Jean Laherrère 25 July 2022

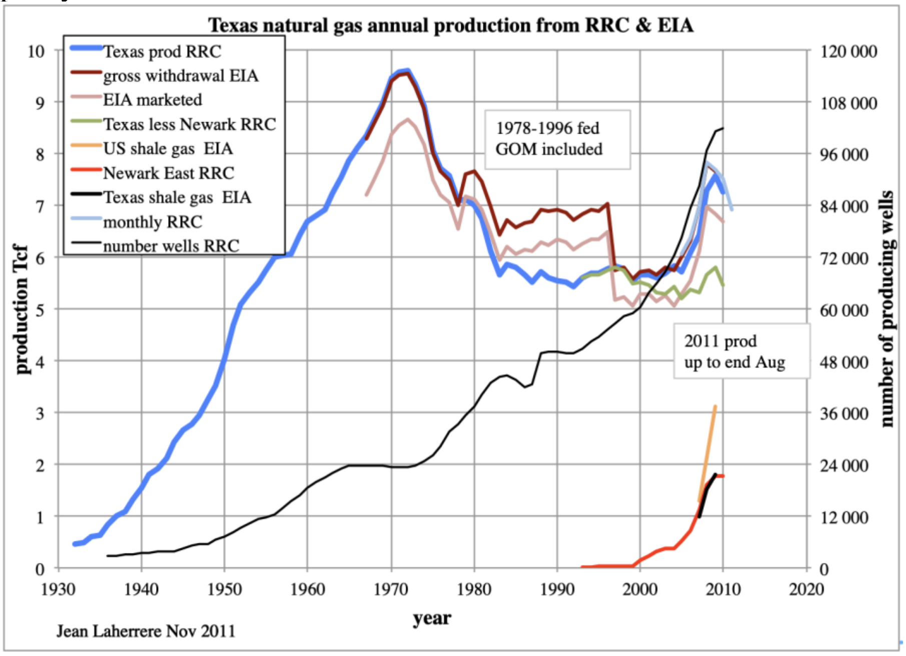
Barnett natural gas production & forecast, US unconventional and tight/shale gas

Table of contents

-Introduction

The goal of this paper is to show the uncertainty of the US unconventional natural gas definition (the ambiguity between tight and shale) and EIA evolution with time, as its production and to study in detail the case of the Barnett which is the first declining shale gas, in order to apply to the more recent gas plays.

Already in 2011, I displayed Texas NG production with Barnett not yet peaking, as already some discrepancy between EIA and RRC data



In our 1994 report -Laherrère J.H., A.Perrodon, G.Demaison "Undiscovered Petroleum Potential" Petroconsultants report, 383p we study the largest 14 Petroleum Systems, estimating the oil and gas generated by the source rocks thanks to measures with the Rockeval equipment and we conclude that the oil & gas ultimate reserves (cumulative production from start to end) are at the most about 1% of the oil and gas generated by the source rocks.

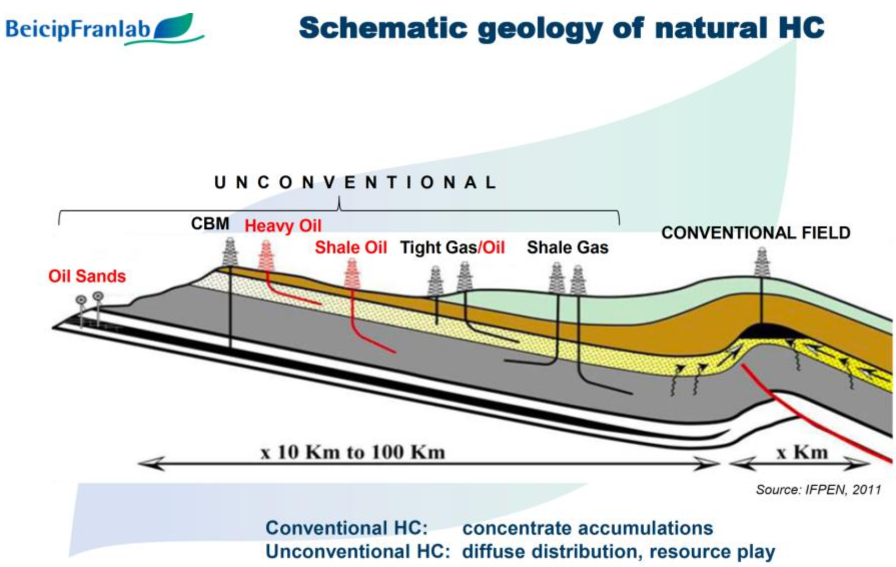
It means that there is a lot of oil and gas left into the sediments, the problem is how to produce them economically.

There is always a lot of confusion between resources and reserves (recoverable resources), as also between technically and economically recoverable.

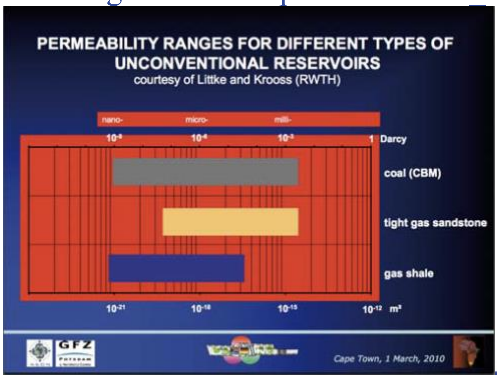
There is no world consensus on the definition of unconventional, and for the US, EIA definition has changed with time: coalbed methane (CBM) was unconventional in the past, but not anymore since 2018! Shale gas and tight gas are well defined by the reservoir, but often confusing mineralogy and permeability, reservoir, and source rock. The reservoir and the source rock are often close or combined.

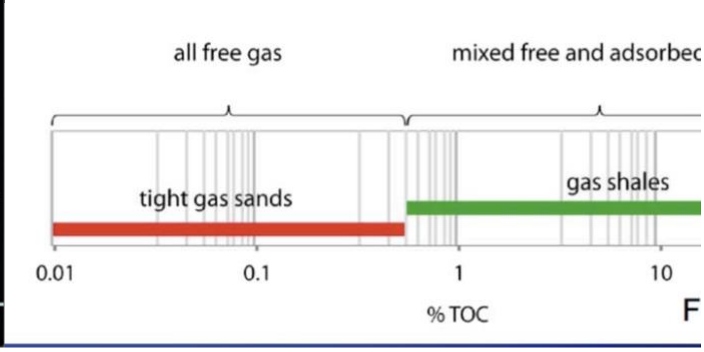
There is confusion between the kind of reservoir (tight) and the way it is produced (horizontal well, fracking)

For unconventional (?), the range of the parameters (permeability, porosity, depth, pressure, temperature, total organic content (TOC), maturity (gas window, oil window) is very large

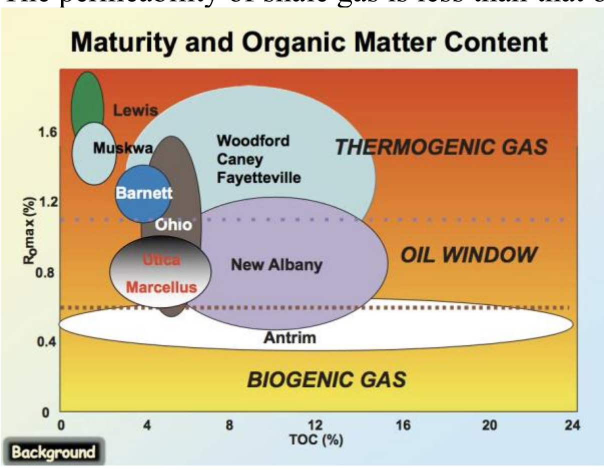


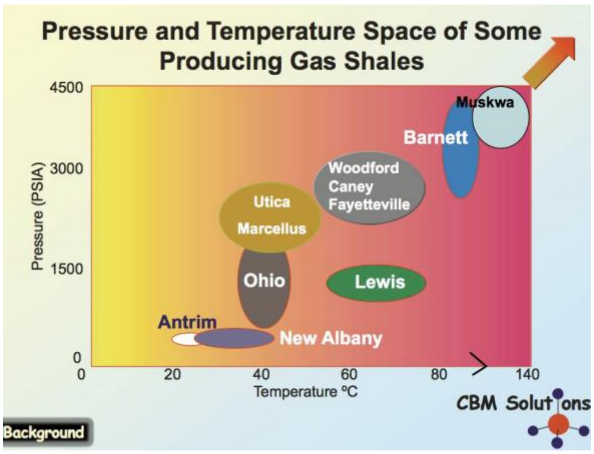
Pillet et al février 2012 : «Les hydrocarbures de roche-mère » http://www.developpement-durable.gouv.fr/IMG/pdf/007612-01_et_007612-03_rapports.pdf,





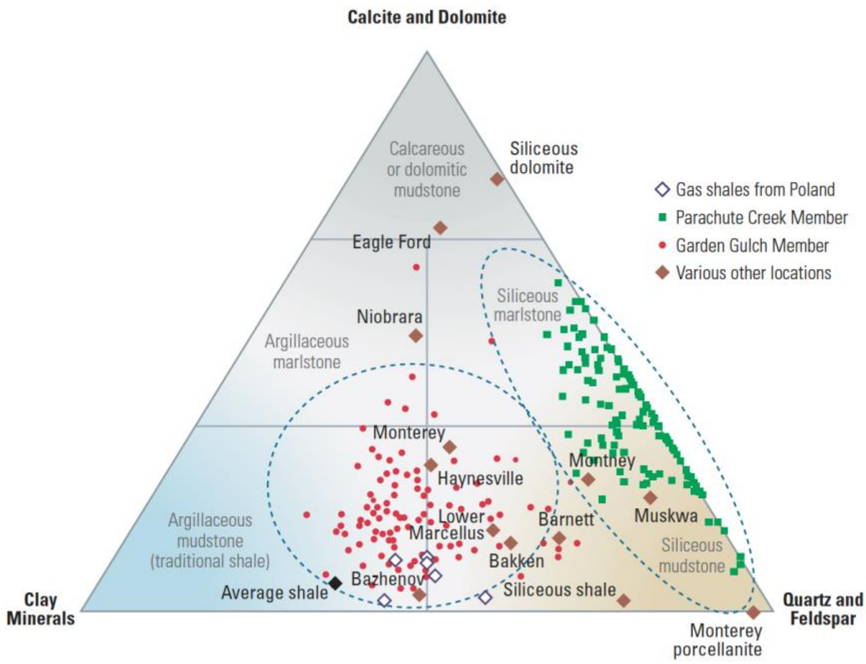
Tight gas reservoirs are generally defined as having less than 0.1 millidarcy (mD) matrix permeability and less than ten percent matrix porosity.
The permeability of shale gas is less than that of tight gas, but their range overlap.





Barnett looks different from Marcellus!

The US shale gas is found in many different plays.
The range of mineralogy is also large
Schlumberger Oilfield Review winter 2010/2011 shale mineralogy

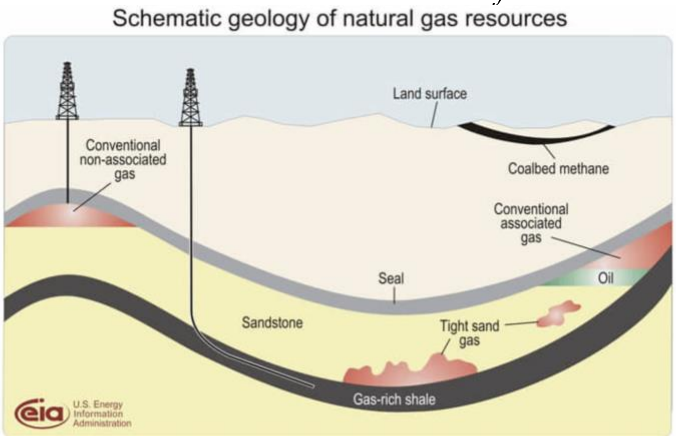


Barnett & Bakken are similar (mainly quartz), far from Eagle Ford (more calcite and dolomite)
The percentage of clay in Barnett is about 30 %!

It is difficult to find a clear definition of tight gas and shale gas
The Shell site https://www.shell.com/energy-and-innovation/natural-gas/tight-and-shale-gas.html writes
Traditionally most natural gas has come from rock formations that, once drilled, allow the gas to flow freely. But supplies of this easy-to-access gas are declining. Many of the remaining vast gas resources lie trapped tightly in dense rock, inside pores up to 20,000 times narrower than a human hair.
Called tight and shale gas, these resources were previously considered too costly or difficult to access, yet the overall volume of available gas can be much higher than in conventional gas reservoirs. We use advanced technology to help gain access, contributing to global growth in natural gas production.
Shell has decades of production experience with tight gas – in the USA and Canada, the North Sea, and mainland Europe. Over time we have found ways to safely develop the fields and produce the gas with greater efficiency, lowering costs and limiting our environmental impact.
Producing tight and shale gas
At all our tight gas operations, we use a technique known as hydraulic fracturing to break open rock and release natural gas. This involves pumping fluids into the well bore at high pressure. The fluids comprise around 99% sand and water, with 1% chemicals added to help the gas flow more freely.
another form of tight gas called coalbed methane – natural gas found in coal seams.
Shell does not give any difference between tight gas, shale gas and coalbed methane!

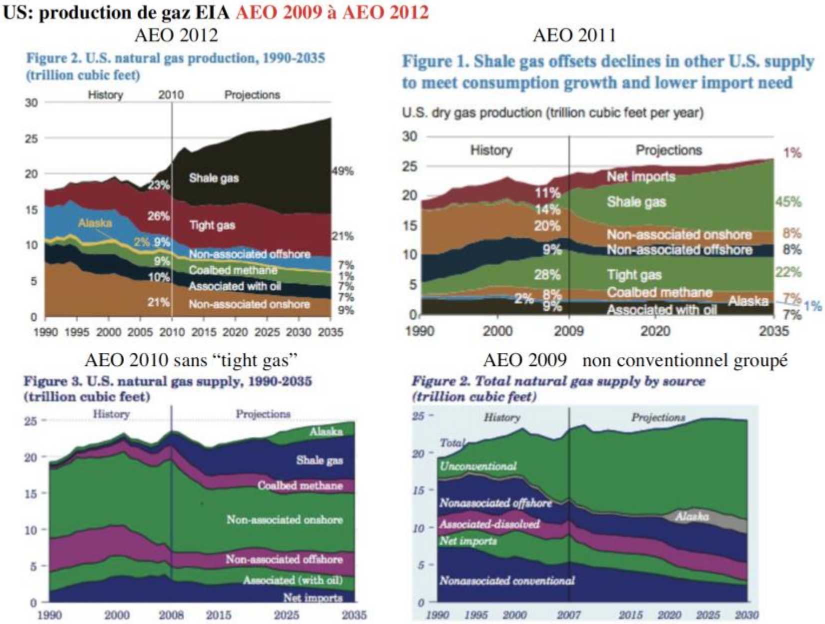
Gas in thermally mature shale reservoirs is considered to exist as adsorbed volume in organic matter and free gas within pores and voids in natural fractures.
Shale gas should contain more adsorbed gas than tight gas.
But few data is found on the proportion of gas production, as gas reserves, between free gas and adsorbed gas. It appears that the gas producers do not know where the gas comes from!

https://mitsuiepmidwest.com.au/what-we-do/shale-tight-coal-seam-gas/
Unconventional gas is natural gas trapped in very dense rocks with low permeability that prevents gas flowing into wells in commercial volumes. Unconventional gas generally requires hydraulic fracturing to improve reservoir permeability and extract the gas resource in commercial quantities.
The three most common forms of unconventional gas are:
Tight gas
Shale gas
Coal seam gas
The most significant difference between shale gas and tight gas is:
Shale gas is mostly found trapped in layers of sedimentary shale rocks
Tight gas is found trapped in sandstone or limestone formations with relatively low permeability.
While coal seam gas is fairly shallow and more easily extracted from the coal seams where it was formed at depths between 300 meters to 1 kilometer, shale gas and tight gas is found at much deeper depths between 2 – 5 kilometers below the surface.



In 2012 I displayed EIA NG production from AEO2009 to AEO2012 which report differently unconventional gas

-Fig 12: **US: production de gaz EIA** AEO 2009 à AEO 2012



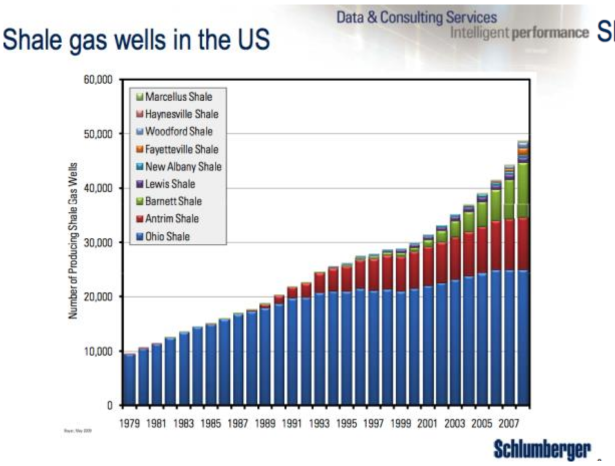
There is a more complete AEO evolution later in the paper

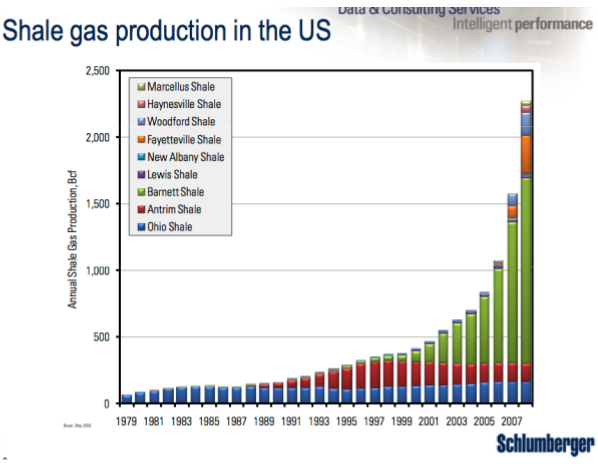
https://en.wikipedia.org/wiki/Tight_gas
Tight gas is natural gas produced from reservoir rocks with such low permeability that massive hydraulic fracturing is necessary to produce the well at economic rates. This natural gas is trapped within rocks with very low permeability, in other words, they are sealed in very impermeable and hard rocks, making their formation "tight". These impermeable reservoirs which produce dry natural gas are also called "Tight Sand". Tight gas reservoirs are generally defined as having less than 0.1 millidarcy (mD) matrix permeability and less than ten percent matrix porosity. Although shales have low permeability and low effective porosity, shale gas is usually considered separate from tight gas, which is contained most commonly in sandstone, but sometimes in limestone.

https://www.nrcan.gc.ca/energy/energy-sources-distribution/natural-gas/shale-tight-resources-canada/geology-shale-and-tight-resources/17675
Conventional reservoirs may have permeability in the range of tens to hundreds of millidarcies. Tight reservoirs usually have permeability from 0.1 to 0.001 millidarcies, and shale reservoirs are even less permeable – in the 0.001 to 0.0001 millidarcies range. As a result, the average permeability of tight and shale reservoirs is usually too small to allow commercial production unless unconventional extraction techniques (horizontal drilling and hydraulic fracturing) are used.

The permeability of shale gas is less than the permeability of tight gas, but both are produced with the same technique = horizontal well with long extent and hydraulic fracking with large volumes of water & sand and small volumes of chemicals: it is why they are often confused.
The problem is that horizontal wells are often used with conventional reservoirs to improve production without using fracking, as if the thickness of a vertical reservoir is 100 m, a horizontal well with an extent of 2 km will have 20 times more surface in front of the productive area. and could produce more than a vertical well: see the graph page 17 of US oil & gas production energy per well with around 1.5 PJ from 1950 to 2015 and jumping in 2021 to 6 PJ thanks to long horizontal wells.
But the bad use of horizontal wells could be dangerous: Shell did use horizontal wells around 1995 to produce faster giant fields: Yibal in Oman to compensate lower oil price and Rabi-Kounga in Gabon with a limit of life of a lease. But conventional reservoirs should be produced slowly, to move slowly the water contact. With fast oil production, water is coming sooner and oil production declines http://aspofrance.viabloga.com/files/Sophia2013.pdf
When water rises in a vertical well, only the part above water is produced, when water fills the horizontal well production is dead.
The problem is that EIA confuses often horizontal production with shale production, in particular in the Permian play.

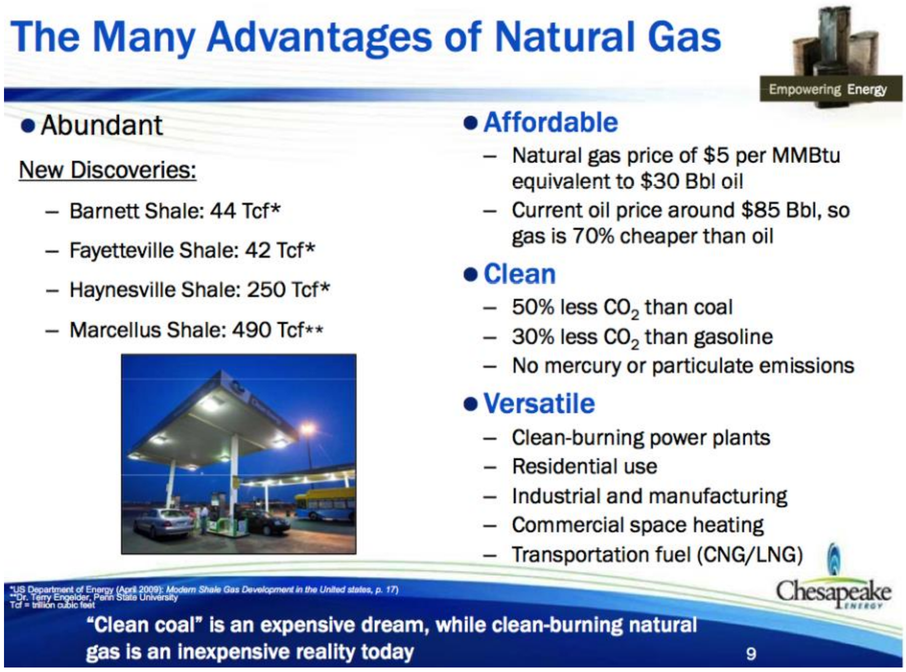
-Shale gas is not new in the US
The first US gas production was in Fredonia in 1821 from the Devonian Dunkirk Shale and the Big Sandy field discovered in 1880 (Ohio shale) had in 1960 thousands of wells fractured by nitroglycerine (7 t per well)
From 1976 to 2000 127 M$ research program by DOE and GRI = development of the Antrim Shale program in Michigan
Shale gas producing wells 1979-2008 from Schlumberger





US shale gas was produced since
-1821 Devonian shale
-1880 Ohio shale
-1989 Antrim shale
-1993 Barnett shale
-1999 Lewis shale
In 2008 almost 50 000 shale wells were producing 2.2 Tcf in the US (mainly from the Barnett)!

McClendon AAPG2010 estimated Barnett at 44 Tcf and Marcellus at 490 Tcf!



My 2013 paper « Peak oil and other peaks » translation of a presentation in Marseilles 22 August Green Party updating a presentation at Toulouse 2004
http://aspofrance.viabloga.com/files/JL_Marseilles-english.pdf
The miracle of shale gas is attributed to promoters such as Mitchell, XTO (bought for $41 billion by Exxon) and above all Chesapeake, which has sold some of its interests to major companies (ExxonMobil, Statoil, Total, CNOOC) wishing above all to include the certified reserves in their balance sheets, because they produce more than they find. In fact, the first US natural gas production was in 1821 at Fredonia in New York State coming from shale gas

and used for illumination. In 1850, lighting was based primarily on whale oil sold at 2000 $ a barrel (in 2013$). The discovery of crude oil in 1859 led to the closing of Fredonia, but the Big Sandy shale gas field in Kentucky discovered in 1880 had in 1960 thousands of wells fractured by nitroglycerine (7 tonnes per well).
The Shale Gas has been rediscovered thanks to subsidies by the US Department of Energy and above all when the price of gas rose above 5 $/kcf, which is about its cost. But the promoters did not manage well this boom (like the East Texas field in 1931), and the lack of gas pipelines depressed the price. This boom does not rely on new technology because hydraulic fracturing and horizontal drilling have been practiced for 50 years but depends on the economics and above all new 2010 Stock Exchange Commission rules, which are even more lax than SPE rules. The major companies (Shell, BP, BHP and Encana) have been obliged to write off more than 10 G$.

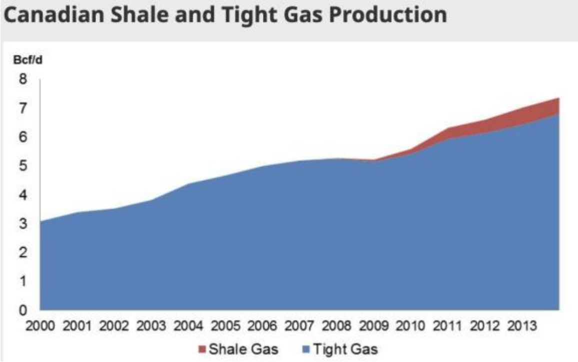
-Tight gas in Canada : Deep Basin
In Canada the tight gas field of Elmworth-Wapiti was estimated to contain 440 Tcf (Elmworth: Case Study of a Deep Basin Gas Field (AAPG Memoir) 1985) by his finder John Masters (in 1980), but in 2006 only 5 Tcf has been produced, because the sweet spots were rare
«Future of natural gas supply» ASPO Berlin May 2004 http://www.peakoil.net/JL/JeanL.html, http://www.hubbertpeak.com/laherrere/ASPO2004JL.pdf
https://en.wikipedia.org/wiki/Elmworth_gas_field
"A review of Deep Basin gas reservoirs of the Western Canada Sedimentary Basin"
· July 2006 Brian Zaitlin Thomas Moslow
"The Deep Basin - A Hot "Tight Gas" Play for 25 Years" Brad J.R. Hayes AAPG 2003

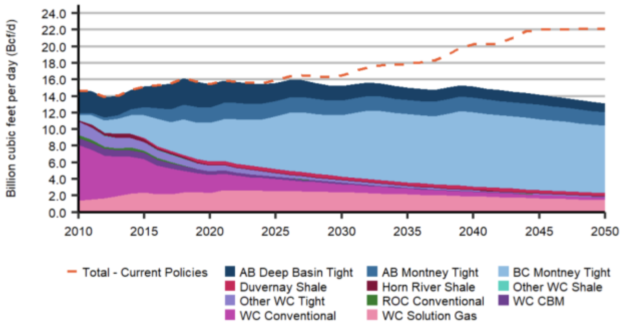
Laherrère J.H. 2008 «Why are remaining oil & gas reserves from political/financial sources and technical sources so different? » International Geological Congress Oslo 11 August
http://aspofrance.viabloga.com/files/JL-IGC2008-part1.pdf
http://aspofrance.viabloga.com/files/JL-IGC2008-part2.pdf
http://aspofrance.viabloga.com/files/JL-IGC2008-part3.pdf
Having spent 5 years exploring Canada, I was very interested by the discovery of Elmworth in the deep basin, in an area where already 200 wells had penetrated the tight reservoir. John Masters who led the discovery by Canadian Hunter Exploration wrote a book in 1980 "The Hunters" stating that the potential recoverable resources of the Deep basin is 440 Tcf (page 77). Elmworth ultimate is now estimated around 5 Tcf. The Britannica Riva site gives 560 Tcf for Elmworth discovered in 1976. In OGJ 15 Nov.1993 Elmworth is stated as Canada's largest gas field.

