Jean Laherrère 24 May 2015

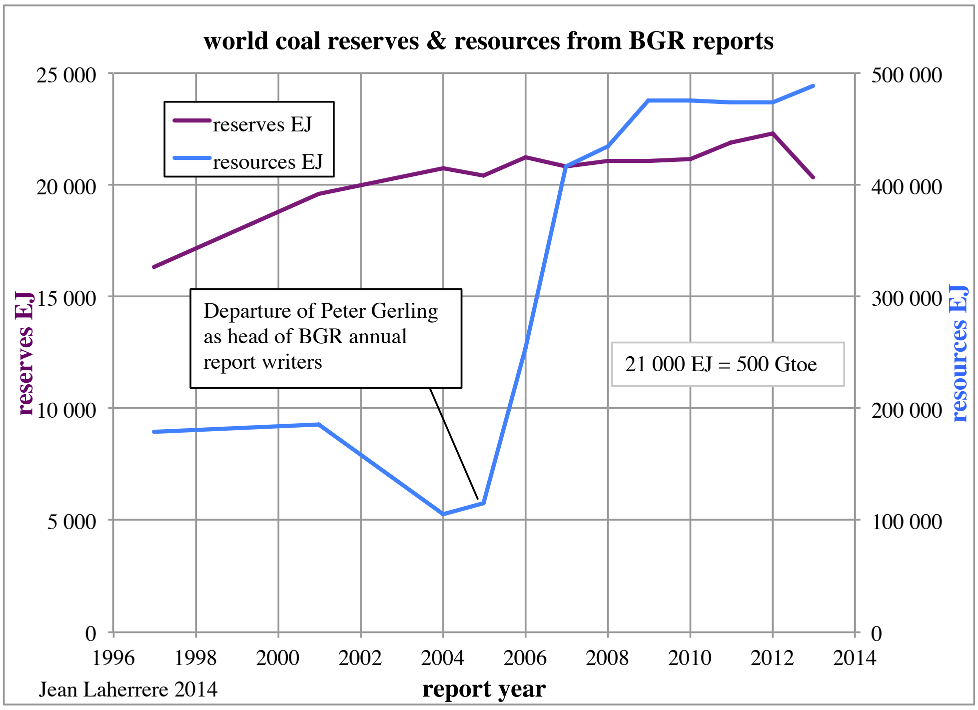
Some examples of oil & gas production linear extrapolation to estimate ultimate

When estimates of reserves from the operator are not available (usually confidential), it is possible from production data to estimates the ultimate reserves by extrapolating the annual production decline (or the percentage annual over cumulative = HL) versus the cumulative production. When the annual or percentage production reaches zero, it means that the production is terminated and that the cumulative production equals the ultimate.
The Hubbert linearization (HL) as described by Deffeyes (in his 2001 book "Hubbert's peak") is often described as unreliable to estimate oil ultimate reserves. The problem is that in many cases the trend displays several linear different periods and that the linear trend is only for few years.
It is true that for conventional fields (where the area, net pay and porosity are well known) the geological estimate of oil in place with a reliable recovery factor is a good way to estimate 2P (equals to the mean value) ultimate recovery, followed by production simulation (with large computer with long Monte Carlo runs for huge grid (100 millions for Ghawar)) before the development of the field and after, using physical data (from well production & log tied to seismic surveys).
In the US, reserves are in fact remaining reserves at a certain date, but the date is rarely given. Reserves without date should be remaining reserves at a certain year plus the cumulative production up this year: they are called initial reserves or ultimate reserves or EUR (Estimated Ultimate Reserves). Uncertainty of the estimate is huge and reserves value can be proved (or proven), probable or possible. There are four main rules for reporting reserves (SEC, OPEC, SPE and ABC1), rarely mentioned. Reserves for a field can vary largely because poor practice due to rules to please the bankers or the shareholders, not the truth!
There is no consensus on the definition of conventional, because in most cases there is no discontinuity on the physical parameter as porosity or permeability or gravity (except for extra-heavy being heavier than water). But an accumulation can be geographically well constrained when oil and gas is trapped in a field above a water level (conventional case) and its area is well defined, but the unconventional shale plays have no water level and are a continuous type accumulation where the limit is mainly economical (sweet spots). It is then easy to confuse reserves (what was and will be produced from start to end) and resources (what in the ground). The estimate of Monterey shale reduced by 96% is a good example!
For a country the plot of cumulative 2P discoveries versus cumulative number of fields (or NFW= new field wildcats, but often not available or wrong like in China) being the creaming curve is the best way to estimate ultimate reserves.
Furthermore it is incorrect to aggregate arithmetically proved reserves, as it is done in every official agency (the arithmetic aggregation is only correct with the mean values).

But for unconventional oil and gas or for coal field the linearization of the production data could give good ultimate estimates.
Coal fields look rather similar with shale (tight) plays in term of often having rather unclear geographical limits and confusion between reserves and resources.
An example is provided by the recent German BGR 2013 estimate for world coal. This gave about 21 000 EJ (exajoules) (about 500 Gtoe) for reserves, and 490 000 EJ for resources (about 24 times greater).
Coal reserves are constrained by the thickness, the depth and the location of the seam. Thin layers, layers deeper than 1500 m and offshore layers are not reserves, but resources, because it will take more energy to extract them than they represent (EROI <1). All the coal measures of the North Sea are only resources. When the underground coal gasification (UCG) is economical, these huge offshore resources would be turned into reserves, but up to now, attempts on UGC were all failures.

However the evolution of the world coal reserves data from the BGR from 1997 to 2013 displays a peak in 2012. By contrast, the estimate of resources displays a sharp increase since 2005, coinciding with the departure of Peter Gerling (an active participant in the foundation of ASPO): it looks queer: something is wrong somewhere, but where!

Fig 1: world coal reserves & resources from BGR



I remind US readers that since 1993 US federal agencies are obliged to use the SI (International System of Units) accepted by every countries, except non federal US, Liberia and Myanmar.

EIA AR 2007

Public Law 100–418, the Omnibus Trade and Competitiveness Act of 1988, states: "It is the declared policy of the United States—

(1) to designate the metric system of measurement as the preferred system of weights and measures for United States trade and commerce. . . .

(2) to require that each Federal agency, by the end of Fiscal Year 1992, use the metric system of measurement in its procurements, grants, and other business–related activities."{45

The rules of SI are clear the symbol of thousand is k (kilo), million M (mega), US billion G (giga) and US trillion T (tera).

Anyone using a computer knows that his RAM memory is now in GB = gigabytes (before it was in MB = megabytes).

EIA is supposed to use SI, but it does it at the minimum reporting one page with SI unit, but EIA uses non SI symbol.

In the English papers, million is often written MM or mm or Mm or m.

IEA being located in Paris respects the SI and uses k, M & G

Canada is metric and respect SI

Another rule by SI to avoid confusion and recommended by USDOC National Institute of Standards and Technology in NIST-SP811 2008 edition

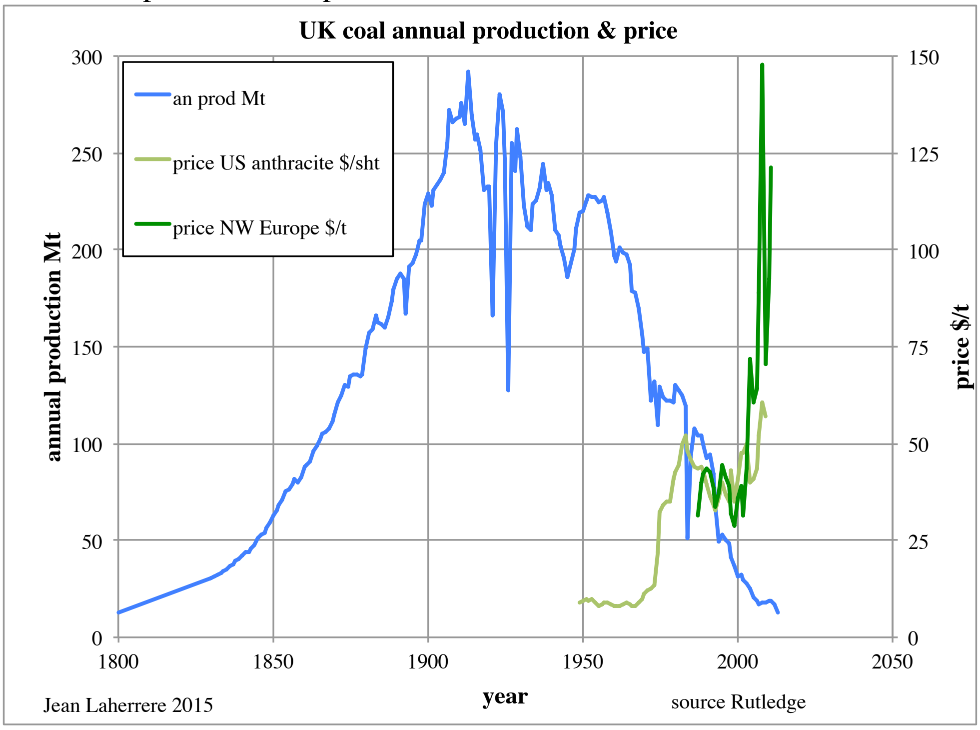
10.5.3 Grouping digits

Because the comma is widely used as the decimal marker outside the United States, it should not be used to separate digits into groups of three. Instead, digits should be separated into groups of three, counting from the decimal marker towards the left and right, by the use of a thin, fixed space.

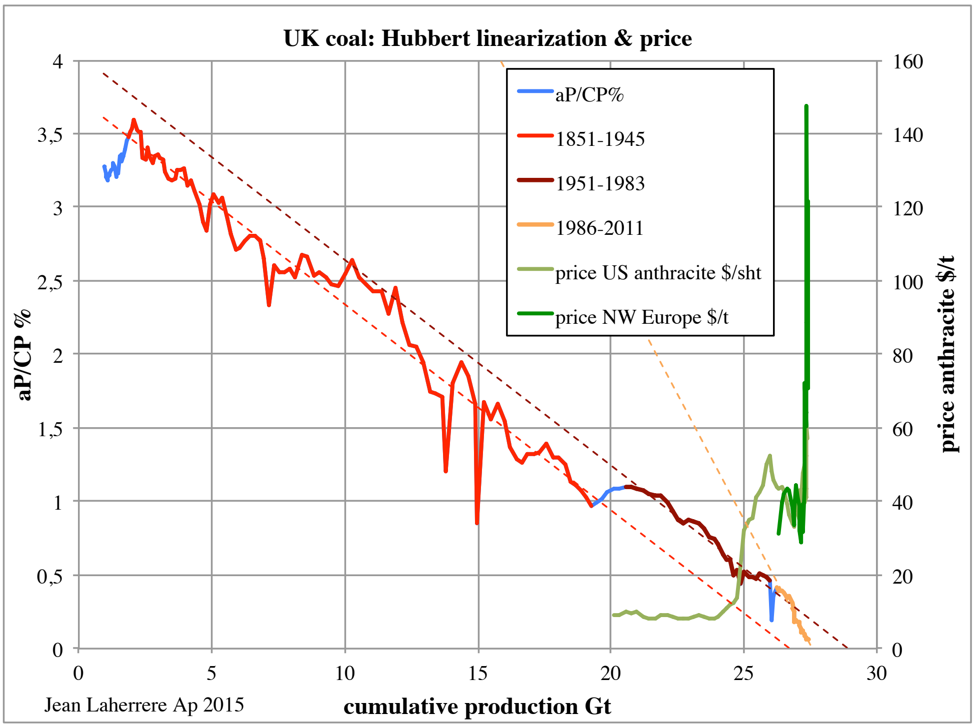
However, this practice is not usually followed for numbers having only four digits on either side of the decimal marker except when uniformity in a table is desired.
It is also recommended by ISO rules.

In my papers, million is M and there is a space to separate thousands following the law of the European Union, but DECC in UK uses M for million but comma to separate thousands and it is a nuisance when using Excel respecting SI!
I remind that the NASA Mars Climate Orbiter probe was lost (150 M$) in 1999 when NASA sent the instructions in SI (newton) but the contractor Lockheed has built the probe for pound!
I asked Adam Sieminski when EIA will use SI mega and giga, his answer: "when hell freezes over": it is likely that I will not see it!

-UK coal production
David Rutledge's beautiful site provides coal data for the world and for the main producing countries.
The best example of good HL results is for UK coal production, which is modeled below with several ultimates, varying with time
The annual production displays an amazing symmetrical cycle, despite the large increases with price
Fig 2: UK coal annual production & price



The HL displays several different linear trends and different ultimates: 1853-1893 = 22 Gt, 1853-1945 = 27 Gt, 1951-1983 = 28 Gt, 1986-2011 = 27.5 Gt (the period 1850-2001 trends towards 28,5 Gt)
The 22 Gt ultimate in 1893 is before the peak of 1913, when in 1913 IGC estimate was 201,4 Gt very far from the real value of 27.5 Gt.
Fig 3: UK coal: HL linear trends & price



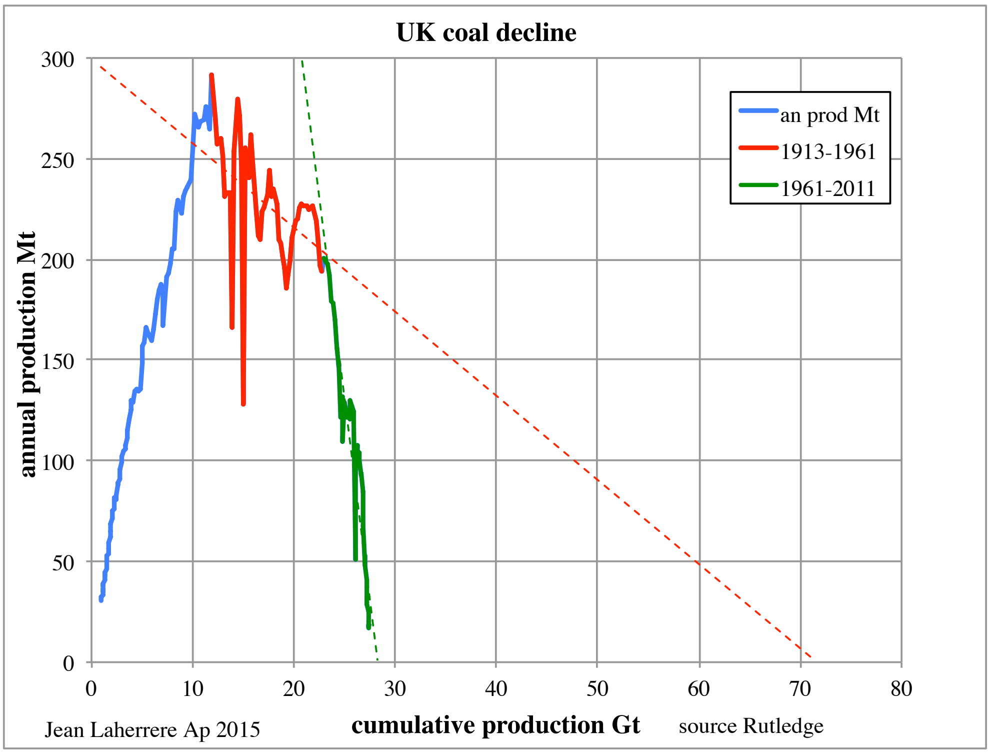
Many argue that price changes upset the extrapolation: but this is not apparently the case on the data shown here with strong price increases occurring in 1974 and 2004

Roger Bentley argued that UK coal production decline was due to lower demand because better and cheaper new energies, this production shows exactly that fact and allows better ultimate estimate than geological estimates which usually ignores such constraints

The variation of ultimates derived from HL is about 10%, which is generally within the accuracy of the underlying data

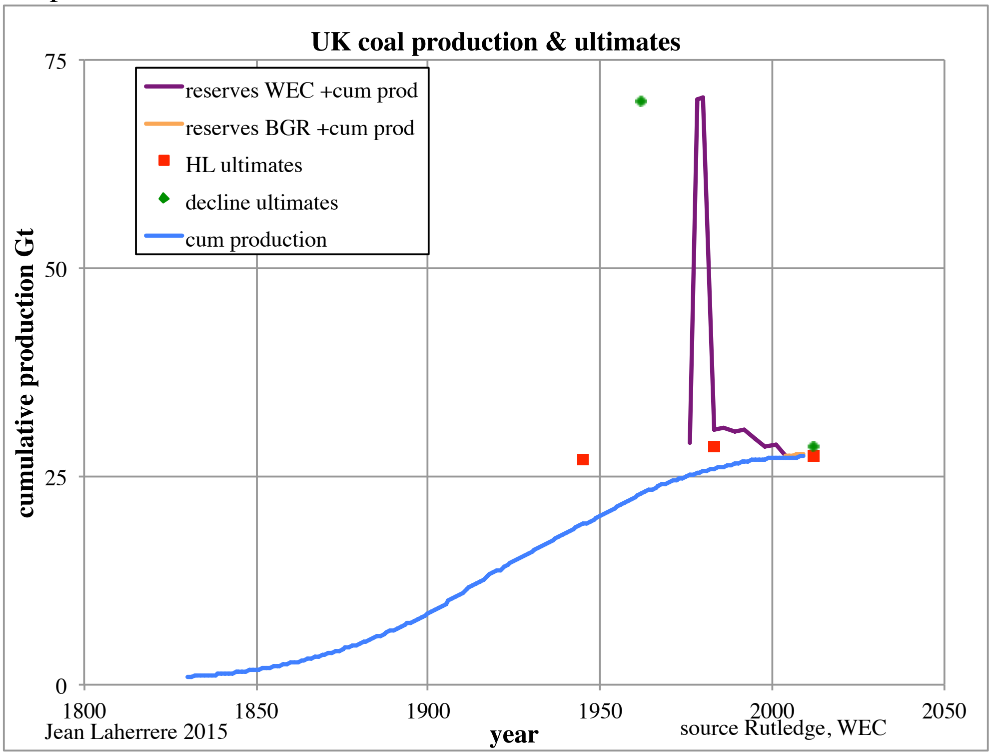
The linear extrapolation of annual production decline displays two trends: 1913-1961 = 71 Gt and 1961-2011 = 28 Gt. These two values are completely different, meaning that the first linear trend can be very misleading!

Fig 4: UK coal decline & linear trends



The plot of the different ultimates from HL, annual decline, WEC (world Energy Council) or BGR (Germany) displays huge variation in particular in the 70s

Fig 5: UK coal production & ultimates

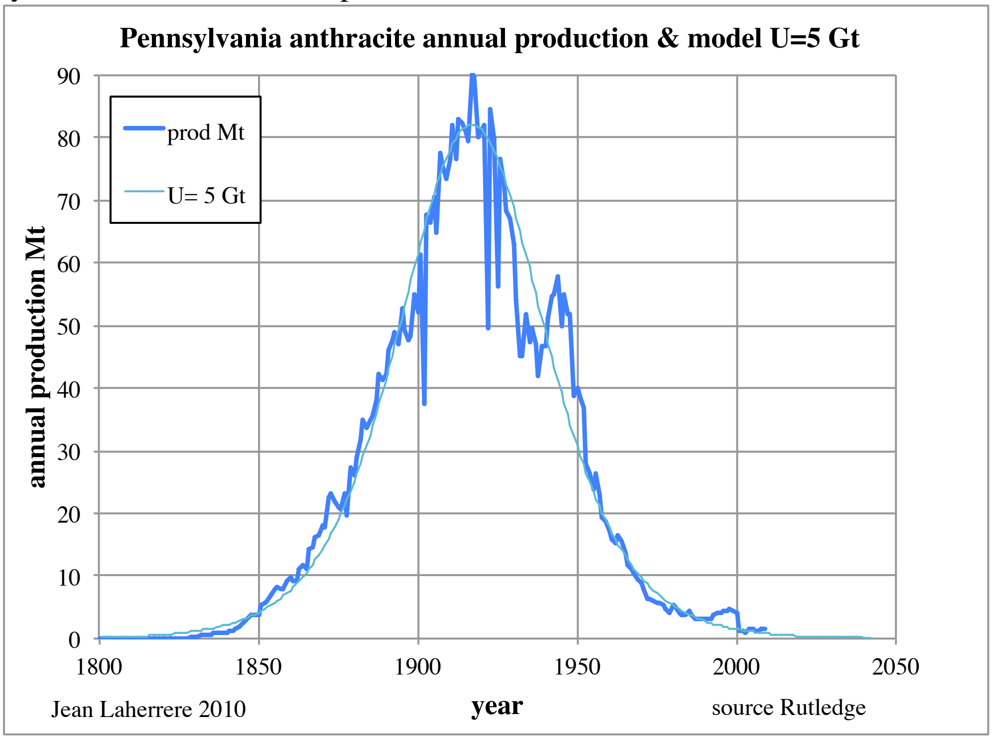


It is obvious that in this case the HL is the best method.

-Pennsylvanian anthracite production

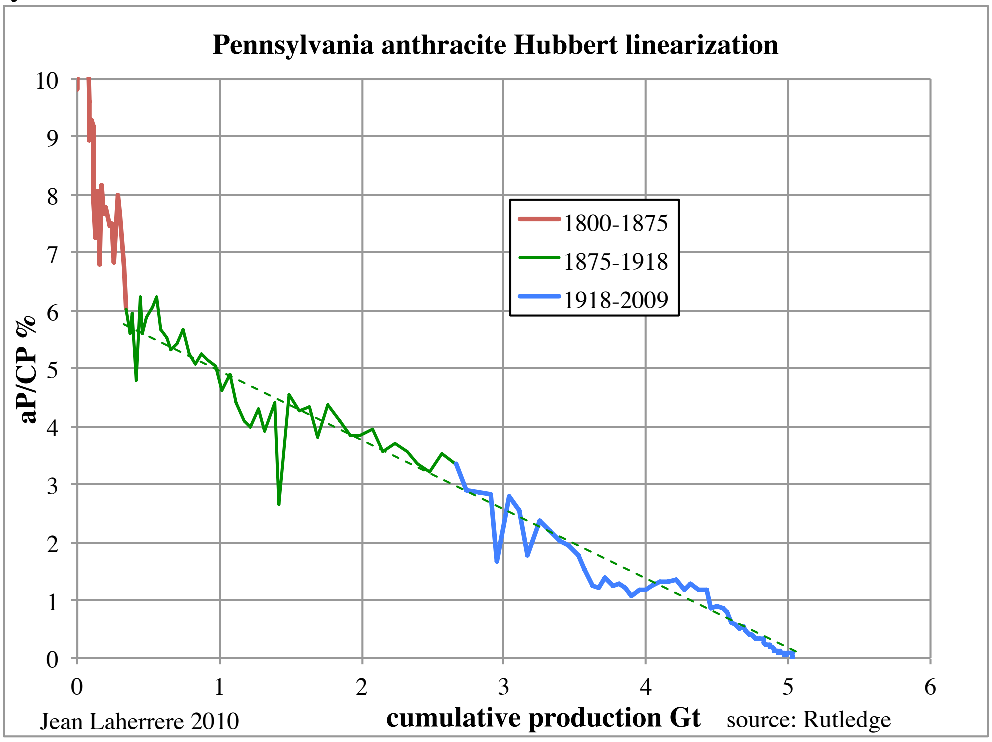
Pennsylvania anthracite production displays an almost symmetrical curve, disturbed by the 1930 depression and is well modeled with an ultimate of 5 Gt. It peaked in 1917.

Fig 6: Pennsylvania anthracite annual production & model U=5 Gt

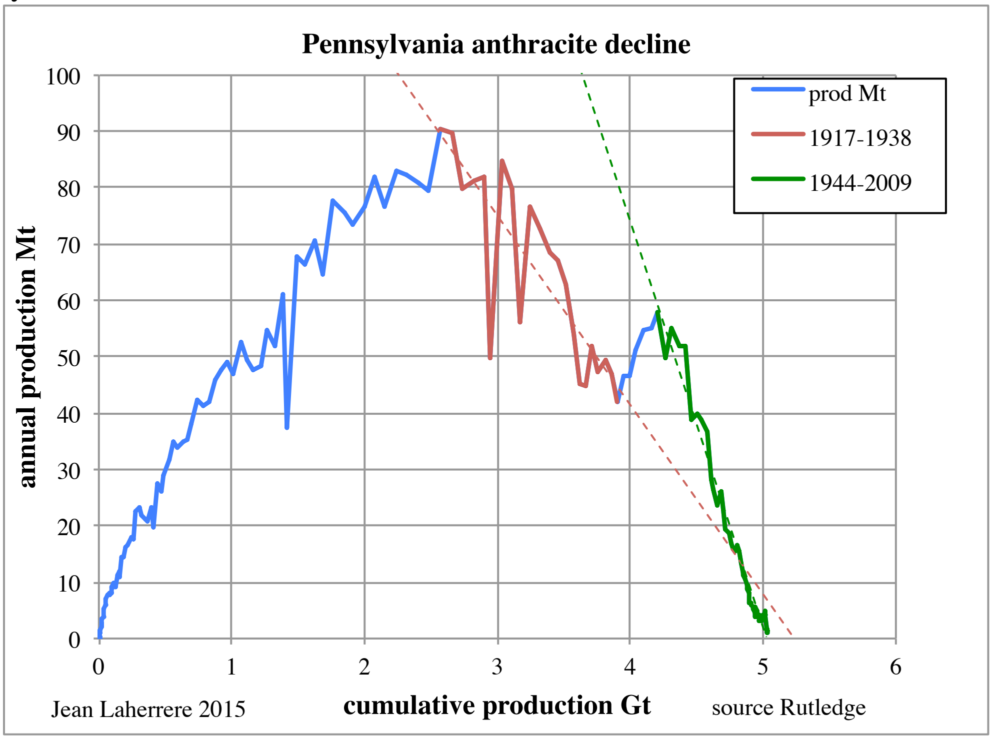


The Pennsylvanian anthracite production HL is the same (5 Gt) for the period 1875-1918 as the period 1918-2009. It is hard to find data after 2009

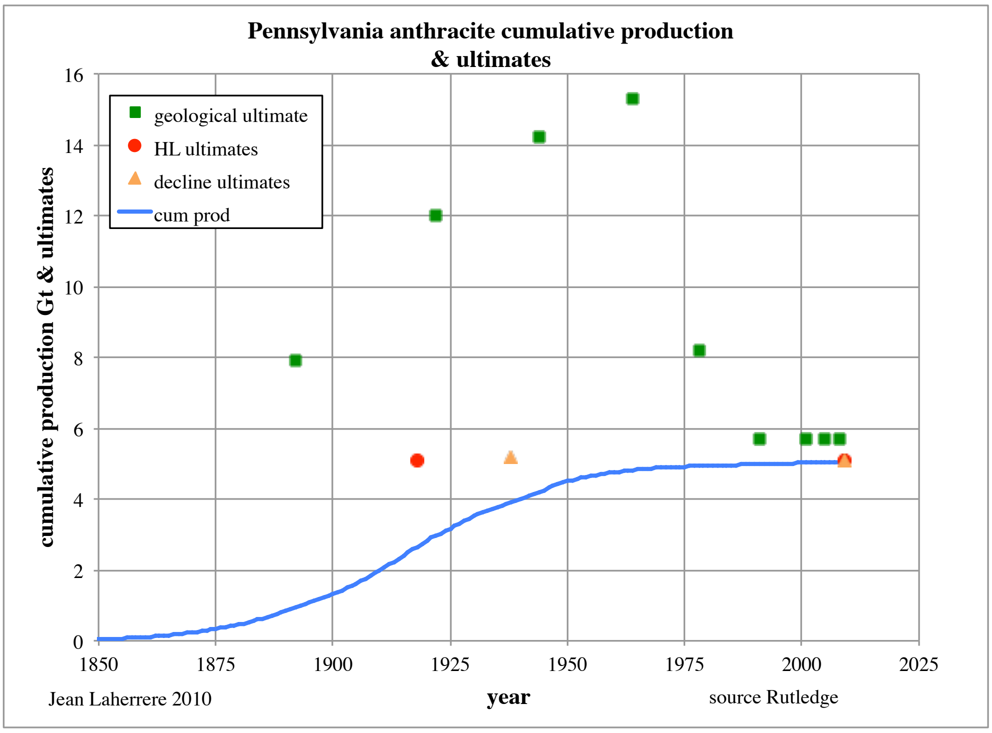
Fig 7: Pennsylvania anthracite: HL & linear trends



The HL modeling for the 5 Gt ultimate (1875-1918) is very good
The decline displays two linear trends towards 5.0-5.2 Gt but the 1917-1938 ultimate at 5.2 Gt is good. The second world war has disturbed the production!
Fig 8: Pennsylvania anthracite decline & linear trends



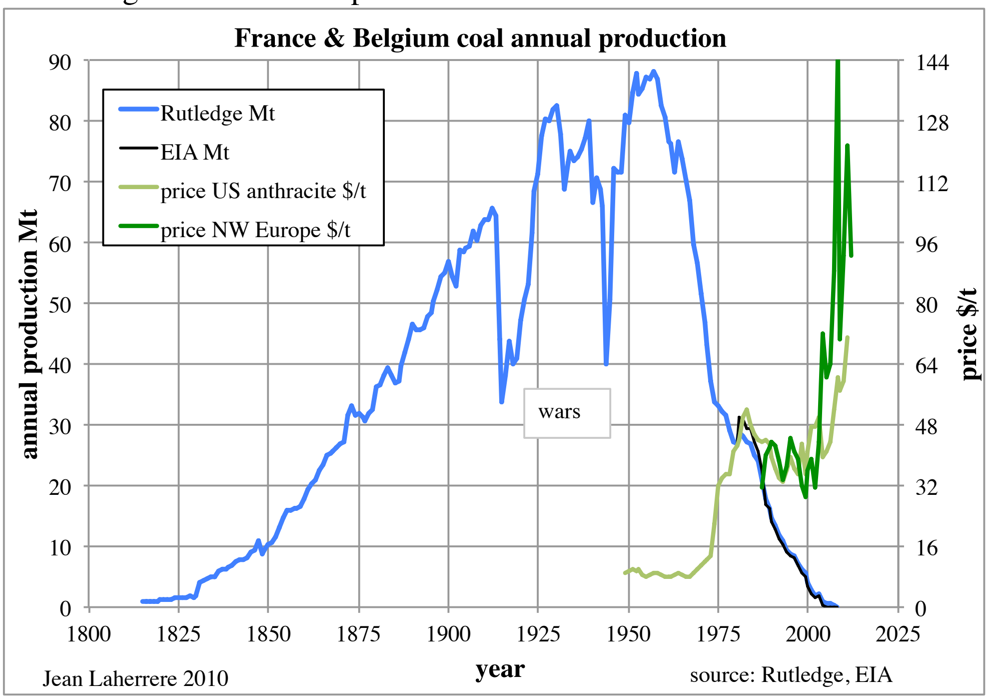
Rutledge reports that the geological estimates of Pennsylvania anthracite ultimate were at 7.9 Gt in 1892, to peak at 15,3 Gt in 1964 (where the production was one tenth of the 1917 peak), 8,2 Gt in 1978 and finally 5.7 Gt in 1991 by EIA when the real value is about 5.1 Gt; which is exactly the linear trend for the period 19875-2009.
The plot of ultimates (geological and from production) and the cumulative production shows clearly that HL and decline are by far the best way to estimate UK coal ultimate, but HL is the best!
Fig 9: Pennsylvania anthracite cumulative production & ultimates



-France & Belgium coal production

France & Belgium coal production, which was terminated on 2007 for an ultimate of 7.2 Gt, the production increase was disturbed by the two wars and after the peak of 1951-1955 the decline was quite sharp despite large increases with price.

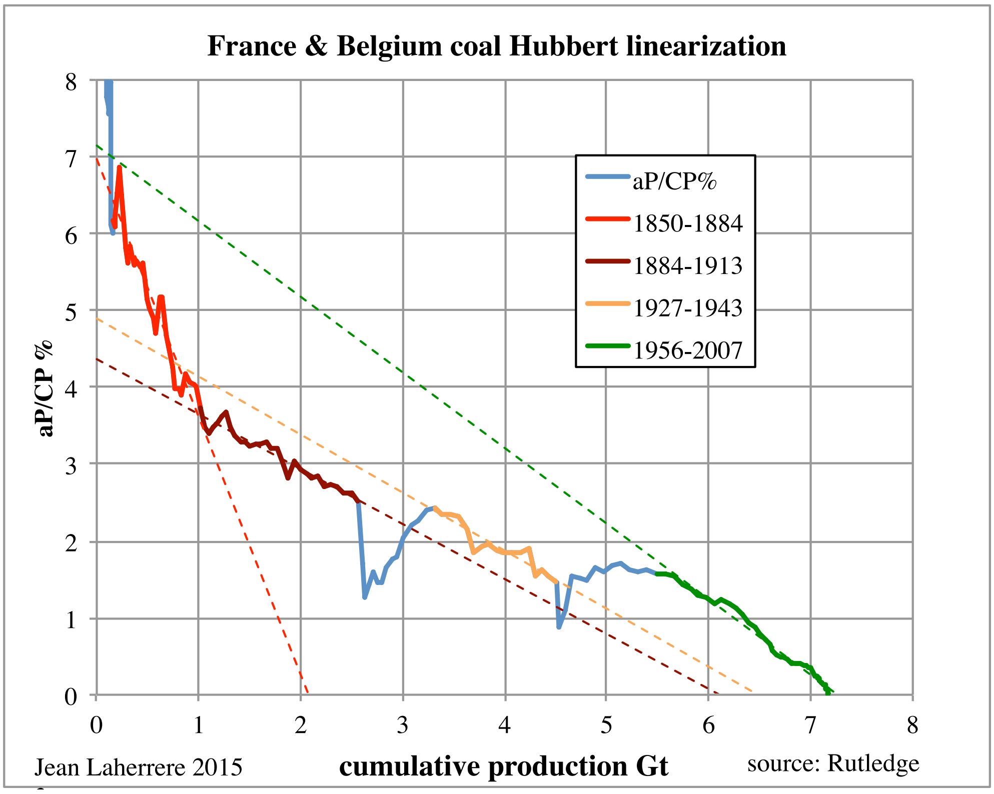
Fig 10: France & Belgium coal annual production



HL displays 4 different linear trends: 1850-1884 = 2 Gt, 1884-1913 = 6 Gt, 1927-1943 = 6.3 Gt and 1956-2007 = 7.2 Gt

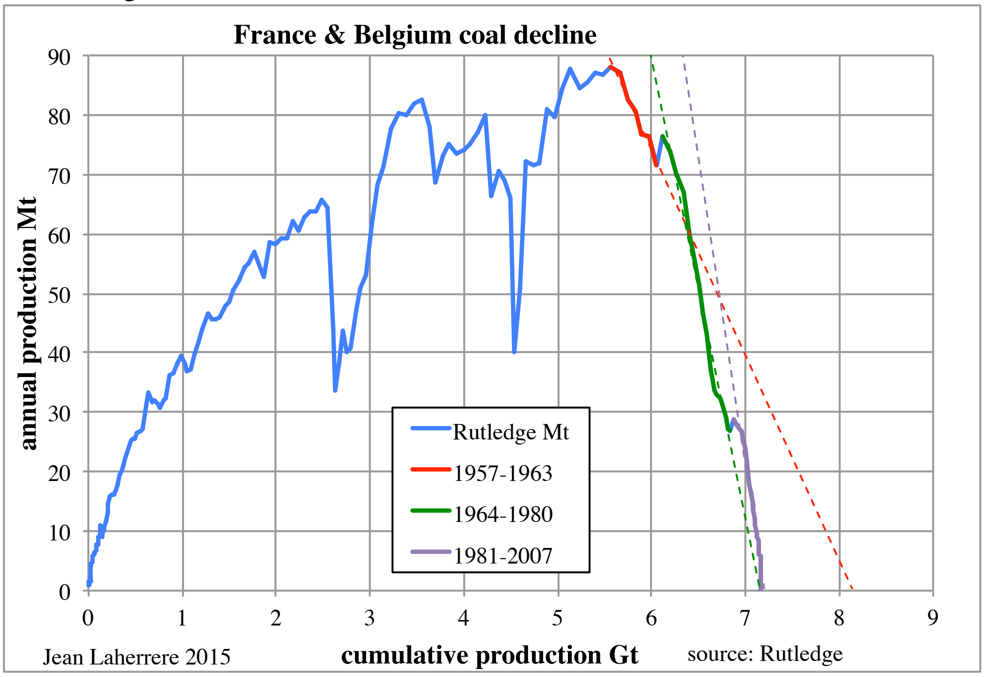
The estimate at 6 Gt from the period 1884-1913, well before the peak which was in 1955 looks a fairly good value

Fig 11: France & Belgium coal: HL & linear trends



The decline of annual production displays three linear trends and the middle one for the period 1964-1980 is right on the real value.

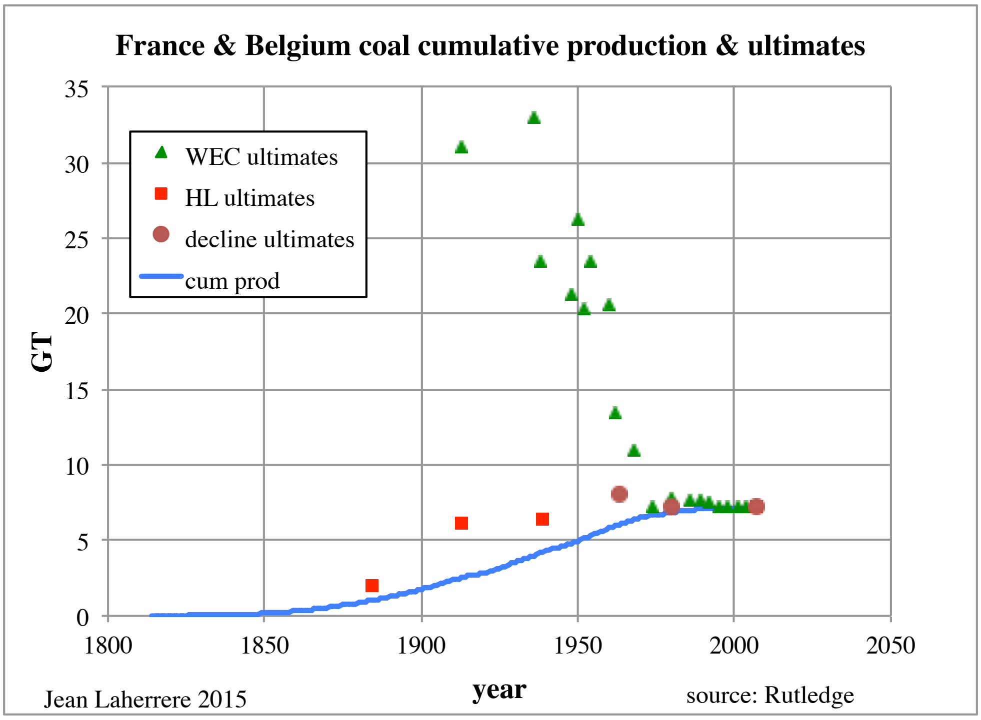
Fig 12: France & Belgium coal decline & linear trends



The coal production displays an unsymmetrical cycle with the decline sharper than the increase (in contrast with UK & Pennsylvania coal which are about symmetrical)

The plot of ultimates (HL, decline & WEC) and cumulative production shows that the geological estimates by the WEC in particular in 1913 and 1936 above 30 Gt) were confusing reserves with resources.

