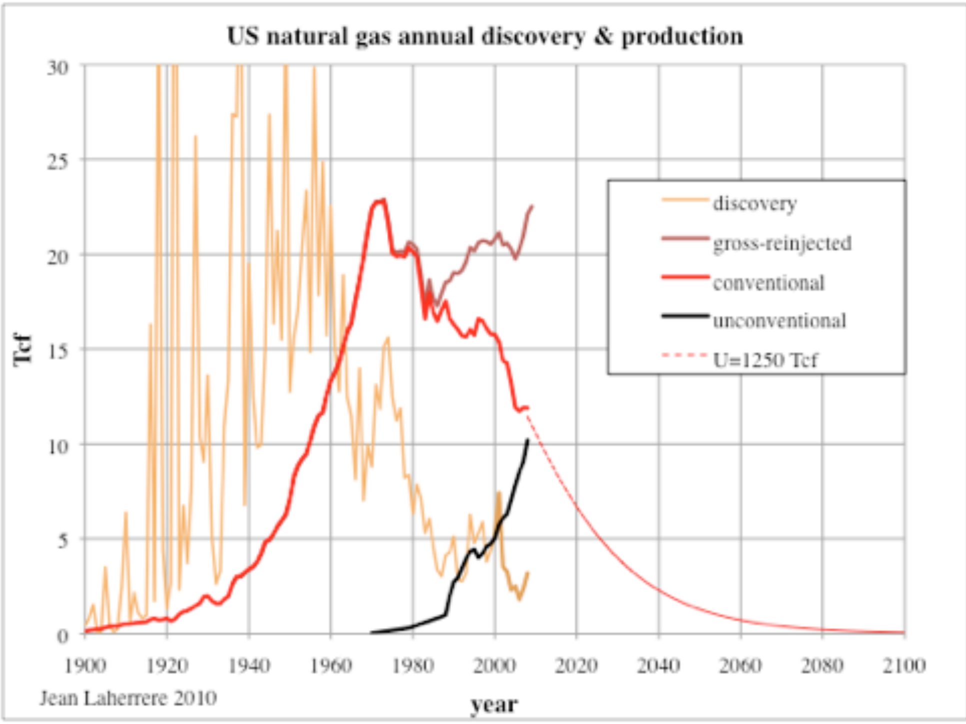


Figure 49: Canada annual crude natural gas discovery & production for U = 300 Tcf

