EMD Shale Gas and Liquids Committee

2018 EMD Shale Gas and Liquids Committee Annual Report

May 17, 2019

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Executive Summary

Shale gas and liquids have been the focus of extensive drilling for the past 14+ years owing to improved engineering, recovery and abundance of reservoir. Although there is international interest in exploiting hydrocarbons from these unconventional reservoirs, with active exploration projects on most continents, much of the successful exploitation from shales continues to be in North America (Fig. 1), particularly in the United States but increasingly so in Canada and South America. While shale-gas production has been declining from 2014-16 some areas saw a revival (e.g., Haynesville Shale) due to LNG facilities being built along the East Coast of the USA. Since the downturn in 2016, shale-gas production has increased to 66Bcf/day through early 2019 (Fig. 2; EIA, 2019) mainly fueled due to increased production in the Marcellus and Permian Basin. New plays in shale liquids contributed to a reversal in oil production after a general decline over the last 20 years (e.g., Permian Basin, Eagle Ford). Shale-oil production remained strong at approximately 7.4 million barrels per day due to improvements in drilling techniques, however daily production is forecasted to increase only in the Permian Basin in 2019 (EIA May, 2019; http://www.eia.gov/petroleum/drilling/pdf/dpr-full.pdf).

Overall, Europe remains relatively unexplored as compared to North America and many parts of Asia remain relatively unexplored for unconventional shale gas and oil, but interest in these plays is certainly high. South America's potential as unconventional shale gas and oil province is currently assessed in Argentina, but exploration and exploitation of these reservoirs and infrastructure are still in the development stages.

The following report provides the reader with information about many shale systems in North America that are actively being exploited for contained hydrocarbons as well as an overview of activities in China and Europe.

Introduction

It is a pleasure to submit the Annual report from the EMD Shale Gas and Liquids Committee looking back to the years 2017/2018. This report contains information about specific shales with recent activities in the US, Canada, Europe, and China. Given the intense interest in shales as "unconventional" hydrocarbon reservoirs, this report contains information available at the time of its compilation, and the reader is advised to use links provided herein to remain as up-to-date as possible.

This report is organized so that the reader can examine contributions from members of the EMD Shale Gas and Liquids Committee on various shales in the United States (presented in alphabetical order by shale name or region; Fig. 1), Canada, China, and Europe. Additional sections of the report include valuable links, additional sources of information, and the Gas Shales and Shale Oil Calendar for 2019/2020.

Please feel free to submit any comments or improvements to the committee chairs or contact Ursula Hammes (hammesu@gmail.com).

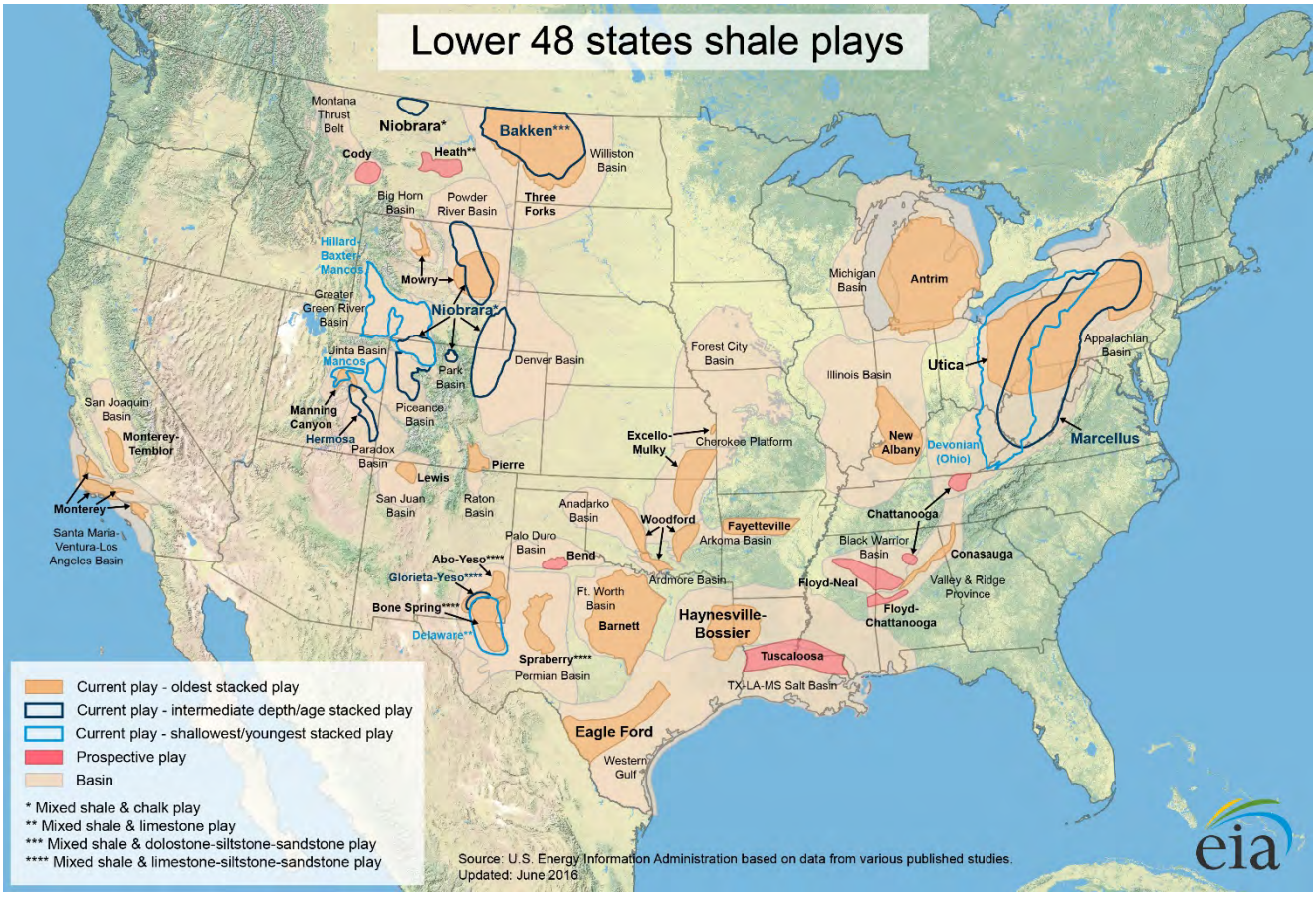

Figure 1: Current shale-gas and liquids unconventional plays in the Lower 48 States (EIA 2016)

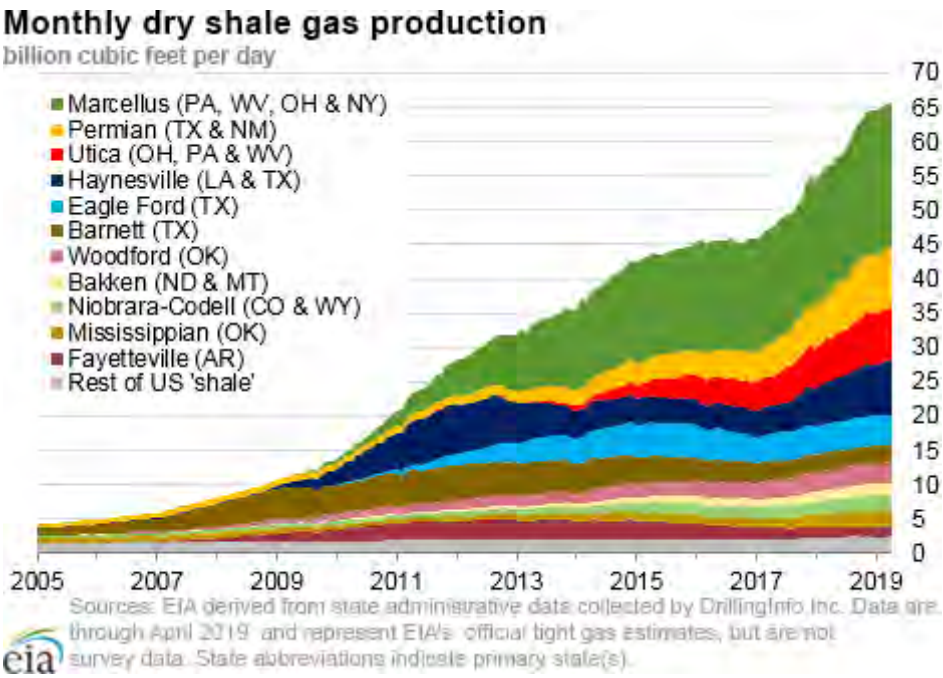

Figure 2: Monthly dry shale gas production (EIA, 2019).

EIA, 2019, https://www.eia.gov/energyexplained/index.php?page=natural_gas_where

The following reports are listed and linked respectively below in alphabetical order:

US SHALES

Bakken Shale

Barnett Shale

Eagle Ford and Tuscaloosa Shales

Fayetteville Shale

Haynesville / Bossier Shale

Marcellus Shale

Mowry Shale, Wyoming

Permian Basin, West Texas

Utah Shales

Utica Shale

Oklahoma shale gas / tight oil plays, U.S.A.

INTERNATIONAL SHALES

Canadian Shales

Chinese Shales

European Shales

GAS SHALES WEB LINKS

Status of U.S. ACTIVITIES

BAKKEN SHALE, WILLISTON BASIN, NORTH DAKOTA

Lyn Canter, Sedimentary Solutions, Denver, Colorado

The Bakken play area was re-assessed by the USGS in 2013 due to data from longer production histories from existing wells, and new technologies and completion techniques (Gaswirth and Marra, 2015). The 2013 assessment estimates the undiscovered technically recoverable reserves at 3.65 billion barrels for the Bakken and 3.73 billion barrels for the Three Forks formations of the U.S. Williston Basin. According to an earlier USGS study, the total amount of oil-in-place contained in the Bakken shale ranged from 271 to 503 billion barrels, with a mean of 413 billion barrels. Whether or not this shale oil is currently technically recoverable is debatable among many operators in the basin, however.

Development of the Elm Coulee Field in 1996 resulted from the first significant oil production from the middle member of the Bakken Formation (Lefever and Nordeng, 2017 EMD shale liquids report). Porosity mapping outlined a northwest-southeast trending interval of dolomitized silty grainstones within the middle member. Horizontal wells drilled in this zone in 2000 resulted in the discovery of the giant Elm Coulee Field in eastern Montana. Production at Elm Coulee was highly dependent on fractures are found in the middle member of the formation.

The Bakken middle member play began in North Dakota in 2004. Wireline logs of the Bakken Formation along the eastern portion of the Williston Basin in Mountrail County, North Dakota resembled those from Elm Coulee. The presence of free oil in DSTs and some minor Bakken production encouraged pursuit of the Bakken play in Mountrail County (Durham, 2009). In 2005, EOG Resources proved that horizontal drilling coupled with large scale hydraulic fracture stimulation of the middle Bakken Formation could successfully tap significant oil reserves along the eastern flank of the Williston Basin (#1-24H Nelson-Farms well in SESE Sec. 24, T156N, R92W). In 2006, EOG Resources drilled the #1-36 Parshall and #2-36 Parshall which resulted in wells with initial production rates in excess of 500 BOPD resulting in the discovery of Parshall Field.

Information obtained from extensive coring in the state resulted in the definition of an additional member of the Bakken Formation called the Pronghorn. Additionally, the original members have been formalized to conform to the adjoining states and provinces. New standard subsurface reference sections have also been designated. The Bakken Formation now consists of four members, including: Upper; Middle; Lower; and Pronghorn (Lefever and Nordeng, 2017 EMD report).

The table included below from the Industrial Commission of North Dakota Oil and Gas Division summarizes the activity in the North Dakota portion of the Williston Basin in 2018. Note that 96% of the state's oil and gas production is from the Bakken and Three Forks formations and 99% of current drilling is in the Bakken petroleum system.

INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL & GAS DIVISION
2018 MONTHLY STATISTICAL UPDATE

Month	Monthly Oil Production	Wells Producing	Average Daily Production	Permits				Spuds	Average Rig Count
				Dev	Ext	WC	Total		
Jan	36,505,281	14,395	1,177,590	150	0	1	151	93	56
Feb	32,900,991	14,416	1,175,035	96	0	0	96	100	57
Mar	36,024,820	14,535	1,162,091	105	0	3	108	122	59
Apr	36,806,359	14,600	1,226,879	104	0	0	104	119	60
May	38,678,065	14,771	1,247,680	120	0	1	121	104	62
Jun	36,932,962	14,798	1,231,099	113	0	0	113	102	63
Jul	39,345,570	14,986	1,269,212	163	0	0	163	123	66
Aug	40,066,158	15,130	1,292,457	152	0	0	152	140	61
Sep	40,777,137	15,291	1,359,238	111	0	2	113	106	65
Oct	43,164,607	15,352	1,392,407	183	0	0	183	143	67
Nov	41,304,086	15,252	1,376,803	116	0	0	116	123	64
Dec	43,442,924	15,351	1,401,385	92	0	0	92	116	67
Totals	465,948,960		1,276,572	1505	0	7	1512	1391	62

2018 Statistical Highlights:

- Total Oil Production = 465, 948, 960 barrels
- Average daily production = 1,276,572 barrels/day
- All time state daily production = 1,392,407 barrels/day in October 2018
- Producing wells at year-end = 15,351; with 13,500+ from the Bakken / Three Forks
- Average rig count = 62, down from a high of 218 rigs in 2012.

2018 Gas Capture Statistics (EIA, 2019):

- November 2018 59,875,592 MCF = 1,995,853 MCF/day
- Statewide Bakken 80%
- ND Commission goals 88% November 2018 – October 2020
- > November 1 2020 91%

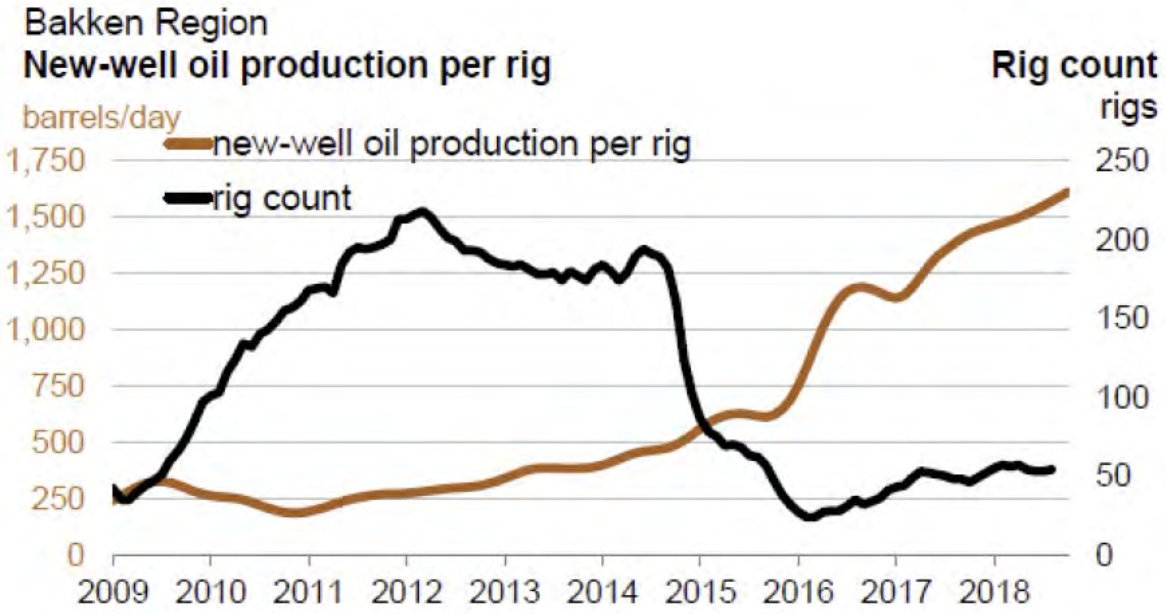

Figure 1. Graph illustrating the increase in barrel per day production per rig from 2009 through 2018 (North Dakota Department of Mineral Resources: Oil and Gas Update, January 4, 2019, House Appropriations Committee).

Improvements in completion technologies have resulted in solid increases in oil production (up to 110% more than existing offset wells), despite new wells being drilled in areas away from the original sweet spots (Figure 1). A typical completion of a 10,000 ft. horizontal Bakken well in 2018:

60-80 stages

2-6 perf clusters per stage

included both coarse and very fine sand

1,100 gallons slick water per foot

977 pounds of sand per foot (NDIC 2019).

Kraken averaged approximately 14.5 million pounds of sand per well, while Liberty, EOG, Bruin, and Equinor averaged 10 -12 million pounds of sand per well in late 2018-early 2019.