Cenovus Energy Inc (former Encana, second Canadian producer) is still producing Elmworth-Wapiti gas field (now considered as conventional): AR 2021: *The Elmworth-Wapiti area provides production potential from more than 10 formations, with the most prospective being the Falher and Dunvegan formations. It is a mature area that was historically developed with conventional vertical well technology. Cenovus has shifted to horizontal drilling in its development programs with a view to unlock the vast resource potential in the tight sand plays. Production 2020 = 51 Gcf, 2021 = 55 Gcf*

Canada shale gas production is much less than tight gas in the past (nrcan 2000-2014) and in the future (neb "Evolving policies scenario") 2020-2050, but discrepancy for 2010 between nrcan and neb on the proportion shale/tight.

https://www.nrcan.gc.ca/energy/energy-sources-distribution/natural-gas/shale-tight-resources-canada/exploration-and-production-shale-and-tight-resources/17677
https://neb-one.gc.ca/en/data-analysis/canada-energy-future/2021naturalgas/index.html





-US shale gas since 2000
As mentioned before, US shale gas was produced in Fredonia in 1821, 1880 Ohio shale, 1989 Antrim shale, 1993 Barnett shale.
In 2010 Barnett was the main shale gas production

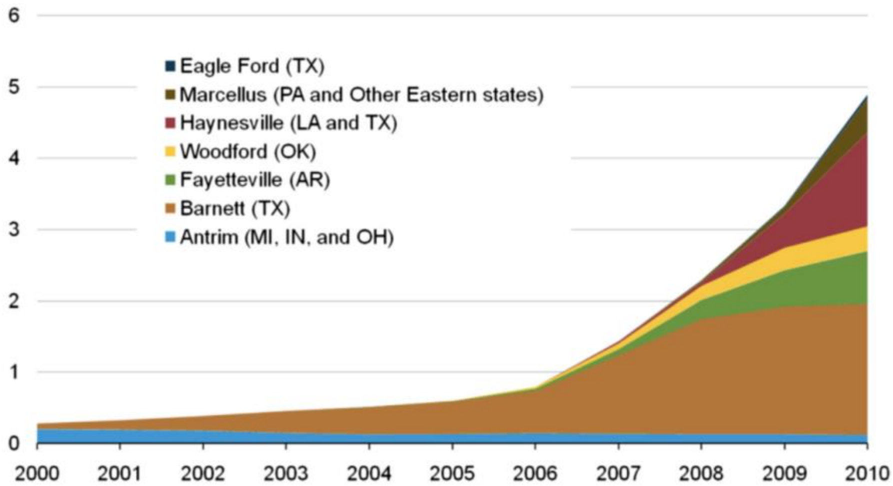
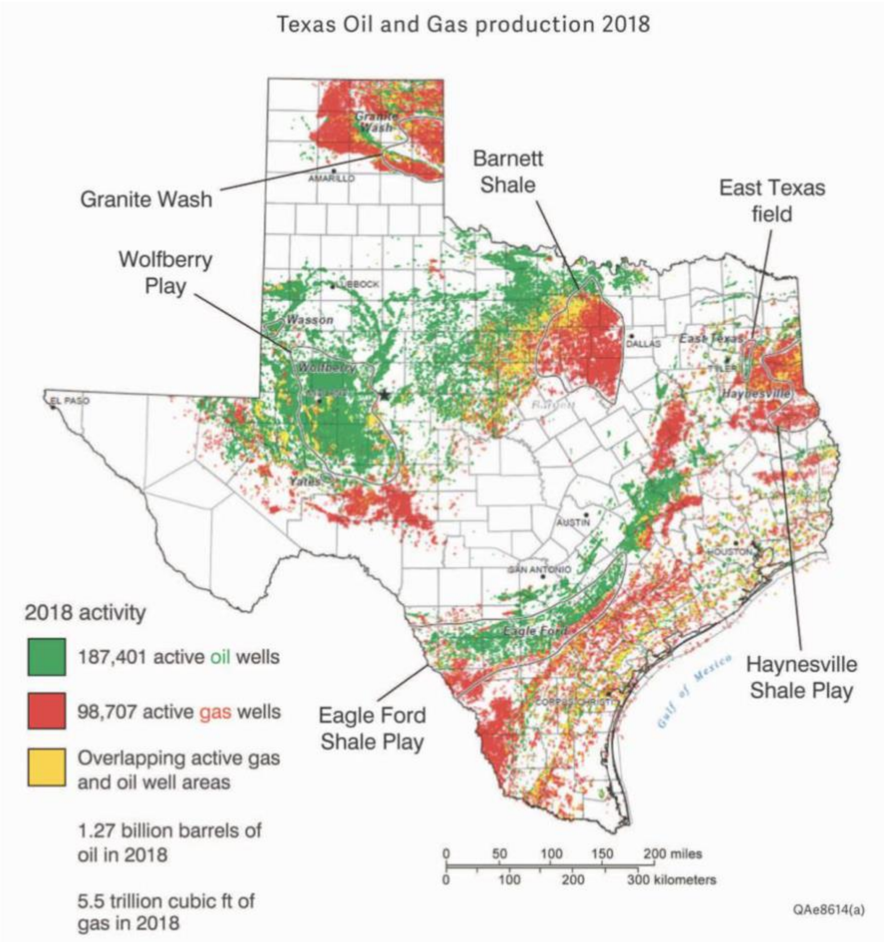


Figure 1.5 The relative importance of different US shale layers. *From Newell (2011).*

-Barnett
Barnett gas wells are displayed in the Texas oil & gas production 2018



Barnett geology and story

Vermylen 2011 GEOMECHANICAL STUDIES OF THE BARNETT SHALE, TEXAS,
The reservoir is complex: yellow = quartz, blue = carbonate, grey = clay
clay is in minority!

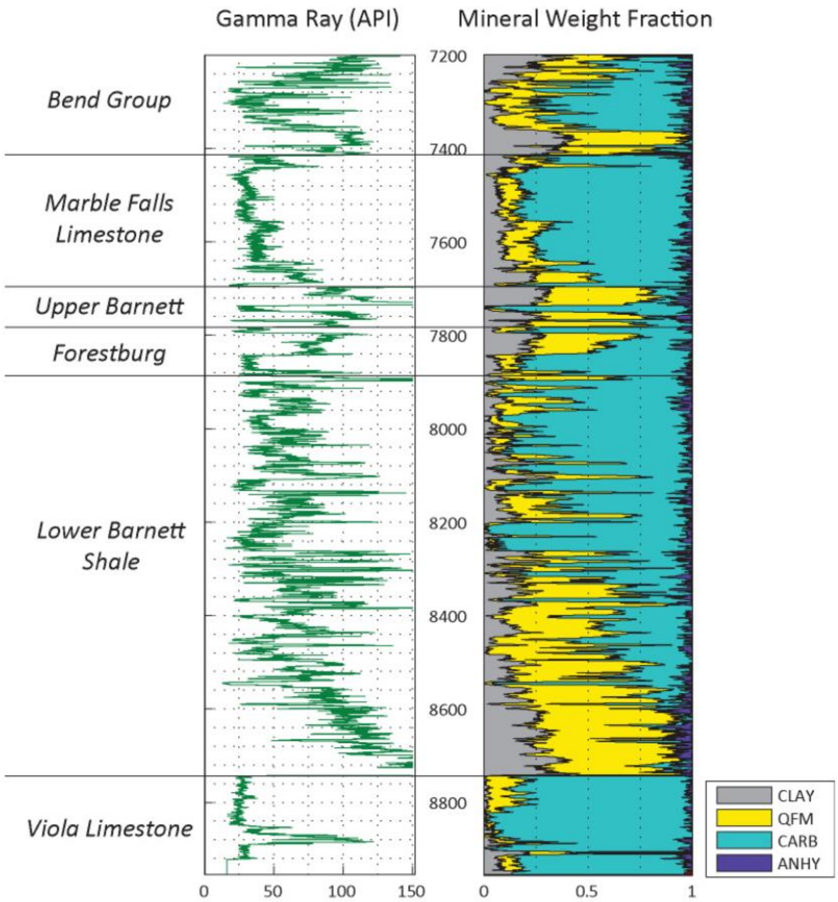


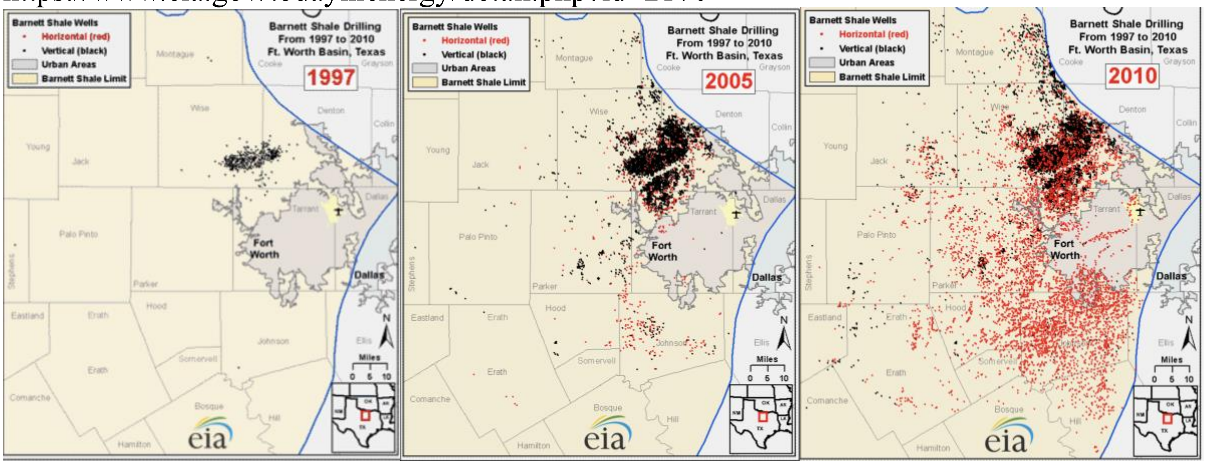
Figure 2.4a: Formation depths, gamma ray, and interpreted mineralogy from cored study well. Well is in region of basin where the Barnett is divided by the Forestburg limestone into upper and lower sections. Mineral fraction based on SpectroLith technique to interpret well log suite. Anhydrite detection may be an interpretation artifact as it was not found in the cored samples. (CLAY: clay minerals; QFM: quartz, feldspar, and mica; CARB: carbonates; ANHY: anhydrite)

It is obvious that the Lower Barnett Shale contains a lot of quartz in its lower half and a lot of carbonates in its upper half

Barnett Mississippian shale gas production is first called Newark East field in Texas by RRC = Rail Road Commission.
https://en.wikipedia.org/wiki/Barnett_Shale
The field was discovered in 1981 when Mitchell Energy drilled and completed the C. W. Slay #1 near Newark, Texas, in Wise County. The well was drilled vertically, completed with a nitrogen foam frac, and did not produce enough gas to cause any excitement.
Despite the low production rate, Mitchell Energy owner George P. Mitchell was convinced that he could find a better way to produce gas from the Barnett. Mitchell persevered for years in the face of low production rates in his initial wells, low gas prices, and low profitability. Industry commentators have written that few, if any, other companies would have continued drilling well after well in the Barnett Shale. Mitchell is widely credited with personally making a success of the Barnett Shale, and thus creating the gas production boom in the Barnett, and, when other companies imitated his techniques, many other shale-gas and tight-oil successes in the US and other countries
Incrementally, Mitchell Energy found ways to increase production. Early on, Mitchell abandoned the foam frac, which had been used with some success in Appalachian Basin shales and found that gel fracs worked better in the Barnett. In 1986, Mitchell Energy applied the first massive hydraulic frac, a gel frac, to the Barnett Shale

In 1991, Mitchell Energy, with a subsidy from the federal government, drilled the first horizontal well in the Barnett, but the experiment was not considered a success. It was not until 1998 that Mitchell drilled two more horizontal wells; they were technical successes, but economic failures. Mitchell's fourth and last horizontal attempt was made in 2000 but ran into drilling problems and was abandoned.
The largest breakthrough in the Barnett came in 1997, when Mitchell Energy petroleum engineer Nick Steinsberger suggested that a slickwater frac, which was being successfully used by other companies in wells to the Cotton Valley Sandstone of east Texas, might work better in the Barnett Shale than the gel fracs. By going against conventional wisdom and switching to the slickwater frac, Mitchell Energy not only lowered the cost of completing wells by $75,000 to $100,000, but also dramatically increased the recovery of gas. Mitchell tried to buy more leases in the area before word spread, but soon many other operators started buying leases and drilling Barnett wells, in what had been until then essentially a Mitchell Energy play

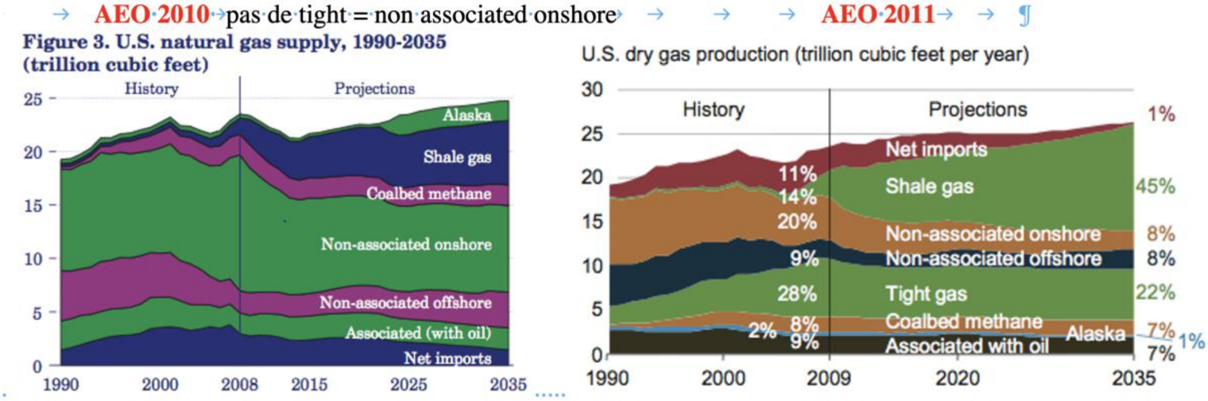
AAPG Wiki Barnett shale play
The Newark East field was discovered in 1981 by Mitchell Energy Corporation (acquired by Devon Energy). The development of the field started slowly, and only 100 wells were completed between 1981 and 1990. In 1998, a major breakthrough in completion techniques occurred when water fracturing replaced gel fracturing. From 1997 to 2006, more than 5829 wells were put on production, and hundreds of additional wells were drilled, completed, or waiting on a pipeline. Vertical wells were the primary drilling method until 2002 when seven experimental horizontal wells were drilled. The excellent success of these wells prompted many operators to move their drilling mode from vertical to horizontal.

Barnett vertical and horizontal wells in 1997, 2005 and 2010
https://www.eia.gov/todayinenergy/detail.php?id=2170


development of the fields (up until 2007), is outlined by Martineau.[3] Development activity continues today with over 14,000 active gas wells as of January 2015.
Gas production reached its highest level to date in 2012, with an average of 5,743 Million Cubic Feet (MMCF) of gas per day, during 2014 production averaged 4,920 MMCF/day. The field also produced oil and condensate at an average rate of 3,207 and 15,757 bbls/day respectively in 2014.
As of 2009 the Barnett (Newark East field) was the largest gas field in the U.S. by proven reserves.[10] However by 2015, in an update by the EIA, it was ranked number 2 having been surpassed, by another shale play, the Marcellus Shale in Pennsylvania and West Virginia.[11] Perhaps more importantly however, the success of developing the Barnett Shale has opened

the door for success not only the Marcellus but also in other gas plays in the United States such as the Woodford, Fayetteville and Haynesville and others.

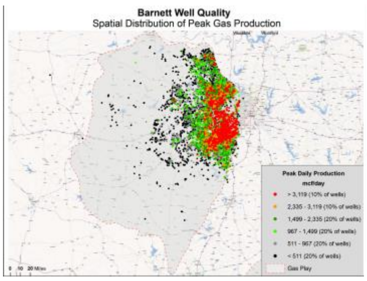
In my 2011 paper " Réserves et ressources des shale oil & shale gas " I mentioned the discrepancy with EIA between shale gas and tight gas between AEO2010 and AEO 2011

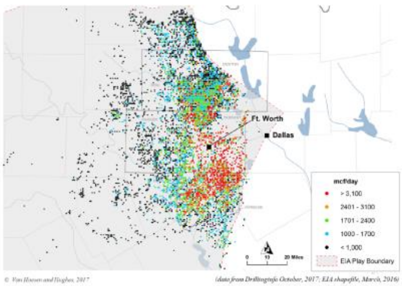


I mentioned also that the big change was not technological but in SEC rules where reserves moved from conservative to very optimistic by authorizing that **proven is the result of model** (kept confidential) for any undrilled area.

Hughes graph on Barnett

2013 2018 2021





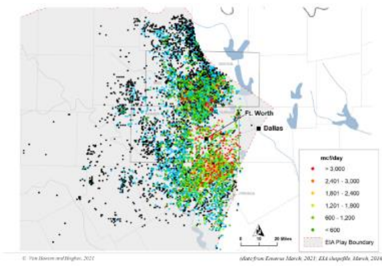


Figure 79. Barnett Play well locations showing peak gas production in the highest month.[150]

2017 2021

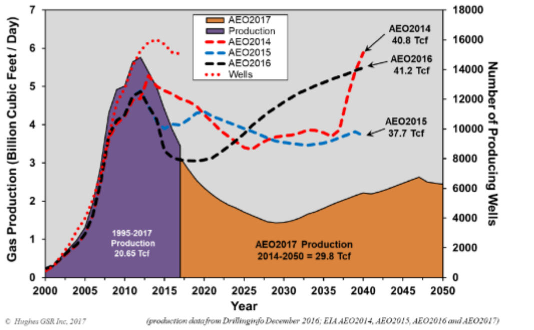


Figure 84. EIA AEO2017 reference case Barnett Play gas production estimate through 2050.

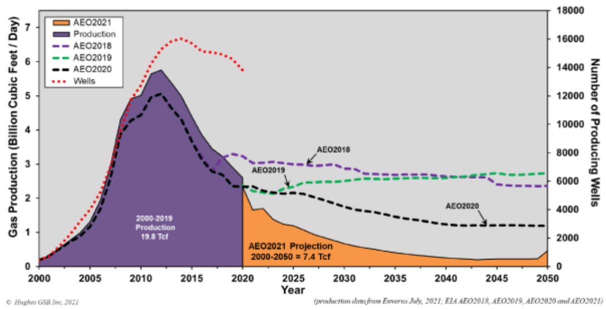


Figure 84. EIA AEO2021 reference case Barnett Play gas production forecast through 2050.[156]

AEO2017 forecasted a Barnett new increase from 2030 to a peak in 2047, but AEO2021denies the new increase except a small bump in 2050 (very queer!)!

2019 Hughes displays the doubling in lateral length from 2010 to 2018

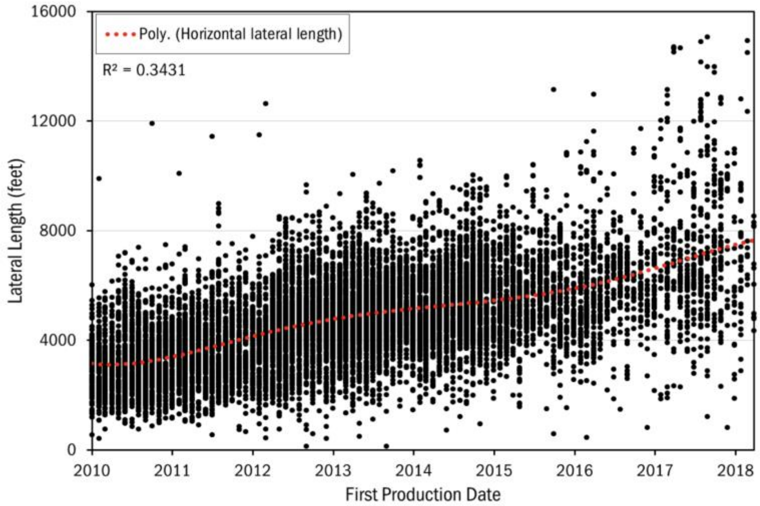
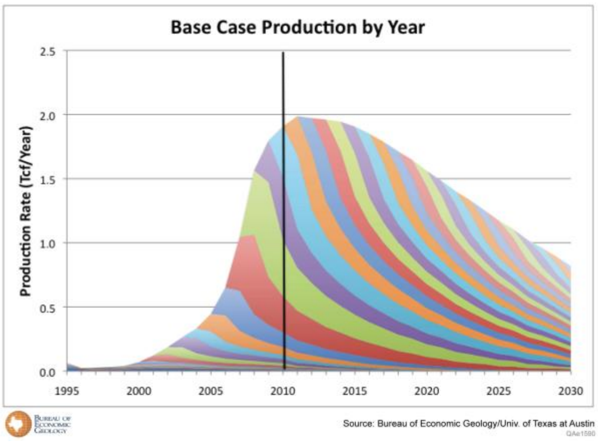


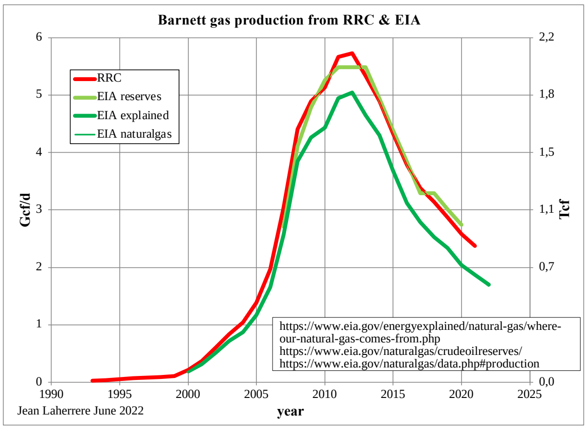
Figure 159. Horizontal lateral length (individual wells) in the Barnett Play from 2010 to 2018.[231]
Although 5,548 feet was the average in 2018, a few wells have exceeded 15,000 feet.

-Barnett forecast in 2013

This 2013 post forecasted rightly the peak https://phys.org/news/2013-03-rigorous-shale-gas-reserves-reliable.html *New, rigorous assessment of shale gas reserves forecasts reliable supply from Barnett Shale through 2030* by University of Texas at Austin with a forecast of >1,5 Tcf in 2020, when in real 2020 production was <1 Tcf
BEG of U of Texas was too optimistic!

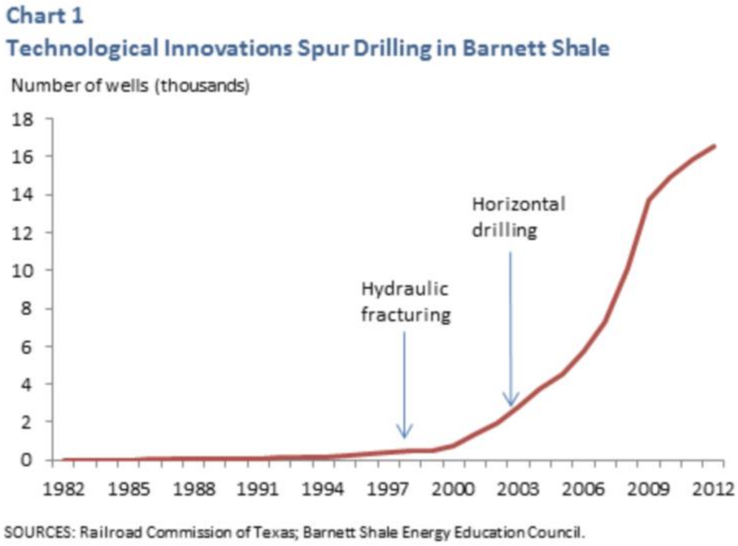
Production Outlook for the Barnett Shale through 2030

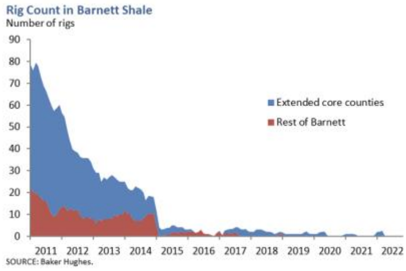


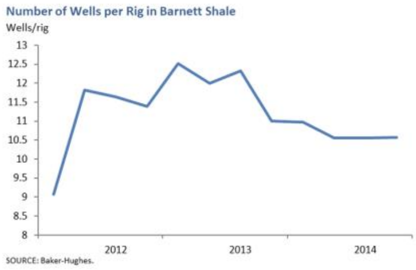


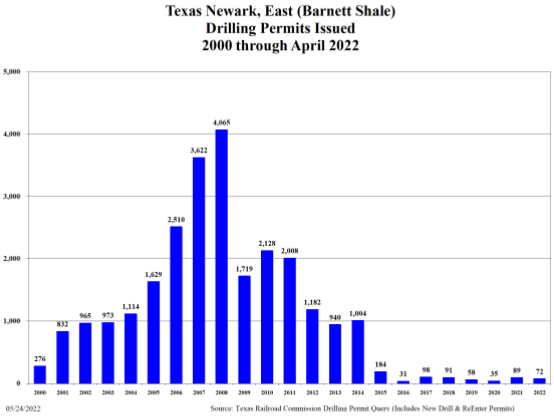
-Barnett drilling activity

Barnett number of wells started to grow since 2000, horizontal wells started in 2003, the rig count peaked in 2011: it is hard to find a graph showing the full historical well activity https://www.dallasfed.org/research/energy11/barnett#History
Hydraulic fracturing started in 1997 for Barnett shale, before horizontal drilling in 2008









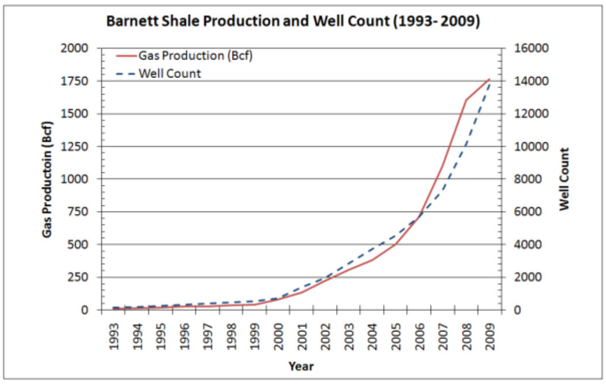
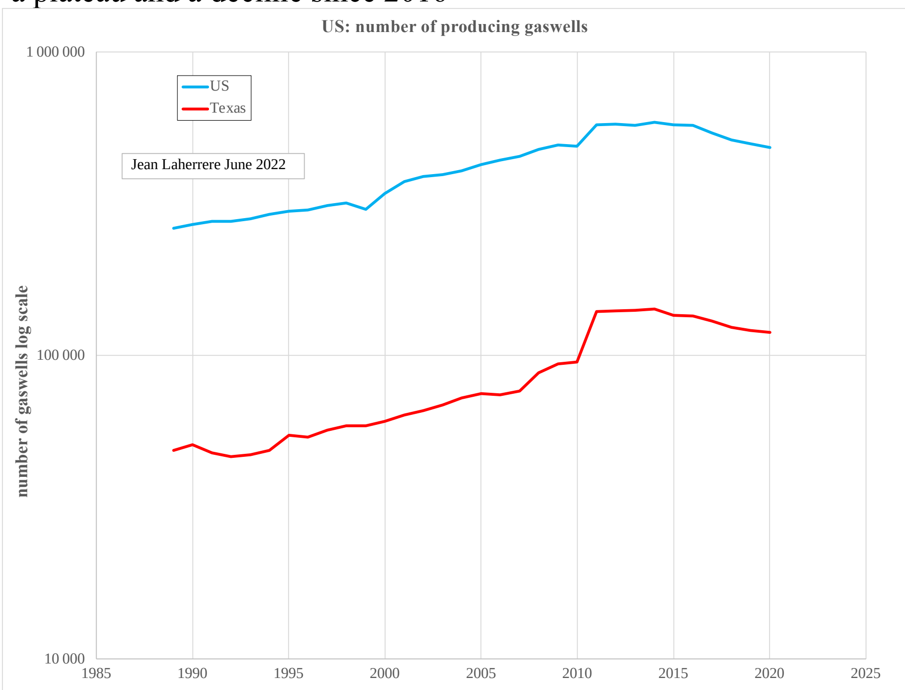


Figure 1.2: Barnett production history and well count, indicating rapid growth over the last 10 years. Source: Texas Railroad Commission (Texas Railroad Commission, 2010).

