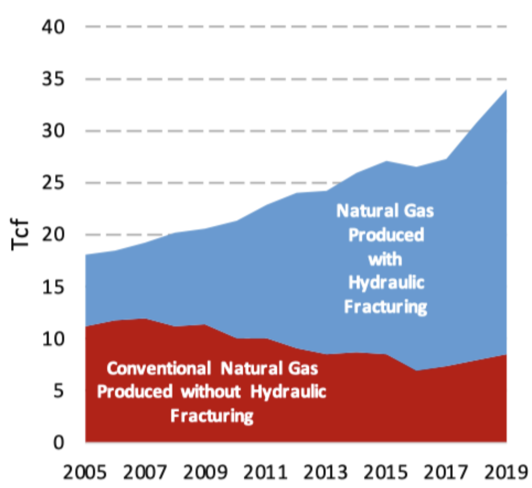
Jean Laherrere 17 November 2021

US shale plays production from EIA Jan2007-Sept2021 & forecasts

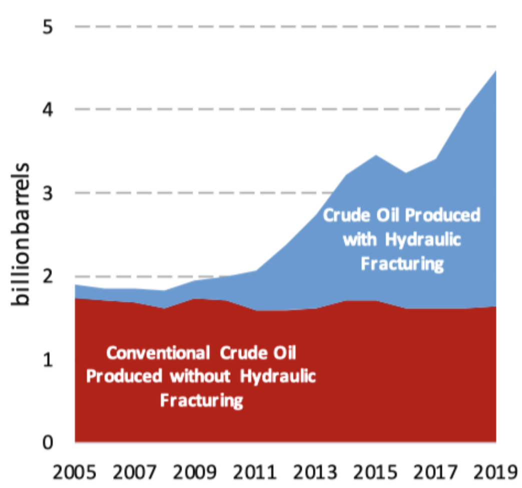
US Shale production is obtained thanks to hydraulic fracturing and the percentage of hydraulic fracturing is more important for gas than for oil as shown on the graphs below
https://www.energy.gov/prod/files
Economic and National Security Impacts under a Hydraulic Fracturing Ban
Report to the President January 2021

Figure 1: U.S. Dry Gas Production (2005–2019)



Source: U.S. Energy Information Administration

Figure 2: U.S. Oil Production (2005–2019)



Source: U.S. Energy Information Administration

The problem is that there is no clear-cut definition on shale plays production and that data vary with sources
There is a need for better defined and reliable production data and EIA fails to do so, as shown below.

EIA, IEA, Rystad provide very optimistic forecasts for the US shale plays future production, contrary to my previous forecasts. An update was necessary.

EIA publishes two sets of data for shale plays production:
-EIAa: monthly production:
https://www.eia.gov/petroleum/drilling/ Oct 2021
https://www.eia.gov/naturalgas/data.php
-EIAb: annual reserves data including production data since 2011 for LTO and 2008 for shale gas https://www.eia.gov/naturalgas/crudeoilreserves/

Shale oil is now called light tight oil = LTO, because oil is produced not from the source-rock but a tight reservoir closeby
Shale gas is reported with tight gas or separately

Table 2 for shale oil

Table 2. Production and proved reserves of crude oil from selected U.S. shale plays, 2018–19

million barrels

Basin	Play	State(s)	2018 Production	2018 Proved reserves	2019 Production	2019 Proved reserves	2018–19 Reserves change
Permian	Wolfcamp/Bone Spring	New Mexico, Texas	922	11,096	1,209	11,994	898
Williston	Bakken/Three Forks	North Dakota, Montana, South Dakota	458	5,862	517	5,845	-17
Western Gulf	Eagle Ford	Texas	449	4,734	451	4,297	-437
Anadarko, South Oklahoma	Woodford	Oklahoma	34	560	53	524	-36
Appalachian	Marcellus*	Pennsylvania, West Virginia	17	345	21	326	-19
Denver-Julesburg	Niobrara	Colorado, Kansas, Nebraska, Wyoming	25	317	25	235	-82
Fort Worth	Barnett	Texas	2	20	2	19	-1
Subtotal			**1,907**	**22,934**	**2,278**	**23,240**	**306**

Table 4 for shale gas in Tcf (not indicated!) by play

Table 4. U.S. shale plays: production and proved reserves of natural gas, 2018-19

Basin	Shale Play	State(s)	2018 Production	2018 Proved Reserves	2019 Production	2019 Proved Reserves	Change in Production	Change in Proved Reserves
Appalachian	Marcellus*	Pennsylvania, West Virginia	7.6	135.1	8.7	139.4	1.1	4.3
Permian Basin	Wolfcamp, Bone Spring	New Mexico, Texas	3.3	46.7	4.5	49.3	1.2	2.6
Texas-Louisiana Salt	Haynesville/Bossier	Louisiana, Texas	2.6	44.7	3.4	46.7	0.8	2.0
Western Gulf	Eagle Ford	Texas	2.0	30.8	2.1	26.6	0.1	-4.2
Appalachian	Utica/Pt. Pleasant	Ohio	2.3	23.9	2.6	34.4	0.3	10.5
Anadarko, S. Oklahoma	Woodford	Oklahoma	1.3	21.4	1.5	20.9	0.2	-0.5
Fort Worth	Barnett	Texas	1.2	17.2	1.1	14.1	-0.1	-3.1
Williston	Bakken/Three Forks	Montana, North Dakota	0.9	12.0	1.0	12.2	0.1	0.2
Arkoma	Fayetteville	Arkansas	0.5	6.0	0.5	5.1	0.0	-0.9
Sub-total			**21.7**	**337.8**	**25.4**	**348.7**	**3.7**	**10.9**
Other shale			0.4	4.3	0.1	4.4	-0.3	0.1
All U.S. shale gas			**22.1**	**342.1**	**25.5**	**353.1**	**3.4**	**11.0**

Table 13 for shale gas by state in Tcf

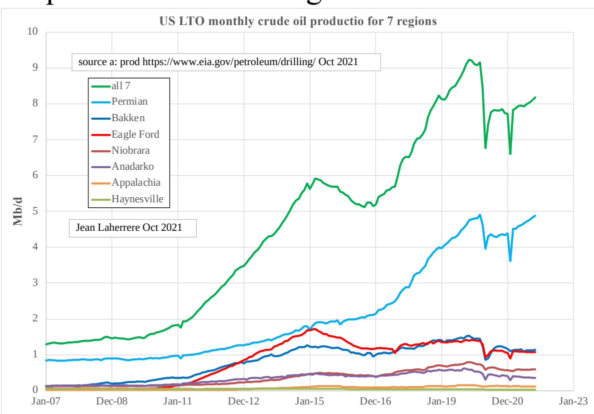
Table 13: Proved reserves and production of shale natural gas, 2016 - 2019

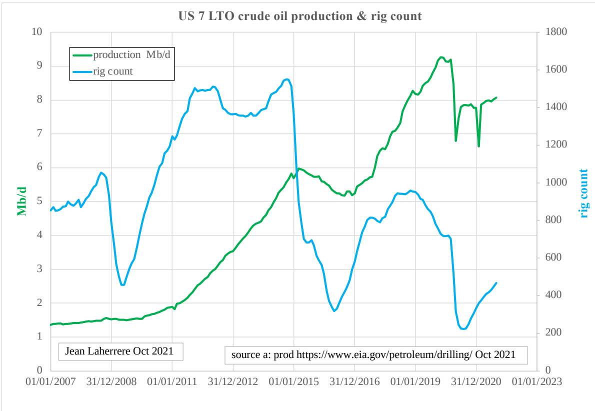
billion cubic feet

State and Subdivision	Reserves 2016	Reserves 2017	Reserves 2018	Reserves 2019	Production 2016	Production 2017	Production 2018	Production 2019
Alaska	0	0	0	0	0	0	0	0
Lower 48 States	**209 809**	**307 903**	**342 135**	**353 086**	**17 032**	**18 589**	**22 054**	**25 556**
Arkansas	6 262	7 090	5 970	5 093	733	618	521	471
California	**41**	**62**	**41**	**0**	**6**	**6**	**4**	**0**
Colorado	2 032	1 885	2 727	2 500	164	97	126	149
Florida	0	0	0	0	0	0	0	0
Kansas	0	0	0	0	0	0	0	0
Kentucky	12	17	0	0	0	1	0	0
Louisiana	**9 637**	**26 484**	**25 598**	**29 553**	**1 111**	**1 450**	**2 044**	**2 518**
North	9 570	26 316	25 598	29 553	1 085	1 414	2 044	2 518
South	67	168	0	0	26	36	0	0
State Offshore	0	0	0	0	0	0	0	0
Michigan	1 128	942	1 457	1 138	84	63	77	72
Mississippi	7	8	0	0	2	2	0	0
Montana	213	258	221	268	19	18	18	21
New Mexico	**5 581**	**9 451**	**13 082**	**13 827**	**497**	**592**	**785**	**1 101**
North Dakota	8 259	9 984	11 737	12 542	582	664	840	1 043
Ohio	15 472	26 468	23 956	34 376	1 386	1 747	2 337	2 558
Oklahoma	20 327	22 675	21 396	20 897	1 082	1 290	1 325	1 490
Pensylvania	60 979	89 478	103 388	105 394	5 049	5 365	6 079	6 782
Texas	**56 577**	**78 666**	**100 789**	**93 477**	**5 029**	**5 171**	**6 392**	**7 440**
RRC District 1	7 493	8 895	11 434	9 511	690	652	693	729
RRC District 2 Onshore	4 126	4 900	4 993	4 345	642	584	654	631
RRC District 3 Onshore	125	744	451	328	23	23	21	23
RRC District 4 Onshore	11 001	12 861	13 953	12 486	706	677	689	682
RRC District 5	8 321	10 636	8 431	6 728	827	730	680	586
RRC District 6	3 249	8 909	18 690	17 026	339	333	515	895
RRC District 7B	1 562	1 736	1 673	1 090	116	110	118	93
RRC District 7C	5 661	7 156	7 454	7 745	451	494	597	705
RRC District 8	7 924	15 319	26 116	27 649	730	1 115	1 960	2 683
RRC District 8A	8	48	104	115	0	1	6	9
RRC District 9	7 107	7 462	7 490	6 454	505	452	459	404
RRC District 10	0	0	0	0	0	0	0	0
State Offshore	0	0	0	0	0	0	0	0
Virginia	45	66	0	0	4	4	0	0
West Virginia	23 146	34 296	31 748	34 020	1 270	1 486	1 504	1 911
Wyoming	17	28	0	0	5	6	0	0
Federal Offshore	0	0	0	0	0	0	0	0
Other states[a]	74	62	25	1	9	10	2	0
U.S. Total	**209 809**	**307 903**	**342 135**	**353 086**	**17 032**	**18 589**	**22 054**	**25 556**

-LTO = light tight oil

-all 7 regions by EIAa (drilling data) for the period January 2007 to September 2021 for production as also rig count

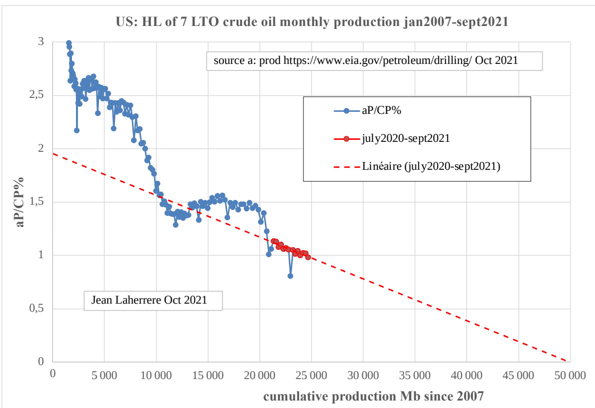


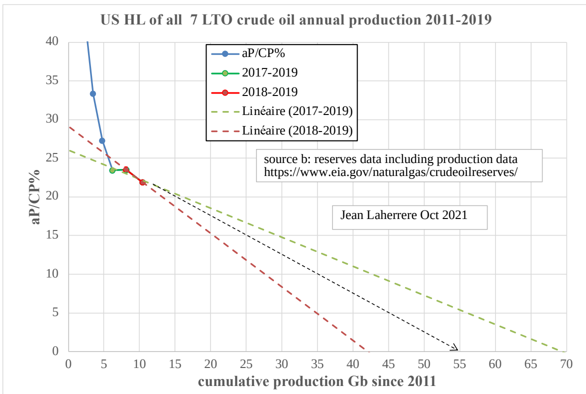


Production (annual & cumulative) forecasts are modelled using the ultimates extrapolated by the Hubbert linearization (HL) for data source a and source b

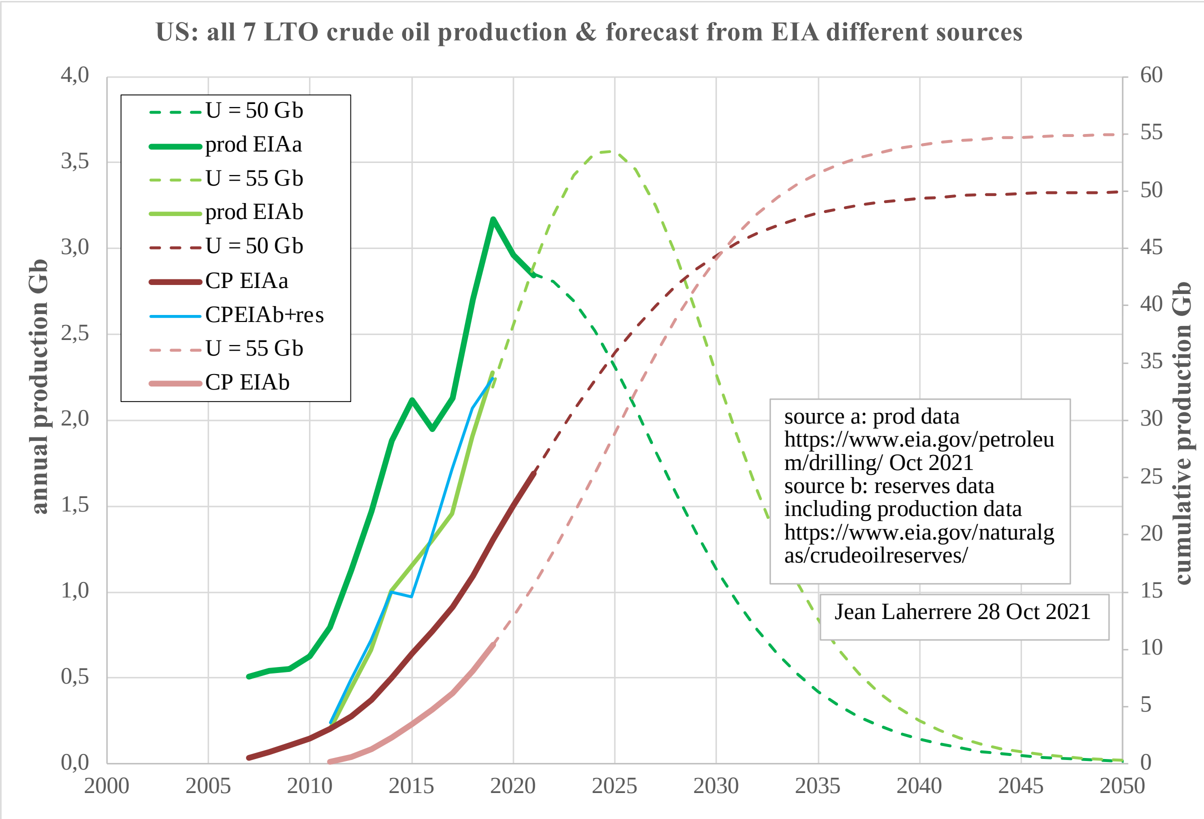
The all 7 ultimate (a) for monthly data (Jan 2007-Sept2021) is 50 Gb

The all 7 ultimate (b) for annual data (2011-2019) is more uncertain at 55 Gb

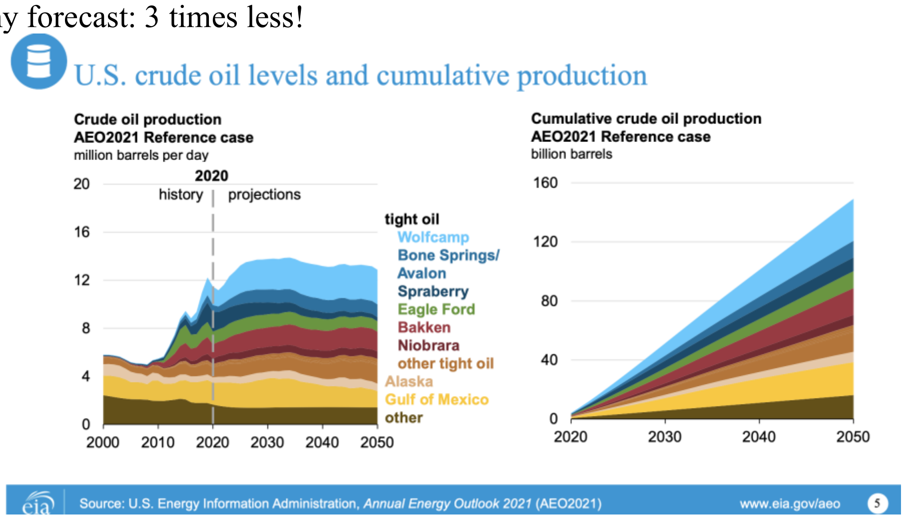




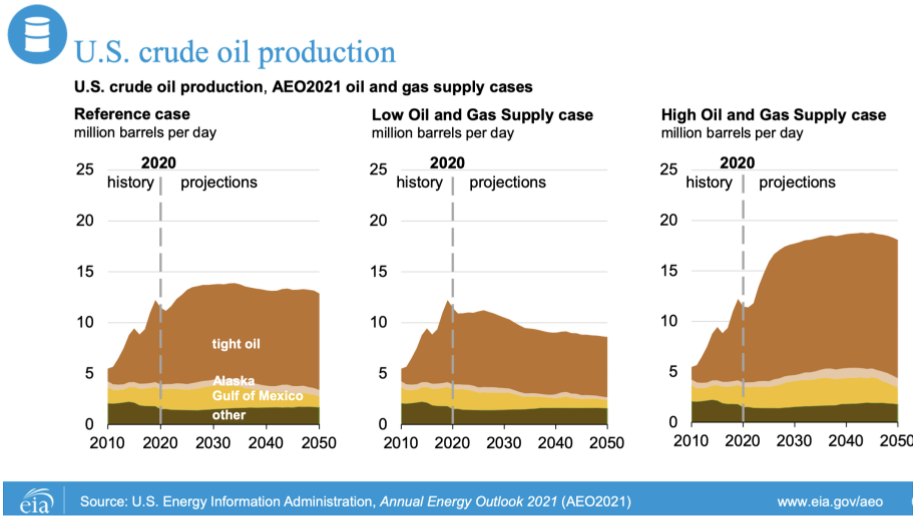
The crude oil all 7 production is modelled with a peak in 2019 for EIAa, and in 2024 for EIAb, but both display a zero production in 2050



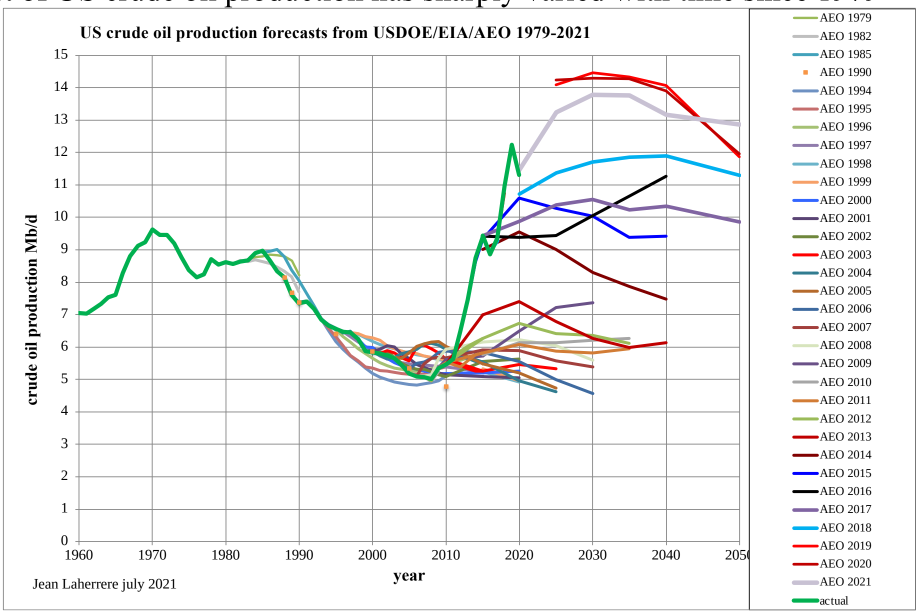
7 LTOs production will be zero in both forecasts when EIA in AEO2021 forecast 7 Mb/d for the reference scenario with a cumulative production 2020-2050 of 80 Gb to be compared with 25 Gb for my forecast: 3 times less!



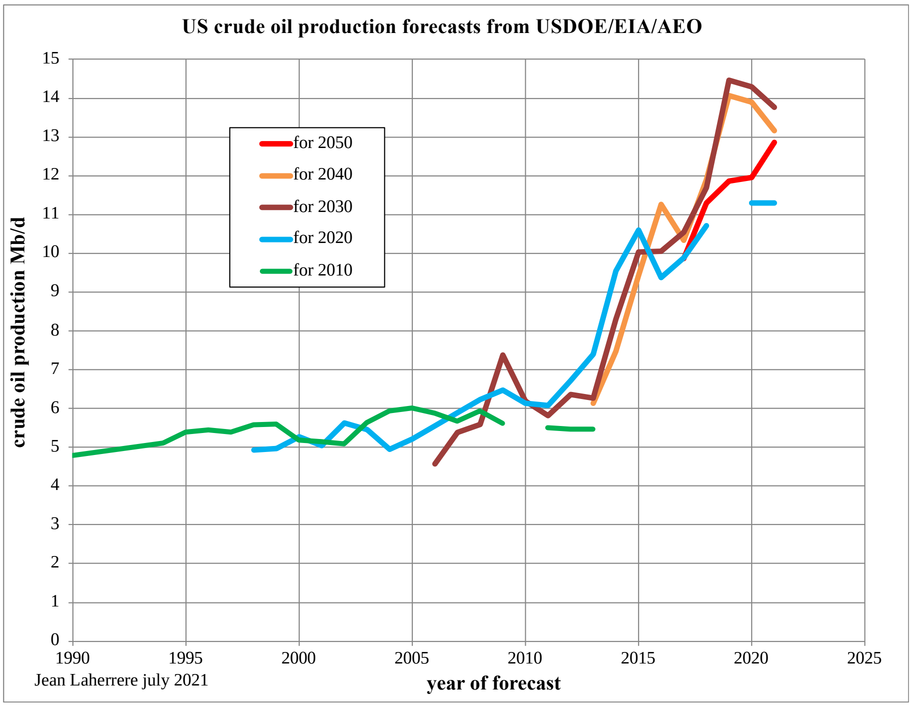
LTO production for the 3 scenarios of AEO2021, only the low case displays a peak for 7 LTO in 2019, but still more than 5 Mb/d in 2050 against zero for my forecast



But the past AEO forecasts were not confirmed by reality!
EIA forecast of US crude oil production has sharply varied with time since 1979

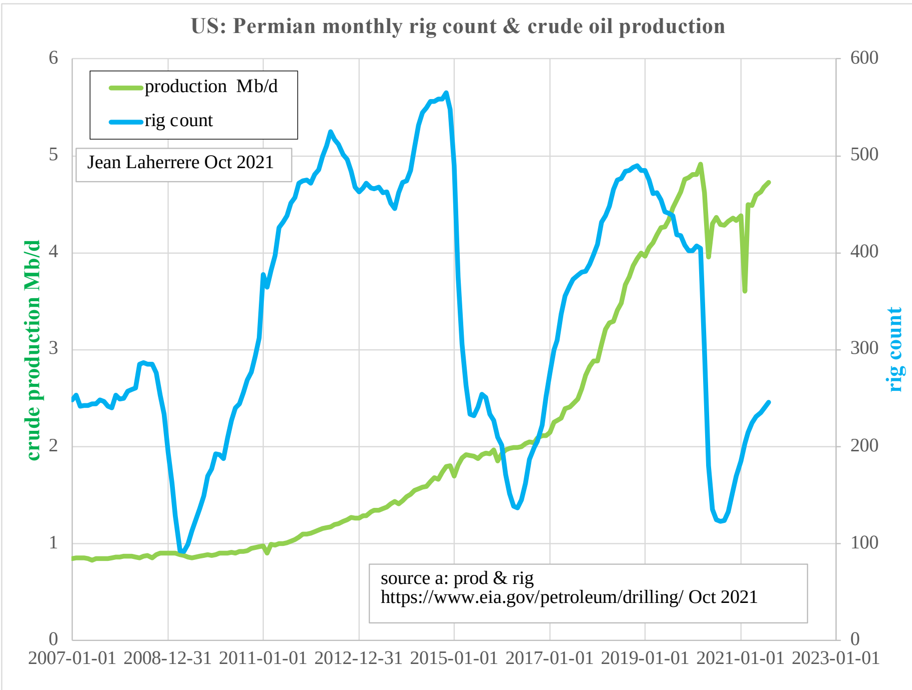


AEO2010 did not forecast LTO
The evolution of the US crude oil production forecasts for 2020, 2030, 2040 and 2050 displays a strong increase since 2013.