Parent wells are the first wells drilled to hold acreage by production and are the only spacing unit wells that are drilled, completed, and produced under virgin reservoir conditions. During field development, infill wells or pad wells are drilled near the parent wells. These wells, called child wells, are drilled, completed and produced under reservoir conditions that have been changed by the parent well's production. In the Bakken, early results indicate that some parent well production benefits from the

fracturing of a nearby child well. It should be noted that parent well responses are variable across the basin and subject to well offset distances and frac designs. Also, both parent (and child well) responses can vary according to diverse "frac-protect" measures and "pressure-up" intensity through parent well water injection.

Additional Information:

https://www.eia.gov

North Dakota Industrial Commission, Department of Mineral Resources, Oil and Gas Division:

https://www.dmr.nd.gov/oilgas/informationcenter

North Dakota Geological Survey:

https://www.dmr.nd.gov/ndgs/bakken/bakkenthree.asp

Gaswirth, S.B. and Marra, K.R., 2015, U.S. Geological Survey 2013 Assessment of Undiscovered Resources in the Bakken and Three Forks Formations of the U.S. Williston Basin

BARNETT SHALE (MISSISSIPPIAN), FORT WORTH BASIN, TEXAS

Kent A. Bowker (Bowker Petroleum, LLC)

Exactly 20 years ago, Mitchell Energy began to ramp up its drilling activity in the Barnett Shale. The initial water fracs and an accurate value of the true gas in place combined that year to convince the company to proceed to full development, albeit with vertical wells at that time. The next year (in 2000) Mitchell drilled the first Barnett horizontal wells, taking the first steps towards the current techniques used in all tight-reservoir plays.

There are sixteen named Barnett fields in the Fort Worth basin, and as of January 2019 they have produced a total of 22.9 trillion cubic feet and gas and 72 million barrels of oil/condendsate (Texas Railroad Commission).

Daily gas production from the Barnett Shale continues to decline, and has recently dropped below 3 BCF/day, but at a rate less than might have been expected given the massive decrease in drilling and completion activity over the past 5 years. Given that there is no prospect of development activity increasing soon, the Barnett can be used to verify production models of shale gas in terminal decline. The current daily gas production is right at 2.9 BCF while oil/condensate production is at 3500 bbls (Figs. 2, 3).

The precipitous decline in the number of drilling permits in the Barnett through March 2019 is illustrated in Figure 4. Much of the recent drilling is concentrated in the northern oil window, in Jack and Palo Pinto counties (see map below; blue dots show locations of recent permits). Operators there are attempting to produce oil from fractured Barnett near karst structures associated with the underlying Ellenburger carbonates. Since the play was established by Mitchell Energy in the late 1980's there has been at least some minimal drilling activity, but for the past few years there are usually no more than a rig or two working in the play.

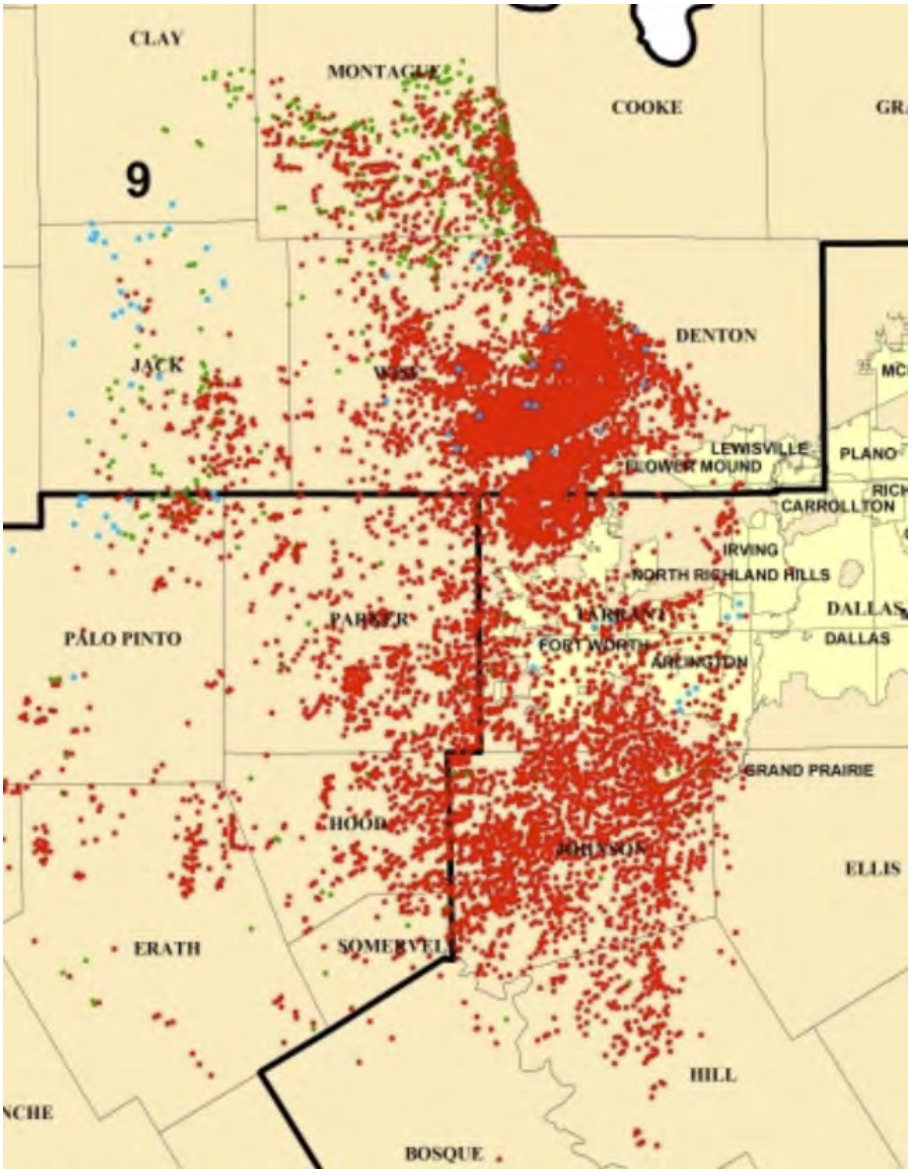

Figure 1: Newark East Barnett shale field and drilled wells (from https://www.rrc.state.tx.us/media/49774/newarke_barnettshale_201901-sm.jpg)

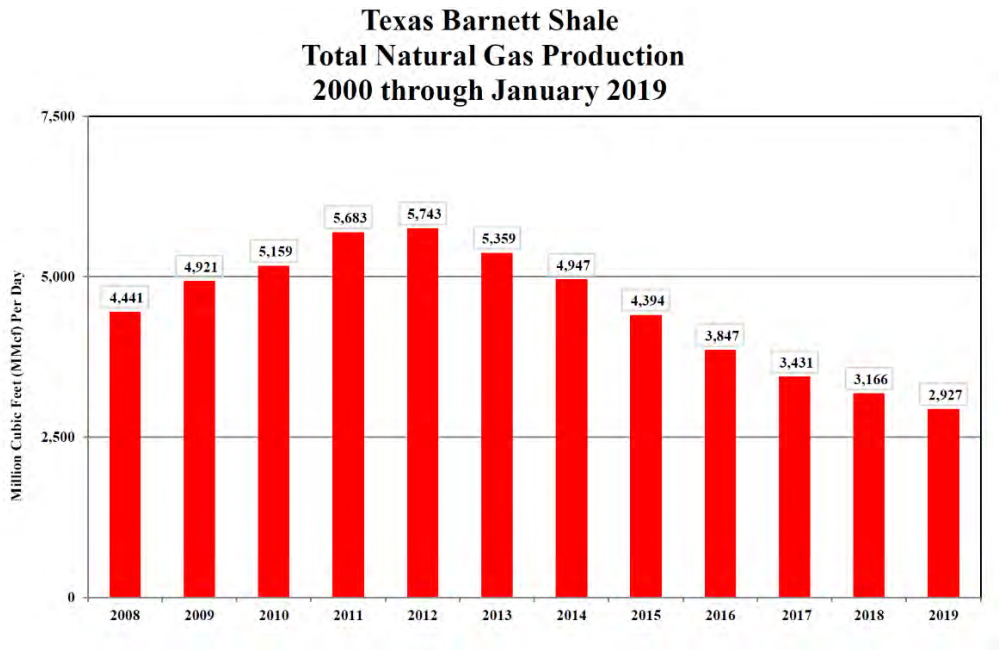

Figure 2: Daily average gas production in the Fort Worth Basin Barnett Shale (from https://www.rrc.state.tx.us/media/51142/barnett-gas.pdf)

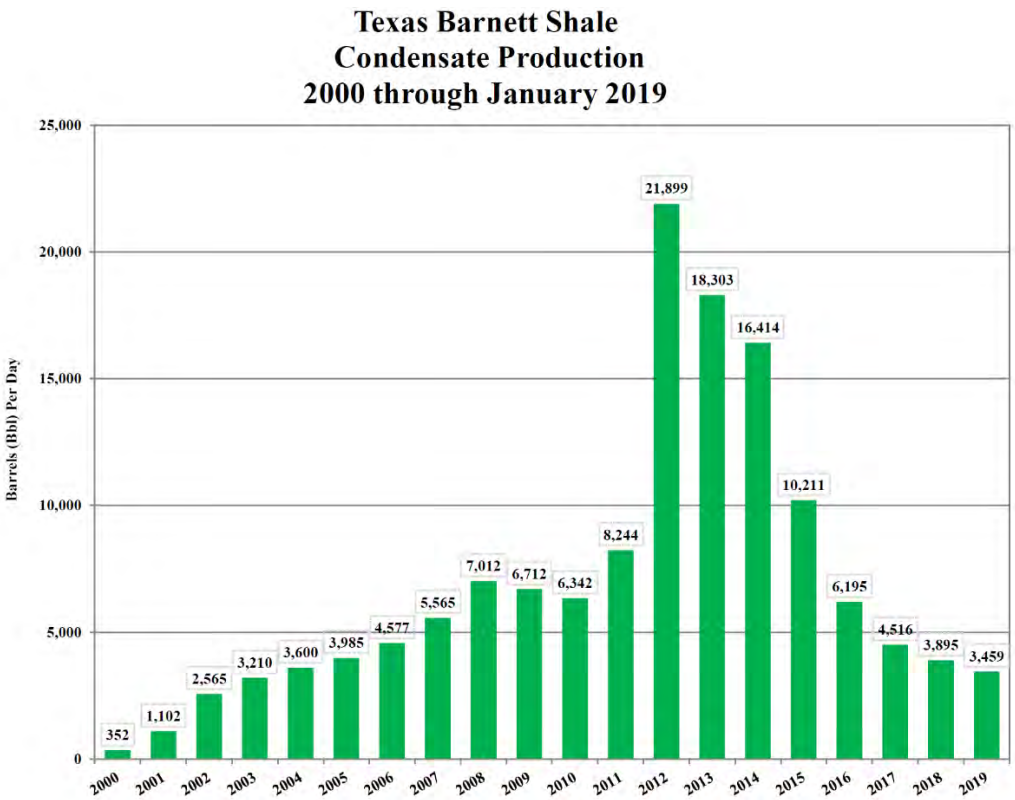

Figure 3: Daily average condensate production in the Fort Worth Basin Barnett Shale (from https://www.rrc.state.tx.us/media/51141/barnett-condensate.pdf)

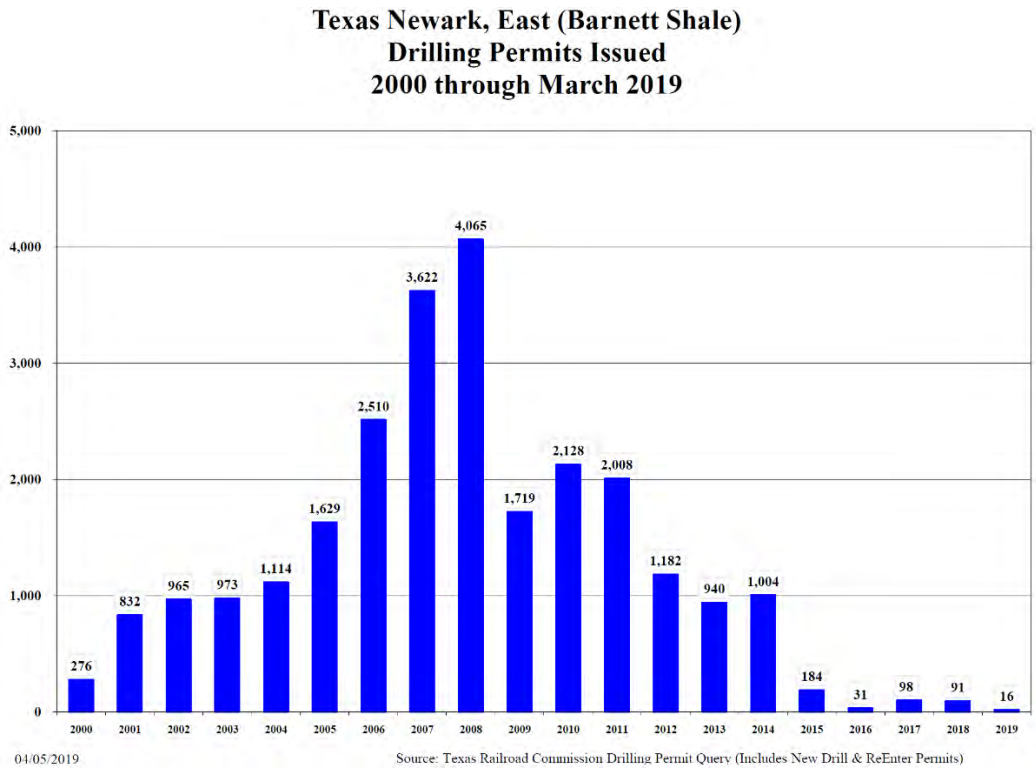

Figure 4: Drilling permits issued in the Fort Worth Basin Barnett Shale (from https://www.rrc.state.tx.us/media/51326/barnett-drilling-permits-march-2019.pdf)

EAGLE FORD SHALE and TUSCALOOSA MARINE SHALE

Justin E. Birdwell (U.S. Geological Survey, Central Energy Resources Science Center, Denver, CO)

Late Cretaceous (Cenomanian-Turonian) strata spanning from southwestern Texas to southwestern Alabama contain prolific marine source rocks deposited north of the shelf margin between the Western Interior Seaway and proto-Gulf of Mexico from approximately 93 to 91 MA. Included in this interval are the Eagle Ford Group and Tuscaloosa marine shale, which are both unconventional oil and gas targets in the onshore Gulf of Mexico region (Upper Jurassic-Cretaceous-Tertiary Composite Total Petroleum System). Though both of these units have been demonstrated to contain substantial resources, the Eagle Ford has been much more extensively developed over the last decade, becoming one of the most productive oil and gas plays in the United States, while development of the Tuscaloosa marine shale has been more limited due to several factors related to drilling costs and limited infrastructure.

Eagle Ford Group

The Eagle Ford Group (or Shale) is a major oil, natural gas, and condensate/natural gas liquids play in southwest to central Texas, extending from the Maverick Basin northeast to the Karnes Trough. The play area is approximately 50 miles wide and 400 miles long with thicknesses varying from less than 100 ft, to over 600 ft thick in some areas including the Maverick Basin, north of the Giddings Field, and near Dallas. The Eagle Ford Group is typically divided into upper and lower strata with the primary target being the mainly Cenomanian, organic-rich, and more calcareous Lower Eagle Ford rather than the Turonian Upper Eagle Ford, which becomes more clastic moving from southwest to northeast. The organic matter content and quality in the Eagle Ford varies stratigraphically primarily due to variability in the depositional environment (Zumberge et al., 2016; Sun et al., 2016; French et al., 2019) and geographic variation may be affected by localized depositional conditions and detrital inputs. Production trends in the Eagle Ford correspond to geologic structure with production distributions from wells being mainly related to depth, which ranges from ~4,000 to over 14,000 ft deep from north to south across the play (Figure 1). Eagle Ford oil is also widely produced in Texas and parts of Louisiana from vertical wells into the overlying Austin Chalk.

The viability of the Eagle Ford play is dependent on the application of horizontal drilling (laterals average ~6,500 ft but extend to ~11,000 ft) and hydraulic fracturing using slick water and acid treatments in multiple fracturing stages. The mineralogy of Eagle Ford Shale facilitates this development approach, as the high carbonate content of marlstone, limestone, and other mudstones (up to 70%) make these strata brittle and amenable to fracture propagation. Completed wells show average initial production rates (first full month) of ~600 bbls/day for oil and 2,000 Mcf/day for gas, followed by steady production declines with time online. Estimated ultimate recoveries are around 150,000 bbl per well for oil and between 500 and 1,500 MMcf per well for natural gas. Over the last decade initial production rates have improved with improvements in production technology but decline rates for production are also steeper.