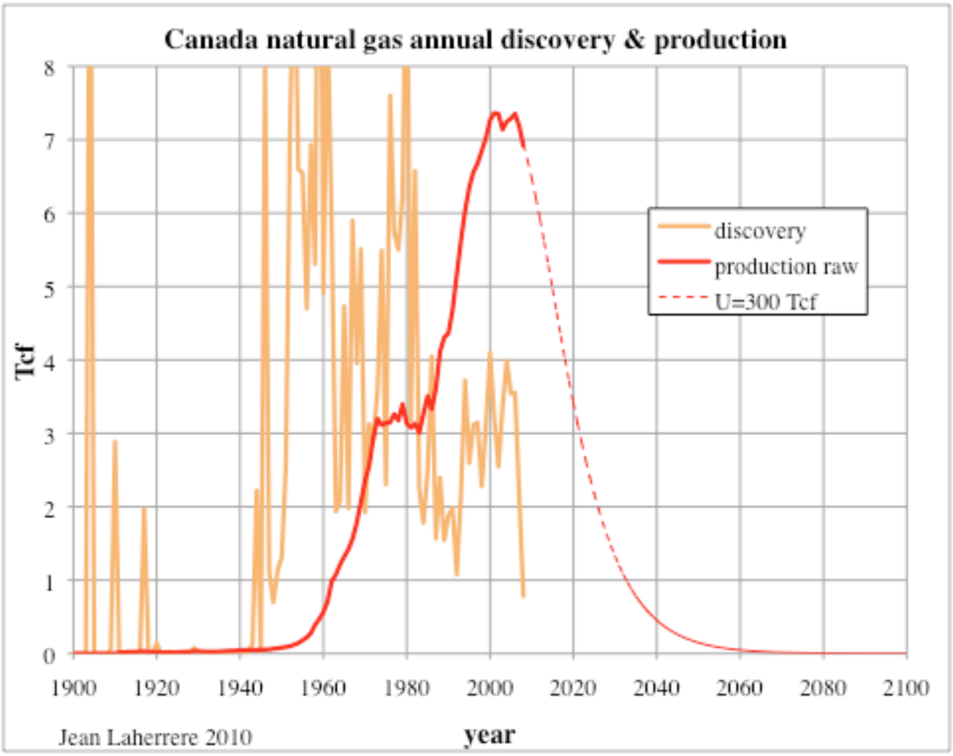
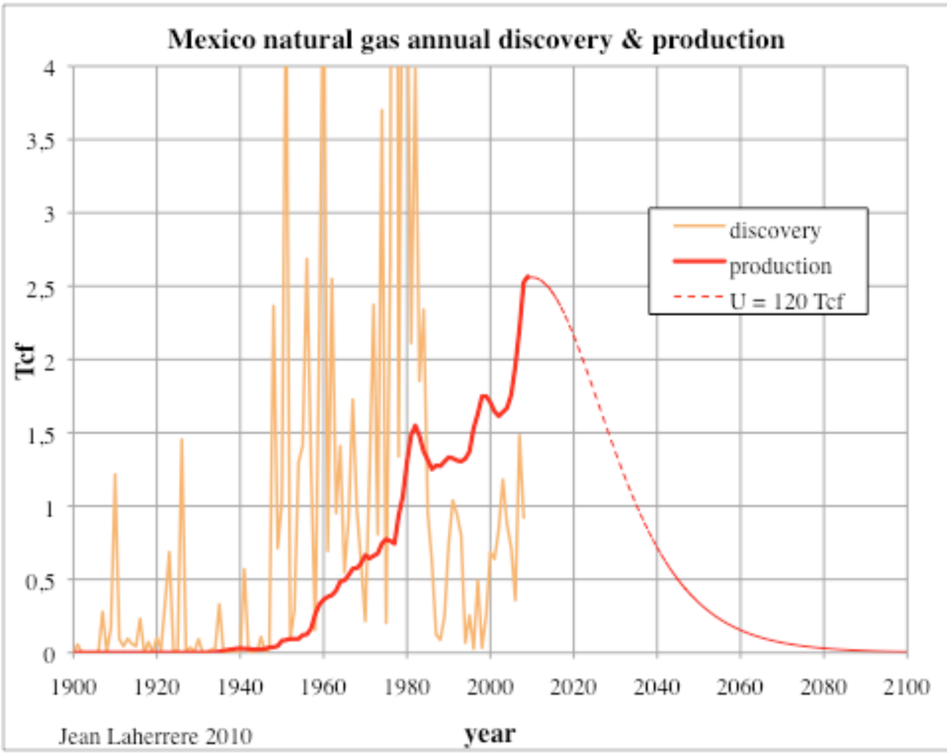
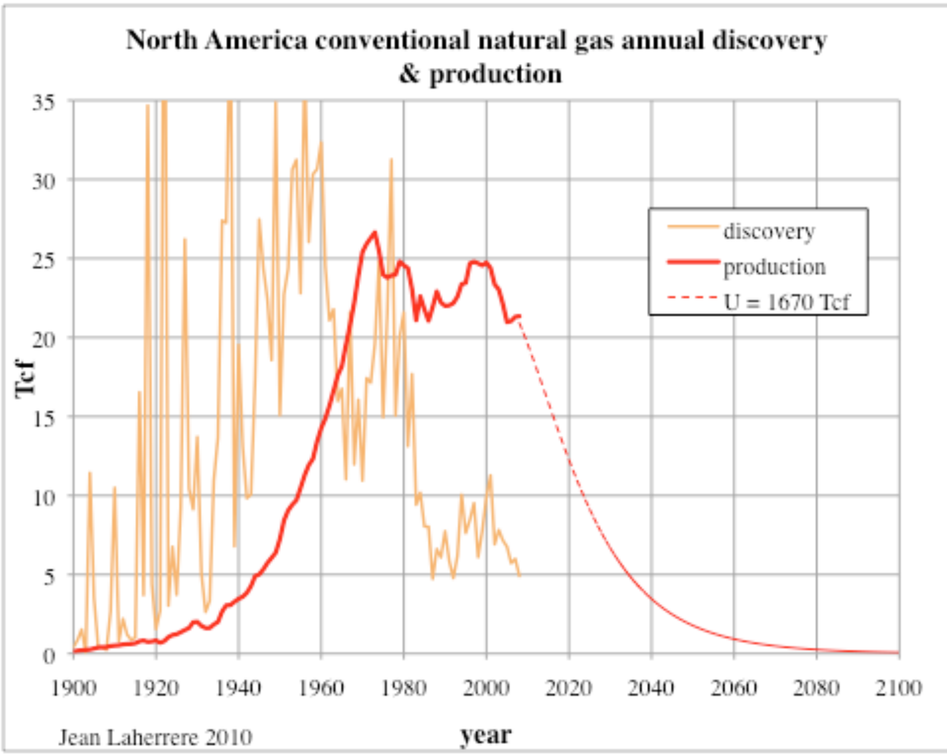