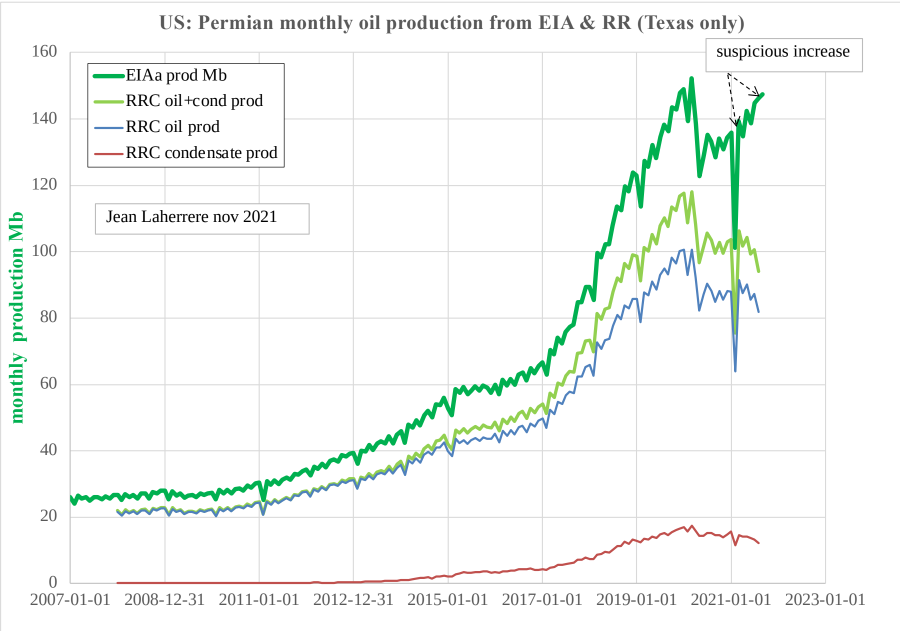


-Permian region

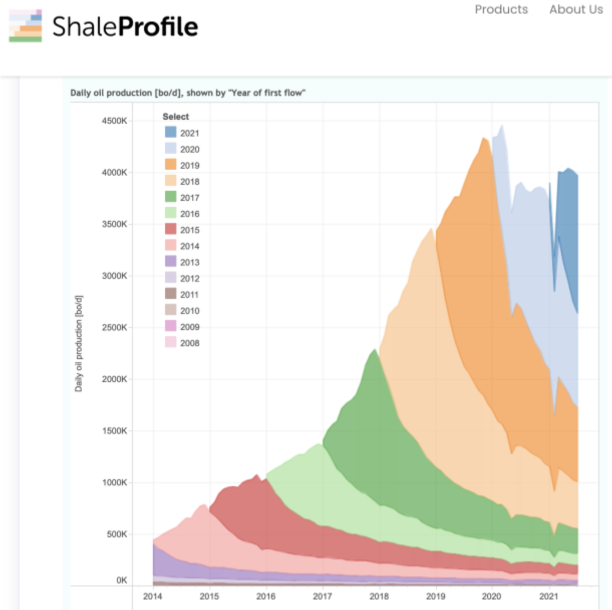
The Permian monthly crude oil production (source a) and rig count jan 2007-sept2021 display up and down

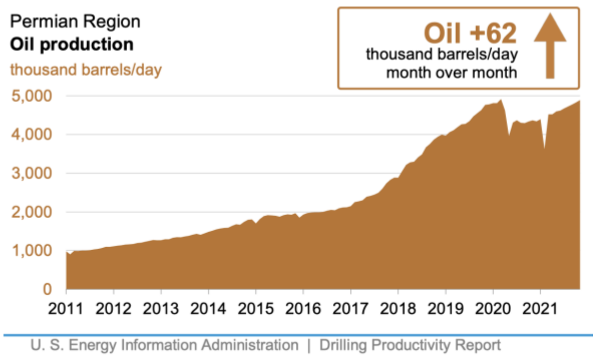


The Permian monthly oil EIAa production is compared with RRC data for Texas only: the last EIA few months since March 2021 increase is suspicious compared with RRC recent decrease (still uncertain)



EIAa is also different from the best source on LTO: Enno Peters with his site shaleprofile
https://shaleprofile.com/blog/permian/permian-update-through-july-2021/
Permian oil production March-July2021 is flat for Enno Peters.

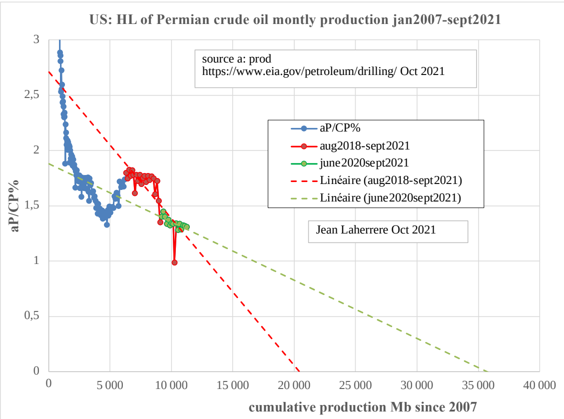


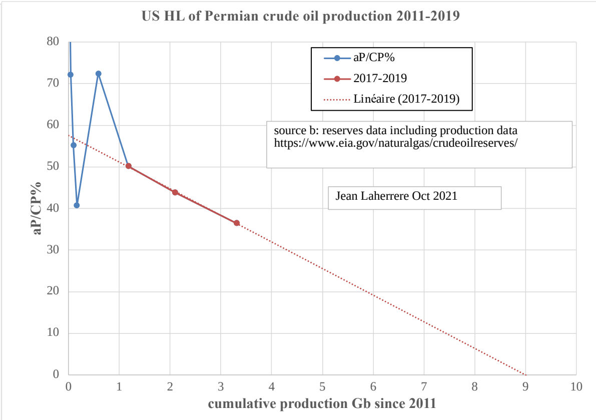


For January 2014 Shaleprofile reports 0.5 Mb/d against 1.5 Mb/d for EIA drilling report: 3 times more!

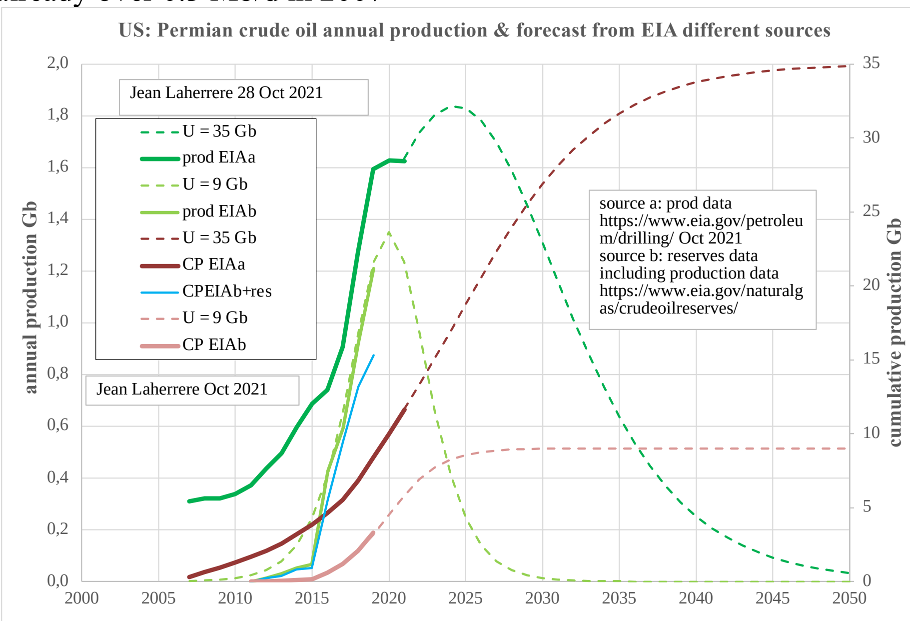
Permian tight oil reservoirs have been produced from a long time from vertical wells, LTO comes from horizontal wells using long extents, fracking, high injection of water and sands. It means that there are many confusions on LTO production data and EIA does not clearly specify the problem and the bad reporting
EIA source a and EIA source b reports different Permian production data and EIA does nothing to clear this confusion.
It is hard to know where and when US LTO starts.

HL of monthly Permian production source a trend towards 35 Gb from the period June 2020-Sept 2021
HL of annual Permian source b data trends towards 9 Gb
Why such discrepancy?

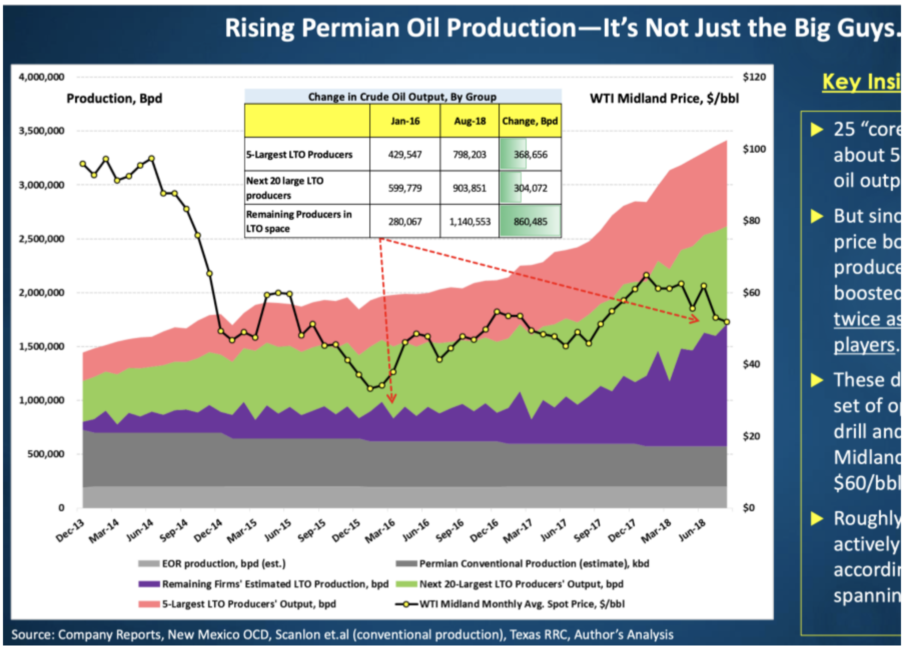




Source b starts LTO Permian production in 2011 when source a reports Permian LTO production already over 0.3 Mb/d in 2007

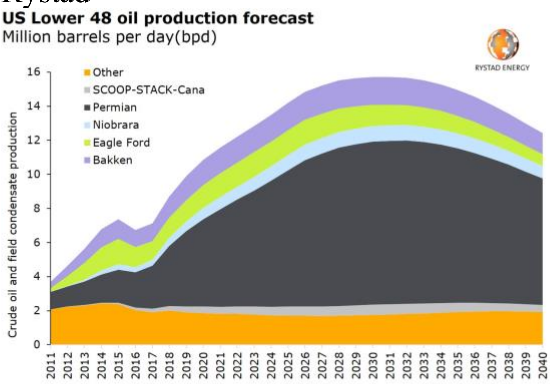


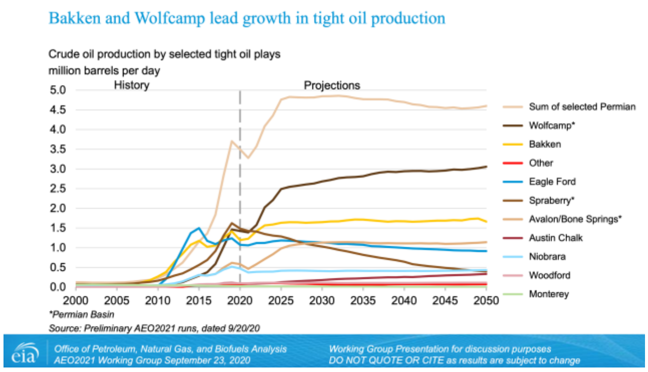
EIAa reports a Permian LTO production at 1.6 Mb/d mid 2014 when EIAb reports 0.7 Mb/d
Gabriel Collins Rice University on a 2018 paper: "Permian Oil & Gas Production: Is It Becoming Financially Sustainable?" reports Permian LTO production (pink + green + purple) at mid 2014 at 1 Mb/d: again another value, showing the uncertainty of the data



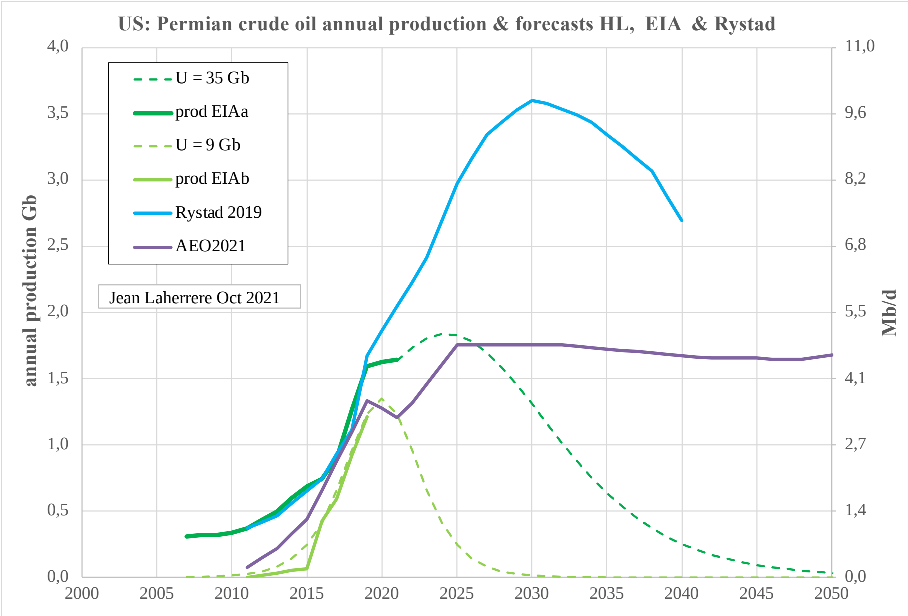
Rystad «US shale to grow to 14.5 million bpd by 2030" September 12, 2019
https://www.rystadenergy.com/newsevents/news/press-releases/us-shale-to-grow-to-14.5-million-bpd-by-2030/
reports a Permian LTO production in 2014 of 1,5 Mb/d and forecasts 10 Mb/d in 2030 (3 times my forecast) and 7.4 Mb/d in 2040 (10 times my forecast).
AEO2021forecasts Permian being over 4,5 Mb/d in 2050 against zero for me

Rystad AEO2021



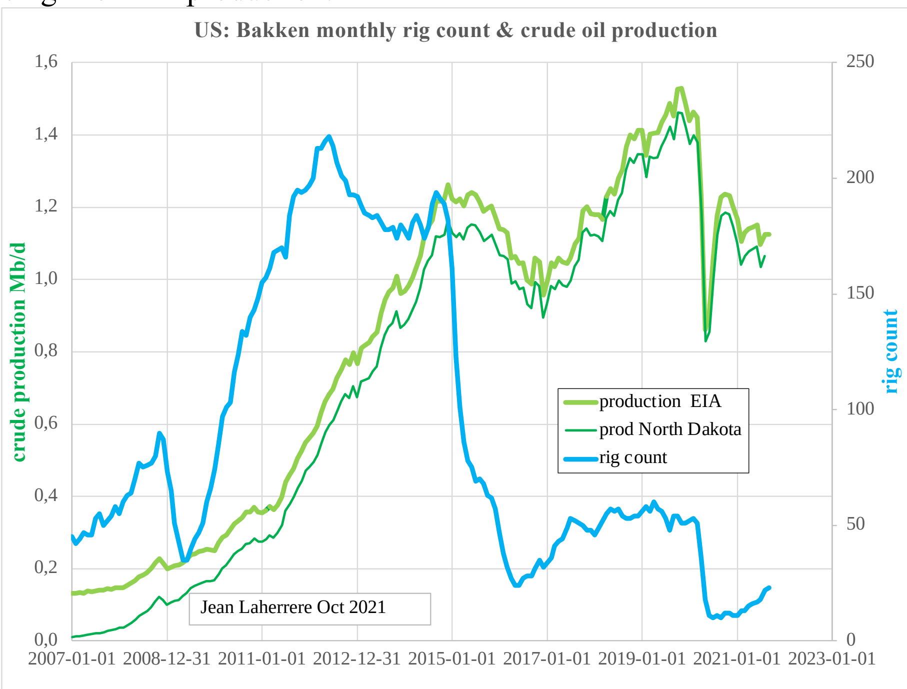


Rystad and EIA forecasts looks unrealistic for me beyond 2030!
Both assumes that the sharp decline of LTO will be compensated by numerous new wells, without bothering to check if there is enough room to drill these new wells, despite the present problems with parent and child wells; see Permian wells map page 30

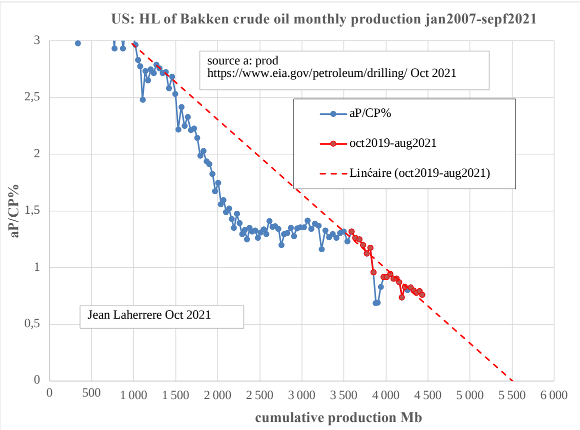


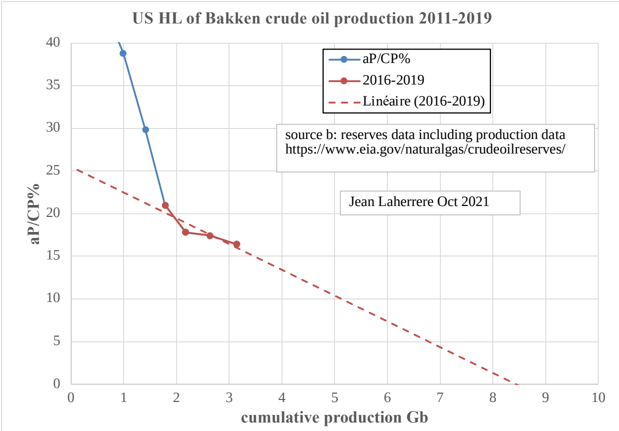
-Bakken region

Bakken oil production EIA source a is plotted, as rig count.
Bakken for North Dakota from https://www.dmr.nd.gov/oilgas/stats/statisticsvw.asp is parallel, the difference being Montana production.

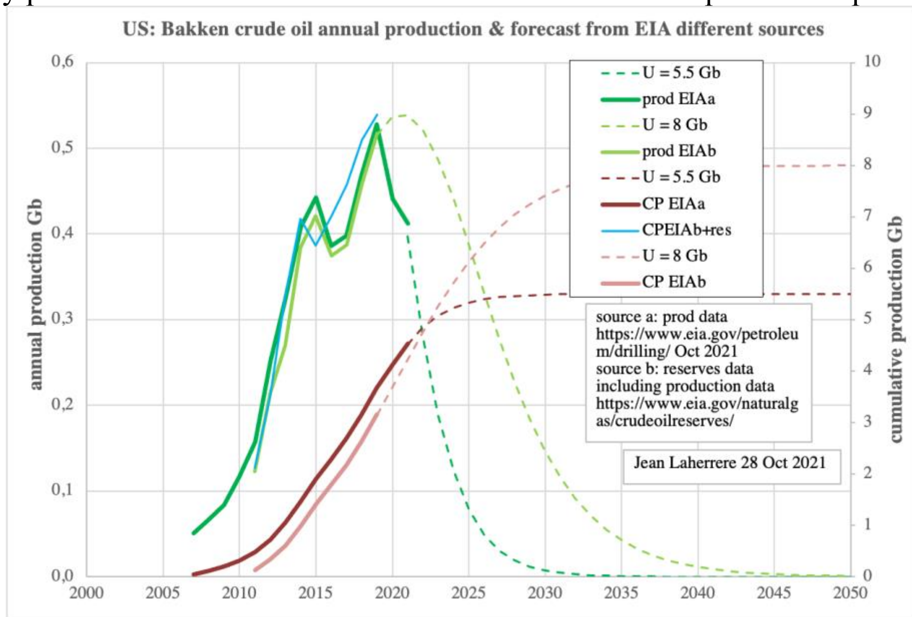


HL of monthly crude oil production (source) trends towards an ultimate of 5.5 Gb
HL of annual production (source b) trends towards 8 Gb

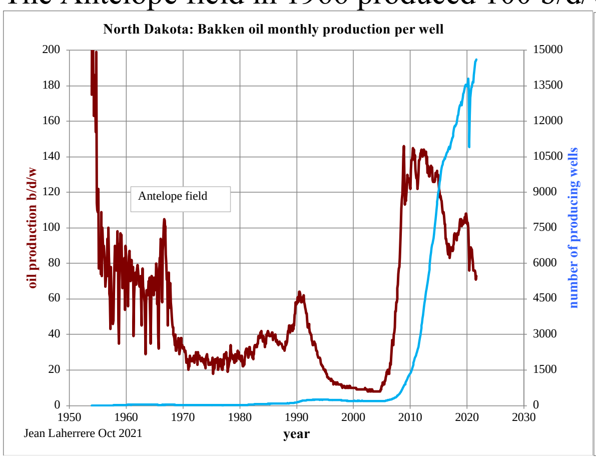


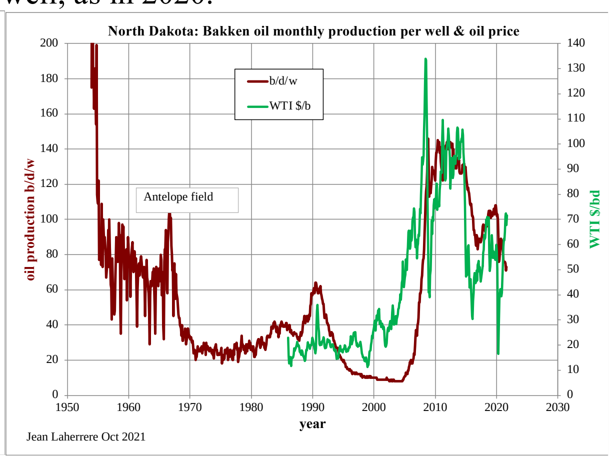


The cumulative production + reserves at end 2019 is about 9 Gb, looking too high.
The monthly production will continue its decline when the annual production peak in 2021

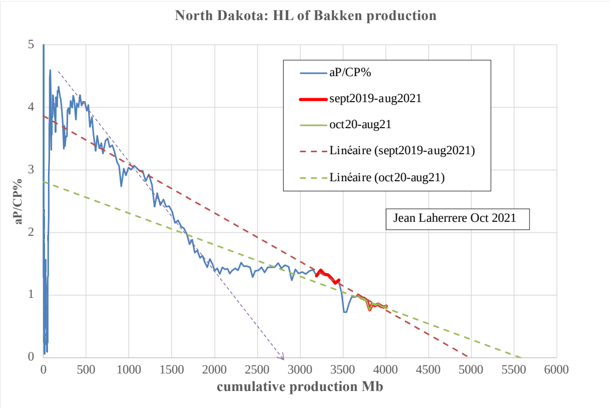


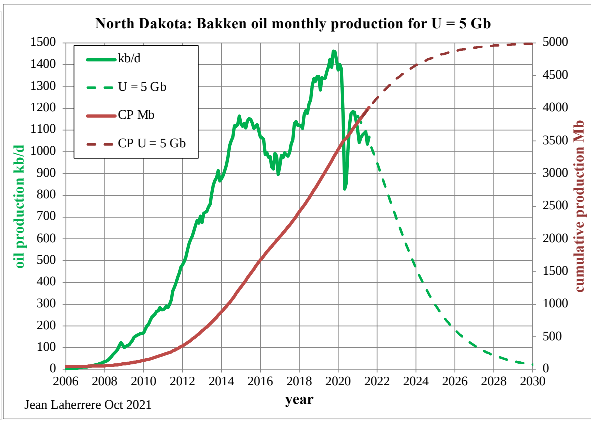
Bakken North Dakota data from https://www.dmr.nd.gov/oilgas/stats/historicalbakkenoilstats.pdf starts in 1954, at a time where Bakken was not yet LTO produced from vertical wells/
The Antelope field in 1966 produced 100 b/d/well, as in 2020.