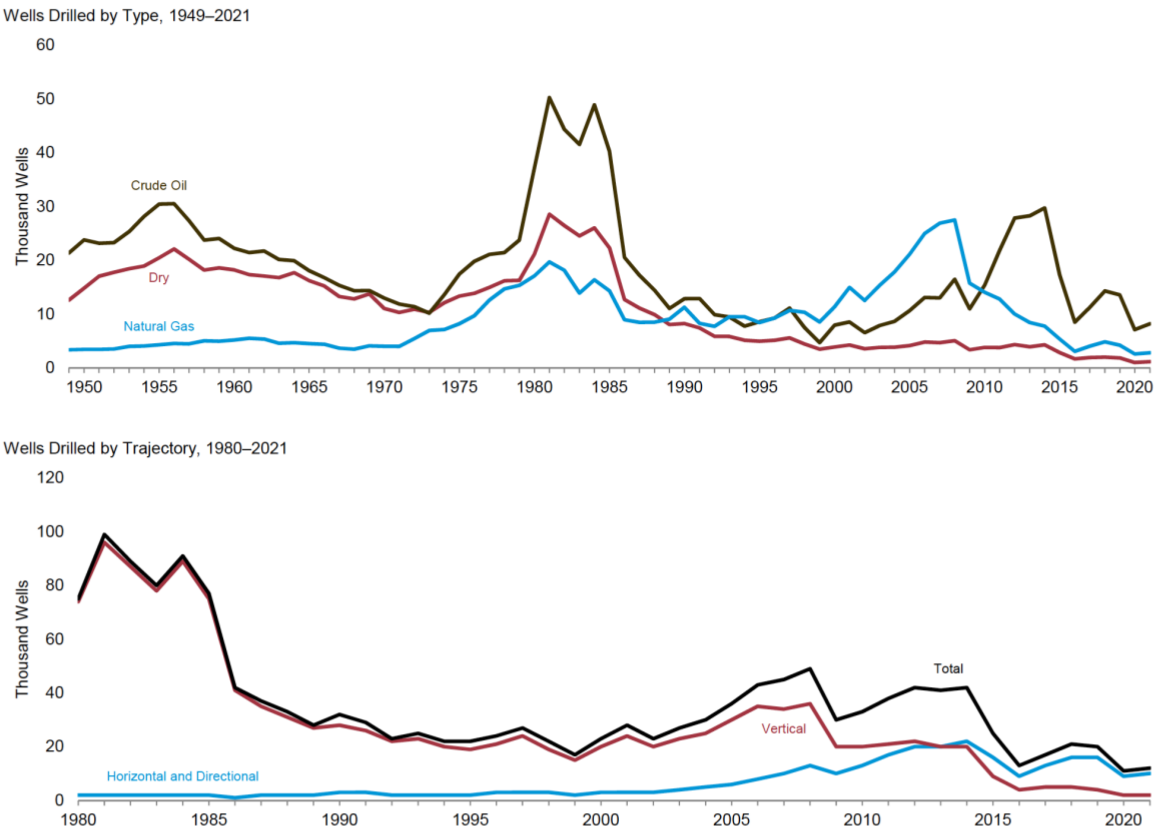
The number of US producing gaswells is reported for Texas and for the US: they are reported in log scale to compare growth and decline: there is a sharp increase in 2011 in Texas, followed by a plateau and a decline since 2016



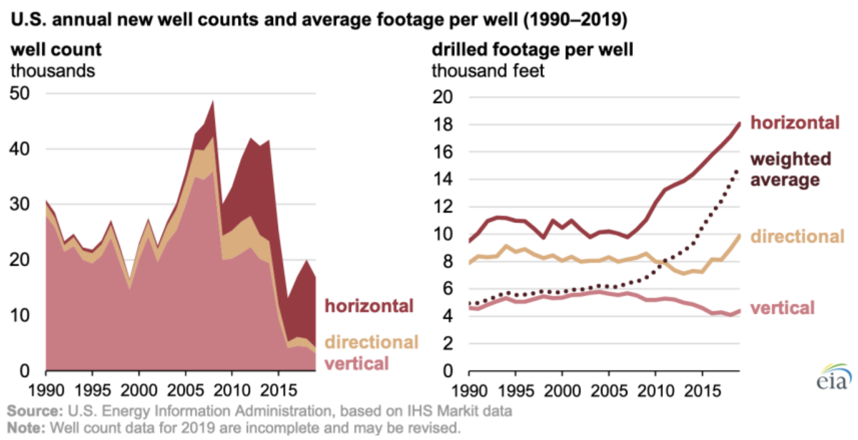
AEO2021reference estimates that 10 542 wells are needed for 2020-2050 to recover over 7 Tcf:
AEO2022 reference forecast for the USL48 for the period 2021-2050 almost 800 000 or an annual average of 26 500 wells
I have strong doubts, as, except in the Permian basin, the sweet spots are almost fully drilled, leading to problems between parent and child wells = https://jpt.spe.org/understanding-well-interference-and-parent-child-well-relationships-liquid-molecular-chemical-tracer

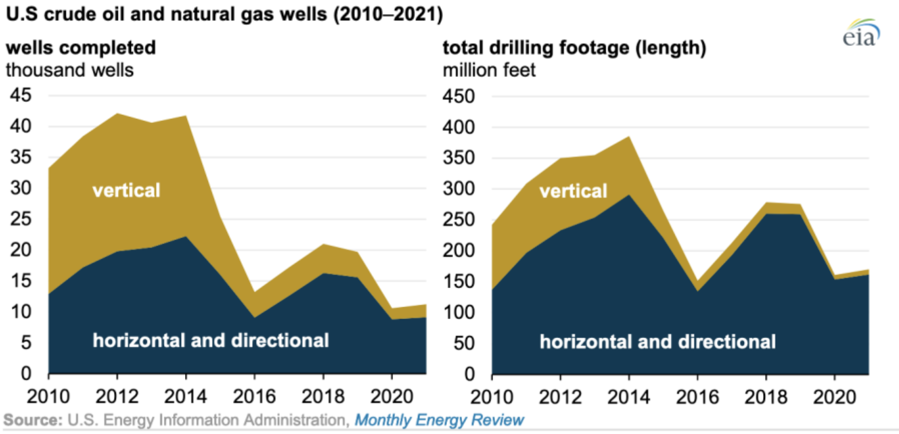
US drilling activity 1950-2021

Figure 5.2 Crude Oil and Natural Gas Wells and Footage Drilled



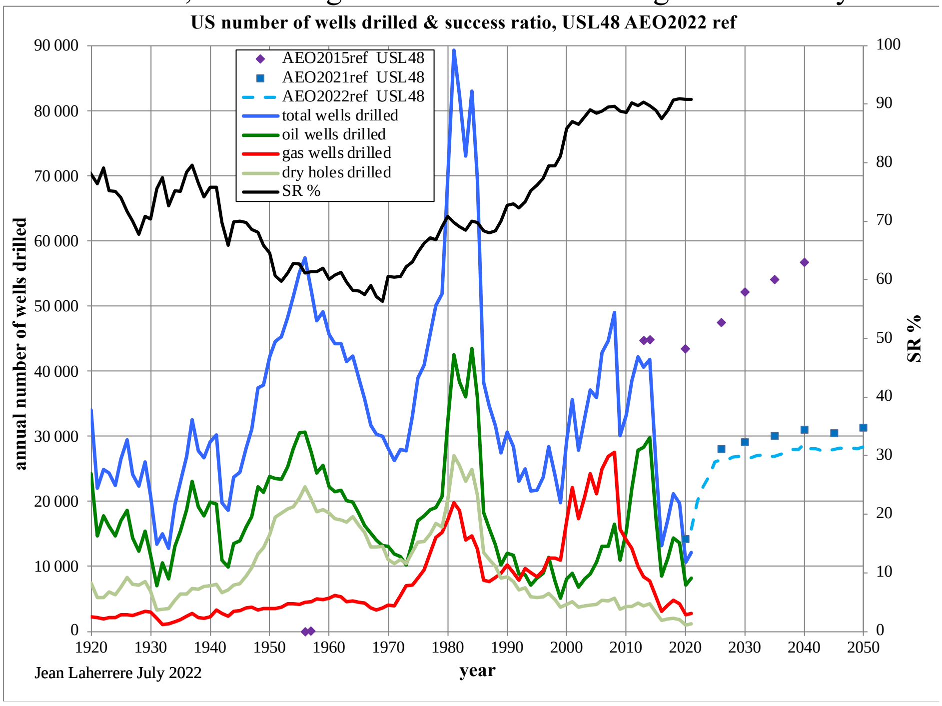
Horizontal drilling takes over vertical drilling in 2014
The US display since 1920 shows that the number of drilled gaswells was higher than the number of oilwells from 1999 to 2009.
The number of US wells has dropped sharply since 2013, when the footage per horizontal well increases since 2008.



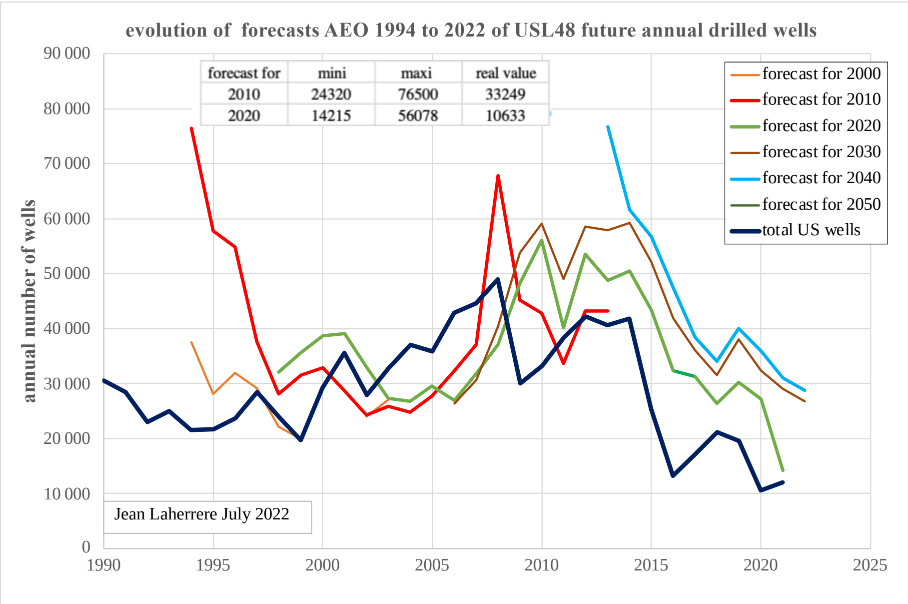


AEO 2022 (table 14) reference forecast of wells drilled for the USL48 for the period 2021-2050 (total of 795 560 wells or an average of 26 500 wells) is much higher than for the last 5 years: it looks unrealistic as EIA does not bother to check where these future wells will be drilled: most are shale wells and most of the shale plays (except the Permian basin and the Pennsylvanian basin) are almost fully drilled. Furthermore, AEO2022 does not foresee any decline beyond 2050. This future drilling plateau activity looks crazy, without any justification! AEO2021 reference was higher, much larger correction is needed, in particular a decline!

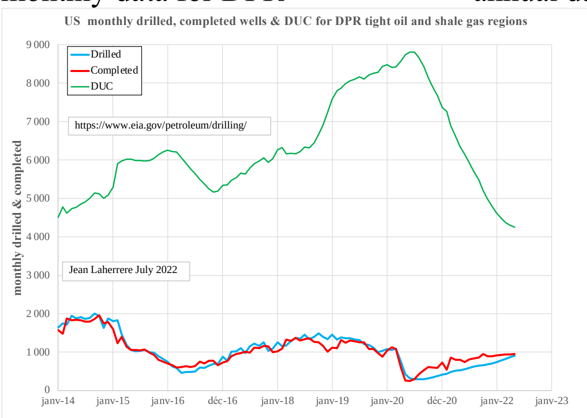
But AEO2015 was crazier, forecasting 46 400 wells for 2020 against in reality 10 633 wells!

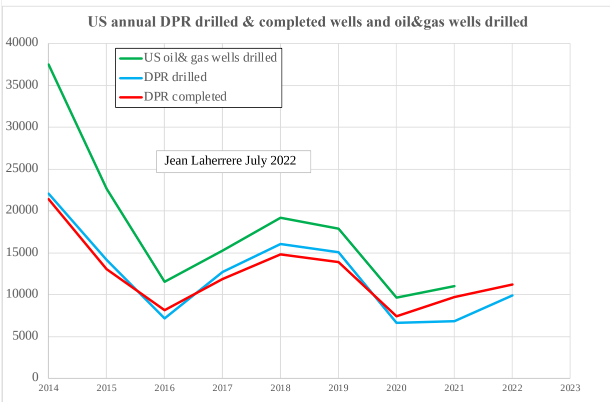


AEO1994 to 2022 (table 14 = oil and gas supply) forecast the annual number of L48 wells drilled as plotted above (Alaska annual wells are below 200). The plot of the forecasts for 2000, 2010, 2020, 2030, 2040 and 2050 is rather erratic: for 2010 the number varies 24 000 to 76 000 (1 to 3) with real value = 33 000 wells, showing EIA poor job in forecasting



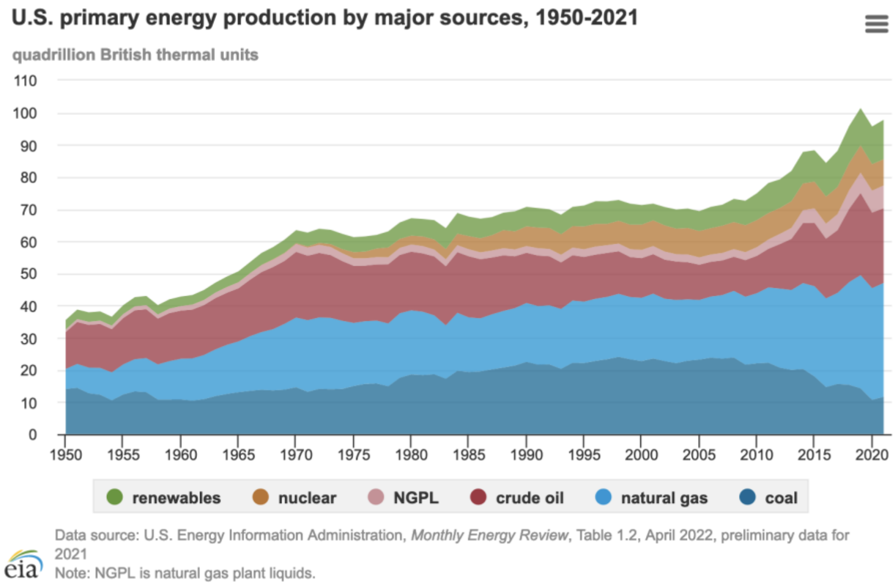
The practice for shale play is to drill a well with a certain rig and later to complete the well with another rig by fracking. The number of DUC (drilled but uncompletes well) reached a peak in 2020 at 9000!
EIA https://www.eia.gov/petroleum/drilling/ reports for the DPR regions the monthly number of wells drilled as completed and the DUCs
monthly data for DPR annual data DPR drilled and US oil&gas wells drilled





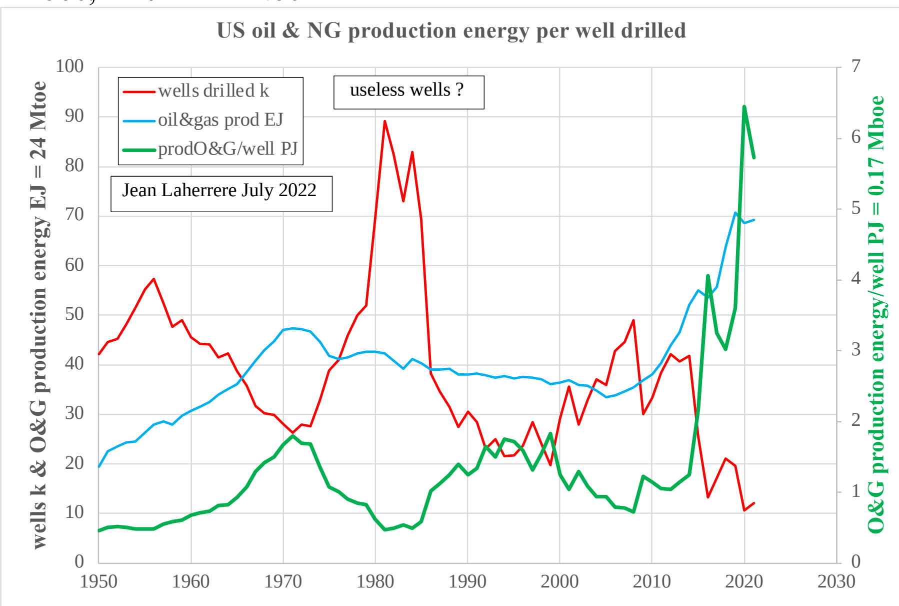
The number of drilled wells had a high peak from 1980 to 1985 following the oil shock of 1979
The success ratio in % was 76 % in 1920, went down to 56 % in 1969 and is about 90 % since 2004: it means that the exploration is dead in the US (except deep-water)!

The primary energy of the oil & gas production is plotted in EJ (from EIA quad = 1.055 EJ)) as the number of wells drilled (EIA, IPAA), and the energy per well



IEA keyworld energy statistics 2021 reports for the world in 2019 606 EJ.

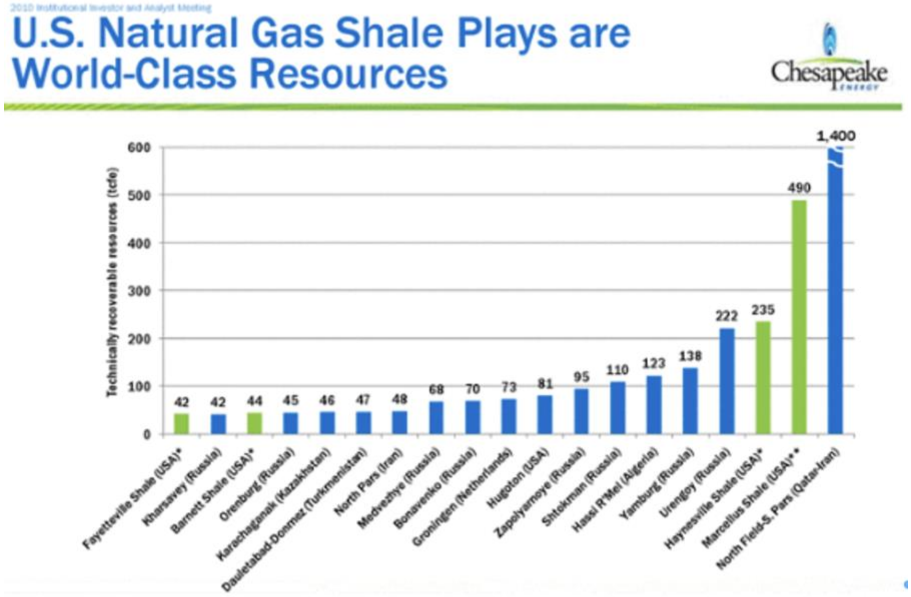
It is surprising to see how much powerful the horizontal drilling with very long extent with fracking is. The energy produced per well was between 0.5 and 1.8 PJ from 1950 to 2015 compared to 6 PJ (1 Mboe) in 2020
To convert EJ in tonne oil equivalent 1 toe = 42 GJ, 1 Mtoe = 42 PJ = 7.3 Mboe, 1 PJ = 0.024 Mtoe = 0.17 Mboe, 1 EJ = 24 Mtoe



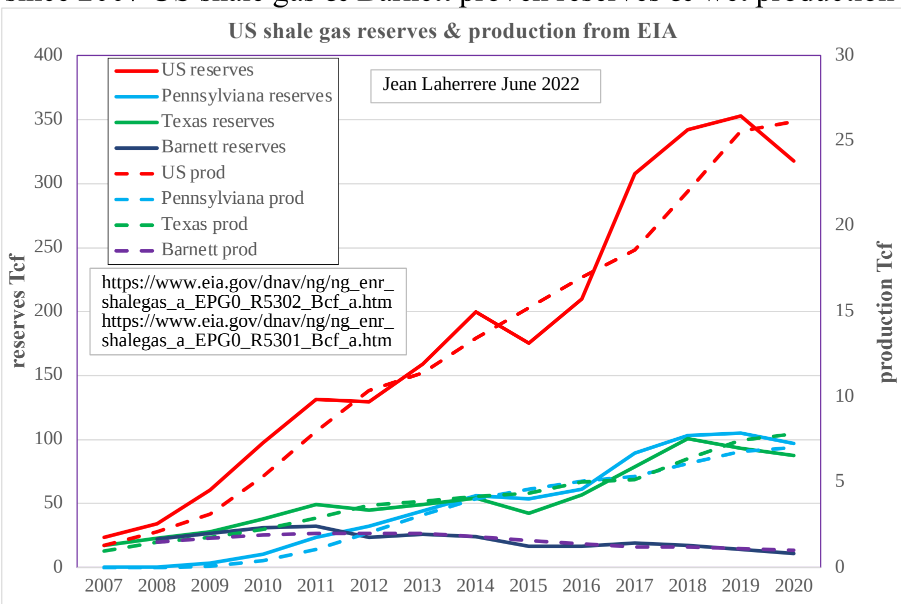
From 1981 to 1984, it appears that some wells were useless (hopeless prospects) drilled because the "1980 windfall tax"

Barnett reserves

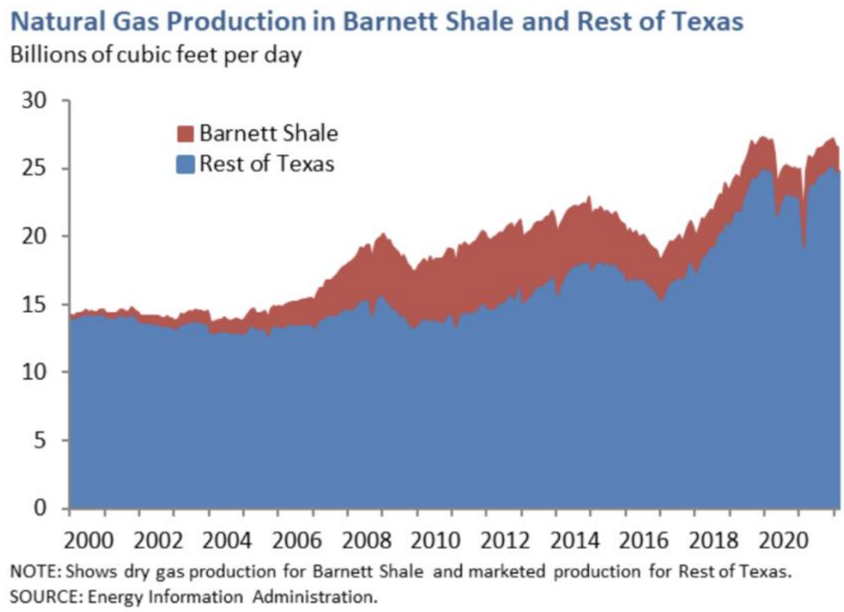
In 2010 Chesapeake compares the ultimate reserves of some gas fields with Barnett at 44 Tcf, Groningen at 73, Hassi R'mel at 123 (I participated in its discovery), Marcellus at 490 and North Field-South Pars at 1400

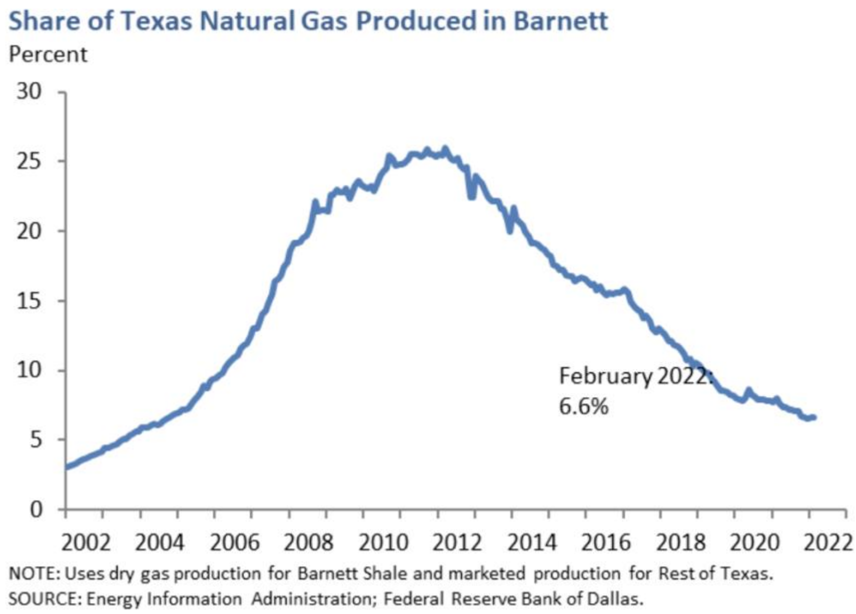


EIA reports since 2007 US shale gas & Barnett proven reserves & wet production

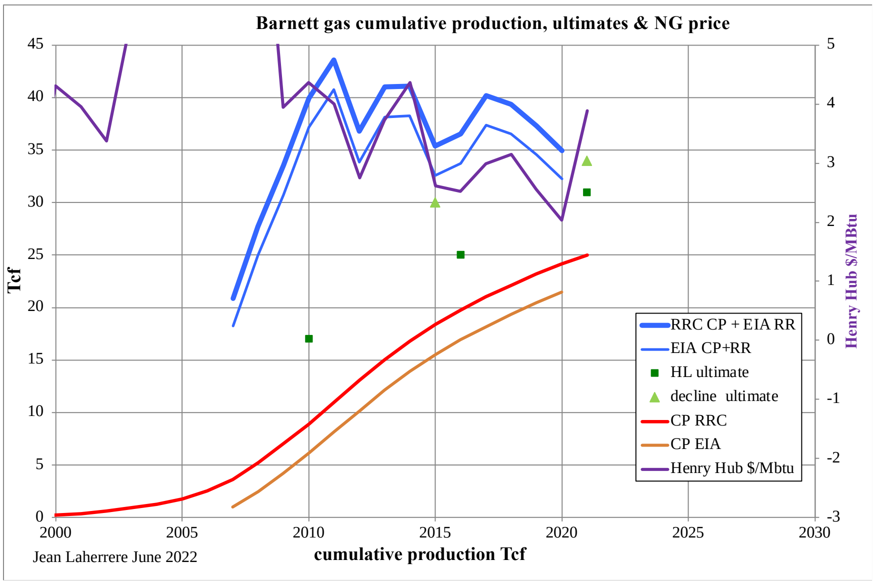


Barnett was in 2012 an important share (25 %) of Texas NG production
https://www.dallasfed.org/research/energy11/barnett#Production





EIA remaining reserves + cumulative production from RRC is in 2020 35 Tcf close to the last HL (aP/CP% vs CP) ultimate (34 Tcf), but more than the ultimate from gas decline (aP vs CP) (31 Tcf): see graph page 25.



Under SEC rules, EIA proven remaining reserves are estimated with the price of the year for the rest of their future production, and the result is that **reserves follow the up and down of gas price**: they should not. It is to protect the banker or the shareholder in case of failure, but it does not represent the future production with future price!

The goal of proven reserves is not to forecast the future production: it is just financial practice.

-Barnett natural gas production

The first problem is the discrepancy between EIA and RRC on Barnett production

EIA does not report measures but estimates (form EIA-914), when RRC reports real data

EIA reports Barnett production on different sites:

-energy explained https://www.eia.gov/energyexplained/natural-gas/where-our-natural-gas-comes-from.php

-reserves https://www.eia.gov/naturalgas/crudeoilreserves/

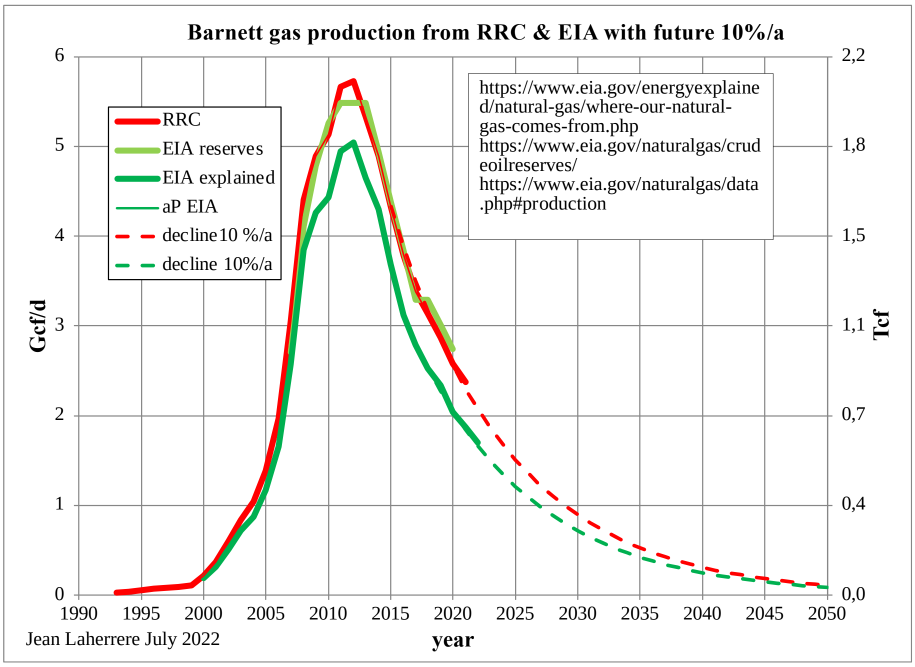
and the data is different: EIA is today making a poor job in not showing the different data on the same graph! It appears that EIA ignores reporting contradictory data (in particular on Niobrara see https://aspofrance.org/2021/11/18/us-shale-plays-production-from-eia-jan2007-sept2021-forecasts/

EIA confuses wet gas (as reported by RRC) and dry gas after removal of the liquids

The difference for 2020 is 34% between Barnett production from EIA reserves (wet gas: light green) and EIA explained (dry gas = dark green) : the explanation as the definition of the data is uncomplete !