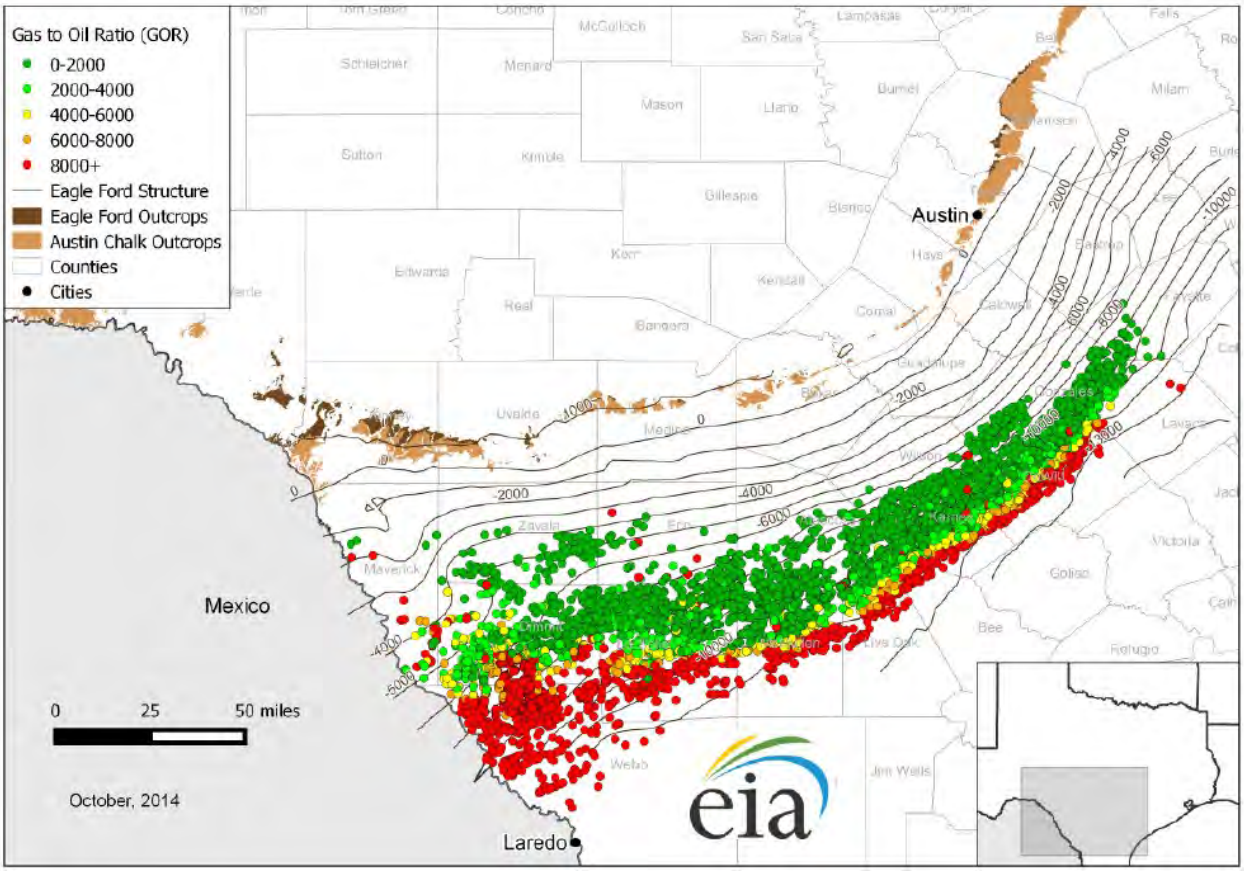

Figure 1. Initial gas-to-oil ratios of Eagle Ford wells (January 2000 – June 2014). Source, U.S. Energy Information Administration and Drillinginfo Inc., September 2014. Note: EIA calculates the initial gas-to-oil ratio for each well using the second through fourth contiguous months of liquid and/or gas production. The first month of production may not represent full production and is, thus, not included in the initial GOR calculation (from U.S. EIA, 2014).

In 2018, the number of operating rigs in the Eagle Ford play was ~280, up from 250 in 2017 with similar new-well production per rig over both years (~500,000 bbls/day per rig; U.S. EIA, 2019). A total of over 1,900 new wells were drilled in the Eagle Ford in 2018, averaging production of ~120,000 BOE/day on an annualized basis (BOE = barrels of oil equivalent). This brought the total number of active wells in the play to over 20,400. More than 80% of new wells were in the top three fields (Eagleville, Briscoe Ranch District 1, and Sugarkane) corresponding to more than 70% of the new wells being drilled in five counties (Dimmit, Karnes, La Salle, Webb, and Dewitt). A total of over 60 operators drilled new wells in the Eagle Ford in 2018, with five operators (EOG Resources, SN EF Maverick, Chesapeake, Burlington Resources, and Marathon Oil) accounting for nearly 50% of these. Based on GORs calculated from reported cumulative 2018 production for new wells only, operators continue to be focused on oil over natural gas production, as expected based on prior trends. Total annual production of oil, natural gas, and condensate are shown in Figure 2 on a barrel per day basis, along with annual totals for new permits issued (Texas Railroad Commission, 2019).

In 2018, the U.S. Geological Survey reassessed the Eagle Ford Group and estimated mean undiscovered, technically recoverable resources of 8.5 billion barrels of oil and 66 trillion cubic feet of natural gas in continuous (unconventional) reservoirs in the Eagle Ford and associated Cenomanian-Turonian strata in Texas and southern Louisiana divided among the seven assessment units shown in Figure 3 (Whidden et al., 2018). It was noted that the Eagle Ford is somewhat unique among U.S. shale plays in that production data and assessed resources indicate it is prolific for both oil and gas, with assessed oil resources comparable to the Bakken Shale in Williston Basin and natural gas resources essentially equivalent to the Mancos Shale in the Piceance Basin (Figure 4).

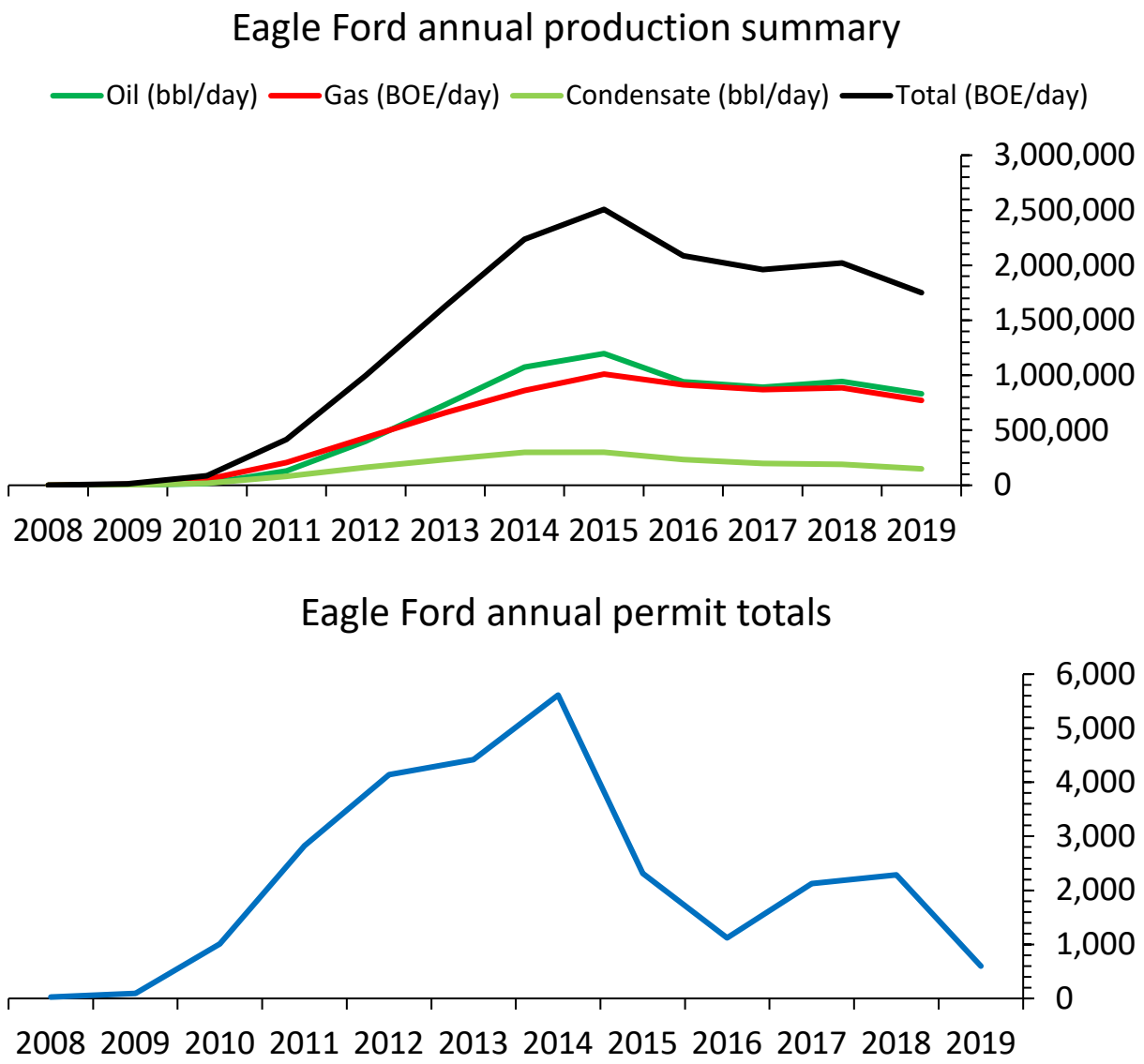

Figure 2. Top: Annual production summaries for gas and liquid products from the Eagle Ford including oil, condensate, and natural gas, 2008 through January 2019. BOE = barrels of oil equivalent, calculated by summing products (gas conversion 1 bbl = ~6 MCF). Bottom: Texas Eagle Ford drilling permits issued annually between 2008 through March 2019. Data compiled by the Texas Railroad Commission (accessed April 18, 2019).

A large number of research articles were published on or referenced the Eagle Ford Shale in 2018. According to Scopus, 193 articles or book chapters referenced the “Eagle Ford” in their title, abstract, or keywords. Google Scholar had over 1000 hits for mentions of the Eagle Ford anywhere in an article (this likely includes many cited references) and 40 publications with “Eagle Ford” in the title. AAPG Datapages reported 170 articles in a full text search and 4 publications with “Eagle Ford” in the title.

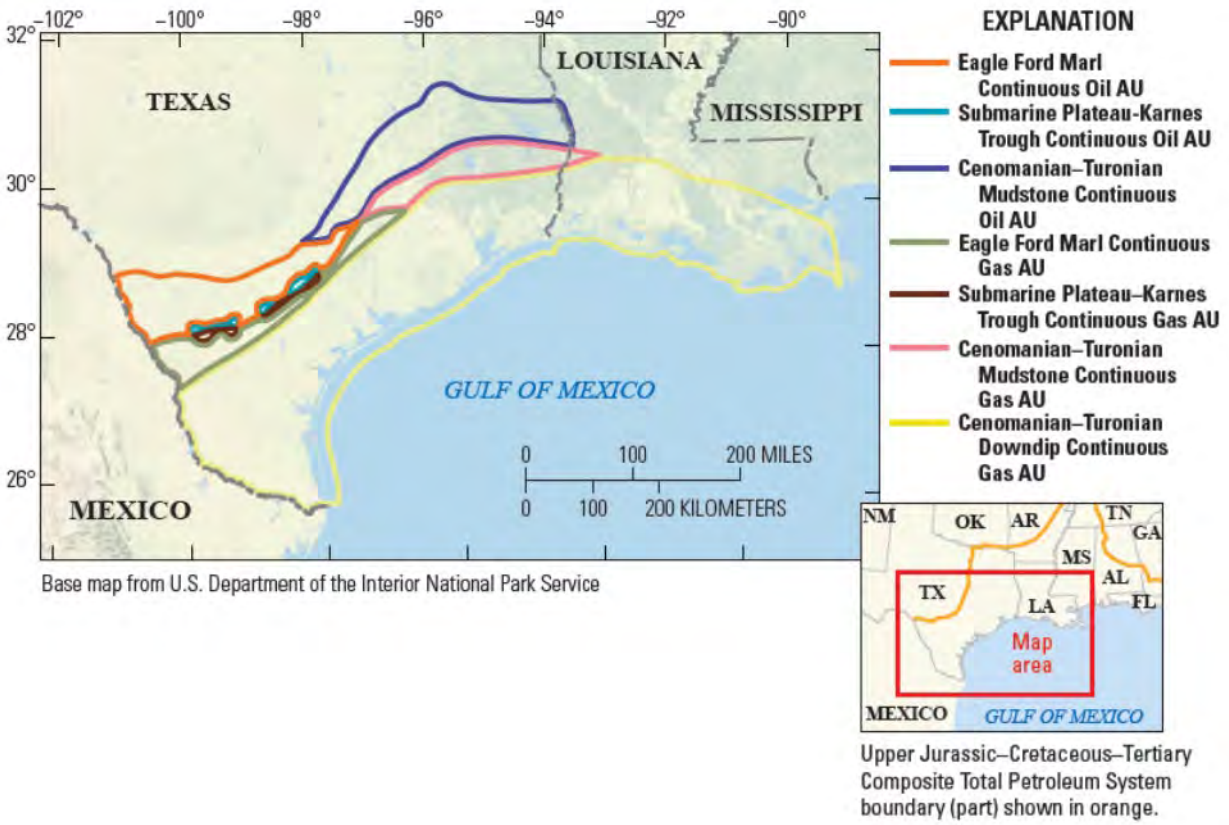

Figure 3. Map showing the extent of the seven assessment units (AUs) in the Eagle Ford Group and associated Cenomanian–Turonian strata in the U.S. Gulf Coast region, Texas (from Whidden et al., 2018).

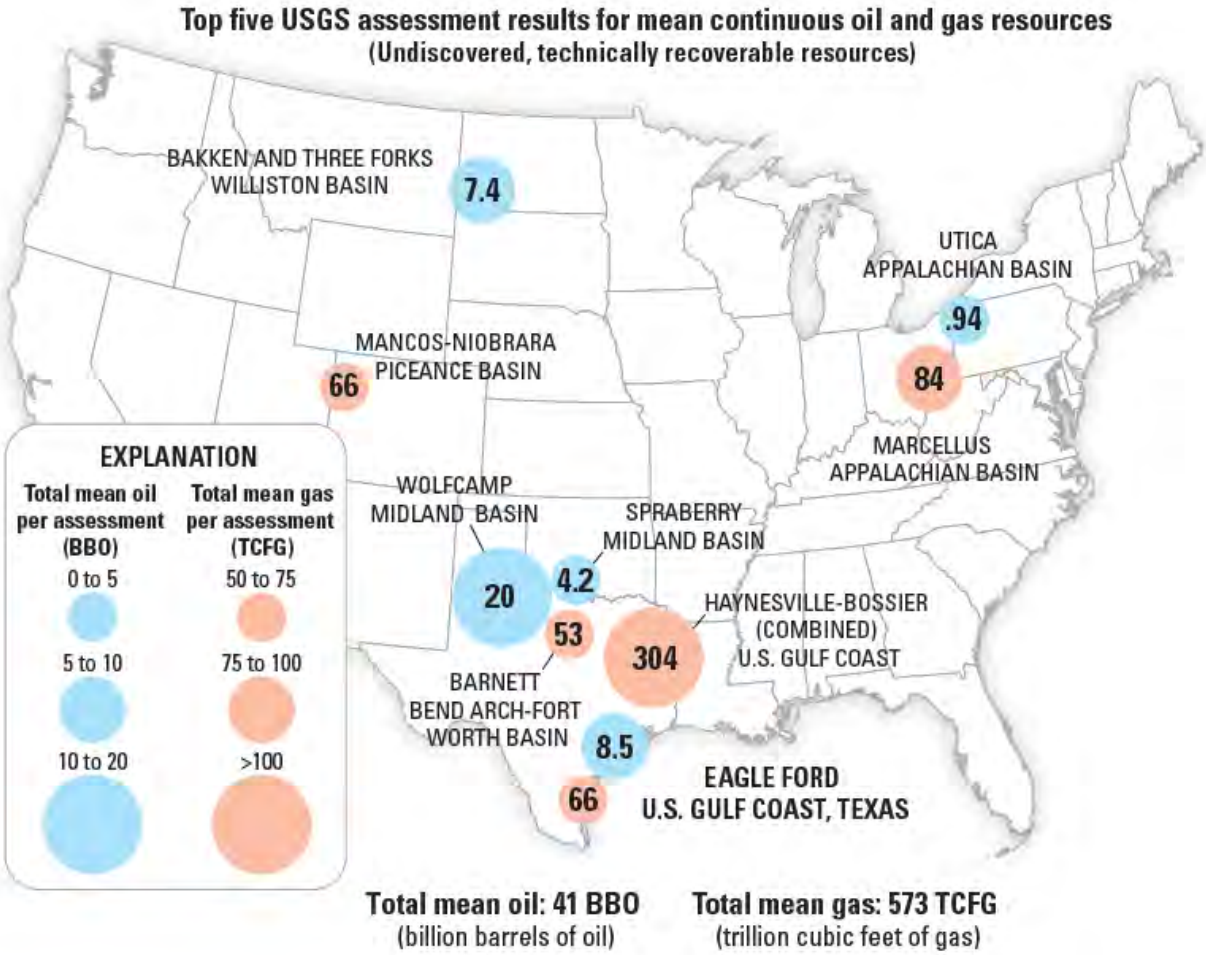

Figure 4. Summary of recent USGS assessments of U.S. continuous oil and gas resources (from Whidden et al., 2018).