Figure 50: Mexico annual crude natural gas discovery & production for U = 120 Tcf



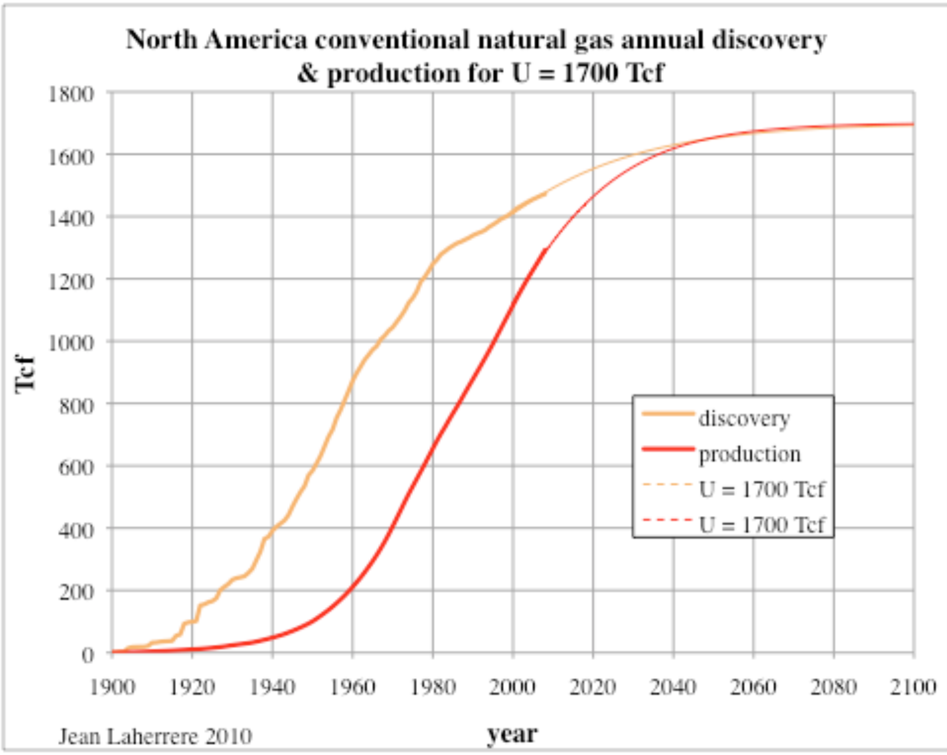
North America conventional natural gas had a bumpy plateau from 1970 to 2000 and is now on decline, which looks symmetrical to its rise.

Figure 51: North America annual conventional crude natural gas discovery & production for U = 1670 Tcf



North America conventional gas cumulative discovery is parallel to cumulative production with a lag of also 25 years, like for oil !

Figure 52: North America cumulative conventional crude natural gas discovery & production for U = 1700 Tcf