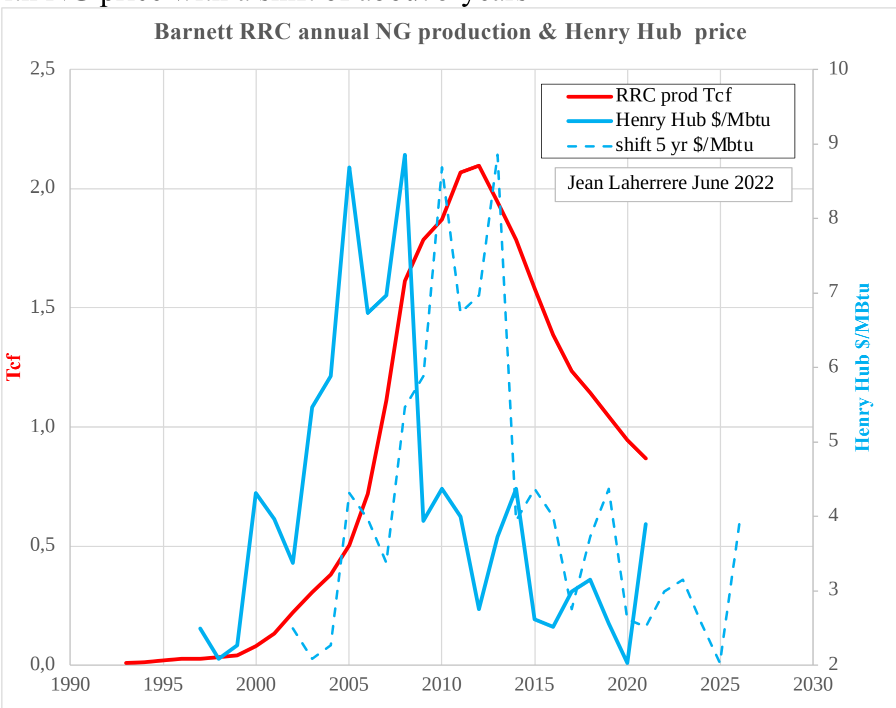
EIA production data (light green) from the reserves report differs with RRC data (red) in 2012 and in 2018 =flat wet when dry declines

It is obvious that EIA data is not checked and corrected: where is the boss?



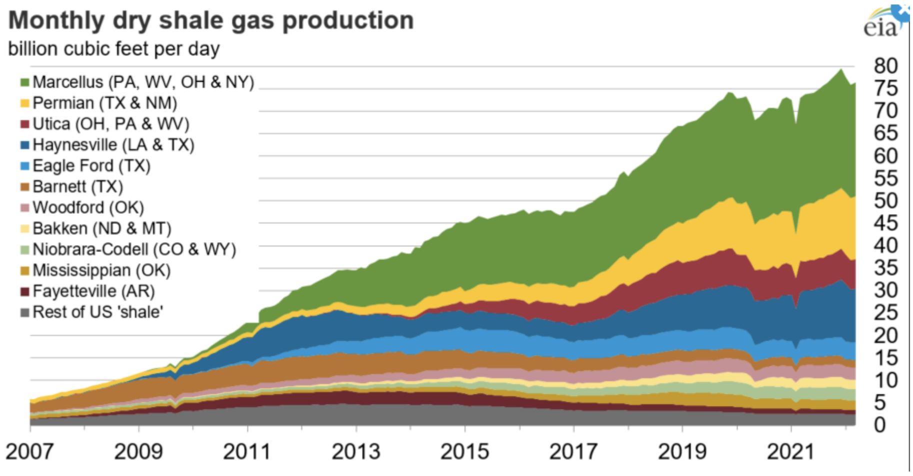
Both RRC and EIA data can be modelled since 2015 in the future with a annual decline of 10%: it is a sharp decline!

The display of the annual Barnett production with the Henry Hub price shows that production correlates with NG price with a shift of about 5 years



Barnett gas production growth was favored by a NG price sharp increase (4 times) from 2.1 to 8.7 $/MBtu from 1998 to 2005. Barnett decline also follows NG price decline from 2008 to 2020

EIA displays dry gas in the shale gas graph, when reporting wet gas in reserves.



David Hughes in Shale reality check 2021 displays past production 2000-2020 as AEO 2018, 2019, 2020 and 2021 which is for 2050 quite lower than AEO2019 which unrealistically forecasted peak beyond 2050!

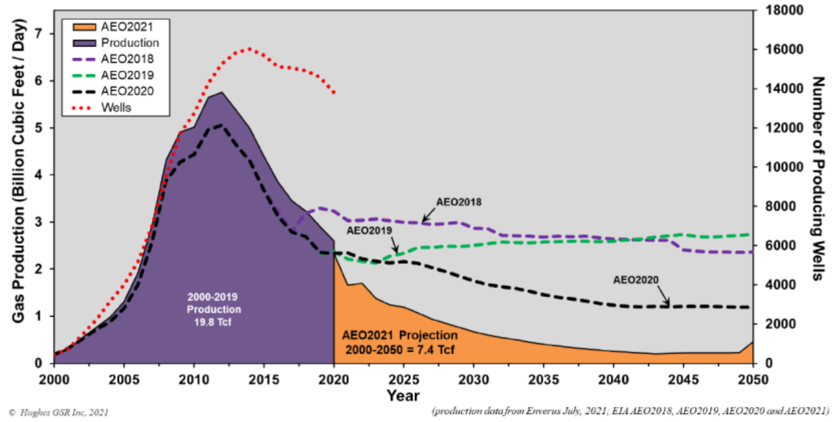


Figure 84. EIA AEO2021 reference case Barnett Play gas production forecast through 2050.[156]

-Barnett gas RRC production

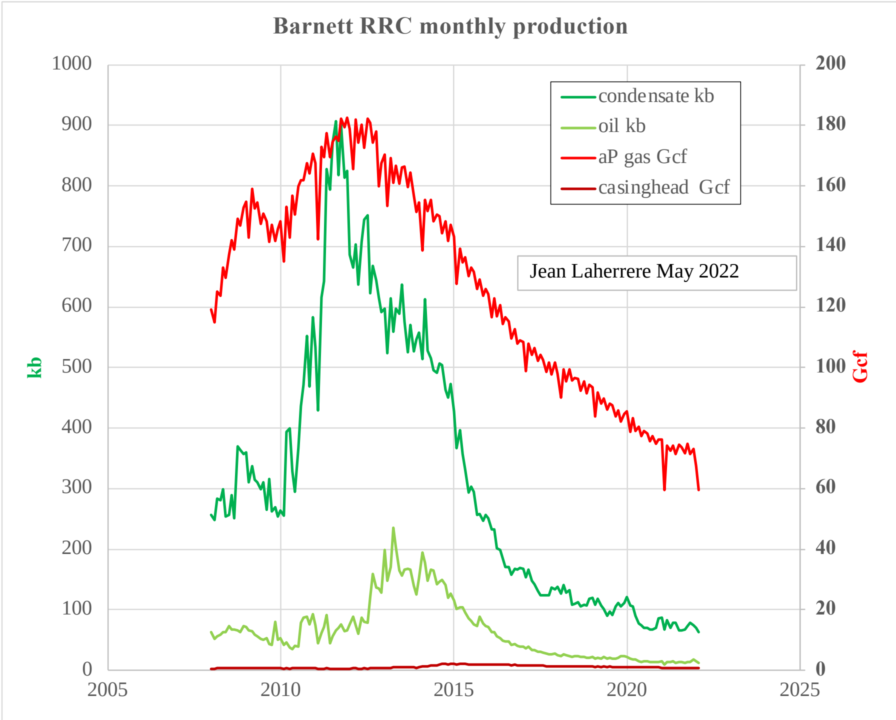
Monthly gas production has peaked

RRC reports gas production (as gas from casinghead but minor) and condensate (as oil but minor)

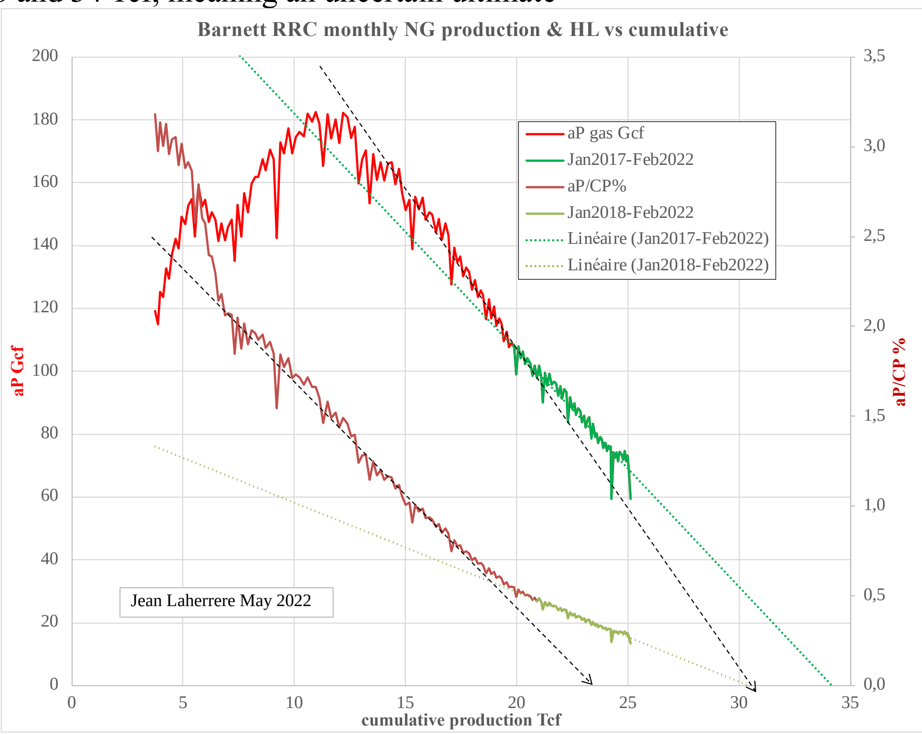
Casinghead Gas = Any gas or vapor, or both, indigenous to an oil stratum and produced from such stratum with oil. Source: Oil and Gas Division, Texas Administrative Code, Title 16, Chapter 3, February 2013. Regulations

The monthly peak has occurred:

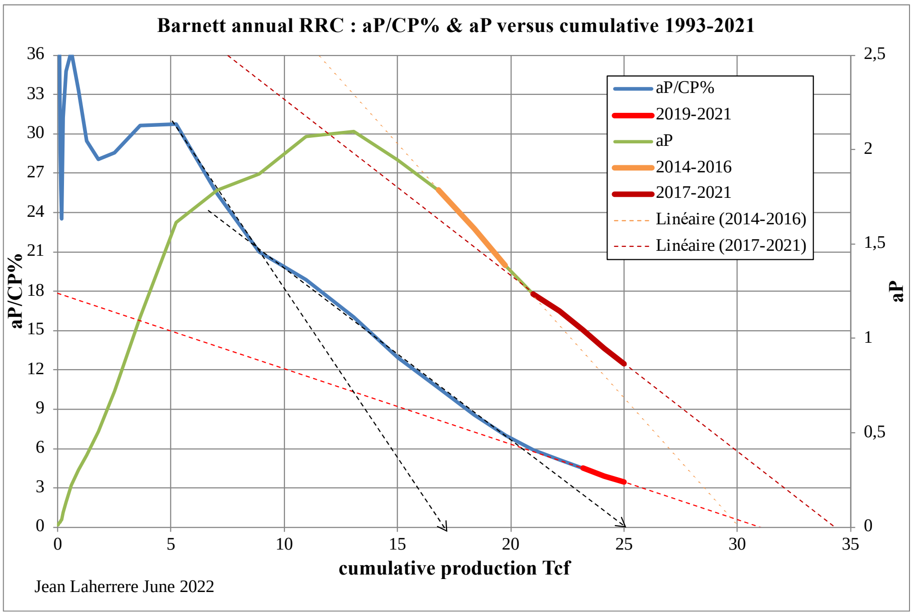
	peak time	peak value (monthly)
condensate	Aug 2011	900 kb
oil	Apr 2012	235 kb
gas	July 2012	180 Gcf
casinghead	Oct 2014	2 Gcf



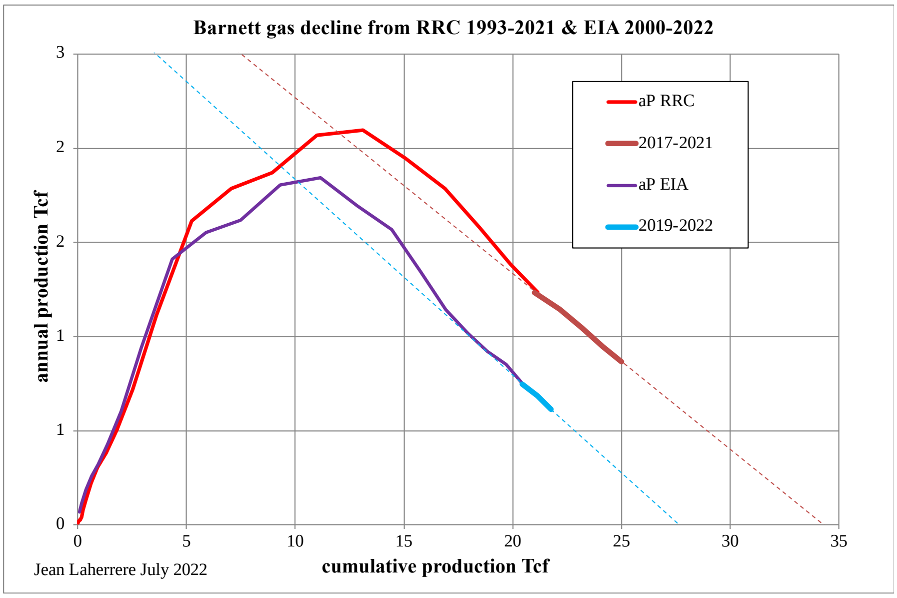
Barnett RRC monthly aP (red) & aP/CP% (deep red) versus cumulative production trends towards 30 and 34 Tcf, meaning an uncertain ultimate



The extrapolation of annual data aP & aP/CP% versus cumulative production trends to different ultimates from 17 to 34 Tcf

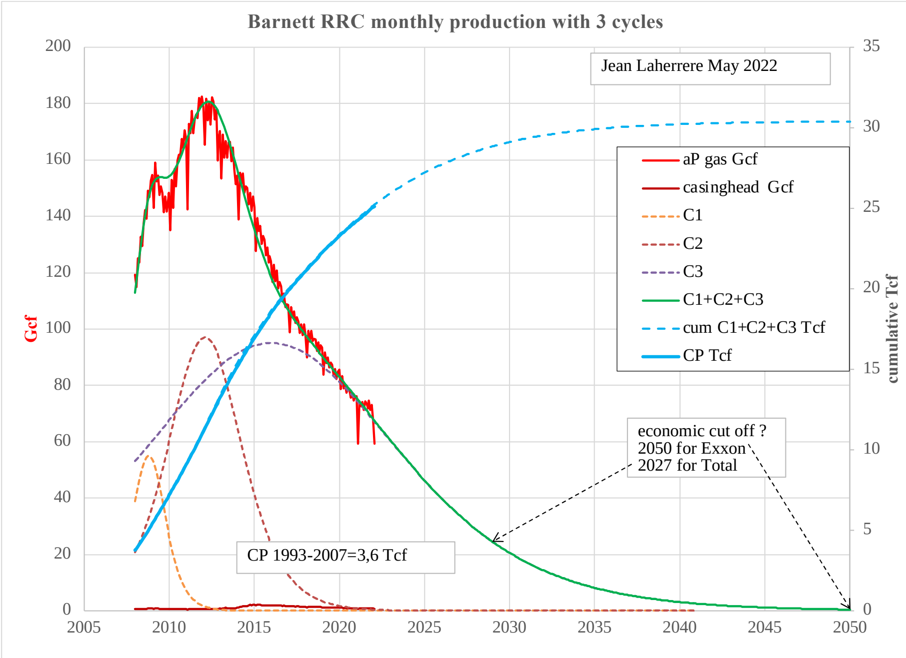


Barnett annual production versus cumulative extrapolation from RRC data (1993-2021) is compared with EIA data (2000-April 2022)
It is obvious that the data is different



-Modelling Barnett RRC with 3 cycles

This modelling looks for me more reliable and confirms that the extrapolation from oil decline (aP vs CP) is more reliable than HL, when the peak is past.



One problem is where to cut the extrapolation to address the economical cut-off as shown later in the forecast for Total and Exxon by offshore-technology.com

-Barnett gas producers

Barnett gas was developed first by George Mitchell who sold Mitchell Energy & Development to Devon in 2002 for $3.5 billion in cash and stock.
Chesapeake sold their Barnett assets to Total in 2009 (25%) and 2016 (75%)

The top 10 gas producers are listed for 2021 and 2016
https://www.rrc.texas.gov/oil-and-gas/major-oil-and-gas-formations/barnett-shale/

2021

GAS

Operator #	Operator Name	Lease Count	Gas Volume (MCF)	Gas Volume Rank
072504	BKV BARNETT, LLC	3752	175,013,529	1
842986	TEP BARNETT USA, LLC	2660	163,855,780	2
945936	XTO ENERGY INC.	2063	111,280,467	3
061620	BEDROCK PRODUCTION, LLC	1230	61,555,582	4
263924	FDL OPERATING, LLC	1111	55,460,169	5
875310	UPP OPERATING, LLC	1110	55,081,515	6
238462	EAGLERIDGE OPERATING, LLC	1388	39,074,101	7
253162	EOG RESOURCES, INC.	1052	34,831,461	8
743223	SAGE NATURAL RESOURCES LLC	468	32,390,556	9
073056	BLACKBEARD OPERATING, LLC	1153	27,466,474	10

2016

GAS

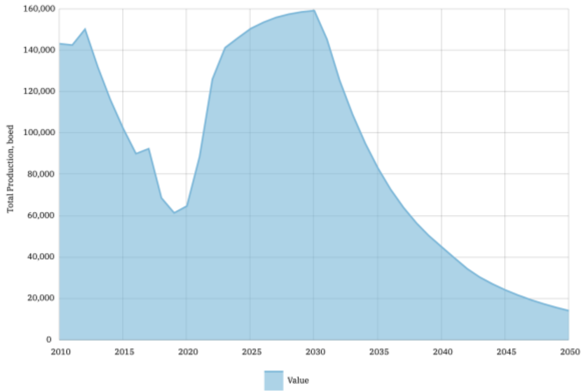
Operator #	Operator Name	Lease Count	Gas Volume (MCF)	Gas Volume Rank
216378	DEVON ENERGY PRODUCTION CO, L.P.	5043	389,719,631	1
147699	CHESAPEAKE OPERATING, L.L.C.	2763	248,414,849	2
945936	XTO ENERGY INC.	2150	199,543,766	3
253162	EOG RESOURCES, INC.	2249	127,601,151	4
252131	ENERVEST OPERATING, L.L.C.	1402	111,070,888	5
76861	BLUESTONE NATURAL RES. II, LLC	1166	65,890,570	6
882575	VANTAGE FORT WORTH ENERGY LLC	283	53,968,759	7
870311	TRINITY RIVER ENERGY OPER, LLC	993	45,553,802	8
109333	BURLINGTON RESOURCES O & G CO LP	653	22,255,259	9
684830	QUICKSILVER RESOURCES INC.	1026	17,799,014	10

In 2021 BKV is number one Barnett gas producer
In May 2022 Exxon Mobil (owner of XTO) sold its Barnett assets to BKV for 750 M$, BKV is a subsidiary of Thailand-based Banpu and TEP is a subsidiary of TotalEnergies
Barnett, which is the US model of shale gas is today produced mainly by 2 foreign companies.

The site offshore-technology.com reported future Barnett production for ExxonMobil up to its economic limit in 2050 (15 000 boe/d) and for Total up to its economic limit in 2027 (45 000 boe/d). These limits do not look homogeneous, and it is difficult to take any economic limit, as in the past production occurred even if not economical!
https://www.offshore-technology.com/marketdata/barnett-shale-exxonmobil-corporation-tx-unconventional-gas-field-us/

Production from Barnett Shale (ExxonMobil Corporation) TX

The Barnett Shale (ExxonMobil Corporation) TX unconventional gas field recovered 33.91% of its total recoverable reserves, with peak production expected in 2030. The peak production will approximately 0.31 thousand bpd of crude oil and condensate, 954 Mmcfd of natural gas and 0.13 thousand bpd of natural gas liquids. Based on economic assumptions, production will continue until the field reaches its economic limit in 2050.

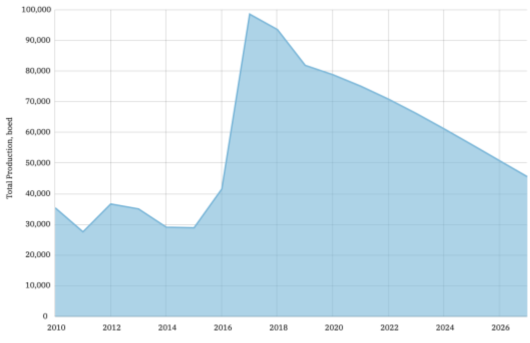


Remaining recoverable reserves

The field is expected to recover 892.28 Mmboe, comprised of 2.64 Mmbbl of crude oil & condensate, 5,331.27 bcf of natural gas reserves and 1.09 Mmbbl of natural gas liquid reserves. Barnett Shale (ExxonMobil Corporation) TX unconventional gas field reserves accounts 0.76% of total remaining reserves of producing unconventional gas fields globally.

Production from Barnett Shale (Total S.A) TX

The Barnett Shale (Total S.A) TX unconventional gas field recovered 65.39% of its total recoverable reserves, with peak production in 2017. The peak production was approximately 592 Mmcfd of natural gas and 0.03 thousand bpd of natural gas liquids. Based on economic assumptions, production will continue until the field reaches its economic limit in 2027.



These Barnett reserves were sold at a cheap price: about 1 \$/boe
https://www.worldoil.com/news/2019/12/18/devon-energy-sells-barnett-shale-assets-for-770-million
Devon Energy sells Barnett shale assets for \$770 million
The transaction with Devon includes over 320,000 gross acres and 4,200 producing wells, making BKV the largest natural gas producer in the Barnett shale.
Net production from the Barnett Shale properties averaged 597 million cubic feet equivalent per day in the third quarter of 2019. At year-end 2018, proved reserves associated with these properties amounted to approximately 4 trillion cubic feet equivalent.
4 Tcf = 667 Mboe = 1,15 \$/boe

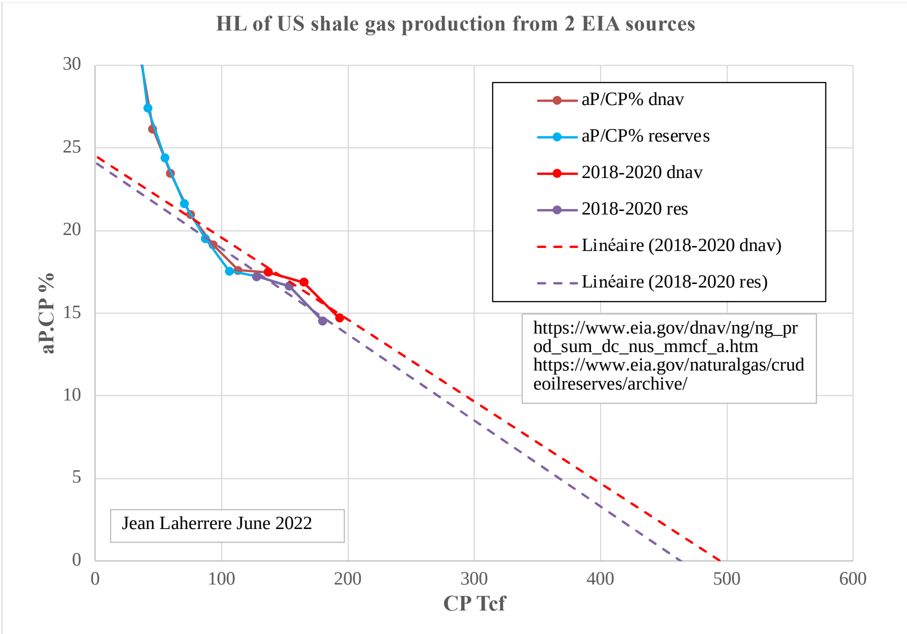
OGJ 30 May 2022
BKV (biggest Barnett producer) to buy ExxonMobil shale assets for 750 M\$ = 160 000 total net acres, 93 % in 2100 wells + 750 miles of pipeline
ExxonMobil reserves = 893 Mboe for 750 M\$ = 0.8 \$/boe = very cheap

BKV (June 2022) https://bkvcorp.com/news/bkv-corporation-and-enlink-midstream-partner-on-carbon-sequestration-project-in-the-barnett-shale wants *to develop a carbon capture and sequestration (CCS) project in the Barnett Shale region: this initiative is anticipated to offset BKV's current emissions by approximately 10 percent, bringing the company even closer to its goal of reaching net-zero by 2025.*
I have some doubt on achieving this net zero goal
CCS requires a huge amount of energy and removing present fossil fuels CO2 emissions should require one thousand more than present CCS plants. Net zero emissions is an utopia (in front of future energy needs), but a marketing tool used by most energy producers.
Zero carbon is wrong (unrealistic), as zero stock was wrong when covid19 started, as zero covid as an epidemic stops when most of the population is vaccinated or contaminated!

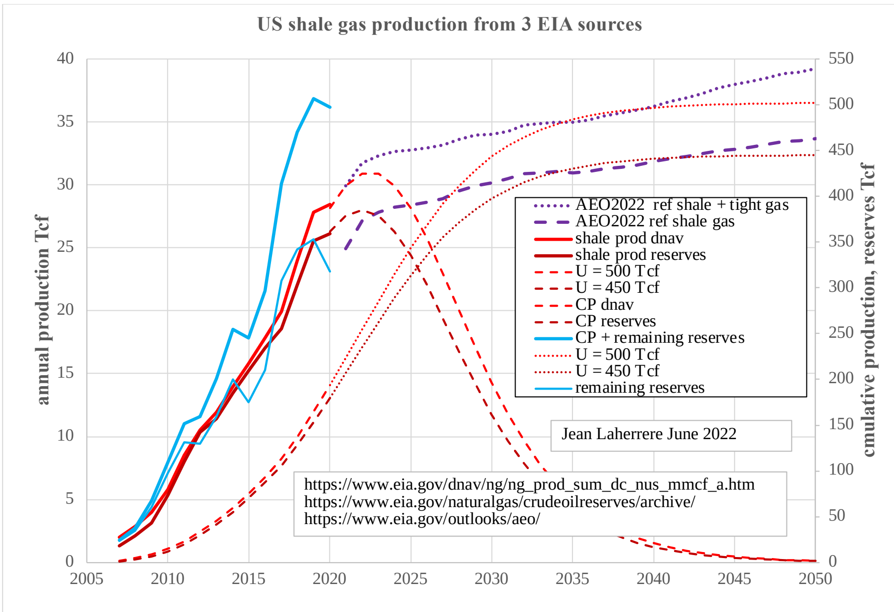
-HL of EIA shale gas production

There are several EIA sources on US shale gas production data (past and future), which are different (wet and dry)
https://www.eia.gov/dnav/ng/ng_prod_sum_dc_nus_mmcf_a.htm
https://www.eia.gov/naturalgas/crudeoilreserves/archive/
https://www.eia.gov/outlooks/aeo/
https://www.eia.gov/petroleum/drilling/faqs.php
But there is no explanation on the discrepancies, either by EIA or any oil and gas magazine! EIA is doing a bad job and no one complaints.