Tuscaloosa Marine Shale

The Tuscaloosa marine shale (TMS) is a minor shale oil play in Louisiana, Mississippi, and Alabama. Though it is known to contain substantial unconventional oil and gas resources, the TMS has been largely undeveloped. This is clearly evident by comparing well counts and production values for the TMS and the stratigraphically equivalent Eagle Ford Shale. The number of active wells in the TMS is currently 88, two thirds of which are in Mississippi with the remainder in Louisiana – this is less than one-half of one percent of the number of active wells in the Eagle Ford.

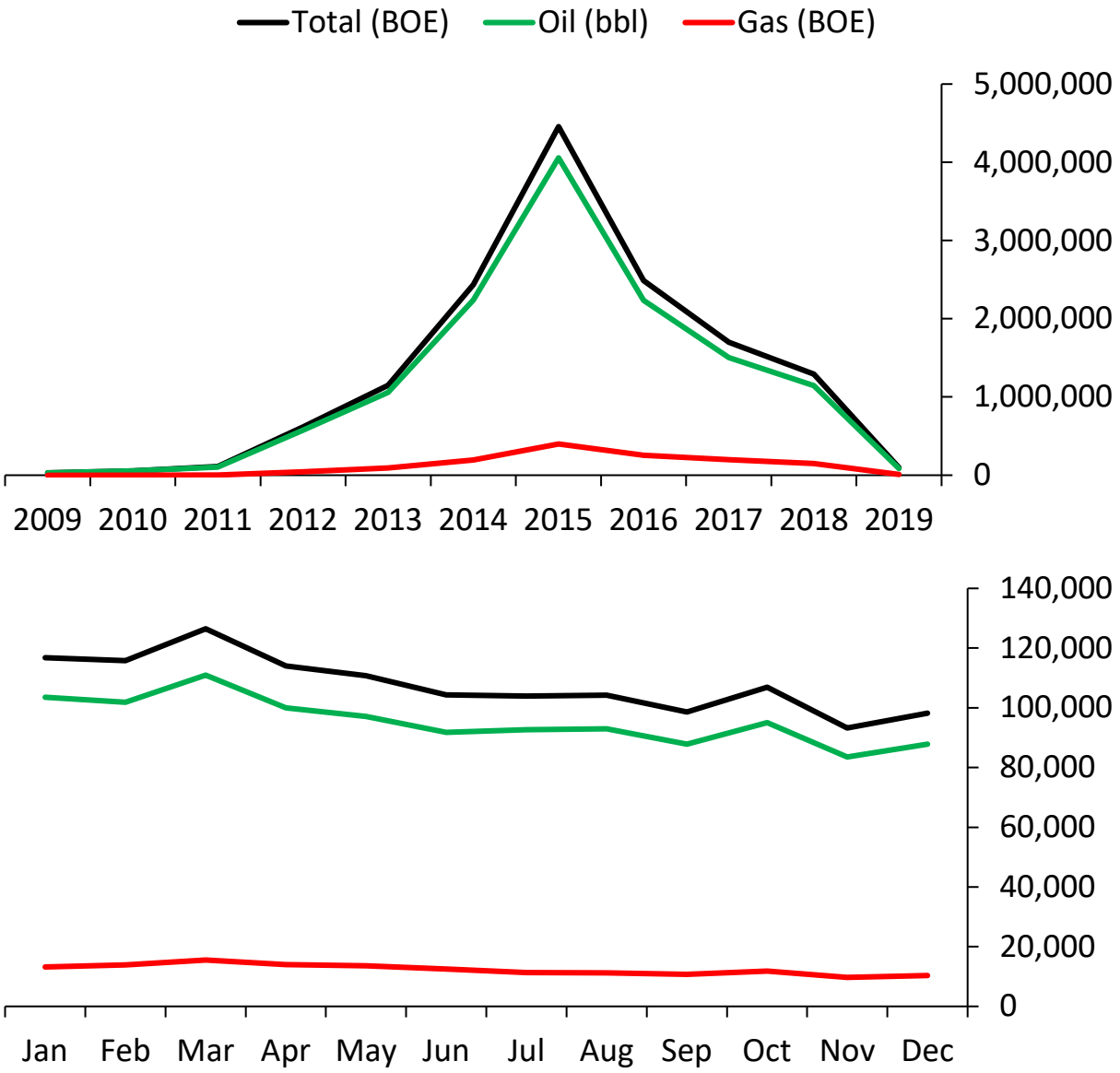

Figure 5. Top: Annual production summaries for gas and liquid products from the Tuscaloosa marine shale including oil, natural gas, and water, 2009 through March 2019. BOE = barrels of oil equivalent, calculated by summing products (gas conversion 1 bbl = ~6 MCF). Bottom: Monthly production for gas and liquid products for 2018. Data from IHS Markit® (accessed April 18, 2019).

Total *annual* production from the TMS in 2018 was around 1.2 million BOE (Figure 5) whereas the total *daily* production from wells in the Eagle Ford was over 2 million BOE. The main reason for this disparity is reported to be production costs. Even though the produced oils from the TMS are high quality ("Louisiana Light Sweet"), the deeper wells needed and higher drilling costs require higher sustained prices ($80+/bbl; MS Business Journal, 2018) than other U.S. plays.

The TMS covers an area that includes much of central and southeast Louisiana, along with southern Mississippi, and part of the southwestern corner of Alabama. This area is around 300 miles across (east-west) and 100 miles wide (north-south), with TMS thicknesses averaging around 500 ft at depths between 11,000 and 15,000 ft. Since 2009, around 100 wells have been drilled, 90% of which are horizontals, and as of April

2019 88 wells are active (81 horizontal) all producing mainly oil. In 2018 around 20 permits were issued (undrilled) in the TMS. No new wells have been drilled since 2016, but in October 2018 it was reported that Australis was planning to drill up to six wells (Associated Press, 2018). The top operators (Australis, Goodrich Petroleum, and Backwater Energy Partners) accounted for over 70% of active wells in 2018. Total production in 2018 was down slightly from the previous year and down around 75% from the high in 2015 (Figure 5, top panel). Monthly production through 2018 from the TMS was steady for both oil and gas (Figure 5, bottom panel).

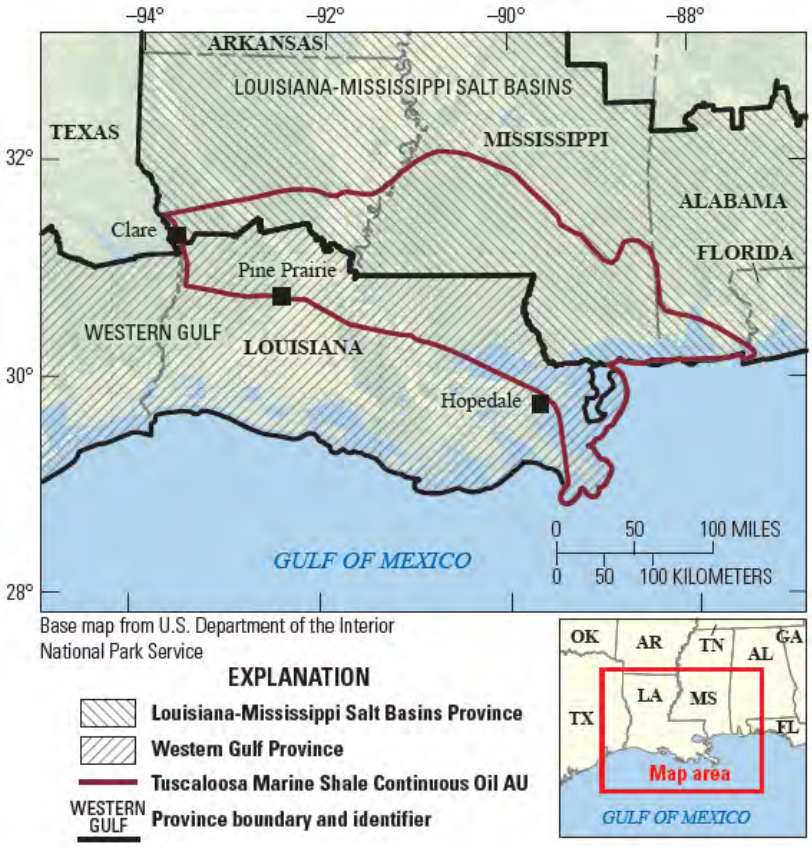

Figure 6. Map showing the Tuscaloosa marine shale Continuous Oil Assessment Unit (from Hackley et al., 2018).

The USGS 2018 assessment of the TMS estimated mean undiscovered, technically recoverable continuous (unconventional) resources of 1.5 billion barrels of oil and 4.6 trillion cubic feet of natural gas in a single assessment unit (Figure 6; Enomoto et al., 2017; Hackley et al., 2018). This is much less than an often cited estimate of 7 billion barrels of oil in the TMS attributed to John et al. (1997).

Few research articles on the “Tuscaloosa marine shale” were published in 2018. Scopus had three listed (title, abstract or keyword search), Google Scholar reported 49 (anywhere in text) and 7 for TMS in the title, and AAPG Datapages listed 11 (full-text search) and 3 with TMS in the title.

References

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French, K.L., Birdwell, J.E., and Whidden, K.J., 2019. Geochemistry of a thermally immature Eagle Ford Group drill core in central Texas. Organic Geochemistry, v. 131, p. 19-33.

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FAYETTEVILLE SHALE, ARKOMA BASIN, ARKANSAS

Peng Li, Arkansas Geological Survey

The Upper Mississippian Fayetteville Shale play is a regional shale-gas exploration and development program within the central and eastern Arkoma Basin of Arkansas. Approximately 2.5 million acres have been leased in the Fayetteville Shale gas play (Figure 1). Production of thermogenic gas from the Fayetteville began in 2004 and continues to the present.

U.S. Energy Information Administration (EIA) reports in 2013 that the Fayetteville Shale contains 31.96 Tcf of technically recoverable gas resource, of which 27.32 Tcf is attributable to the core producing area (eastern area) and 4.64 Tcf for the remainder of the producing area (western area). A study by the Bureau of Economic Geology at the University of Texas at Austin found the play holds 38 Tcf in technically recoverable resources, of which a cumulative 18.2 Tcf are economically recoverable reserves by 2050. EIA also reports that the proved gas reserves of the Fayetteville Shale in 2013 are 12.2 Tcf, an increase over the 2012 estimate of 9.7 Tcf. Estimated ultimate recovery (EUR) for a typical horizontal Fayetteville gas well decreased from 3.2 Bcf in 2011 to 3 Bcf in 2013.

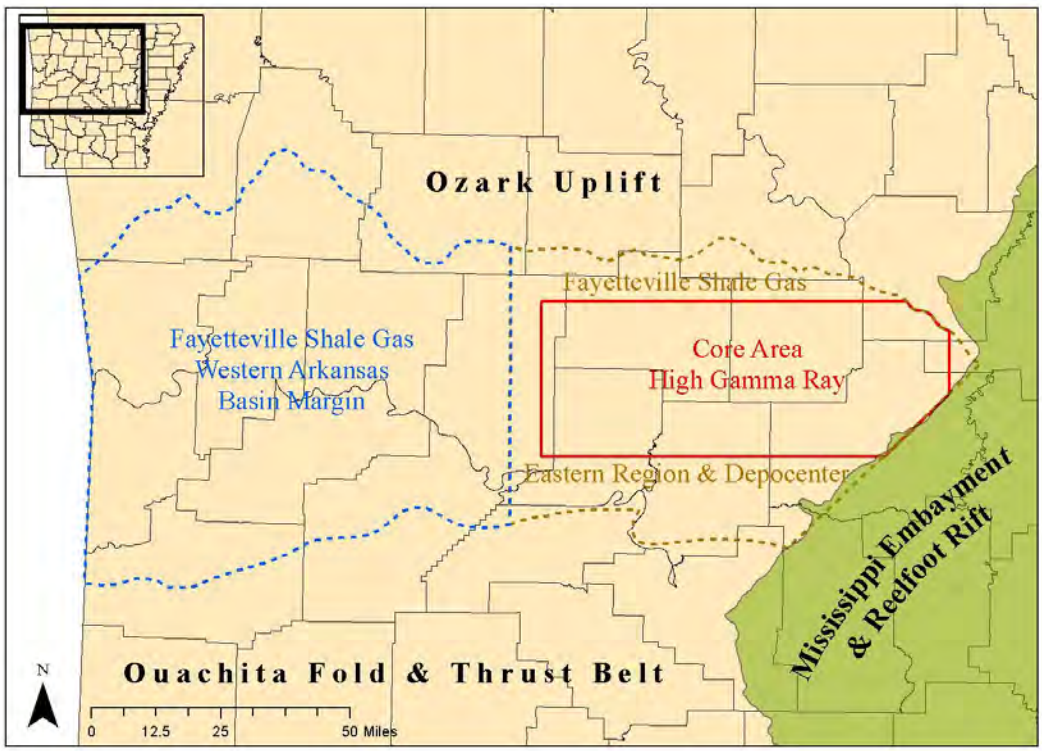

Figure 1. Primary area of the Fayetteville Shale exploration and development in Arkansas.

Most Fayetteville Shale wells are drilled horizontally and have been fracture stimulated using slickwater or cross-linked gel fluids. Baker Hughes' FracPoint Multi-stage fracturing system has provided most of the hydraulic fracturing completions in the

Fayetteville Shale. Fayetteville Shale gas production generally ranges over a depth between 1,500 to 6,500 feet. The thickness of Fayetteville Shale varies from 50 feet in the western portion of the Arkoma Basin of Arkansas (fairway area) to 550 feet in the central and eastern regions (primary producing area).

Due to a decline in drilling activity driven by lower natural gas prices, Fayetteville Shale gas production has decreased since peaking in 2013. In 2017, there was approximately 621,300,071 Mcf of gas produced in the play, a 17% decline over the last year. Estimated cumulative production of gas as of 2017 has totaled 7.96 Tcf. Initial production rates of horizontal wells in 2017 averaged about 5.3 MMcf/day. For more Fayetteville Shale production information, please refer to the Arkansas Oil and Gas Commission's web link at http://www.aogc.state.ar.us/Fayprodinfo.htm.

In 2017, only one rig operated by SEECO (a subsidiary of Southwestern Energy) worked in the Fayetteville Shale gas play (Figure 2). Eleven (11) wells were drilled in 2017, which demonstrated a rapid decline in well completion since 2015 (Figure 3).

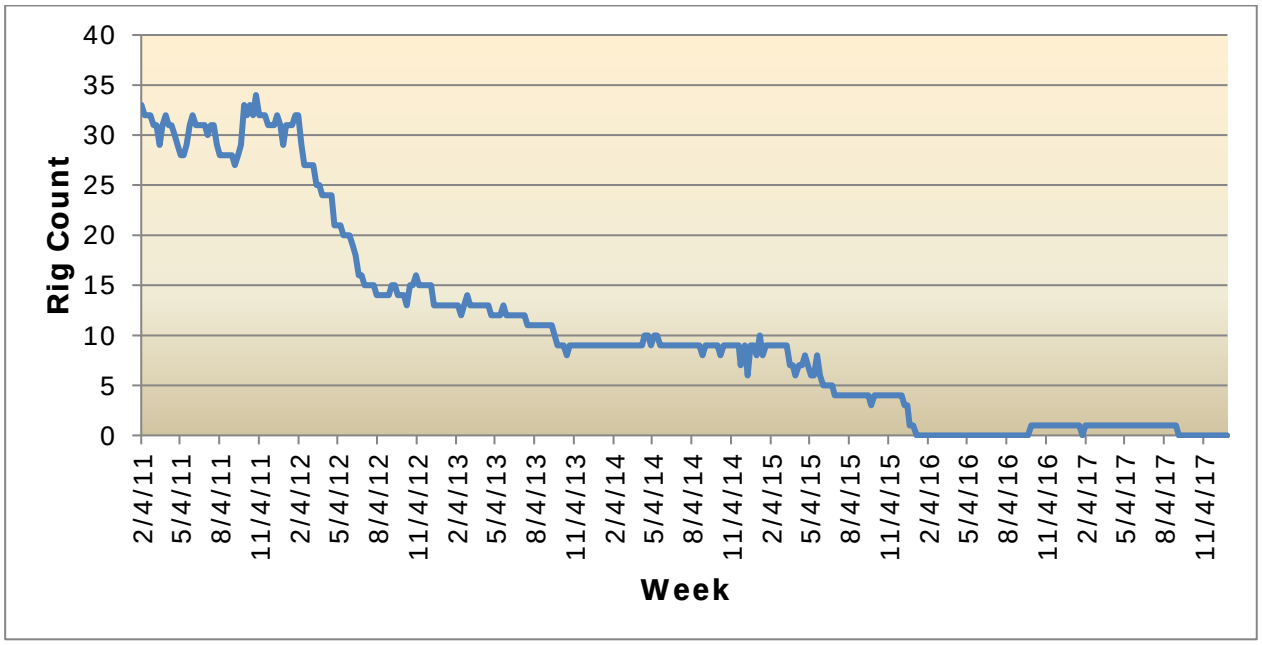

Figure 2. Weekly drill rig numbers in the Fayetteville Shale gas play (2011-2017).