Fig 13: France & Belgium coal cumulative production & ultimates



The three coal examples (UK, US & France) show clearly that the geological ultimates estimates give too optimistic values and that HL estimates are much better, in particular before peak.

-Eagle Ford oil and gas production

Eagle Ford HL for the period 2013-Jan 2015 is extrapolated towards 2.5 Gb for oil & condensate and 10 Tcf for natural gas, when the EIA reserves estimates at end 2013 reports remaining reserves of 4.2 Gb and 17.4 Tcf, which represent an ultimate of 4.8 Gb and 19 Tcf (almost twice as much)

Fig 14: Eagle Ford oil + condensate: HL & linear trends

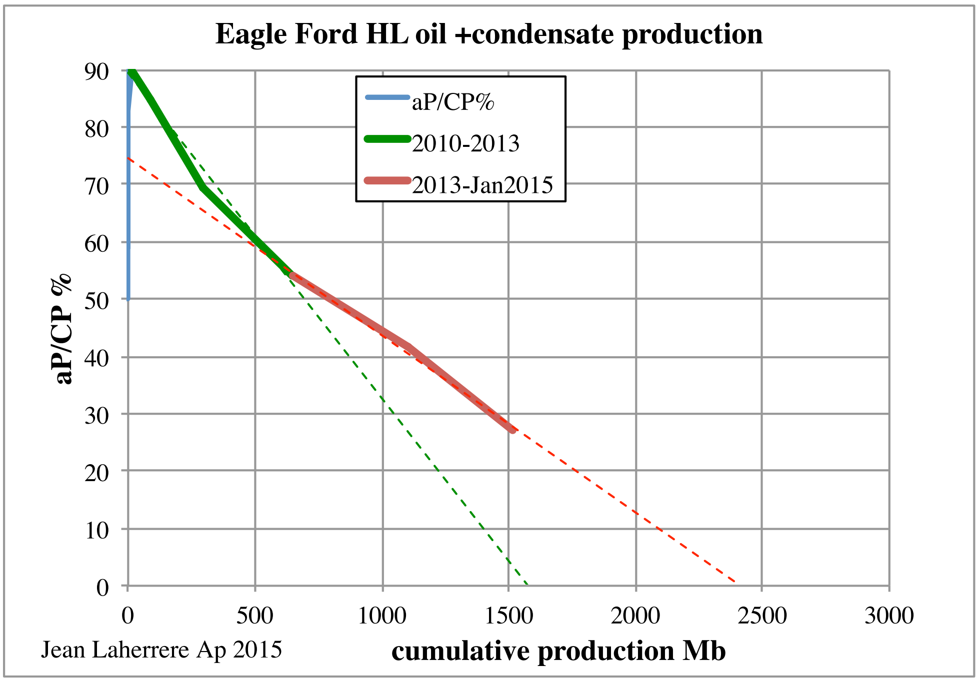
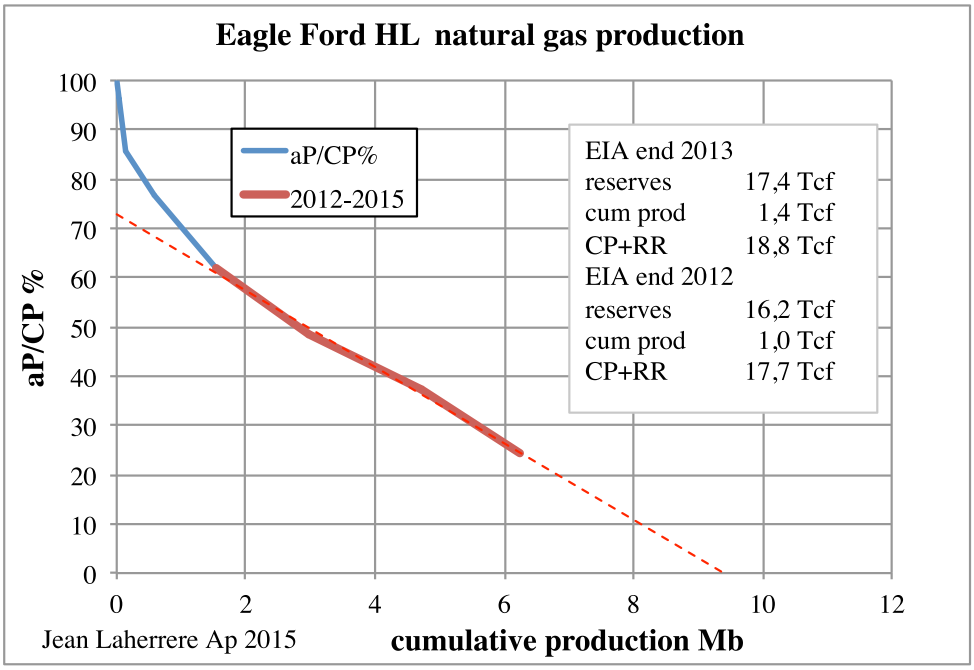


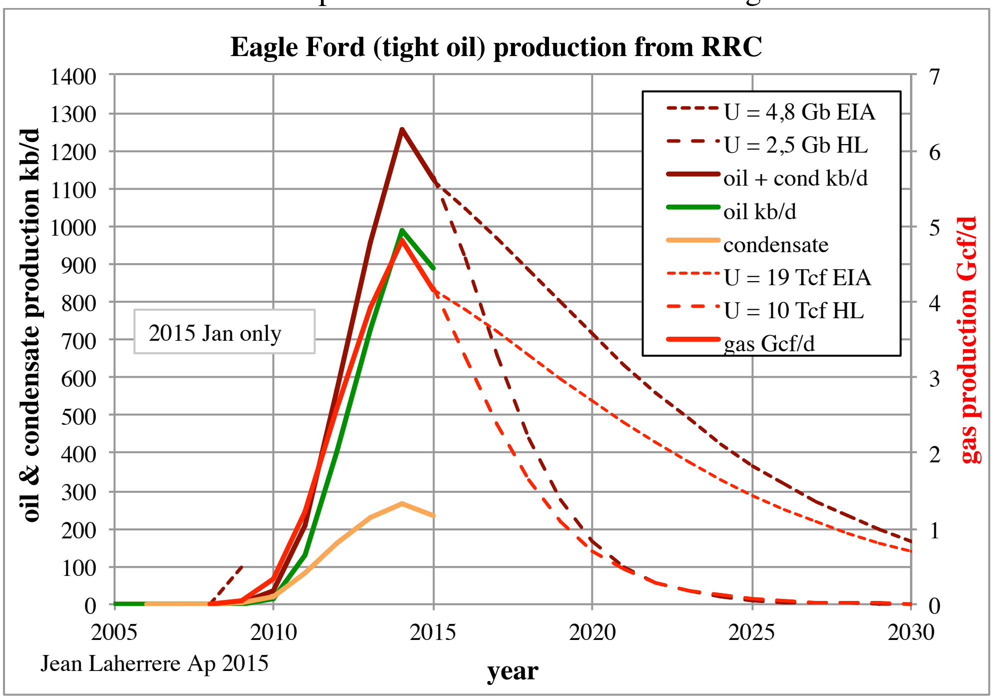
Fig 15: Eagle Ford oil + condensate: decline & linear trends



2015 production values are only for January and on decline compared to 2014, but more data are needed to confirm this decline.

The production forecasts from HL and from EIA reserves values are different, almost symmetrical for HL and not from EIA estimates.

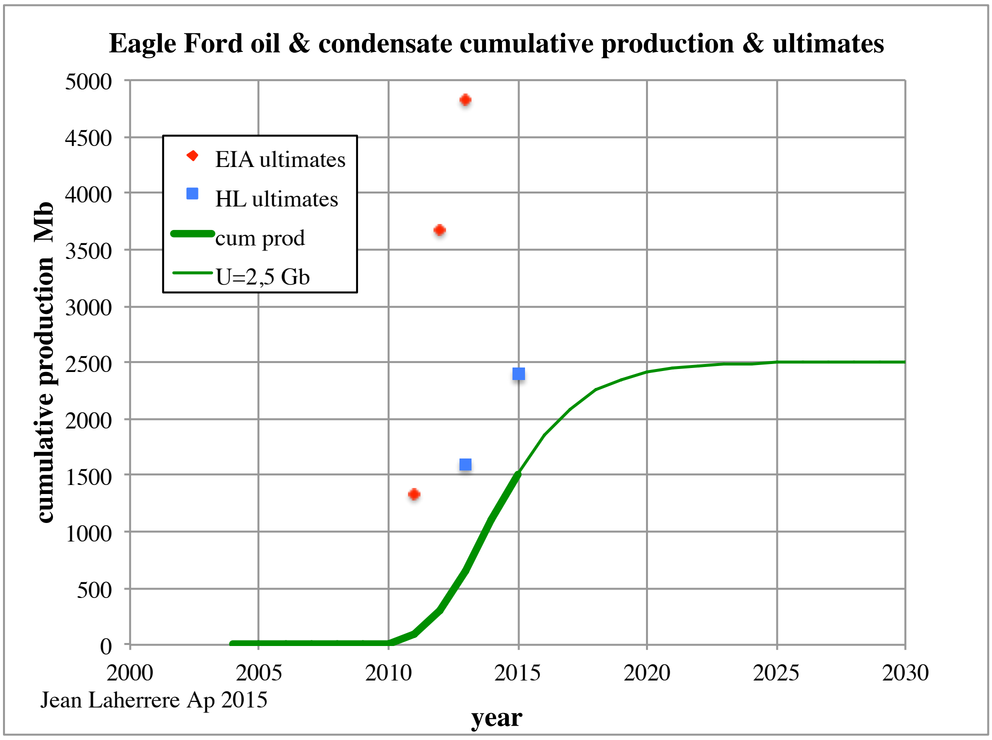
Fig 16: Eagle Ford oil + condensate production from RRC & modeling



The plot of the cumulative oil production and the HL (no reliable decline value) and EIA ultimates, displays a drastic increase of the EIA estimates which look too optimistic.

A forecast for U = 2,5 Gt is drawn.

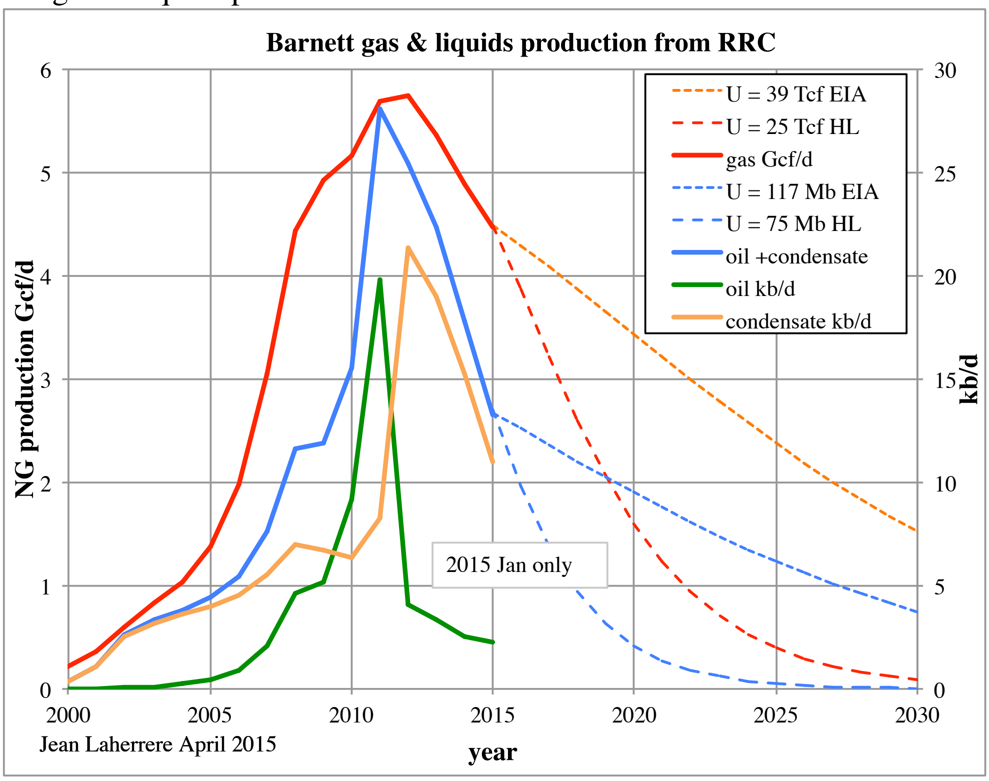
Fig 17: Eagle Ford oil + condensate: cumulative production & ultimates



-Barnett gas production

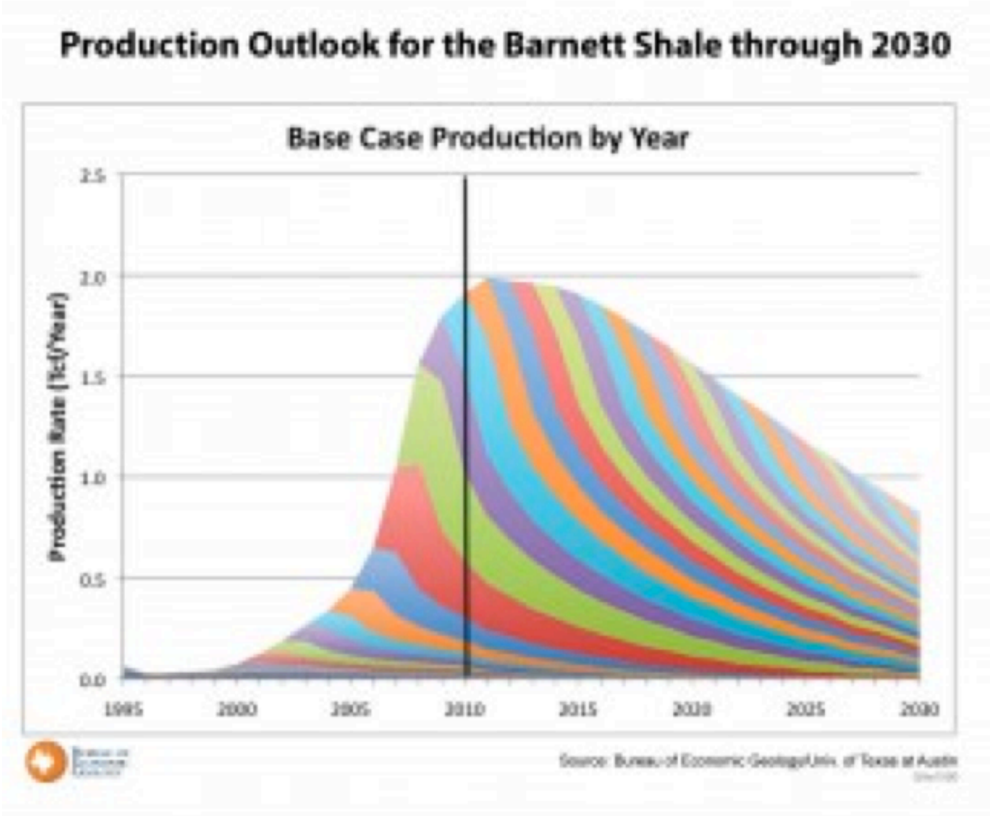
Barnett gas field is interesting because it is the first publicized shale gas production (forgetting Fredonia (NY state) in 1821 for lightning and Big Sandy field 3 Tcf (discovery 1880 or 1914? Kentucky & W Virginia) >20 000 wells with many fractured wells in the 60s with explosives 1.5-3.5 t/well) and because Barnett is declining since 2012. The ultimate could be 25 Tcf from HL leading to a symmetrical curve or 39 Tcf (EIA) leading to a low decline. Oil production peaked in 2011.

Fig 18: Barnett gas & liquids production from RRC



The Bureau of Economic Geology (BEG) at The University of Texas has an ultimate of 44 Tcf for the Barnett http://news.utexas.edu/2013/02/28/new-rigorous-assessment-of-shale-gas-reserves-forecasts-reliable-supply-from-barnett-shale-through-2030

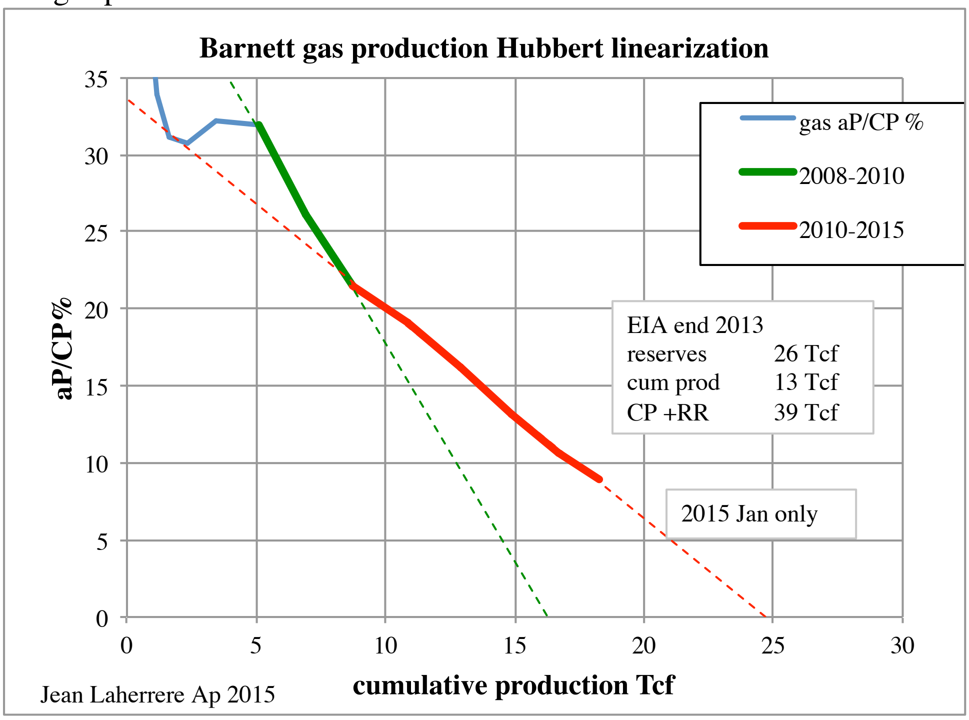
Fig 19: Barnett gas production outlook 2030 BEG



The HL of Barnett gas production trends towards 25 Tcf for the period 2010-2015, when EIA reports remaining reserves and cumulative production at end 2013 at 39 Tcf.

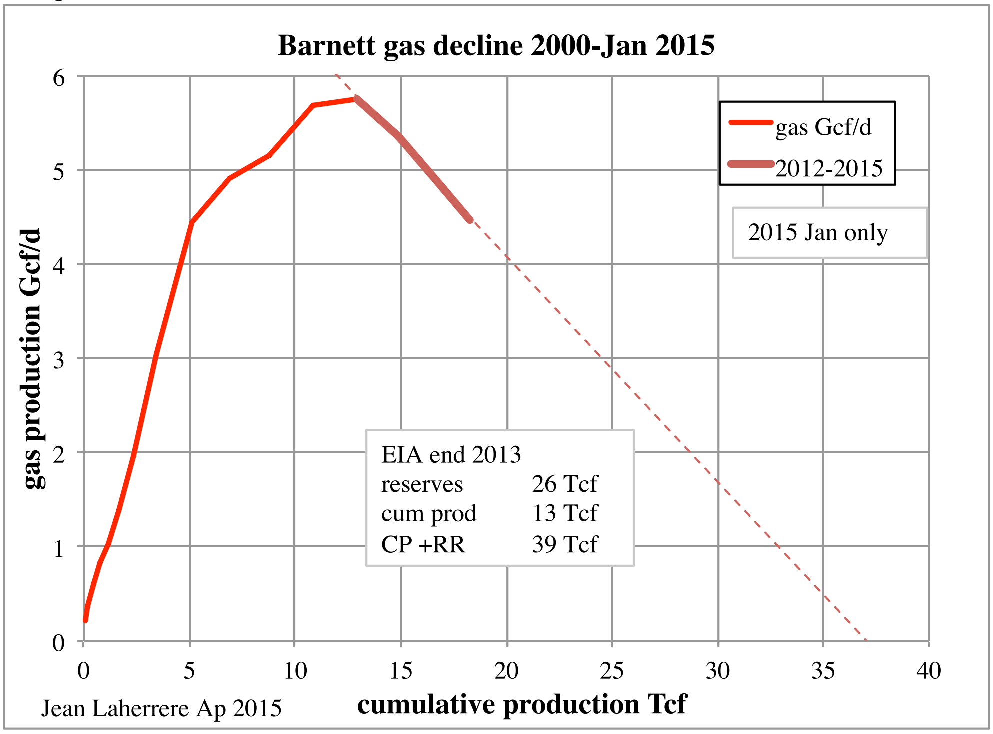
But the first linear trend from 2008 to 2010 trends towards 16 Tcf.

Fig 20: Barnett gas production: HL & linear trends



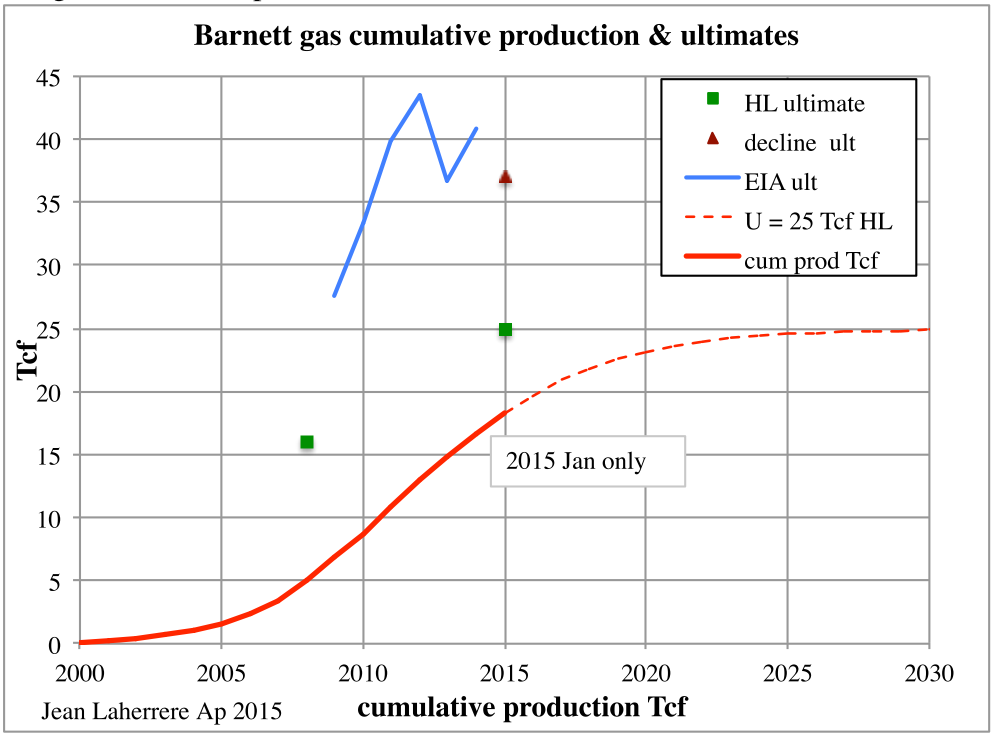
The annual NG production decline for the period 2012-2015 (only January) trends towards 37 Tcf, in line with EIA estimate

Fig 21: Barnett gas decline & linear trends



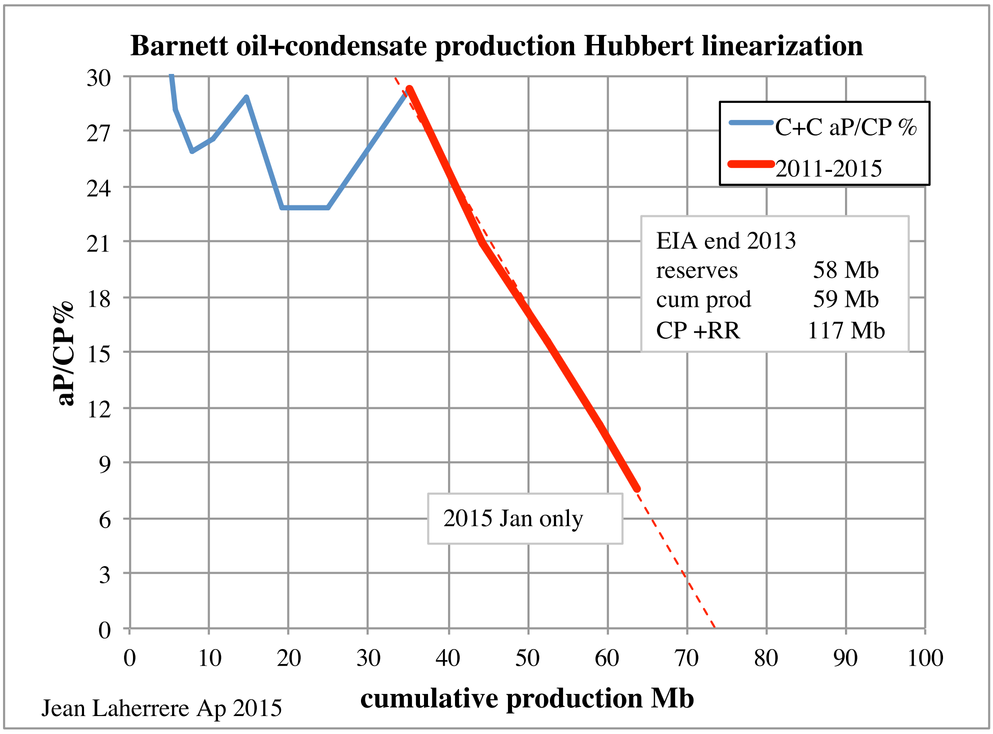
The plot of Barnett cumulative NG production with HL, decline and EOA ultimates
I trust more the HL estimates than decline or EIA estimates and the forecast of the cumulative production is modeled with U= 25 Tcf.

Fig 22: Barnett gas cumulative production & ultimates



Barnett HL oil + condensate production trends for the period 2001-2015 towards 75 Mb when EIA reports a cumulative production + remaining reserves at 117 Mb.

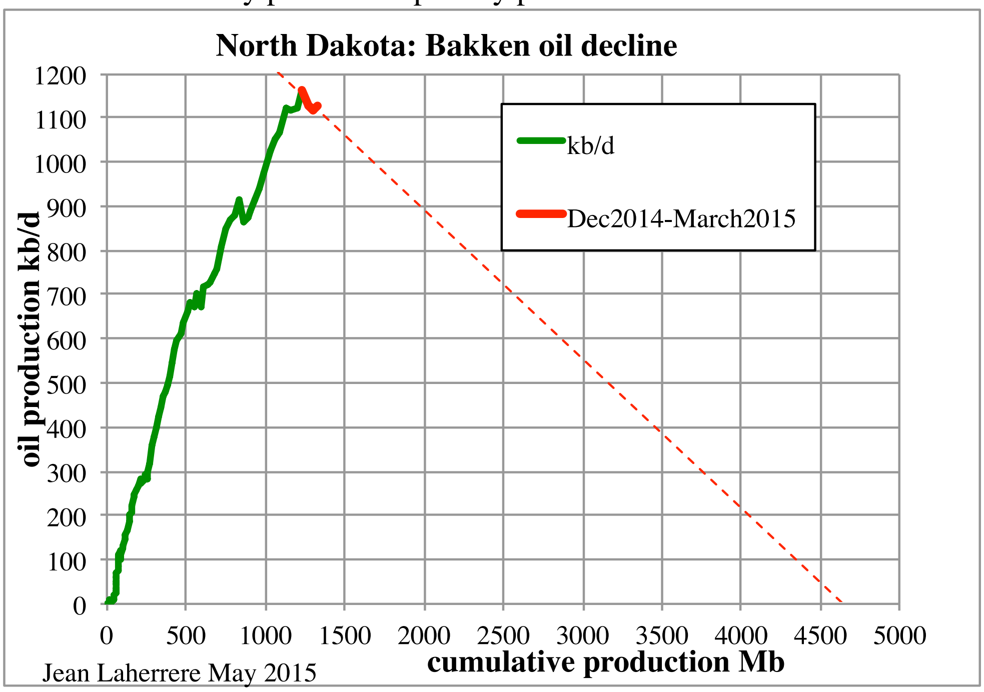
Fig 23: Barnett oil + condensate production; HL & linear trends



-Bakken North Dakota oil production

Bakken North Dakota is with Eagle Ford the booming shale oil now called tight light oil because the reservoir is a silty dolomite between two Bakken shales and it is tight. However Bakken production started in ND in 1954 with the field of Antelope with vertical wells. The daily production per well was around 75 b/d/w (starting over 200 b/d/w) compared to 130 b/d/w now, when the number of wells was multiplied by around 40. In 1966 a sharp decline to 25 b/d/w for two decades, then a burst increase occurs in 1990 and quickly a similar decrease but going to a mower level of less than 10 b/d/w (US average) and a steep burst to a peak in 2008 to over 140 b/d/w

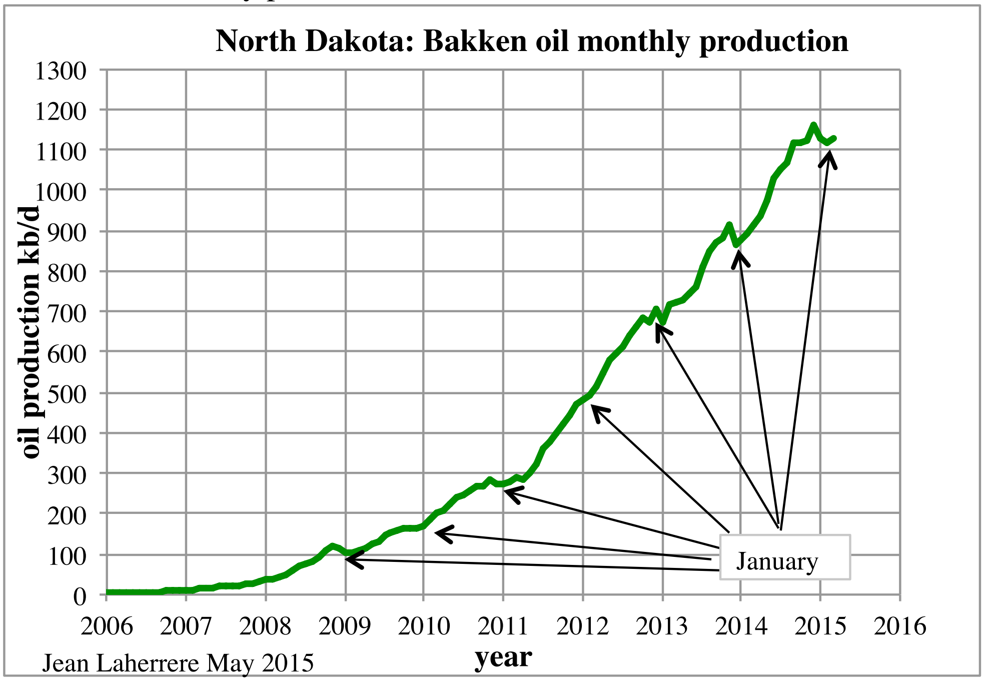
Fig 24: Bakken ND oil monthly production per day per well



The Bakken has shown a small decrease in production for the past winters (January because big freeze prevents hydraulic fracturation) since 2009.

It occurs also on January 2015, but also on February 2015

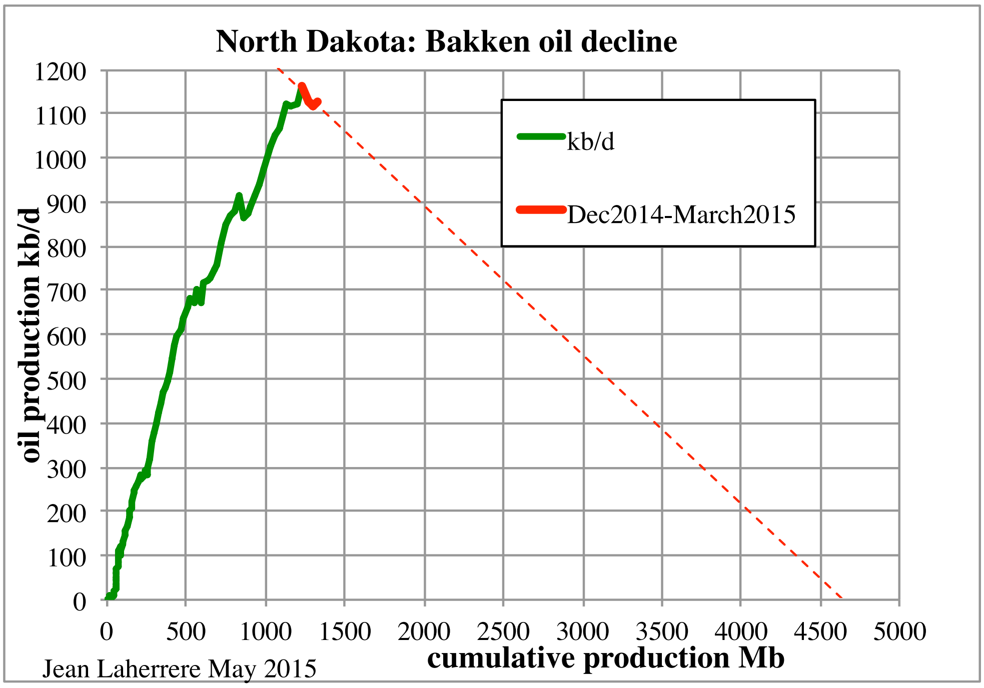
Fig 25: Bakken ND oil monthly production



It is necessary to wait few months to see if the Bakken production will decrease with the sharp decrease in rigs. The problem is that about 800 wells are waiting to be fractured.