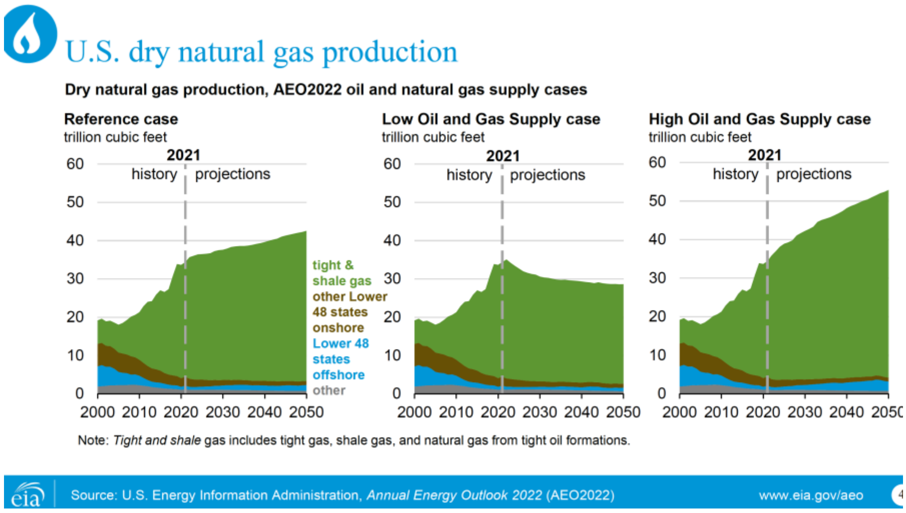
HL of NG production from the first two sources "dnav" and "reserves" trends towards an ultimate of 450 and 500 Tcf



The forecast for the ultimates 450 & 500 Tcf gives a peak around 2023, against a no peak yet in 2050 for AEO22 reference

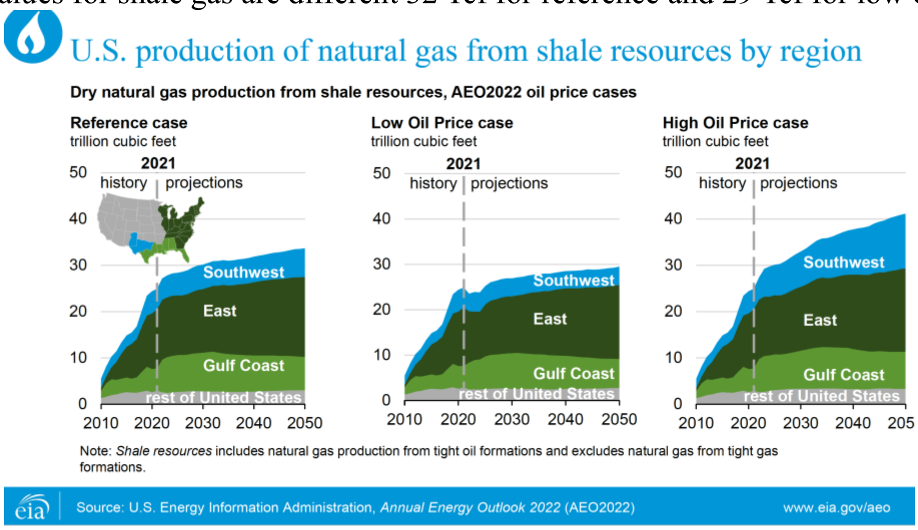


AEO2022



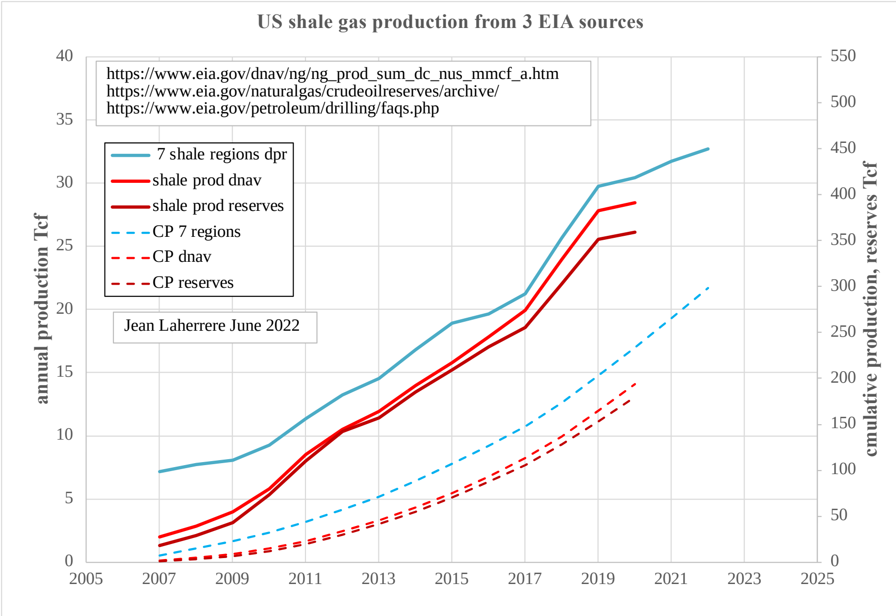
My forecast for US shale gas in 2050 is zero against 39 Tcf (tight and shale gas) for AEO2022 reference and 26 Tcf for AEO2022 low oil and gas supply: huge difference

The 2050 values for shale gas are different 32 Tcf for reference and 29 Tcf for low oil price



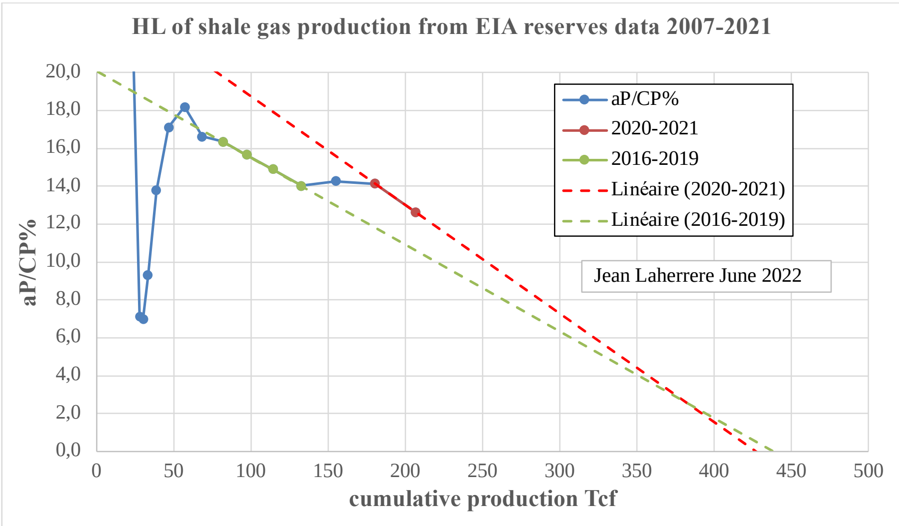
The range of US dry natural production in 2050 is wide: 28 - 53 Tcf, but not enough, denying a collapse of the shale gas by lack of drilling location.

US shale gas production from 3 EIA sources

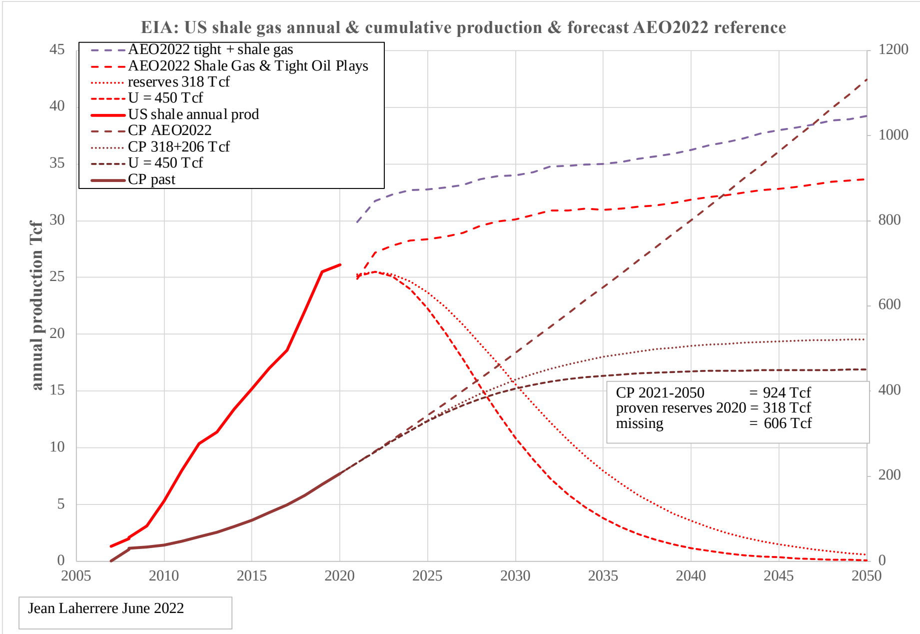


-US shale gas production forecast

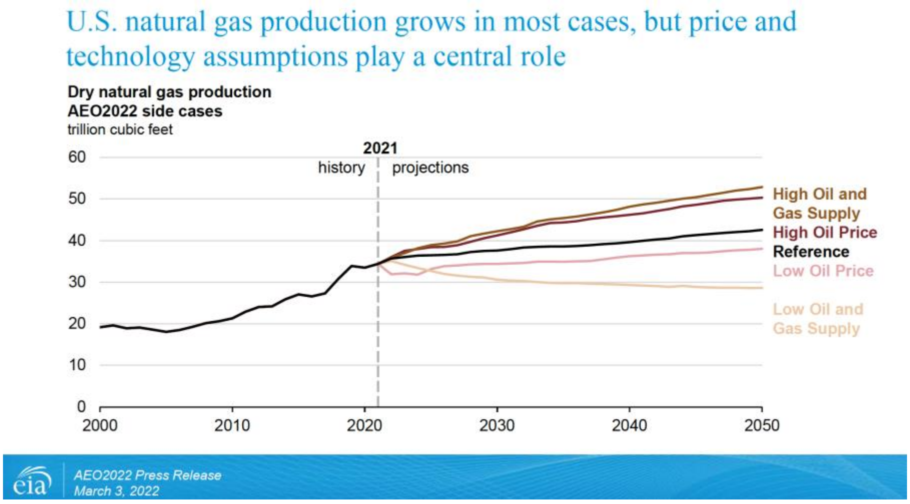
The HL of US shale gas (EIA reserves data) trends towards 450 Tcf for the period 2016-2019 as 2020-2021

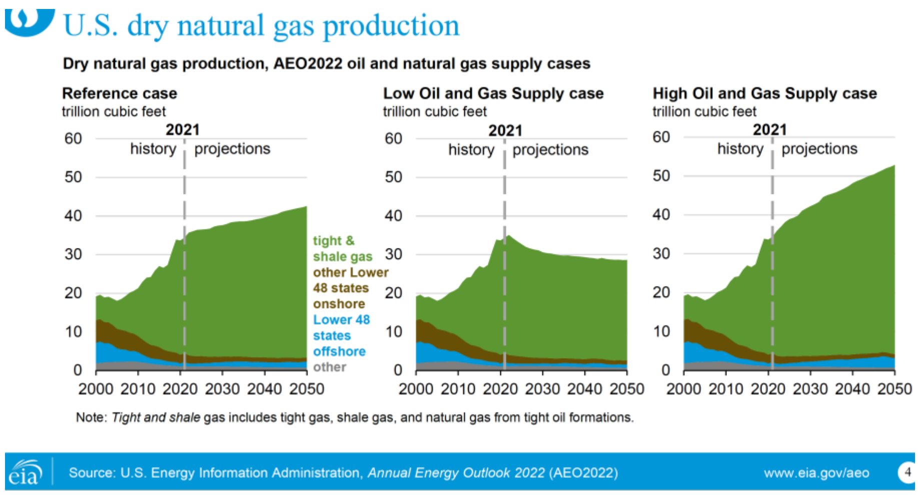


So there are three ultimates: well over 1200 Tcf for AEO2022 reference, 520 Tcf for 2020 proven reserves and 45 Tcf from HL



AEO2022 different scenarios



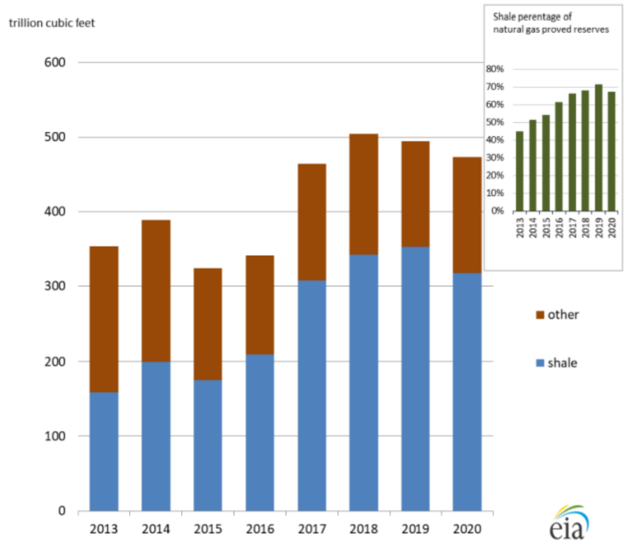


In the low gas supply case, US tight & shale gas production is forecasted to be about 25 Tcf in 2050: it is unrealistic: where are the locations left to be drilled in the sweet spots to reach such production?

Furthermore, AEO2022 cumulative dry gas production 1921-2050 is 1166 Tcf for reference and 913 Tcf for "low oil and gas supply", when the US NG proven reserves at end 2020 is only 318 Tcf = only one third of the low forecasts
AEO2022 NG forecast is contradicted by EIA reserves estimate.

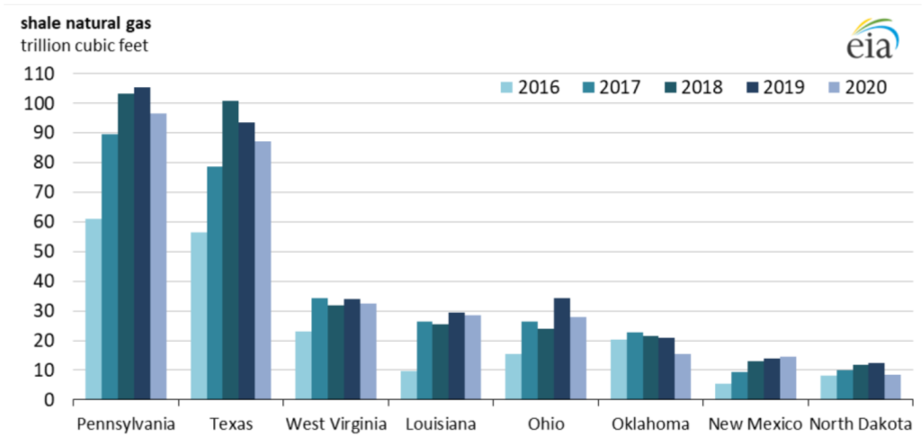
Most of the US NG reserves comes from shale

Figure 12. Proved reserves of U.S. natural gas (from shale and other sources), 2013–20



The proved shale gas reserves of the eight US shale gas states 2016-2020

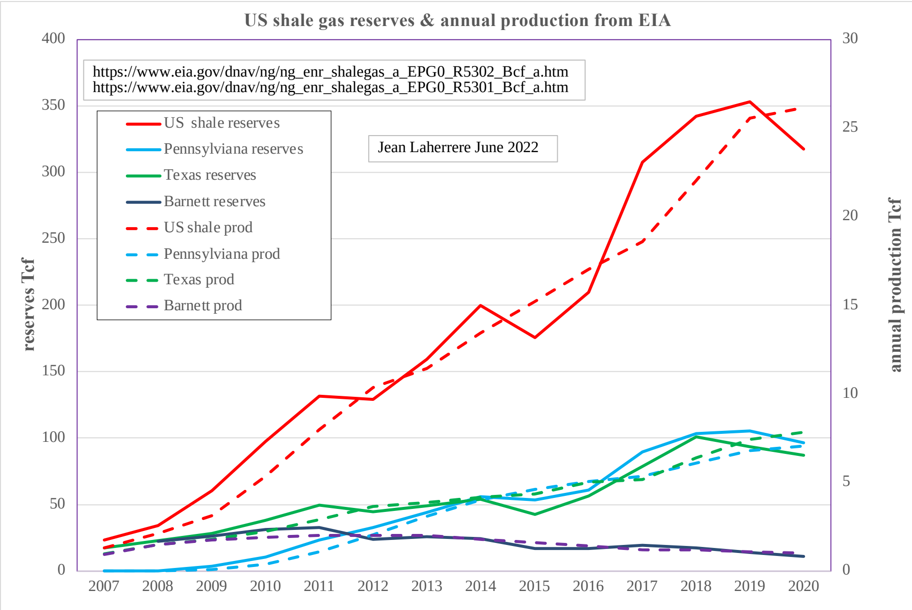
Figure 13. Proved shale gas reserves of the top eight U.S. shale gas reserves states, 2016–20



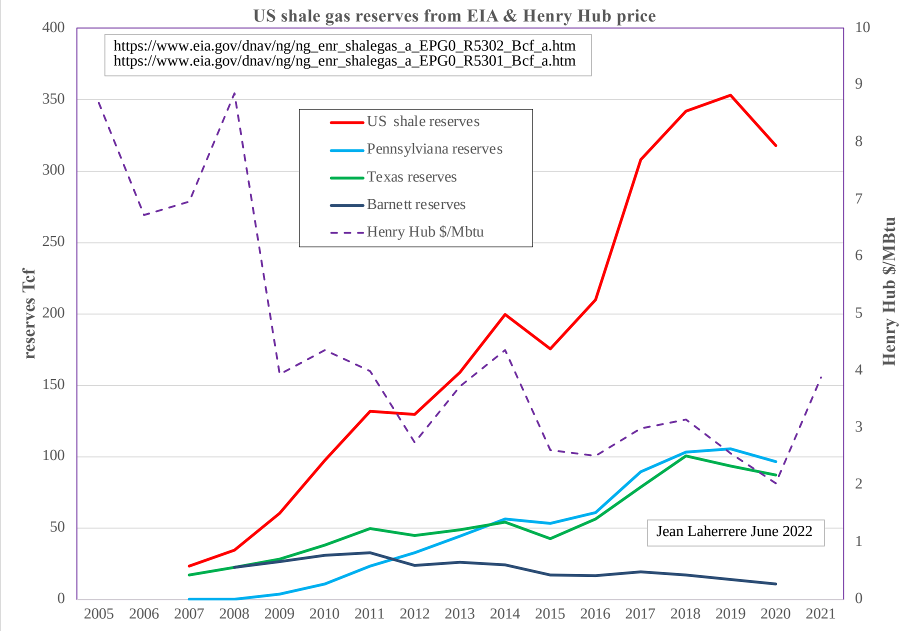
Source: U.S. Energy Information Administration, Form EIA-23L, *Annual Report of Domestic Oil and Gas Reserves, 2016–20*

Texas and Pennsylvania have similar reserves, much larger than the other states

https://www.eia.gov/petroleum/drilling/faqs.php
The detail for shale gas displays the reserves moving like production.



It is queer to see such correlation between proven (remaining) reserves and annual production: if remaining reserves were rightly estimated at the start and cover the play, they should decrease since the start, but US proven reserves following SEC rules are estimated with the oil price of the year (WTI) and not with the future price when produced!

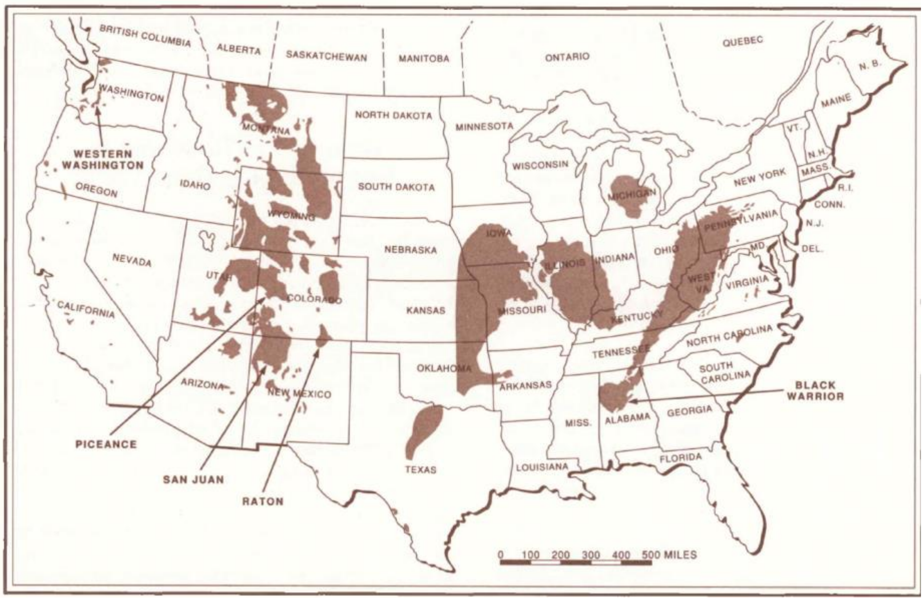


In 2014 Henry Hub price increases, so NG reserves!
In 2015 Henry Hub price decreases, so NG reserves!

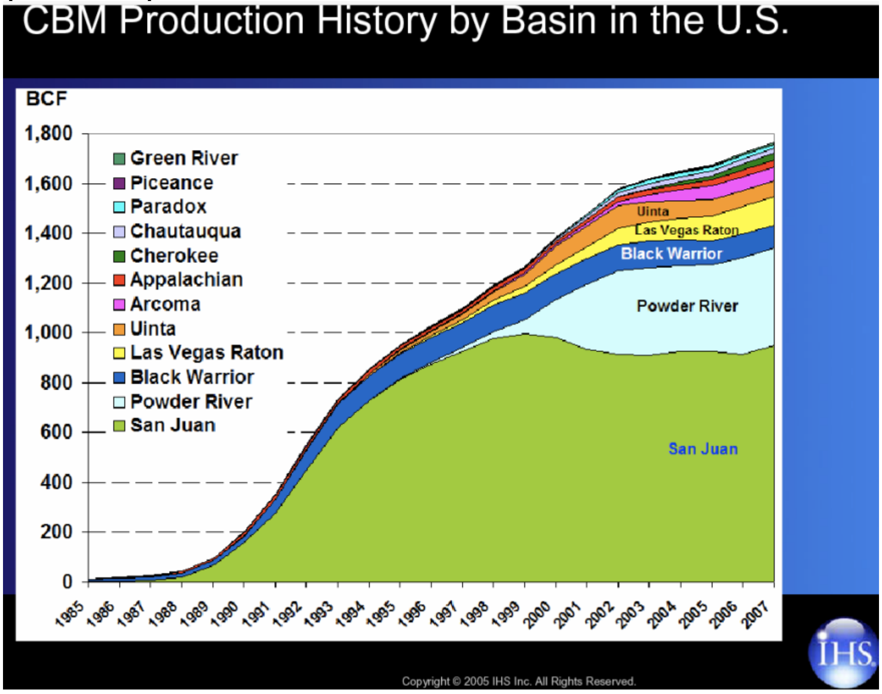
-Coalbed methane = CBM

US reserves report 1988 displays US CBM activity

Figure 11. U.S. Coalbed Methane Activity



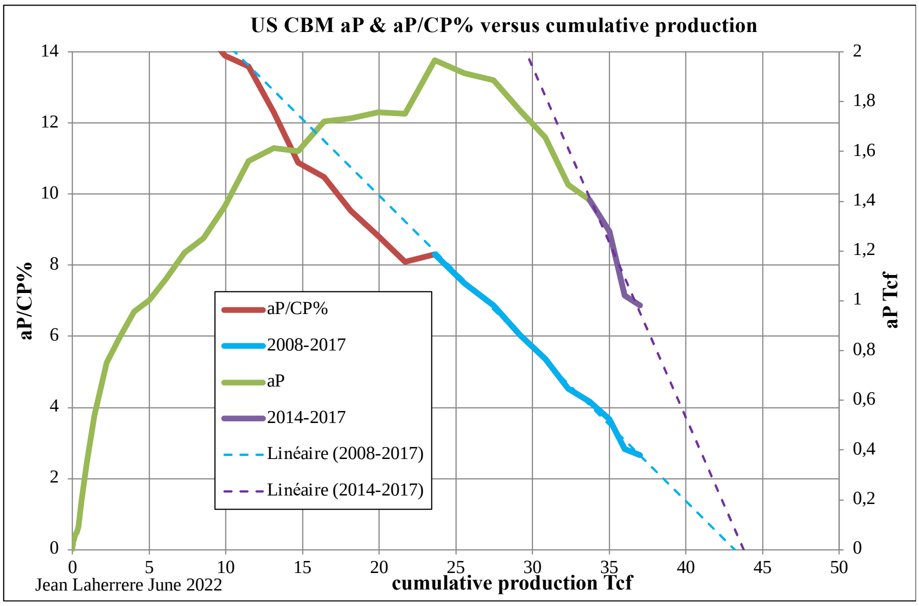
Most of the past CBM production was in the San Juan basin



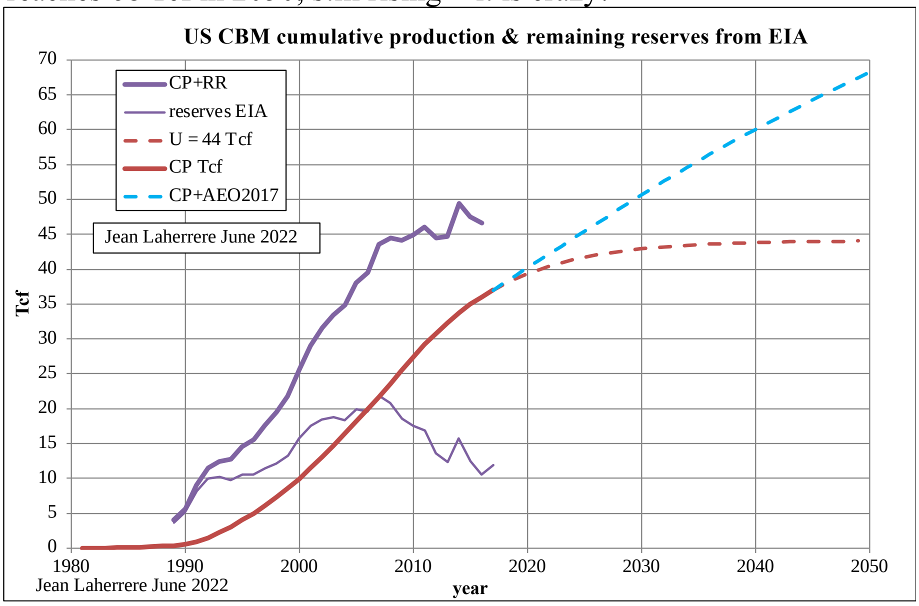
EIA reserves report end 2020

Coalbed natural gas (discontinued since the 2018 report) At year-end 2017, proved reserves of coalbed methane represented 2.6% of total U.S. proved natural gas reserves.11 We have not published proved coalbed methane reserves as a separate data category since the 2017 report. They (CBM) are now included as conventional natural gas.

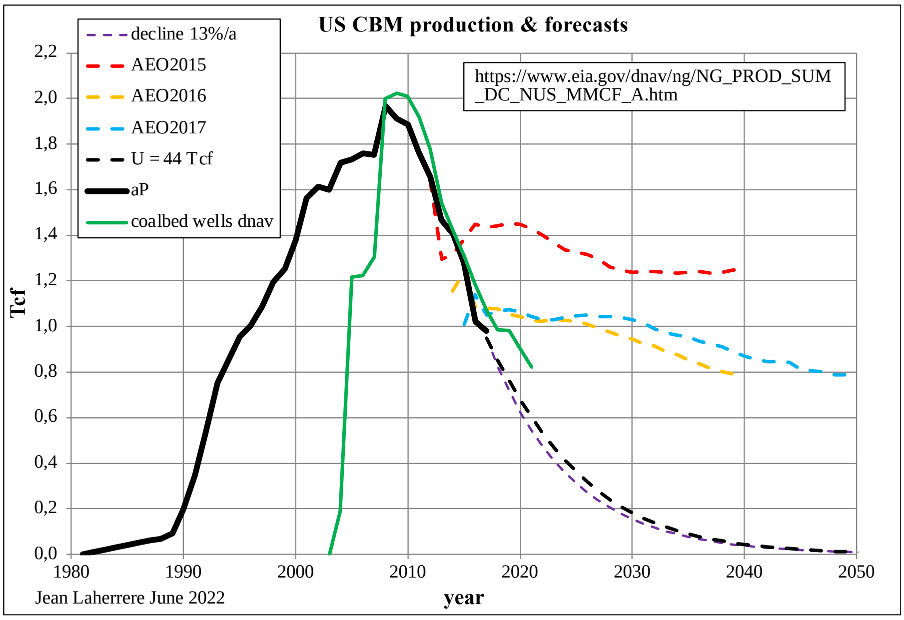
HL of CBM production trends towards 44 Tcf, as the CBM decline versus CP, making this ultimate reliable, contrary to AEO forecasts.