Since the play's inception, the Fayetteville Shale play has been dominated by a small number of large players. Three operators – Southwestern Energy (SWN), BHP Billiton, and XTO Energy (a subsidiary of ExxonMobil) – accounted for over 99% of gross operated production from the field. The three companies hold close to 2 million net acres under lease in the play. Southwestern Energy, with 918,535 net acres lease and nearly four thousand producing wells, is by far the largest operator among the three companies and accounts for about two-thirds of the field's total production volume. XTO and BHP are approximately equal in terms of their acreage and gross operated production. In 2017, Southwestern contributed 463 Bcf in Fayetteville gas sales, good for 74.6% of the play's total sales that year. XTO

Energy sold 78 Bcf (12.6%) and BHP traded 79 Bcf (12.7%). The remaining 0.1 % of sales, or 1.8 Bcf, was spread out among eight companies.

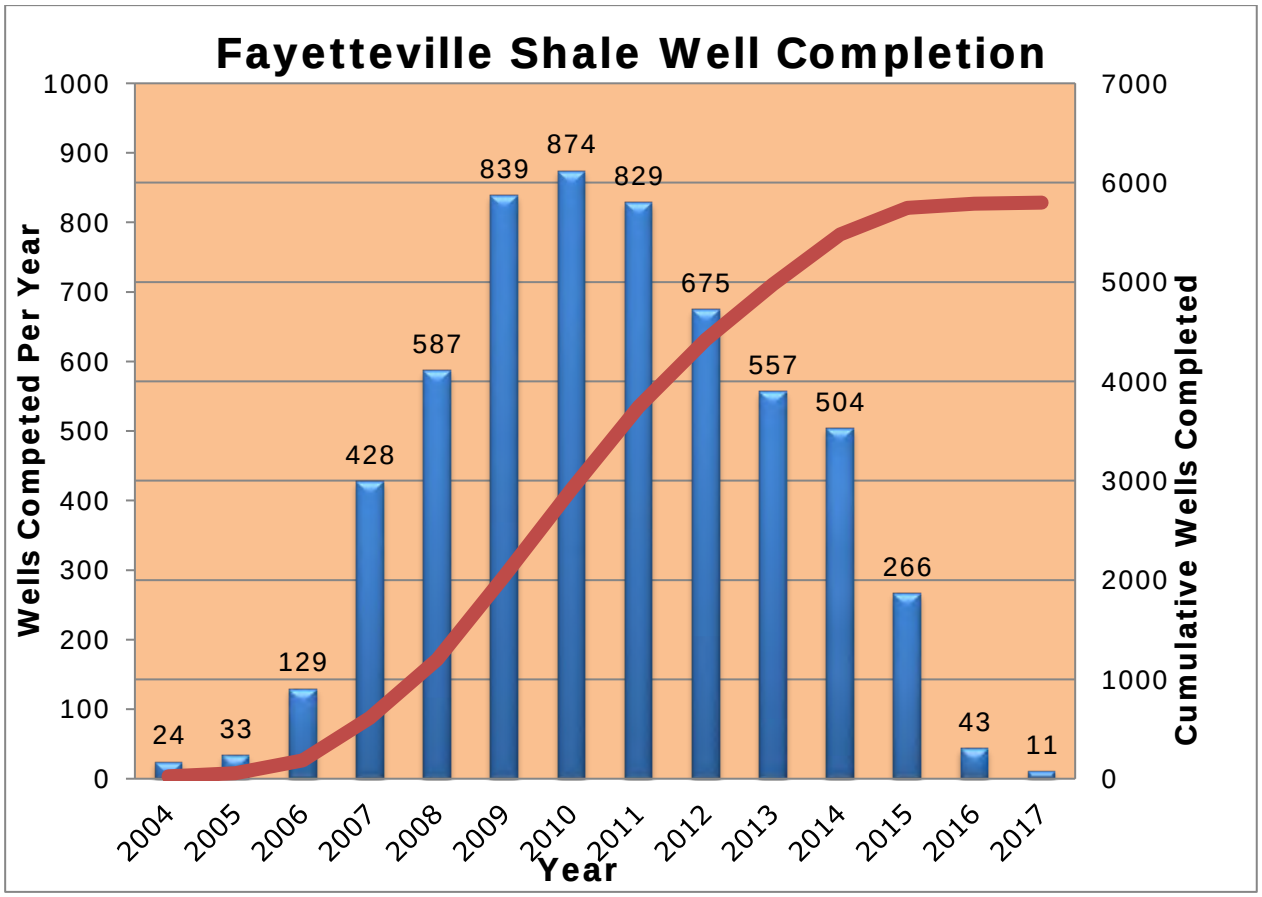

Figure 3. Fayetteville Shale well completion numbers.

The top three operators of the Fayetteville Shale gas play as of the end of 2017, based on numbers of producing wells, are as follows (Figure 4):

1) SEECO Inc. (an exploration subsidiary of Southwestern Energy) (3,663 wells)

2) BHP Billiton Petroleum (909 wells)

3) XTO Energy, Inc. (a subsidiary of ExxonMobil) (844 wells)

The Arkansas Geological Survey (AGS) has completed two extensive geochemical research projects on the Fayetteville Shale and has provided this information to the oil and gas industry and the public to assist with exploration and development projects. The results of these studies were published by the AGS as Information Circular 37 (Ratchford et al., 2006) and Information Circular 40 (Li et al., 2010), which integrated surface and subsurface geologic information with organic geochemistry and thermal maturity data.

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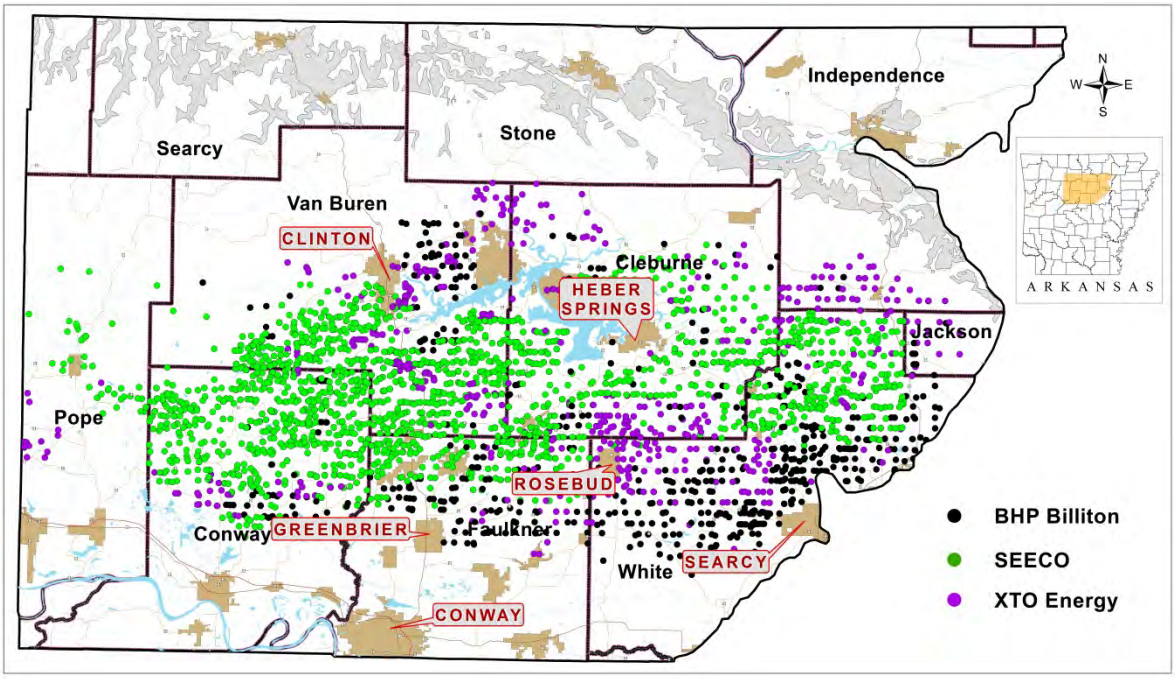

Figure 4. Location map of the Fayetteville Shale producing wells of top three operators.

HAYNESVILLE and BOSSIER SHALES (Upper Jurassic), EAST TEXAS and Northwest Louisiana

Ursula Hammes (Hammes Energy & Consultants, LLC, Austin, TX and Texas A&M University, Geosciences Department, College Station, TX)

The Kimmeridgian/Tithonian Haynesville and Bossier Shales span more than 16 counties/parishes along the boundary of eastern Texas and western Louisiana. Basement structures and salt movement influenced carbonate and siliciclastic

sedimentation associated with the opening of the Gulf of Mexico forming the Haynesville basin. The Haynesville shale is an organic- and carbonate-rich mudrock that was deposited in a deep, partly euxinic and anoxic basin during Kimmeridgian to early Tithonian time, related to a second-order transgression that deposited organic-rich black shales worldwide. The overlying Bossier shale is intermittently organic-rich related to third-order sea-level transgressions and exhibit similar organic-rich facies as the Haynesville Shale (Hammes et al., 2012). The Haynesville basin was surrounded by carbonate shelves of the Smackover and Haynesville lime Louark sequence in the north and west. Several rivers supplied sand and mud from the northwest, north, and northeast into the basin. Haynesville/Bossier mudrocks contain a spectrum of facies ranging from more calcareous in the southern part of the productive area to more siliceous and argillaceous in the northern and eastern part of the productive area (Fig. 1; Hammes et al., 2011). Haynesville and organic-rich Bossier reservoirs are characterized by overpressuring, high porosity averaging 8–12%, low Sw of 20–30%, nano-darcy permeabilities, reservoir thickness of 200-300 ft (70–100m), and initial production ranging from 3 to 30 MMCFE/day (Wang and Hammes, 2010). Reservoir depth ranges from 9,000 to 14,000 ft (3000–4700 m), and lateral drilling distances range between 4,600-10,000' using slick water fluid, 3000-4000 lbs/ft proppant with 100-150' frac intervals and 20-30' cluster spacing (Goodrich Investor presentation, 2019).

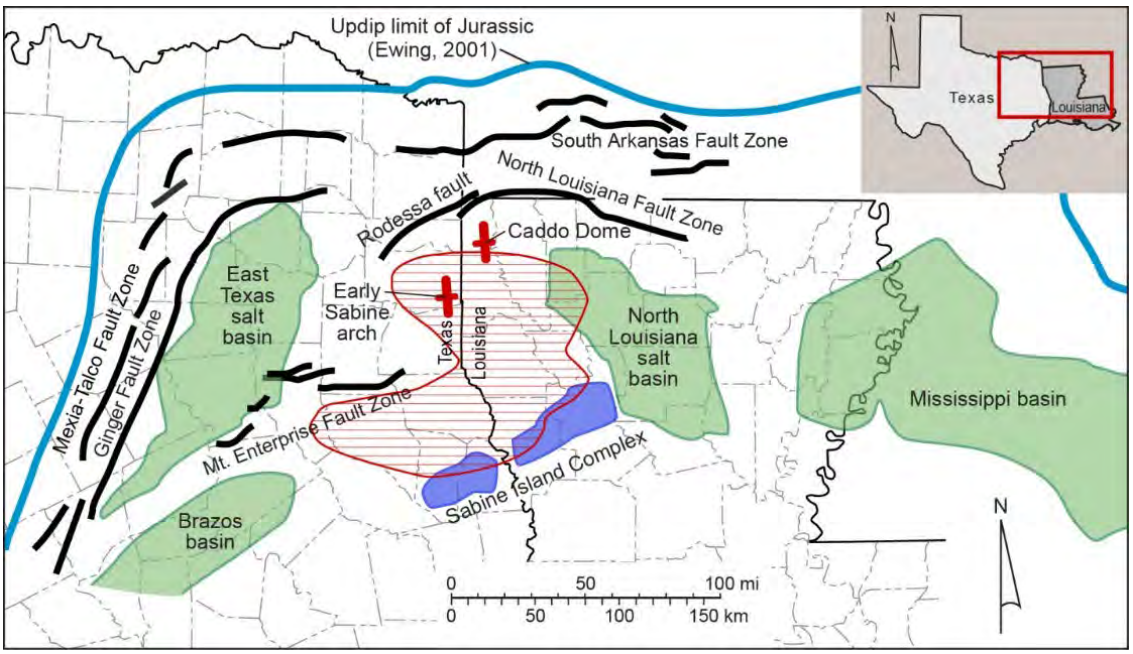

Figure 1: Location of Haynesville Basin and productive zone of Haynesville Shale (red stippled pattern; from Hammes et al., 2011).

The Haynesville/Bossier producing areas are strategically located near petrochemical complexes and LNG export facilities on the U.S. Gulf Coast, which helps facilitate rapid "spuds-to-sales" cycle times. Currently, the play is experiencing a renaissance due to new well design (extended reach laterals, increased proppant loading/concentration), re-fracs of existing wells and associated incremental production, as well as huge

development inventory from existing locations and pad drilling (Fig. 2). One of the advantages of the Haynesville shale gas is that it is dry gas and will not have to be processed before being liquefied. Gas production in Texas increased to 1.64 Bcf/day recording the highest production since inception of the play while condensate production has been steadily falling since its high in 2014 (Fig. 3). Overall production, including Louisiana, rose to 7.5 billion cubic feet equivalent per day (Bcfe/d) by year-end 2018, an increase of 4% from the 7.2 Bcfe/d reported for September 2017 (Fig. 4; from Hart Energy, 2019). Figure 5 shows drilling permit activity for 2015 to present year. In terms of activity, Northwestern Louisiana historically has been the "sweet spot" related to higher percent weight of total organic content (TOC), higher average total porosity and higher original gas in place (OGIP); however, increasing permits in East Texas, notably the Shelby Trough and Angelina River Trend (ART) as reflected in the higher production of Texas gas in 2019 (Figs. 3, 5). Additional information on the Haynesville can be found at the Texas Railroad Commission http://www.rrc.state.tx.us/oil-gas/major-oil-gas-formations/haynesvillebossier-shale/ and from Louisiana Oil and Gas association http://dnr.louisiana.gov/index.cfm?md=pagebuilder&tmp=home&pid=442 accessed April 29, 2019.

Figure 2: Normalized EUR per year (upper left) and by 1000 ft (upper right) showing increase in production related to increase in lateral length (from https://www.oilandgas360.com/the-haynesville-a-natural-gas-bellwether/).

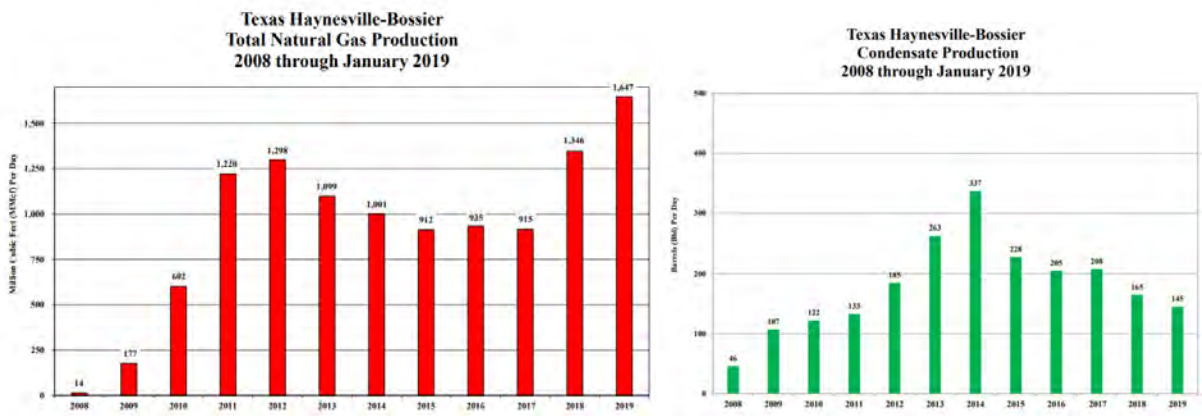

Figure 3: Yearly gas production chart (MMCF/day) and condensate production (right; in barrels per day) through January 2019 shows a steady decline in liquids production but an increase in gas production since the high in 2014.