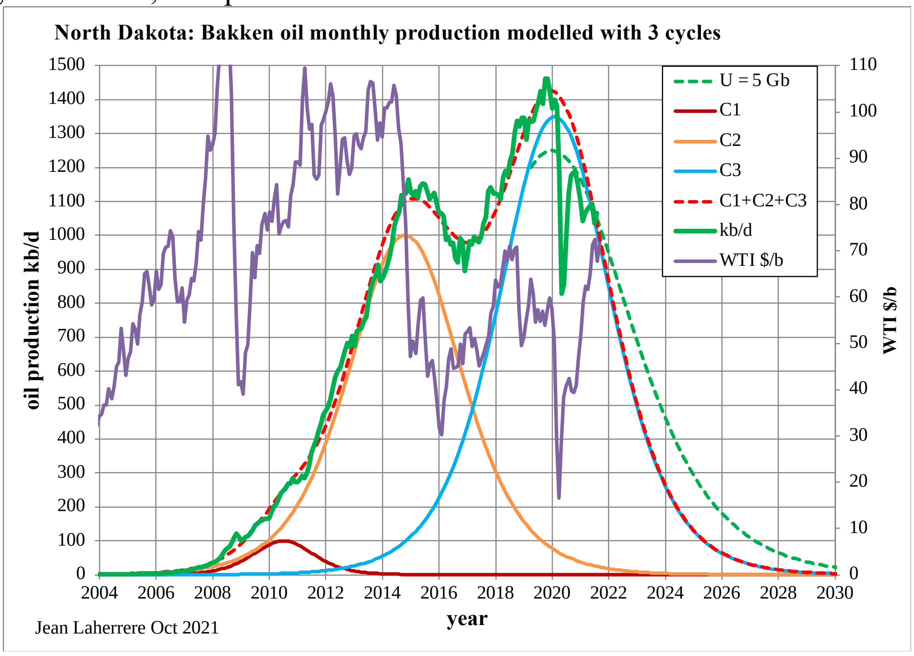


The HL of Bakken ND production trends towards 5 Gb with a large uncertainty due to covid19 and wild oil price changes

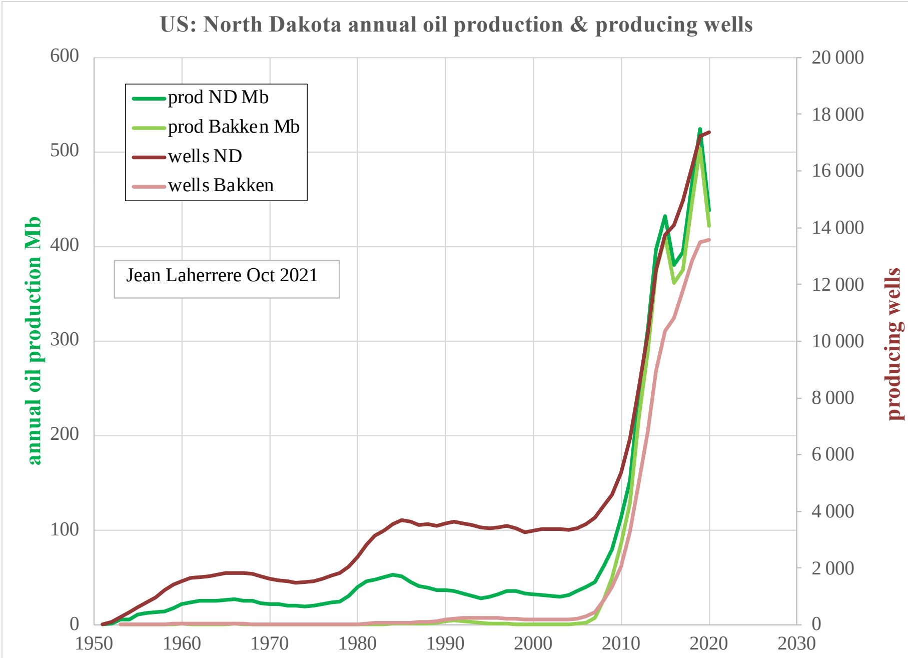




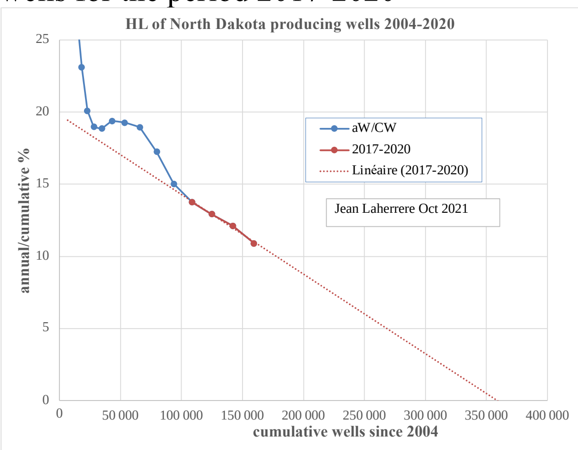
The Bakken production is modelled with 3 cycles: it is compared with WTI oil price, which has a strong correlation, except for 2021.

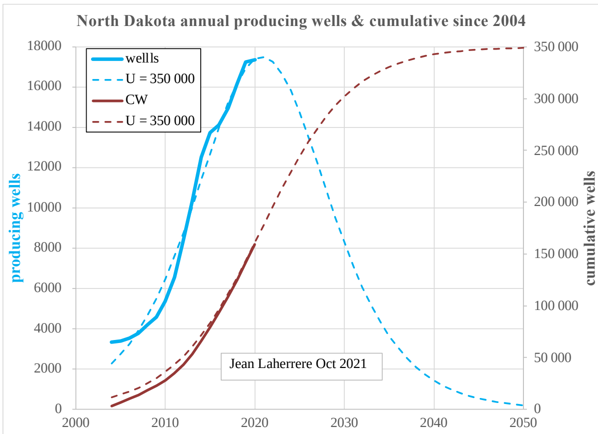


ND oil production correlates with the number of producing wells, as Bakken oil and Bakken wells



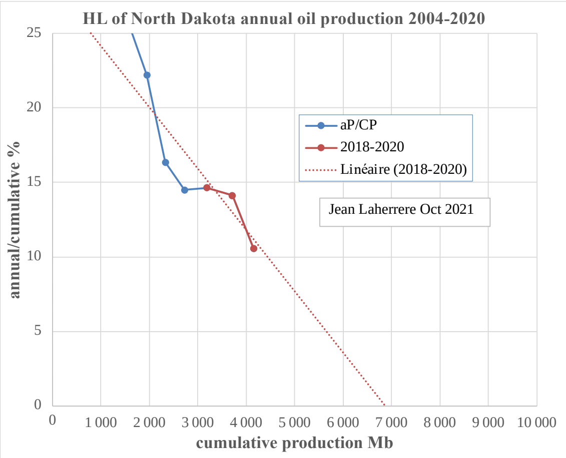
HL of the North Dakota producing wells 2004-2004 trends towards a cumulative of 350 000 wells for the period 2017-2020

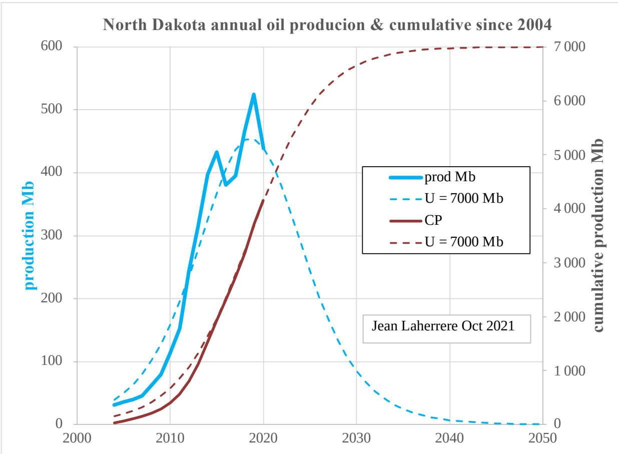




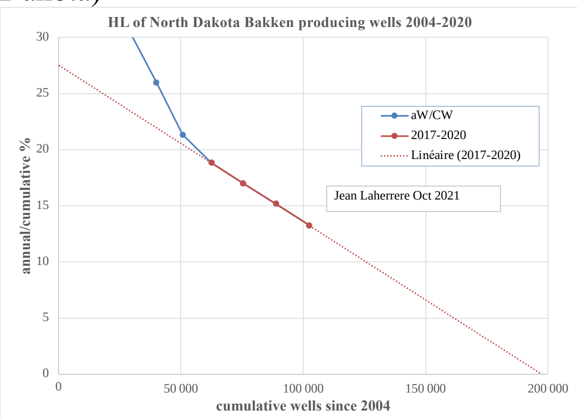
This ultimate of cumulative wells corresponds to a peak in 2020, as the peak on oil production, but this ultimate of ND wells is more than he double of the present number and I doubt that such amount of drilling can be achieved

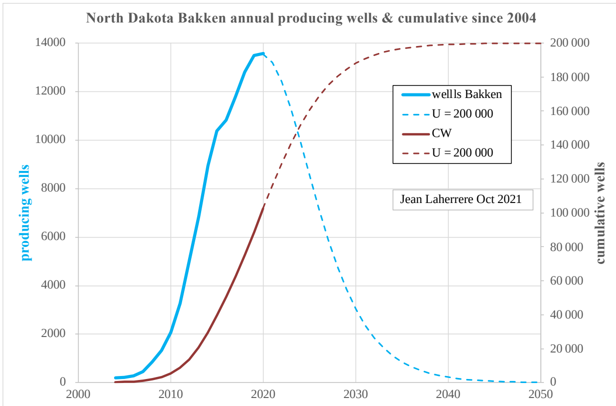
HL of North Dakota crude oil production 2004-2020 trends towards an ultimate of 7 Gb





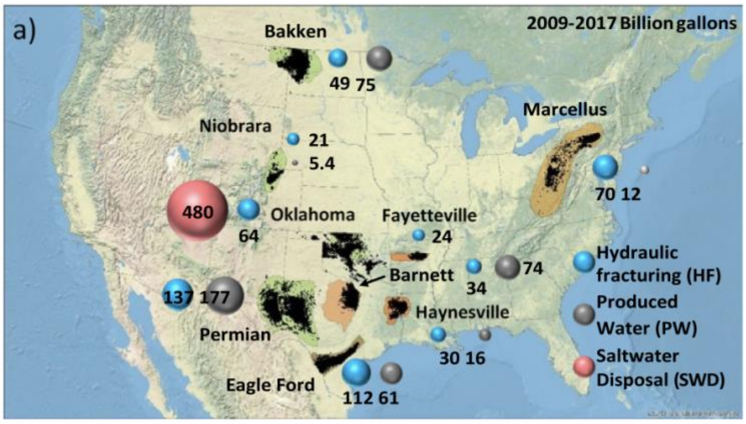
HL of ND Bakken producing wells trends towards 200 000 (against 350 000 for all North Dakota)

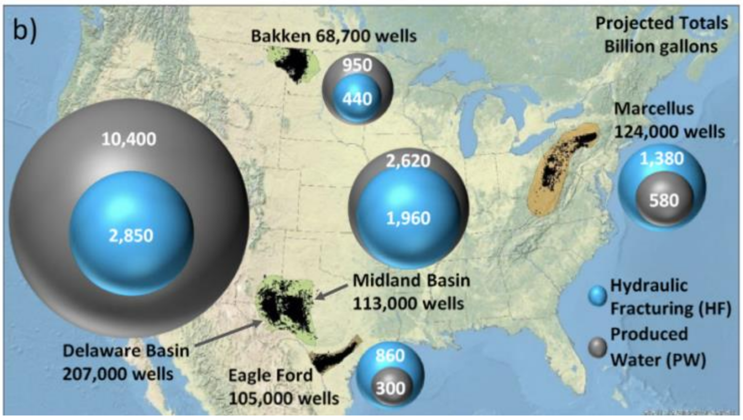




This ND Bakken wells ultimate corresponds to a peak in 2020, as the peak of ND Bakken production, but as for ND wells this ultimate is about the double of present wells and I doubt that it is possible to double the number of wells on ND Bakken as there is little room for that amount!

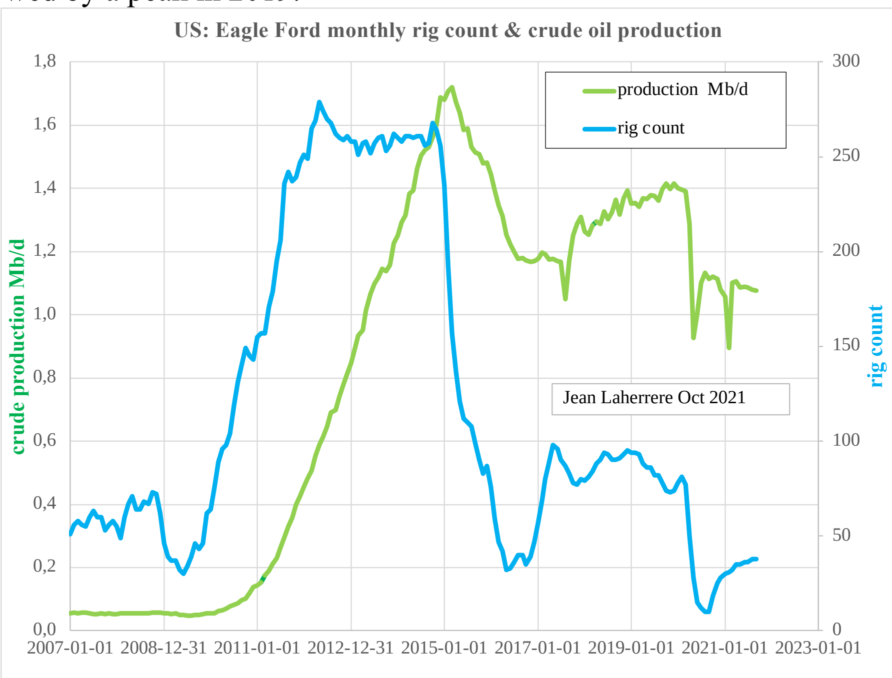
The "2018-2020 Biennium report" jan 2021 by STARR and BEG forecast the future water demand for hydraulic fracturing for US LTO
Figure 4. (a) Historical water use for hydraulic fracturing and produced water volumes along with saltwater disposal throughout the U.S. and (b) projections of future water demand for hydraulic fracturing and produced water volumes over the life of the plays (~ 50 yr).
For Bakken hydraulic fracturing used 49 Ggallons of water for 2009-2017, for the next 50 years 440 will be needed (9 times more) and 68 700 wells; for the produced water 75 Ggallons 2009-2017, 950 Ggallons for the future: it seems unrealistic.



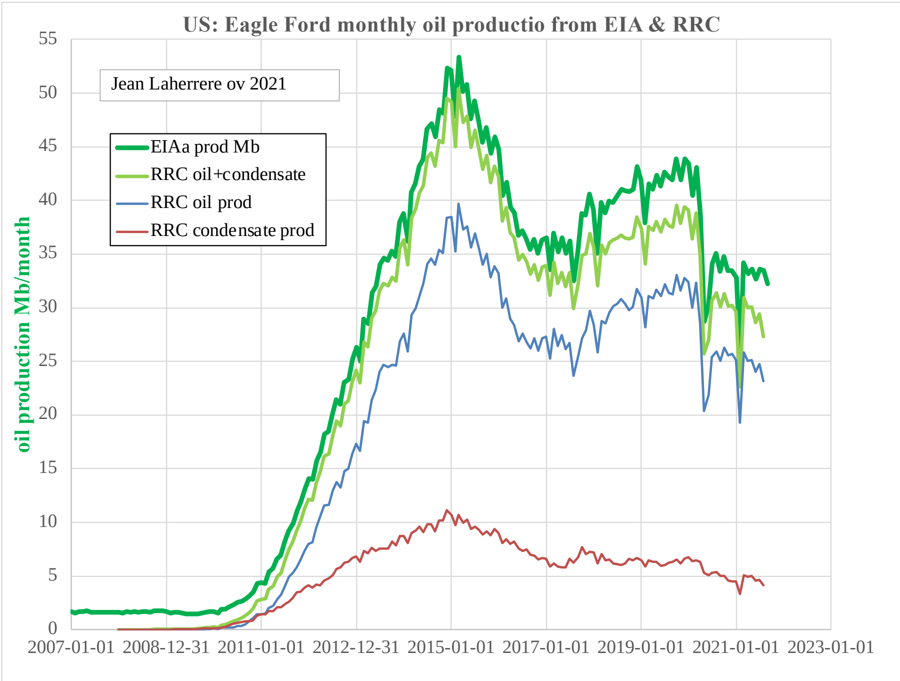


-Eagle Ford region

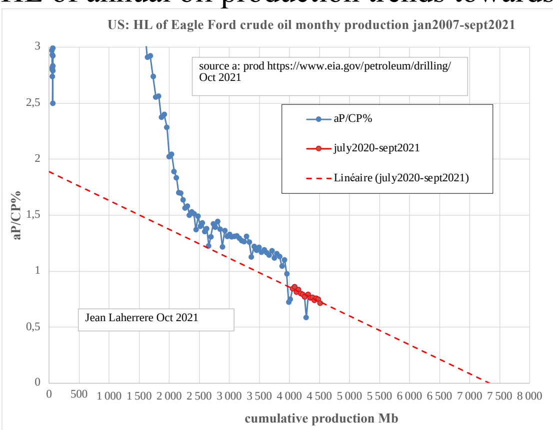
Eagle Ford monthly production and rig count displays a symmetrical production peak at first of 2015, followed by a peak in 2019.

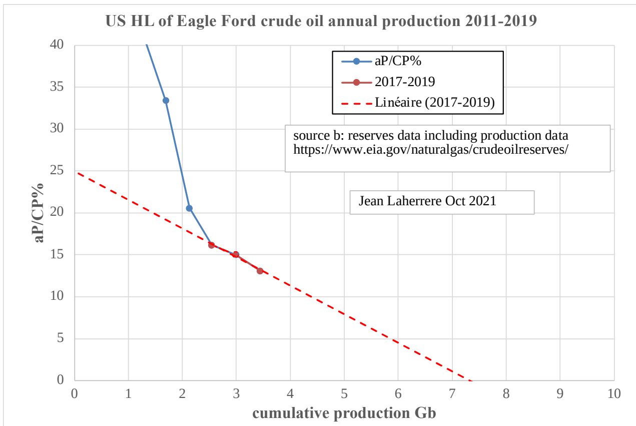


EIAa oil production data is compared with RRC, which distinguishes crude oil and condensate: the data is very different from 2007 to 2010 (as RRC is close to zero) and since 2012 EIAa is 10% higher, without any explanation from EIA!

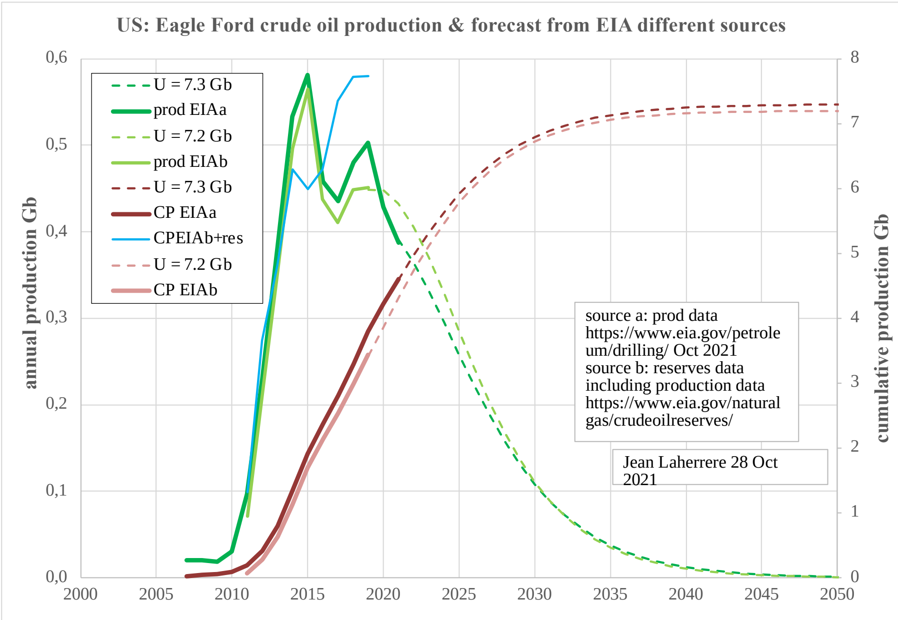


HL of monthly oil production trends towards 7.3 Gb
HL of annual oil production trends towards 7.2 Gb



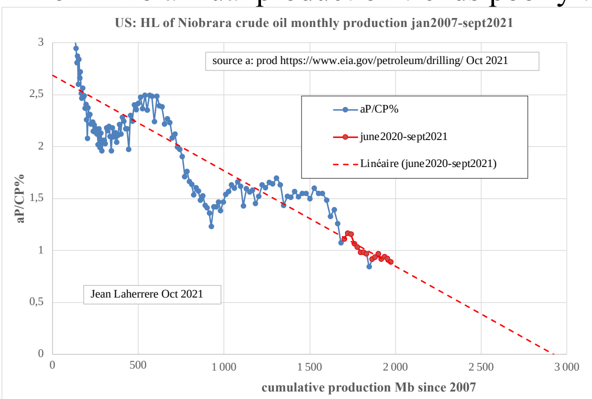


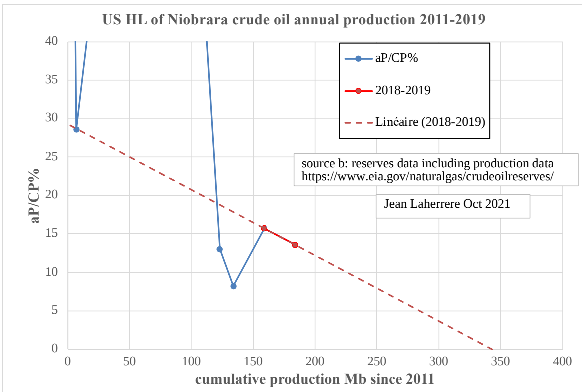
Both ultimates give a future decline in line with past decline.



-Niobrara

HL of EIAa monthly production trends towards 3000 Mb
HL of EIAb annual production trends poorly towards 350 Mb





Why such discrepancy?
Check with data:
EIAa prod 2019 = 0,7 Mb/d = 250 Mb EIAb prod 2019 = 25 Mb = 10 times less!