EIA CP + proven reserves are higher than 44 Tcf, about 47 Tcf, but the cumulative past +AEO2017 reaches 68 Tcf in 2050, still rising = it is crazy!



CBM production peaked in 2008 and the decline in the future will be strong , about 13%/a AEO2017 forecasts CBM production in 2050 to be 0.8 Tcf, the ultimate of 44 Tcf forecasts zero! AEO2017 is in contradiction with proven reserves in 2017 of 12 Tcf, as the cumulative production 2018-2050 = 31.2 Tcf, being about 20 Tcf higher than reserves!
AEO2015 too high is contradicted byAEO2017, which is still too high



EIA does not check its forecasts with their estimate of reserves!
Since 2018 EIA does not report any more CBM production, considering CBM now as conventional: in fact they mention that the production is withheld because confidentiality

U.S. Coalbed Methane Production (Billion Cubic Feet)

Decade	Year-0	Year-1	Year-2	Year-3	Year-4	Year-5	Year-6	Year-7	Year-8	Year-9
1980's										91
1990's	196	348	539	752	851	956	1,003	1,090	1,194	1,252
2000's	1,379	1,562	1,614	1,600	1,720	1,732	1,758	1,753	1,966	1,914
2010's	1,886	1,763	1,655	1,466	1,404	1,269	1,020	980	W	W

- = No Data Reported; -- = Not Applicable; NA = Not Available; W = Withheld to avoid disclosure of individual company data.

Release Date: 1/11/2021
Next Release Date: 12/20/2021

But EIA in https://www.eia.gov/dnav/ng/NG_PROD_SUM_DC_NUS_MMCF_A.htm reports annual production from coalbeds from 2002 to 2020, as from gaswells & oilwells since 1967 and from shale gas wells since 2007

Natural Gas Gross Withdrawals and Production
(Volumes in Million Cubic Feet)

Area: U.S. Period-Unit: Annual-Million Cubic Feet

Download Series History Definitions, Sources & Notes

Show Data By: Data Series / Area	Graph / Clear	2016	2017	2018	2019	2020	2021	View History
Gross Withdrawals		32,591,578	33,292,113	37,325,539	40,780,210	40,613,767	41,483,478	1936-2021
From Gas Wells		7,287,858	6,161,420	7,864,063	7,433,288	6,749,352		1967-2020
From Oil Wells		6,385,120	6,217,438	4,503,499	4,603,548	4,611,984		1967-2020
From Shale Gas Wells		17,847,539	19,927,602	23,977,248	27,840,830	28,431,290		2007-2020
From Coalbed Wells		1,071,062	985,653	980,730	902,544	821,141		2002-2020
Repressuring		3,548,106	3,538,733	3,587,368	3,521,924	3,716,990		1936-2020
Vented and Flared		230,410	255,488	470,601	539,480	419,723		1936-2020
Nonhydrocarbon Gases Removed		413,013	260,066	258,703	271,889	274,607		1973-2020
Marketed Production		28,400,049	29,237,825	33,008,867	36,446,918	36,202,446	37,011,455	1900-2021
NGPL Production, Gaseous Equivalent		1,807,934	1,897,242	2,234,593	2,547,897	2,717,182	2,865,776	1930-2021
Dry Production		26,592,115	27,340,583	30,774,274	33,899,021	33,485,264	34,145,679	1930-2021

-US natural gas reserves

Meanwhile EIA was reporting in natural gas reserves only shale gas, when AEO reports shale gas but also tight gas production

January 2022

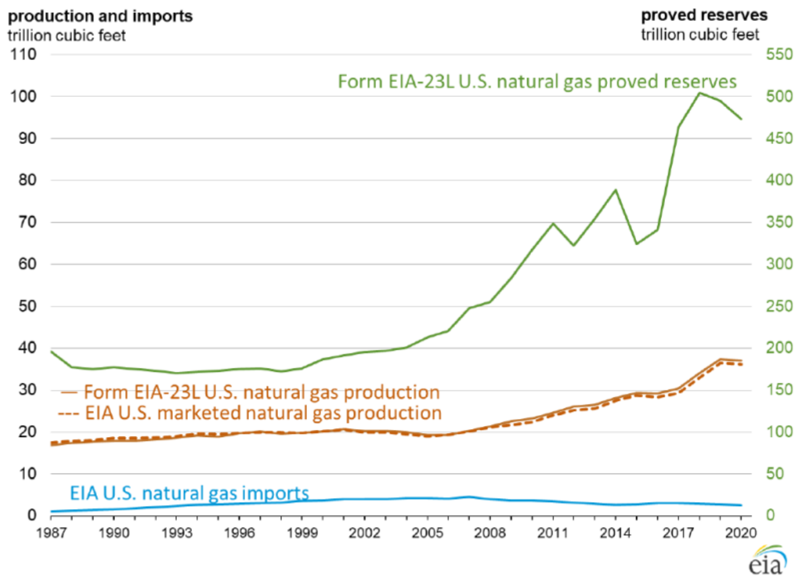
Table 3. Changes to proved reserves of U.S. natural gas by source, 2019–20
trillion cubic feet

Source of natural gas	Year-end 2019 proved reserves	2020 extensions and discoveries	2020 revisions and other changes	2020 estimated production	Year-end 2020 proved reserves
Shale	353.7	32.7	-42.5	-26.1	317.8
Other U.S. natural gas					
Lower 48 states onshore	125.9	7.0	-9.2	-9.8	113.9
Lower 48 states offshore	6.4	0.0	-0.4	-0.9	5.1
Alaska	9.4	0.1	27.3	-0.2	36.5
U.S. total	**495.4**	**39.8**	**-24.9**	**-37.1**	**473.3**

In our paper -Laherrere J.H. 2021 "US shale plays production from EIA Jan2007-Sept2021 & forecasts" November https://aspofrance.org/2021/11/18/us-shale-plays-production-from-eia-jan2007-sept2021-forecasts/
we mention the discrepancy between 3 series of US oil and gas production data
source a: prod data https://www.eia.gov/petroleum/drilling
source b: reserves data including production data
https://www.eia.gov/naturalgas/crudeoilreserves/
source c: energy explained https://www.eia.gov/energyexplained/oil-and-petroleum-products/data/US-tight-oil-production.

EIA Proved reserves of crude oil and natural gas in the US end 2020

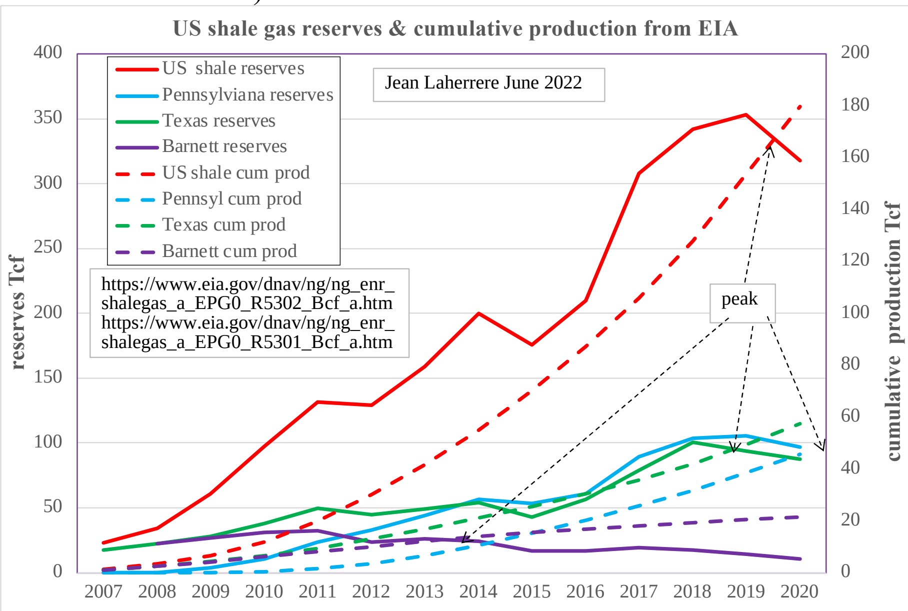
Figure 5. Proved reserves, production, and imports of U.S. natural gas, 1987–2020



Form 23L:
It is not feasible to perform a complete census of all domestic oil and gas well operators (see Section L Definitions, page 8) every year. Instead, the U.S. Energy Information Administration selects a sample of operators from each producing area of the United States; (e.g., state, state subdivision, state waters, and Federal Offshore waters) for a survey year (Survey Year sample).
Selection to the Survey Year sample is determined by the total or gross (8/8ths) annual operated production rate within the producing area. Production refers to the total survey year production from all domestic oil and/or gas wells you operated on December 31, of the survey year, including wells abandoned during the survey year.
It is not real data but sample! It is not dry gas but gross gas

EIA provides different values for 2020 NG production: 36,2 and 37,1 Tcf
Our official published estimate of marketed natural gas production was 36.2 Tcf in 2020, a decrease of less than 1% from 2019 (36.4 Tcf). Using Form EIA-23L responses instead of official statistics, we estimate that U.S. production of total natural gas, wet after lease separation, in 2020 was 37.1 Tcf

The plot of proven remaining reserves and cumulative production indicates that the peak is reached when cumulative production is above remaining reserves (cumulative future production from now to the end).

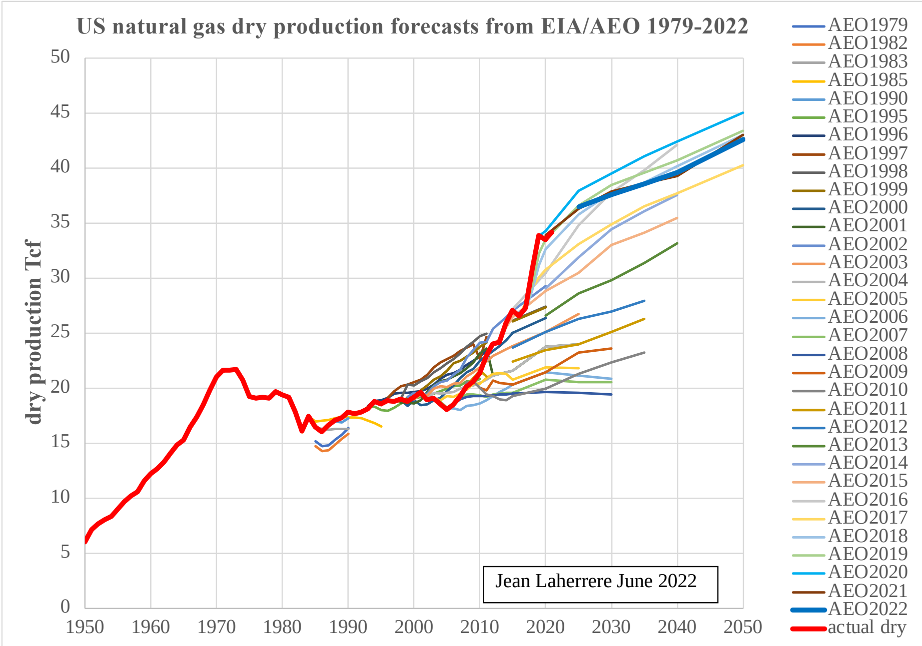


The peak has occurred for Barnett in 2013, for Texas in 2019 and for US shale in 2020, but not yet for Pennsylvania (2022?)

EIA estimates that the proven shale gas reserves are 318 Tcf at end 2020, meaning that the cumulative production from 2021 to the end is 318 Tcf but AEO 2022 reference forecasts for shale gas an increasing production from 2021 (25 Tcf) to 2050 (34 Tcf) with a total of 924 Tcf, completely against the 318 Tcf of proven reserves: 606 Tcf are missing in proven reserves compared to AEO forecast. These 318 Tcf will corresponds to a peak in 2022 and almost zero production for 2050 against 34 Tcf for AEO 2022 reference, and 28 Tcf for AEO2022 low oil and gas supply!
The discrepancy is huge

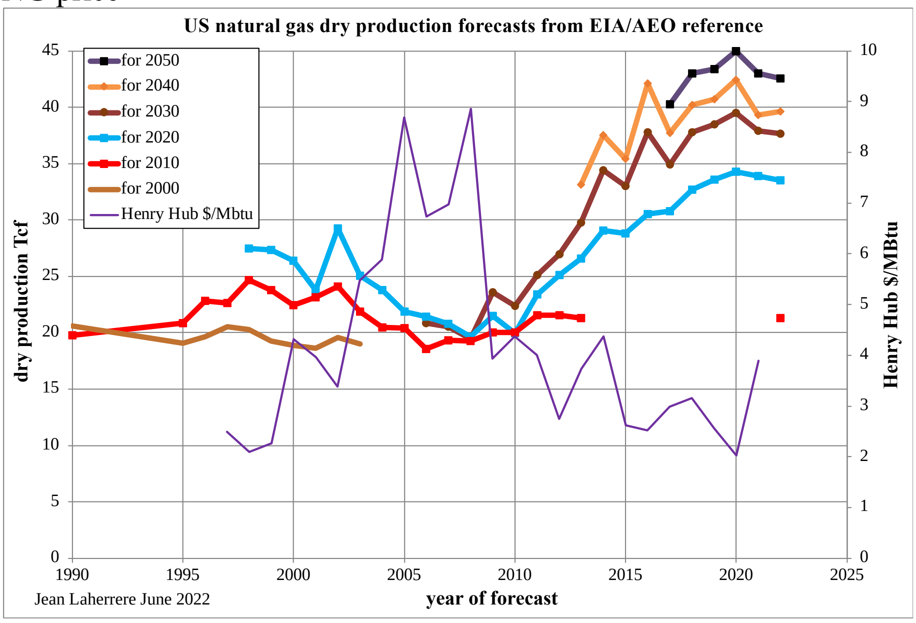
-Evolution of EIA/AEO natural gas production forecasts

EIA natural gas dry production is forecasted by AEO since 1979 to 2022
The evolution of the forecast is rather chaotic as shale gas was not forecasted before 2010



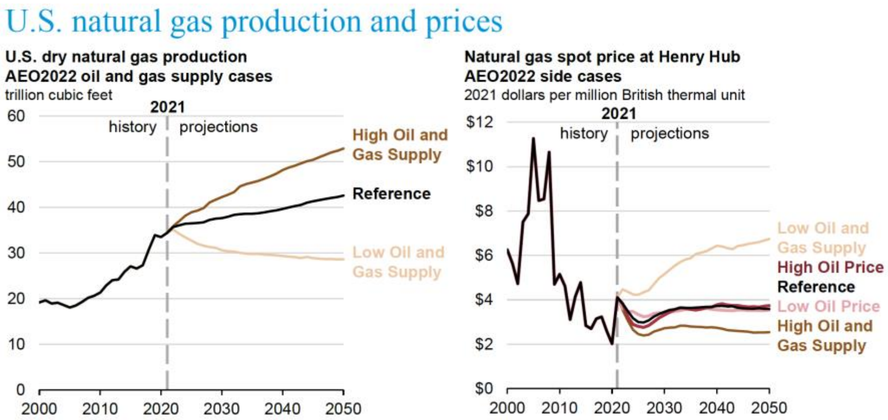
2020 NG production is 33.5 Tcf was forecasted as 20 Tcf in 2010, but 29 Tcf in 2002 = poor job!

The US NG production forecast for 2020 and 2030 varies drastically since 2008, despite the decrease in NG price



The forecast of 42.6 Tcf in 2050 by AEO2022 reference looks to me very optimistic, close to unrealistic: see below: my forecast is about zero!

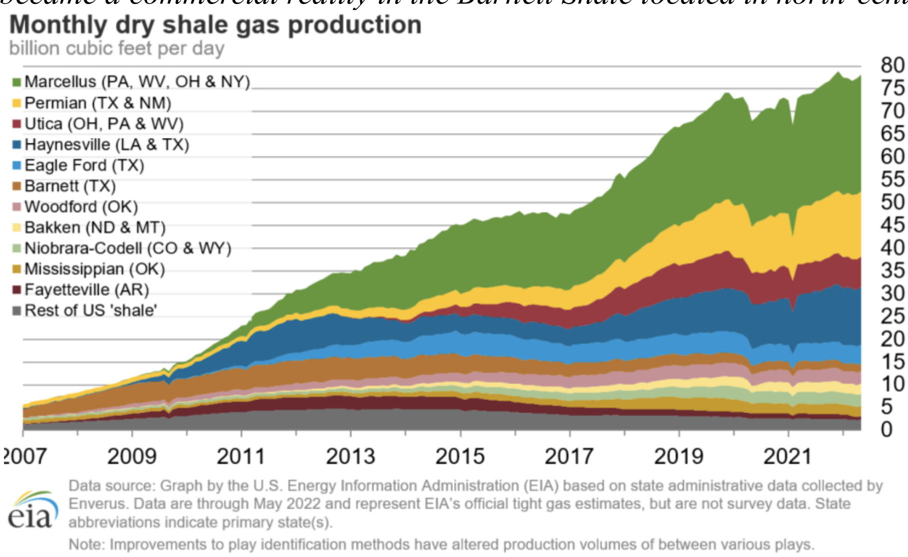
AEO2022



AEO reports future production of separate gas shale and tight gas
The site https://www.eia.gov/energyexplained/natural-gas/where-our-natural-gas-comes-from.php defines

-shale natural gas

Large-scale natural gas production from shale began around 2000, when shale gas production became a commercial reality in the Barnett Shale located in north-central Texas.



-tight natural gas

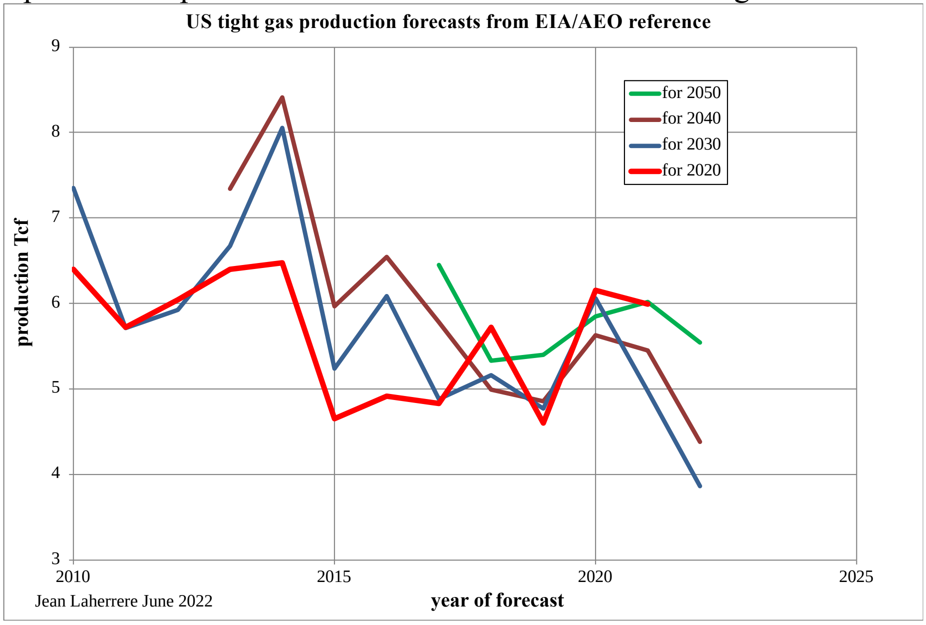
Tight natural gas was first identified as a separate category of natural gas production with the passage of the Natural Gas Policy Act of 1978 (NGPA). The NGPA established tight natural gas as a separate wellhead natural gas pricing category that could obtain unregulated market-determined prices. The tight natural gas category gave producers an incentive to produce high-cost natural gas resources when U.S. natural gas resources were believed to be increasingly scarce.

With the full deregulation of wellhead natural gas prices and the repeal of the associated Federal Energy Regulatory Commission (FERC) regulations, tight natural gas no longer has a specific definition, but it generically still refers to natural gas produced from low-permeability sandstone and carbonate reservoirs.

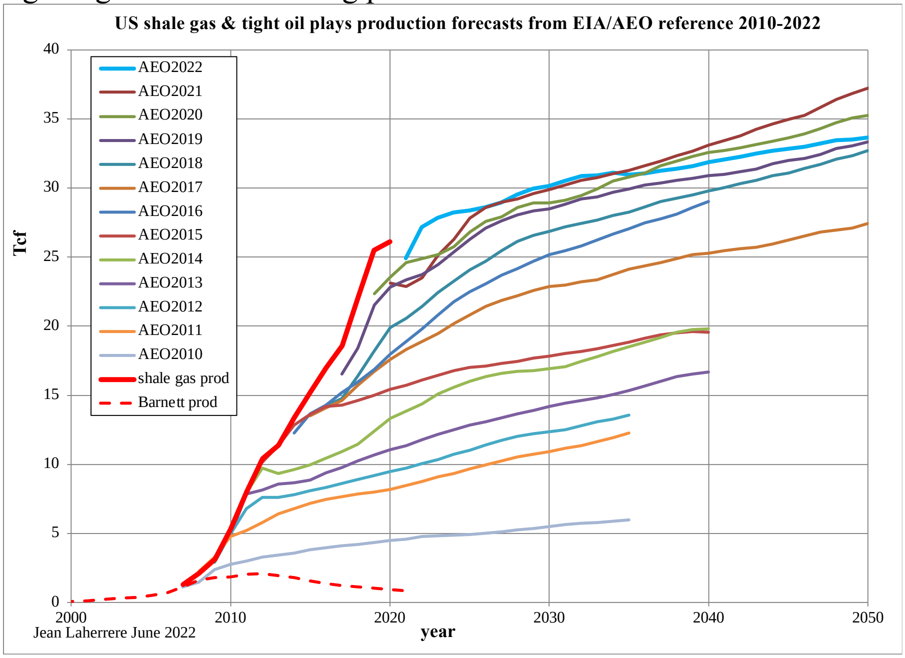
Notable tight natural gas formations include, but are not confined to:

Clinton, Medina, and Tuscarora formations in Appalachia
Berea sandstone in Michigan
Bossier, Cotton Valley, Olmos, Vicksburg, and Wilcox Lobo along the Gulf Coast
Granite Wash and Atoka formations in the Midcontinent
Canyon formation in the Permian Basin

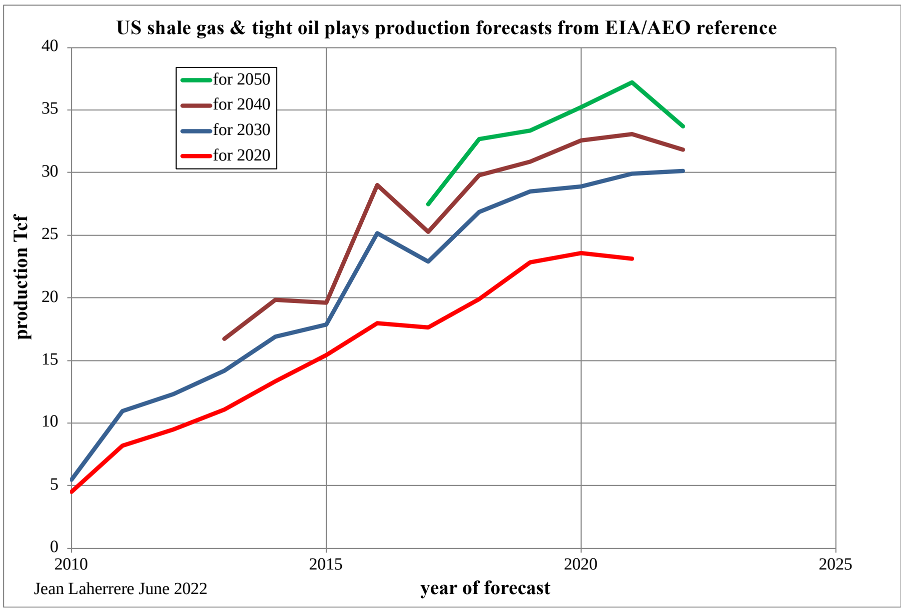
Mesaverde and Niobrara formations in multiple Rocky Mountain basins
But EIA does not display any graph on tight gas production in this paper
It appears that the difference between shale and tight gas comes from financial reasons!
EIA reports only shale gas reserves, but tight gas production!
AEO2022 ref for tight gas production is much lower than AEO2014 ref: tight gas is replaced by shale gas!
AEO still reports future production with the breakdown shale and tight



Since 2010 the forecast for shale gas & tight oil plays production is on the increase
AS EIA did not forecast in 2010 the shale/tight burst, being too pessimistic, to day EIA is too optimistic forgetting to forecast coming peak and decline

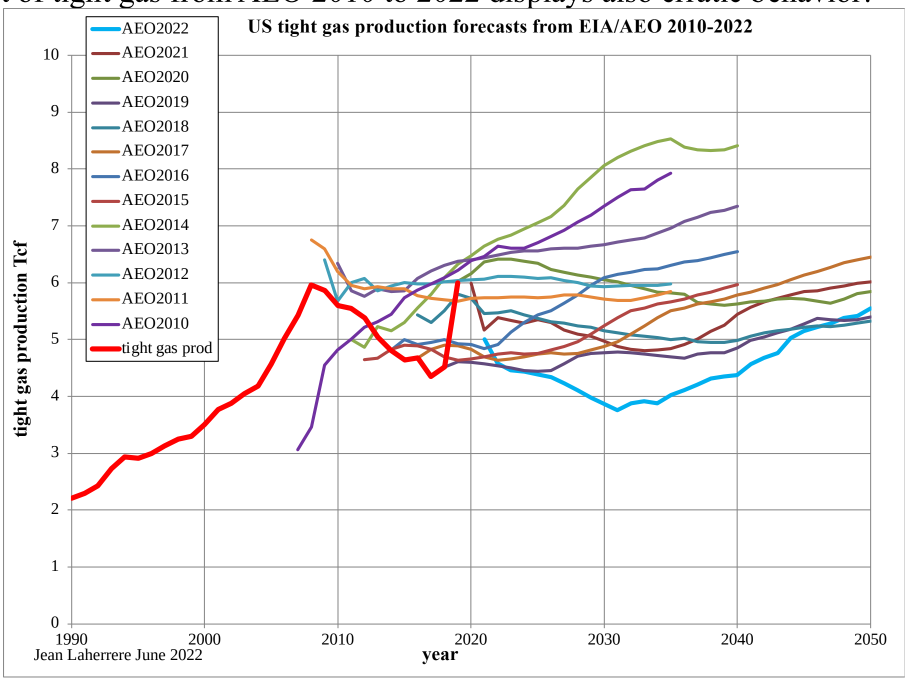


The shale gas forecast for 2040 was 16.9 Tcf in 2013 but 31,9 Tcf in 2022: shale gas future is bright for EIA but much less for me. For 2050 it is higher, when it is zero for me, because all the sweet spots will be drilled then: it is necessary to keep drilling just to maintain the production.

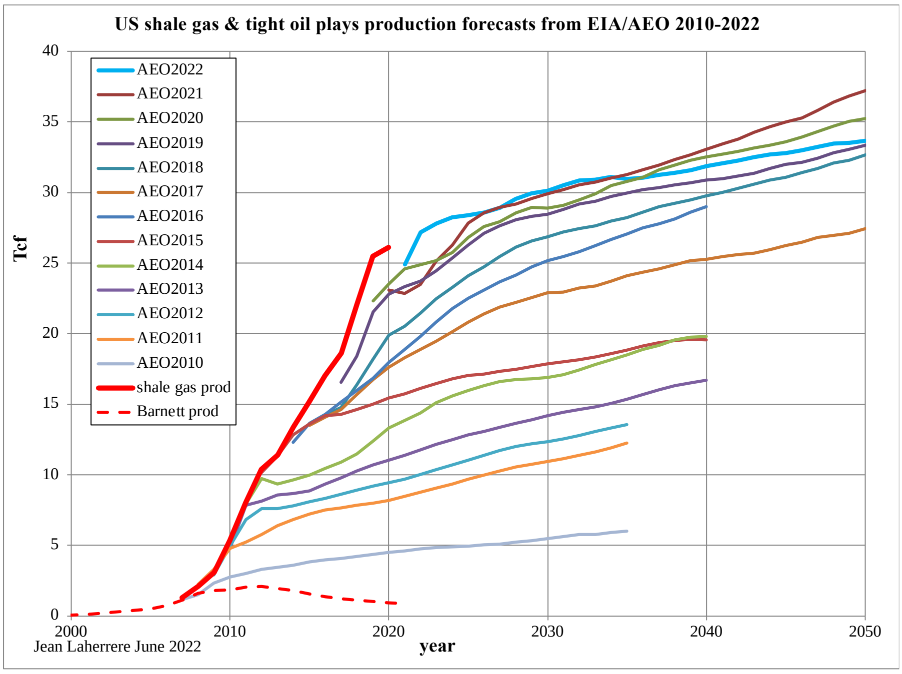


The graph page 17 of the forecast 1997 to 2022 of US annual wells (base of the forecast of production) shows EIA poor in forecasting.