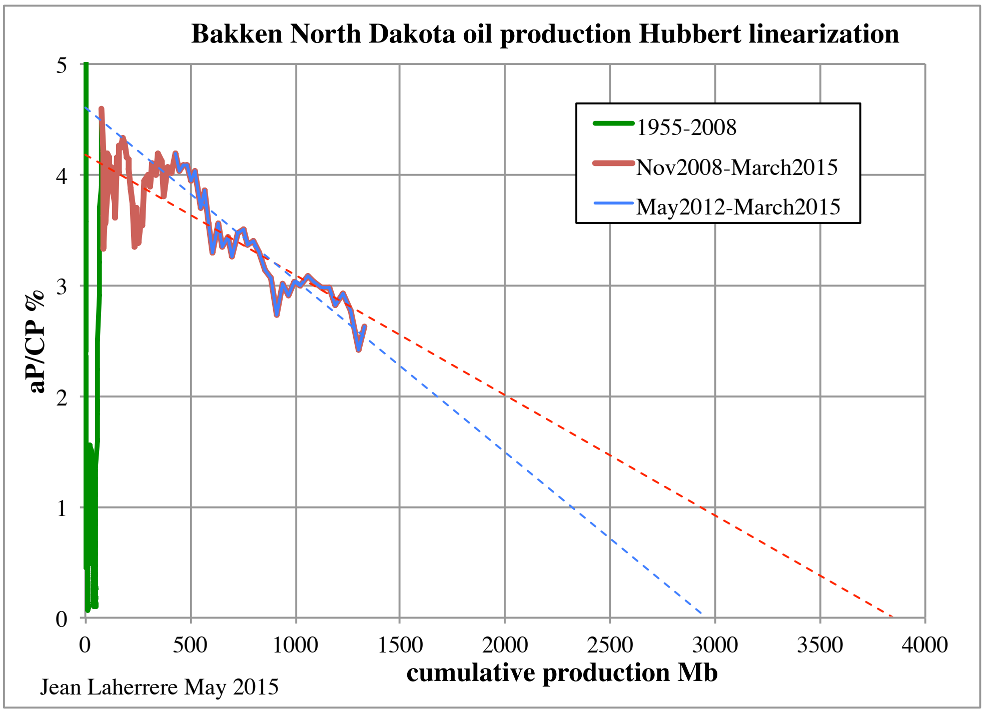
The oil decline of the last three months could be extrapolated towards 4.6 Gb

Fig 26: Bakken ND oil decline & linear trends



The North Dakota Bakken monthly oil production from the State department can be extrapolated for the period May 2012 to March 2015 towards about 3 Gb, when for the period Nov 2008 to March 2015 towards about 3.8 Gb

Fig 27: Bakken ND oil production: HL & linear trends

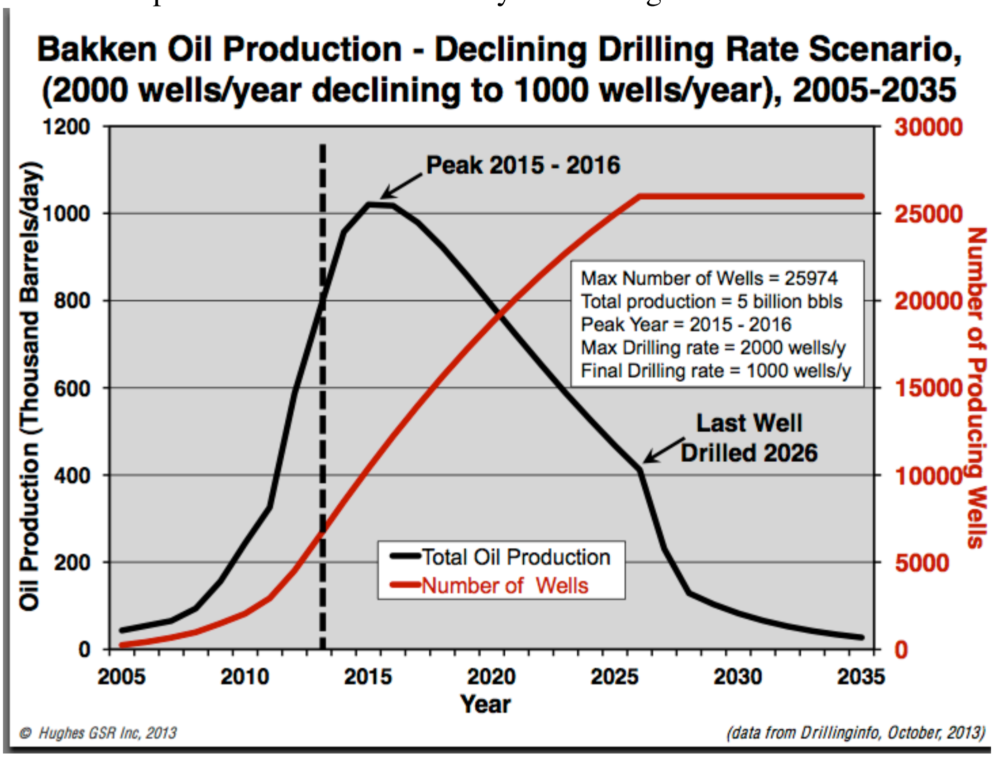


David Hughes estimated in 2013 the Bakken ultimate at 5 Gb, but it includes North Dakota and Montana, when my ultimate 3-4 Gb is for North Dakota only. However I added the 5 Gb ultimate as a possibility for ND

Hughes's graph for an ultimate of 5 Gb peaks around 1.1 Mb/d at 2015-2016

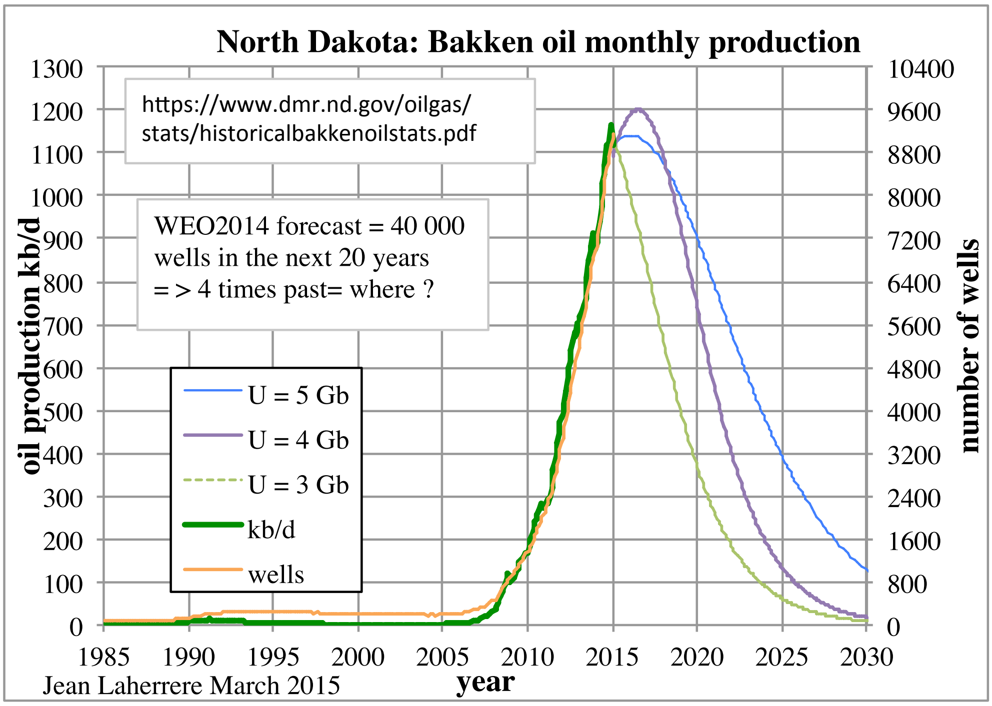
http://legacy.firstenergy.com/UserFiles/HUGHES%20First%20Energy%20Nov%2019%202013.pdf

Fig 28: Bakken ND oil production forecast 2013 by David Hughes 2005-2035



Bakken ND is modeled with 3 ultimates 3, 4 & 5 Gb

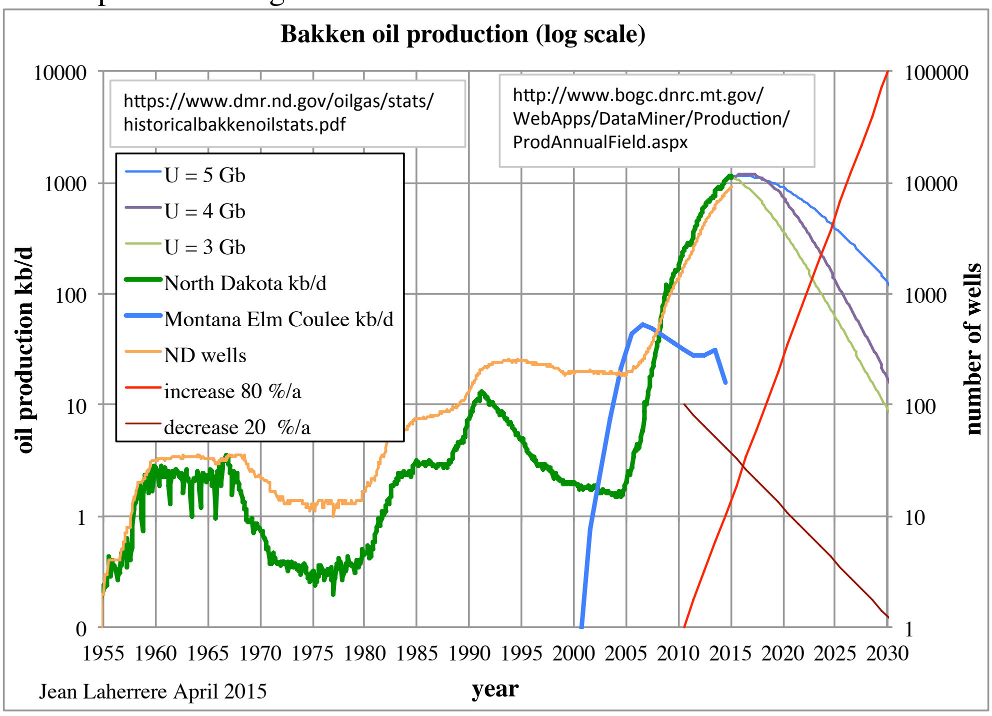
Fig 29: Bakken ND oil production & forecasts 1985-2030



The three ultimates 3, 4 or 5 Gb display a rather symmetrical cycle with a fairly steep decrease, when the official forecasts display a slow decline.

The plot with production in log scale allows comparing slopes as there were in ND already several Bakken peak in 1960-1966; 1991 and 2015. The three increases looks rather parallel to the pink slope of +80% per year and the two declines look rather parallel to the brown slope of -20% per year. The Bakken production of Elma Coulee field in Montana which peaked in 2007 fits with the 80%/a rise and the 20%/a decrease. The three ultimates of 3 to 5 Gb declines are not far from this 20%/a decrease.

Fig 30: Bakken oil production log scale



The plot of the cumulative production with HL, decline and EIA ultimates allow thinking that the last EIA estimate is too optimistic and the USGS 2013-3013 with 7 Gb (excluding Montana) for undiscovered oil mean (excluding NGL which about 500 Mb) too high. Including North Dakota, Montana and South Dakota USGS reports in 2013 7383 Mb for Bakken and three Forks undiscovered mean resources

Fig 31: Bakken USGS2013-3013 undiscovered resources

Total Petroleum Systems (TPS) and Assessment Units (AU)	Field type	Total Undiscovered Resources											
		Oil (MMBO)				Gas (BCFG)				NGL (MMBNGL)			
		F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean
Bakken TPS													
Elm Coulee-Billings Nose Continuous Oil AU 50310161	*Oil*	218	281	355	283	174	278	410	283	11	21	36	22
Central Basin Continuous Oil AU 50310162	*Oil*	892	1,113	1,379	1,122	699	1,103	1,604	1,122	46	85	139	88
Nesson-Little Knife Continuous Oil AU 50310163	*Oil*	907	1,139	1,423	1,149	714	1,130	1,648	1,149	47	87	144	90
Eastern Transitional Continuous Oil AU 50310164	*Oil*	706	876	1,082	883	275	435	629	441	18	33	55	35
Northwest Transitional Continuous Oil AU 50310165	*Oil*	90	197	357	207	57	134	268	145	4	10	22	11
Three Forks Continuous Oil AU 50310166	*Oil*	1,604	3,440	6,834	3,731	1,508	3,286	6,685	3,583	105	252	553	281
Total continuous resources		**4,417**	**7,046**	**11,430**	**7,375**	**3,427**	**6,366**	**11,244**	**6,723**	**231**	**488**	**949**	**527**
Bakken TPS													
Middle Bakken Conventional AU 50310101	*Oil*	1	4	10	5	0	2	4	2	0	0	0	0
	Gas					0	0	0	0	0	0	0	0
Three Forks Conventional AU 50310103	*Oil*	0	3	7	3	0	1	3	1	0	0	0	0
	Gas					0	0	0	0	0	0	0	0
Total conventional resources		**1**	**7**	**17**	**8**	**0**	**3**	**7**	**3**	**0**	**0**	**0**	**0**
Total undiscovered oil and gas resources		**4,418**	**7,053**	**11,447**	**7,383**	**3,427**	**6,369**	**11,251**	**6,726**	**231**	**488**	**949**	**527**

But USGS2008-3021 has for the same basin quite different estimates.

Fig 32: Bakken USGS2008-3021 undiscovered resources

Table 1. *Bakken Formation, Williston Basin Province assessment results.*

[MMBO, million barrels of oil. BCFG, billion cubic feet of gas. MMBNGL, million barrels of natural gas liquids. Results shown are fully risked estimates. F95 represents a 95 percent chance of at least the amount tabulated; other fractiles are defined similarly. TPS, total petroleum system; AU, assessment unit]

	Total Petroleum System and Assessment Unit	Field Type	*Total Undiscovered Resources*											
			Oil (MMBO)				*Gas (BCFG)*				*NGL (MMBNGL)*			
			F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean
Continuous Oil Resources	**Bakken-Lodgepole TPS**													
	Elm Coulee–Billings Nose AU	***Oil***	374	410	450	410	118	198	332	208	8	16	29	17
	Central Basin–Poplar Dome AU	***Oil***	394	482	589	485	134	233	403	246	10	18	35	20
	Nesson–Little Knife Structural AU	***Oil***	818	908	1,007	909	260	438	738	461	19	34	64	37
	Eastern Expulsion Threshold AU	***Oil***	864	971	1,091	973	278	469	791	493	20	37	68	39
	Northwest Expulsion Threshold AU	***Oil***	613	851	1,182	868	224	411	754	440	16	32	64	35
	Total Continuous Resources					**3,645**				**1,848**				**148**
Conventional Oil Resources	Middle Sandstone Member AU	***Oil***	1	4	8	4	1	1	3	2	0	0	0	0
	Total Conventional Resources					**4**				**2**				**0**
	Total Undiscovered Oil Resources					**3,649**				**1,850**				**148**

There is nothing wrong in 2013 by reporting a mean estimate too optimistic (out of a Monte Carlo run where all the work is done by the computer from poor assumptions (called by USGS the seventh approximation sheet http://pubs.usgs.gov/bul/b2165/B2165.pdf), what is wrong is to pretend to give for the undiscovered oil resources a 90% range with F95 = 4418 Mb, mean = 7383 Mb and F5 = 11 447 Mb. It is stupid to give so many significant digits but it is what the computer said. It is wrong to estimate that the minimum 2013 is well above USGS 2008-3021 mean.

USGS 2013 said that USGS2008 was wrong, what about USGS2013?

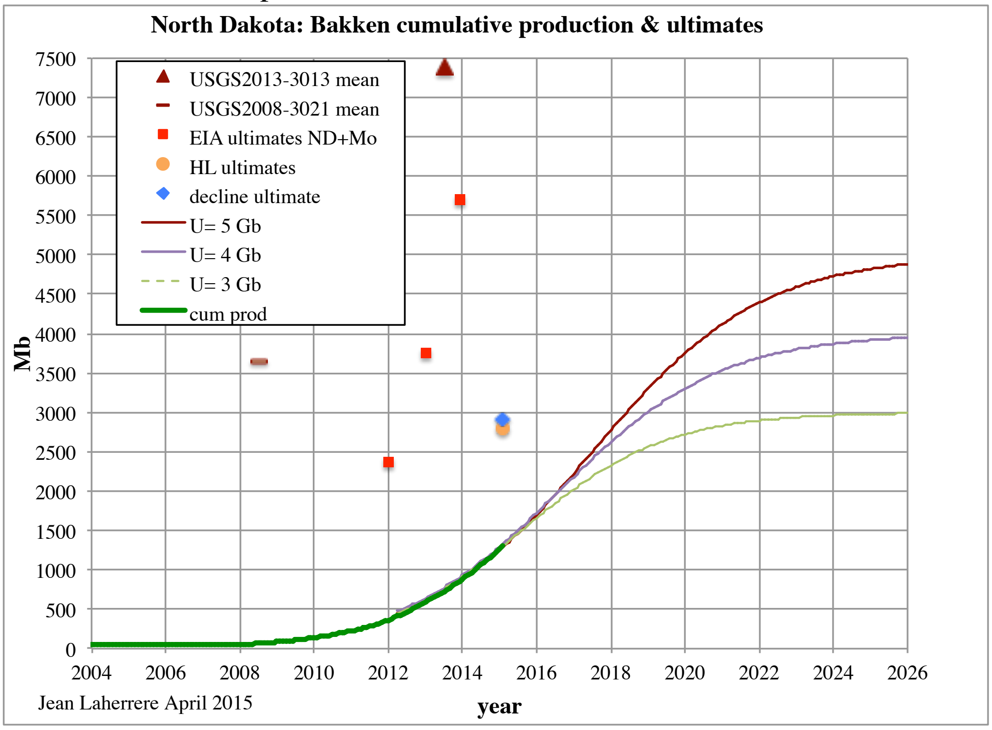
Furthermore it is well known that an arithmetic aggregation of F95 units does not represent the F95 of the whole system, but an underestimation. Only arithmetic aggregation is correct for mean value, for F5 it is an overestimation. USGS2008-3021 was reporting the aggregation for mean but not for F95 & F5! USGS2008 was right but USGS2013 is wrong on resources aggregation

The trick of USGS is to call their estimates resources and not reserves?

Resources are what is in the ground and only a small part will be recovered depending the economy and the technology.

But consumers are interested to know what the reserves (future production) are, but not by the speculative resources.

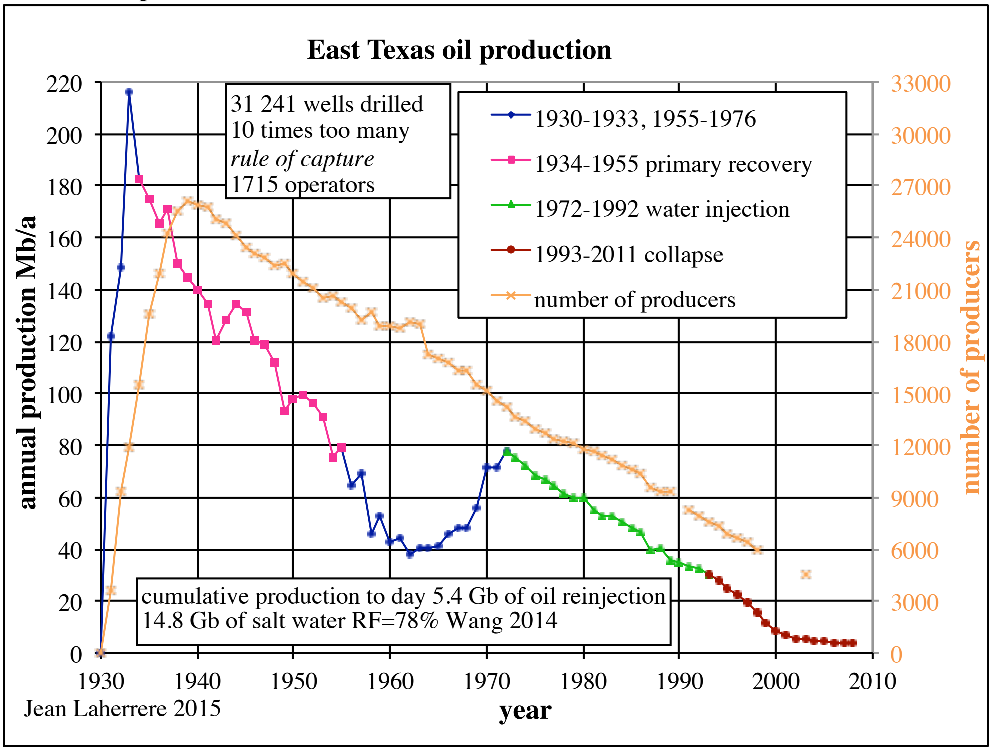
Fig 33: Bakken ND cumulative production & ultimates



-East Texas oil field

East Texas oil field is the largest oil field in the USL48. It started production in 1930, reached peak 1932 and a minor peak in 1972. It started water injection after unitization in 1968. It is almost exhausted, it left the top 100 US fields in the last edition of 2013, its rank was 96 in 2009, 77 in 2008, 23 in 1997 and 1 in 1931 with a daily peak over 1 Mb/d. The number of producers peaked in 1940 with over 25 000. Up to 1955 only primary recovery was used and water injection started

Fig 34: East Texas oil production



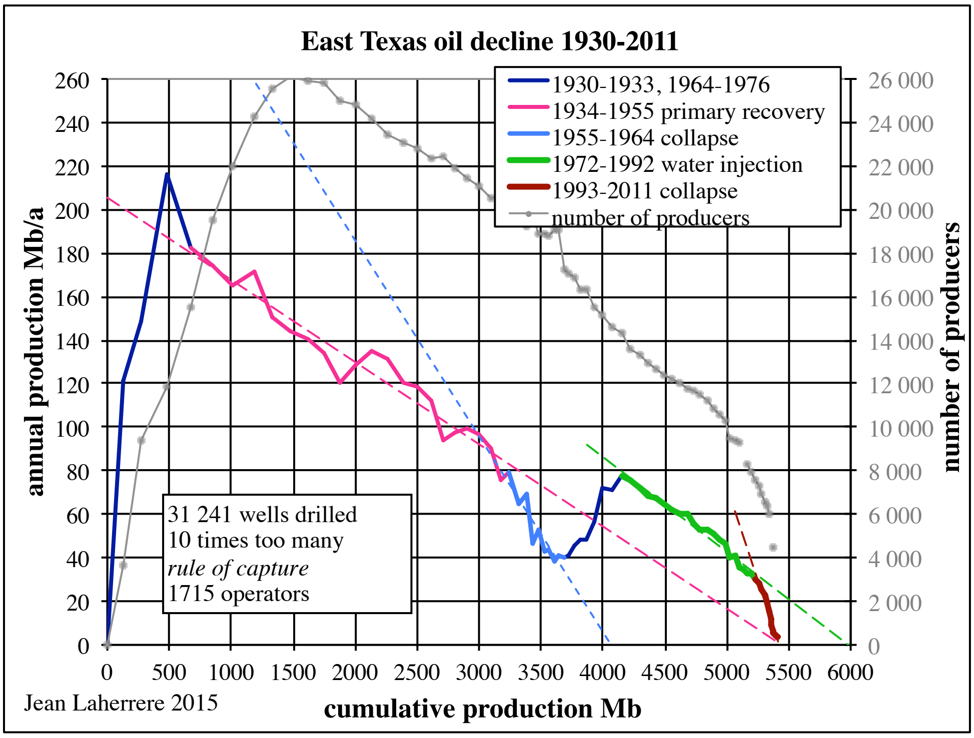
There are several linear trends of the oil decline versus cumulative production:

-1934-1955 primary recovery towards 5.4 Gb

-1955-1964 collapse towards 4 Gb
-1972-1992 water injection towards 6 Gb
-1993-2011 collapse towards 5.4 Gb

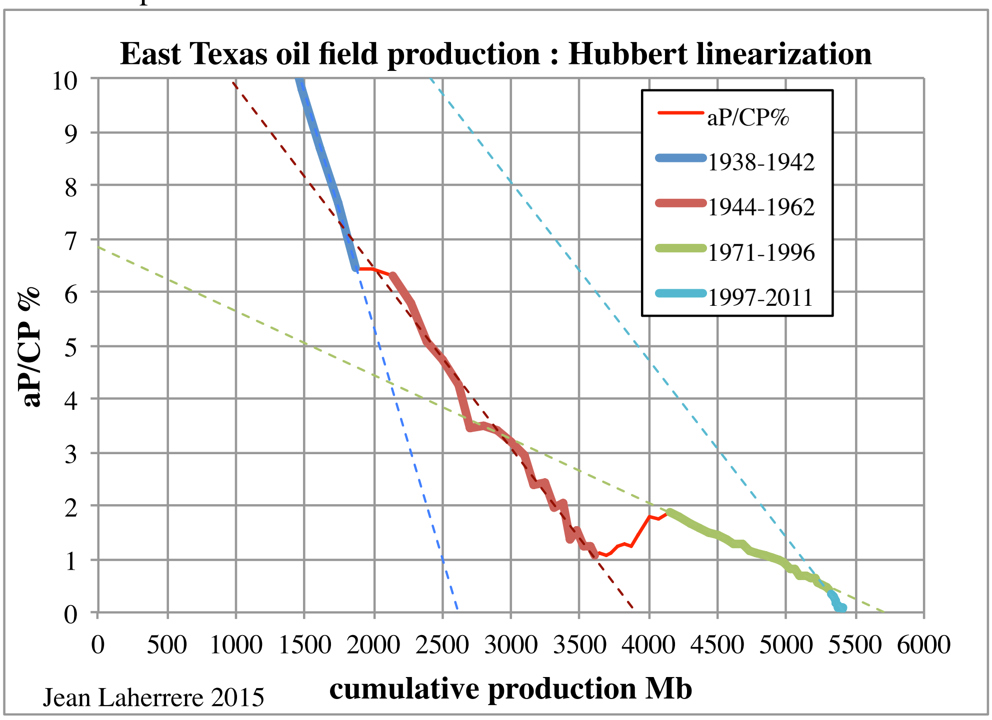
It is amazing to find that the first trend using only primary recovery is the same as the collapse decline, when the s water injection trend is too optimistic.

Fig 35: East Texas oil decline & linear trends

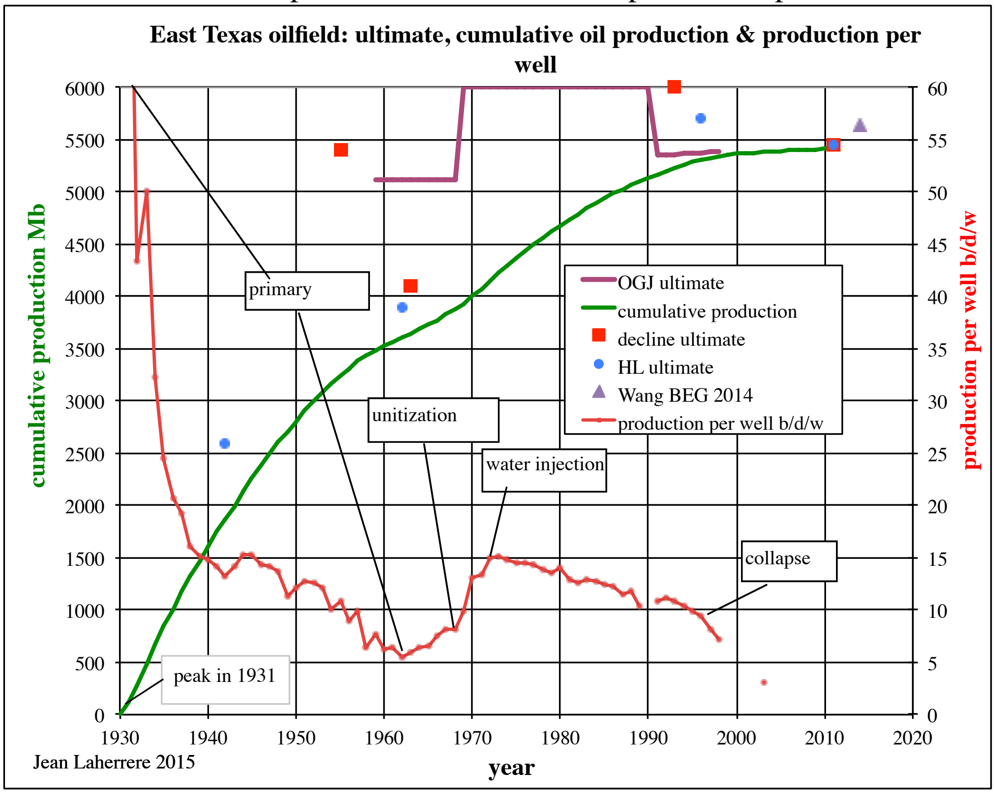


Plotting the Hubbert linearization on production growth decline is not as good as plotting the production decline

Fig 36: East Texas oil production: HL & linear trends

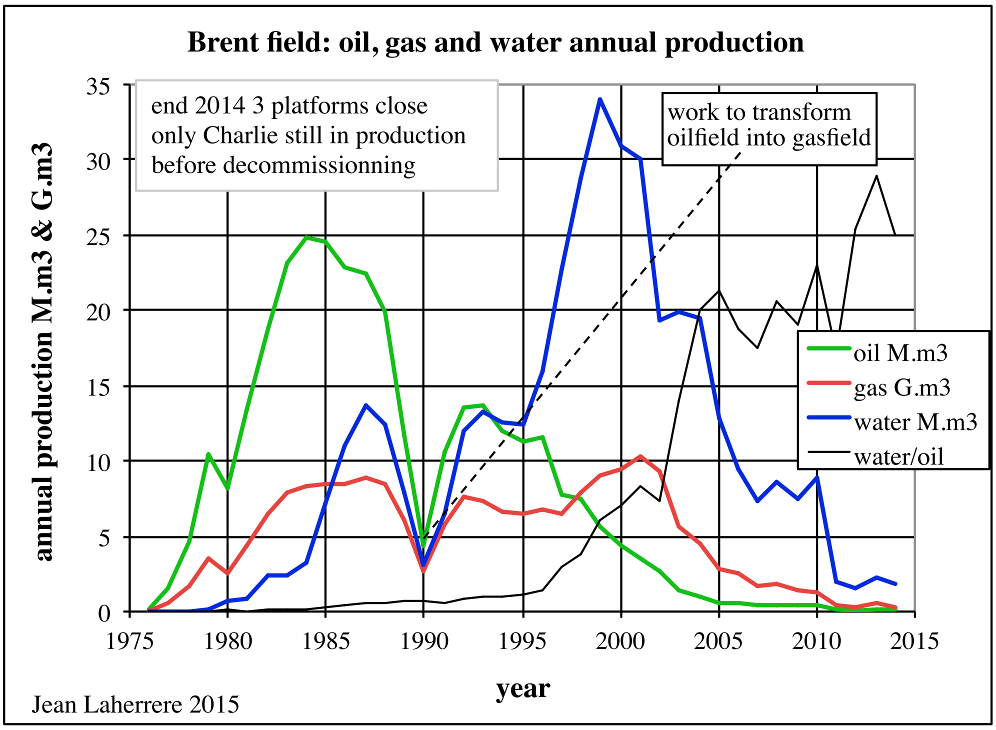


The HL extrapolation gives four values as the oil decline but far from the real value except for the last period ending in 2011and for the decline trend ending the primary recovery in 1955. The OGJ ultimate in 1960 was 5.1 Gb, much better than the HL value (4.1 Gb).
The plot of the cumulative production and of the different ultimates since shows that it is hard to see which is the best way to estimate ultimate, even 50 years after the peak!
But decline in 1955 was right, the problem is that decline gave in 1964 & 12992 wrong estimates!
Fig 37: East Texas cumulative oil production & ultimates & production per well



-Brent oil field

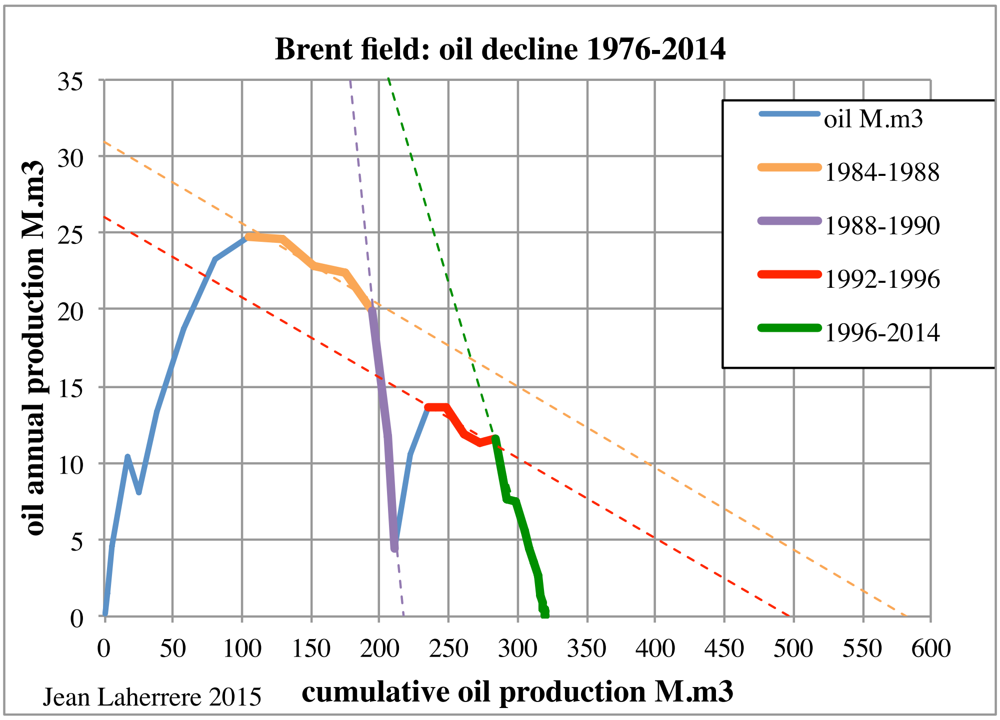
Brent field started production in 1976, reached oil peak in 1984, in 1990 was transformed into a gas field, Delta platform was shut in 2001, Alpha & Bravo were shut in November 2014, with only Charlie platform left producing before full commissioning. The Brent oil price is in fact from Brent field almost depleted, but from other fields around.
Fig 38: Brent field: oil, gas & water production



HL of oil production in 1996 using the linear trend from 1992 to 1996 would have estimated ultimate at 380 M.m3 when the real value is 320

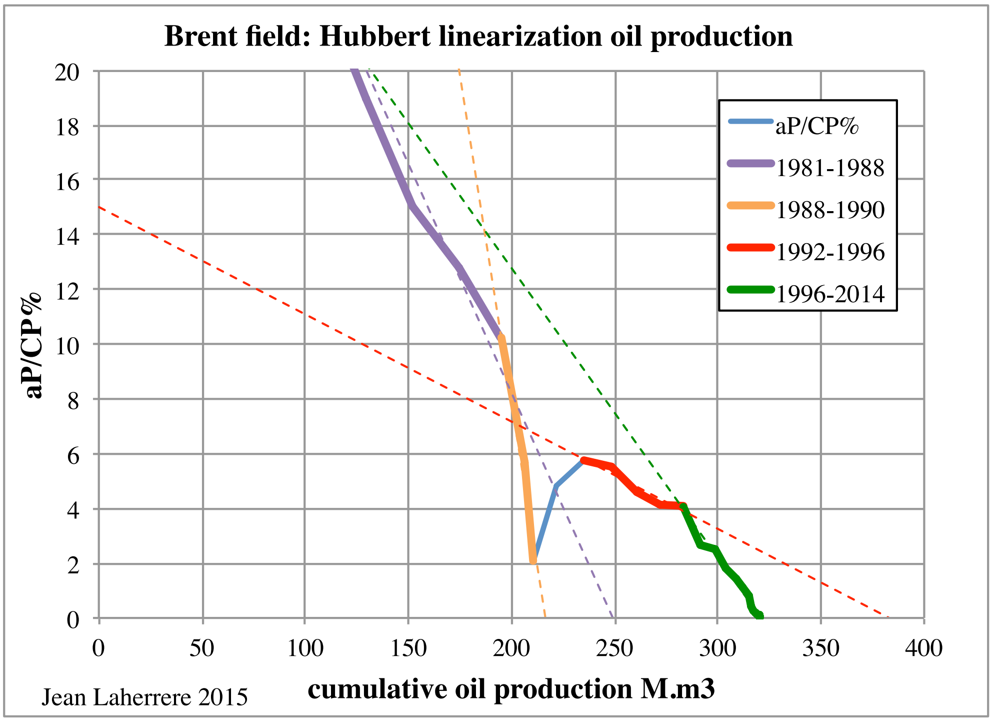
Using only the decline of annual production for the same period the forecast would have been much larger at 500 M.m3

Fig 39: Brent field oil decline & linear trends



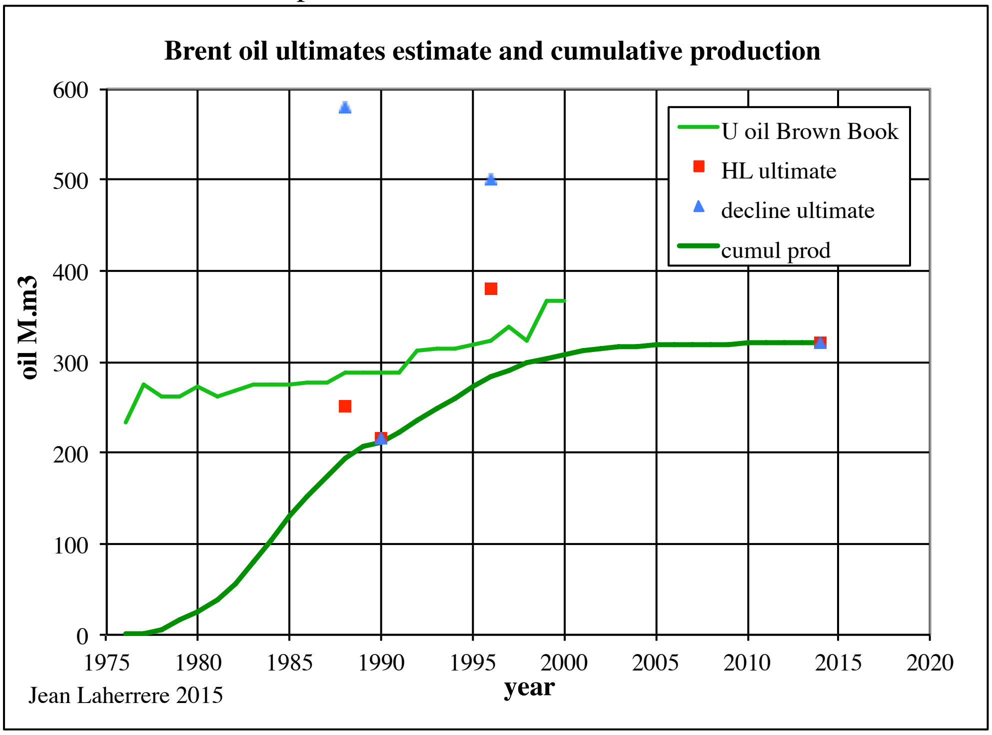
The HL displays four different trends with ultimates from 215 to 380 M.m3

Fig 40: Brent field oil production: HL & linear trends



HL is better than oil decline as shown in the graph of the cumulative production and ultimates
The operator reserves estimate from the Brown Book increased from 1976 to 2000 from 233 M.m3 to 368 M.m3 too high from the real value of 320 M.m3

Fig 41: Brent field: oil cumulative production & ultimates



Natural gas production peaked in 2001, both HL and gas decline for the period 2002-2014 give similar results, but HL for the period 1992-1997 was not far from the real value.