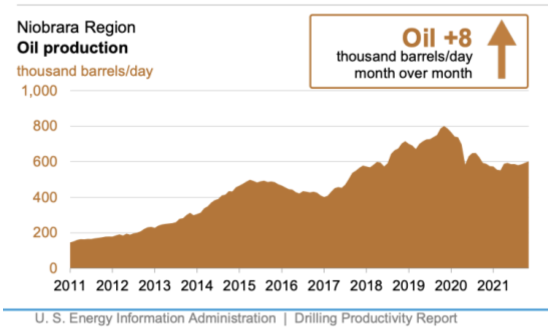
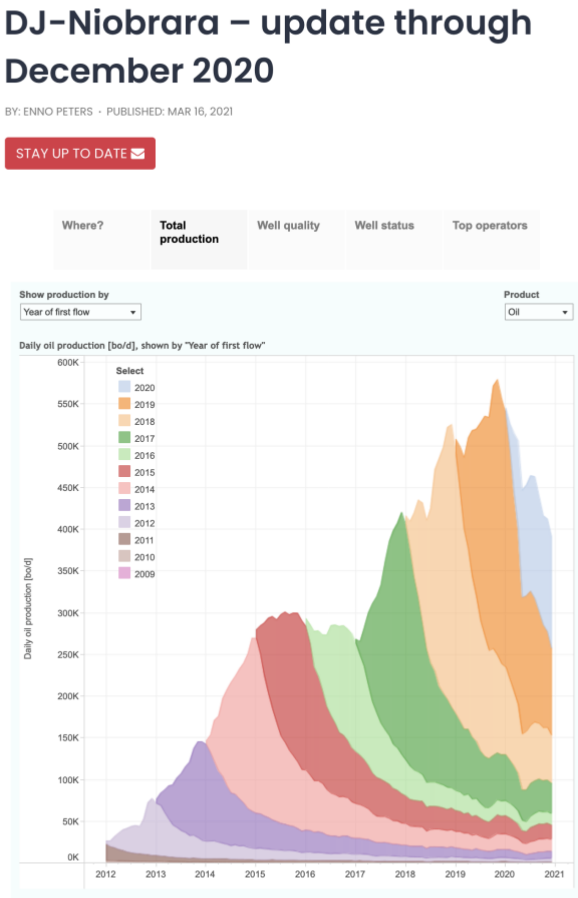


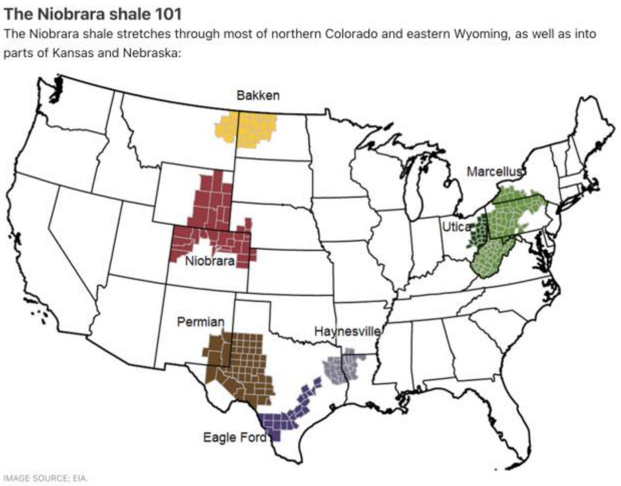
Table 2. Production and proved reserves of crude oil from selected U.S. shale plays, 2018–19
million barrels

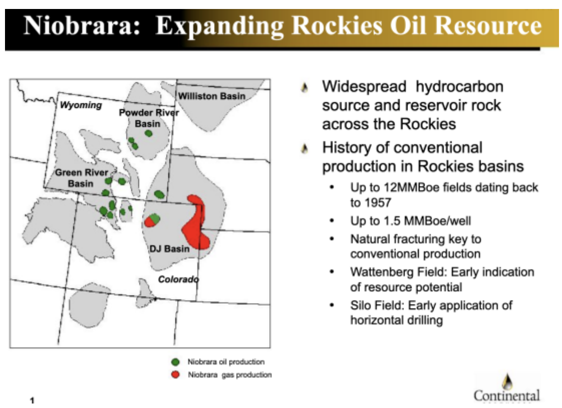
Basin	Play	State(s)	2018 Production	2018 Proved reserves	2019 Production	2019 Proved reserves	2018–19 Reserves change
Permian	Wolfcamp/Bone Spring	New Mexico, Texas	922	11,096	1,209	11,994	898
Williston	Bakken/Three Forks	North Dakota, Montana, South Dakota	458	5,862	517	5,845	-17
Western Gulf	Eagle Ford	Texas	449	4,734	451	4,297	-437
Anadarko, South Oklahoma	Woodford	Oklahoma	34	560	53	524	-36
Appalachian	Marcellus*	Pennsylvania, West Virginia	17	345	21	326	-19
Denver-Julesburg	Niobrara	Colorado, Kansas, Nebraska, Wyoming	25	317	25	235	-82
Fort Worth	Barnett	Texas	2	20	2	19	-1
Subtotal			**1,907**	**22,934**	**2,278**	**23,240**	**306**

Enno Peters reports Niobrara in 2019 about 0.48 Mb/d = 175 Mb, closer to EIAa than EIAb, but for January 2012 at 0.02 Mb/d against 0.15 Mb/d for EIAa



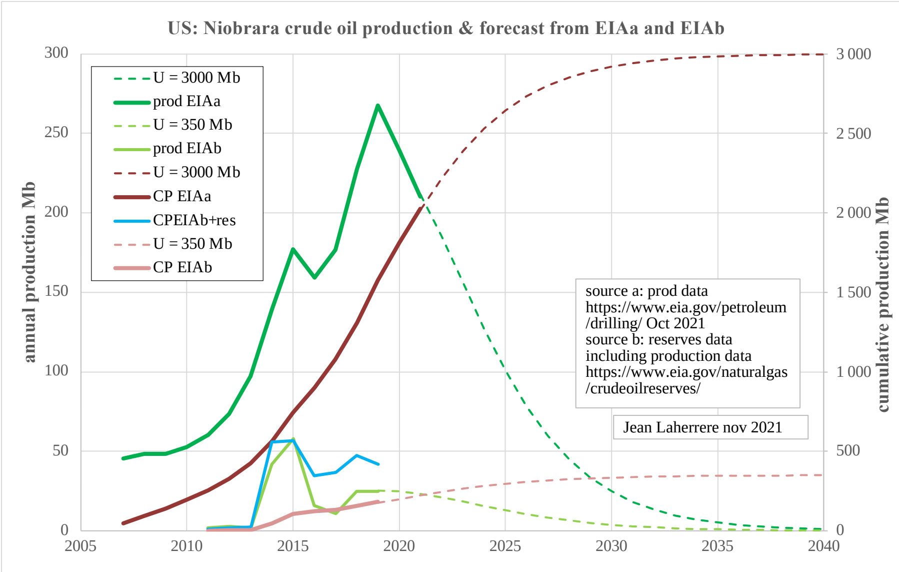
EIA map of Niobrara displays a large area, in fact covering several basins: Denver-Julesberg, Powder River and Green River and 4 states





It is obvious that EIAb (10 times smaller production) covers a different area than EIAa
It is obvious that EIAa does not bother to check what EIAb does. Where is the boss?

Niobrara EIAA peaked in 2019 with 270 Mb; Niobrara EIAb peaked in 2015 with 58 Mb

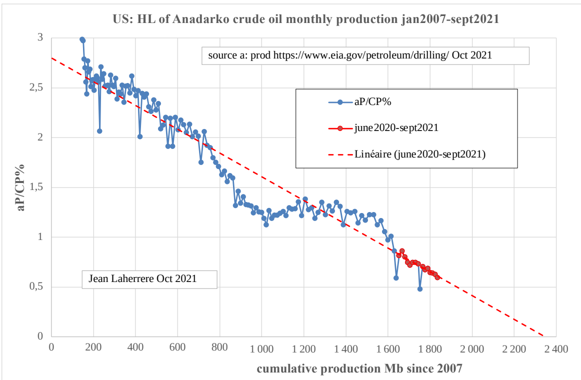


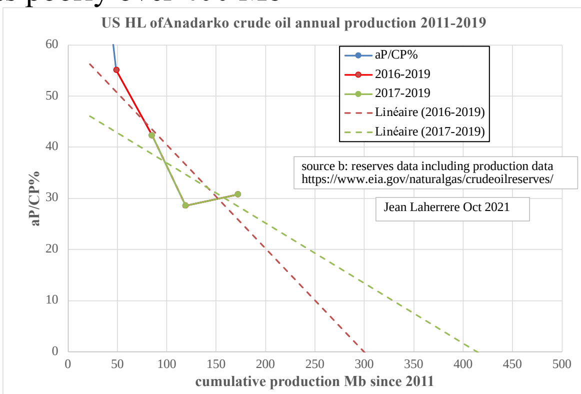
It is also amazing to not find any paper on the net mentioning such huge discrepancy between Niobrara production data from two EIA offices.

-Anadarko basin = Woodford shale

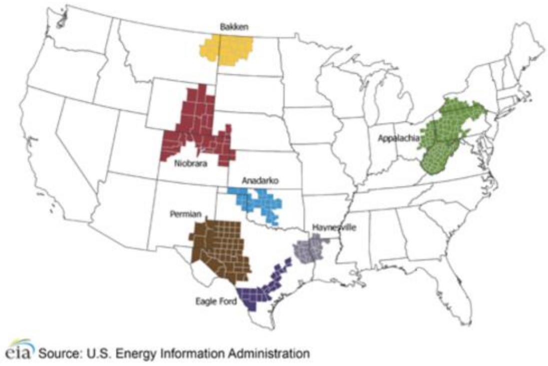
HI of EIAa monthly Anadarko production trends towards 2400 Mb

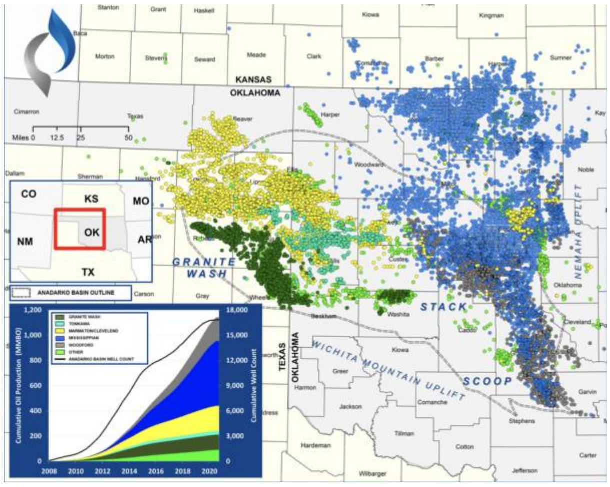
HI of EIAb annual Anadarko production trends poorly over 400 Mb



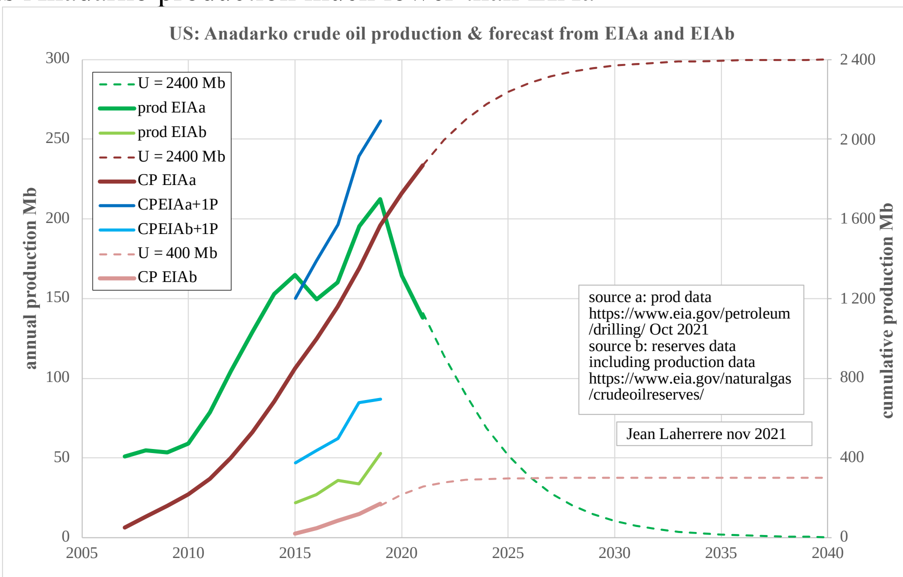


Again, as for Niobrara, large discrepancy between Anadarko production from EIAa and EIAb Anadarko basin = Woodford shale has several reservoirs: https://www.vsoinc.com/anadarko-basin/ displays the wells drilled since 2008 and Woodford wells (grey) represent only few of them



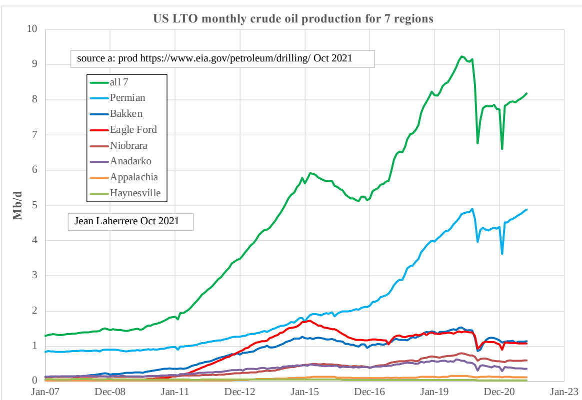


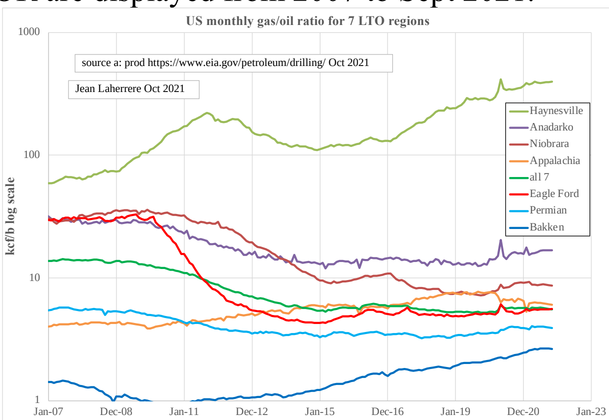
EIAb reports Anadarko production much lower than EIAa



-recapitulation of the shale oil plays

EIAa 7 LTO plays monthly production and GOR are displayed from 2007 to Sept 2021.





GOR is increasing since 2017 for Haynesville and Bakken, meaning close to decline.

Annual production for 2020 as the cumulative since 2007 for EIAa data, annual production for 2019 and cumulative production for EIAb data, as RRC for Eagle Ford and ultimates are displayed in the table for comparison, in particular for Niobrara and Anadarko

shale oil Gb	2020 prod EIAa	EIAa CP2007-2020	2019 prod EIAb	EIAb CP 2019	EIAb CP+1P 2019	RRC prod 2020	RRC CP 2020	Ultimate EIAa	Ultimate EIAb
Permian	1,6	10	1,2	3,3	15			35	9
Bakken	0,4	4,1	0,5	3,1	9			5,5	8
Eagle Ford	0,42	4,2	0,45	3,4	13	0,4	3,8	7,3	7,2
Niobrara	0,24	1,8	0,025	0,2	0,4			3	0,35
Anadarko	0,16	1,7	0,05	0,2	0,7			2,4	0,4
total 5 plays	2,8	21,8	2,2	10	38			53	25
7 plays	3	22	2,3	10	33			50	55

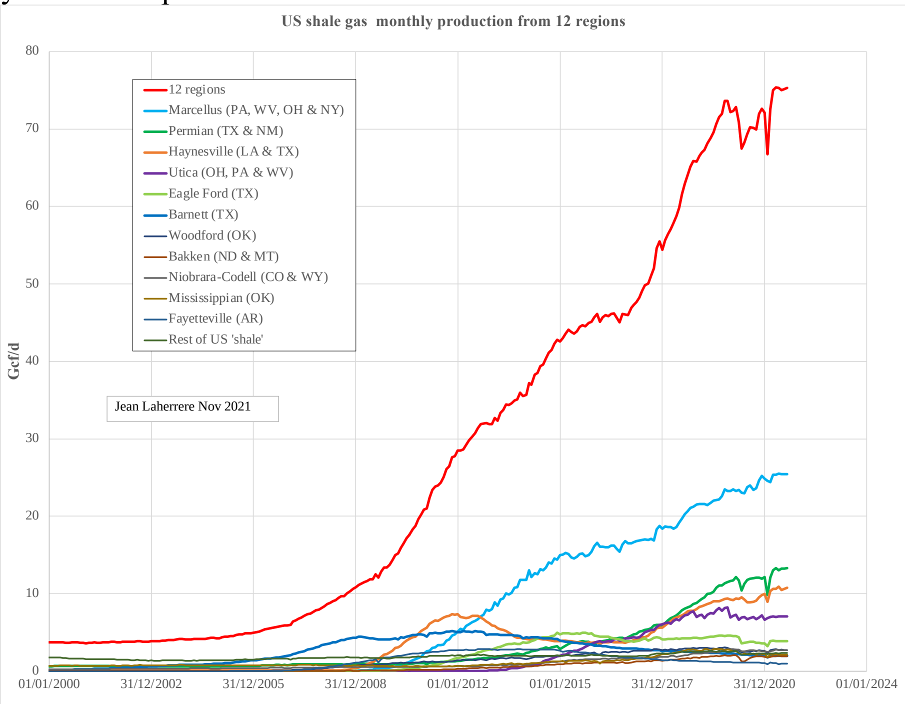
The aggregation of the 5 plays cumulative is 21.8 Gb comparted with 22 Gb for the 7 plays, meaning that the 2 shale oil plays not studied (table 2 page 2) Marcellus and Barnett) are negligeable

The ultimate for the 5 detailed plays is 53 Gb compared with the ultimate of 50 Gb for the global 7 plays, well within the range of certainty.

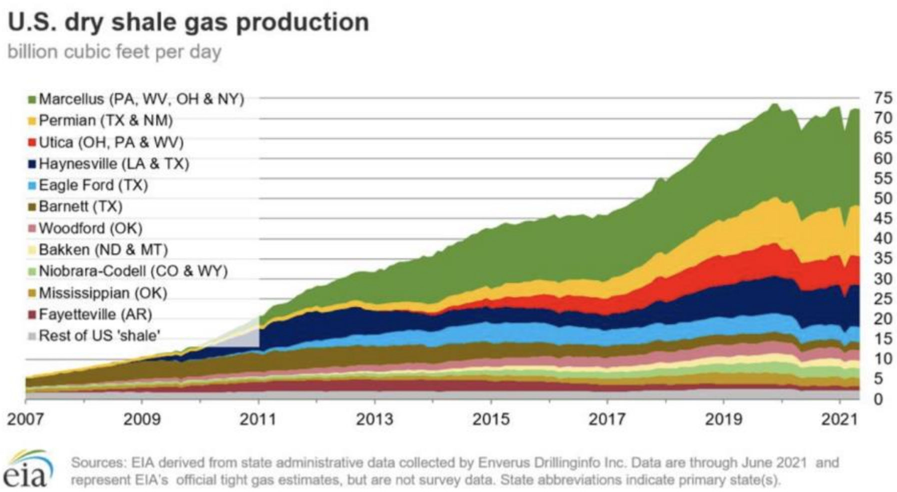
-Shale gas

-monthly shale gas production

Monthly shale gas production is reported in https://www.eia.gov/naturalgas/data.php for 12 regions from January 2000 to September 2021

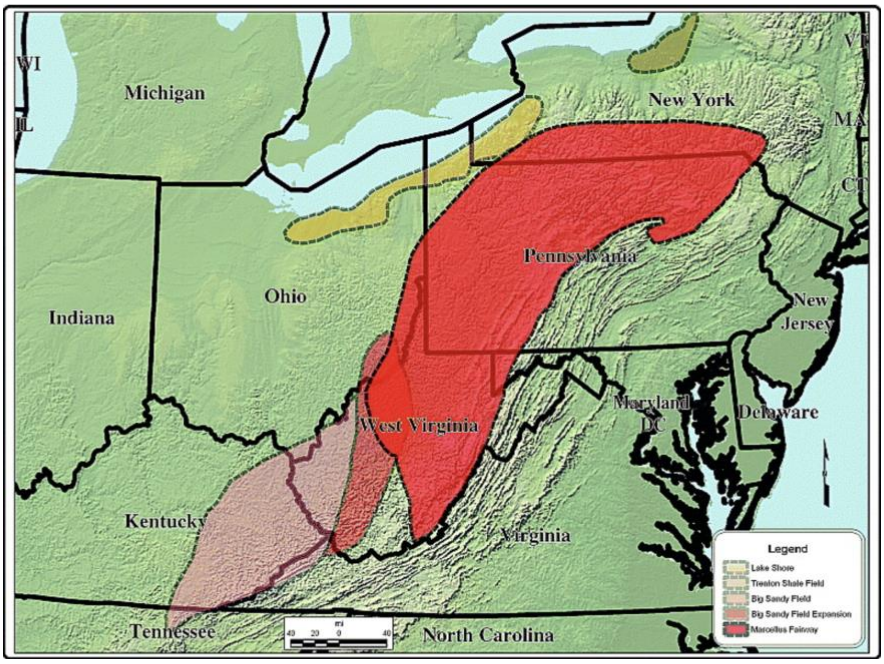


EIA graph



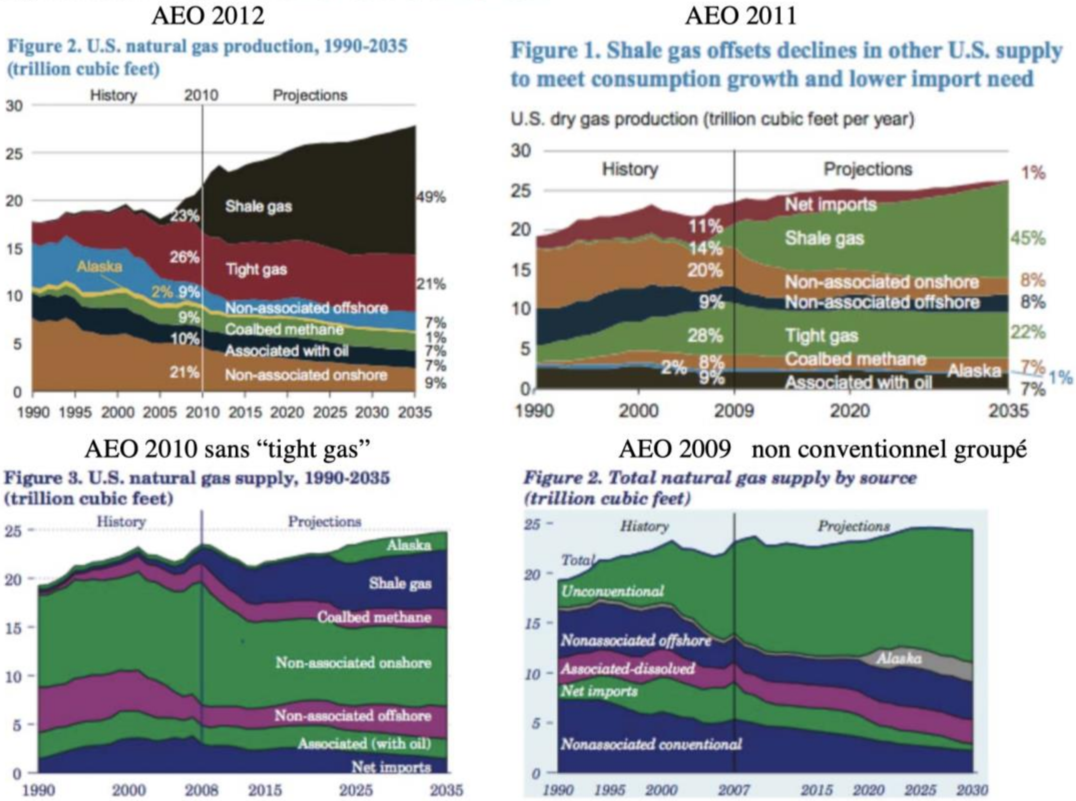
-old shale play

The first US natural gas production was in 1825 (1821?) at Fredonia, which belongs to the Appalachian basin (= Marcellus now) where Big Sandy field was developed in 1914?
https://www.searchanddiscovery.com/pdfz/documents/2014/70168lash/ndx_lash.pdf.html
Early History of the Natural Gas Industry, Fredonia, New York*
Gary G. Lash 1 and Eileen P. Lash1 August 29, 2014
Gas shale tight gas as LTO is not new, what is new is huge fracking and long extent horizontal wells.