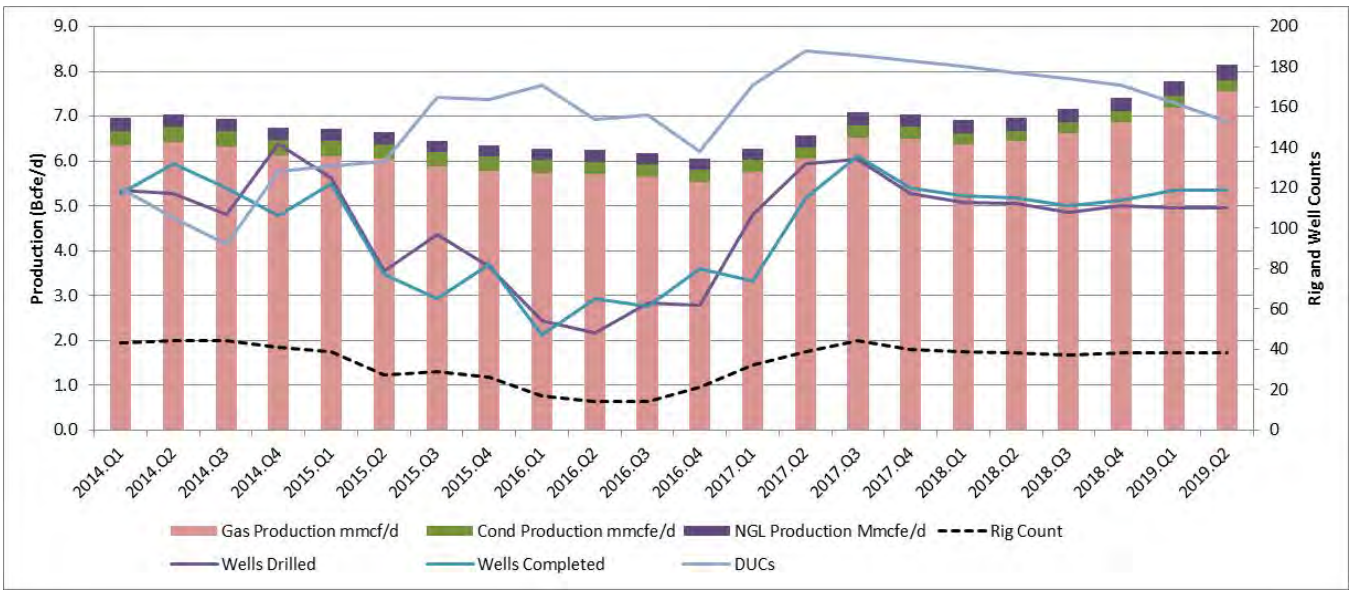

Figure 4: Haynesville production has risen to 7.5 billion cubic feet equivalent per day (Bcfe/d) by year-end 2018, an increase of 4% from the 7.2 Bcfe/d reported for September 2017 (from Hart Energy, 2019).

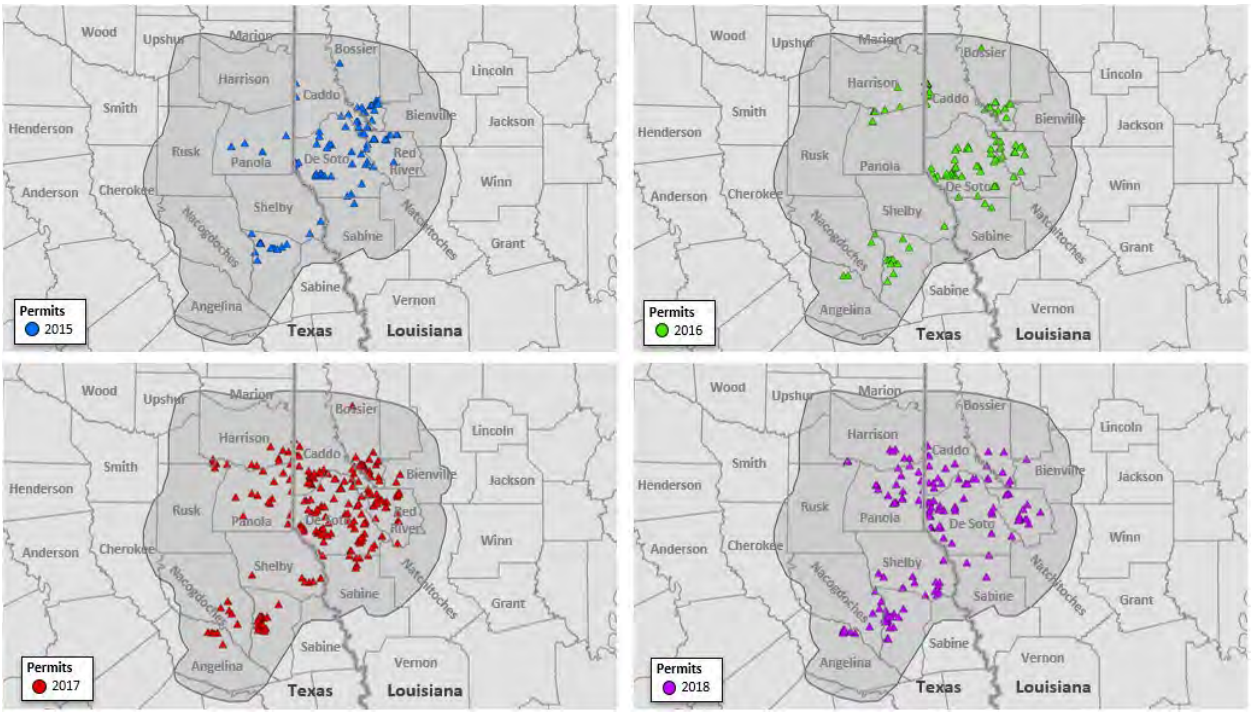

Figure 5: Haynesville shale permit activity (2015-2018) has shown a steady increase in permits in East Texas particularly in the area of the Angelina River Trend and Shelby Trough area from 2015-2018.

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MARCELLUS SHALE, APPALACHIAN BASIN, U.S.A.

Catherine Enomoto (U.S. Geological Survey, Reston, VA), December 2016

The Middle Devonian Marcellus Shale of the Appalachian Basin is the most extensive shale play in the U.S., covering about 66,600,000 acres (USGS Marcellus Shale

Assessment Team, 2011). Extending from Tennessee to New York, the gross thickness of the Marcellus Shale increases to the northeast, with the thickest area located in northeastern Pennsylvania (Wrightstone, 2009; Erenpreiss and others, 2011; Wang and Carr, 2013). The organic-rich zone of the Marcellus Shale has a net thickness of 50 to over 400 feet (Erenpreiss and others, 2011), and exists at drilling depths of 2,000 to 9,000 feet measured depth (MD) (Zagorski and others, 2012; Wang and Carr, 2013). The organic-rich Marcellus Shale has high radioactivity responses, and thus high gamma ray values on well logs, because the organic matter tends to concentrate uranium ions (Harper, 2008). According to studies during and after the Eastern Gas Shales Project (EGSP), there is a strong relationship between higher-than-normal gamma ray response and total gas content in the black, organic-rich Marcellus Shale. Published data indicates the total organic carbon content (TOC) of the Marcellus Shale is as high as 11% (Repetski and others, 2008). As reported in Milici and Swezey (2006), Repetski and others (2008), and Ryder and others (2013), analyzed samples of the Marcellus Shale had mean random vitrinite reflectance values between 1.0 and 2.5% in the majority of the currently productive area, where most production has been natural gas and natural gas liquids. However, in southwest Pennsylvania, eastern Ohio, and northern West Virginia, reported production included condensate and oil from wells in the Marcellus Shale.

In late 2004, the Marcellus Shale was recognized as a potential reservoir rock, instead of only a regional hydrocarbon source rock. Technological improvements resulted in improved commerciality of gas production from the Marcellus Shale, and caused rapid development of this play in the Appalachian Basin, the oldest producing petroleum province in the United States. According to the Pennsylvania Department of Conservation and Natural Resources, the first horizontal wells in the Marcellus Shale were drilled in 2006. Natural gas production was reported from horizontal wells that were completed in the Marcellus Shale in West Virginia as early as 2007.

As in other shale plays, horizontal drilling and hydraulic fracturing increase production rates of petroleum, which improves the commerciality of hydrocarbon production from this formation. The orientation of the horizontal sections of the wells and the design of the staged hydraulic fracturing operations enhance the natural fracture trends in the Marcellus Shale. “Slick-water fracs” have provided the best method for recovering large volumes of natural gas efficiently. These use sand as a proppant and large volumes of freshwater that have been treated with a friction reducer such as a gel. The slick-water frac maximizes the length of the induced fractures horizontally while minimizing the vertical fracture height (Harper, 2008). Water supply for large volume fracturing is a concern, as are the potential environmental impacts related to handling and management of produced formation water and used hydraulic fracturing fluid, called “flow-back” fluid (Engle and Rowan, 2014; Skalak and others, 2014; Capo and others, 2014). The management of produced formation water and used hydraulic fracturing fluid have been addressed with a variety of approaches including 1) treatment followed by discharge into receiving basins or streams, 2) injection into subsurface disposal wells, or 3) treatment to remove solids and unwanted contaminants followed by reuse.

According to a report published by the U.S. Energy Information Administration (EIA) in October, 2015 (U.S. Energy Information Administration, 2015a), which contained analyses of drilling and production data through September, 2015, the number of rigs that completed wells in the Marcellus Shale decreased by about 50% from January 1, 2012, to September, 2015. However, the new-well gas production per rig in the Marcellus Shale region (which includes production from overlying and underlying formations (U.S. Energy Information Administration, 2015b)) increased from 3.2 million cubic feet (Mcf) per day in January 2012, to 8.7 Mcf per day in September 2015. The production from the Marcellus Shale region was about 16.5 billion cubic feet (bcf) of gas per day and about 60,000 barrels (bbls) of oil and condensate per day, in July, 2015, according to the EIA (U.S. Energy Information Administration, 2015b).

In August 2011, the U.S. Geological Survey (USGS) published Fact Sheet 2011-3092, “Assessment of undiscovered oil and gas resources of the Devonian Marcellus Shale of the Appalachian Basin Province” (Coleman and others, 2011). According to this publication, the USGS estimated a mean undiscovered, technically recoverable natural gas resource of about 84 trillion cubic feet (tcf) and a mean undiscovered, technically recoverable natural gas liquids resource of 3.4 billion bbls in continuous-type accumulations in the Marcellus Shale. The estimate of natural gas resources ranged from 43 to 144 tcf (95 percent to 5 percent probability, respectively), and the estimate of natural gas liquids (NGL) resources ranged from 1.6 to 6.2 billion bbls (95 percent to 5 percent probability, respectively).

The estimates are for resources that are recoverable using currently available technology and industry practices, regardless of economic considerations or accessibility conditions, such as areas limited by policy and regulations. The Marcellus Shale assessment covered areas in Kentucky, Maryland, New York, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia. In Figure 1, the extent of three assessment units (AU) defined in this latest assessment are shown. Ninety-six percent of the estimated resources reside in the Interior Marcellus AU.

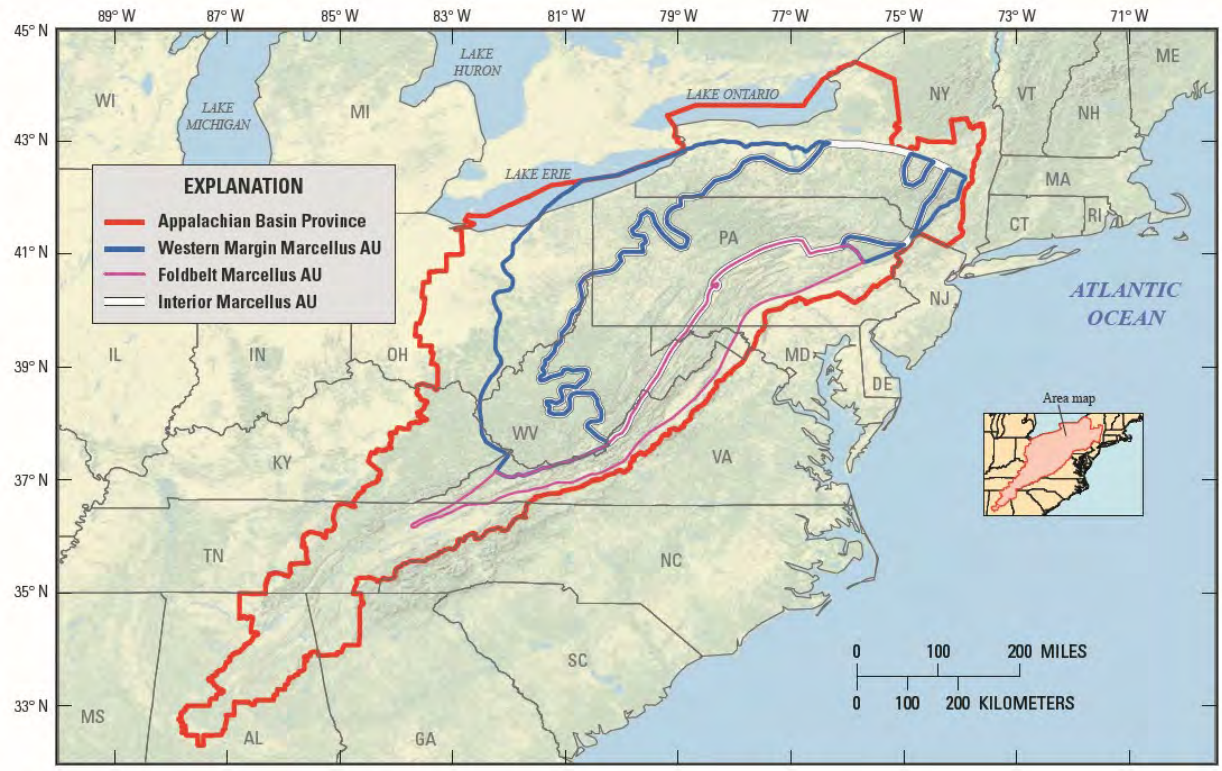

Figure 1. Map of the Appalachian Basin Province showing three Marcellus Shale assessment units (Coleman and others, 2011).

Maryland: According to the Maryland Geological Survey (MGS), the Marcellus Shale is present in Garrett and Allegany counties in western Maryland, where its thickness is 150 to 250 feet (Brezinski, 2010, 2011). The depth of the Marcellus Shale in western Maryland is zero to more than 8,000 feet MD (Brezinski, 2010, 2011). Although natural gas production is not available online, it is believed there is currently (2018) no production from the Marcellus Shale in Maryland. There were no exploration wells drilled to the Marcellus Shale in Maryland between 1996 and 2018. Due to the estimated thermal maturity of the Marcellus Shale in Maryland (Repetski and others, 2008), it is likely that dry gas will be found if wells are drilled and completed in the Marcellus Shale. Oil and gas exploration and production regulations were published in the November 14, 2016, edition of the Maryland Register. (http://mde.maryland.gov/programs/LAND/mining/marcellus/Documents/261901_Proposed_111416.pdf)

The regulatory proposal was open for public comment through December 14, 2016. According to the Maryland Department of the Environment (MDE), the regulations may not become effective, nor may a permit be issued for a horizontal well that will utilize hydraulic fracturing, until October 1, 2017. Comments received are being reviewed. Underground injection control regulations were published in the Maryland Register:

http://mde.maryland.gov/programs/LAND/mining/marcellus/Documents/26080704_Proposed.pdf. Comments were accepted for 30 days; these comments are being reviewed.

New York: The Marcellus Shale extends into the northernmost part of the Appalachian basin in central New York. The organic-rich thickness of the Marcellus Shale increases from 20 feet in the west to 250 feet in the eastern part of the basin in New York (Smith and Leone, 2010). The depths of the Marcellus Shale range from zero to as much as

7,000 feet MD in the eastern part of the basin in south-central New York (Smith and Leone, 2010). According to the New York State Department of Environmental Conservation (DEC), 50 vertical wells have been drilled that reported Marcellus Shale as a producing formation. Of those, 14 were listed as active in 2017. Production reported from the Marcellus Shale from the 14 active wells in 2017 (most recent data available) was 19.2 Mcf of gas, down from the high of 64 Mcf reported for 2008. There was no reported oil or condensate production. In 2017, most of the productive wells were located in Steuben County, with some also in Allegany, Chautauqua, Livingston, Schuyler, and Wyoming counties. According to the DEC, there were over 328 Mcf of gas produced from the Marcellus Shale between 2000 and 2017. The DEC also reported that between 1967 and 1999, there may have been as much as 543 Mcf of gas produced from the Marcellus Shale.