Fig 42: Brent field: gas production: HL & linear trends

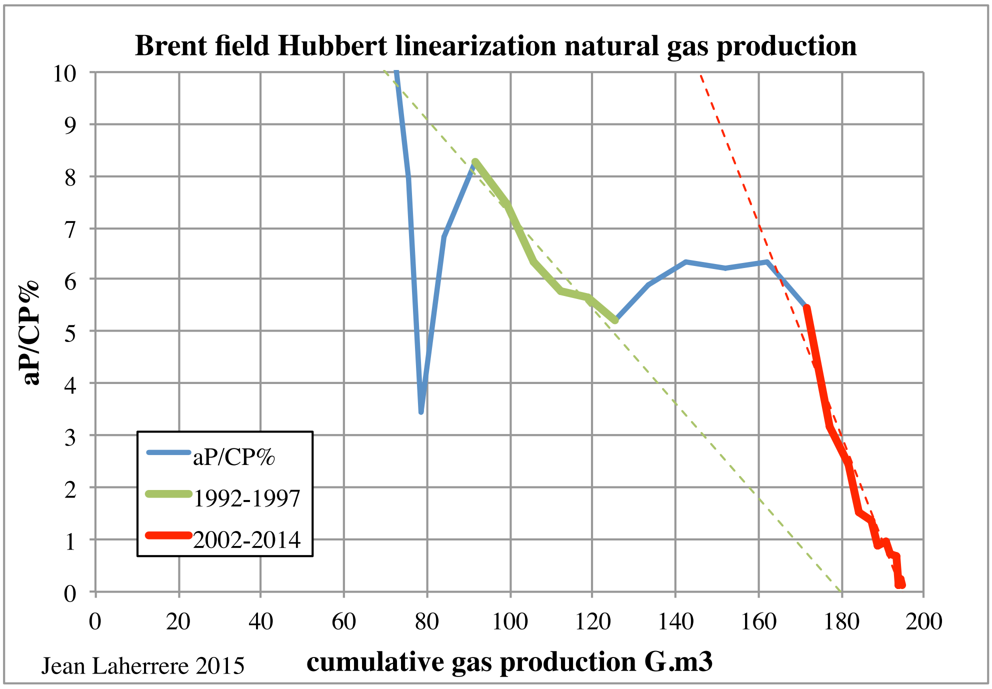
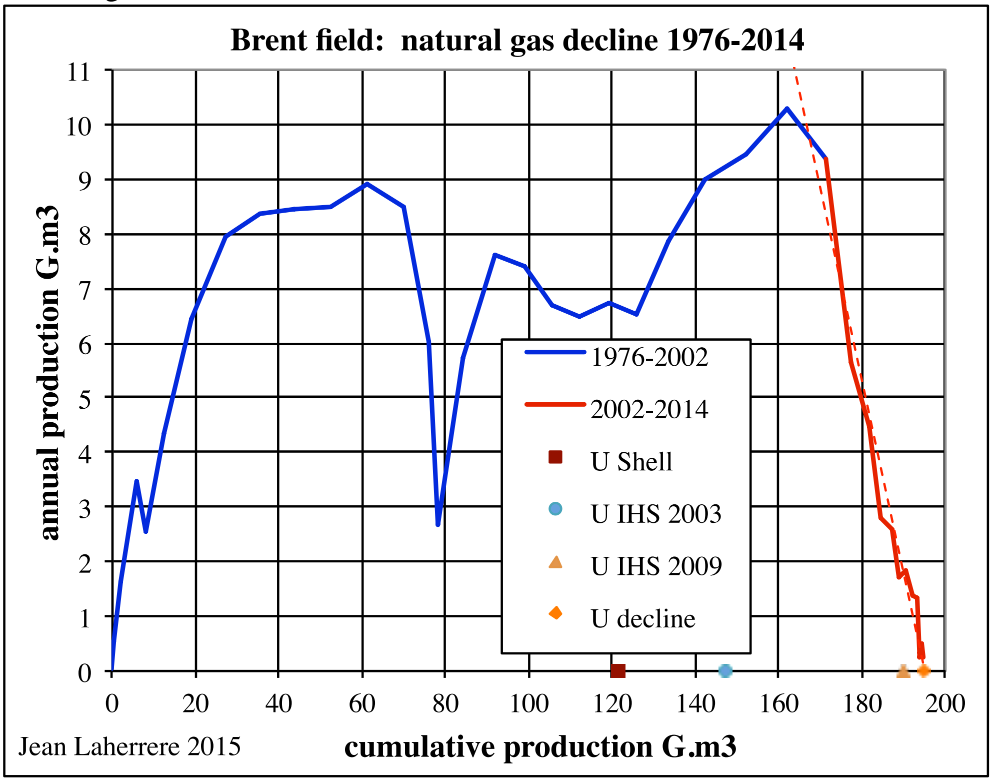


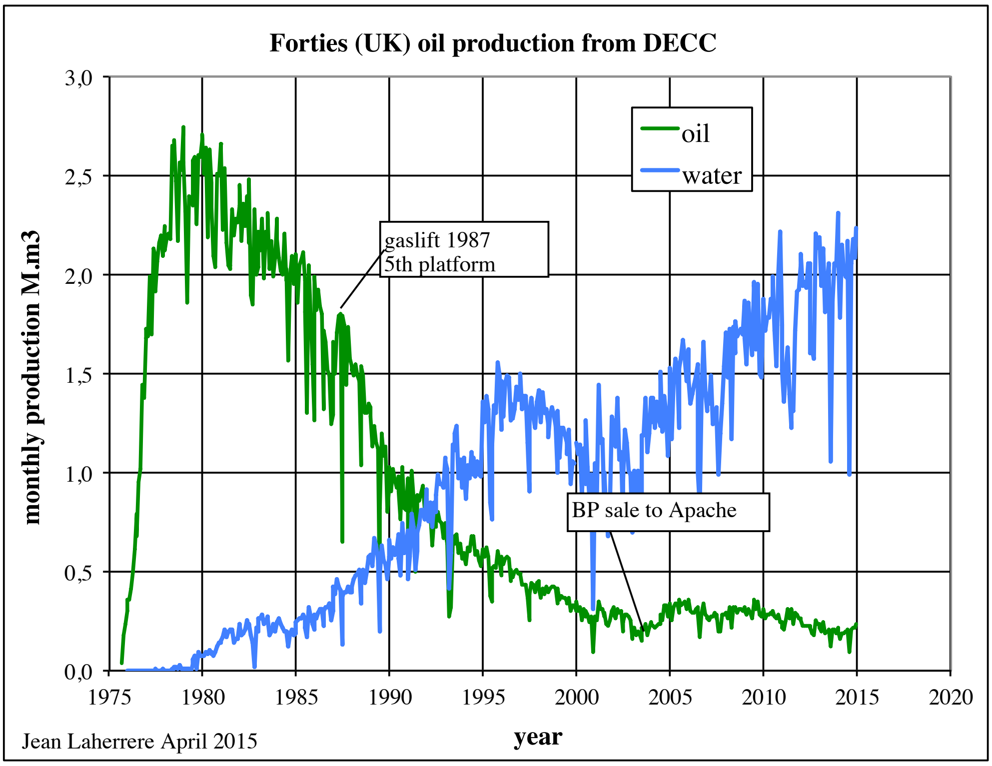
Fig 43: Brent field: gas decline & linear trends



-Forties oil production

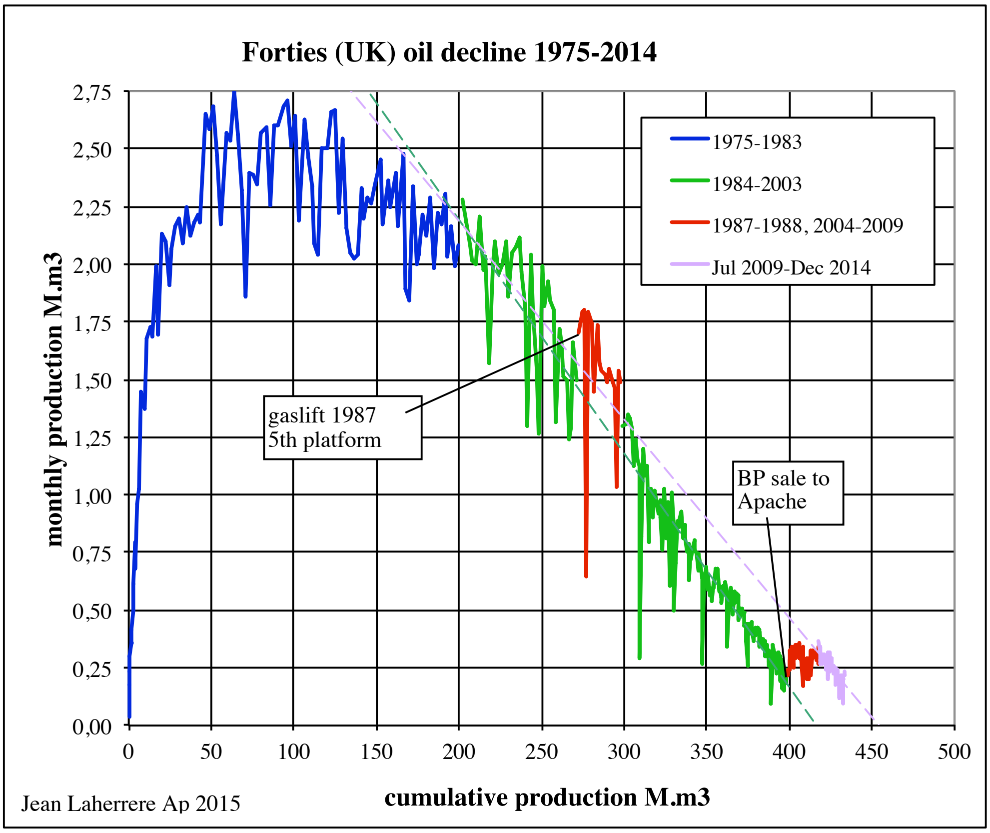
It is interesting to study Forties oil field with the change from a major operator (BP) to a smaller operator with lower costs in 2003

Fig 44: Forties oil & water production



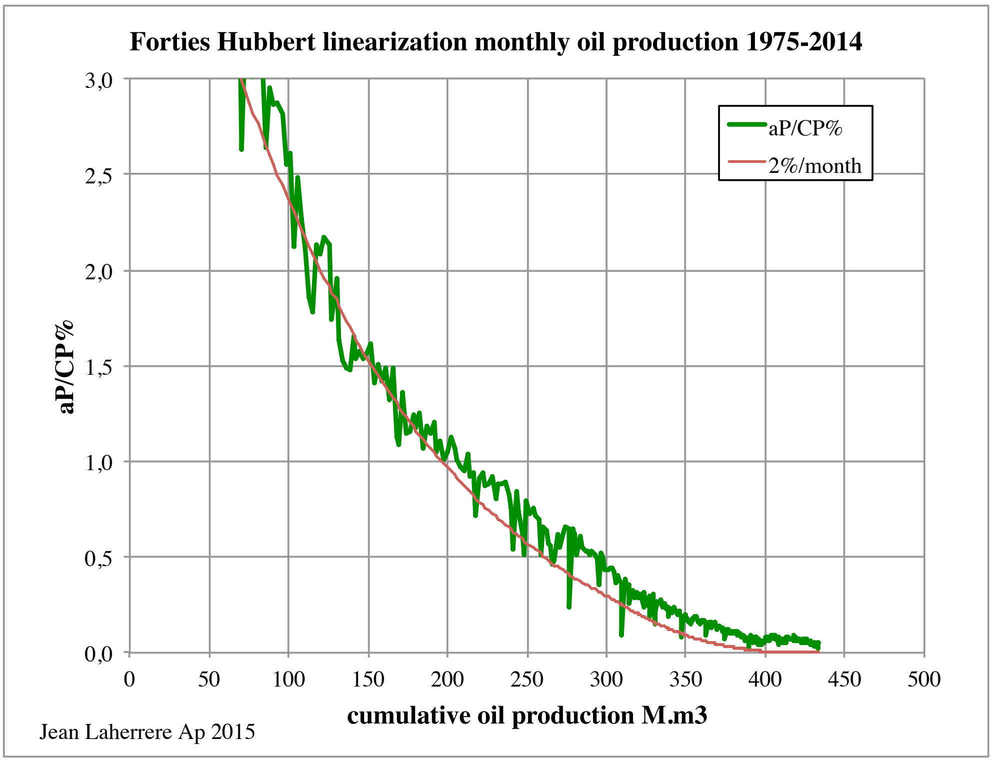
Oil decline for the period 1984-2003 excluding 1987 with the installation of gas lift and a fifth platform (in green) trends towards 410 M.m3 but the new operator Apache drilled more wells and this infill drilling increase the ultimate (2009-2014) to 450 M.m3

Fig 45: Forties oil decline & linear trends



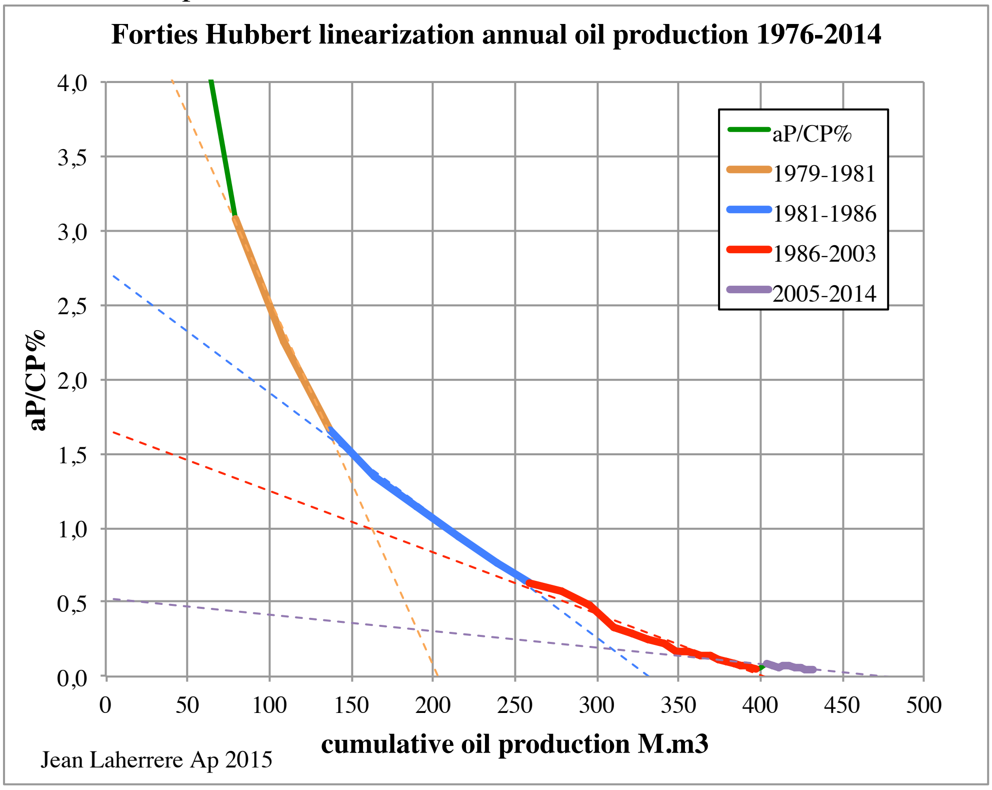
The HL of the monthly production displays a curved plot with no linear part, close to a decrease of 2% per month

Fig 46: Forties oil monthly production: HL



However using the annual production, some linear portions (4) can be used and obviously with increasing estimates of ultimates. This example shows the weakness of the HL method.

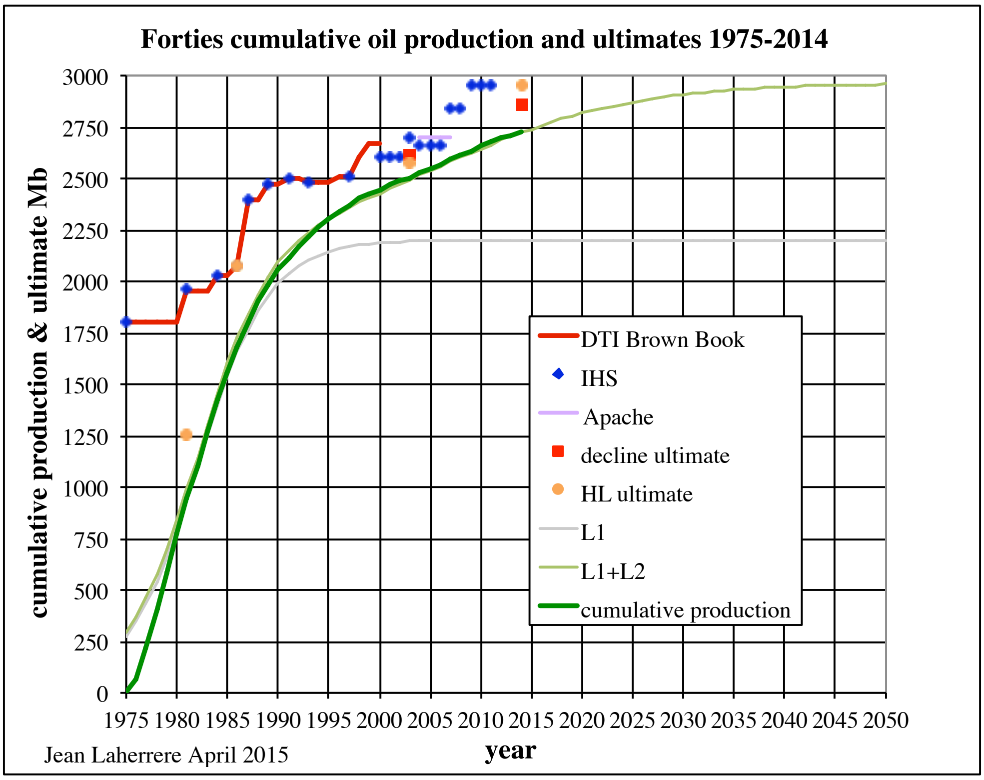
Fig 47: Forties oil annual production: HL & linear trends



The plot of the cumulative oil production and of the HL, decline, Brown Book, HIS & Apache ultimates displays a continuous increase with time.

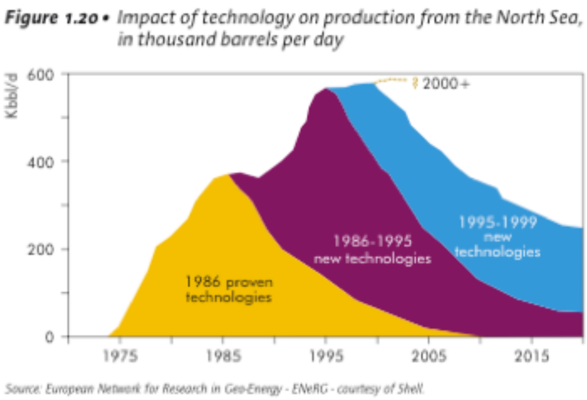
A modeling of the cumulative production is drawn with two logistic curves L1 & L2 for an ultimate of 2965 Mb.

Fig 48: Forties oil cumulative production & ultimates

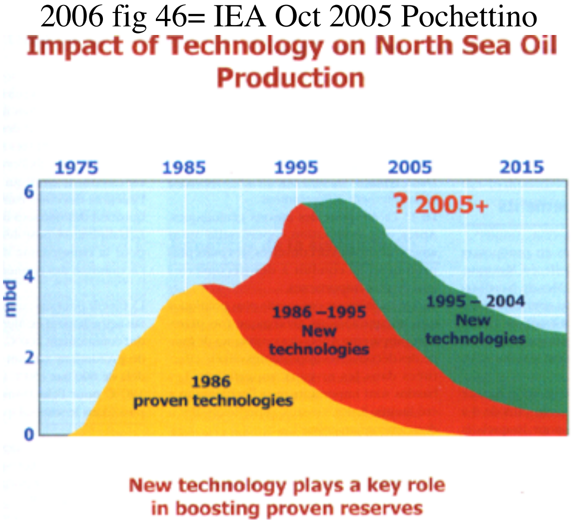


For this example there is no best method for estimate, every operator at first underestimated the ultimate and as most operators were listed on the US stock market; they reported proved reserves following SEC rules.
North Sea oil reservoirs are good and were produced with water injection. At the beginning the recovery was taken at one third (world average), but with time it was found that water injection was performing well and that a 50% recovery factor was possible for this kind of reservoir.
This reserve growth in North Sea led to a campaign of belief that world reserves can be increased easily by using new techniques, but unfortunately reserves increases in North Sea was not due to new technology (water injection is an old technique) but to poor (or lack of knowledge) practice in reserve estimate.
IEA in May 2005 promoted the theory of reserve growth due to technology on a manipulated (crooked) graph (changing date 1999 by 2004), forecasting good surprise by 2005 (in real none): see my 2006 paper fig 44 to 48: Laherrère J.H. 2006 “Uncertainty on data and forecasts” ASPO 5 Pisa 18-19 July www.oilcrisis.com/laherrere; http://aspofrance.viabloga.com/files/JL-ASPO%205-long.pdf; http://www.aspoitalia.it/images/stories/aspo5presentations/Laherrere_ASPO5.pdf

2006 fig 44 Shell Rodriguez



2006 fig 46= IEA Oct 2005 Pochettino

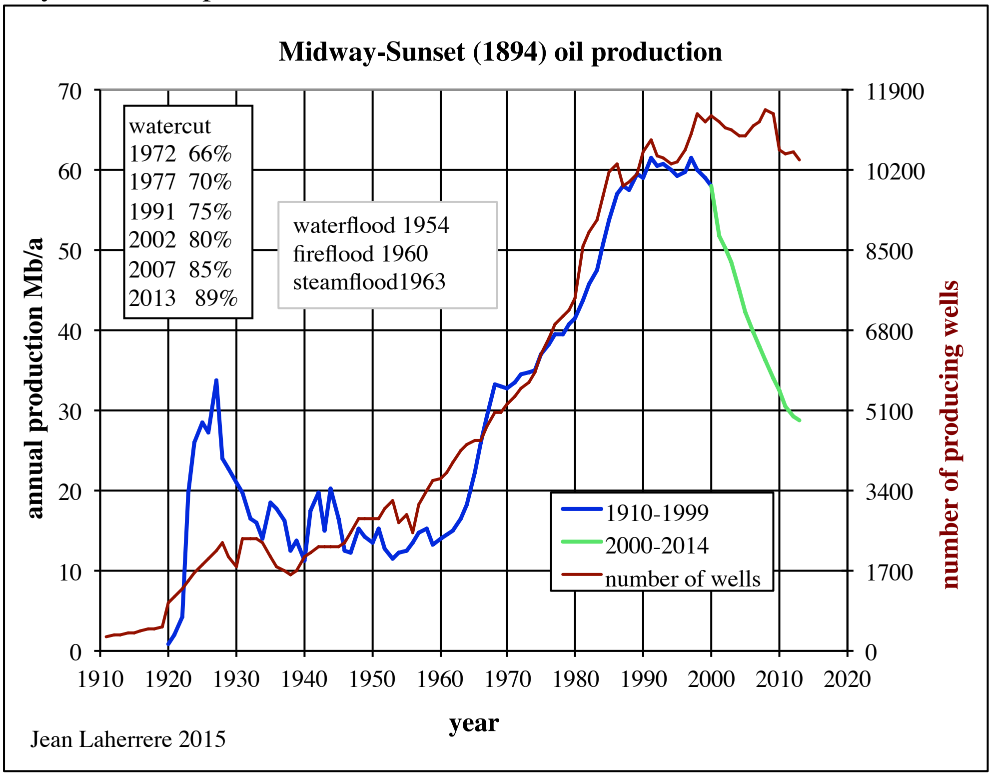


The trough of North Sea production in 1988 is due to Piper blow out (160 dead) and Brent works for gas repressuring (see fig 38)! The rise after 1988 (same slope starting 1975) is not new technology, but resume of production by Piper and Brent

-Midway-Sunset oil production

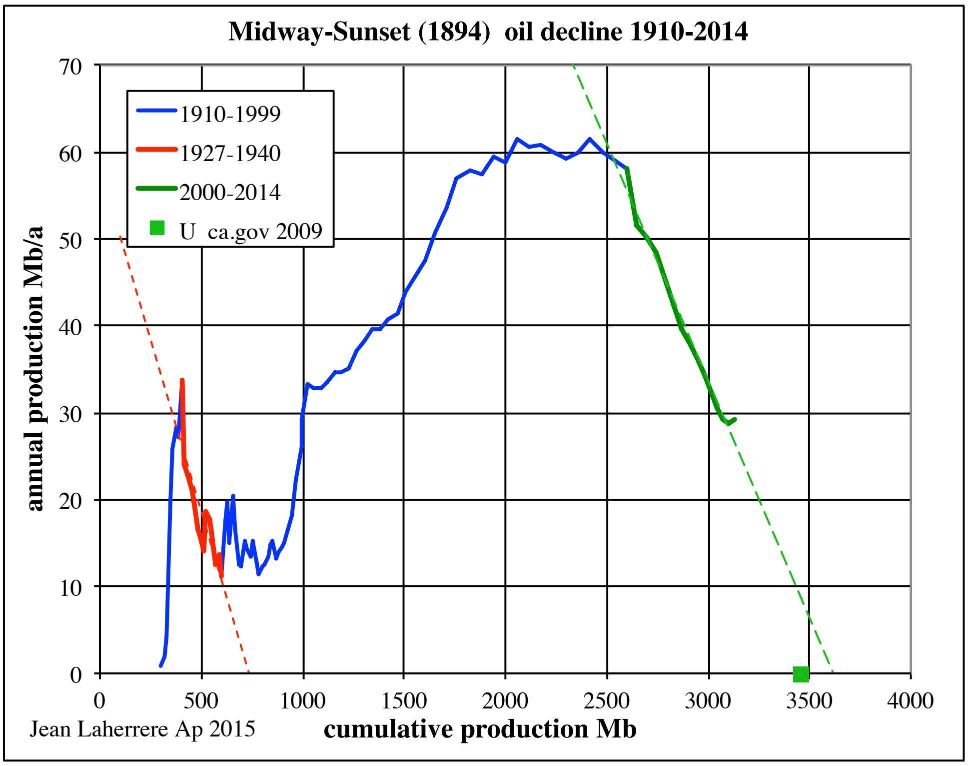
Midway-Sunset is an interesting example as it reached its peak one century after discovery. Its oil is heavy and needs steam (1963) to get good recovery. Its reserves value has grown with the number of wells, following old SEC rules that proved reserves are only allowed for the spacing unit of producing wells. Since 2010 SEC has changed the rule (to please the owners of unconventional reserves) and allows to report proved undeveloped reserves to take into account the undrilled reserves of a known accumulation. SEC rules went from too pessimistic to too optimistic (allowing to use model from seismic which can be kept confidential), explaining the burst of unconventional reserves, which allows operators to borrow cheap money. It is why shale players are so much in debt.

Fig 49: Midway-Sunset oil production & number of wells



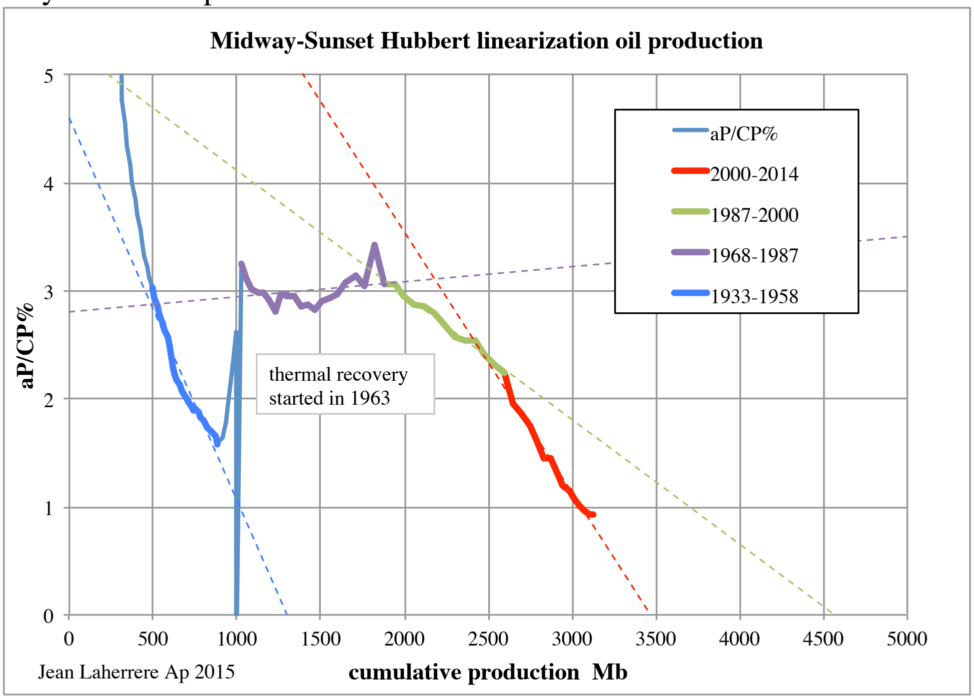
The oil decline has two linear trends, but the first one seems to be due to the depression (no more drilling) and the second one for 2000-2014 is close to the State value around 3.5 Gb

Fig 50: Midway-Sunset oil decline & linear trends



The HL trends are four but the second one (1968-1987) is growing, due to the start of thermal recovery (1963) and the third one (1987-2000 = peak plateau) looks too high!

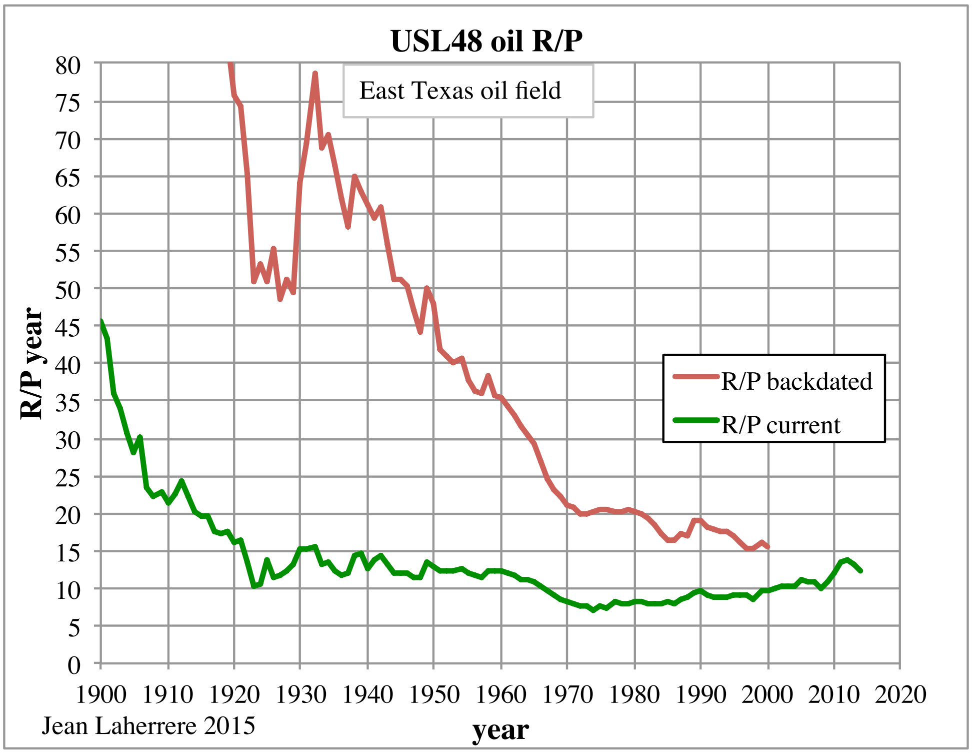
Fig 51: Midway-Sunset oil production: HL & linear trends



The US practice (rule of thumb) is to report remaining reserves as ten times the annual production. It is why the US famous R/P has been 10 years for the last 100 years, showing clearly that these remaining current reserves are mainly financial data

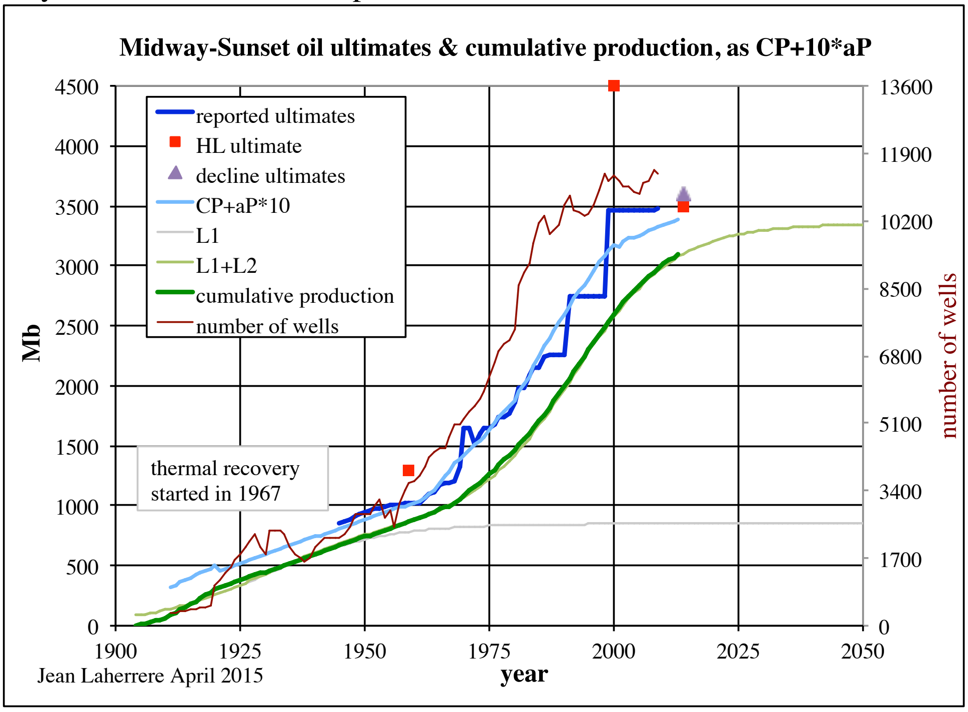
The USL48 R/P has been around 10 years since 1920, but the backdated (EIA534) R/P has peaked in 1931 with East Texas oil field around 80 years and decreased down to 20 years in 1970

Fig 52: USL48 oil R/P



The plot of cumulative production and ultimates shows that the reported ultimates (dark blue) and with reserves = ten times annual production (light blue by adding cumulative production).

Fig 53: Midway-Sunset cumulative oil production & ultimates



My forecast in 2001 was an ultimate around 3400 Mb

-Laherrère J.H. 2001 "Estimates of Oil Reserves " IIASA International Energy Workshop June 19-21 2001 Laxenburg

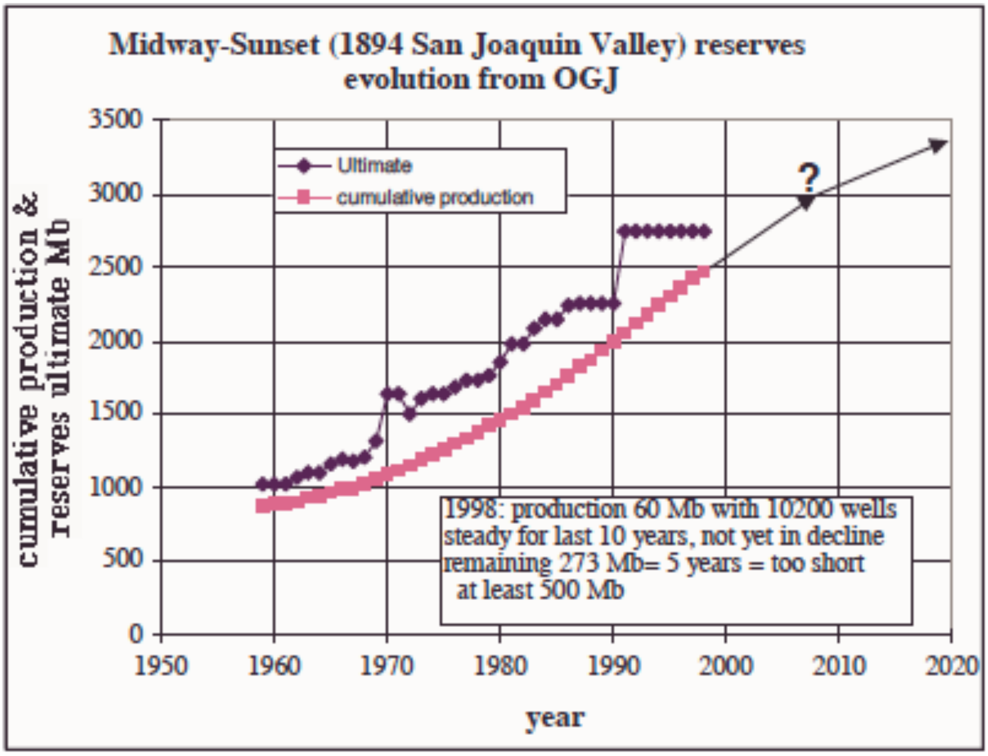
http://webarchive.iiasa.ac.at/Research/ECS/IEW2001/pdffiles/Papers/Laherrere-long.pdf

http://www.scribd.com/doc/55367641/10/Impact-on-climate-change-IPCC-scenarios

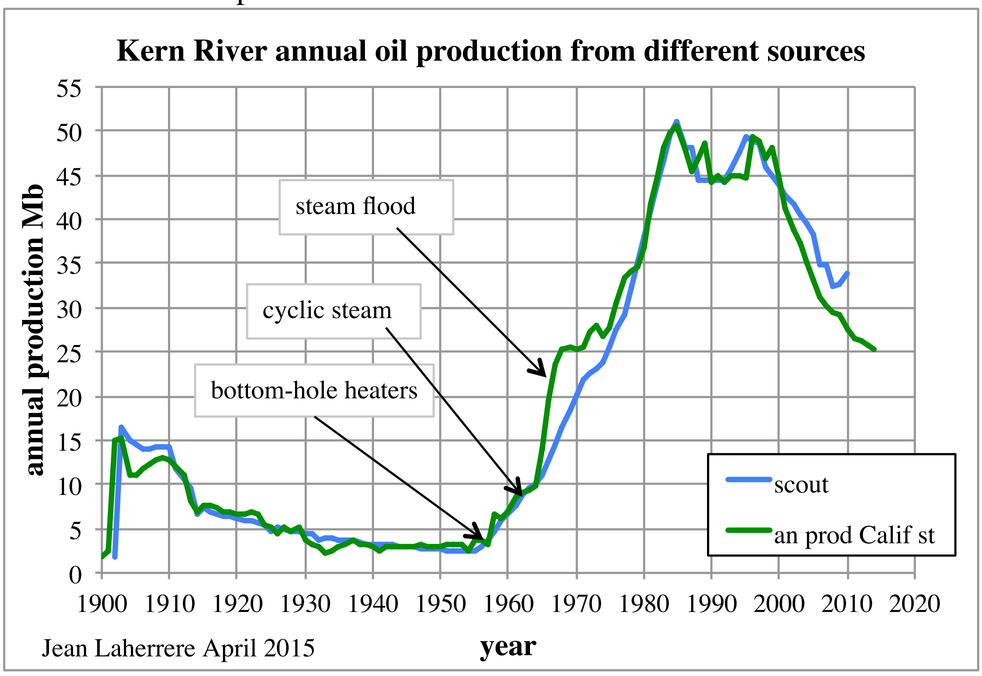
http://www-personal.umich.edu/~twod/oil-ns/articles/laherrere-long_iew2001.pdf

http://www.oilcrisis.com/laherrere/iiasa_reserves_long.pdf

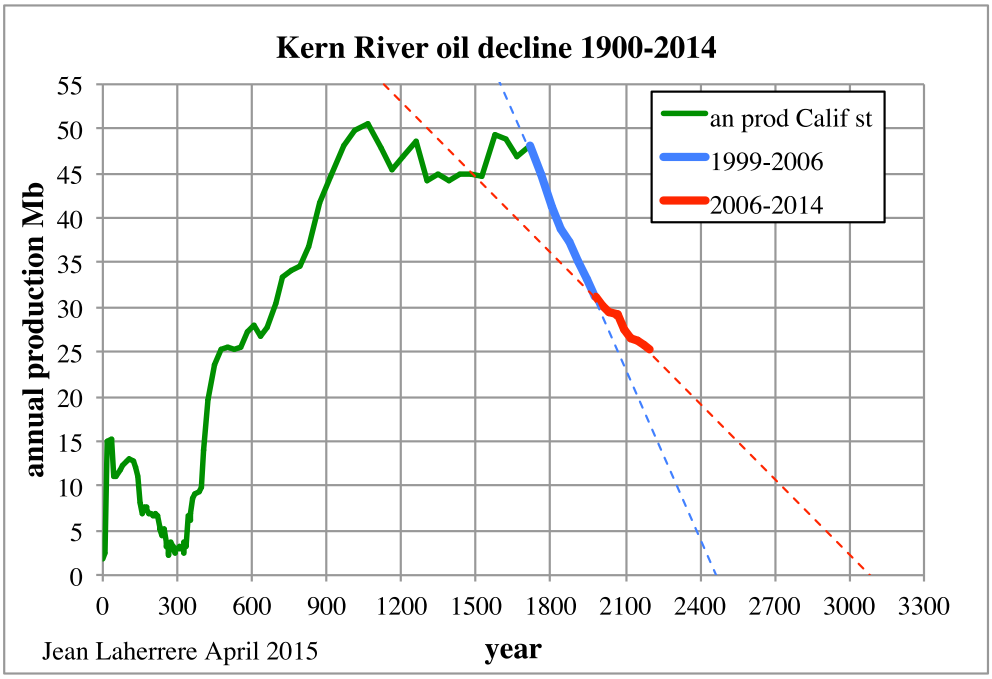
2001 fig 77



-Kern River oil field
Not far from Midway-Sunset, Kern River oil field discovered in 1899 and produces also heavy oil (13°API). It is operated by Chevron using the best techniques combining thermal and generation of electricity. Annual production data vary with sources
Fig 54: Kern River oil annual production from different sources

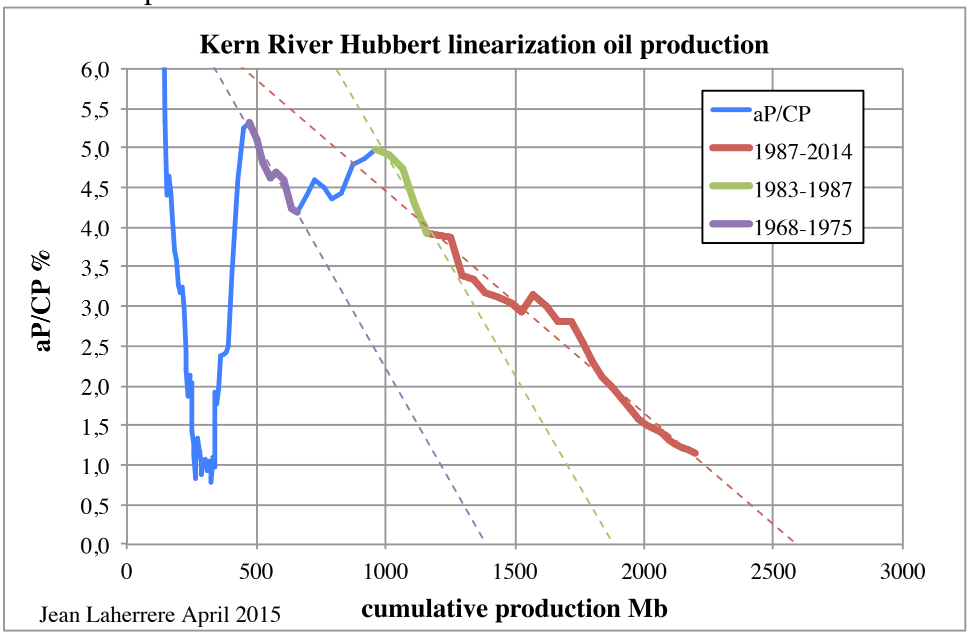


Kern River oil decline displays two linear trends, the first 1999-2006 trends around 2.4 Gb and the last one 2006-2014 around 3 Gb
Fig 55: Kern River oil decline & linear trends



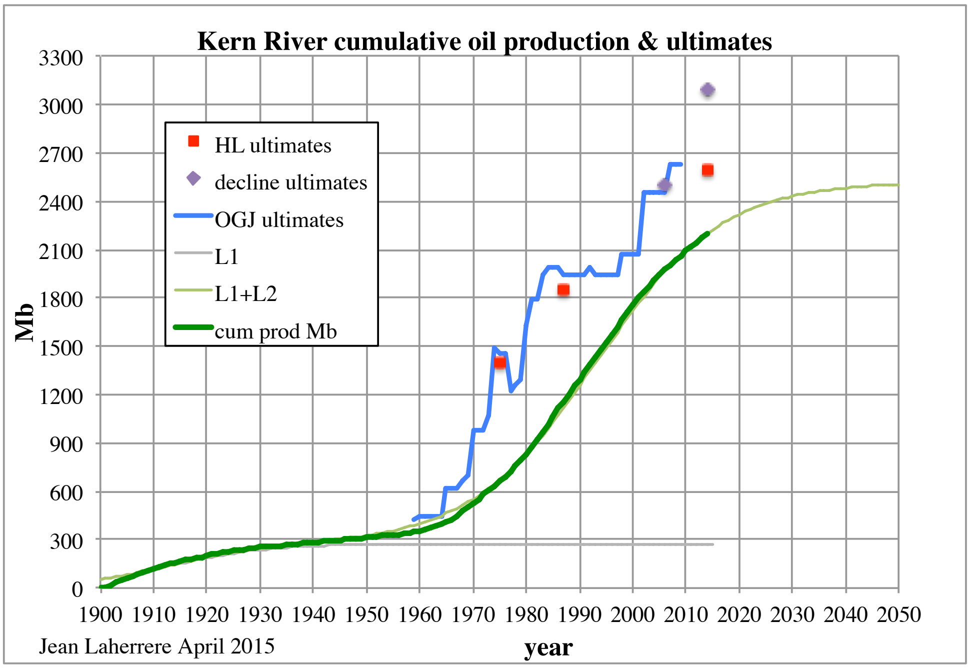
The HL displays three linear trends which increase with time, the last one around 2.6 Gb

Fig 56: Kern River oil production: HL & linear trends



The plot of cumulative production and HL, decline & OGJ ultimates shows that no one is able to forecast in advance the ultimate. Modeling the cumulative production with two logistic cycles L1 and L2 towards 2.5 Gb gives a good fit.