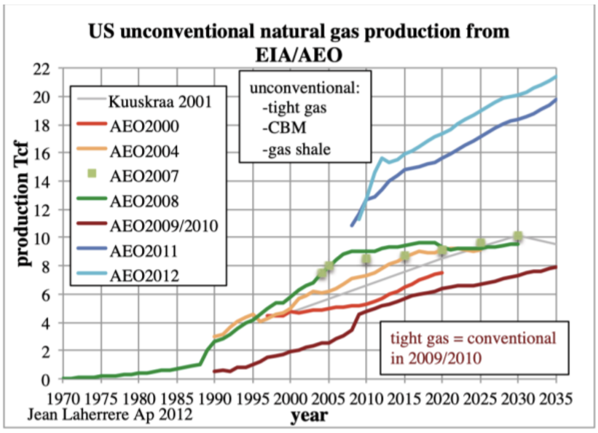
-Laherrere J.H. 2012 « Point de vue d'un géologue pétrolier» table ronde sur les gaz de schiste » Club de Nice 5 décembre
http://aspofrance.viabloga.com/files/JL_2012_NICE-gazrochemere.pdf,
http://www.clubdenice.eu/2012/Jean_Laherrere_Gaz_de_Schiste.pdf

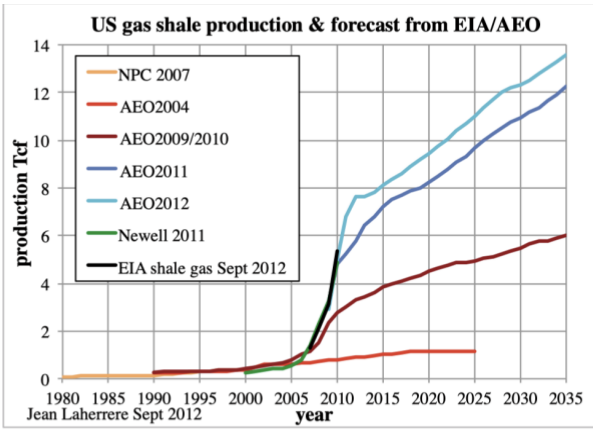
-Fig 12: **US: production de gaz EIA AEO 2009 à AEO 2012**



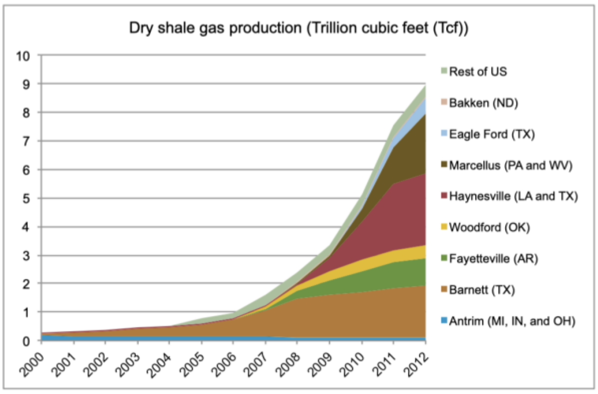
Il faut rappeler que la première production de gaz aux US a été en 1821 à Fredonia (Etat de New York) avec du shale gas utilisé pour l'éclairage. Mais ce shale gas a été abandonné dés que le gaz conventionnel a été mis en production. En 1880 (Hill 2002) (ou 1881, 1914, 1915

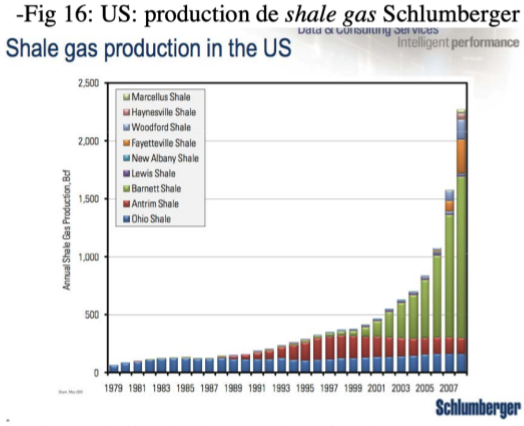
ou 1918) découverte de shale gas dans le champ de Big Sandy (Kentucky & West Virginia) dans la formation Ohio shale (Dévonien Supérieur). Le Marcellus shale est du Dévonien Moyen.
Mais de 1976 à 2000 USDOE & GRI ont dépense 127 M$ dans un programme de recherche pour le Antrim shale au Michigan. En 1977 USDOE a montré la fracturation hydraulique dans les shales.
De 1980 à 2002, le crédit d'impôt sur le shale gas (section 29) de 0,5 $/kcf a été une forte incitation qui a poussé George Mitchell a foré le Barnett, ainsi que les aides de l'USDOE et de l'Institut de recherche du gaz (GRI) pour développer les moyens techniques du forage, de la production et de la sismique. En 1986 première multi–fracturation dans un puits horizontal par USDOE/privé. En 1991 GRI subventionne Mitchell Energy pour le premier puits horizontal dans le Barnett. Le shale gas ne commence qu'en 1990 dans le rapport AEO et les données détaillées EIA de shale gaz qu'en 2007 -
Fig 13: US: production gaz non conventionnel -
Fig 14: US: production de shale gas EIA/AEO 2004 à 2012





La production US de shale gas publiée par EIA depuis 2000 diffère de celle de Schlumberger qui remonte à 1979
-Fig 15: US: production de *shale gas* EIA -Fig 16: US: production de *shale gas* Schlumberger

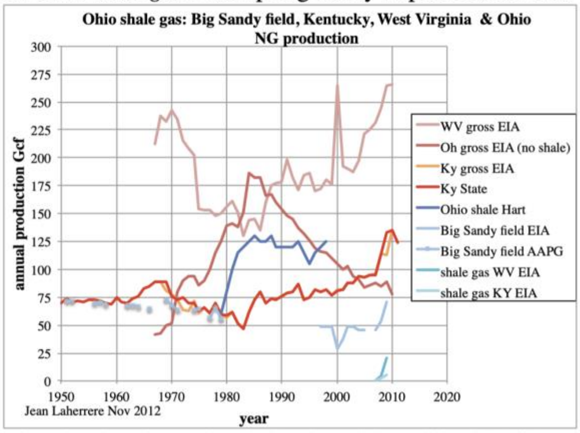




Schlumberger (Boyer) distingue une production de l'Ohio shale alors qu'elle n'existe pas dans les documents récents EIA. Cette omission semble volontaire: **le *shale gas* est nouveau, pas ancien.** On oublie donc l'ancien!
Cependant le champ de gaz de Big Sandy (en fait un agrégat de nombreux petits champs) découvert en 1914 (?) produit depuis 1921 (déjà 2,5 Tcf produit fin 2010). Dans le rapport annuel USDOE sur les réserves des US il y a la liste des 100 plus grands champs de pétrole et de gaz avec production et date de découverte. De 1997 à 2009 (dernière donnée) le champ de Big Sandy a débuté à la 18 e place, puis 14 puis 23 et enfin retour à 18 (en 2006 sorti de la liste des 100 ?).
Par contre la date de découverte était de 1881 de 1997 à 2003 pour passer à 1926 de 2004 à 2009. Mais les rapports annuels d'activité d'AAPG donne soit 1914 ou 1918 avec première production en 1921. La date de 1926 est donc fausse. Pourquoi l'USDOE omet actuellement tout le passé de shale gaz avant 1990, alors que l'USDOE a joué un rôle important dans ces découvertes. Est ce une querelle entre anciens et nouveaux chefs? Il n'y a pas de plus grande querelle entre chefs que dans une même famille (PS, UMP, AIE 2002 contre AIE 1998, USGS 2000 contre USGS 1995).

Il est difficile d'avoir des données fiables sur la production de Sandy Big (rien de 1921 à 1950 avec plus de 4000 puits).
Il ne faut pas confondre Ohio shale qui est une formation géologique et la production de shale de l'Etat d'Ohio

-Fig 17: Ohio *shale gas* : champ Big Sandy & production Etats



-Fig 18: carte Big Sandy : agrégat de petits champs

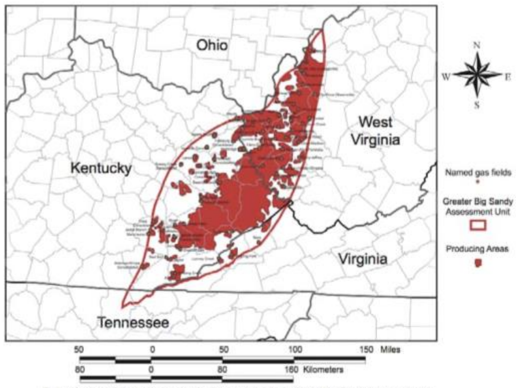


Figure 19. Named fields producing from the Devonian shale in the Greater Big Sandy Assessment Unit. Locations are approximate field centers (data from Roen and Walker, 1996).

La production du champ de Big Sandy a été amélioré (1964) en utilisant des explosifs (nitroglycérine) dans le *black shale*

Table 1

Inventory of the response to well stimulation by shooting in the black shale in parts of Big Sandy gas field in Kentucky*

County	Percent: Natural producing wells	Percent: Wells shot	Average open flow Mcfd: Before shot	Average open flow Mcfd: After shot	Percent after shot: Wells less 100 Mcfd	Percent after shot: Dry holes
Floyd	10	90	68	360	25	8
Martin	4	96	46	269	32	8
Knott	2	98	58	238	31	7
Pike	3	97	48	201	37	12
Magoffin	0.1	100	26	151	60	41
Johnson	0	100	21	105	51	26
Perry	0	100	37	133	31	16
Letcher	0	100	12	86	68	24

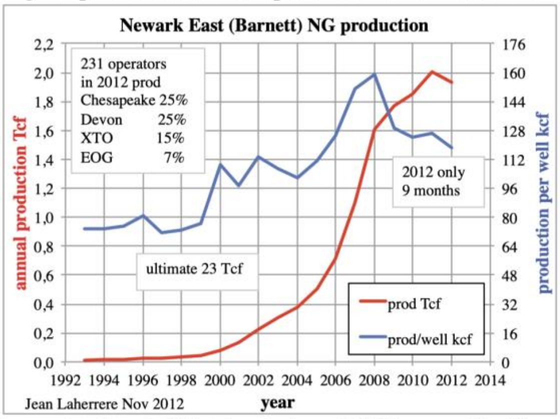
*Modified from Hunter (1964).

-Fig 19: stimulation par explosif

-US: le *shale gas nouveau*

Le renouveau du *shale gas* a été le Barnett avec le champ de Newark East au Texas, grâce aux techniques anciennes de forage horizontal et de fracturation hydrauliques, à l'aide de l'USDOE et du crédit d'impôt, mais surtout grâce au prix élevé du gaz à plus de 10 $/kcf en 2006 et 2008

-Fig 20: production du champ de Barnett : Newark East



-Fig 21: production par réservoir Sarsfield-Hall 2012

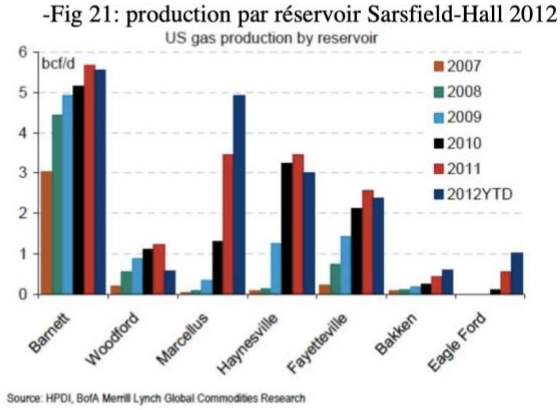


Figure 4 - Production of natural gas from various shale plays in the US from 2007 to 2012.

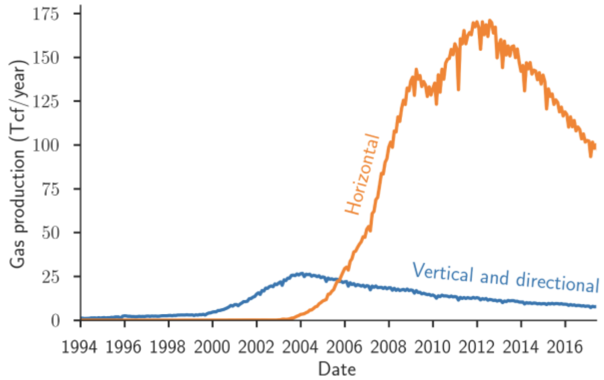
-Barnett

Barnett shale play is the oldest new shale gas with modern fracking and is called also Newark East field

Barnett gas production started in 1962 with vertical wells and in 2004 with horizontal wells

https://www.geoexpro.com/articles/2018/01/newark-east-barnett-shale-s-spindletop

R.M.Pollastrop AAPG v61 n°4 April 2007



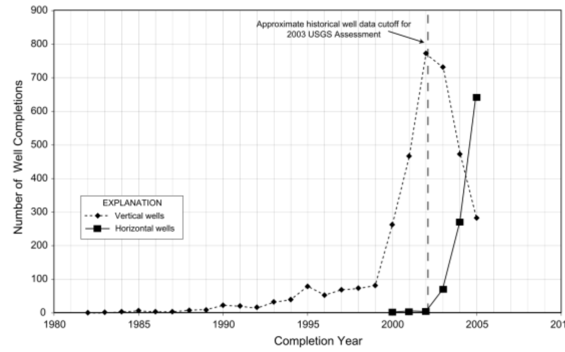
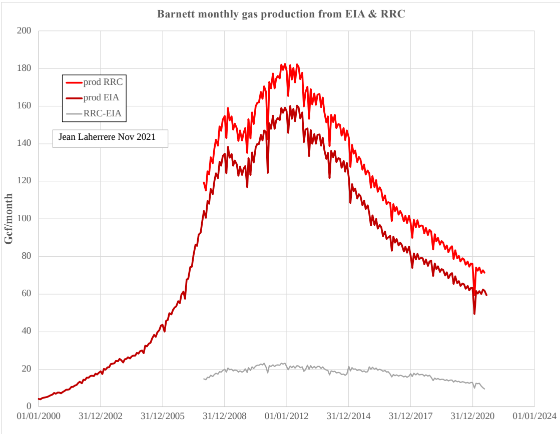


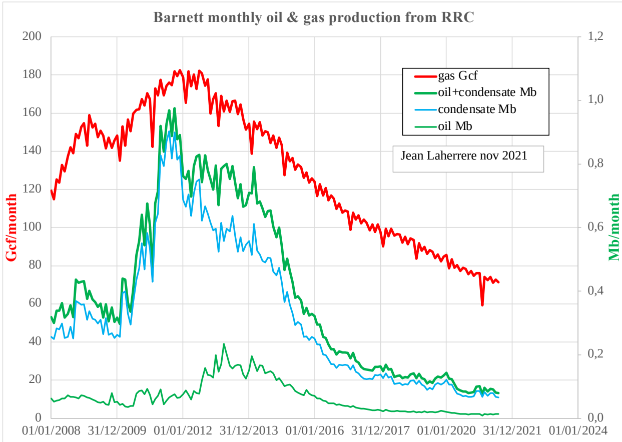
Figure 2. Plot of annual number of vertical and horizontal well completions in Barnett Shale versus year. Data derived from the IHS Energy well production database (IHS Energy, 2006).

POLLASTRO 555

The scale of the above graph is not Tcf/year but Gcf/d

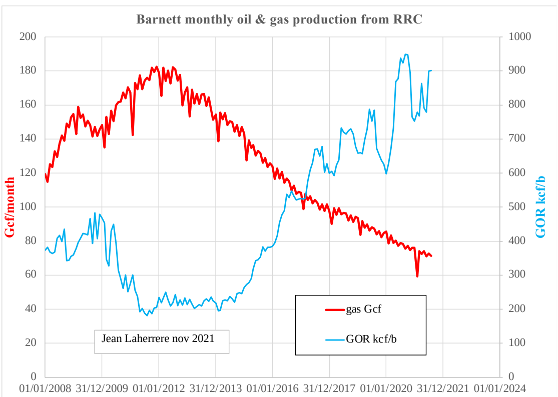
The monthly EIA production data (dry) is lower than RRC data, which reports oil as condensate production since January 2008 https://www.rrc.texas.gov/oil-and-gas/major-oil-and-gas-formations/barnett-shale/

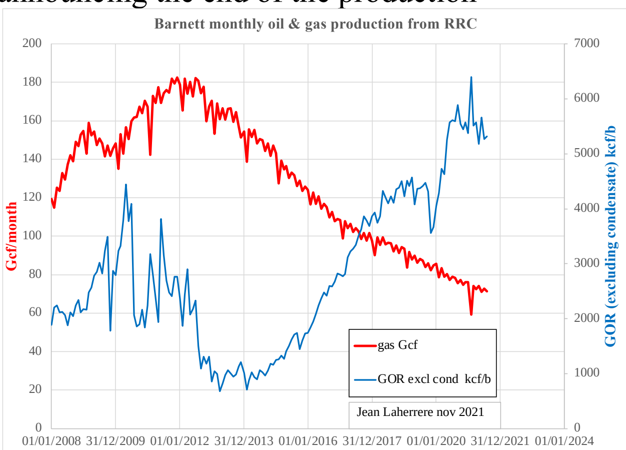




RRC Barnett gas production has peaked in January 2012, oil in October 2011 and condensate in April 2014.

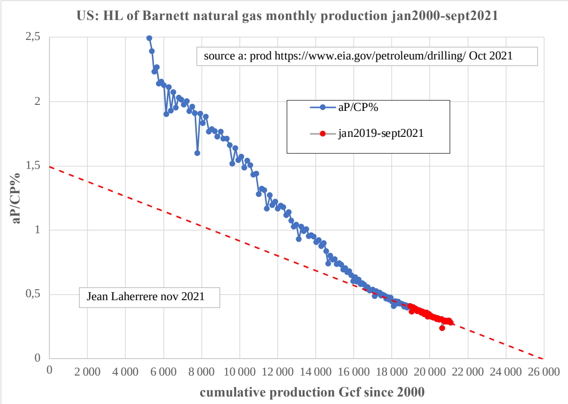
Barnett gas/oil ratio is growing since 2014, announcing the end of the production

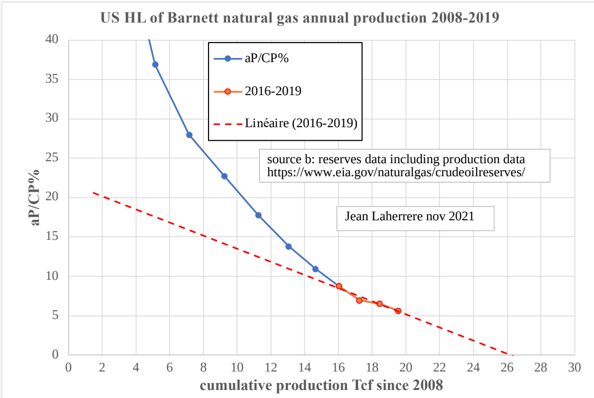




HL of EIAa monthly data trends towards 26 Gb

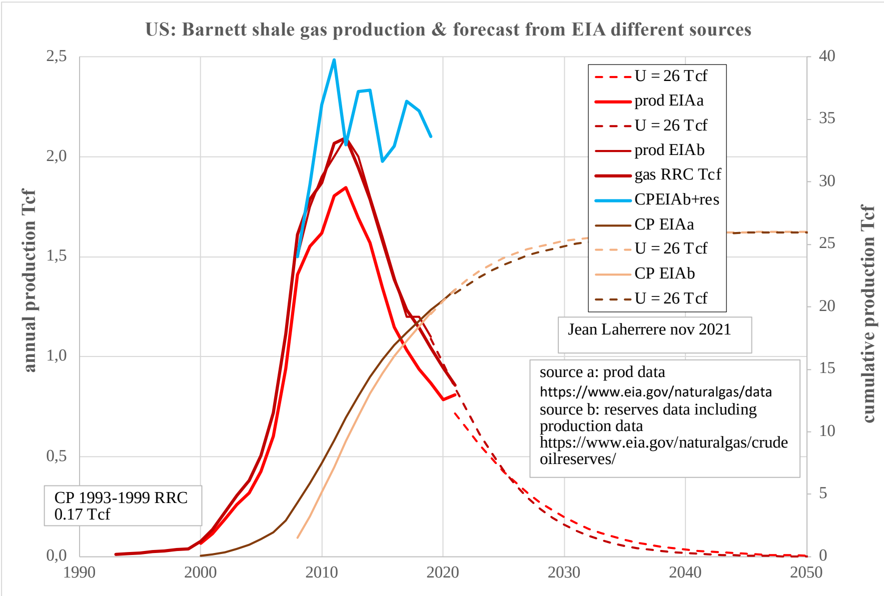
HL of EIAb annual data trends also to 26 Gb





The 26 Gb ultimate (estimated at 23 Gb in 2012 see above)

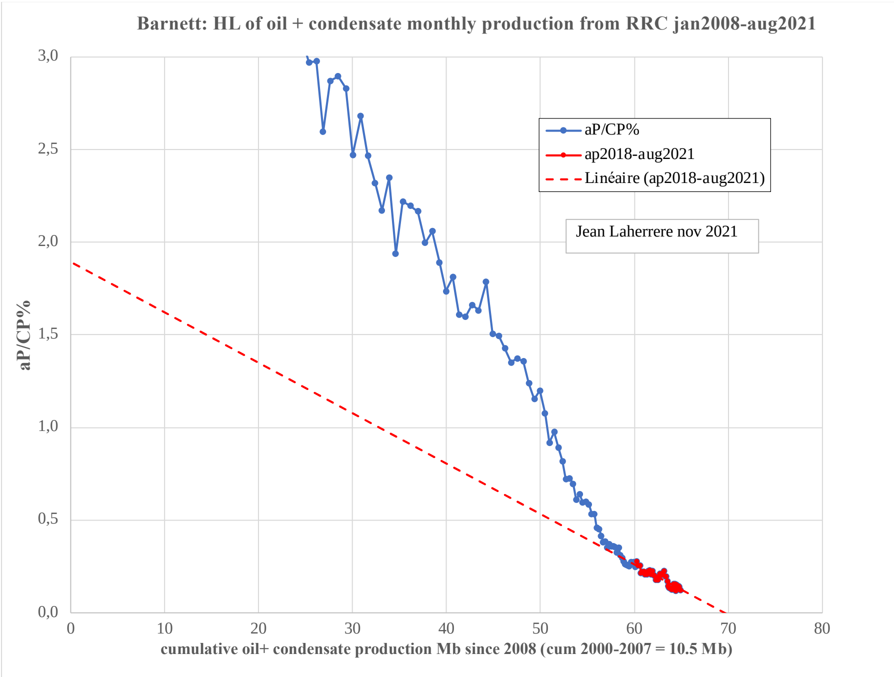
The 26 Tcf ultimate for EIA b corresponds to a future decline in line with the past decline since the peak of 2012



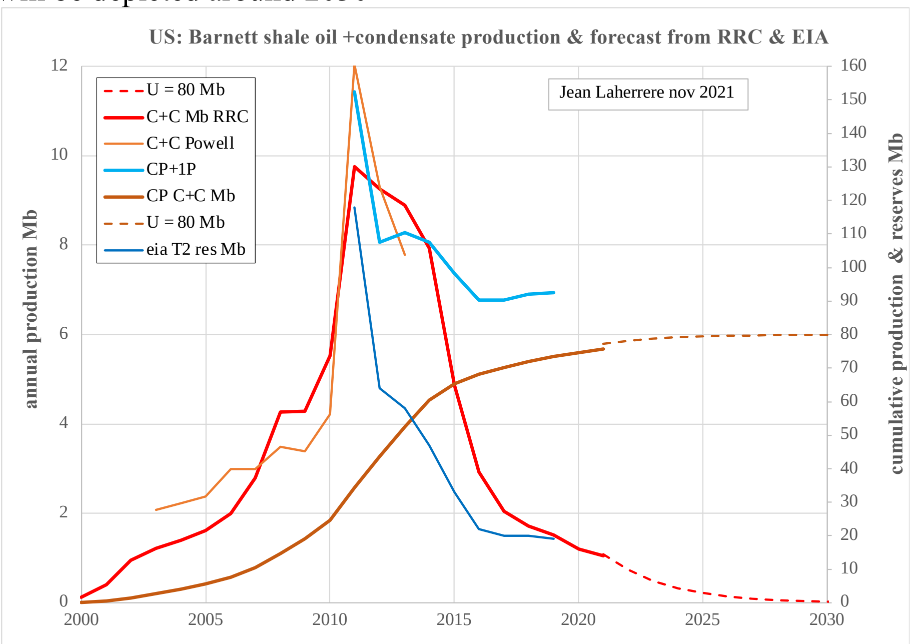
It appears that EIAb production data from reserves is identical with RRC data
The cumulative EIAb production + proven reserves range from 2010 to 2019 from 32 to 40 Gb, well above the HL ultimate.
This shale play well in decline shows that EIA proven gas reserves are overestimated.