The forecast of tight gas from AEO 2010 to 2022 displays also erratic behavior!



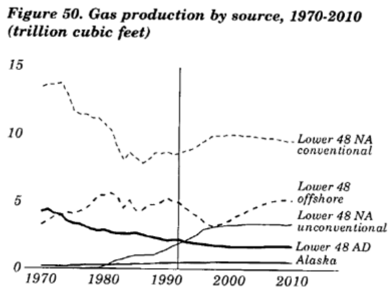
The sum of shale + right is less erratic, but displays a huge range : for 2030 from 5 to 30 Tcf = 6 times!

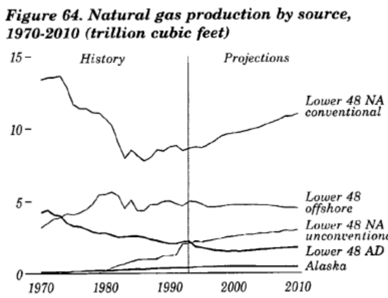


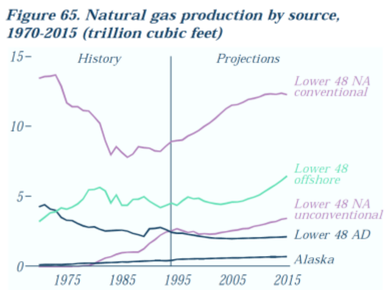
EIA was poor in the definition of unconventional gas, displaying different types in their AEO (annual energy outlook) since 1994:

A look at annual AEO displays is better than a long text:

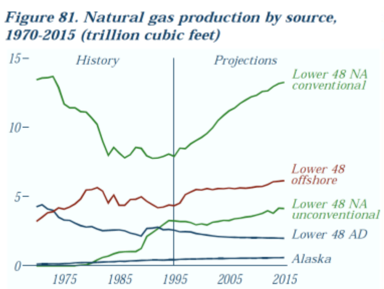
AEO1994 AEO1995 AEO1996

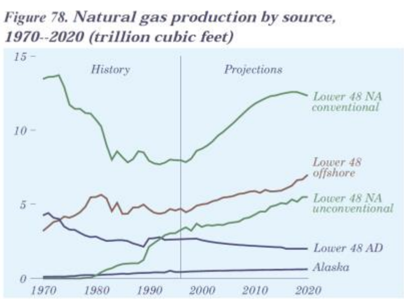


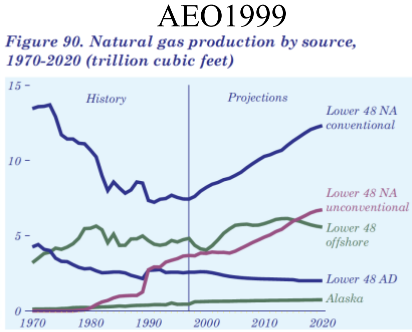




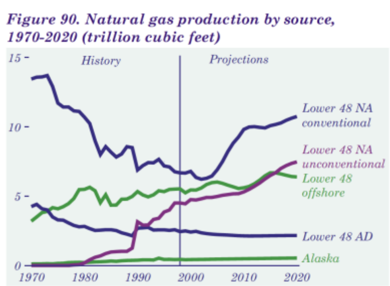
AEO1997 AEO1998 AEO1999

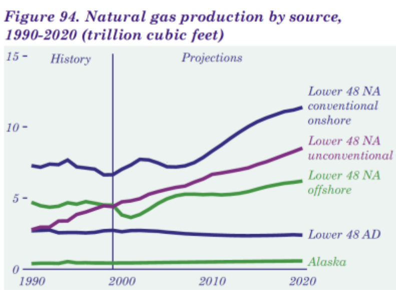


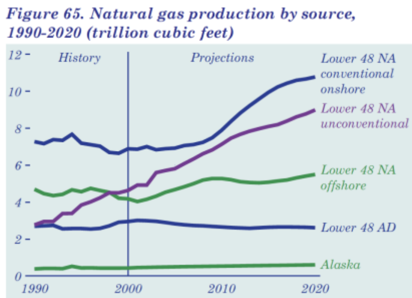




AEO2000 AEO2001 AEO2002

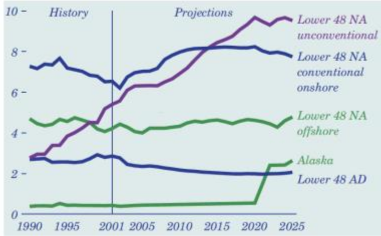






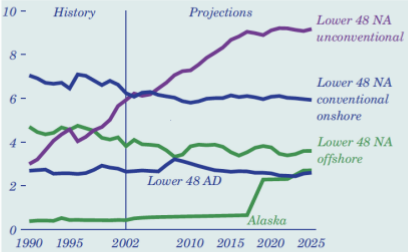
AEO2003 AEO2004 AEO2005

Figure 80. Natural gas production by source, 1990-2025 (trillion cubic feet)



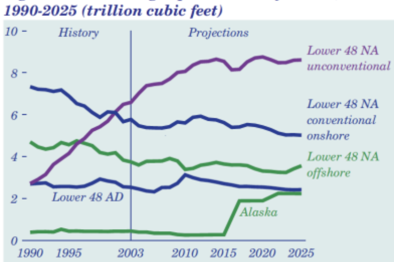
AEO2006

Figure 87. Natural gas production by source, 1990-2025 (trillion cubic feet)



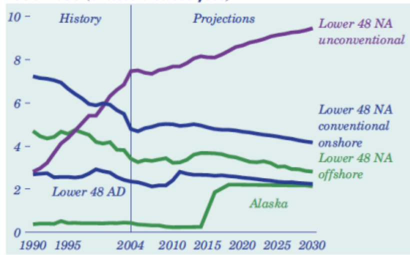
AEO2007

Figure 83. Natural gas production by source, 1990-2025 (trillion cubic feet)



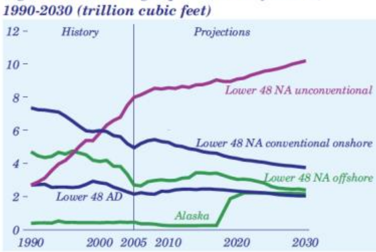
AEO2008

Figure 73. Natural gas production by source, 1990-2030 (trillion cubic feet)



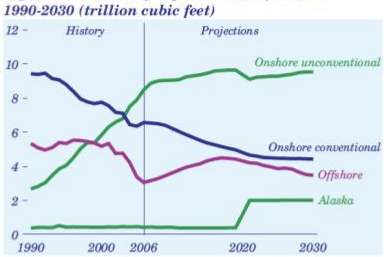
AEO2009

Figure 75. Natural gas production by source, 1990-2030 (trillion cubic feet)



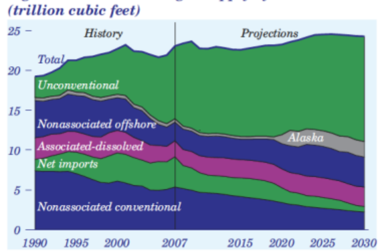
AEO2010

Figure 80. Natural gas production by source, 1990-2030 (trillion cubic feet)



AEO2011

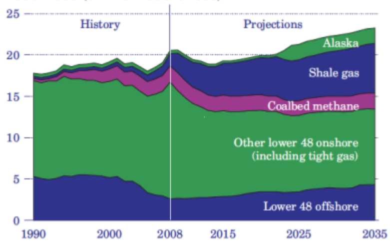
Figure 2. Total natural gas supply by source (trillion cubic feet)



on / Annual Energy Outlook 2009

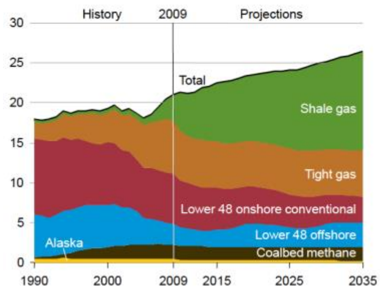
AEO2012

Figure 73. Natural gas production by source, 1990-2035 (trillion cubic feet)



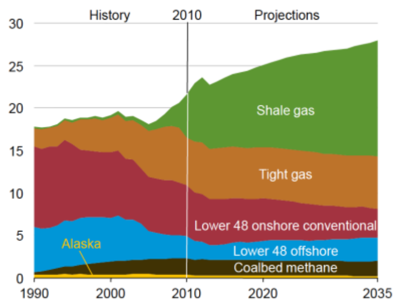
AEO2013

Figure 89. Natural gas production by source, 1990-2035 (trillion cubic feet)



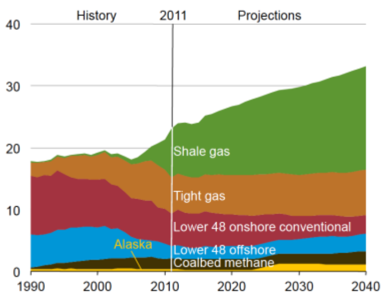
AEO2014

Figure 107. Natural gas production by source, 1990-2035 (trillion cubic feet)



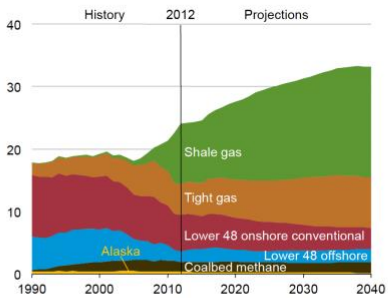
AEO2015

Figure 91. Natural gas production by source, 1990-2040 (trillion cubic feet)

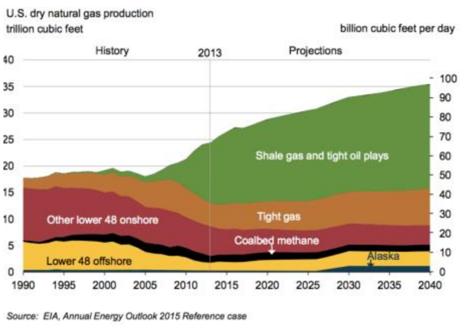


AEO2016

Figure MT-44. U.S. natural gas production by source in the Reference case, 1990-2040 (trillion cubic feet)

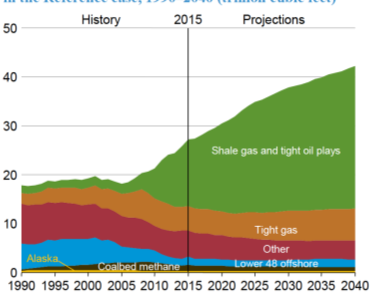


AEO2017



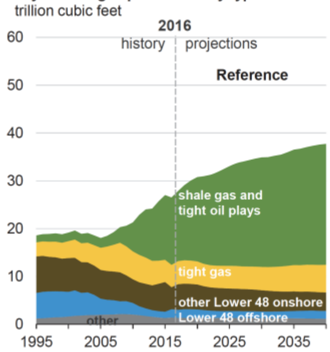
AEO2018

Figure MT-46. U.S. dry natural gas production by source in the Reference case, 1990–2040 (trillion cubic feet)

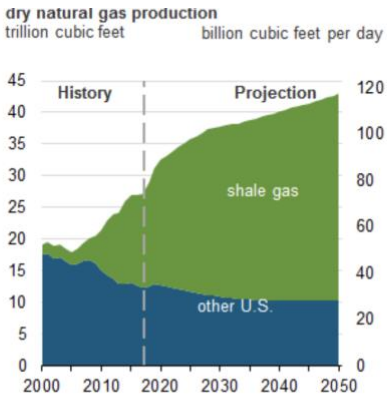


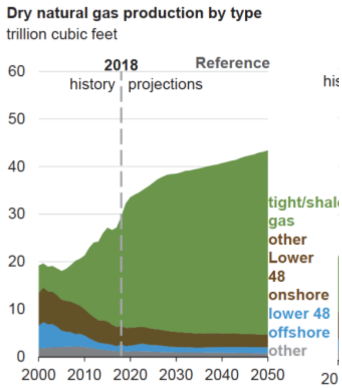
AEO2019

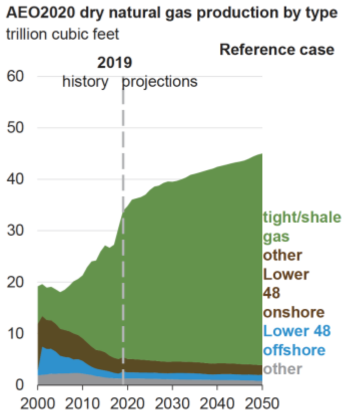
Dry natural gas production by type
trillion cubic feet



AEO2020

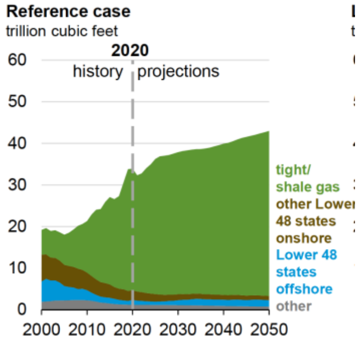


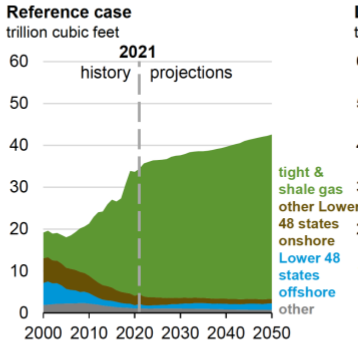




AEO2021

AEO2022





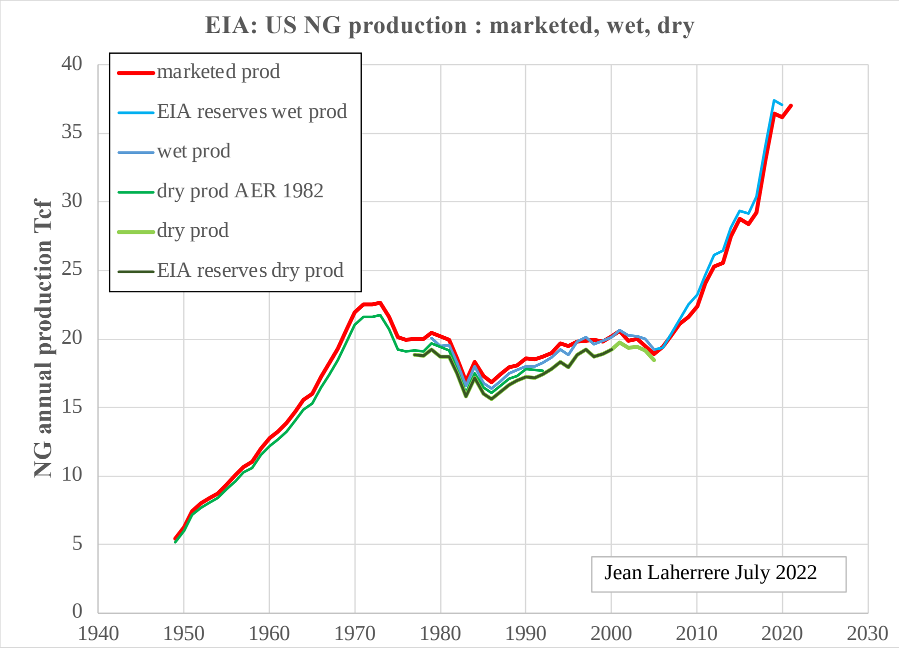
Only the last graphs from 2019 to 2022 display the same definition or almost: tight/shale or tight & shale

Unconventional titles from AEO1994 to AEO2022

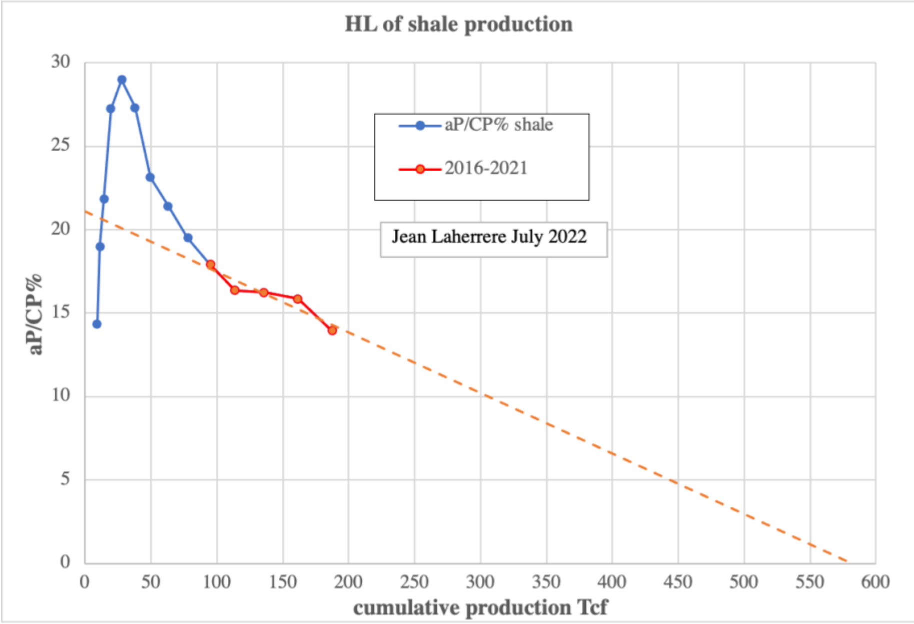
AEO	unconventional
1994	L48 unconv
1995	L48 unconv
1996	L48 unconv
1997	L48 unconv
1998	L48 unconv
1999	L48 unconv
2000	L48 unconv
2001	L48 unconv
2002	L48 unconv
2003	L48 unconv
2004	L48 unconv
2005	L48 unconv
2006	L48 unconv
2007	L48 unconv
2008	onshore unconv
2009	unconv
2010	shale gas, CBM, onshore inc tight gas
2011	shale gas, tight gas, CBM
2012	shale gas, tight gas, CBM
2013	shale gas, tight gas, CBM
2014	shale gas, tight gas, CBM
2015	shale gas & tight oil plays, tight gas, CBM
2016	shale gas & tight oil plays, tight gas, CBM
2017	shale gas & tight oil plays, tight gas
2018	shale gas

2019 tight/shale gas
2020 tight/shale gas
2021 tight/shale gas
2022 tight & shale gas
It is obvious that EIA is lost when dealing with unconventional, changing the title with time!
EIA glossary definition is poor, explaining the confusion of its data
-Unconventional oil and natural gas production: An umbrella term for oil and natural gas that is produced by means that do not meet the criteria for conventional production. See Conventional oil and natural gas production. Note: What has qualified as "unconventional" at any particular time is a complex interactive function of resource characteristics, the available exploration and production technologies, the current economic environment, and the scale, frequency, and duration of production from the resource. Perceptions of these factors inevitably change over time and they often differ among users of the term. For these reasons, the scope of this term will be expressly stated in any EIA publication that uses it
-Conventional oil and natural gas production: Crude oil and natural gas that is produced by a well drilled into a geologic formation in which the reservoir and fluid characteristics permit the oil and natural gas to readily flow to the wellbore.
Barnett NG does flow to the wellbore and should be conventional.
The site https://www.planete-energies.com/en/medias/close/what-unconventional-oil-and-gas defines only methane hydrate as unconventional gas
Furthermore, EIA reports several different data for shale gas production data

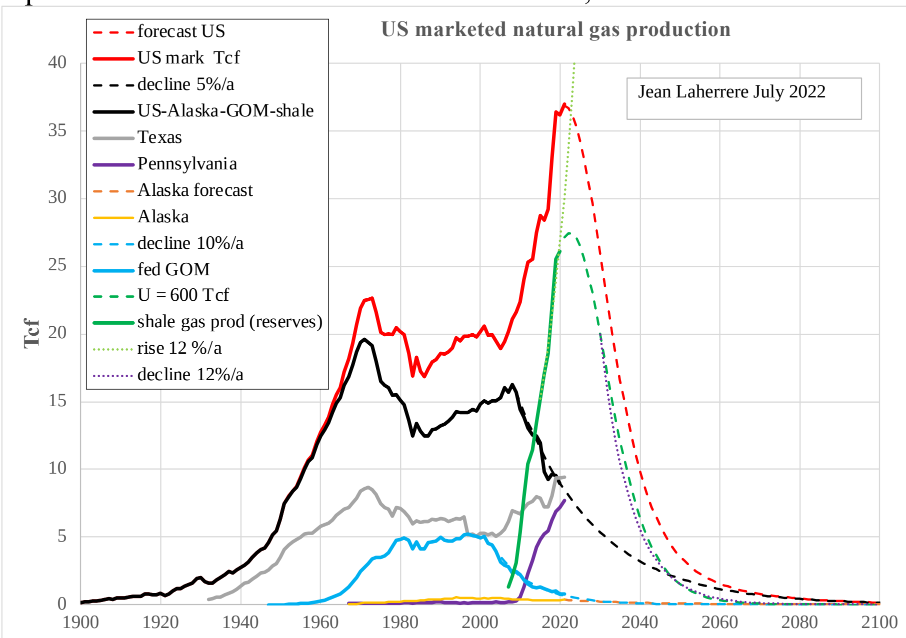
-US NG production modelling
US NG production is reported by EIA under different products: marketed, wet and dry gas



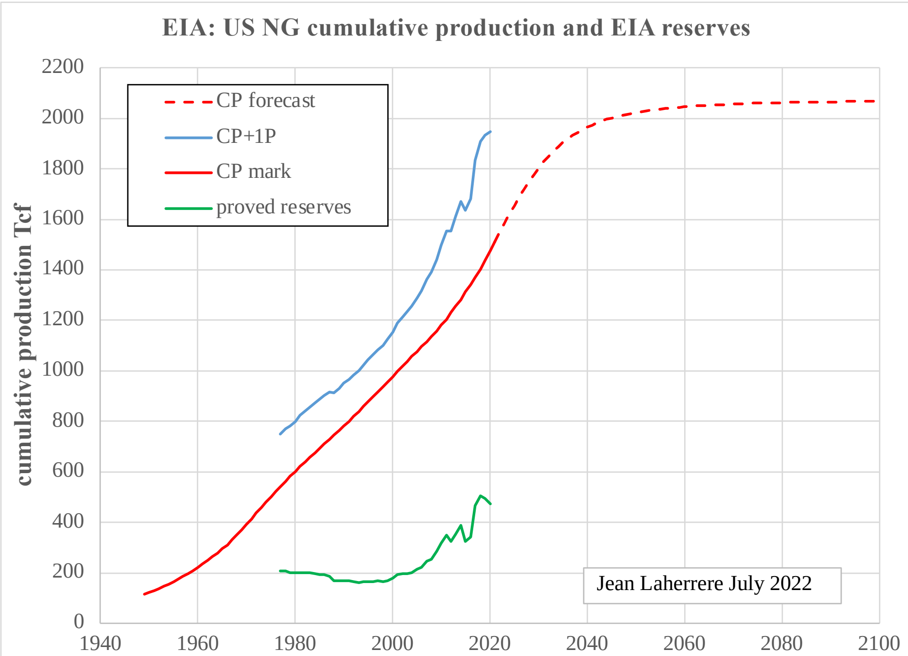
US NG marketed production is broken down as US, Alaska declining at 5 %/a, GOM declining at 10 %/a, and shale with an ultimate of 600 Tcf
HL of shale production (from EIA reserves) trends towards 600 Tcf



US marketed production is forecasted as the sum of shale, GOM and Alaska forecasts

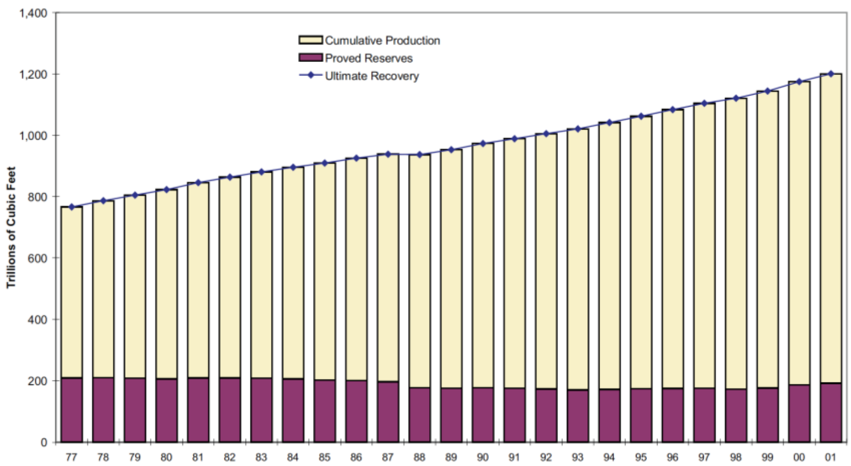


US NG cumulative production is plotted as NG proven reserves (1P) and the total cumulative production + reserves is compared with the cumulative future production forecast being about 2100 Tcf in 2050, not far from EIA 1950 Tcf as CP+reserves at end 2020



EIA AER2001 displays the ultimate for wet natural gas being at 1200 Tcf at end 2001 = value of CP+1P in the above graph.