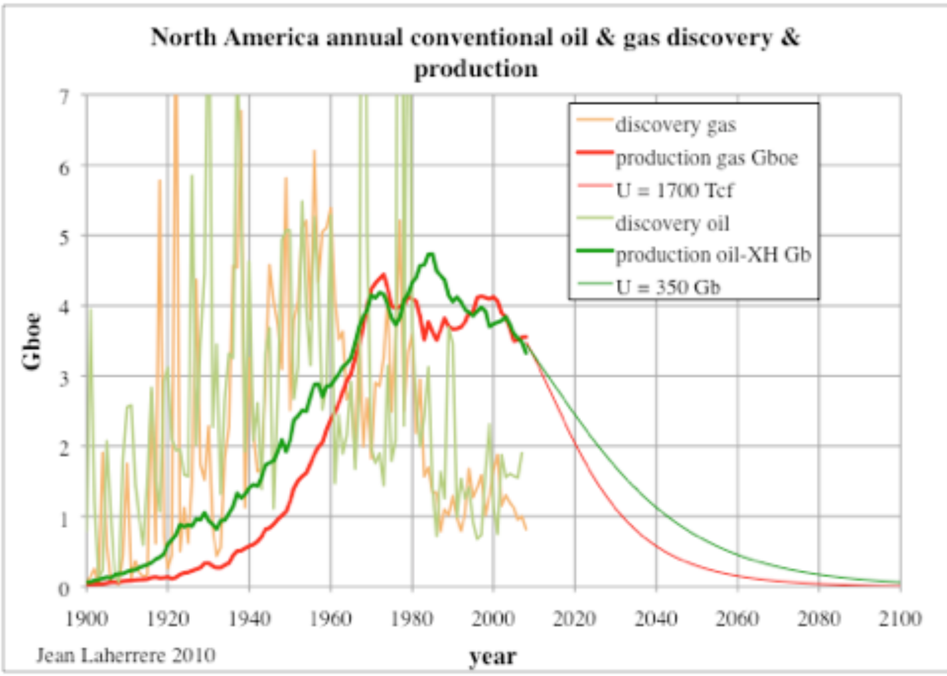
-natural gas plant liquids

Natural gas plants liquids forecasts can be easily correlated with NG production forecasts for US and Canada using a ratio of 33 Mb per Tcf, but it is impossible for Mexico because a strange behavior on the recent years.

-oil and gas

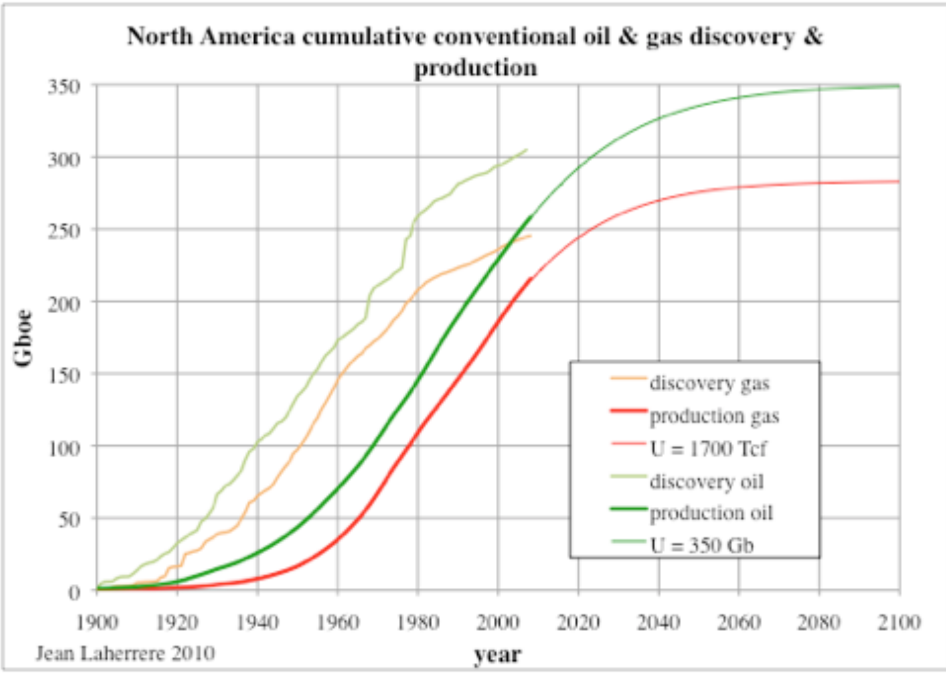
The comparison for North America between oil and gas annual production shows well symmetry centered on 1990

Figure 53: North America annual conventional oil & gas discovery & production



The cumulative discovery and production are also parallel between oil and gas !

Figure 54: North America cumulative conventional oil & gas discovery & production



-Conclusions

North America discovery data is unreliable because the reporting of the three countries is completely different, proved for US, established = proved +half probable for Canada and 2P = proven +probable for the rest of the world in scout database

A unique approach for definitions and reporting should be recommended, using the mean value (if not, arithmetic aggregation is incorrect), why not within the NAFTA!

The USDOE/EIA, which has a very useful site to get historical updated production data, should try to match the CAPP handbook in matter of reserves now that the SEC rules have been changed

This paper deals mainly with conventional oil and gas because unconventional production is submitted to political or financial constraints that I am unable to foresee.

NB: sorry for my broken English: no time to have it corrected