HL of RRC oil and condensate monthly production trends towards 70 Mb for data from 2008, but to get from the start

HL of RRC oil +condensate monthly production trends towards 70 Mb



Barnett shale oil +condensate peaked in 2012, declined sharply until 201 and since declines slowly and will be depleted around 2030

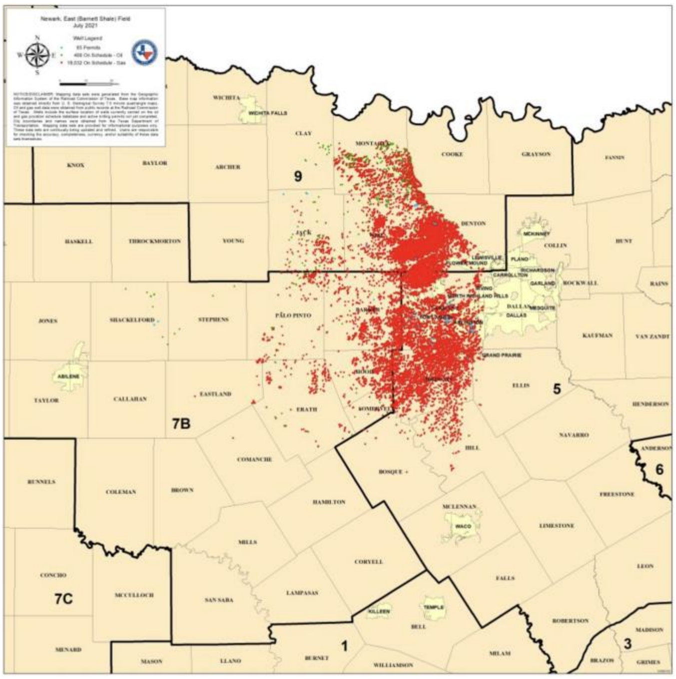


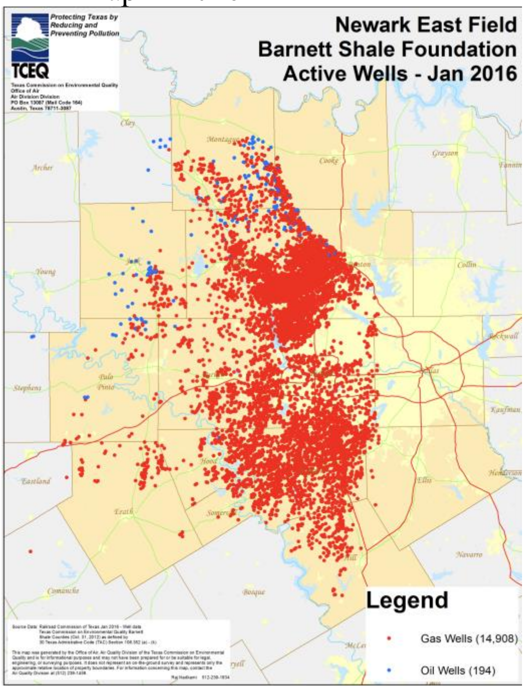
Oil + condensate data from Gene Powell (Barnett shale newsletter) were different from RRC data by year, less in cumulative, meaning that US production data is poorly reported.

Barnet oil + condensate EIA remaining reserves were overestimated in 2021 at 119 Mb in 2011, when my remaining ultimate was 80 Mb less cumulative production 2010 of 25 Mb = 55 Mb = half of EIA estimate!
EIA 2019 reserves were down to 19 Mb in 2019.
In 2021 the remaining reserves should be less than 5 Mb.
Estimates of shale reserves is very hard, because different from conventional plays and because there is not yet any historical depleted shale production to compare past estimates and reality.

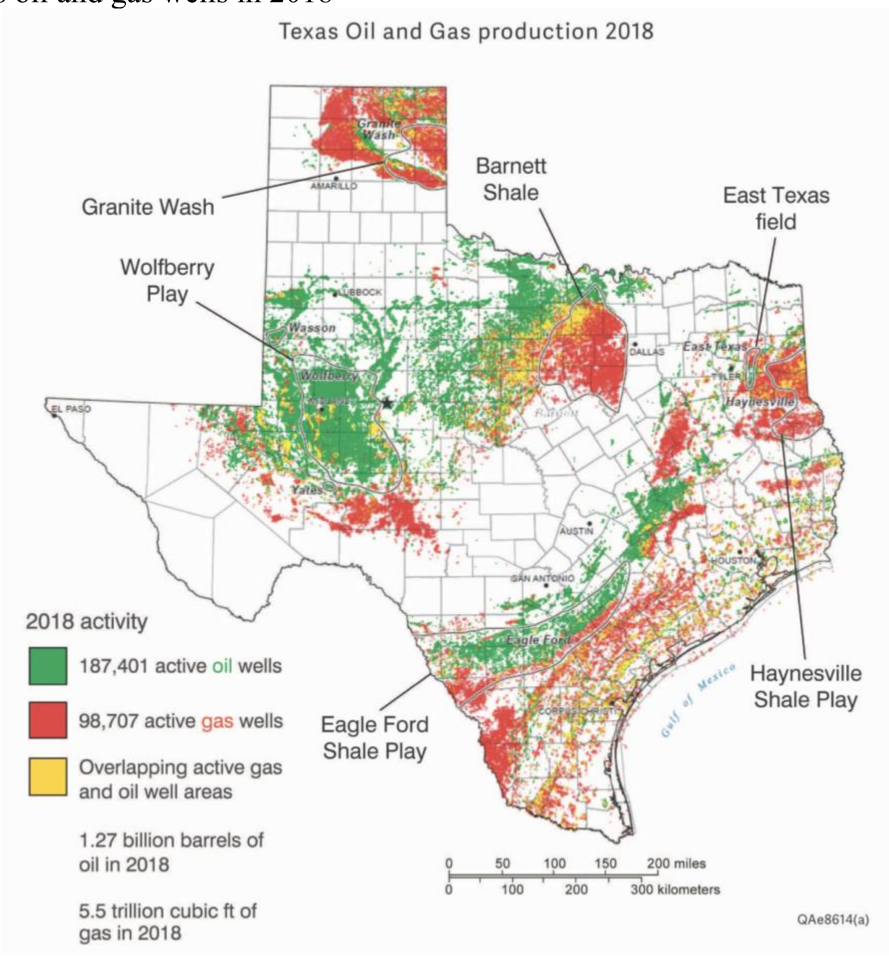
RRC provides a map of Barnett wells updated at July 2021: it is obvious that the sweet spots are almost fully drilled! it is compared with a map in 2016: little change: Chesapeake sold in 2016 their assets to Total = TEP Barnett USA

map in 2021 map in 2016



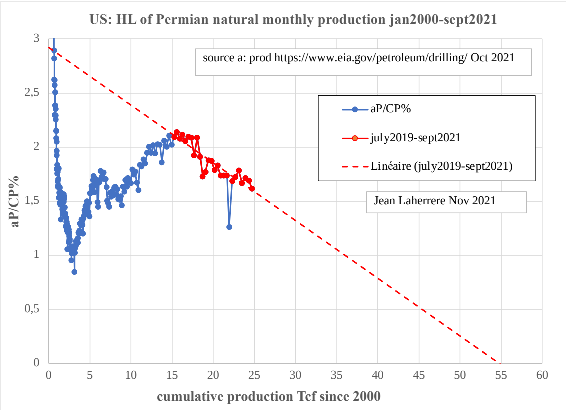


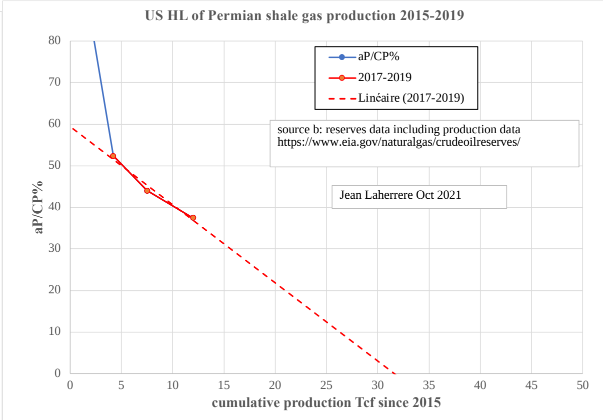
Map of Texas oil and gas wells in 2018



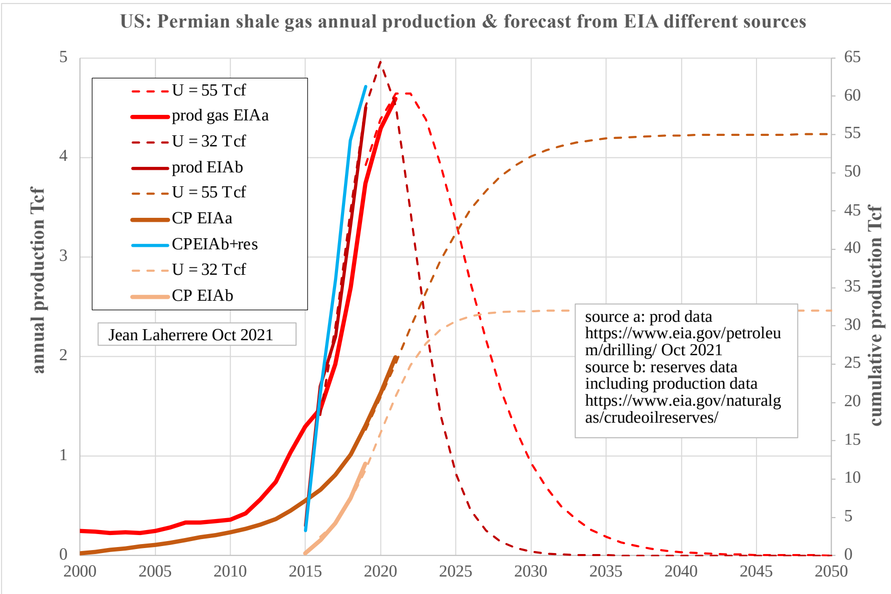
-Permian

Permian region is the first US LTO play, but only the second shale gas.
HL of monthly Permian EIA a gas production since 2000 trends towards 55 Tcf
HL of annual Permian EIA b gas production since 2015 trends towards 32 Tcf, the cumulative production 2000-2014 is 6 Tcf

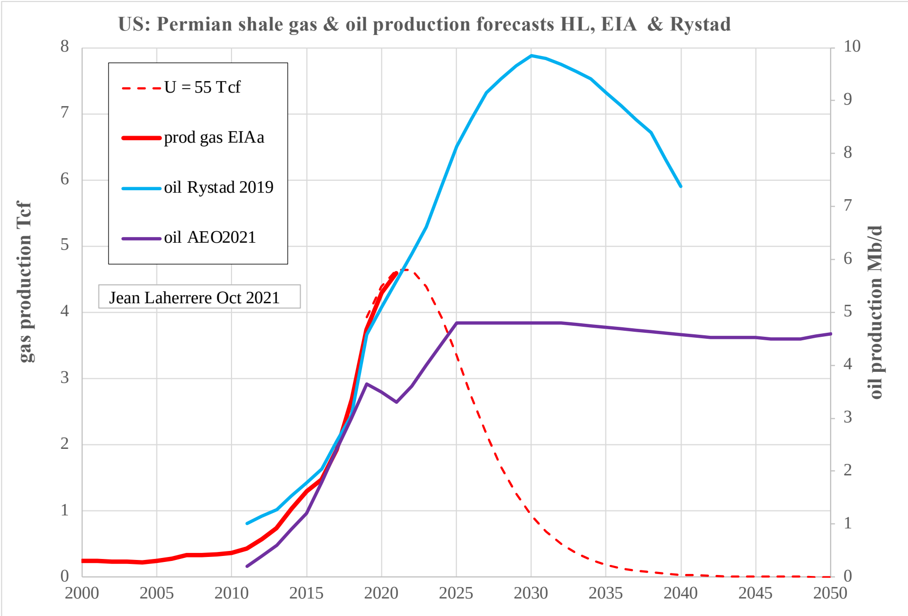




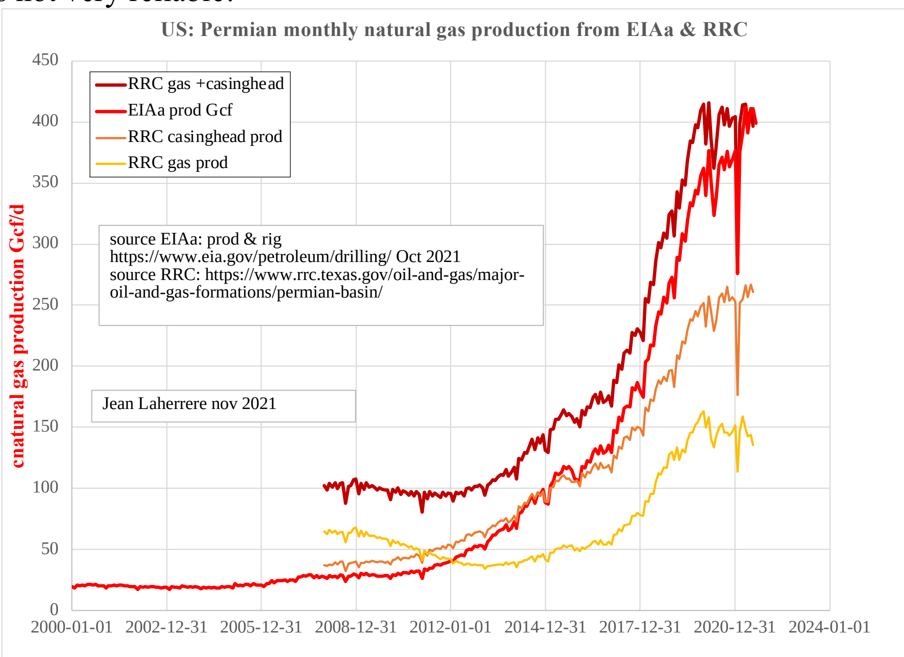
Annual Permian shale gas will peak soon and will decline after



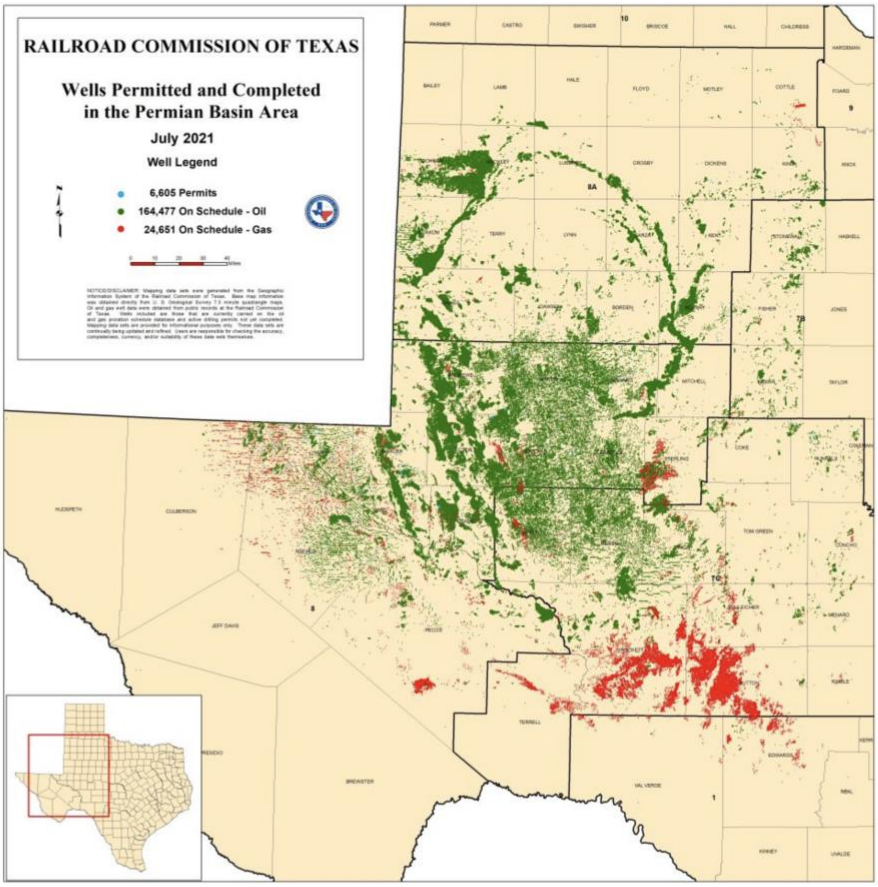
Permian forecast on shale gas is compared with Rystad & EIA shale oil forecast: it is striking!



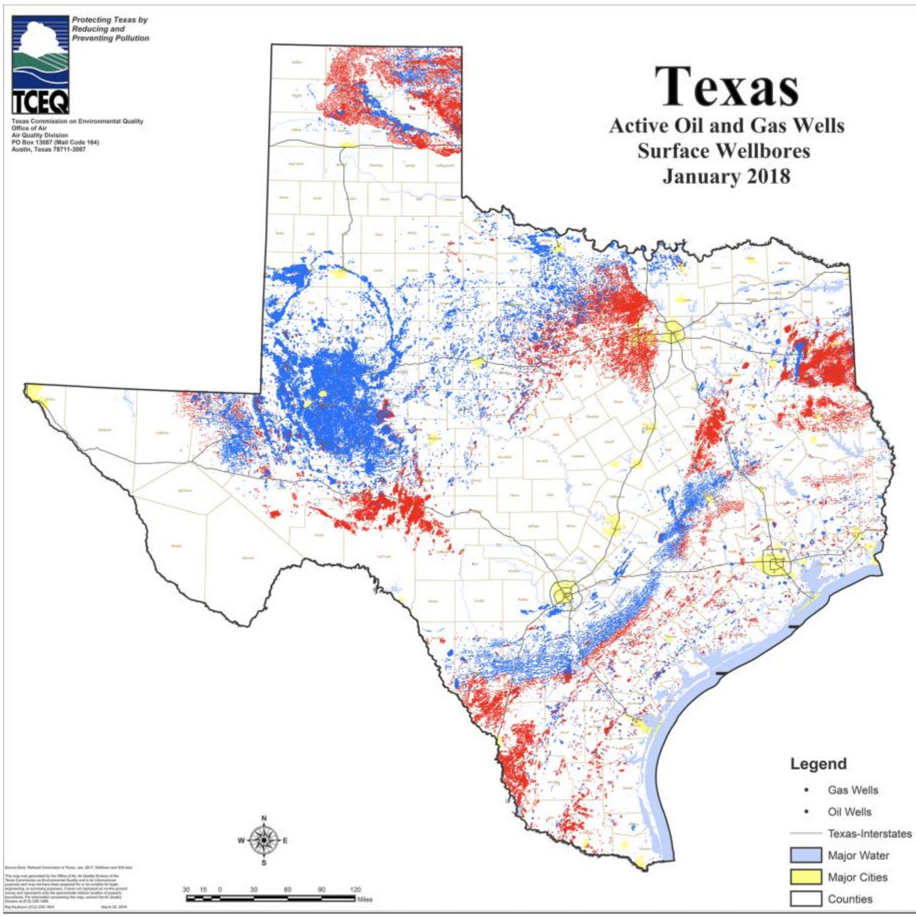
Permian EIAa gas production is compared with RRC Permian shale gas (broken down into casinghead and gas). EIAa data is lower than RRC except for the last few months since March 2021: this increase looks suspicious!
EIAa data is not very reliable!



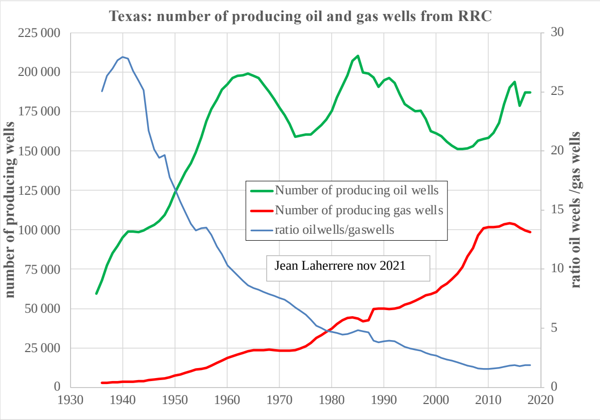
RRC provides a map of Permian wells in Texas updated to July 2021; the shale play is well drilled!

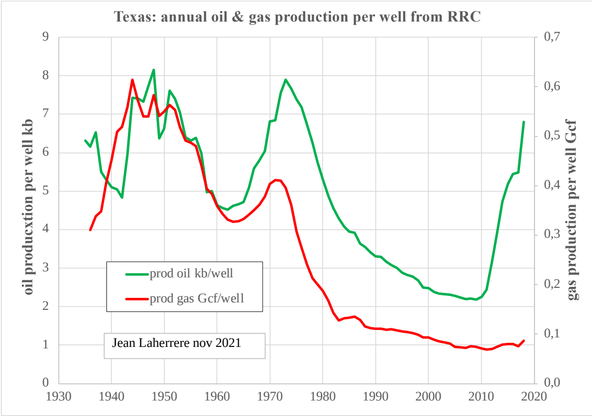


The map of Texas wells in 2018



Texas number of oil wells and gas wells from 1936 to 2018 (RRC data) and production per well





The oil and gas production per well was higher in the 1940s or in the 1970s than now, in particular for gas!

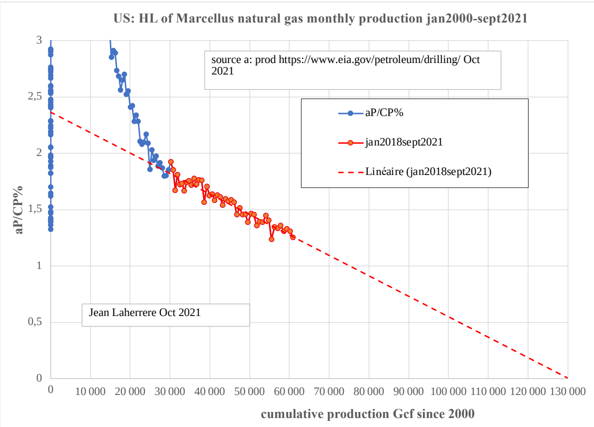
-Marcellus

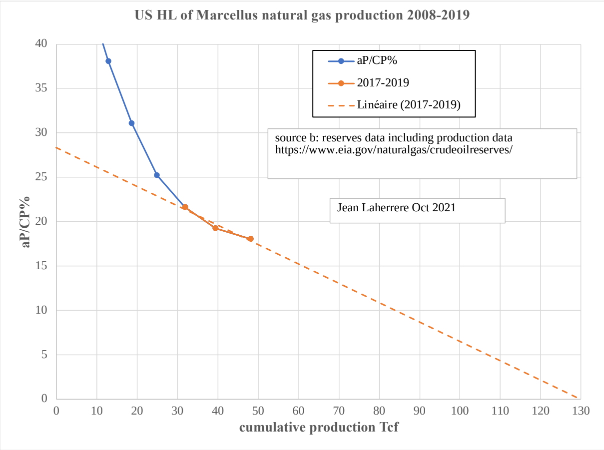
Marcellus belongs with Utica to the Appalachian basin

Marcellus is the largest shale gas play

HL of EIAa monthly production since 2000 trends towards 130 Tcf

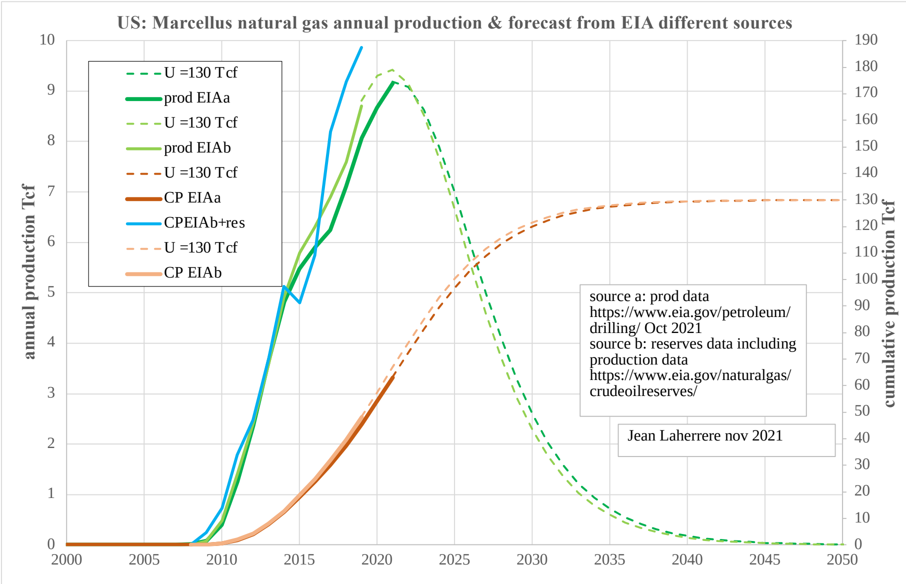
HL of EIAb annual production since 2008 trends also towards 130 Tcf as shale gas starts really only in 2008





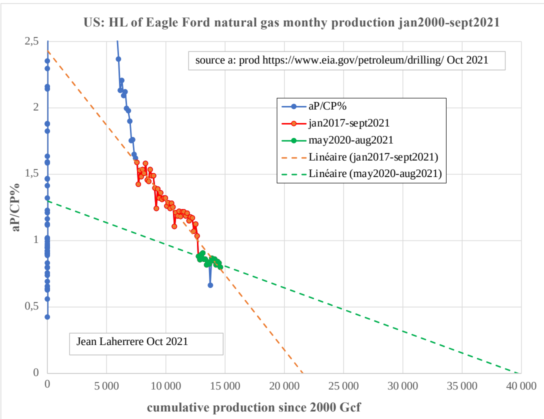
With an ultimate of 130 Tcf Marcellus will peak in 2021

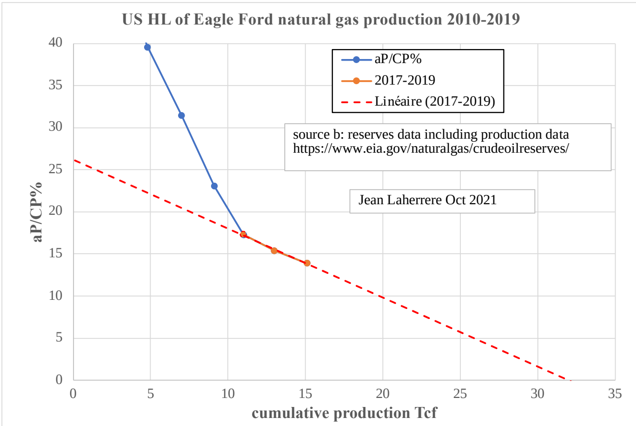
Marcellus proven remaining reserves at end 2019 are 139 Tcf, giving with the cumulative production about 190 Tcf well above our ultimate of 130 Tcf, meaning that proven reserves are overestimated.