At the conclusion of a seven-year study of the environmental impact of high-volume hydraulic fracturing (HVHF), the New York DEC published the Final Supplemental Generic Environmental Impact Statement (SGEIS) in April, 2015; it is available at http://www.dec.ny.gov/energy/75370.html. On June 29, 2015, the State Environmental Quality Review (SEQR) Findings Statement for HVHF was issued by the DEC Commissioner (available at http://www.dec.ny.gov/docs/materials_minerals_pdf/findingstatehvhf62015.pdf), which officially prohibits HVHF in New York.

Ohio: Based on completion reports from the Ohio Department of Natural Resources (DNR), about 18.2 bcf of gas and almost 753,000 bbls of condensate and/or oil were produced from the Marcellus Shale from 2007 through 2018 (most recent data available). There were about 22 horizontal wells that reported production from the Marcellus Shale in 2018. According to the DNR completion reports, there were about 6.4 bcf of gas and about 279,000 bbls of oil and/or condensate produced in 2018. The horizontal Marcellus Shale wells reported as active were in Belmont, Carroll, and Monroe counties.

The maximum thickness of the Marcellus Shale in Ohio is about 75 feet, but generally the Marcellus Shale is 30-50 feet thick in the productive area in eastern Ohio (Erenpreiss and others, 2011). The depth to the base of the Marcellus Shale in the productive area in eastern Ohio is 2,500-5,000 feet MD (Wickstrom and others, 2011).

According to Repetski and others (2008), the Marcellus Shale is in the oil-thermal maturity window in eastern Ohio.

Pennsylvania: The Marcellus Shale is deepest in north-central Pennsylvania, and the deepest wells to test the Marcellus Shale have been drilled to 8,500 feet MD in Clinton County (Harper and Kostelnik, undated). The organic-rich, high gamma ray portion of the Marcellus Shale is thickest in southwestern and north-central Pennsylvania (Perry and Wickstrom, 2010; Harper, 2008), reaching over 400 feet thick in Susquehanna and Wyoming counties (Erenpreiss and others, 2011). Pennsylvania has continued to be the state with the most production from the Marcellus Shale. In 2018, according to the Pennsylvania Department of Conservation and Natural Resources (DCNR) and Department of Environmental Protection (DEP), the areas of greatest drilling activity in the Marcellus Shale continued to be in southwestern and northeastern Pennsylvania. According to the Pennsylvania DCNR and DEP, the county with the most gas production in 2018 from the Marcellus Shale was Susquehanna County. After Susquehanna, the other counties with the most natural gas production in 2018 were Bradford, Washington, Greene, Lycoming, and Wyoming. The counties with the most condensate production in 2018 from the Marcellus Shale were Washington and Butler. The only counties with reported oil production in 2018 were Butler, Forest, and Mercer.

According to DCNR and DEP, by the end of 2018, about 6,730 wells reported production from the Marcellus Shale, with most production from horizontal wells. Almost 2.8 tcf of gas, about 1.6 million bbls of condensate and 2,700 bbls of oil were produced from the Marcellus Shale in 2018. In 2018, the largest producers of natural gas from the Marcellus Shale were Cabot Oil & Gas Corporation, Chesapeake Appalachia LLC, SWN (Southwestern Energy) Production Company LLC, Range Resources Appalachia LLC, and EQT Production Company. Range Resources was the largest producer of condensate from the Marcellus Shale in 2018.

Tennessee: According to de Witt and others (1993), the Marcellus Shale is present in the subsurface in northeastern Tennessee. Therefore, in 2011, the USGS determined that the Foldbelt Marcellus Assessment Unit extended into Tennessee (Figure 1). According to the Tennessee Department of Environment and Conservation, Division of Water Resources, Oil and Gas Section, there is no production from the Marcellus Shale in Tennessee.

Virginia: According to the Virginia Division of Gas & Oil (DGO), there were no wells drilled exclusively for the Marcellus Shale in Virginia between 2004 and 2018. It is possible that natural gas was produced from the Marcellus Shale co-mingled with other zones in vertical wells, but the quantity is unknown. According to Ryder and others (2015), the Marcellus Shale is present but thin in southwest Virginia. Erenpreiss and

others (2011) and Wang and Carr (2013) indicate the Marcellus Shale is less than 50 feet thick in southwest Virginia.

West Virginia: West Virginia is second to Pennsylvania in cumulative production of natural gas from the Marcellus Shale. According to the West Virginia Geological & Economic Survey (WVGES), the first production reported from a horizontal well completed in the Marcellus Shale in West Virginia was in 2007. From 2007 through 2018, about 6.8 tcf of gas were produced from horizontal wells completed in the Marcellus Shale, as well as about 40 million bbls of oil and/or condensate, and about 75 million bbls of NGL. According to the WVGES, there was reported production from the Marcellus Shale in 2,437 horizontal wells and 1,428 vertical wells in 2018. Production was co-mingled in the vertical wells, thereby making it difficult to separate Marcellus Shale production figures for those wells. In 2018, there were about 10.3 million bbls of oil and/or condensate, almost 60 million bbls of NGL, and over 1.3 tcf of gas produced from the Marcellus Shale in horizontal wells. In 2017, the companies that reported the most gas production from the Marcellus Shale were Antero Resources Corporation, EQT Production Co., Southwestern Production Co., HG Energy, Inc., and Northeast Natural Energy (Dinterman, 2018). The companies reporting the most liquids production from the Marcellus Shale in 2017 were CNX Gas LLC, Southwestern Production Co., Antero Resources Corp., HG Energy LLC, and EQT Production Co. (Dinterman, 2018).

In 2017, the counties from which most of the liquids were produced from the Marcellus Shale were Ritchie, Marshall, Tyler, Ohio, and Brooke (Dinterman, 2018). The counties from which most of the natural gas was produced were Doddridge, Wetzel, Tyler, Ritchie, and Marshall (Dinterman, 2018).

In the area where there is Marcellus Shale production in West Virginia, the thickness of the Marcellus Shale is 30 to 120 feet, according to WVGES. The depth to the base of the Marcellus Shale ranges from about 4,000 feet MD in Brooke and Jackson Counties to about 7,000 feet MD in Taylor and Preston Counties. According to Moore and others (2015), in northern West Virginia, the total organic carbon (TOC) content is generally 10% or greater, and reservoir pressures range from 0.3 to 0.7 psi/foot.

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Unconventional Petroleum Potential in the Mowry Shale, Southern Powder River Basin, Wyoming

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Abstract

The Mowry Shale has long been recognized as an important source bed in the Rocky Mountain region. The Powder River Basin has a long history of production from mainly Cretaceous reservoirs sourced by the Mowry Shale. New technology (horizontal drilling and multistage hydraulic fracture stimulation) is now being used in the Mowry Shale.

Momper and Williams (1984) calculated that the Mowry generated about 170 billion barrels of oil and expelled about 11.9 billion barrels (7% expulsion efficiency) of oil from 10,500 square miles effective source area in the Powder River Basin. The high generated and expelled numbers suggest potential for a large unconventional, continuous accumulation in the Mowry Shale.

The Mowry Shale is a highly siliceous mudrock. The siliceous nature of the Mowry is due to diagenesis (silica cement), detrital silt-sized quartz, and recrystallized radiolaria. The high silica content impacts the mechanical rock properties of the Mowry Shale.

The Mowry Shale has these attributes that are similar to other proven shale plays: good TOC content (2-5 wt. %), adequate thickness (150 - 200 ft across the basin), hydrocarbons of thermal origin, abnormal pressure, generally lacking in produced water and down dip water, low matrix permeability and porosity, favorable mechanical stratigraphy, presence of fractures, current fields with diffuse boundaries, inverted petroleum system, gas-oil-ratios greater than 1000 cubic feet per barrel, historic conventional systems present, and relatively tectonically quiet basin setting.

Introduction

The Lower Cretaceous Mowry Shale is a major source rock in the northern Rocky Mountain region (Schrayer and Zarrella, 1968; Nixon, 1973; Byers and Larson, 1979; Burtner and Warner, 1984; Momper and Williams, 1984; Davis et al., 1989; Modica and Lapierre, 2012). The source rock contains primarily Type II organic matter with an admixing of Type III kerogen towards the west. Thermally mature Mowry Shales are closely associated with petroleum accumulations in both Lower and Upper Cretaceous reservoirs.

The Mowry Shale has produced modest amounts of oil from older vertical wells in the Powder River basin (Figure 1). With technology improvements (horizontal drilling and multistage hydraulic fracture stimulation) over the past decade, the Mowry is now prospective target for hydrocarbon production (Finley, 2017). Horizontal drilling is currently targeting the Mowry in the deeper parts of the Powder River Basin.

The Mowry Shale overlies the Shell Creek Shale or Muddy/Newcastle sandstones and is overlain by the Frontier Formation or Belle Fourche Shale (Figure 2). The Mowry

petroleum system consists of the Mowry source rock and the following Cretaceous reservoirs: Lakota, Fall River, Muddy, Newcastle, Mowry, Frontier, and Turner.

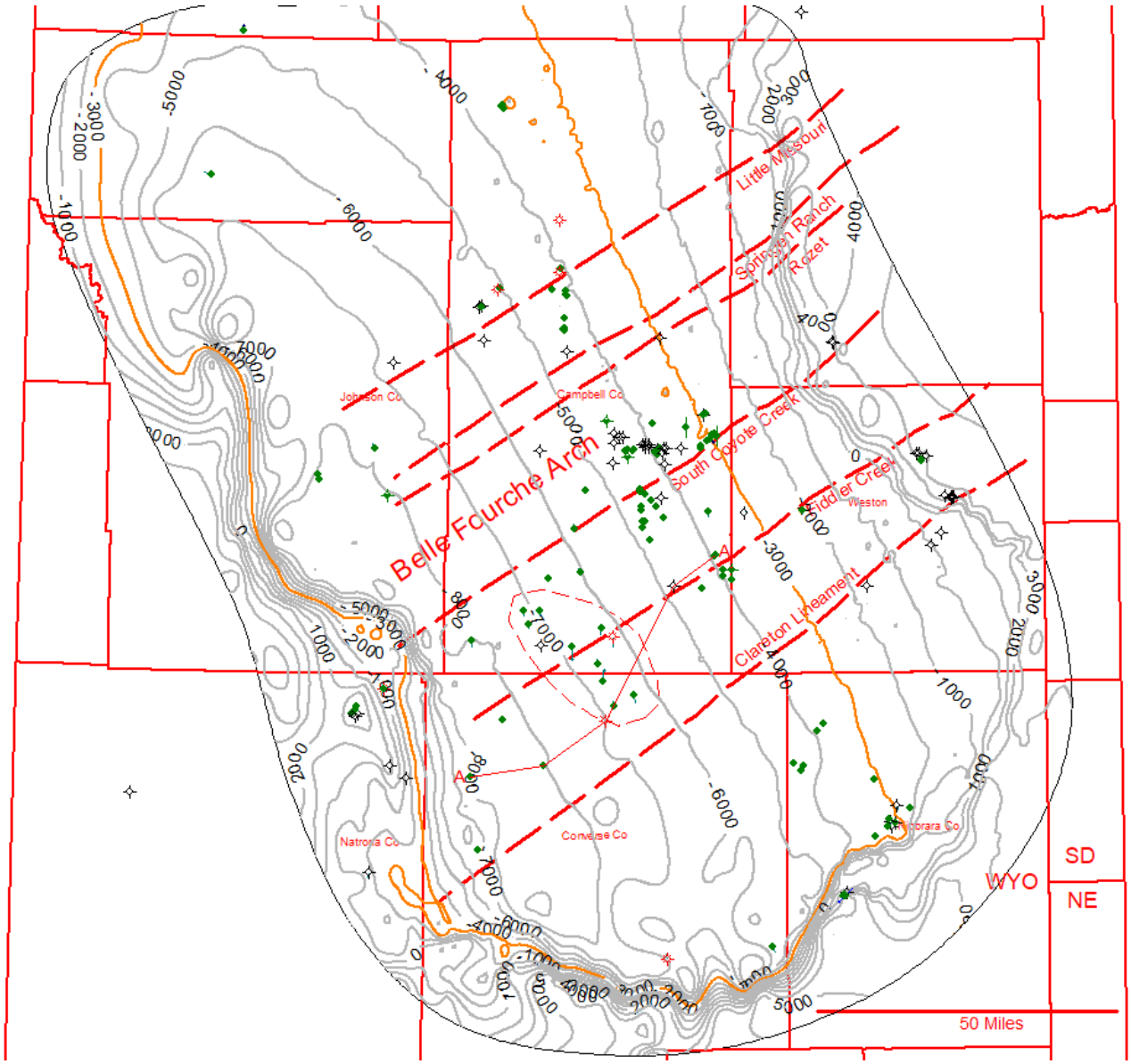

Figure 1. Structure contour map, top Muddy Sandstone, Powder River Basin, WY. Map also shows wells productive from the Mowry Shale. Orange contour indicates approximate depth of thermal maturity for the Mowry Shale. Dashed line shows location of new drilling in Crossbow field. Lineaments from Slack (1981).

Geologic Setting

The Mowry Shale was deposited in the Western Interior Seaway of North America. This inland sea existed from the Cretaceous to very early Paleogene. The foreland basin formed as a result of the Pacific Farallon tectonic plate being subducted under the North American plate during the Cretaceous.

The Western Interior Seaway experienced a series of marine transgressions during the Cretaceous. The Mowry represents the early stages of the Greenhorn transgression (Davis et al., 1989) in latest Albian time. The sea transgressed southward from the Boreal Ocean to form the Mowry Sea (Figure 3). The Mowry and its equivalents range in thickness from approximately 700 ft in western Wyoming to less than 50 ft in thickness in North Dakota (Burtner and Warner, 1984). This seaway did not connect to the Gulf of Mexico region until the Cenomanian time and Frontier/Belle Fourche deposition (Figure 2). The primary input of fine-grained siliciclastic sediments was from rivers draining the Cordilleran highlands to the west. During lower Mowry time sediment lobes projected into the basin from both western and southeastern margins. In upper Mowry time sediment appears to come exclusively from the west.

The Powder River basin formed during the Laramide orogeny (Late Cretaceous to Eocene). The Laramide orogeny broke the Western Interior Seaway into several smaller intermontane basins. The fragmentation of the Western Interior basin is attributed to flat-slab subduction of the Farallon plate.

The Mowry is typically dark-gray, siliceous mudrock containing fish scales and interbedded bentonite layers. The Mowry is overlain by the Belle Fourche Shale and underlain by the Shell Creek Shale or in its absence the Muddy Sandstone.

Several bentonite marker beds are present within the Mowry interval. The top of the Mowry is the Clay Spur Bentonite Bed and the base is a high gamma ray zone and the Shell Creek Bentonite (Modica and Lapierre, 2012). The Mowry is regarded as being upper Albian in age. The Clay Spur Bentonite has been dated as 95.78 Ma and the Shell Creek Bentonite is dated as 98.74 Ma (Modica and Lapierre, 2012).

Figure 4 illustrates the informal subdivisions of the Mowry used in this study (upper, middle, lower). Abundant data was available from the Wild West Unit # 1 well so the well is used several times in this report (data from Hollon, 2014). Maximum TOC occurs in the middle Mowry which is interpreted to be where the maximum flooding surface occurs. Total organic carbon (TOC) content ranges from 2-5 wt. % (Figure 4). The well shown in Figure 4 was completed in the middle Mowry for 12 barrels oil per day (uneconomic but a good show well).