Fig 57: Kern River cumulative oil production & ultimates



Unfortunately HL and decline extrapolations are not better than the estimates by the operator using restrictive old SEC rules.

-Yates oil field (Permian Basin Texas)

The Permian basin (with several sub basins) discoveries were mainly from 1925 and 1960 as shown by this graph of discovery years and cumulative production up to 2000 from the 2004 report of BEG University of Texas Dutton et al

Fig 58: Permian Basin cumulative oil discoveries & annual discovery 1921-2000 from BEG

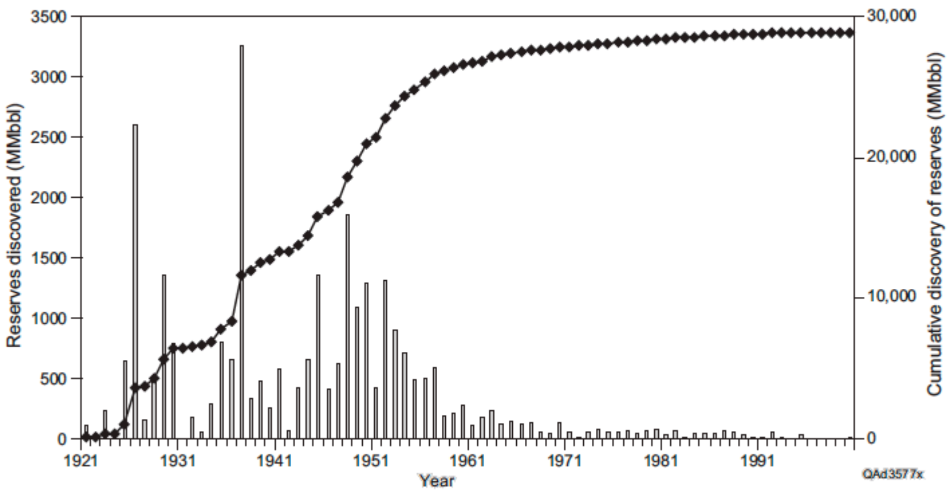


Figure 124. Permian Basin cumulative oil production discovered by year. Bars show years in which reservoirs were discovered, with height of bar indicating volume of oil produced by those reservoirs through 2000.

The peak of discovery of the Permian Basin was in the 50s. The number of discovered reservoirs counts by hundred.

Fig 59: Permian Basin number of reservoirs 1930-2000

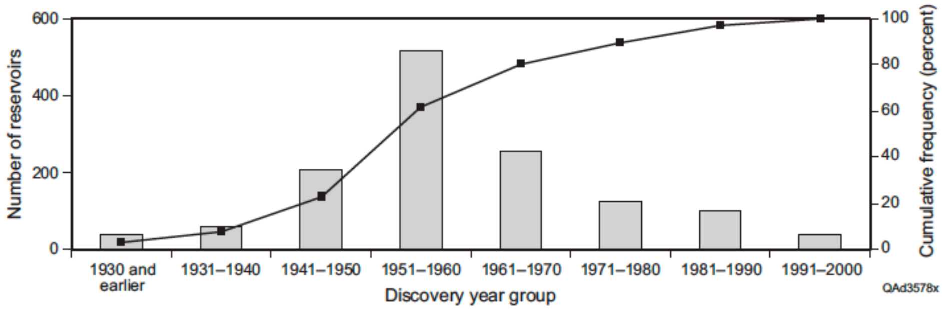


Figure 125. Reservoir discovery-year histogram of the 1,339 major oil reservoirs in the Permian Basin that produced >1 MMbbl through 2000.

Most of the oil production is from carbonate, but its share is decreasing
Fig 60: Permian Basin annual production from reservoir types

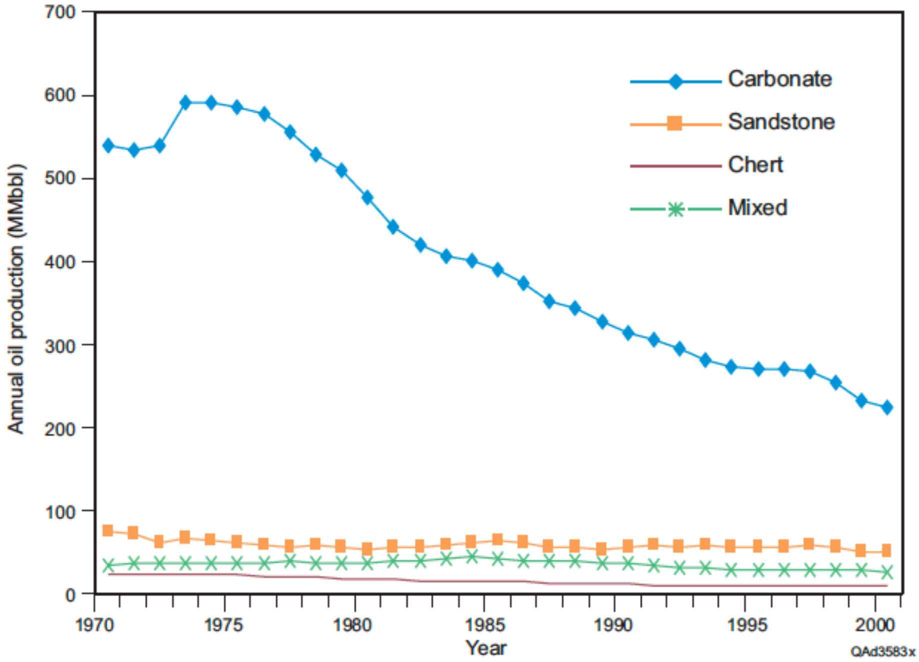
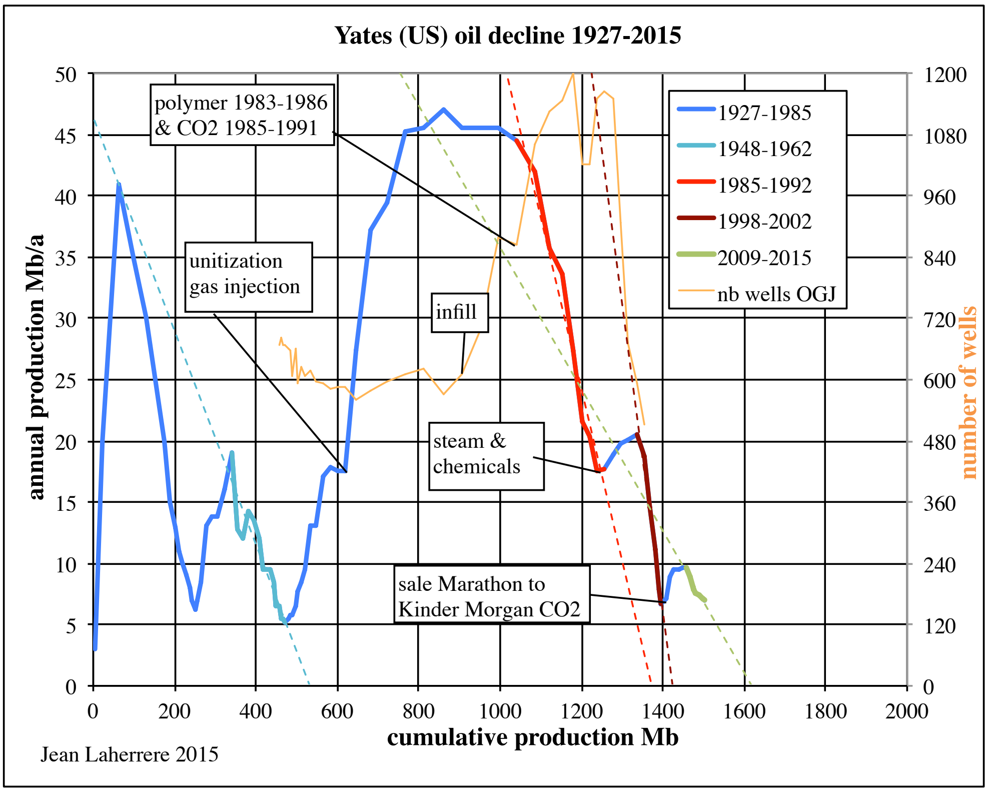
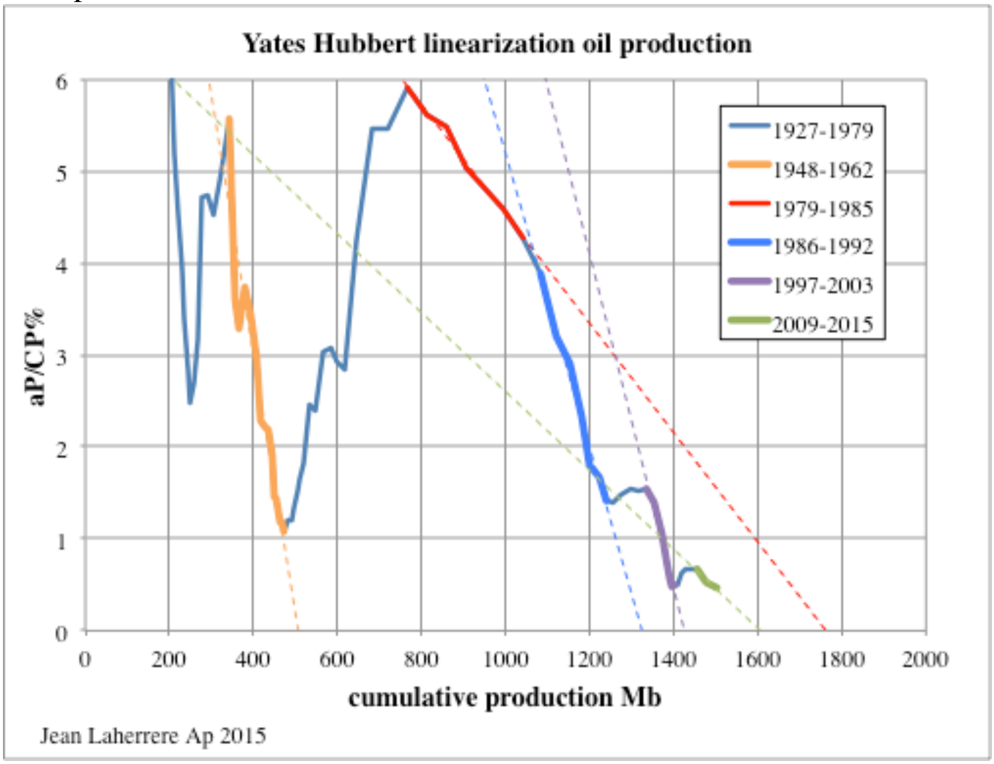


Figure 130. Production histories of significant-sized oil reservoirs in the Permian Basin by lithology.

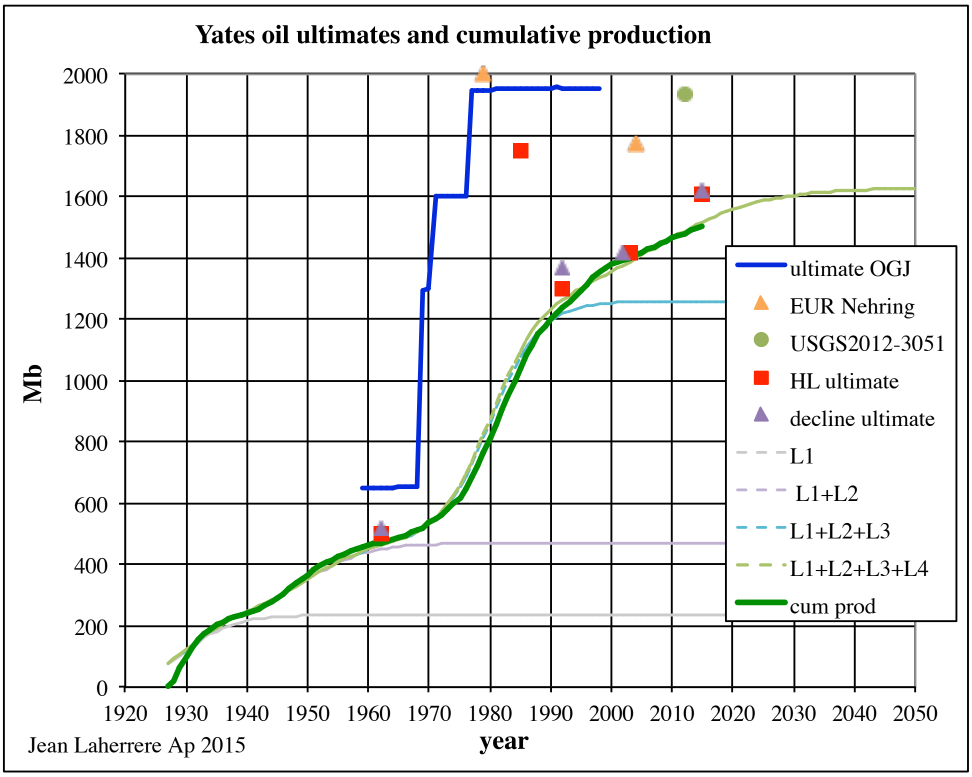
Yates oil field is located south of the Permian basin is a good example of difficult field with the use of different tertiary techniques as chemical, CO2 and steam and the change of operator (Kinder Morgan).
Yates started production in 1927 and pealed in 1981 after previous smaller peaks in 1929 and 1948, followed with smaller peaks in 1997 and 2009. The peak of the number of wells was 1200 in 1989.
Yates oil decline displays four linear trends with two trending towards 1.4 Gb and the last one towards 1.6 Gb when
Fig 61: Yates oil decline & linear trends



The HL displays five linear trends ranging from 500 to 1750 Mb: too wild!
Fig 62: Yates oil production: HL & linear trends



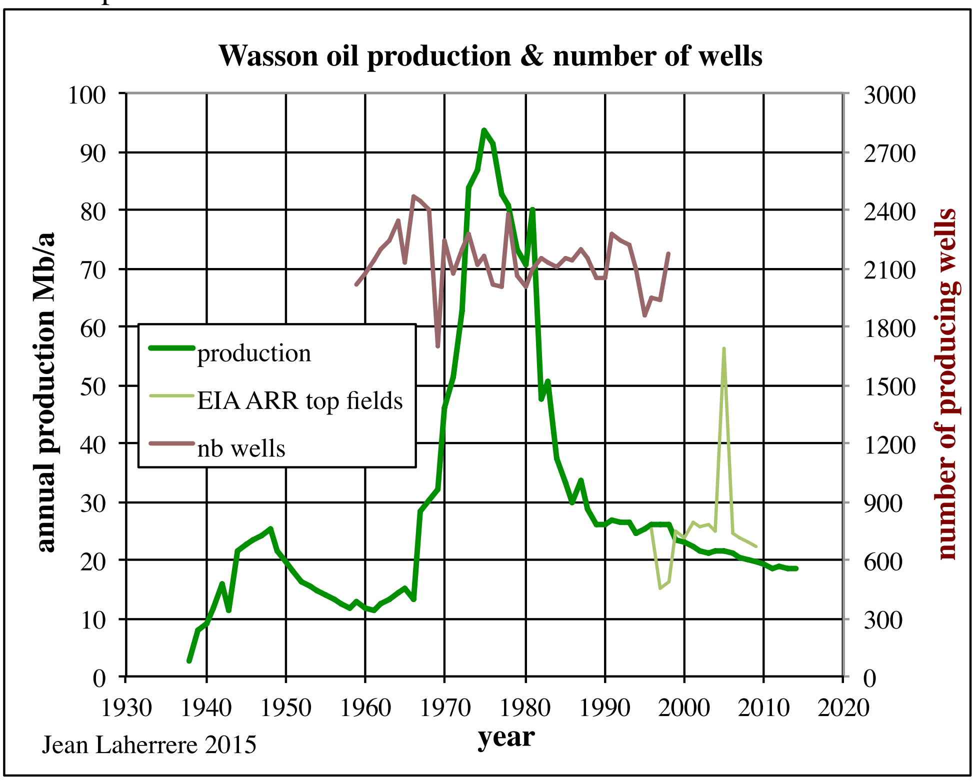
The plot of cumulative production and HL, decline, OGJ, Nehring, USGS ultimates shows that before 2009 no one is good as the USGS 2012.
The cumulative production can be modeled with four logistic cycles for an ultimate of 1630 Mb.
Fig 63: Yates cumulative oil production & ultimates



-Wasson

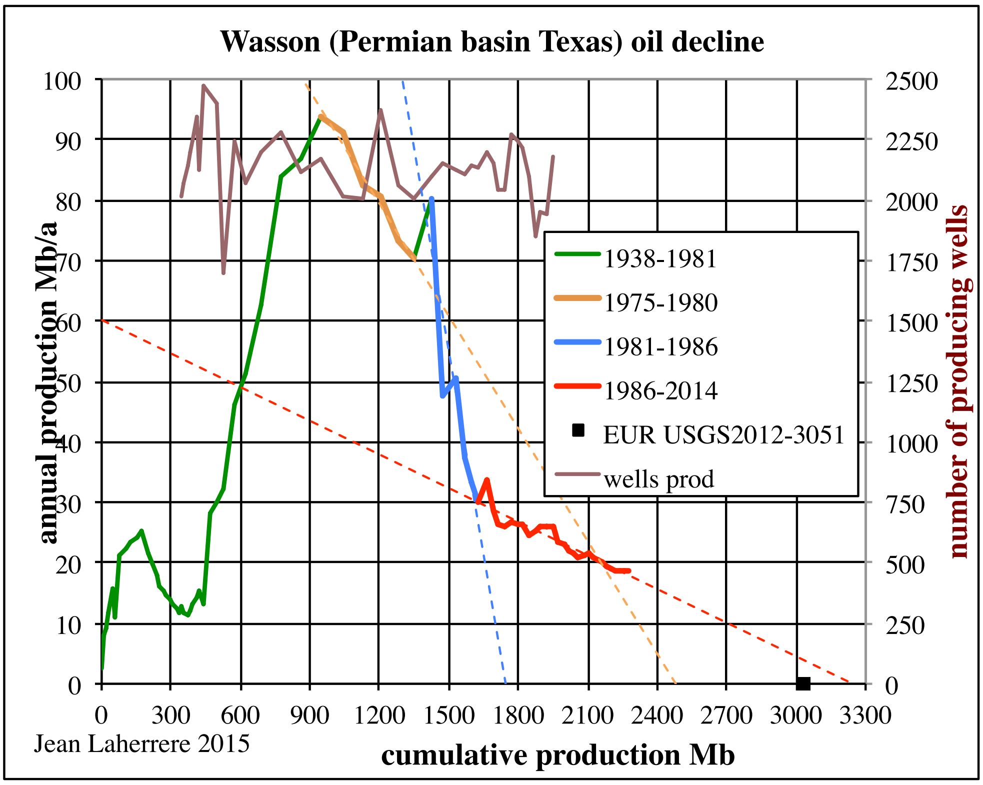
Wasson is also in the Permian Basin but found later and larger and in a different sub-basin. Wasson peaked in 1974 with about 2100 wells. EIA reports in the 100 top oil fields the rank of the reserves and the production (often wrong).

Fig 64: Wasson oil production & number of wells



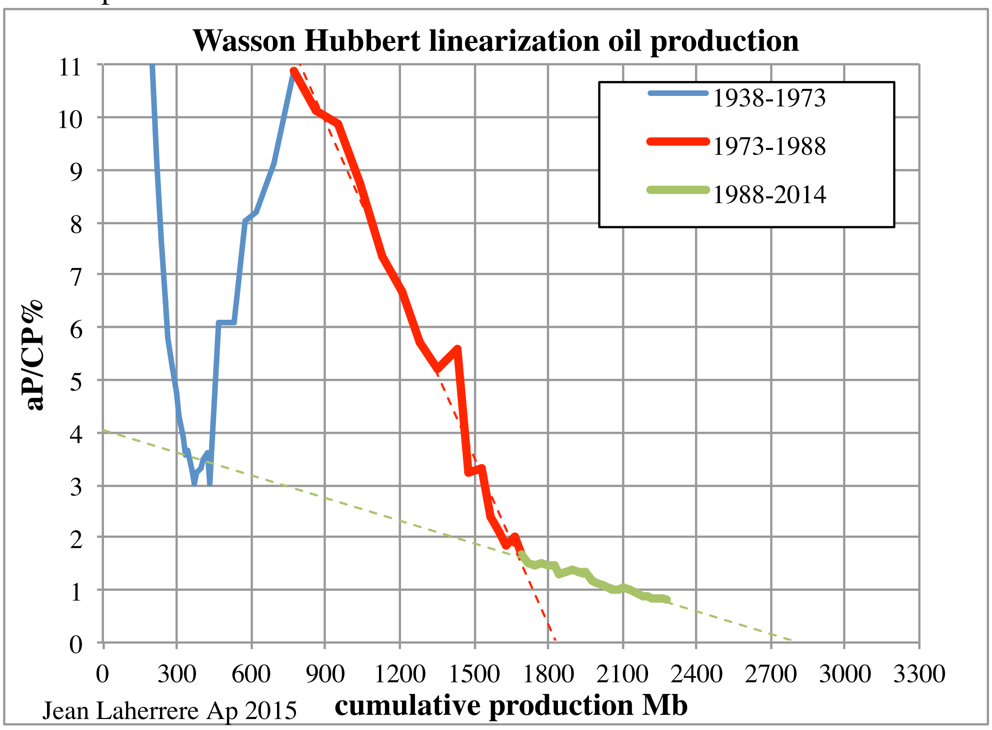
The oil decline displays three linear trends ranging from 1750 to 3200 Mb!

Fig 65: Wasson oil decline & linear trends



HL displays two ultimates ranging from 1800 to 2800 Mb

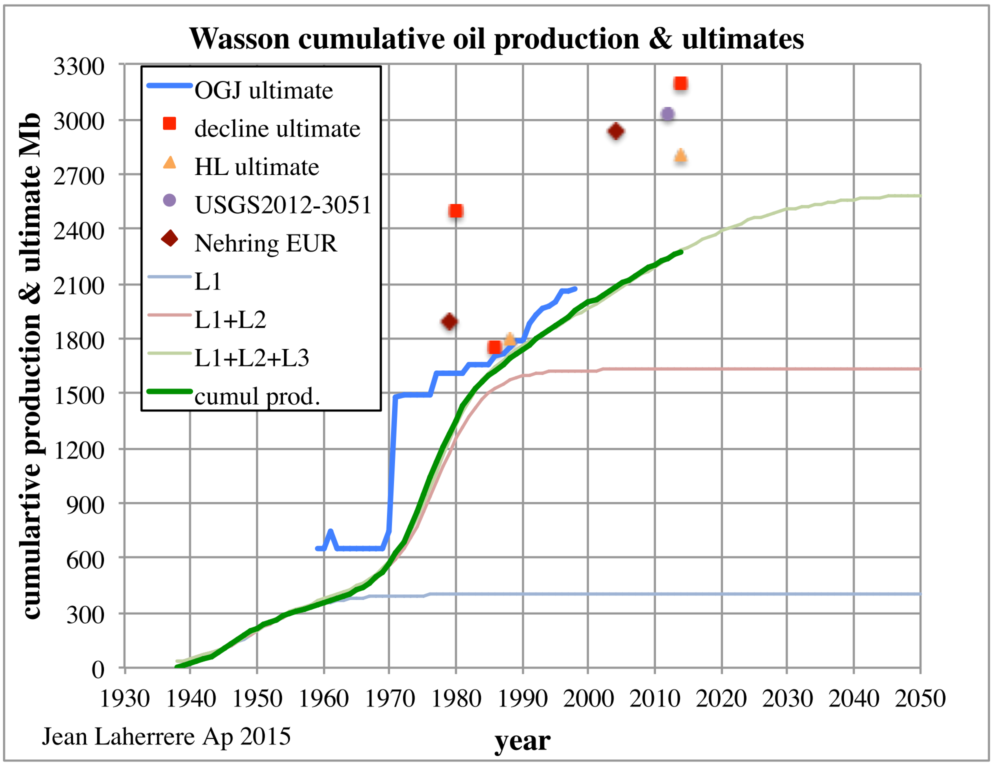
Fig 66: Wasson oil production: HL & linear trends



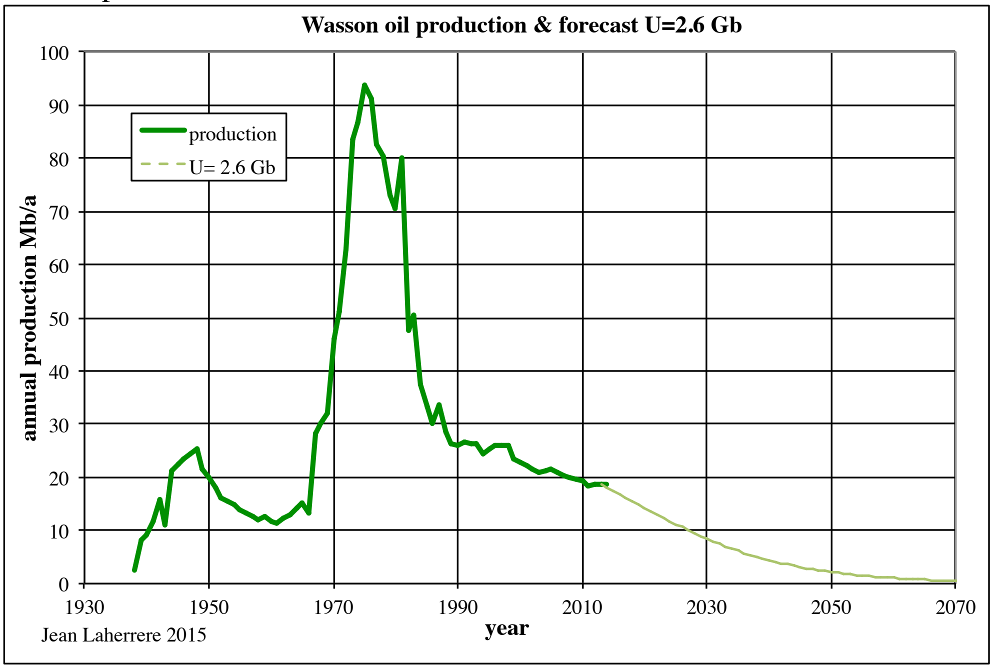
The plot of cumulative production and the OGJ, Nehring, USGS, HL & decline ultimates show that no one looks reliable.

The cumulative production is modeled with three logistic cycles for an ultimate of 2.6 Gb

Fig 67: Wasson cumulative oil production & ultimates

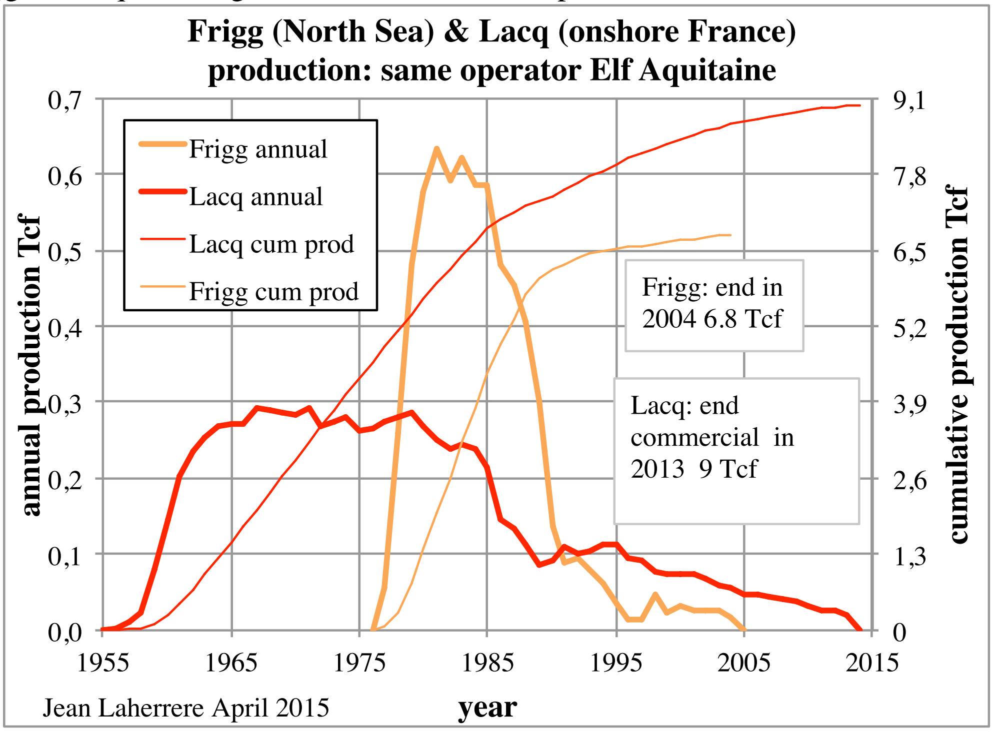


Wasson annual production is modeled with an ultimate of 2.6 Gb, showing that the peak of production in 1974 (93 Mb/a) displays for the period 1970-1988 (best reservoir = carbonate) where the annual production was over 30 Mb is quite symmetrical: the rise is as sharp as the decline. What is erratic is the production before 1970 and after 1988. However the minor peak in 1948 (25 Mb) is also rather symmetrical.
It seems that in such giant field with several different reservoirs the best one is produced quickly and the other reservoirs need more time to be depleted.
Fig 68: Wasson oil production & forecast U = 2.6 Gb

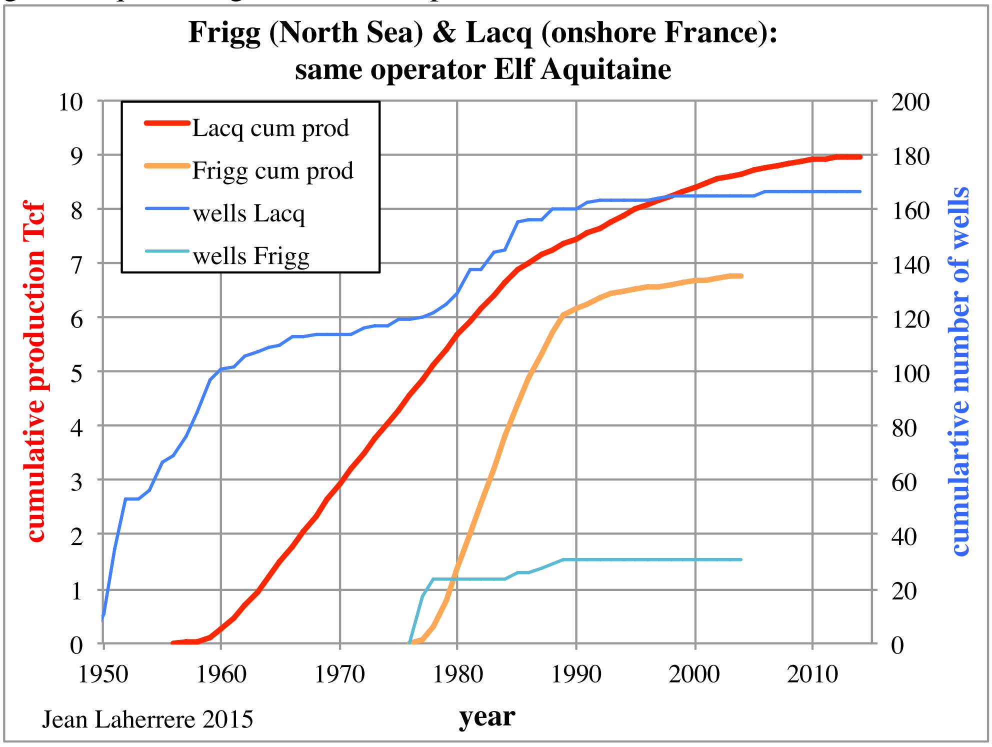


-Frigg and Lacq gas fields
The comparison is interesting because of having the same operator but being offshore and onshore, and with different development profiles: offshore with high costs and high productivity leads to

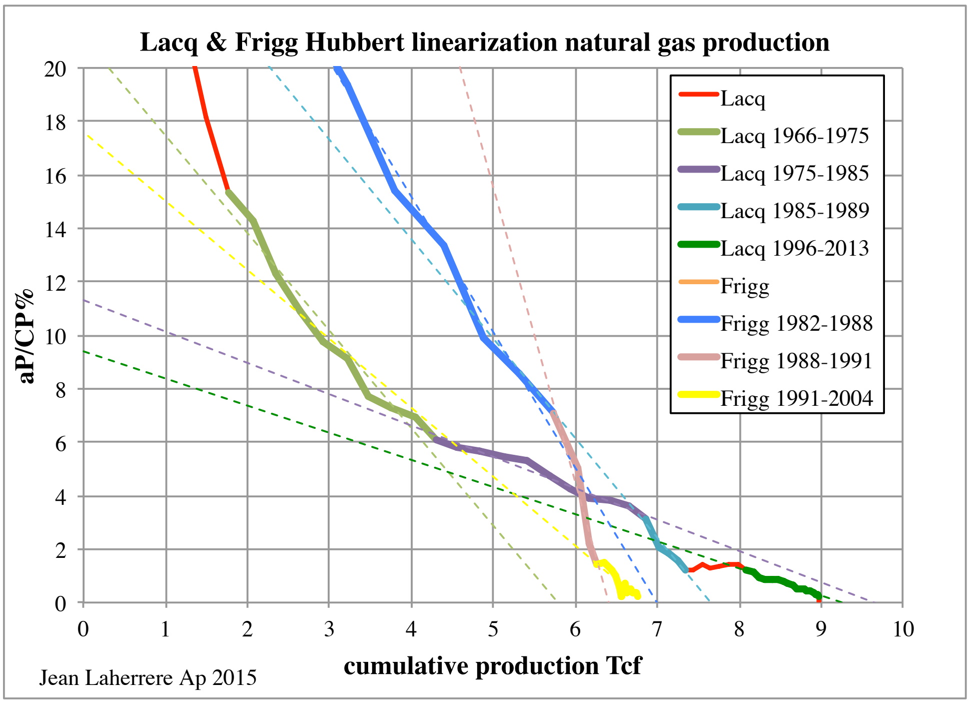
quick production with a high and short plateau (5 years against 20 years onshore) Frigg was from 1976 to 2004 (28 years); when Lacq production was from 1955 to 2013 (58 years).
Fig 69: Frigg & Lacq natural gas annual & cumulative production



Lacq produced 9 Tcf with 165 wells when Frigg produced 6,8 Tcf with only 31 wells
Fig 70: Frigg & Lacq natural gas cumulative production & number of wells

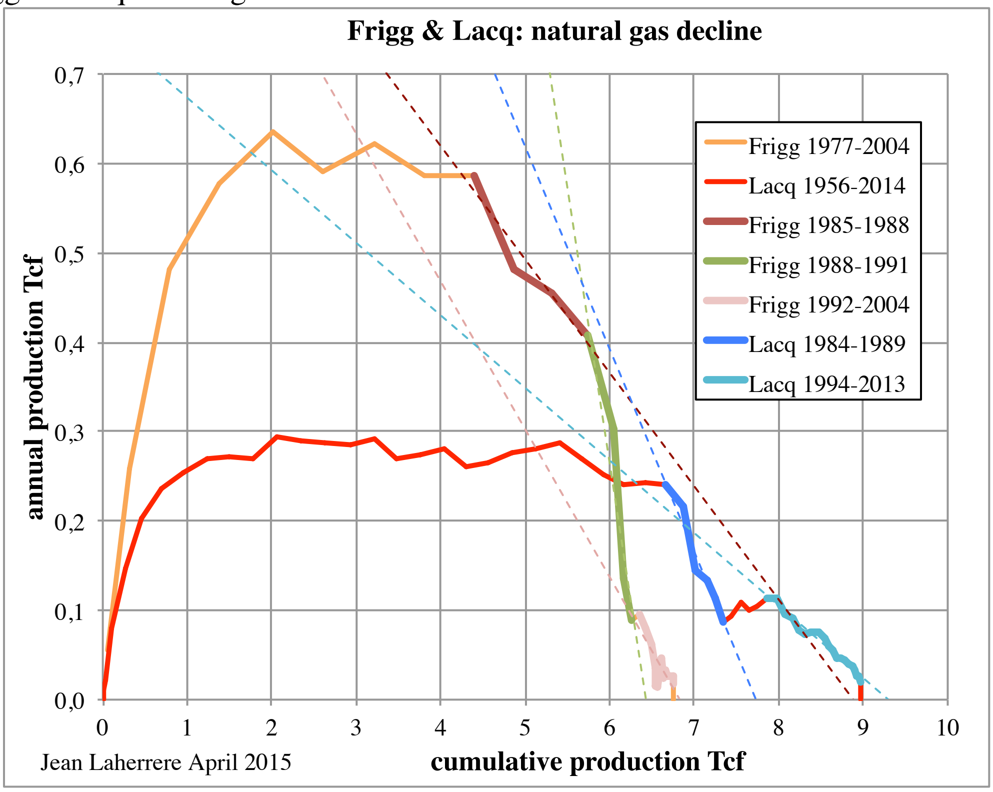


Hubbert linearization of the NG production displays several changing linear trends, meaning that HL was not very reliable.
Fig 71: Frigg & Lacq natural gas production; HL & linear trends



Linear extrapolation of the NG decline displays also several linear periods, meaning that this extrapolation is not better than the HL!