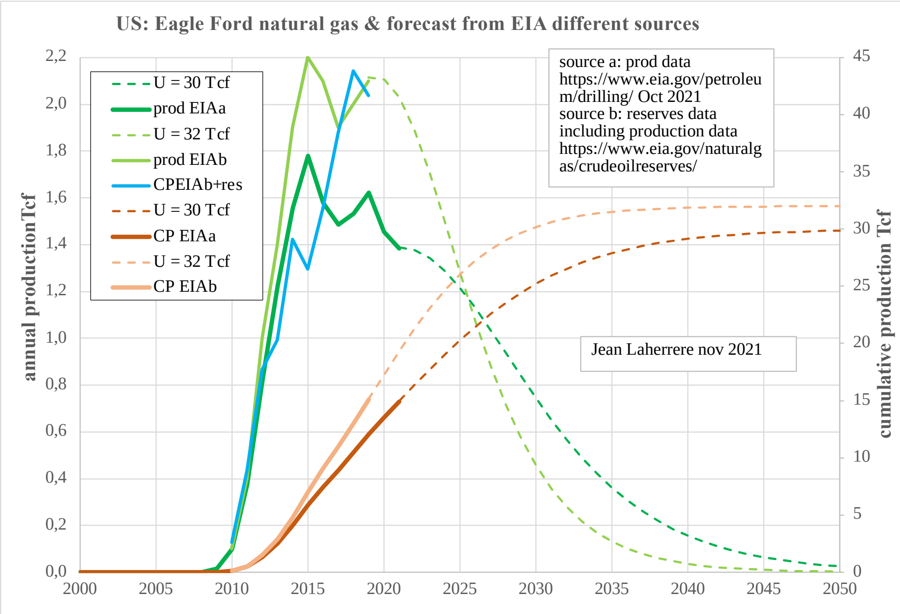
-Eagle Ford

HL of Eagle Ford EIAa monthly production since 2000 trends towards a range 22-40 Tcf, taking a poor estimate of 30 Tcf
HL of EIAb annual production since 2010 trends towards 32 Tcf and cumulative 2000-2009 is small about 0,02 Tcf

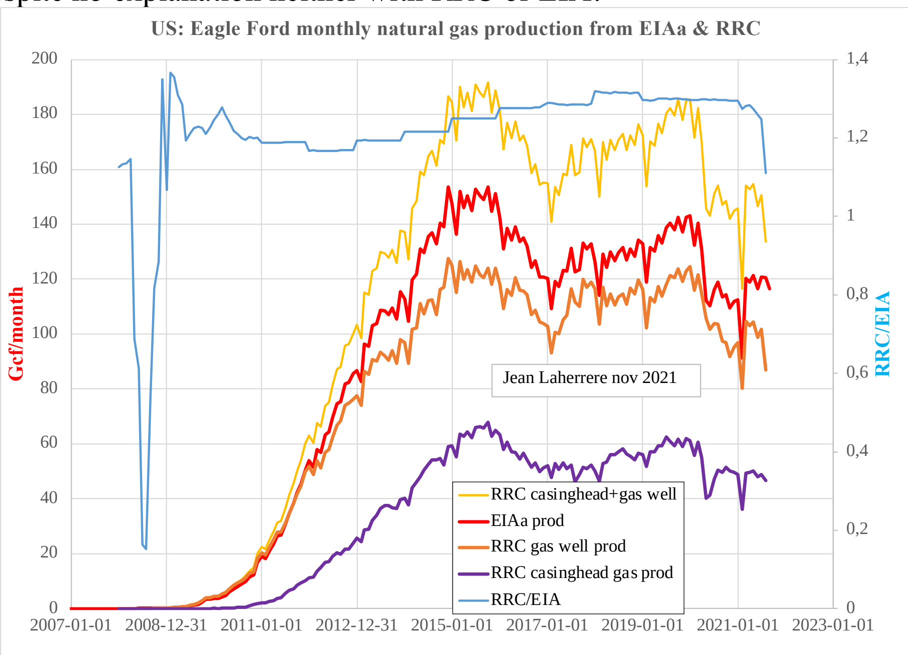




Eagle Ford shale gas production differs between EIAa and EIAb, they have peaked in 2015 and will continue to decline in the future
Eagle Ford proven remaining gas reserves are 26.6 Tcf, giving with the cumulative production 42 Tcf above my estimated ultimate.



Eagle Ford monthly production is compared between EIAa and RRC data: the data is different, despite no explanation neither with RRC or EIA!



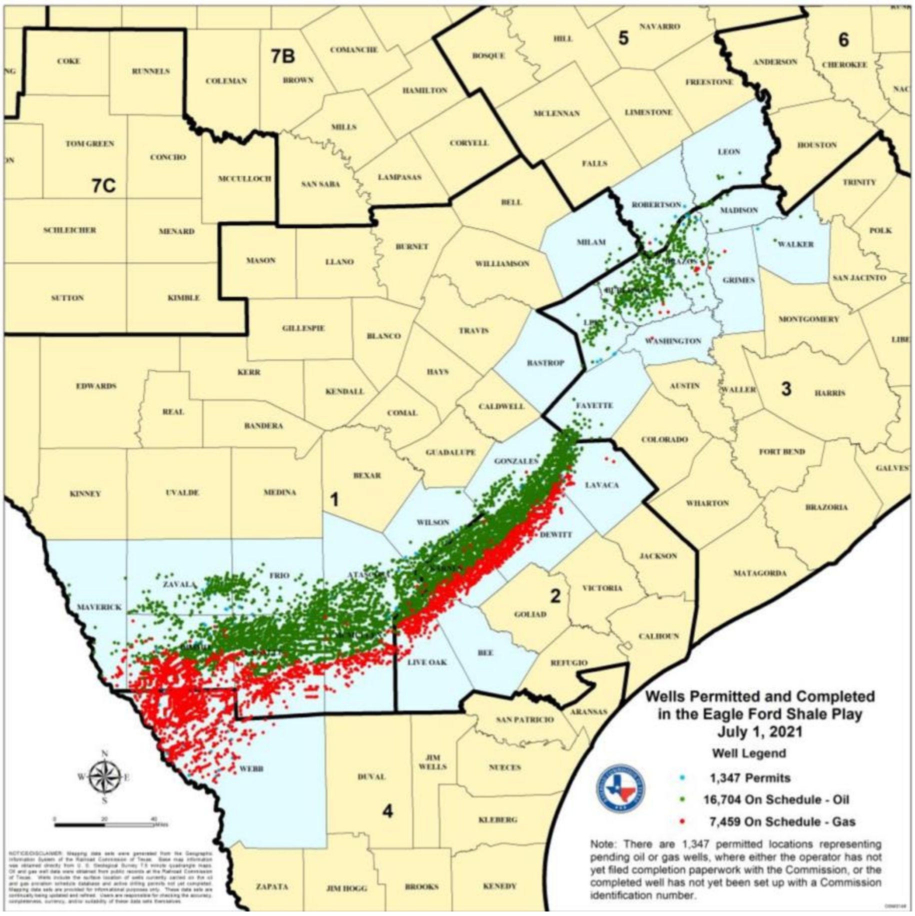
In RRC glossary:
Casinghead Gas = Gas found naturally in oil and produced with the oil.
Gas Well = Any well:

(a) which produces natural gas not associated or blended with crude petroleum oil at the time of production.

(b) which produces more than 100,000 cubic feet of natural gas to each barrel of crude petroleum oil from the same producing horizon; or

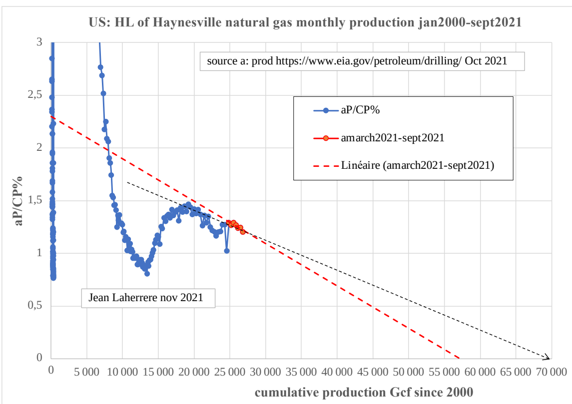
(c) which produces natural gas from a formation or producing horizon productive of gas only encountered in a wellbore through which crude petroleum oil also is produced through the inside of another string of casing or tubing. A well which produces hydrocarbon liquids, a part of which is formed by a condensation from a gas phase and a part of which is crude petroleum oil, shall be classified as a gas well unless there is produced one barrel or more of crude petroleum oil per 100,000 cubic feet of natural gas; and that the term "crude petroleum oil" shall not be construed to mean any liquid hydrocarbon mixture or portion thereof which is not in the liquid phase in the reservoir, removed from the reservoir in such liquid phase, and obtained at the surface as such.

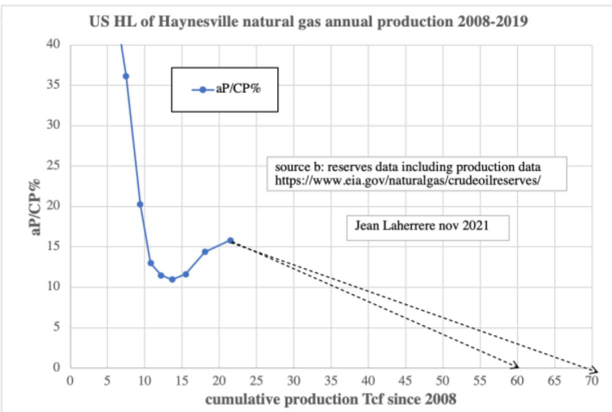
RRC provides a map of Eagle Ford wells updated July 2021: it is obvious that the sweet spots are almost fully drilled



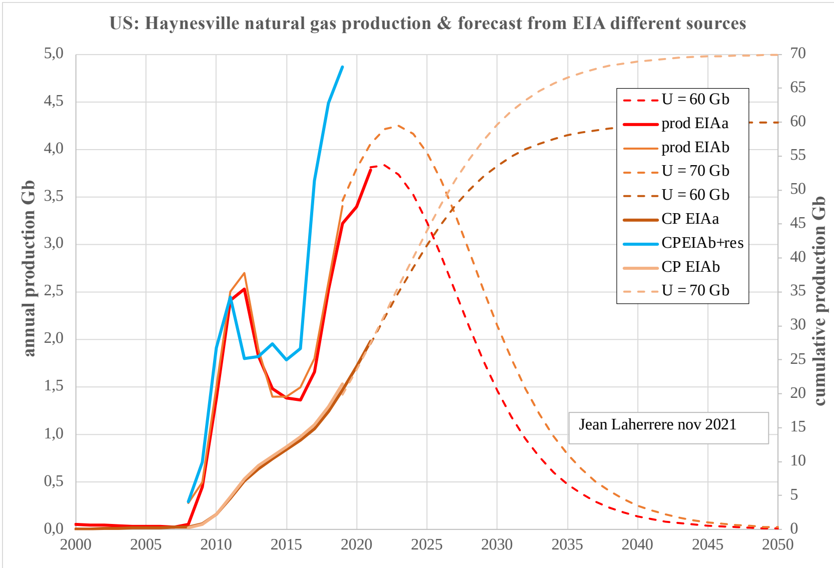
-Haynesville

Haynesville play covers Texas and Louisiana
HL of EIAa monthly production trends for the last few months towards a poor 60 Tcf
HL of EIAb annual production is useless

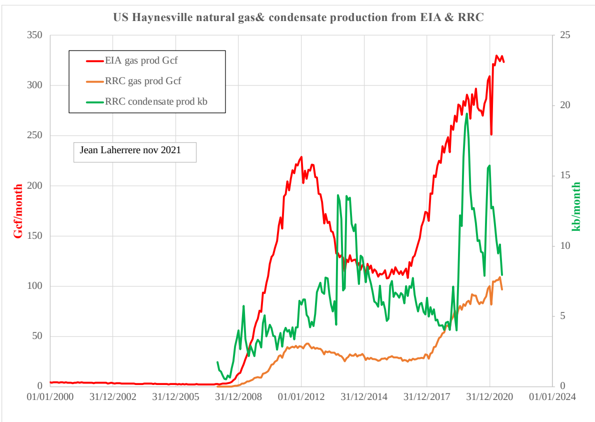


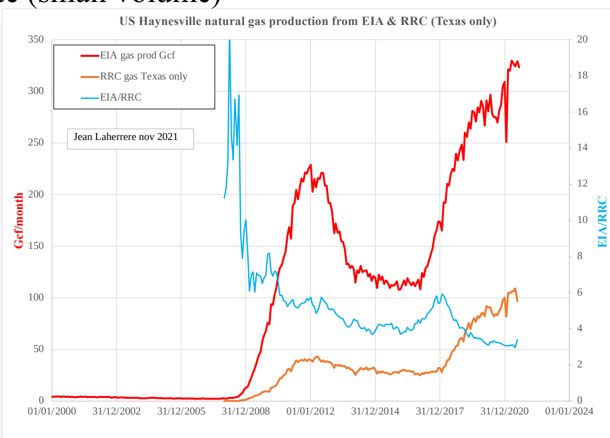


For an ultimate of 60 or 70 Tcf (in line with proven reserves at end 2019 + cumulative production) Haynesville production will peak in 2022 or 2023

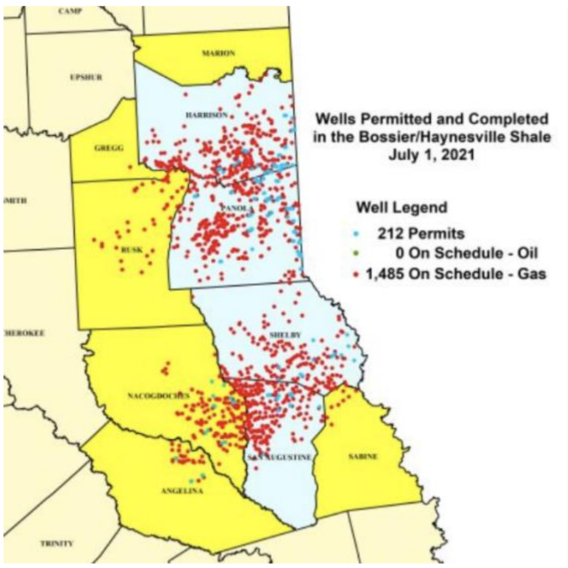


RRC reports Haynesville shale gas production only for Texas with zero oil and casinghead production, only gas production and condensate (small volume)



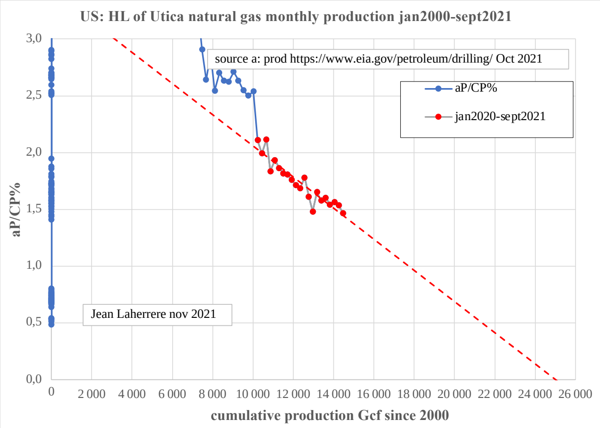


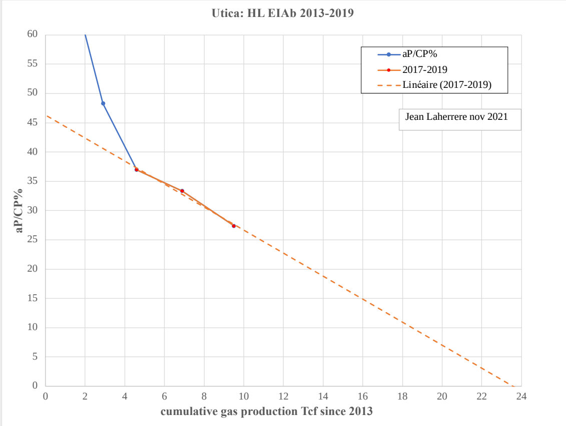
RRC provides a map of Haynesville wells for Texas updated July 2021, showing some room for more wells



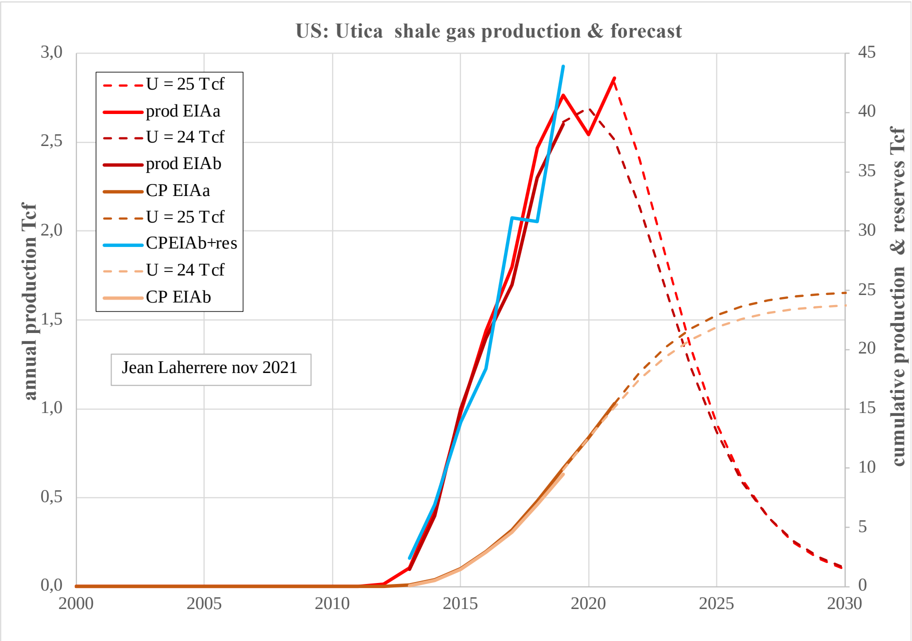
-Utica

HL of EIAa Utica monthly gas production trends towards 25 Tcf
HL of EIAb Utica annual gas production trends towards 24 Tcf





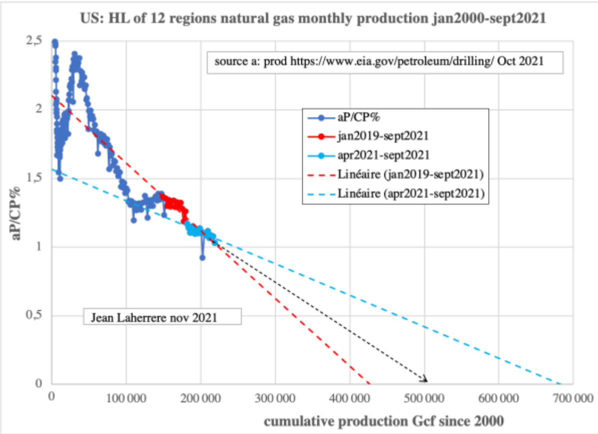
Utica gas production with an ultimate of 25 Tcf will decline in 2022

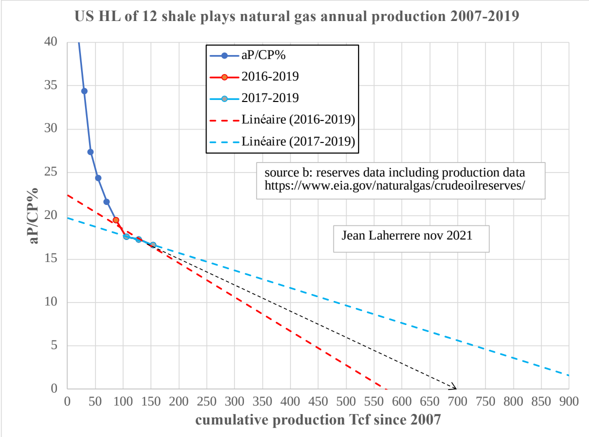


EIAb Utica proven reserves +cumulative production in 2019 are 44 Tcf well over our ultimate of 25 Tcf.

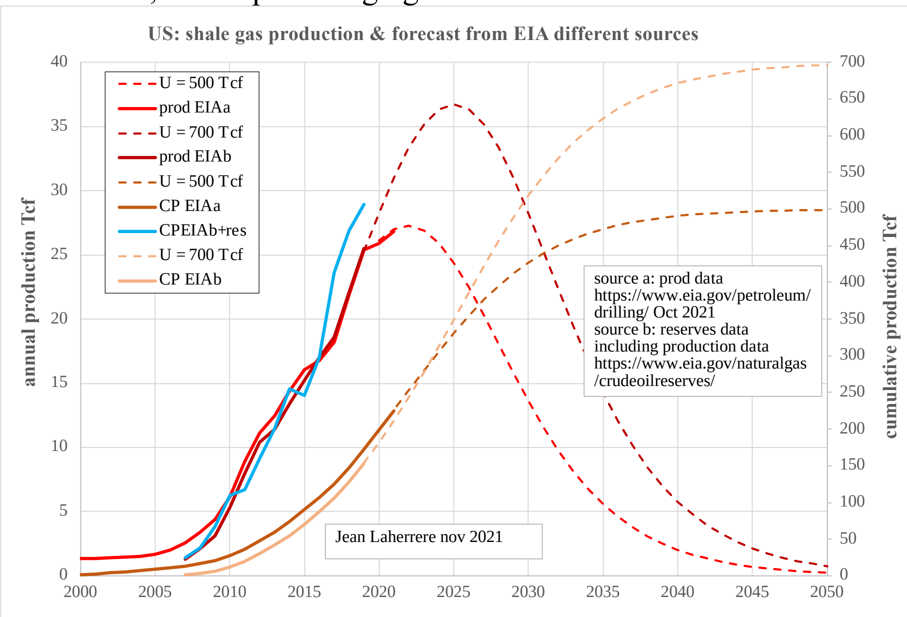
-12 regions

HL of 12 shale gas EIAa monthly productions trends towards a range of 420 to 700 Tcf
HL of 12 shale gas EIAb annual production trends towards a range of 550 to 900 Tcf.