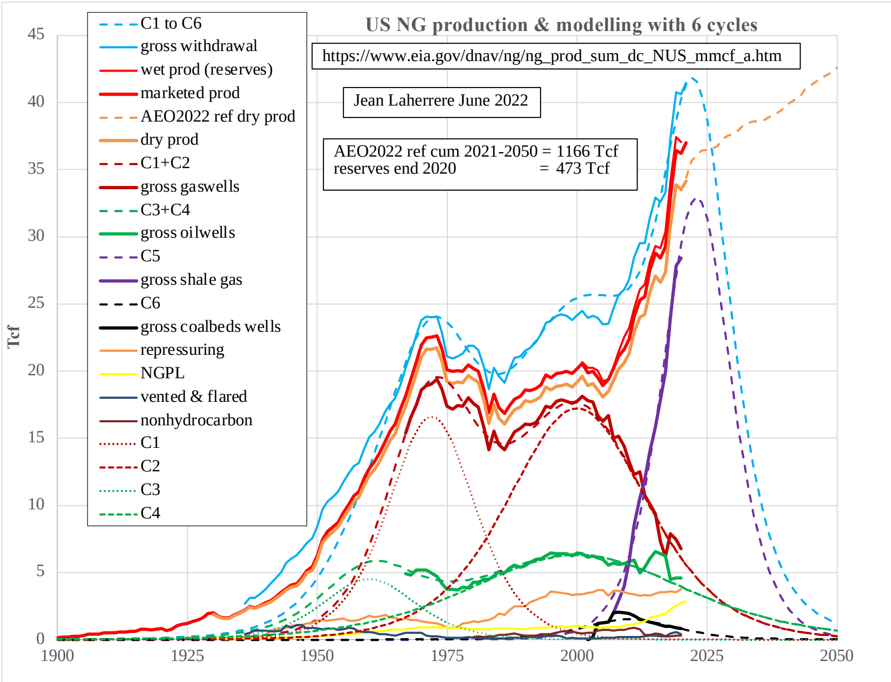
Figure 14. Components of Proved Ultimate Recovery for Wet Natural Gas, 1977-2001



Sources: Annual reserves and production - American Petroleum Institute and American Gas Association (1945–1976) {32} and Energy Information Administration, Office of Oil and Gas (1977–2000){1-24}. Cumulative production: *U.S. Oil and Gas Reserves by Year of Field Discovery* (1977-1988).{33}

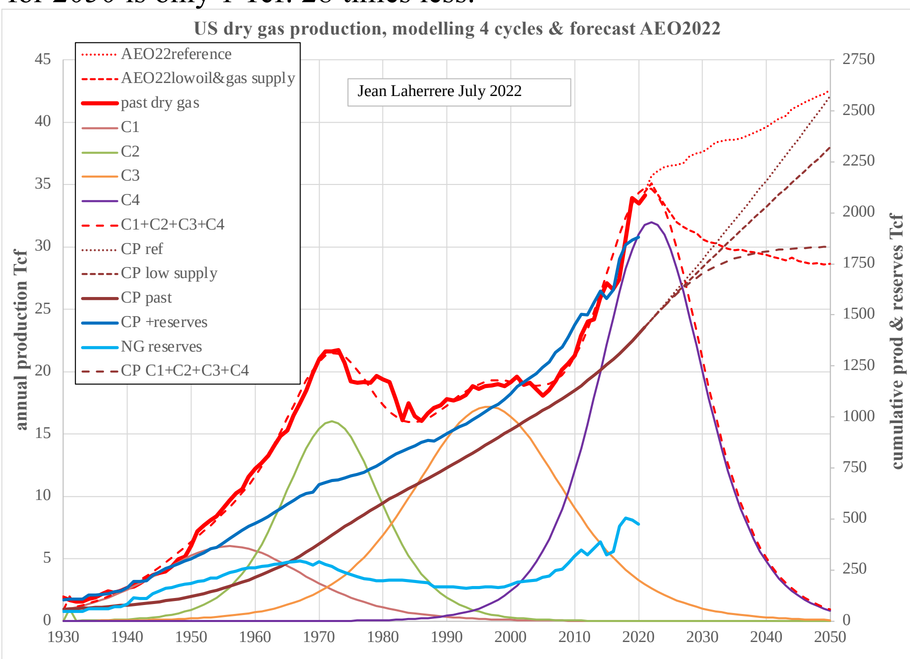
But there are other EIA data

US NG gross withdrawal is the sum of gross withdrawals from gas wells, oil wells, shale gas wells and coalbed wells. It is possible to model fairly well those 4 withdrawals with 6 cycles



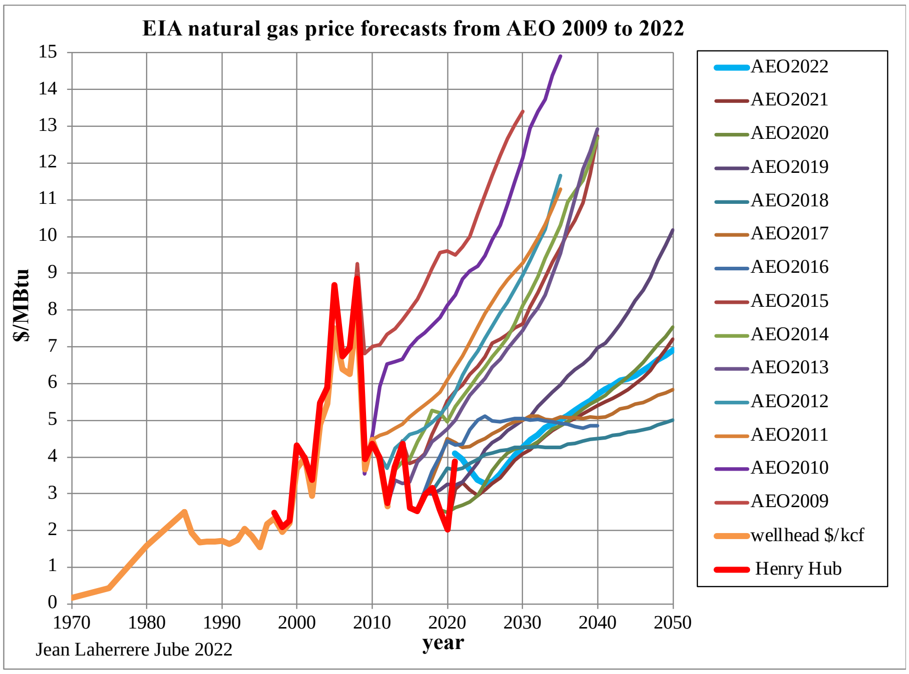
The peak of gross withdrawal is then forecasted in 2023 at 42 Tcf, but AEO2022 reference forecasts a peak beyond 2050 with 41,6 Tcf in 2050 for dry production (against 34 Tcf in 2021): it is unreal as the cumulative production of dry gas 2021-2050 represents 1186 Tcf (before peak, so at least the double until the end of production) when the proven reserves at end 2020 are for shale plays 318 Tcf and for all US wet gas 473 Tcf: less than half of the forecasted 2021-2050!

The US dry gas production is modelled with 4 cycles and compared with AEO 2022
As AEO2022 forecast is for dry gas, the modelling of US dry gas since 1930 with 4 cycles (peak 1956, 1972, 1996 ad 2022) trends towards an ultimate of 1850 Tcf.
AEO 2022 reference forecasts a production of 42.6 Tcf in 2050 not yet peaking, and a cumulative production of 2573 Tcf. AEO2022 "low oil and gas supply" scenario forecasts a peak in 2022 and a production in 2050 of 28.6 Tcf, (cumulative production 2320 Tcf), when my forecast for 2050 is only 1 Tcf: 28 times less.

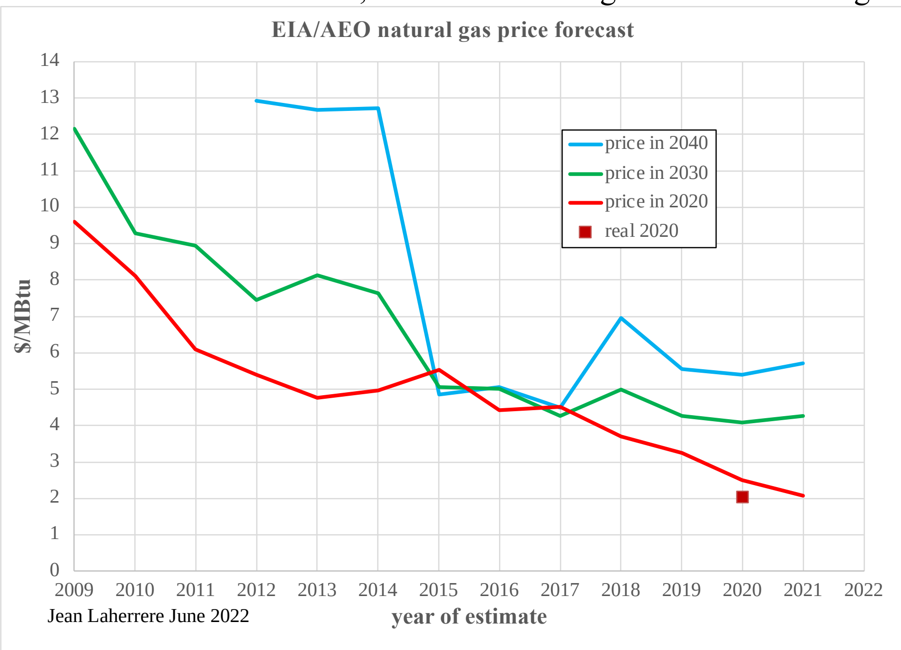


-US NG price

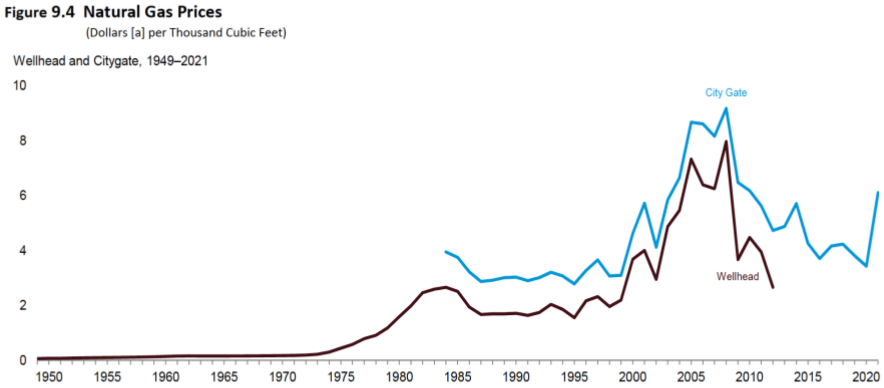
EIA displays a NG price which is erratic, but if I forecast production, I refuse to forecast price because human behavior is too erratic



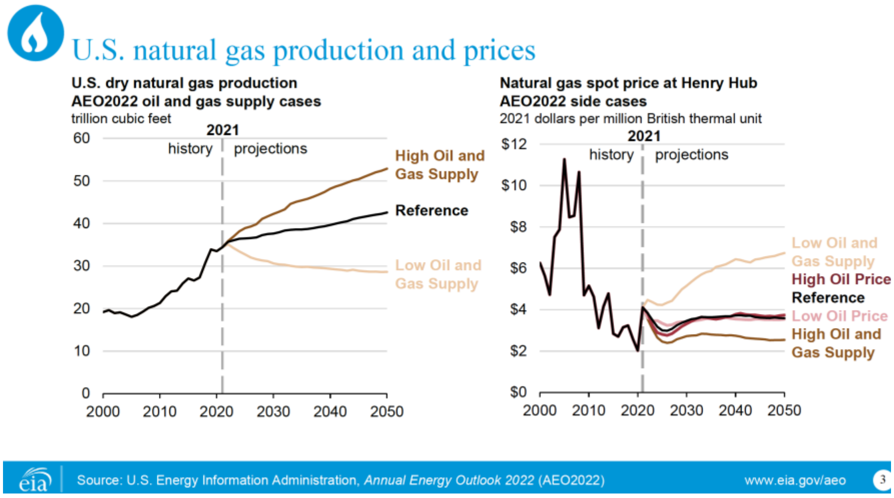
NG price forecast for 2020 has declined, because the flaring due to the lack of gas pipeline



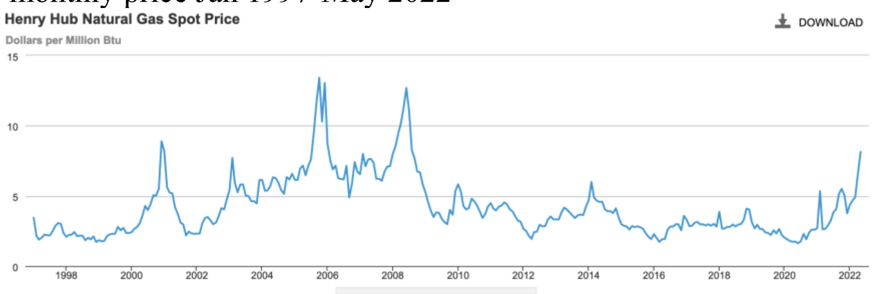
US NG price in $/kcf for wellhead and for city gate displays burst around 2007



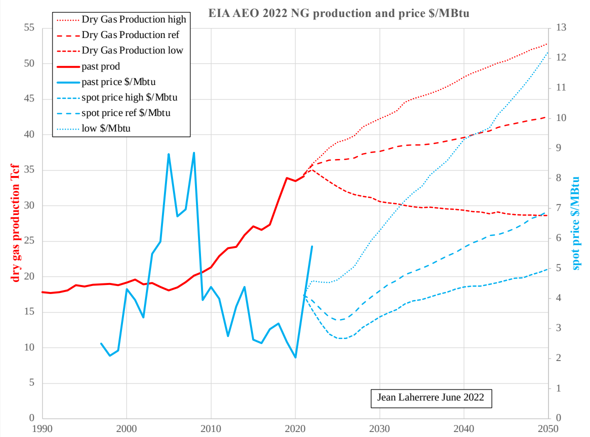
The range of the forecasted AEO2022 NG price in 2050 is 2.5-6.5 $2021/MBtu looks too short, as the NG price of May 2022 is 8.14 $/MBtu

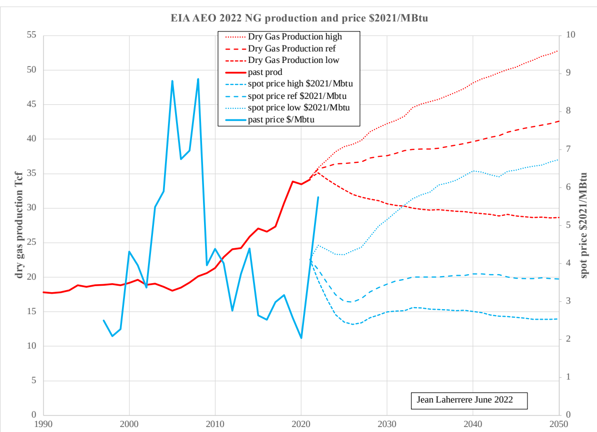


Today NG monthly price Jan 1997-May 2022

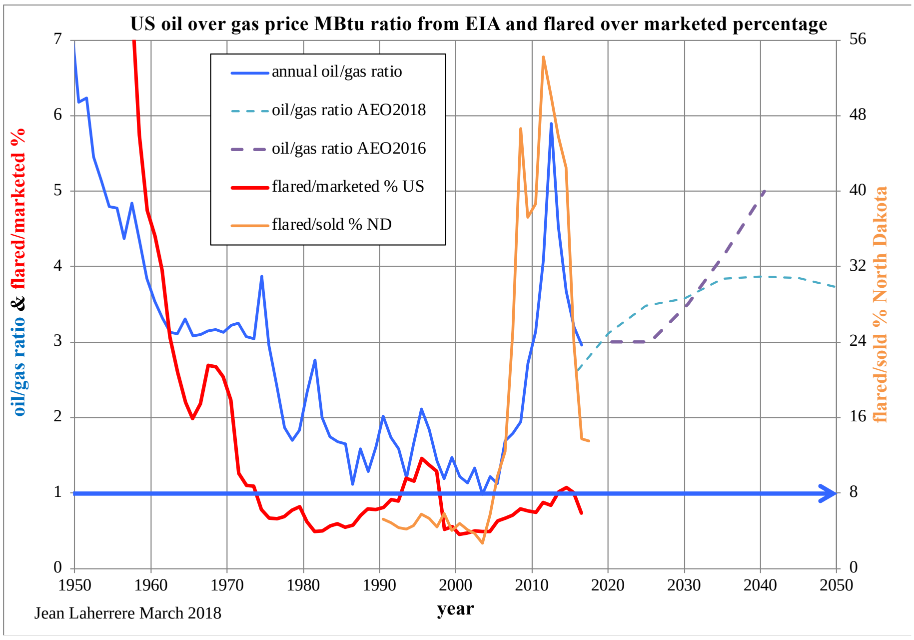


AEO2022 for NG production and price ($/MBtu and $2021/MBtu = little inflation)

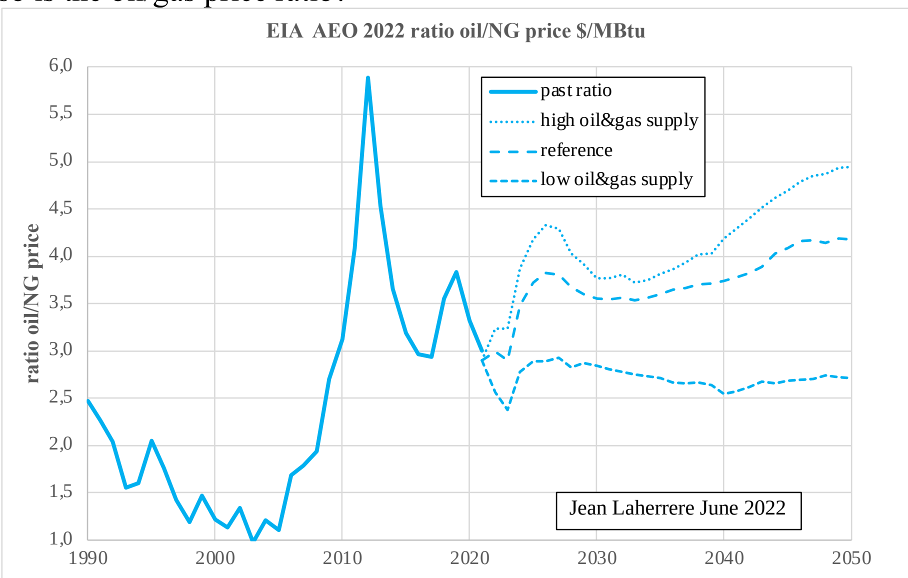




It is interesting to plot the ratio of the oil price in MBtu (1 b = 5.8 MBtu) versus NG price
A 2018 plot was comparing the annual oil/gas price ratio to the percentage of flaring
Only in 2003 NG price equals oil price as the flaring was at a minimum, but AEO2018 ref forecasted for 2050 a ratio of 3.8



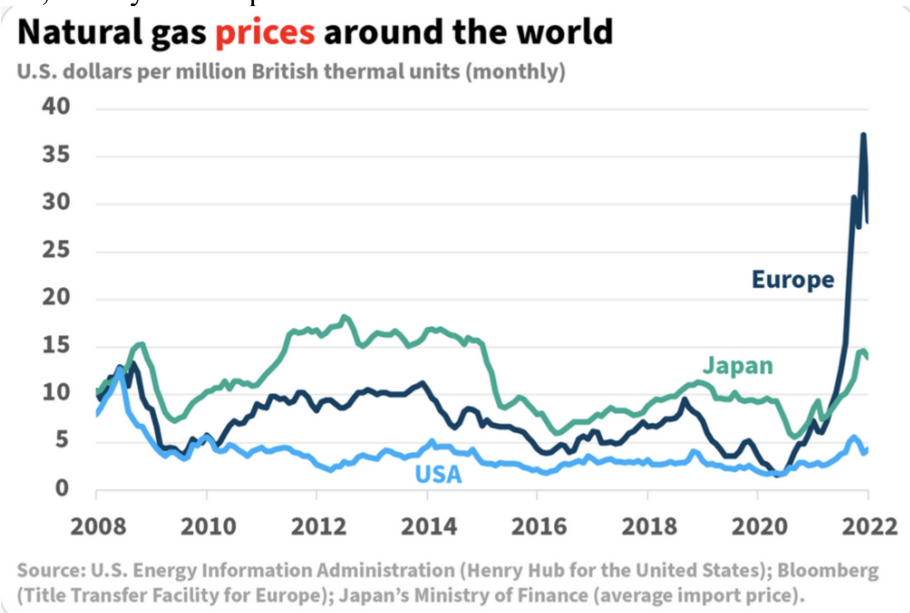
AEO2022 ratio oil/NG price for 2050 has a range of 5-2.7 (high oil&gas supply-low oil&gas supply) with 4.2 for reference.
As in the past 4 ratio is associated to high flaring (lack of gaspipeline), it is queer to see EIA forecasting in 2050 high flaring. But as I said before, EIA NG production forecast in 2050 is unrealistic, so is the oil/gas price ratio?



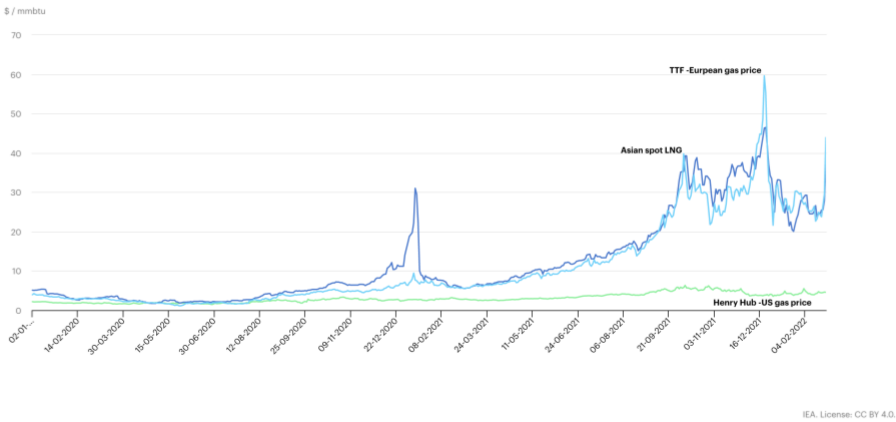
-comparison with Europe and Asia

If there is one crude oil market as the transport of oil is cheap, there are 3 NG markets as the transport of gas is ten times more expensive: US, Europe and Asia Pacific

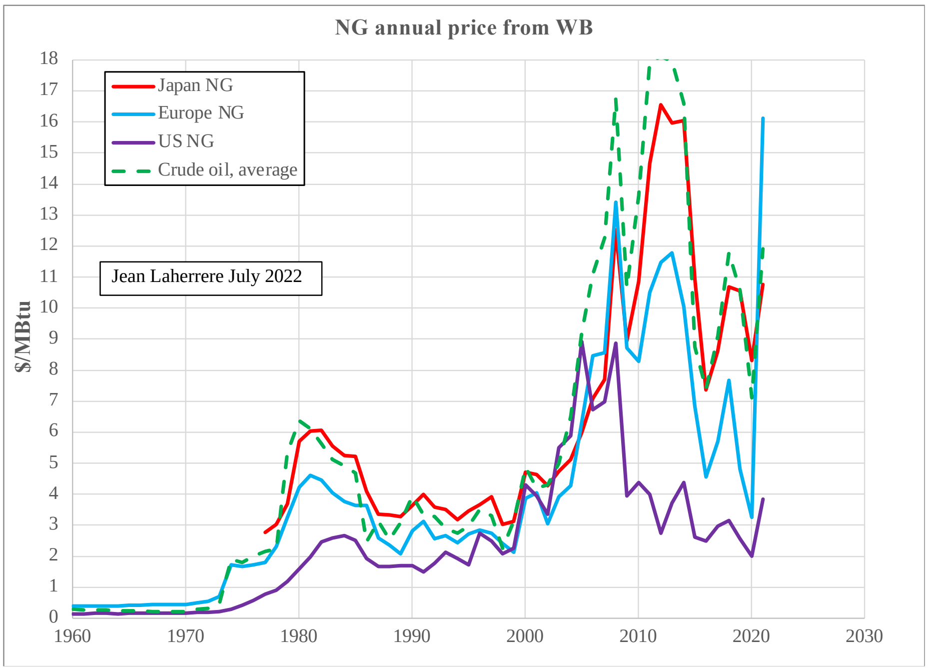
NG price in $/MBtu shows that in 2008 the prices were similar but they differ since 2009 and widely in 2022, mainly in Europe



The plot since 2021 shows that Asian spot LNG price is similar with TTF Europe, but since 2021the gap is huge
https://www.iea.org/data-and-statistics/charts/natural-gas-prices-in-europe-asia-and-the-

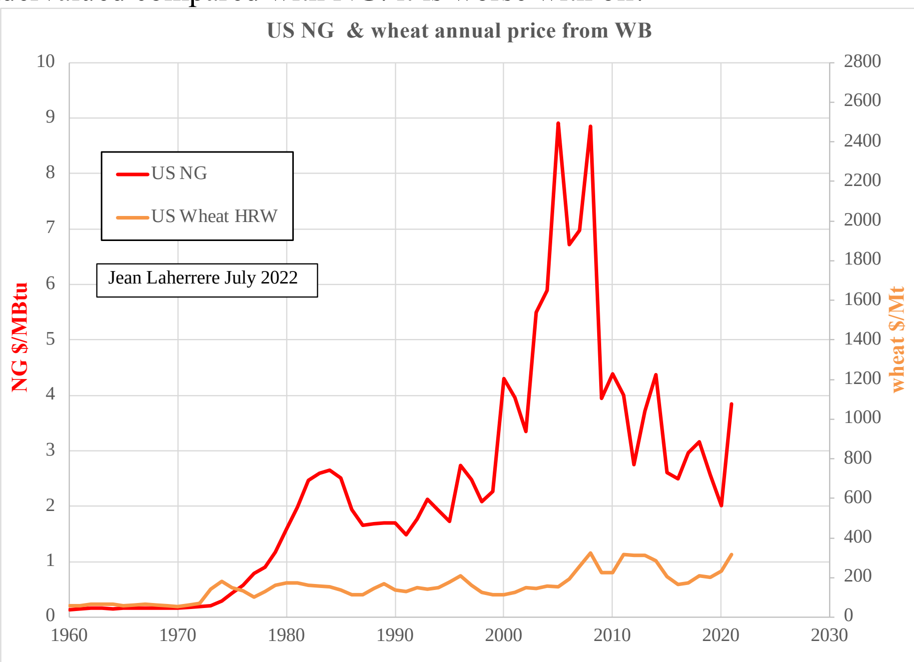


WB reports the annual price since 1960 and the US NG price is lower than Japan and Europe since 2008 because of shale gas, because of lack of gas pipeline giving higher flaring



US NG annual price compared with US wheat price fitted before 1973 oil shock, but they differ widely after, mainly on 2005-2008 and in 2021

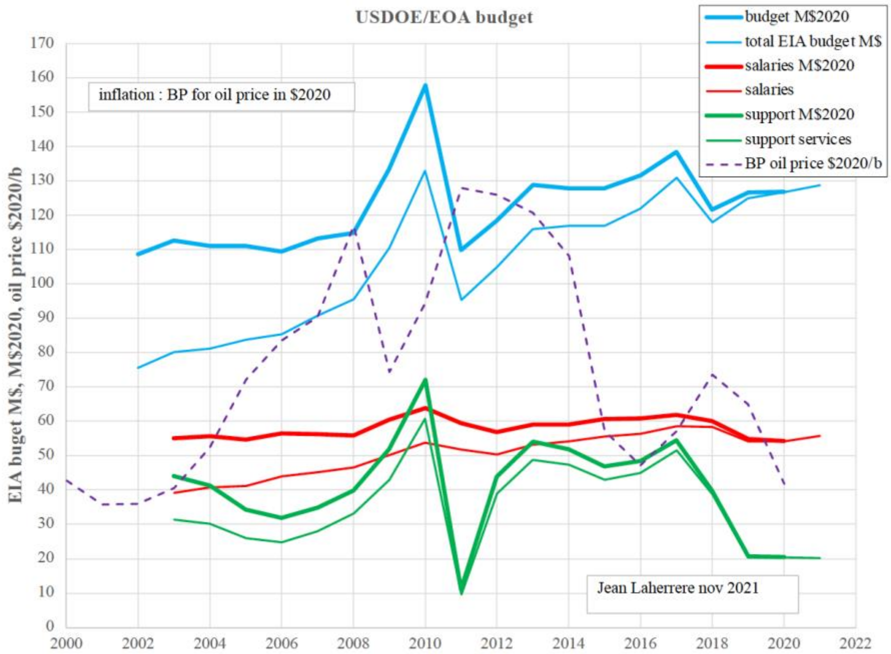
Wheat is undervalued compared with NG: it is worse with oil!



-EIA mission

EIA budget for support (green) has been cut from 2017 to 2021 from 50 M$ to 20 M$.

This decline in support explains the collapse in quality in EIA work.



FY2022

*The U.S. Energy Information Administration (EIA) is the statistical and analytical agency within the U.S. Department of Energy (DOE). EIA collects, analyzes, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding of energy and its interaction with the economy and the environment. **EIA is the nation's premier source of energy information** and, by law, its data, analyses, and forecasts are independent of approval by any other officer or employee of the U.S. government. EIA conducts a wide range of data collection, analysis, forecasting, and dissemination activities to ensure that its customers, including Congress, federal and state governments, the private sector, the public, and the media, have ready access to timely, reliable, and relevant energy information. EIA's data and analysis inform important energy related decisions, such as the availability of energy sources; government, business, and personal investment decisions; and policy development*

This paper has found several areas of EIA poor job (past and future production): it means that the nation is poorly informed on the energy matter.

-Conclusion

Barnett shale/tight play is declining since 2013 with a sharp annual decline of 10%: it is a good model for other US shale/tight plays.

Tight gas is different from shale gas, but both are produced the same way = hydraulic fracking in long horizontal wells and they are often confused by EIA. Tight and shale have to be reported together, but it was not the case in the past.

EIA since 1994 to 2022 has reported US unconventional gas on a chaotic manner, reporting several different production data from different sites: there is no check and no control.

EIA forecasts for the year 2020 have varied from 1 to 3 with time

It is not surprising to find that AEO2022 forecasts for 2050 shale gas production at 33.7 Tcf and tight gas production at 5.7 Tcf when my forecast is zero for both.

The cumulative NG production forecasts (2021 to 2050) of AEO2022 reference and low oil and gas supply are higher than EIA proven reserves, which are assumed to represent future production from 2020 to end of production.

EIA NG production forecast was too pessimistic in 2010, but today EIA is too optimistic.

AEO oil and gas forecasts are based only on drilling many wells without bothering to check if there is enough room for them: EIA ignores the geology, as their reserves estimates.
US shale/tight gas production has increased with an annual rate of 12%, it is likely that its annual decline will be about 12 % after a peak in 2023.
Europe is counting on US LNG to replace Russian gas and in few years will be quite surprised to see this source vanished.
Since few months I have lost some certainty, as "no more war in Europe", "democracy will rule the world", "science will overrun beliefs".
But I am still convinced by my graphs that the world will be short of energy in a few years (except a deep depression).
The more I know, the more I know that I do not know and the others neither.

NB:
Sorry for my broken English and for being too long, but at 91 years I write my paper as it could be the last one.