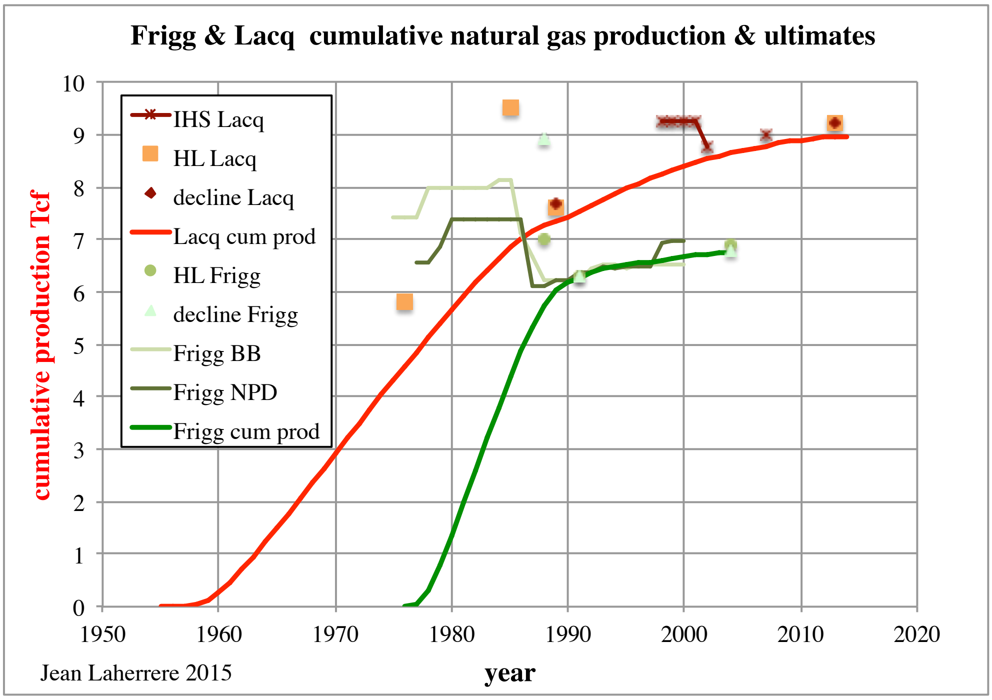
Fig 72: Frigg & Lacq natural gas decline



Both ultimates from HL and NG decline are compared with the cumulative production and around 1990 these estimates were quite too low, when the previous estimates were quite too high.

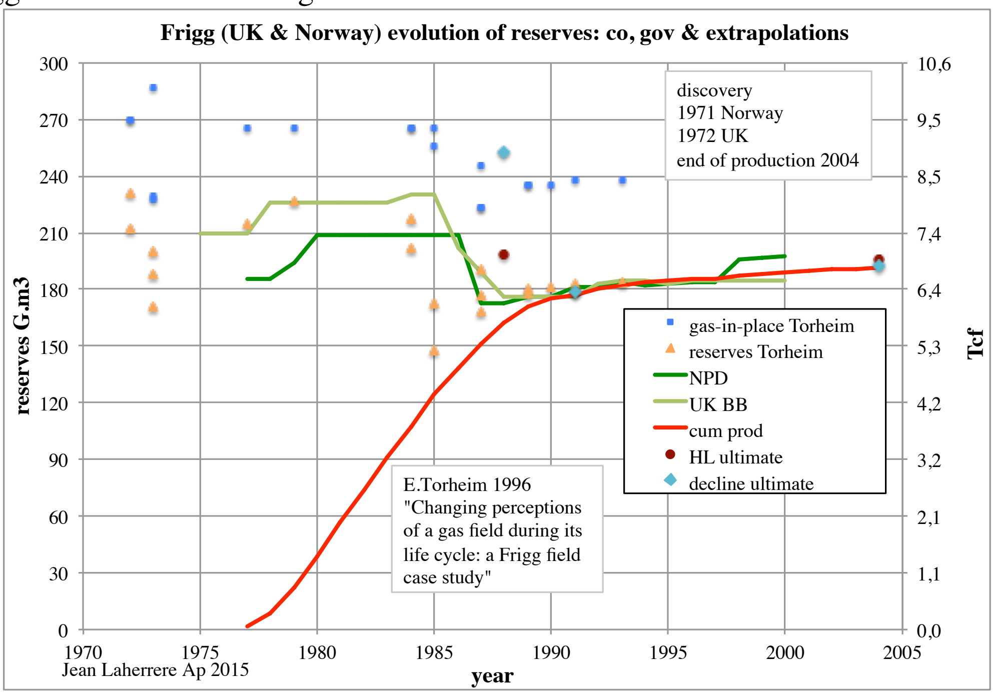
The plot of the cumulative NG production and the HL, decline, IHS, Brown Book and NPD ultimates shows that for Lacq ultimates were underestimated in contrary with Frigg.

Fig 73: Frigg & Lacq natural gas cumulative production & ultimates



On the Frigg field located on the border in Norway and in UK, many seismic surveys were run in order to estimate the precise volume of the accumulation in place. The official volume of the reserves by UK (Brown Book light green) and NPD (dark green) were from 1980 to 1985 (most of the production) well above the real value. It was the goal of the operator to overestimate the field in order to have the highest authorized daily level to produce the field as fast as possible because the offshore production costs are high.

Fig 74: Frigg: evolution of natural gas reserves



-Eugene Island 330

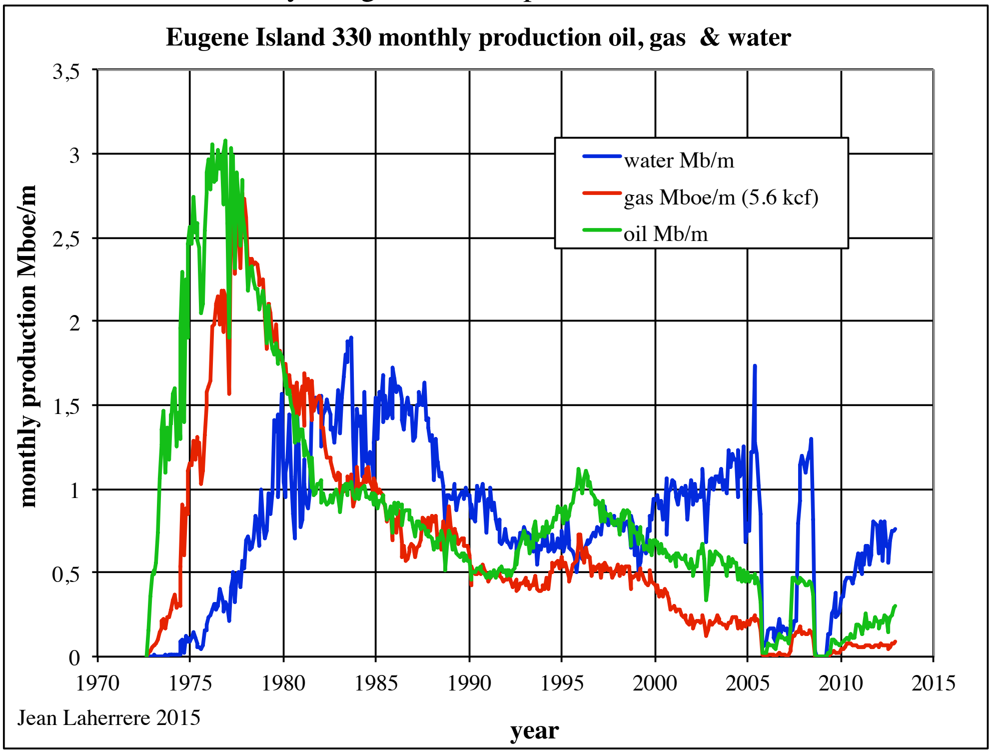
Eugene Island 330 oil field is famous because an article by Cooper 1999 in the Wall Street Journal described its apparent huge increase (from 60 Mb to 400 Mb) as an example of abiogenic source coming from the mantle, even suggesting that oil is renewable and explaining the large increase of reserves in the ME! (Laherrere 2006 ASPO 5 Pisa http://aspofrance.viabloga.com/files/JL-ASPO%205-long.pdf

From 1992 to 1996 the oil production doubled and reserves grew.

The explanation of reserve growth is easy; the field was recharged after a very drastic pressure decline from the source-rock because the reservoir is connected to the source-rock by a large fault (called the red Fault known by every university of Texas. What is done usually in thousands or millions of years what done in few years because of exceptional circumstances. But the reserve increase in EI 330 was about 10% (and not what is claimed in the Wall Street Journal), which is in fact less than the usual accuracy of a field reserve estimate (plus or minus 20%). Laherrere 2003 Copenhagen http://www.hubbertpeak.com/laherrere/Copenhagen2003.doc

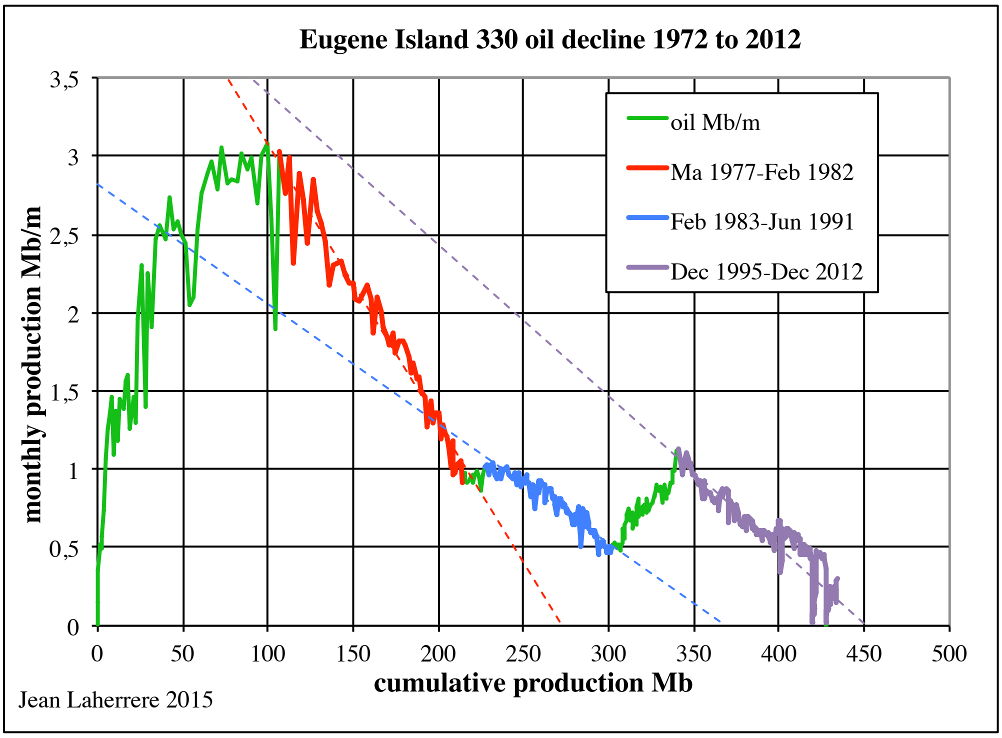
The monthly oil, gas & water productions display up to 1985 a sharp rise and a rapid decrease but beyond up to now (BOEM (former MMS) historical data stops at 2012) it was rather chaotic.

Fig 75: Eugene Island 330 monthly oil, gas & water production



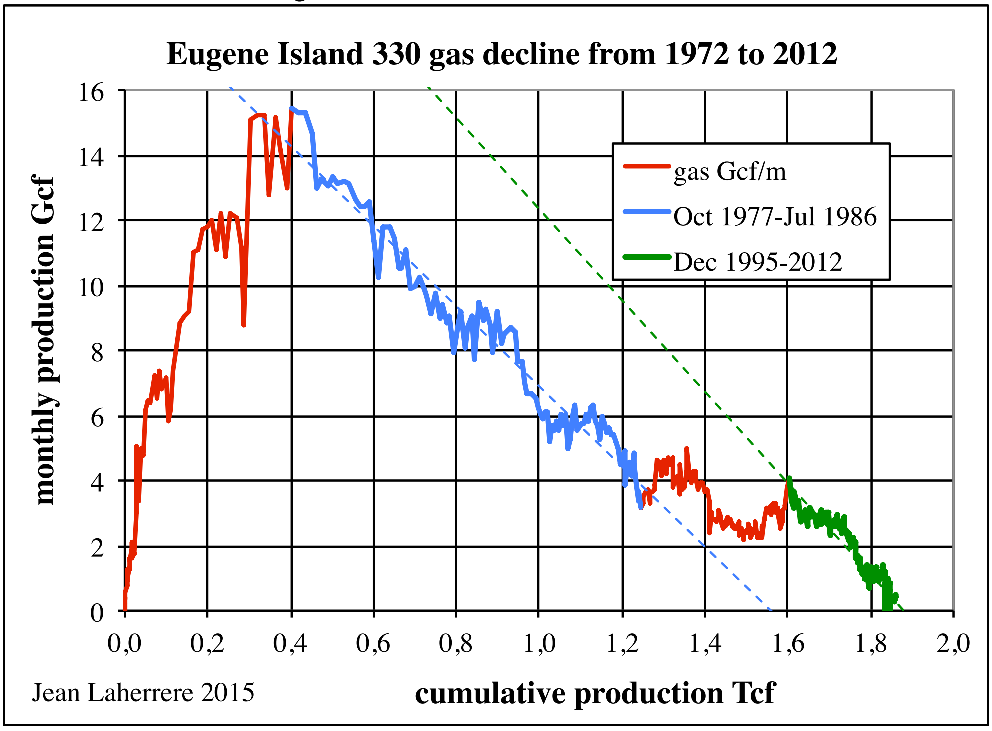
The oil decline displays three fairly long linear declines where the extrapolations increase from 270 to 360 and the last in 2012 to 450 Mb.

Fig 76: Eugene Island 330 oil decline & linear trends



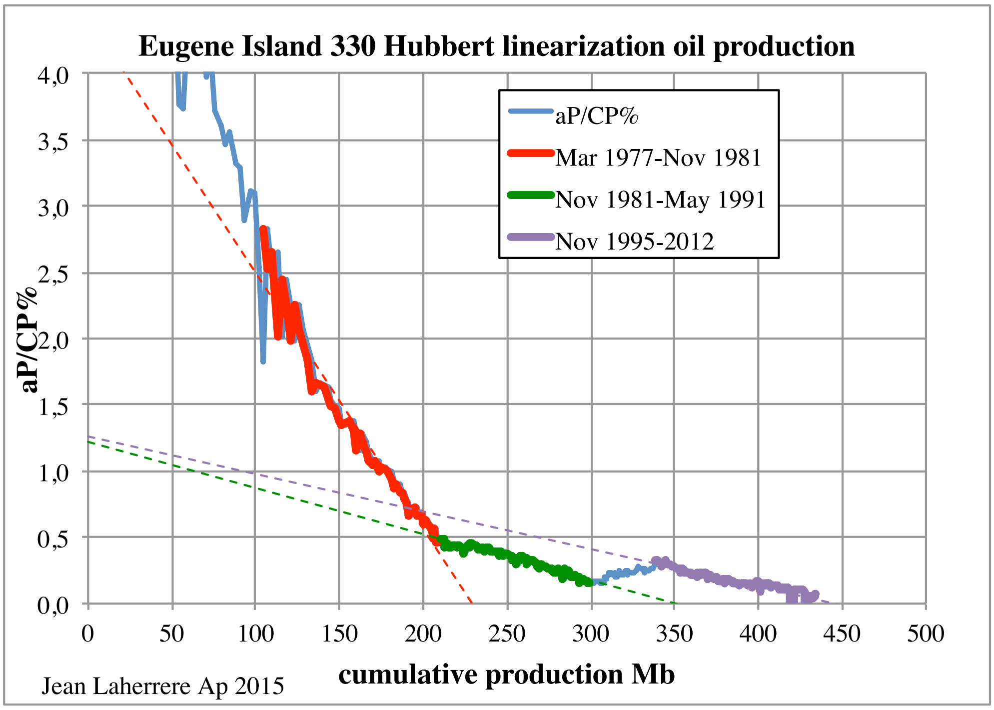
The natural gas decline displays only two linear trends.

Fig 77: Eugene Island 330 natural gas decline & linear trends



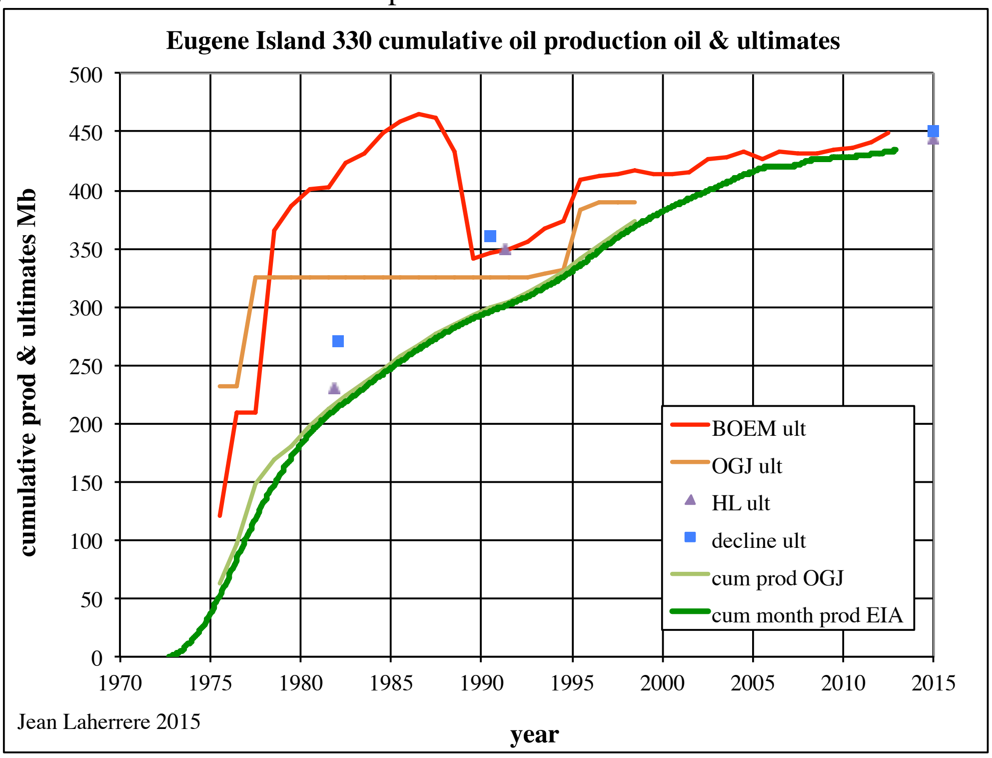
The HL oil production displays also three linear trends

Fig 78: Eugene Island 330 oil production: HL & linear trends



The plot of the cumulative oil production and the HL, decline, OGJ & BOEM ultimates show that they were in the past all bad? MMS (now BOEM) was fairly right from 1985 to 1987 but badly wrong in 1990. OGJ did increase their constant ultimate from 1978 to 1994 only when it was below the cumulative production

Fig 78: Eugene Island 330 cumulative oil production & ultimates

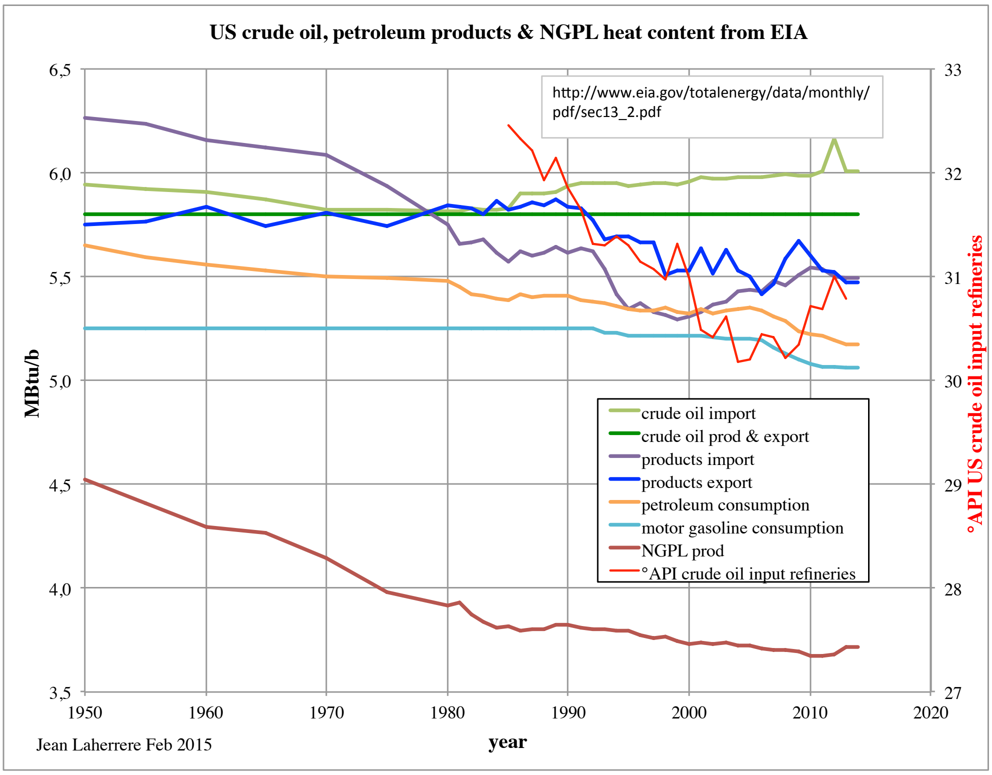


Again the published reserves data (BOEM) in federal land where data is public after few years did not perform well.

-US oil production

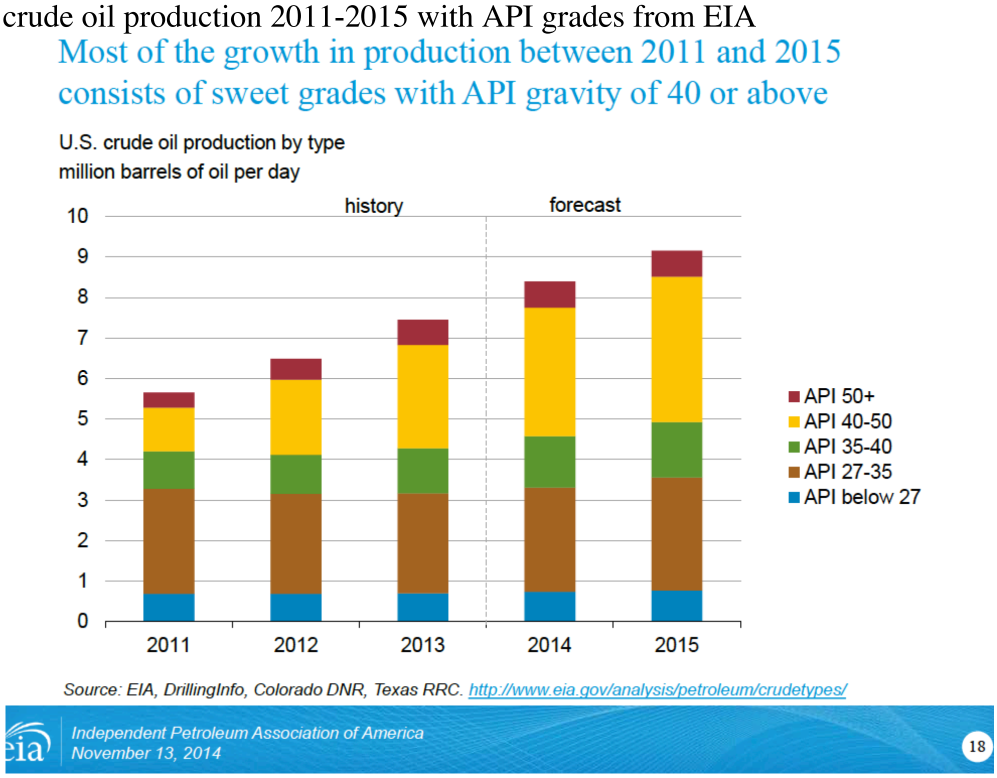
It is amazing that in the US, the crude oil production is reported including the condensate, but the crude oil price is without condensate. Furthermore there is no US legal definition of an oil barrel (EIA is obliged to add after barrel 42 US gallons because there are many definitions of barrel (the

liquid barrel is usually 31.5 gallons in the US). The definition of the gallon is different in UK (UK gallon = 1.2 US gallon), but UK reports oil production in cubic metre.
In the beginning wood barrel volume used to carry oil were between 30 and 50 gallons. In 1872 the 42 gallons unit per barrel was decided by the private Petroleum Producers Association in Pennsylvania to be 40 gallons plus 2 gallons to take care of the losses (42 gallons was the size of the traditional tierce, a wine barrel).
40 gallons barrel was for whiskey!
The steel drum is 55 US gallons or in metric country 200 L
Bbl is often used for symbol of barrel but the origin is not known: for some = blue barrel because crude barrels were painted in blue and refined barrel in red or because blue was the color of Standard of California, but for other bb is the indication of plural to avoid confusion with bl = bale!
The US government adopted the metric system in 1866 to be rid of the British system but the US people do not like to follow that the government says and they preferred to stick to old practices.
The US is the only country in the world with Burma and Liberia to not use the International system of units (known as SI or metric system)
Since 1993 all federal US agencies are obliged to use the International System of Unit (SI = metric system).
EIA AR 2007
Public Law 100–418, the Omnibus Trade and Competitiveness Act of 1988, states: "It is the declared policy of the United States—
(1) to designate the metric system of measurement as the preferred system of weights and measures for United States trade and commerce. . . .
(2) to require that each Federal agency, by the end of Fiscal Year 1992, use the metric system of measurement in its procurements, grants, and other business–related activities."{45}
In 1998 Mars Climate Orbitor was crashed (150 M$) on Mars because NASA sent the instructions to orbit the planet in SI unit but the probe was built by Lockheed, which designed the equipment in pounds.
There is no US legal definition of condensate. IEA reports condensate either as crude oil when sold with it or natural gas liquid when sold with them, it is why there is a 2 Mb/d discrepancy between world NGL between EIA and IEA.
In many countries oil is measured by weight, but in the US it is not possible to get a measure of the US production in weight or even in energy.
EIA reports US oil production in energy (quad) but in using a constant heat content which was decided in 1950 and stay constant up to now (5.8 MBtu/b) when the heat content of imported barrel has changed as the NGPL (natural gas plant liquids from 4.5 to 3.7)). The heat content of gasoline is down since 1991.
Fig 79: US crude oil, petroleum products & NGPL heat content



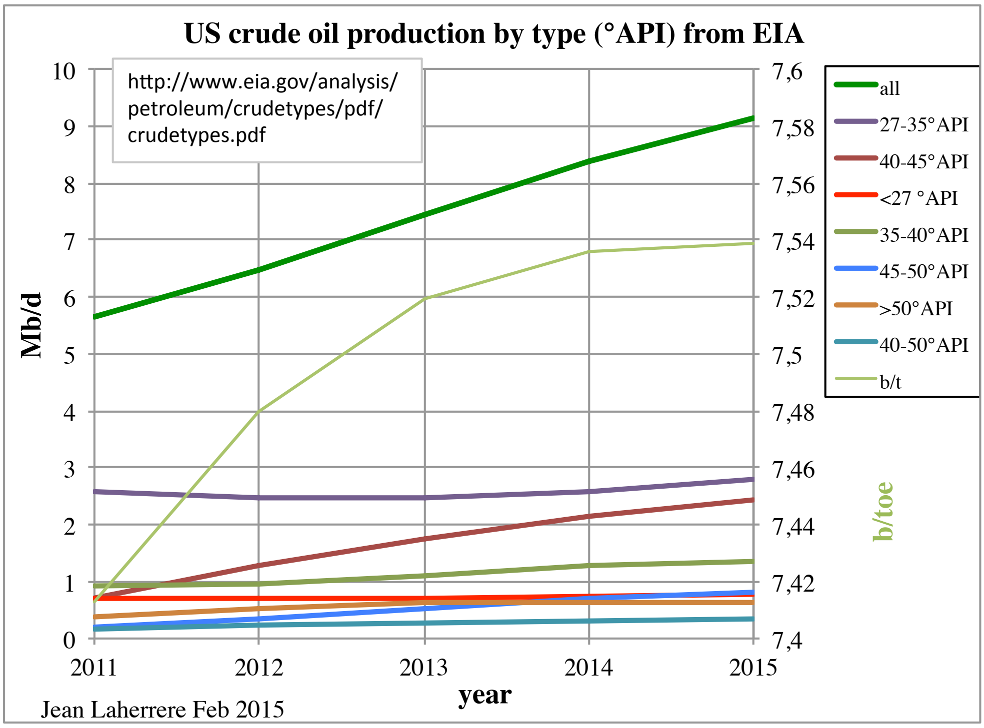
EIA has just recently reported US production volume by API since 2011 to 2015 (2014 & 2015 being forecast) but EIA has not the data before 2011 because EIA relies on State data and States do provide gravity of their oil production.

Fig 79: US crude oil production 2011-2015 with API grades from EIA



EIA production by type from 2011 to 2015 shows that 40-45°API production has increased from 0,7 Mb/d to 2,5 Mb/d when <27°API went from 0,7 to 0,8 Mb/d and 27-35°API from 2.6 to 2.8 Mb/d. One good indicator of energy is the number of barrel in a tonne oil equivalent = b/toe: its value goes from 7.42 to 7.54 from 2011 to 2015

Fig 80: US crude oil production per type from EIA & b/toe

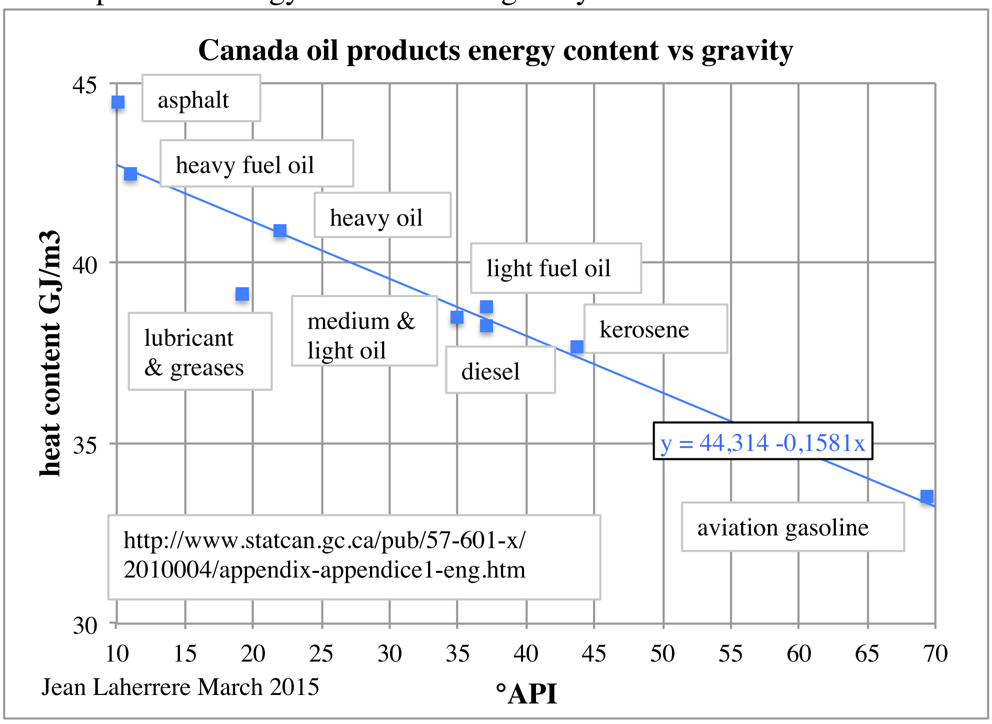


EIA does not furnish any correlation between API gravity and heat content. Using data from Canada and from Chevron the following correlation is taken, as

GJ/m3 = 44,3 - 0,16 °API   or

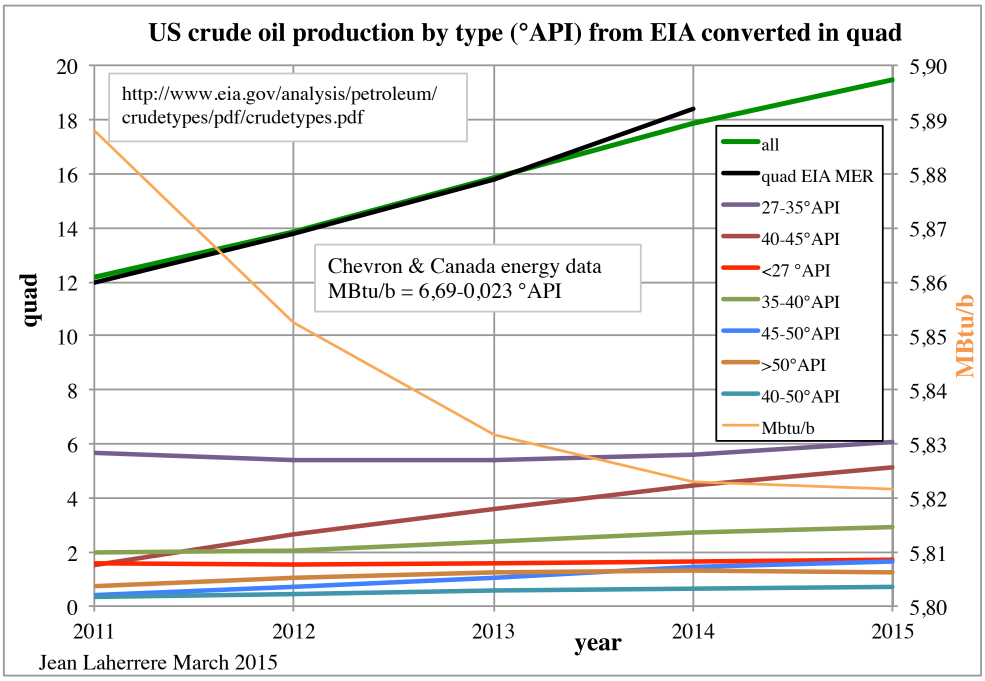
Mbtu/b = 6.69 – 0.023 °API

Fig 81: Canada oil products energy content versus gravity °API



With such equation it is possible to transform the EIA production 2011-2015 data by °API into energy (quad)

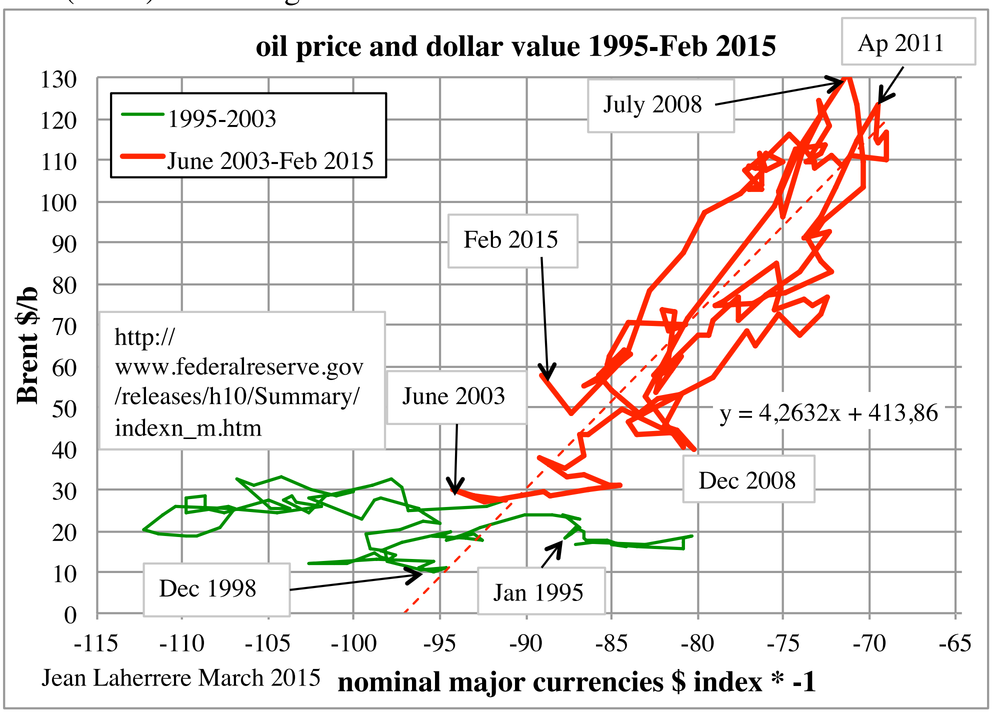
Fig 82: US crude oil production by type (°API) from EIA converted in quad



The result is that the real heat content of the US crude production was in 2011 5.89 Mbtu/b and will be in 2015 only 5.82 Mbtu/b. EIA MER forecast for 2014 is 18.37 quad using the constant heat content of 5.8 Mbtu/b but in fact it should be 17.84 quad: it is 3% too high, because poor practice in heat content.