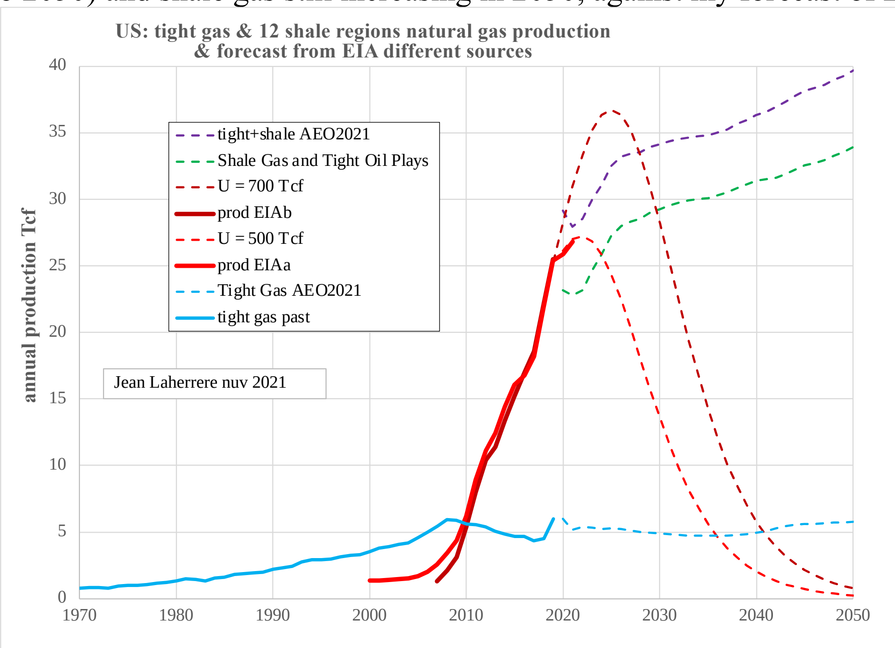




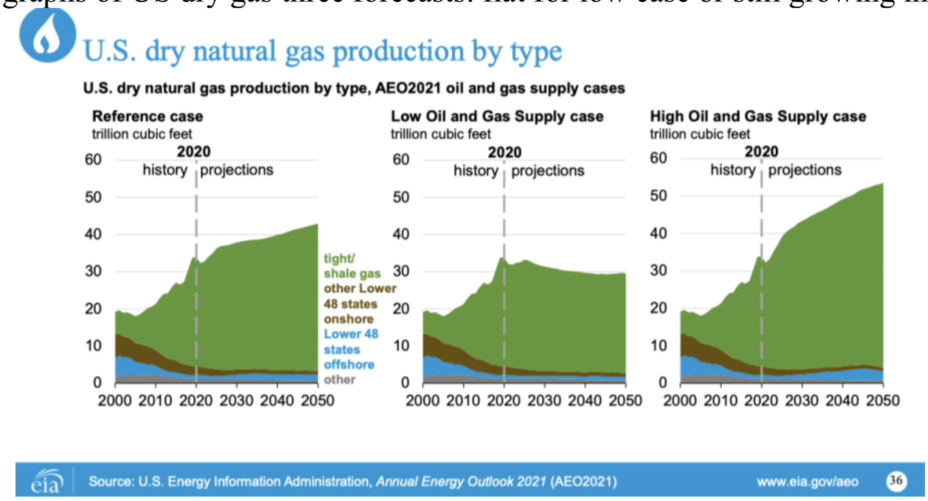
The poor extrapolation of the aggregation of 12 plays leads to a poor forecast with a range of ultimate 500 to 700 Tcf, with a peak ranging from 2022 to 2025



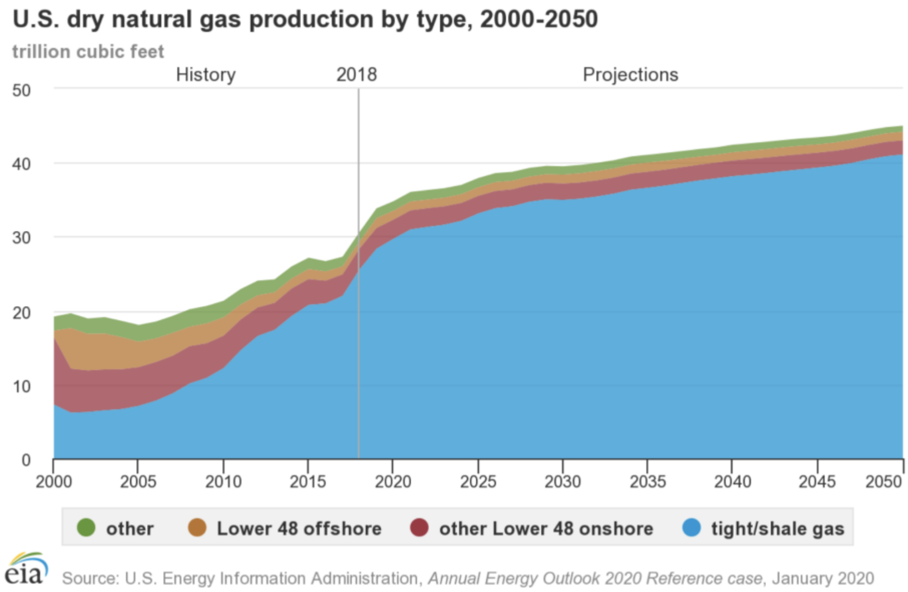
EIA/AEO2021 displays a forecast with a breakdown between tight gas (almost flat at 6 Tcf from 2009 to 2050) and shale gas still increasing in 2050, against my forecast of zero!



AEO2021 graphs of US dry gas three forecasts: flat for low case or still growing in 2050!

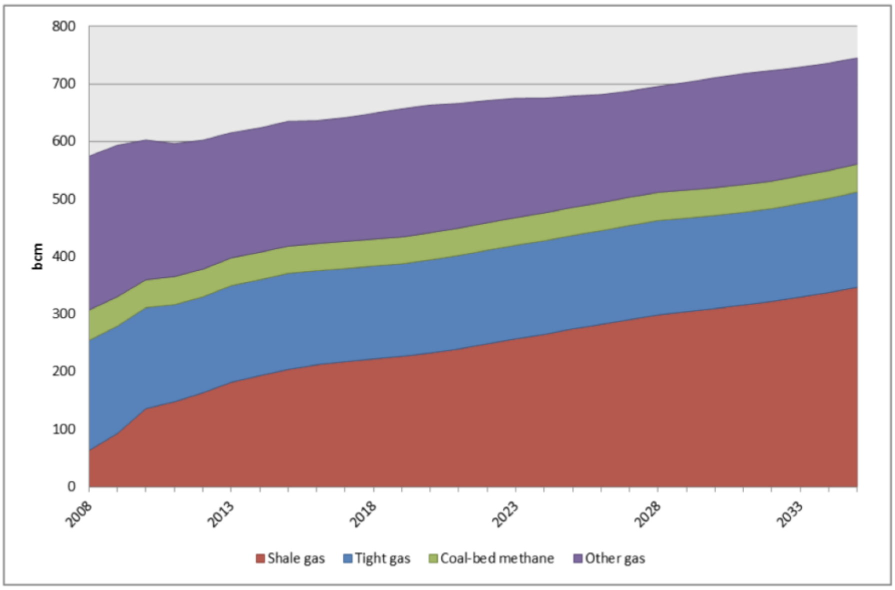


AEO2020 graph 2000-2050: 2000 is a minor peak for tight/shale gas, but not yet peaking in 2050

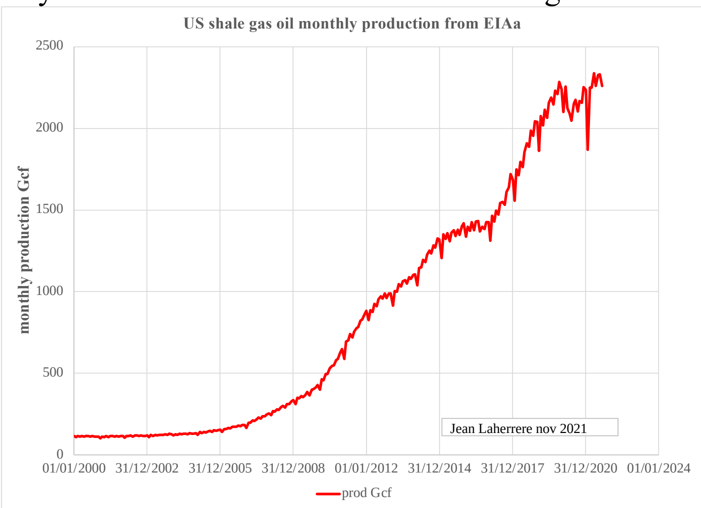


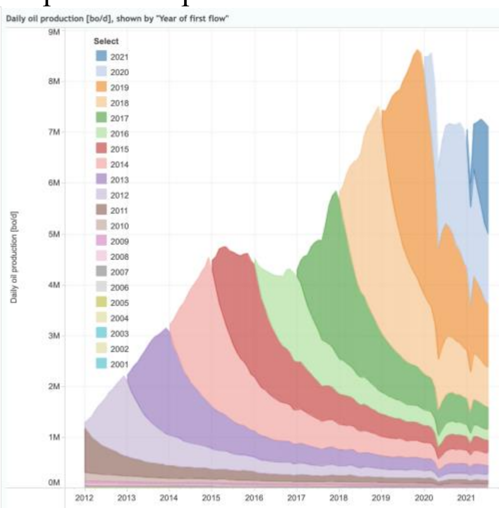
European Commission 2012 paper on unconventional gas displays different products and different forecast!

Figure 5-2: Forecasts of US natural gas production by type[8]



EIAa shale gas monthly past production is compared with Enno Peters graph update through July 2021: the last increase since March higher than 2020 peak is suspicious



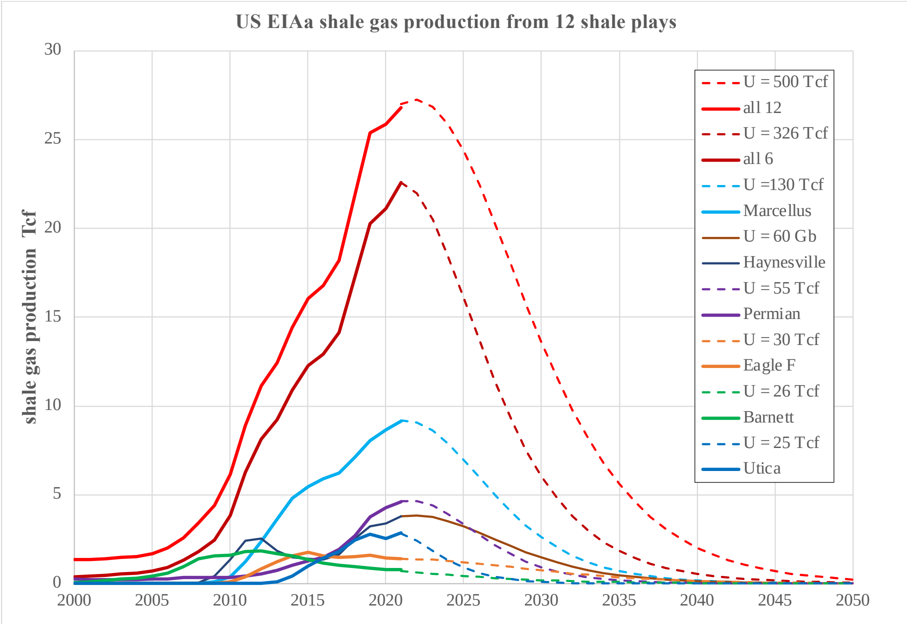


-Recapitulation of shale gas

The values for EIAa and EIAb production are reported, as RRC and ultimates

shale gas Tcf	2020 prod EIAa	EIAa CP2007-2020	2019 prod EIAb	EIAb CP 2019	EIAb CP+1P 2019	RRC prod 2020	RRC CP 2020	Ultimate EIAa	Ultimate EIAb
Permian	4,6	26	4,5	12	61			55	32
Marcellus	8,7	54	8,7	48	188			130	130
Eagle Ford	1,5	13,5	2,1	15	42	1,9	17	30	32
Haynesville	3,4	24	3,4	21	68			60	70
Barnett	0,8	20,5	1,1	19,6	34	0,9	24	26	26
Utica	2,5	12,6	2,6	9,5	44			25	24
total 6 plays	21	151	22	125	437			326	314
12 plays	26,0	198	26	153	507			500 ?	700 ?

My forecasts for the 12 plays, as the detail for 6 plays.



This 2012 European Commission report displays the estimates of technically recoverable shale plays reserves, as the surface.
"Unconventional Gas: Potential Energy Market Impacts in the European Union"
Ivan Pearson, Peter Zeniewski, Francesco Gracceva & Pavel Zastera (JRC) Christophe McGlade, Steve Sorrell & Jamie Speirs (UK Energy Research Centre) Gerhard Thonhauser (Mining University of Leoben) Other contributors: Corina Alecu, Arne Eriksson, Peter Toft (JRC) & Michael Schuetz (DG ENER)

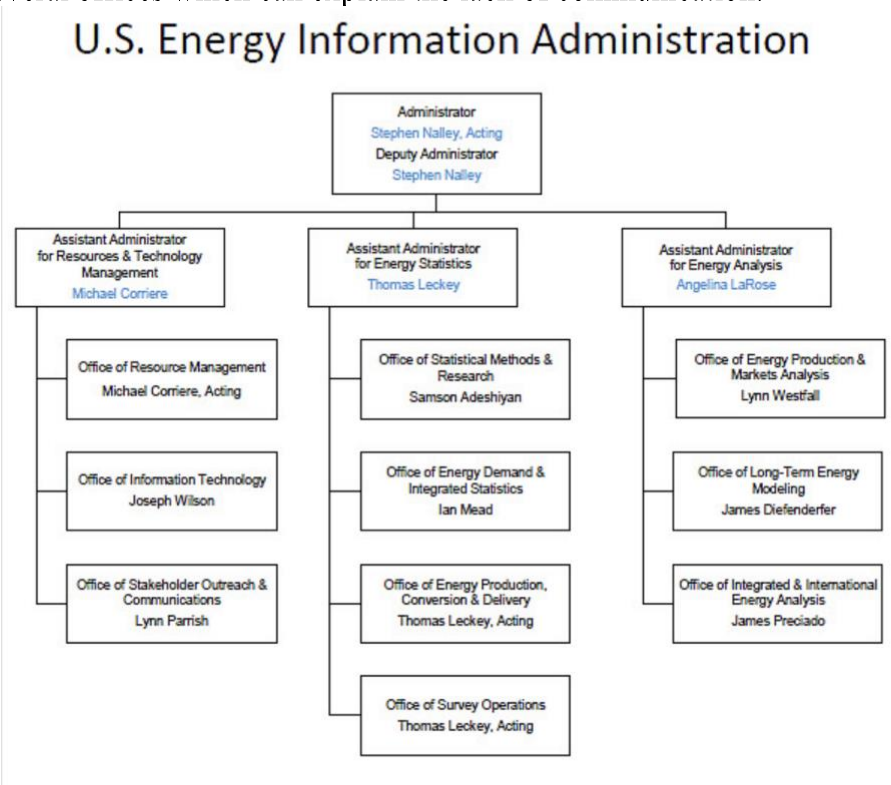
Table 3-10: Technically recoverable shale gas resources for the USA[72]

Play	Technically recoverable resource		Area (sq. miles)		Average EUR	
	Gas (Tcf)	Oil (BBO)	Leased	Unleased	Gas (Bcf/well)	Oil (MBO/well)
Marcellus	410.34	...	10 622	84 271	1.18	...
Big Sandy	7.4	...	8 675	1 994	0.33	...
Low Thermal Maturity	13.53	...	45 844		0.3	...
Greater Siltstone	8.46	...	22 914		0.19	...
New Albany	10.95	...	1 600	41 900	1.1	...
Antrim	19.93	...	12 000		0.28	...
Cincinnati Arch	1.44	...	NA		0.12	...
Total Northeast	472.05	...	101 655	128 272	0.74	...
Haynesville	74.71	...	3 574	5 426	3.57	...
Eagle Ford	20.81	...	1 090		5	...
Floyd-Neal & Conasauga	4.37	...	2 429		0.9	...
Total Gulf Coast	99.99	...	7 093	5 426	2.99	...
Fayettsville	31.96	...	9 000		2.07	...
Woodford	22.21	...	4 700		2.98	...
Cana Woodford	5.72	...	688		5.2	...
Total Mid-Continent	59.88	...	14 388		2.45	...
Barnett	43.38	...	4 075	2 383	1.42	...
Barnett Woodford	32.15	...	2 691		3.07	...
Total Southwest	75.52	...	6 766	2 383	1.85	...
Hilliard-Baxter-Mancos	3.77	...	16 416		0.18	...
Lewis	11.63	...	7 506		1.3	...
Williston-Shallow Niobraran	6.61	...	NA		0.45	...
Mancos	21.02	...	6 589		1	...
Total Rocky Mountain	43.03	...	30 511		0.69	...
Total Lower 48 United States	750.38	...	160 413	36 081	1.02	...

Table 3-11: Technically recoverable shale oil resources for the USA

Play	Technically Recoverable Resource		Area (sq. Miles)		Average EUR	
	Gas (Tcf)	Oil (BBO)	Leased	Unleased	Gas (Bcf/well)	Oil (MBO/well)
Eagle Ford	...	3.35	3 323		...	300
Total Gulf Coast	...	3.35	3 323		...	300
Avalon & Bone Springs	...	1.58	1 313		...	300
Total Southwest	...	1.58	1 313		...	300
Bakken	...	3.59	6 522		...	550
Total Rocky Mountain	...	3.59	6 522		...	550
Monterey/Santos	...	15.42	1 752		...	550
Total West Coast	...	15.42	1 752		...	550
Total Lower 48 United States	...	23.94	12 910		...	460

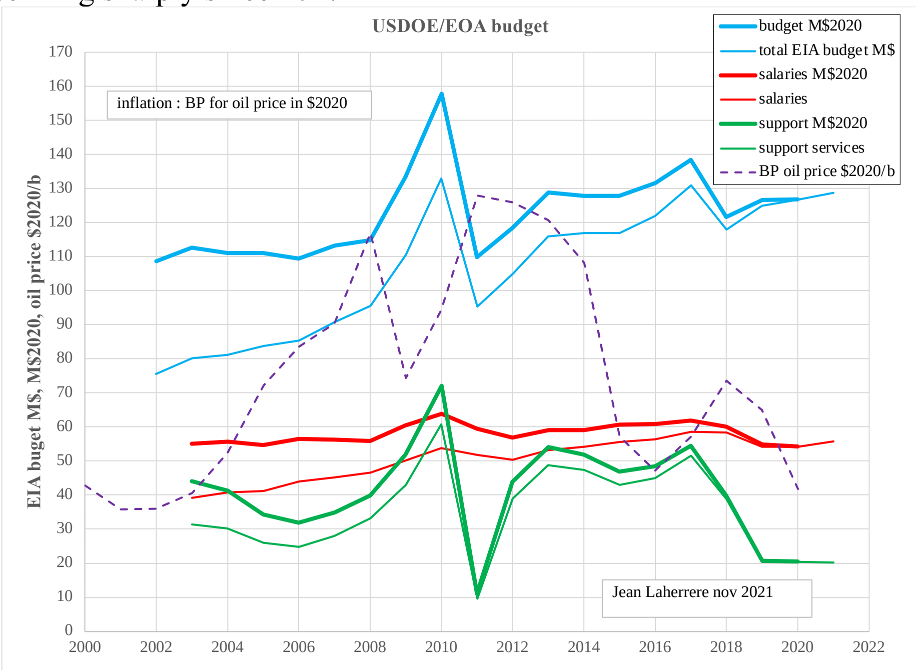
-Quality of the EIA data
Most of the graphs show discrepancies between the data from drilling, from reserves or from AEO, in addition with differences from other organizations as Texas RRC.
It is amazing to find Niobrara shale oil production reported by EIAa (drilling data) 10 times larger than EIAb data (reserves data) with the same title, due likely from poor definitions of reservoirs and plays
It is obvious that there is no communication between the different EIA offices
There is confusion between old fracking techniques and the modern fracking, between tight gas and shale gas.
It appears that these EIA data come from different places and that there is nobody in EIA to check the discrepancies: where is the boss?
There are several offices which can explain the lack of communication:



The budget of EIA is available since 2003, but it is difficult to get a complete historical series and in annual report it is hard to distinguish between the current and the requested values

The annual values were converted in $2020 using the BP deflator to obtain the oil price in $2020

EIA budget from 2003 to 2021 displays in $2020 flat salaries and support services peaking in 2010 and declining sharply since 2017



It was in 2011 a flat decline in EIA budget

https://www.reuters.com/article/idUS171012769020110504

The EIA announced last week it would also suspend, reduce or terminate several programs due to a $15.2 million shortfall in its fiscal 2011 budget -- a 14 percent decline

And a new decline since 2017 in support services leads to the decline in the quality of the data

EIA guidelines

https://www.eia.gov/about/information_quality_guidelines.php

EIA shall conduct quality reviews of information prior to dissemination

Information products are reviewed by technically qualified staff prior to dissemination to ensure their quality. Products that are considered to be more technically complex may also be reviewed by independent expert reviewers from outside EIA to provide additional perspective and expertise. The level of review an information product is subjected to prior to dissemination is determined by the characteristics of the product and EIA-established review procedures.

EIA shall correct errors and issue revisions of previously disseminated information, as appropriate

If a substantive error is detected after a product is disseminated, EIA will make correction and issue an errata notice or other notification as appropriate.

I was not able to find the number of EIA employees: 726 for owler, 325 for wkipedia

Conclusion
My previous forecasts on US LTO are confirmed with this update, using new data.

EIA data from monthly oil production (drilling data = EIAa) are different from annual production (reserves data = EIAb) and EIA does not provide any explanation: in the case of Niobrara play EIAa production is 10 times higher than EIAb: it is shocking of finding such discrepancy within EIA!
It is shocking to find that there is in the web no word on such huge EIA discrepancy!

It is obvious that production from shale and tight reservoirs started with vertical wells and some fracking, before the new technique of horizontal wells with long extents and modern fracking with huge volume of water and of sand.
There is confusion in the definition of LTO production and EIA should provide better definition and explanation.

EIA and Rystad LTO production forecasts look unrealistic beyond 2030.
They rely only about drilling many wells without bothering to check if there is enough room to drill these wells. The LTO sweet spots are well known and almost fully drilled.

It is the same for the US shale tight gas future production with the optimistic exportation of LGN in 2040.

AEO2021 reference forecasts light tight oil being 9 Mb/d in 2050, when my forecast is zero!

AEO2021 reference forecasts shale gas and tight gas being 50 Tcf in 2050 (still growing, no peak forecast), when my forecast is zero!

EIA budget for support services is declining since 2017 (cut by 2.5 from 50 M\$2020 to 20 M\$2020 in 2021), so is the quality of EIA past data and forecast.

NB: sorry for my broken English but I use SI symbols:
The SI is in 2021 used by 7 500 M in the world (96%) when only US + Liberia (337 M) do not use SI and are the only buying their gasoline by gallon.
Symbols for number:
M = 10^6 = million = **mega** from Greek large
G = 10^9 = US billion = **giga** from Greek giant
T = 10^{12} = US trillion = SI billion (square million) = **tera** from Greek monster
For 10^{15} CGPM experts in 1975 were short of word beyond monster and moved to number: 15 = 3 X 5, 5 in Greek is penta when 4 is tetra which becomes tera when removing a letter, penta when removing a letter becomes **peta = P**
For 10^{18} , 18 = 3 x 6, 6 in Greek is hexa, when removing a letter becomes **exa = E**

In US a comma is used to separate digits into group of 3, when SI requires a space.
USDOC/NIST guide to the SI publication 811 recommends a space

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.

Examples:	76 483 522	*but not:*	76,483,522
	43 279.168 29	*but not:*	43,279.168 29
	8012 or 8 012	*but not:*	8,012
	0.491 722 3	*is highly preferred to:*	0.4917223
	0.5947 or 0.594 7	*but not:*	0.59 47
	8012.5947 or 8 012.594 7	*but not:*	8 012.5947 or 8012.594 7

Note: The practice of using a space to group digits is not usually followed in certain specialized applications, such as engineering drawings and financial statements.