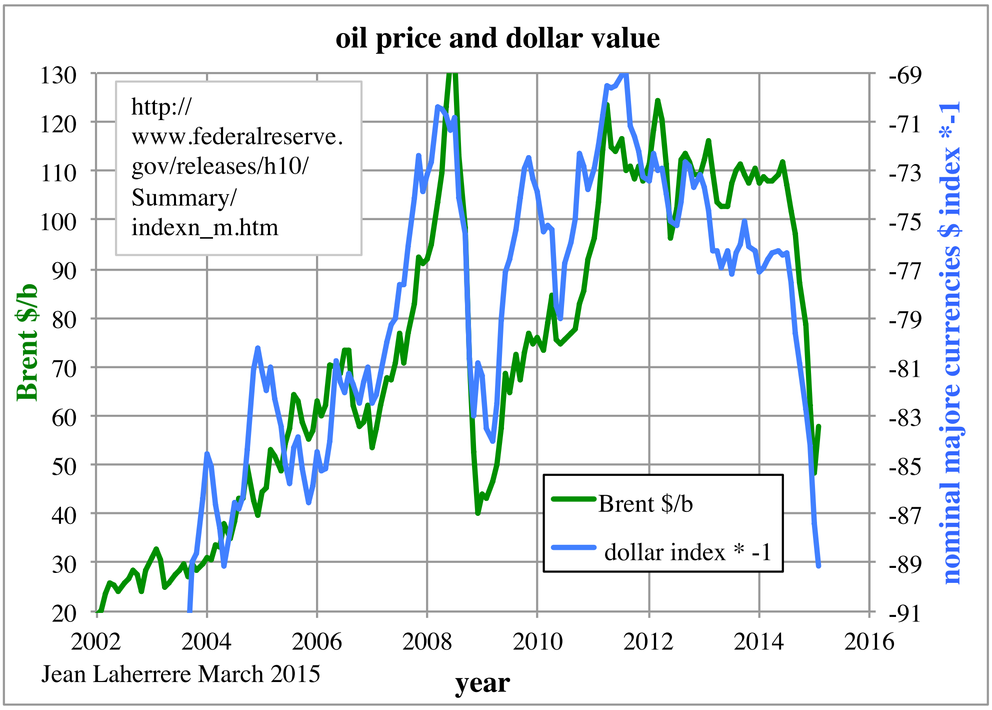
Oil price is down for two reasons; the heat content is down and the dollar value is up
Using the dollar value against major currencies (scale in negative growth) against the Brent oil price from 1995 to 2015 it is obvious that since 2003 the oil price goes up when the dollar index goes down

Fig 83: oil price (Brent) versus negative dollar value 1995-2015



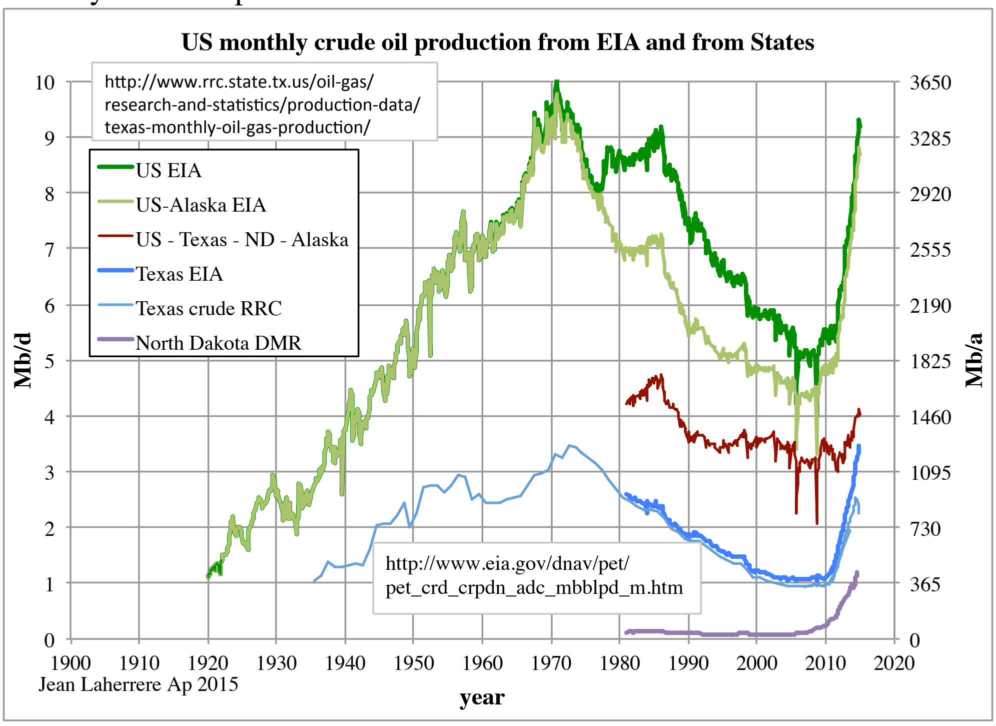
The plot of Brent oil price and the dollar index multiplied by -1 looks a good fit. To return to 100 $/b the dollar index should d go down to 75

Fig 84: oil price (Brent) and dollar value 2002-2015



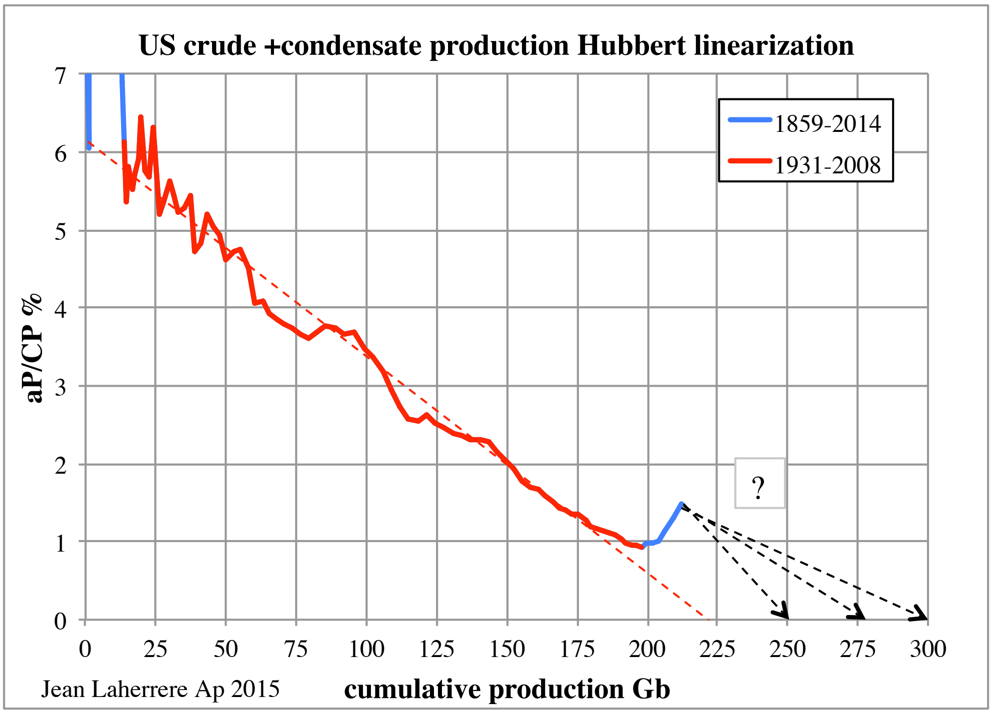
The US crude oil (including condensate) from EIA is plotted with the production of Alaska, Texas and North Dakota The US production excluding Alaska, Texas & North Dakota (brown) is since 1990 between 3 and 4 Mb/d. The US production increase since 2011 comes mainly from Texas and North Dakota (but also deepwater)

Fig 85: US monthly crude oil production from EIA and from States



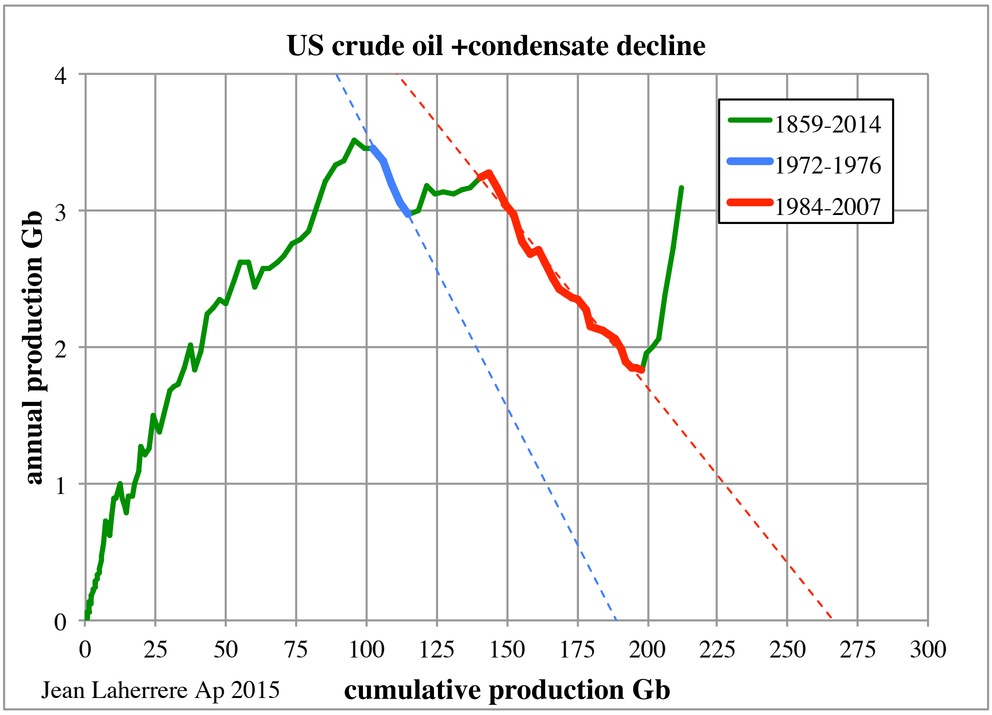
The HL of crude +condensate US production displays from 1931 to 2008 a fairly linear trend towards 225 Gb, but the increase from 2008 to 2014 change the extrapolation, assuming the same slope the ultimate could be 275 Gb, adding 50 Gb coming from the LTO. We have seen above that the ultimates of Bakken and Eagle Ford are less than 10 Gb so 275 seems too high, but the recent past shows that high oil prices can do miracles!

Fig 86: US crude oil + condensate production: HL & linear trends



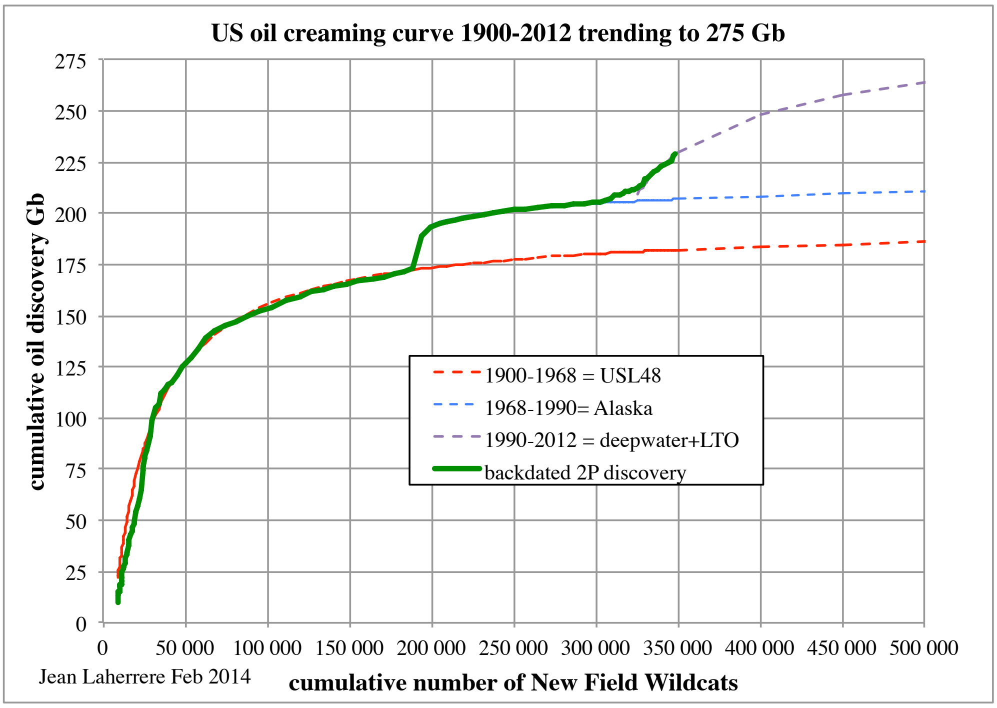
The crude oil + condensate decline displays two linear trends and the last one for 1984 to 2007 trends towards 270 Gb.

Fig 87: US crude oil + condensate decline & linear trends



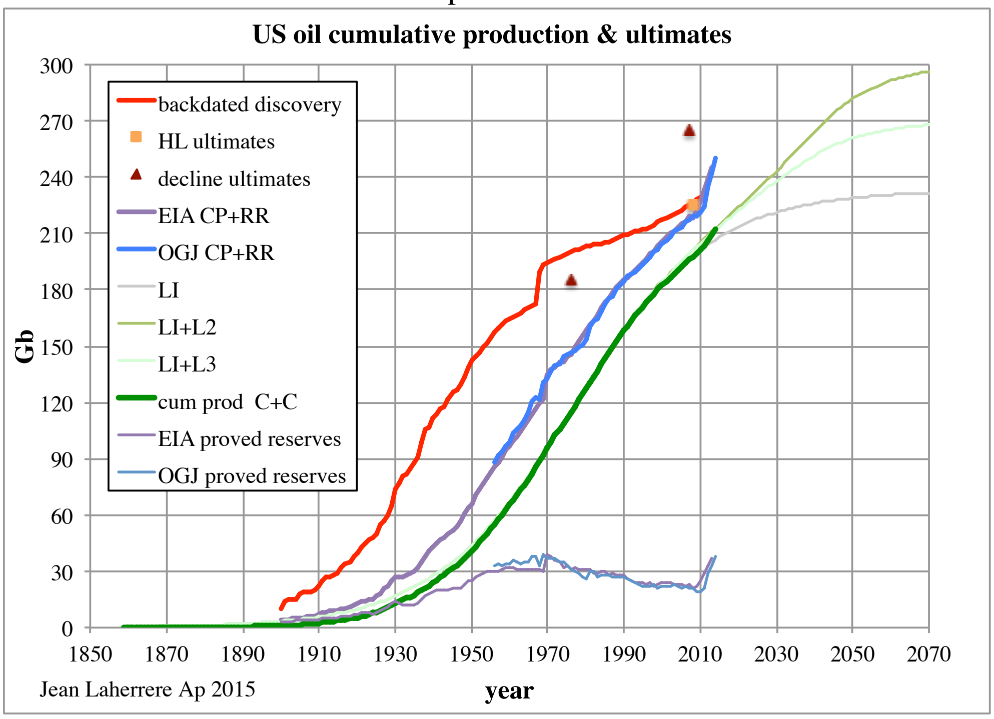
The US creaming curve using backdated 2P discovery versus new field wildcats is extrapolated towards 275 Gb

Fig 88: US oil creaming curve 1900-2012 trending to 275 Gb



The plot of the cumulative production and HL, decline, EIA, OGJ ultimates as backdated discovery (from EIA534). A logistic modeling with two cycles towards 270 and 300 Gb is added.

Fig 89: US crude oil + condensate cumulative production & ultimates



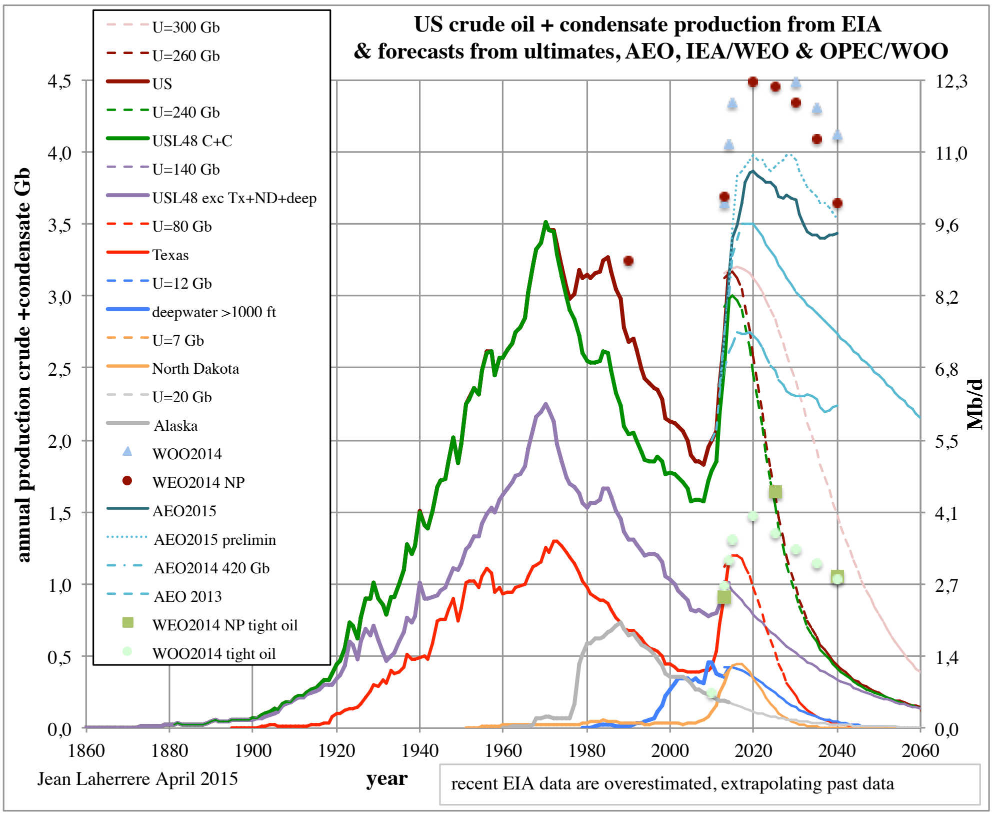
The US annual crude oil +condensate production with breakdown of Alaska, Texas, North Dakota as deepwater is forecasted with their ultimates, giving an US ultimate of 260 Gb (dark brown), which peaks in 2016 with a sharp decline down to 7 Mb/d on 2020.

A possible 300 Gb ultimate is added (light brown) with 8.5 in 2020. The forecasts by EIA/AEO, IEA/WEO and OPEC/WOO are added. The AEO 2015 forecasts 10.7 Mb/d in 2020 (AEO 2013 was only 7.5 Mb/d).

EIA/AEO 2015 was higher than AEO 2014 but lower than the preliminary AEO 2015(unofficial)!

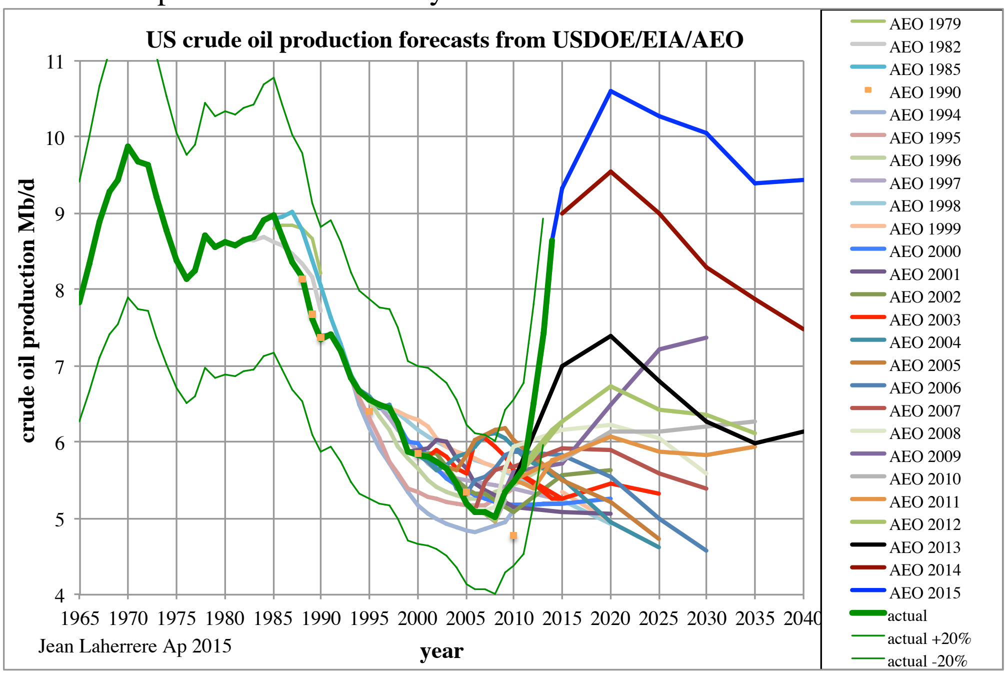
IEA/WEO 2014 NP forecasts 12.3 Mb/d in 2020. It looks to me as wishful thinking!

Fig 90: US crude oil + condensate annual production & forecasts from ultimates, EIA, IEA & OPEC



The forecasts on US oil production by EIA/AEO from 1979 to 2015 show that EIA was wrong by more than 20 %: too optimistic like in 1995, too pessimistic like in 2005

Fig 91: US crude oil production forecast by EIA/AEO from 1979 to 2015

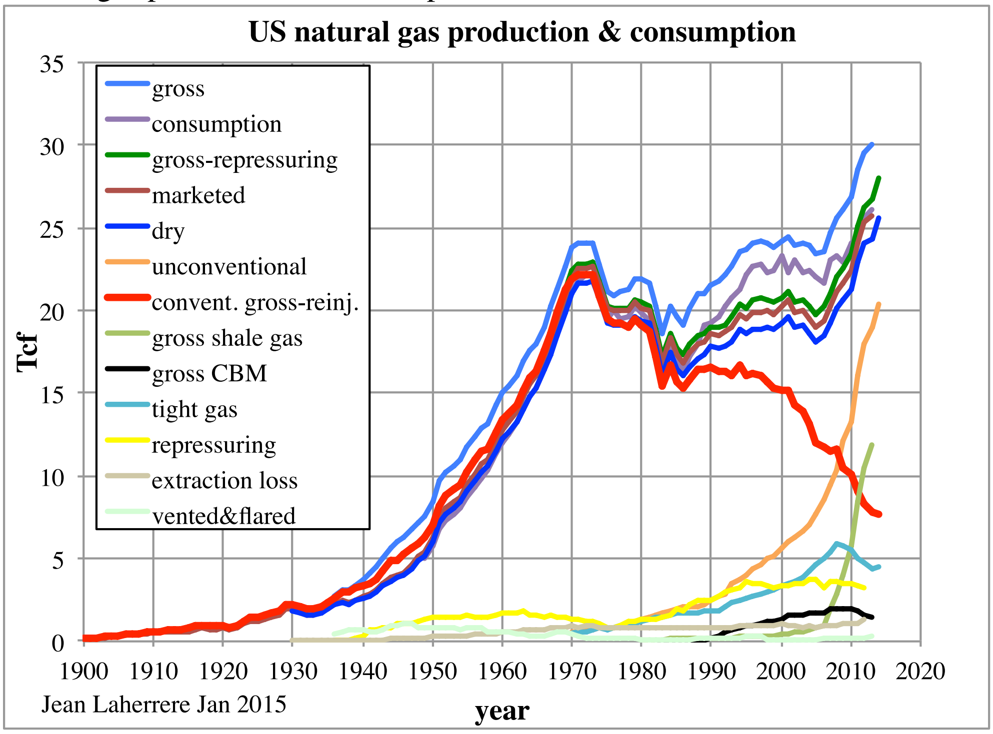


-US NG production

Most of official NG forecasts are for the dry production, which is removed from the reserves, forgetting the losses as vented or flared or liquids extraction. Production to be removed from reserves should be gross less reinjected volumes (dark green in the graph below), which increases since 2005.

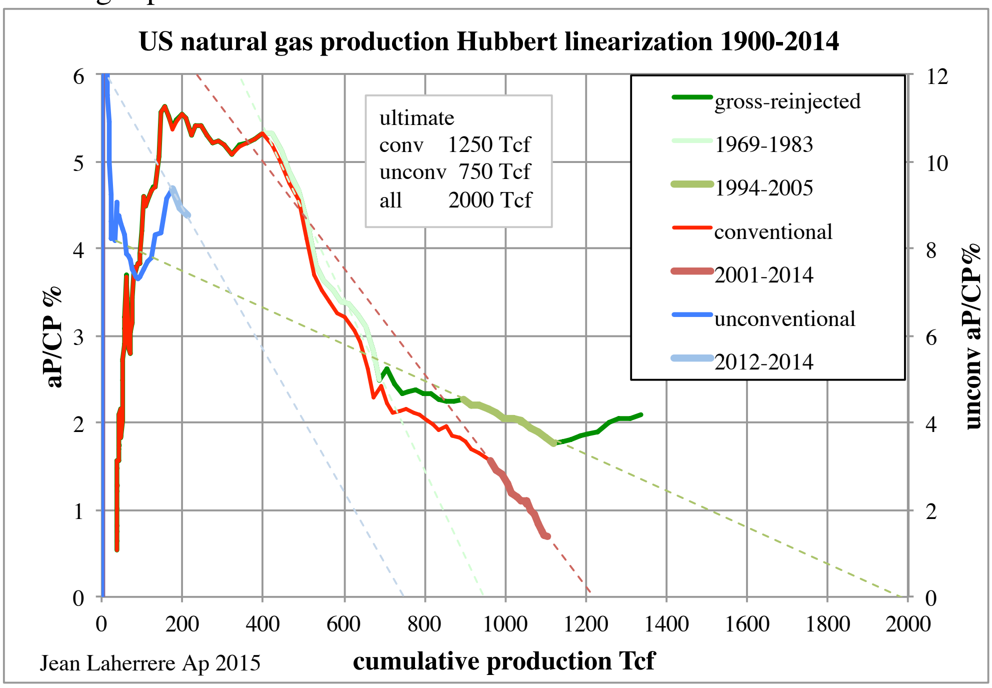
The conventional gross-reinjected (red curve) is on the decline since 1995

Fig 92: US natural gas production & consumption



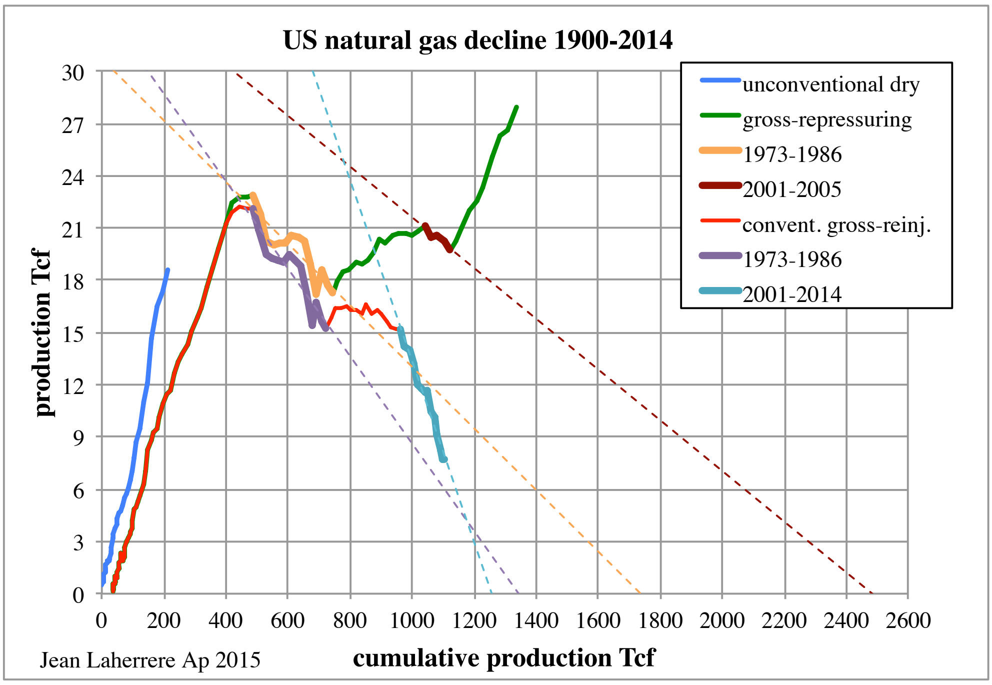
The HL of the US gross less reinjected production displays two linear trend, the last one 1994-2005 trends towards 2000 Tcf. The unconventional (blue) HL trend (2012-2014) trends towards 750 Tcf and the conventional HL trend (red) towards 1250 Tcf, in good agreement with the global being 2000 Tcf = 1250 + 750

Fig 93: US natural gas production: HL & linear trends

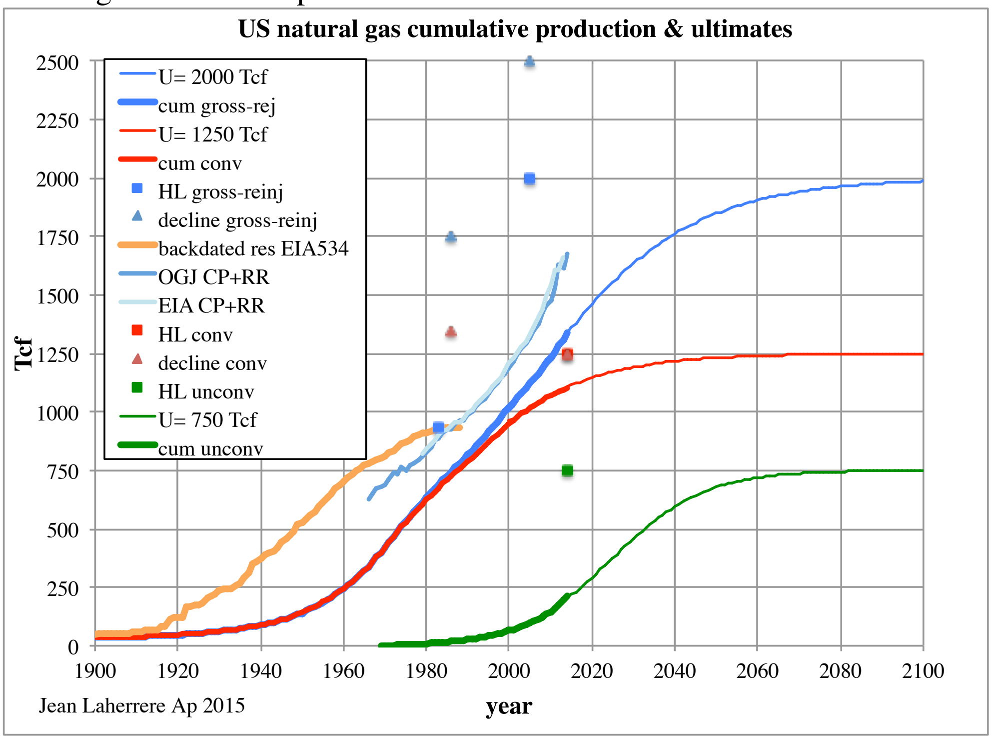


The US conventional NG decline (red) displays two linear trends towards 1250 and 1300 Tcf. The gross-reinjected decline displays two trends towards 1700 and 2500 Tcf, in line with the HL 2000 Tcf last ultimate.

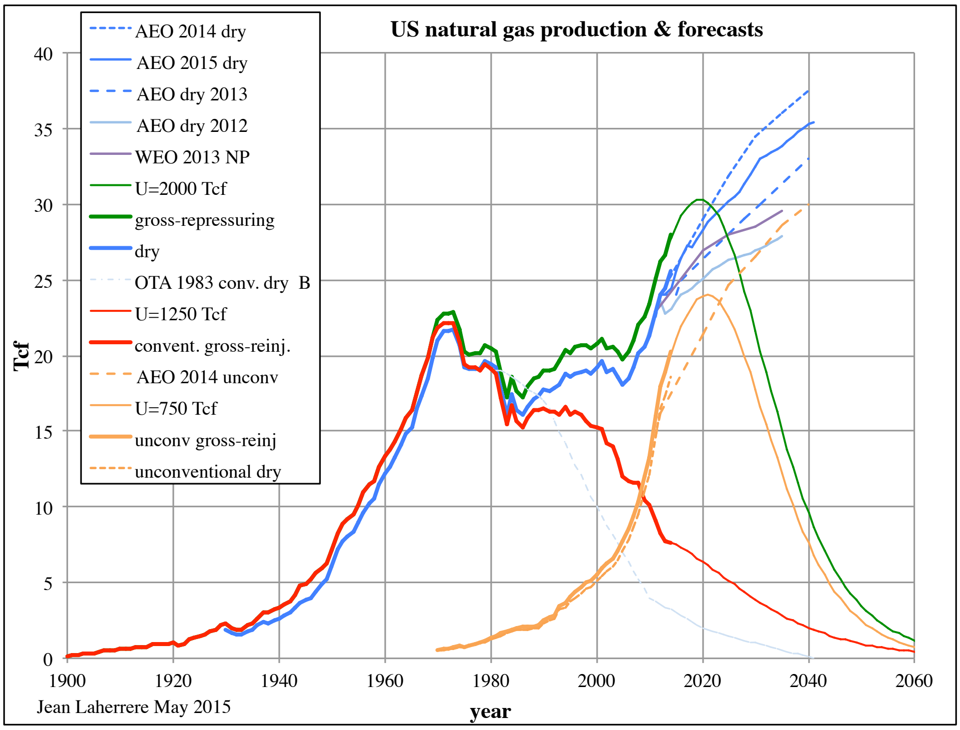
Fig 94: US natural gas decline & linear trends



The plot of the cumulative NG production (unconventional, conventional and global gross-reinjected) and HL, decline, backdated (orange parallel to cumulative production red up to 1960), OGJ and EIA ultimates is added with the logistic forecast for an ultimate of 750 Tcf unconventional, 1250 Tcf conventional and 2000 Tcf for the total.
The use of round values means that the uncertainty is large and that any other value with a difference of less than 10% does not matter!
Fig 95: US natural gas cumulative production & ultimates

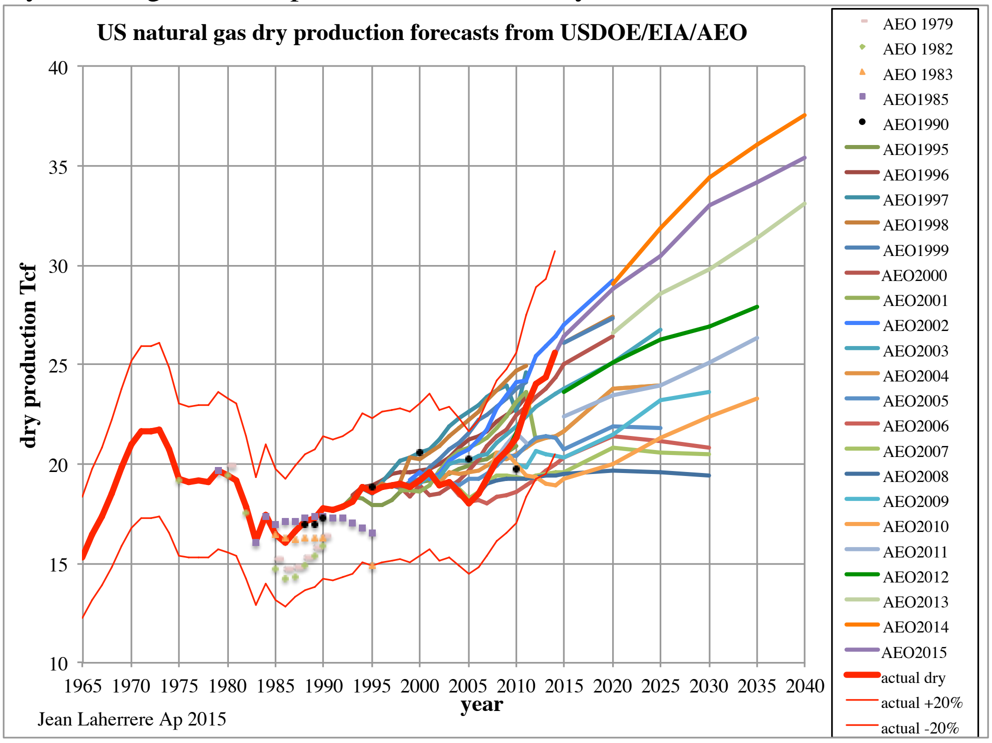


US annual NG production is modeled with the above ultimates and compared with the forecasts by EIA/AEO 20012 to 2015 as IEA/WEO 2013 NP and OTA 1983. AEO increases from 20102 to 2014 but decreases in 2015
We forecast a peak of US NG production around 2020 at 30 Tcf in line with AEO 2015, but beyond our forecast declines, when EIA is still rising with no peak ahead!
Fig 96: US natural gas annual production & forecasts 1900-2060



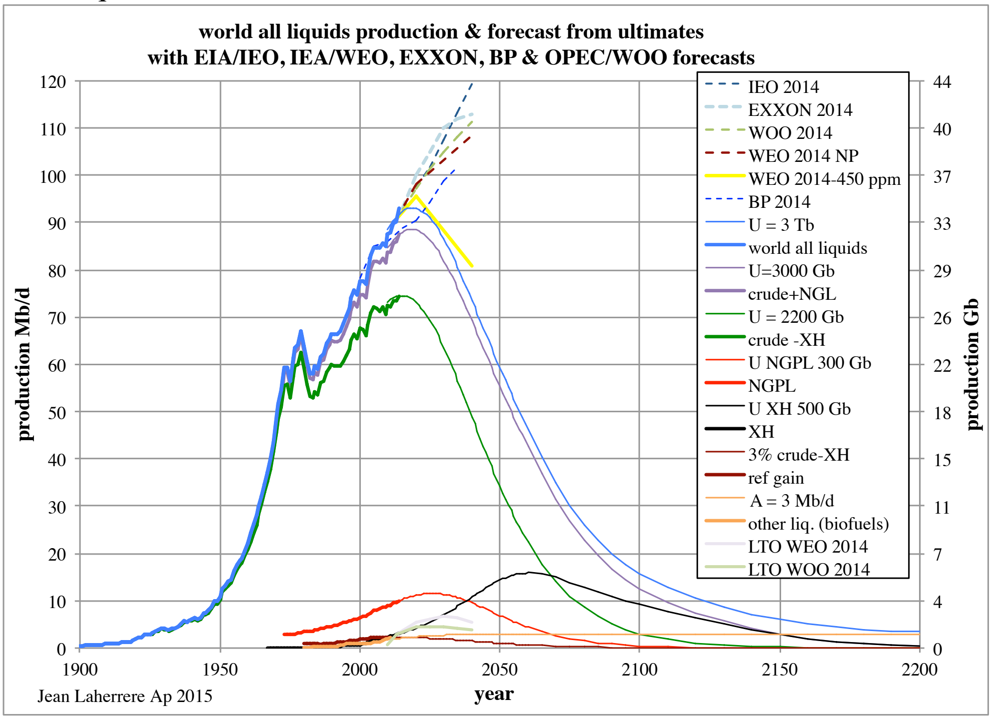
What goes up will come down, the question is about the slope of the decline.
It is interesting to see the slope of the number of US rigs in plotting in a log scale. The number of gas rigs (red) has a rise (1993-2009) of about 10% per year and a fall (2009-2014) of about 20% per year: it is the rise and the slope of the US rig

EIA in their AEO forecasts on US NG production were not too good, being more than 20% wrong from real: too optimistic in 1995 too pessimistic in 2004
Fig 97: US dry natural gas annual production forecasts by EIA/AEO from 1979 to 2015

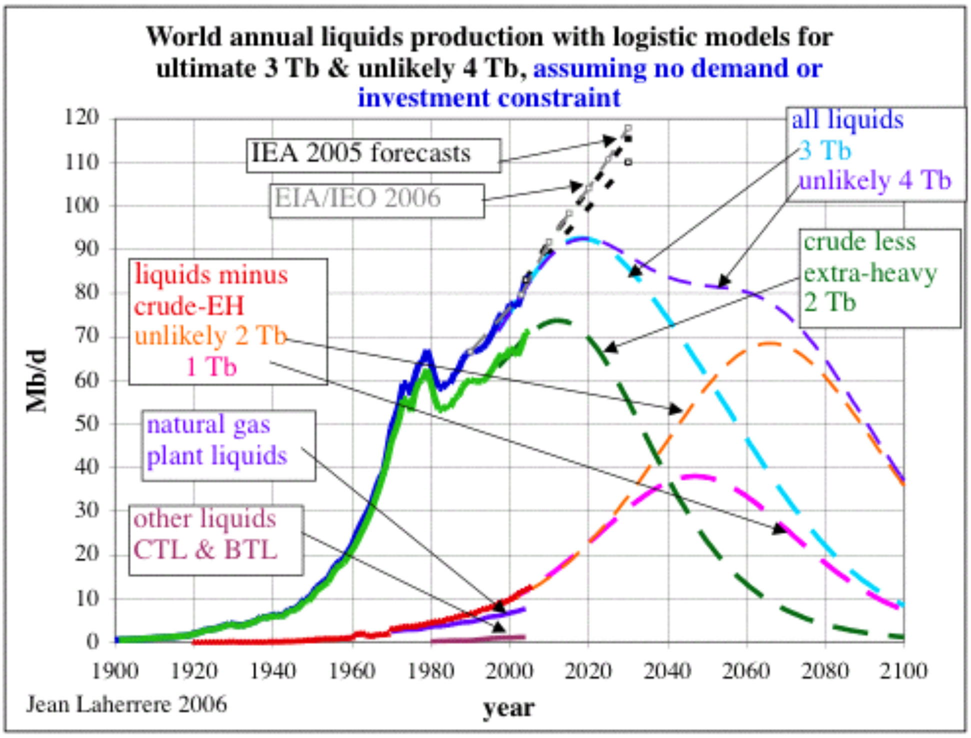


-world crude oil production

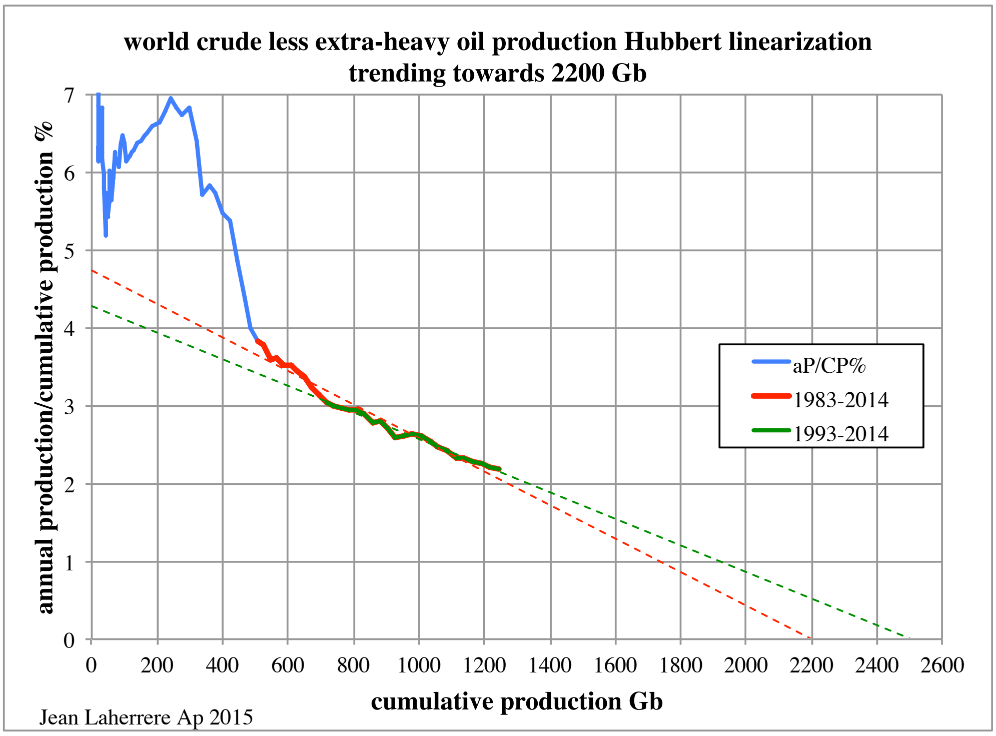
The world all liquids production is forecasted in Mb/d and Gb with the breakdown of crude oil less extra heavy (U=2200 Gb), extra-heavy (U=500 Gb), NGPL (U=300 Gb), crude + NGL (U= 3000 Gb). The all liquids need to add the refinery gain (gain in volume but not in energy or weight)
Fig 98: world all liquids & forecasts from ultimates, EIA, IEA, BP, OPEC



My 2015 forecast is not far from my 2006 forecast (ASPO 5 http://aspofrance.viabloga.com/files/JL-ASPO%205-long.pdf)
2006 Figure 61

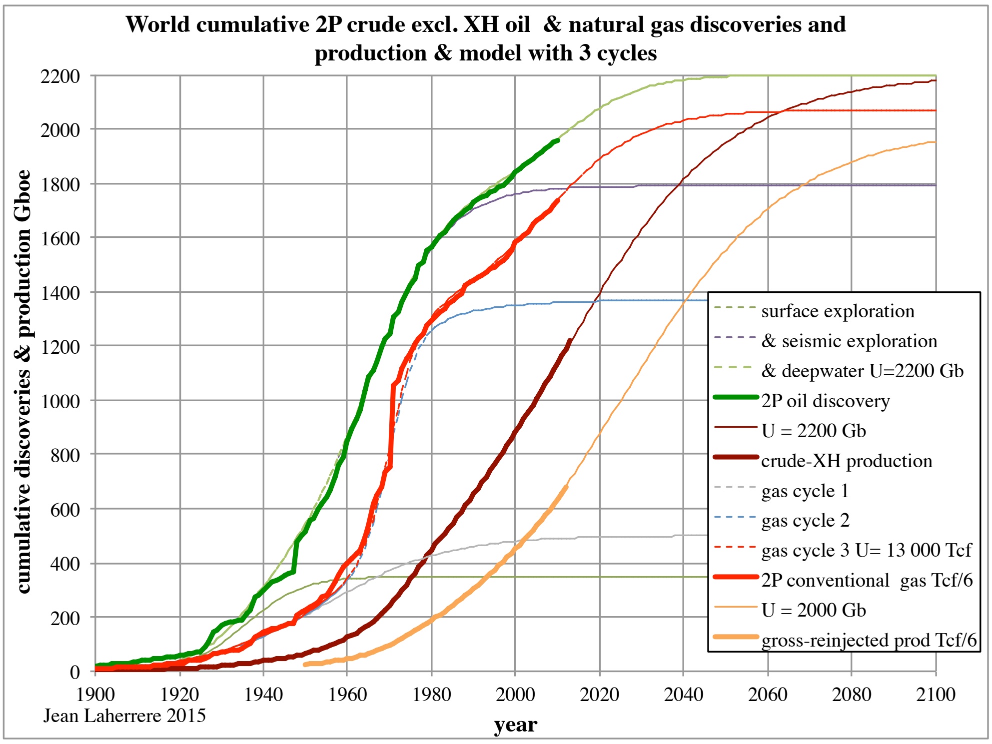


HL of crude oil less extra-heavy (Athabasca and Orinoco) could be extrapolated for the period 1983-2014 towards 2200 Gb but towards 2500 Gb for the period 1993-2014.
Fig 99: world crude less extra heavy oil production: HL & linear trends



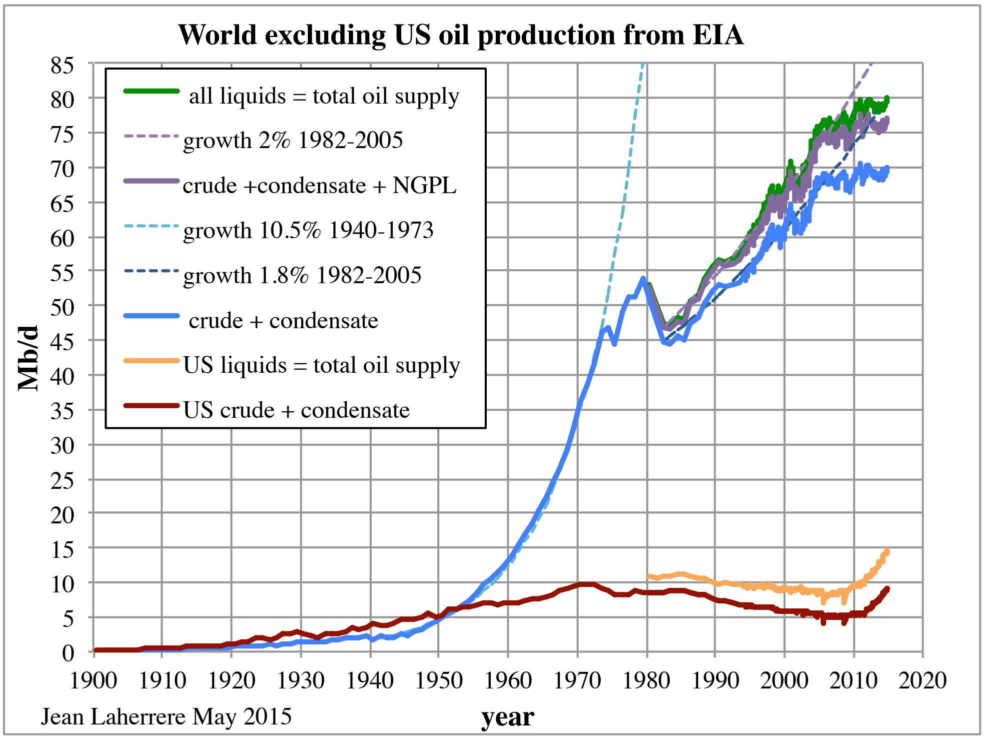
We prefer the first ultimate of 2200 Gb in line with the extrapolation of backdated discoveries

Fig 100: world cumulative crude less extra heavy oil & natural gas discoveries & production & logistic model



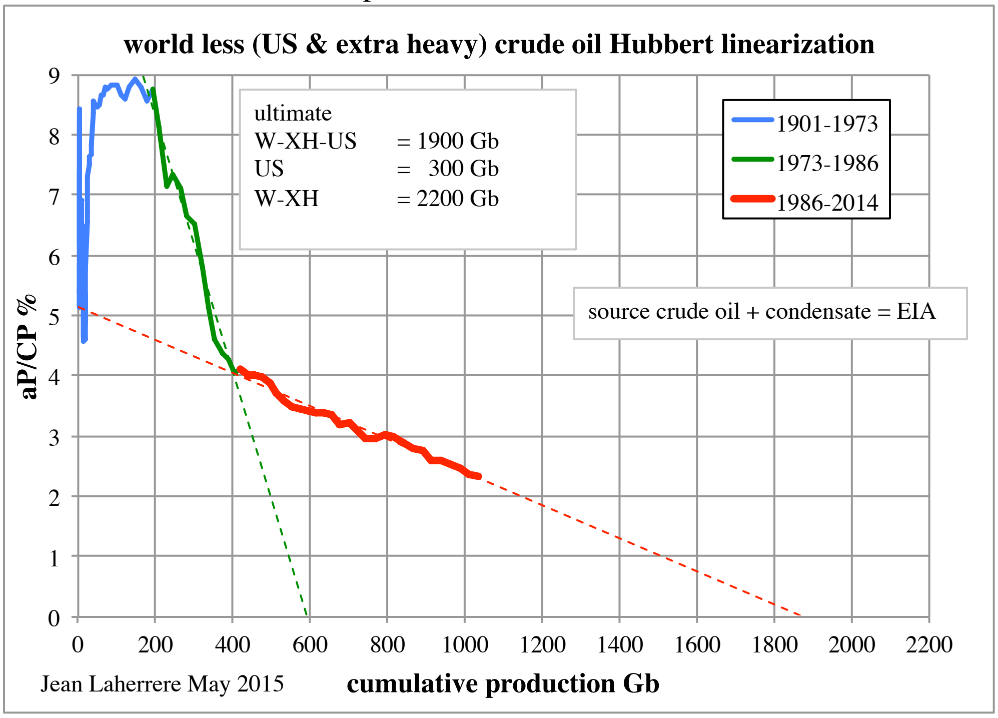
World crude oil production is disturbed since 2009 by US LTO production and the world excluding US crude oil production (in blue) displays a plateau since 2005

Fig 101: world excluding US oil production from EIA



The HL of World less US and extra heavy crude oil production displays two linear trends: 1973-1986 trending towards 600 Gb and 1986-2014 trending towards 1900 Gb.

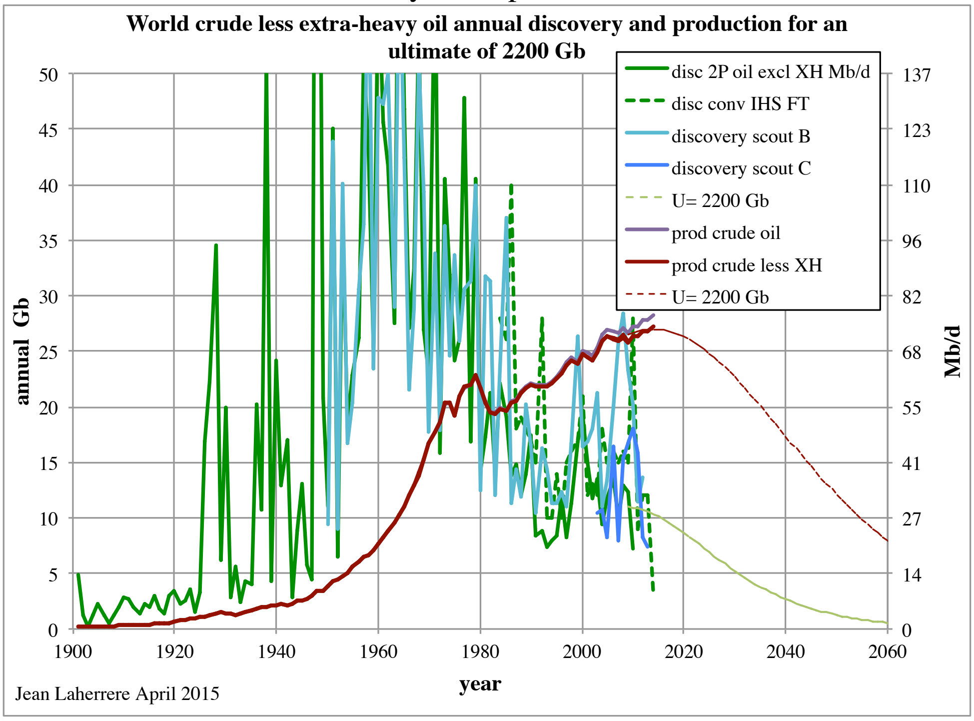
Fig 102: world less US & XH crude oil production HL



As US ultimate crude ultimate is around 300 Gb the world excluding XH ultimate is about 1900 +300 = 2200 Gb. This estimate from fig 102 based on a clear linear trend duting 28 years is much more reliable than the estimate from fig 99 where the trend is crooked because the US and stands for a shorter period.

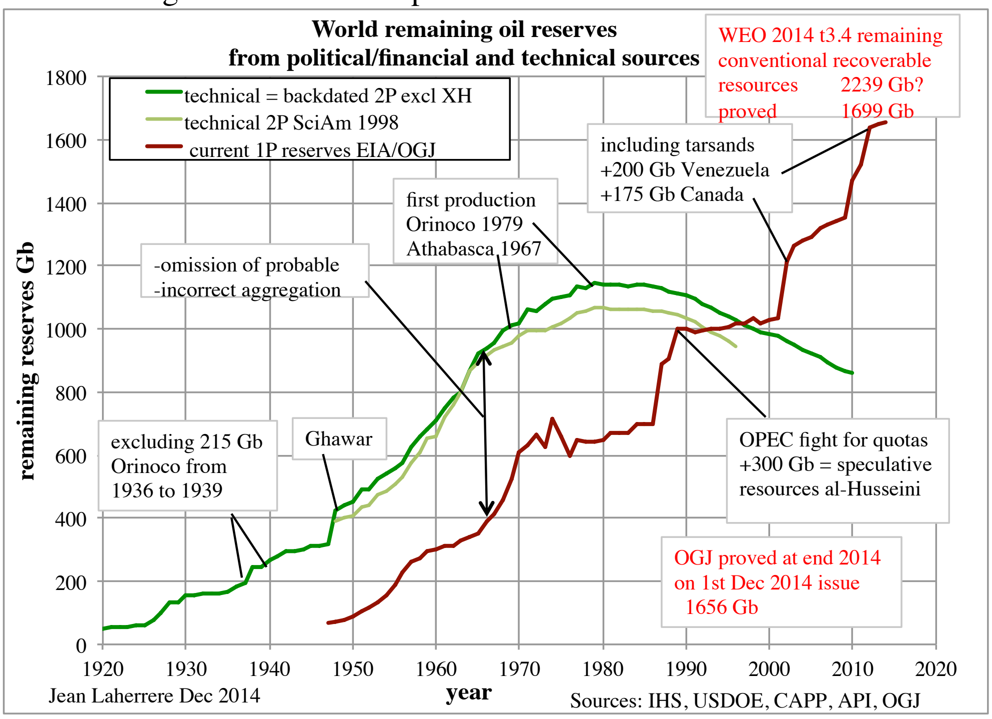
The annual discovery of crude less extra-heavy oil is plotted from the databases of three different scout companies and compared to the annual production with forecast for an ultimate of 2200 Gb. It is obvious that since 1990 annual production is larger than the annual discovery, meaning that the remaining reserves must decrease as shown in figure 102. The average oil discovery for the last 3 years is about 10 Gb compared to a production of 28 Gb = about one third!

Fig 103: world annual crude less extra heavy oil & production & model for an ultimate of 2200 Gb



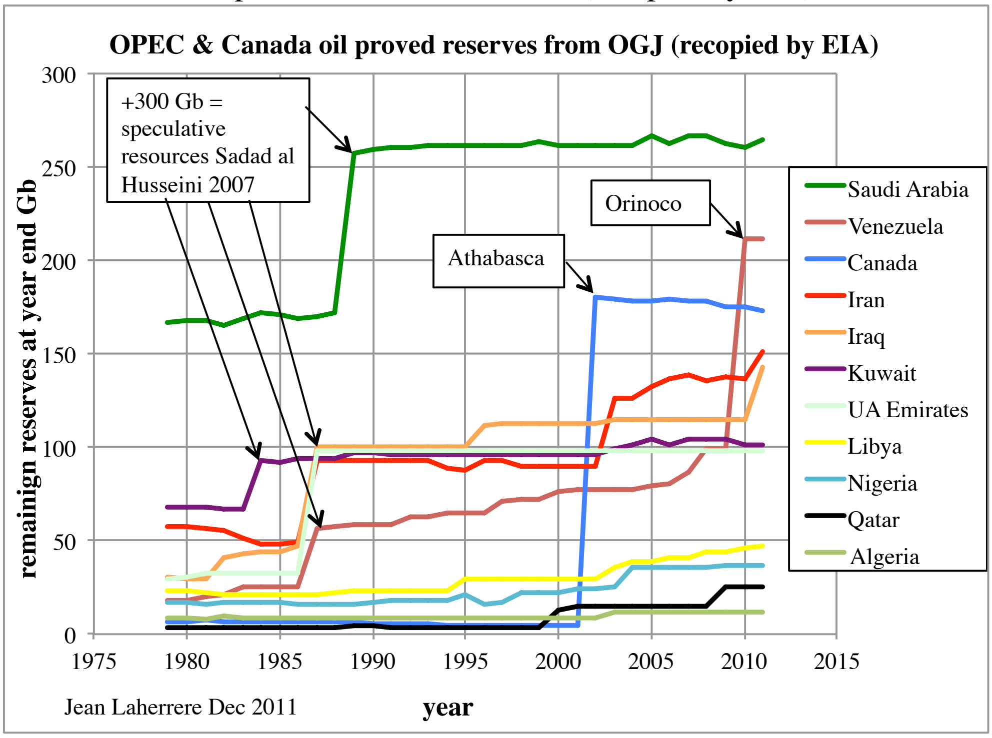
The backdated 2P crude oil less extra-heavy remaining reserves has peaked in 1980, but the current 1P political/financial reserves has been rising since 1950 with irrational bump like from 1986 to 1989 a bump of 300 Gb because the fight between OPEC members on quotas (qualified by al-Husseini former Aramco VP as speculative resources) or in

Fig 104: world remaining oil reserves from political/financial and technical sources



The detail of OPEC & Canada reserves published by OGJ (recopied by EIA) shows the jump in reserves due to political stands and not from discoveries. To add confusion OGJ publishes its inquiry done in the fall in December as being on the first of the following year, when reserves should be quoted at the end of the year. Countries, which do not answer OGJ enquiry, are assumed to have the same reserves as last year as if annual discoveries have exactly replaced annual production. On the last publication (OGJ Dec 1, 2014) for January 1, 2015, 66 countries out of a total of 106 report no change! It is a joke, but it is the Bible for many!

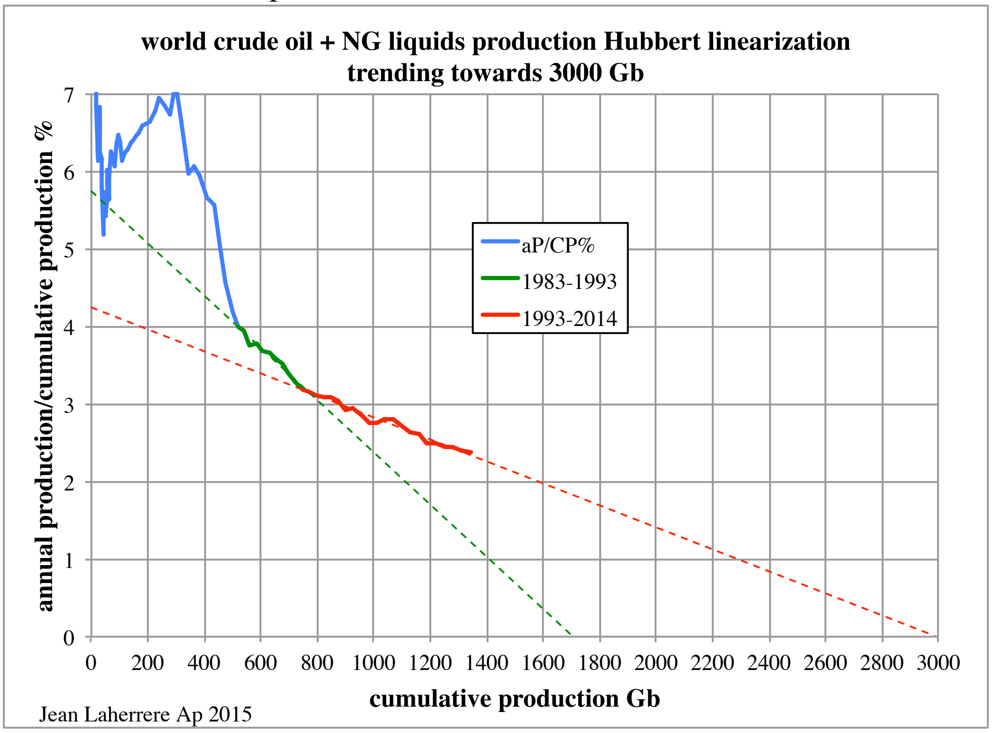
Fig 105: OPEC & Canada oil proved reserves from OGJ (recopied by EIA) 1979-2011



Because OPEC members lie on reserves to get the highest quota, they lie on production. The OPEC monthly report displays two production tables for OPEC members: the first one table 5.8 based on secondary sources report for March 15, 2015 OPEC production of 30.786 Mb/d, but table 5.9 based on direct communication (from OPEC members?) report 31.488 Mb/d (+2.3 %); for Venezuela it was 2.35 and 2.729 Mb/d (+16%). OPEC data is not reliable.

The HL of crude +NGL trends towards 3000 Gb for the last trend (1993-2014) being in line with the aggregation of the above trends

Fig 106: world crude oil + NGL production: HL & linear trends

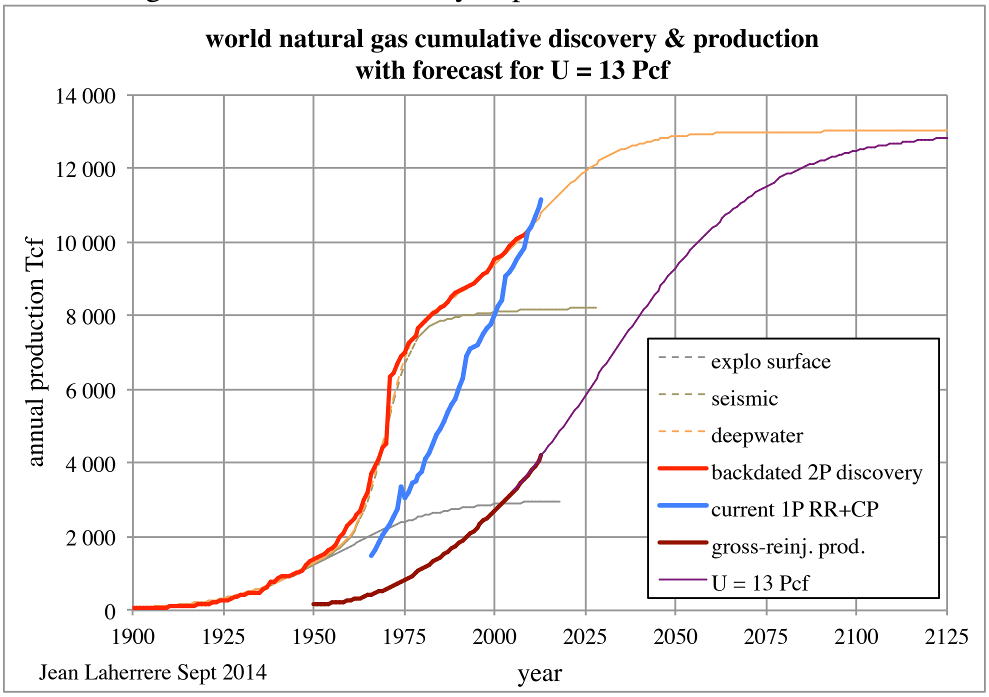


Each method of estimating ultimates is uncertain, but by combining several approaches (production and discoveries) we feel more confident in our choice of ultimates. Again our choice is for round value and this round value covers any value around within 10 to 20%. Ten years ago our ultimate for world less extra-heavy was 2000 Gb (only one significant digit) and it is only recently that because deepwater and LTO that we increase the value to 2200 Gb. We will keep this value until new data convinces me in the future to move to a higher value like 2500 Gb or to return to 2000 Gb.

-world natural gas production

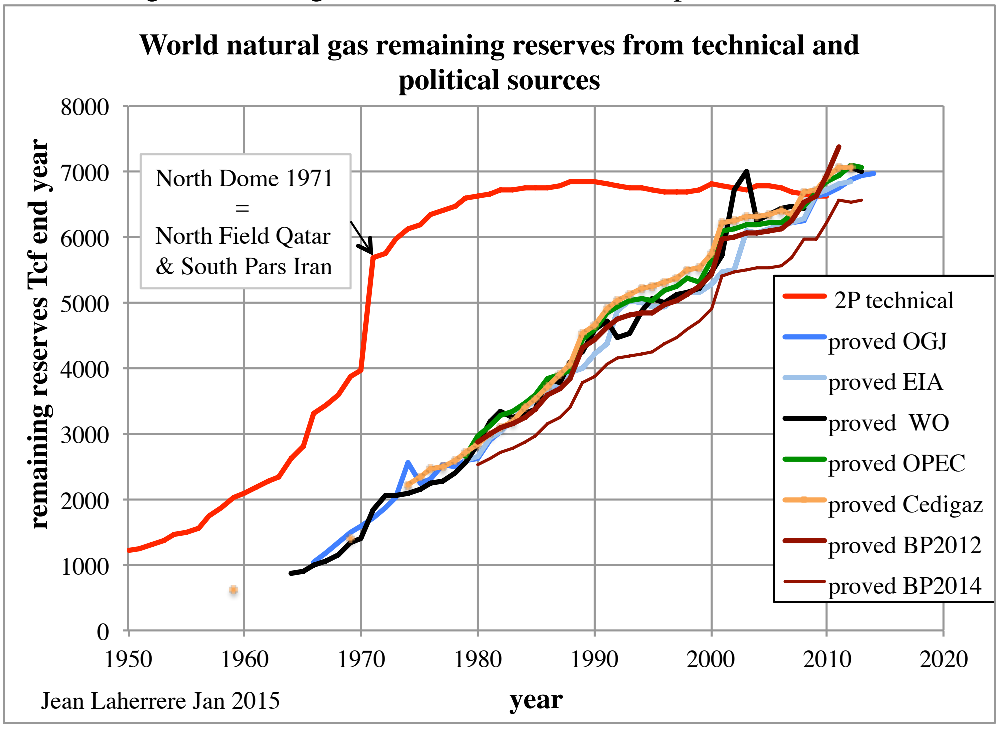
Ten years ago my world NG ultimate was 12 000 Tcf and to day it is 13 000 Tcf as shown in the cumulative backdated discoveries modeling, but both values are as good for this graph

Fig 107: world natural gas cumulative discovery & production & forecast U = 13 Pcf

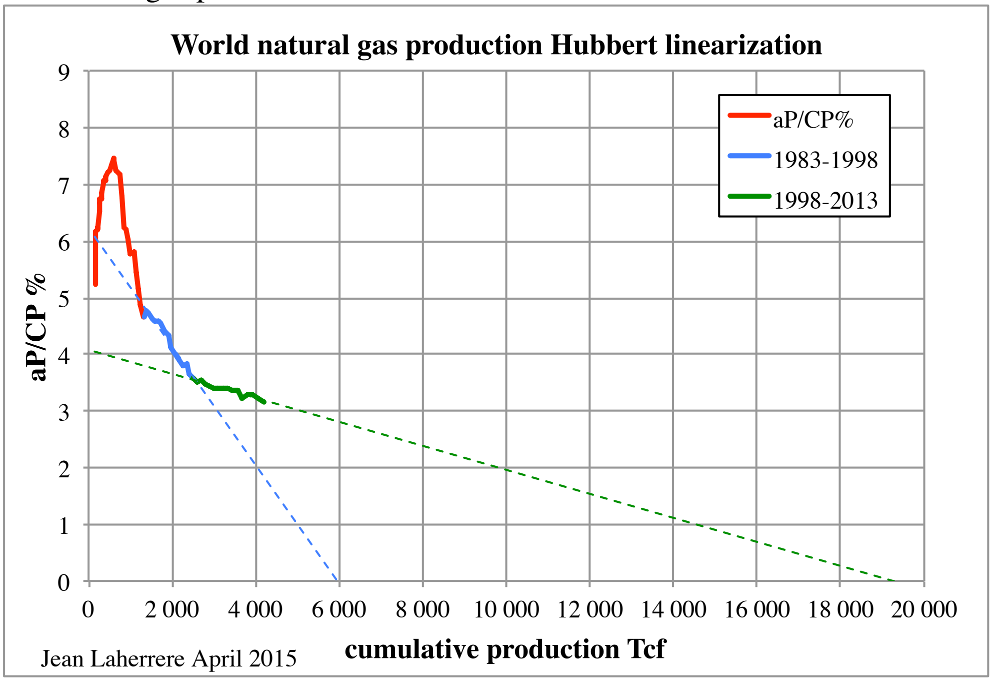


World remaining reserves vary with sources

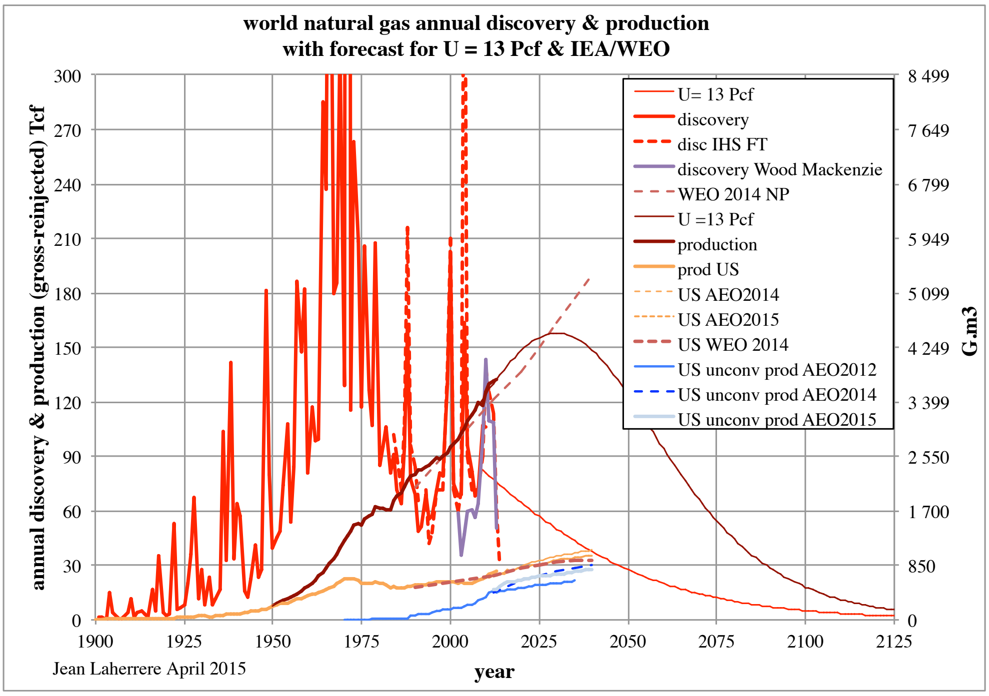
Fig 108: world natural gas remaining reserves from technical & political/financial sources



The HL of world NG production displays two linear trends, but the first on is in contradiction with the discovery data and the second at 19 000 Tcf looks too high compared to backdated discovery
It appears that both HL trends are not reliable
Fig 109: world natural gas production: HL & linear trends



There is no linear decline in world NG production.
It means that there is very little data, which can give reliable estimate on the world NG ultimate, outside the estimates of reserves by operators, but the recent burst in shale plays show that it is very easy to confuse resources and reserves.
The largest gasfield is North Dome shared two thirds by Qatar (North Field drilled in 1971) and one third in Iran (South Pars drilled in 1991) The reserves of North Field were in 2011 1500 Tcf = 250 Gboe: (bigger than the world largest oilfield = Ghawar = 145 Gb) in the graph below, but now it seems that these reserves should be diminished to be around 1000 Tcf or 500 Tcf less, and this correction corresponds to about two thirds of the US unconventional ultimate as shown above.
It means that the world new shale play ultimates could be around the uncertainty of the world conventional
With our 13 Pcf ultimate the world NG production will peak around 2030 around 160 Tcf when IEA/WEO2014 forecasts the same value for 2030, but 190 Tcf for 2040
Fig 110: world natural gas annual discovery & production & forecast U = 13 Pcf & IEA



-Conclusions

Paul Valery said "all that is simple is wrong, and all that is not is useless" and in 1931 in a book entitled "Looks to the Present World": "the time of the finite world begins". Both sentences are very true, but very many people believe in simple models and that universe & resources are infinite. Nature is complex and to model it with simple equations leads to false conclusions.

Several approaches should be carried out to estimate ultimates reserves of a field or of a country

The operator of the field knows the most, but he wants to keep confidential the data but he needs to show that the reserves are great and he has to fulfill or legal obligations (SEC rules for companies listed on the US stock market).

The problem is that there are several classifications of reserves: SEC (only proved and audited), SPE PRMS (1P, 2P & 3P), OPEC (proved unaudited), Russian ABC1.

After the counter shock of 1986, OPEC production was ruled by quotas (based on reserves, population and few other national parameters). From 1986 to 1989, the OPEC so-called proved (unaudited) reserves increased by 300 Gb without making any major discovery! It was only a political move, without any justification and arguing was attacking the sovereignty of the country!

Proved reserves are usually corresponding to the minimum volume (to protect the banker or the shareholder) and the aggregation of minimum field reserves underestimates the minimum reserves of the country: it is unscientific to add proved reserves but it is done by every official agency and database. Only the mean reserves (proved +probable) can be arithmetic added.

OPEC members cheat on reserves and on production data for their own benefit.

Publishing data is a political act because it depends upon the image the author wants to give: rich in front of bankers or shareholders, poor in front of taxes!

To obtain complete historical world oil and gas production and reserves data, the only way is to buy scout database (IHS, Rystad,), but they show discrepancy and mistakes and should be compared to sort them.

Very few countries publish field production and reserves data: UK, Norway, federal US (GOM BOEM) and some States like California.

It is from these field data that production graphs should be plotted as I did above.

Some claim that the HL does not work and some claim that the HL works, but all without showing any example.

It is obvious that HL work well when the linear period is very long (even if a little crooked): several decades like for UK coal. The big advantage of HL on decline is that HL can display a linear trend without peak when decline needs to be after peak. Another advantage of production data is that they include all above ground constraints that geological estimates rarely take into account.
But decline can be better than HL (example of East Texas in 1955, but not in 1964 !)

The best way is to combine as many as possible approaches and to stay very humble in from of the results and the only advice is to give as few as possible of significant digits, in fact never more than two!
The best approach is to never stop drawing graphs and looking at data with always question and doubt.
It is obvious that most data are poor and every one should keep asking the governments for better and free data.
Freedom of information act should be the law of every country and when it is statutory, it should be better respected.