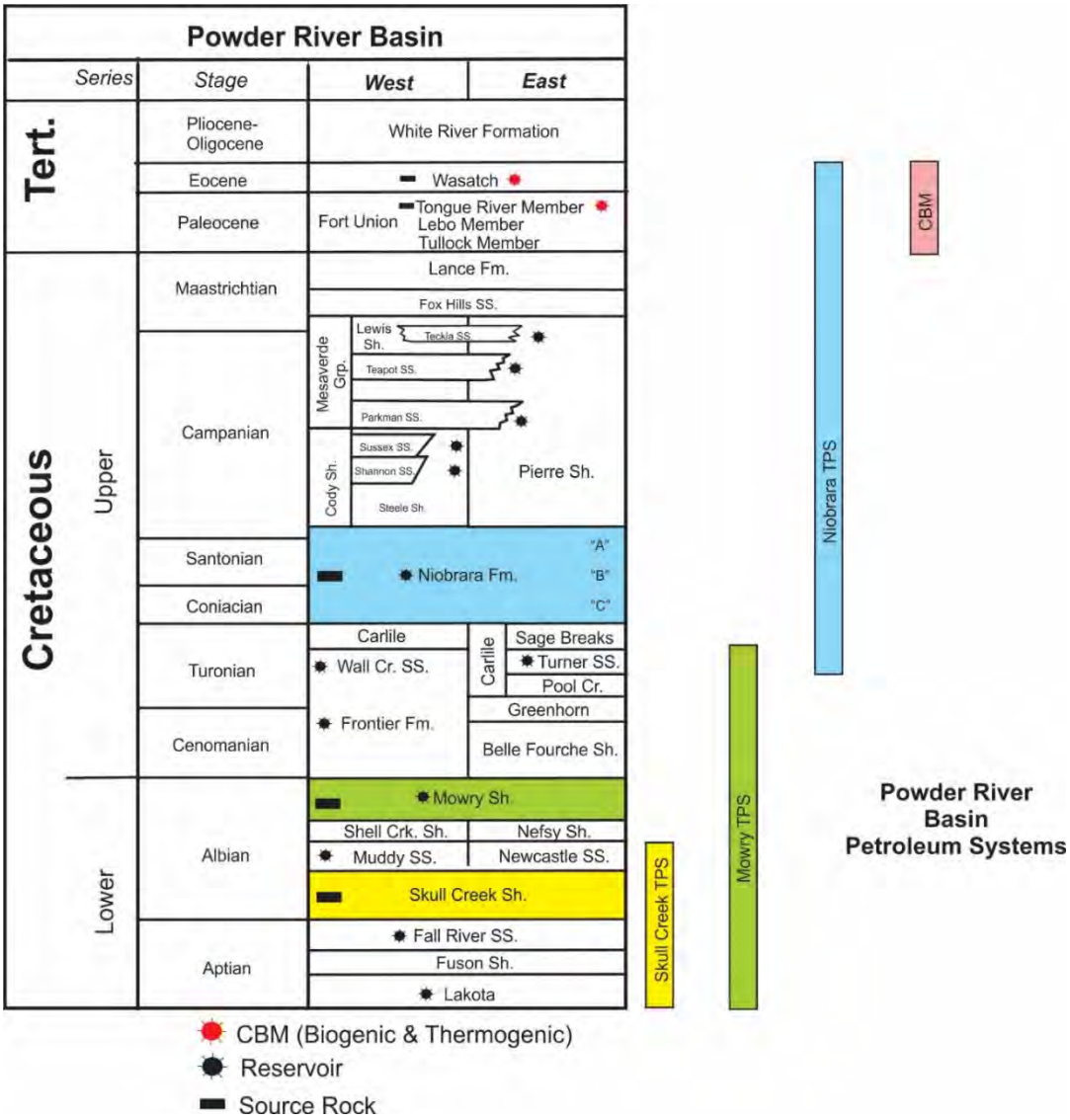

Figure 2. Stratigraphic column for Cretaceous and Tertiary units, Powder River Basin, Wyoming. The Mowry petroleum system (green bar) consists of source beds in the Mowry and reservoirs in the Lakota, Fall River, Muddy/Newcastle, Mowry, Turner, and Frontier.

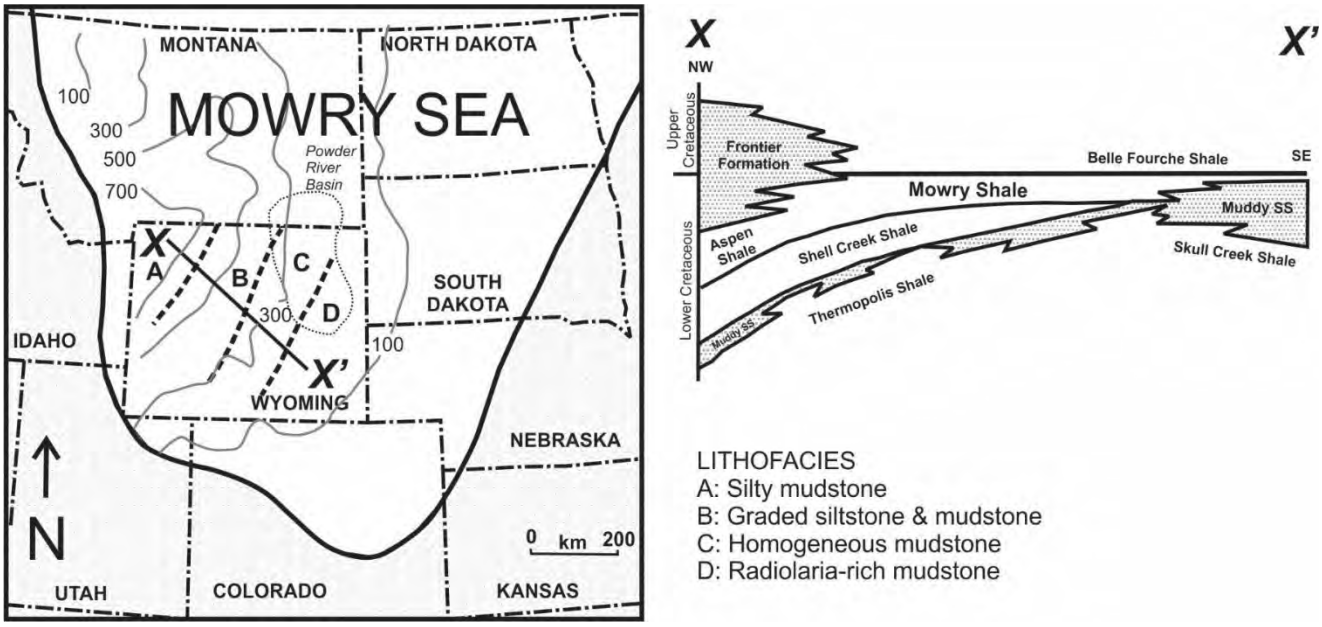

Figure 3. Map of Mowry Sea; thickness of Mowry; Lithofacies in the Mowry and cross section X - X'. Adapted from Burtner and Warner, 1984; and Davis et al., 1989.

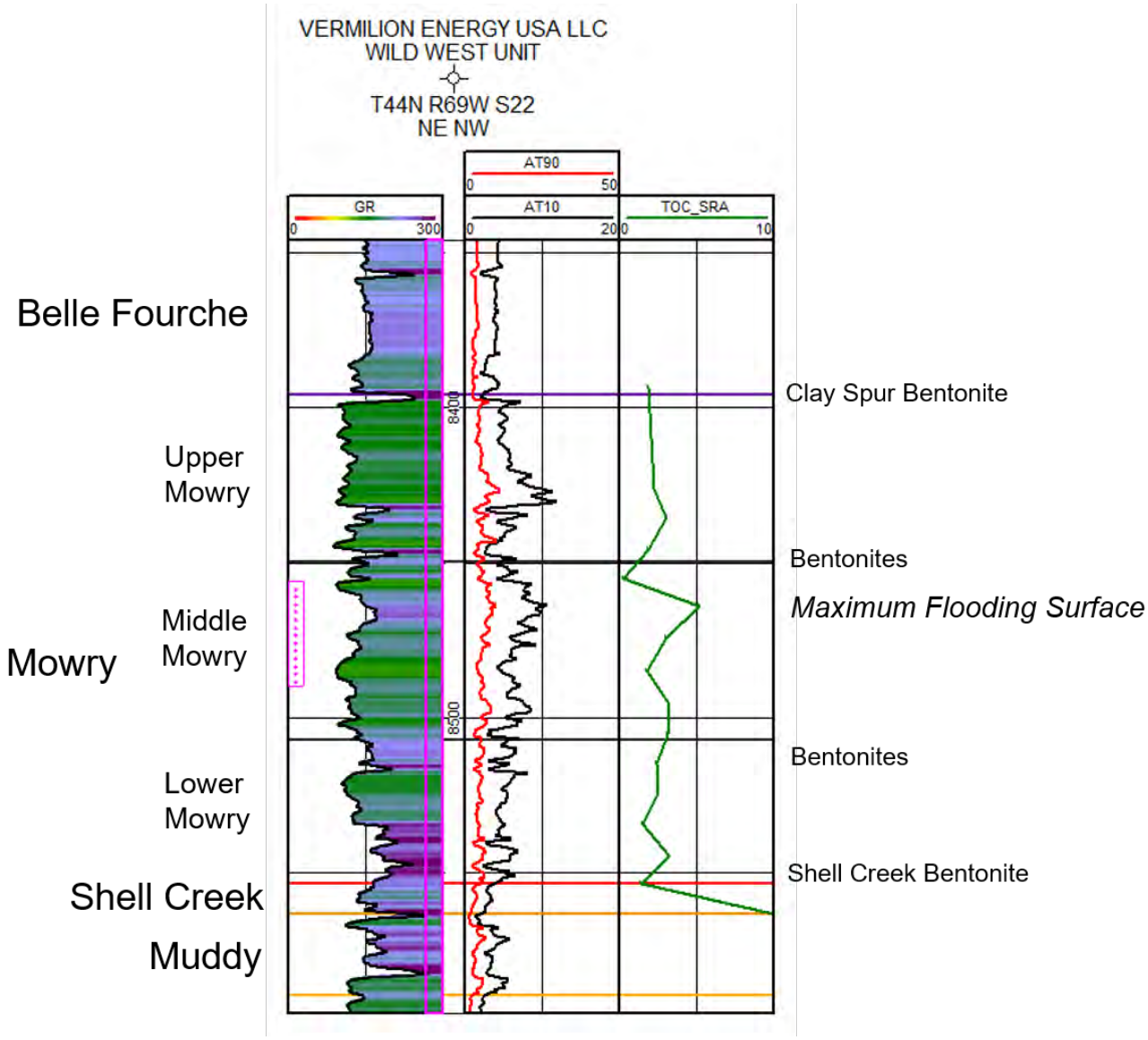

Figure 4. Well log from Wild West Unit 1 showing gamma ray (GR), resistivity (AT90, AT10), and total organic content (TOC). Bentonites are common and can be recognized by high GR readings and low resistivity spikes. TOC data from Hollon, 2014.

Petroleum Source Rocks

The Mowry Shale across the PRB has a TOC of 2 to 5 weight percent (Burtner and Warner, 1984; Modica and Lapierre, 2012; Schrayer and Zarrella, 1968). Some areas of anomalously low TOC coincide with the deeper parts of Laramide basins which reflects a reduction in TOC by thermal maturation in the deep basin setting (Burtner and Warner, 1984). Other areas of low TOC are attributed to dilution effects associated with proximity to the Mowry shoreline or simply low organic productivity.

The Mowry Shale contains a mixture of predominantly Type II and subordinate amounts of Type III organic matter (Figures 4, 5). Figure 5 is a modified Van Krevelen diagram (Hydrogen Index plotted against Oxygen Index) for the Mowry in the Wild West Unit # 1

well (Section 22, T44N, R69W). The plot illustrates the presence of both Type II and III kerogens.

Thermal maturity of the Mowry coincides with pyrolysis Tmax values of 435ºC or greater. In the Powder River Basin, Anna (2009) noted that the Mowry was thermally mature at present-day drilling depths of approximately 8,000 ft. Momper and Williams

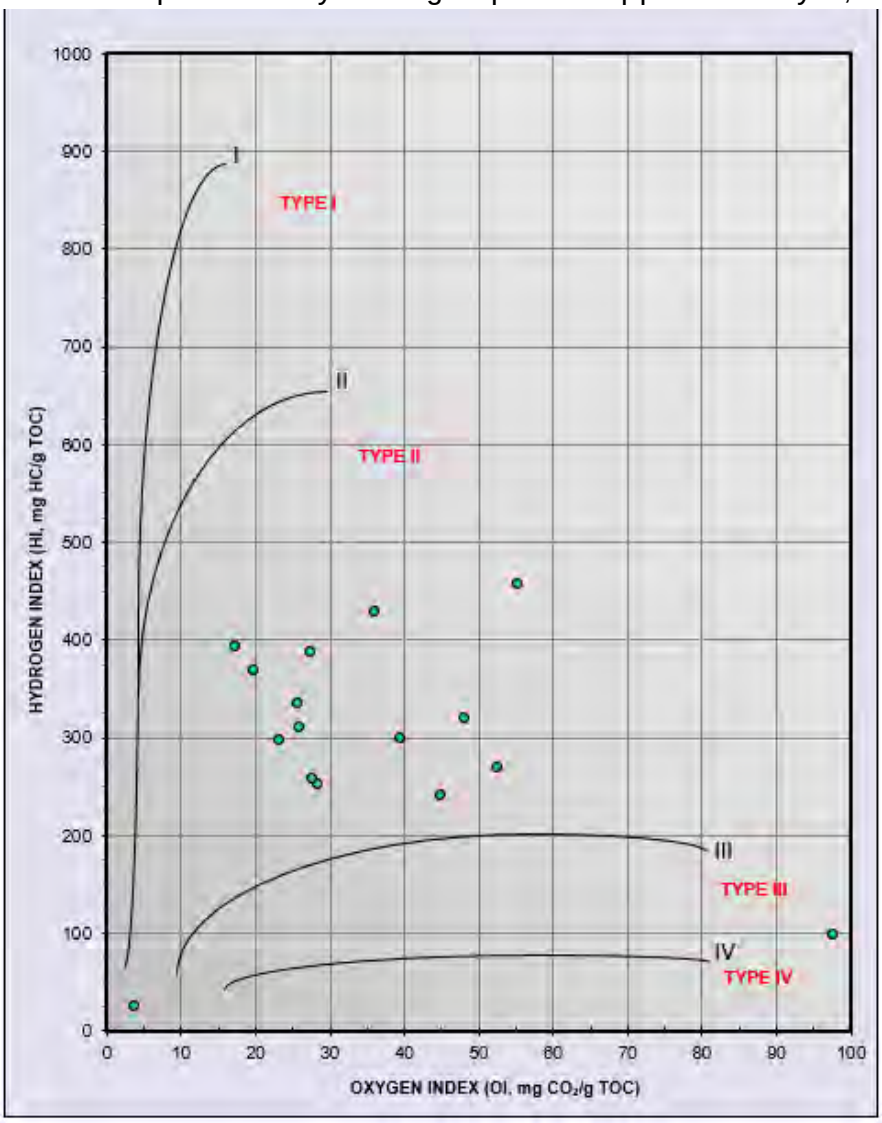

Figure 5. Source rock analysis data Hydrogen Index and Oxygen Index for the Mowry Shale in the Wild West Unit # 1 well (Sec. 22-T44N, R69W). Kerogen is Type II with admixture of Type III.

predict that expulsion of oil varies with changing geothermal gradients. At gradients of 2.0 ºF per 100 ft, expulsion begins at approximately 7,500 ft; whereas, at gradients of 1.7 ºF per 100 ft, expulsion begins at 9,000 ft. Hydrocarbon generation started 65 Ma on the west side of the Powder River Basin. The -3,000 ft (orange) contour line in Figure 1 is the approximate depth where the Mowry becomes thermally mature (based on a geothermal gradient of 2.0 ºF per 100 ft).

Momper and Williams (1984) calculated that the Mowry generated about 170 billion barrels of oil and expelled about 11.9 billion barrels (7% expulsion efficiency) of oil from 10,500 square miles effective source area. They used an average TOC content of 3 wt.% and a thickness of 240 ft of organic-rich shale. The shales have an oil-generating capability of 105 barrels per acre foot. A small percent of the expelled volume (~5%) can be accounted for by current cumulative production in known reservoirs (Anna, 2009). The generated oil numbers suggest significant potential for the Mowry Shale play.

Davis et al. (1989) recognized four lithofacies within the Mowry of Wyoming: 1) silty mudstone; 2) graded siltstone and mudstone; 3) homogeneous mudstone; 4) radiolarian mudstone (Figure 3). The four lithofacies represent transitions northwest to southeast across Wyoming from nearshore to distal offshore. The silty mudstone facies are characterized by poorly silicified silty mudstones, wavy bedding, and modest bioturbation and was deposited in a prodelta environment. The graded siltstone and mudstone lithofacies contain interlaminated silt-lean muds and fining-upward millimeter to centimeter-thick silt and mud strata. These units have a scoured base and consist of a basal silt layer, alternating silt, and mud laminae, with a general increase in mud upwards. Burrowing is restricted to silty layers. These units are interpreted as fine-grained turbidites and distal storm deposits. The homogeneous mudstone lithofacies consists of moderately silicified, homogeneous mudstone and lacks silt and sandstone. This unit contains layers of concentrated radiolarians (recrystallized to microcrystalline quartz), kerogen, fish debris, and thin graded silt and clay laminae. Radiolarians are planktonic protozoa (diameter of 0.1 - 0.2 mm) that secrete silica around their cells. This unit is interpreted to have been deposited in dysaerobic waters and mainly by pelagic settling but does contain a tractive component. The radiolarian facies are siliceous, silt-poor mudstone. The unit is dark colored and speckled by fine sand-sized white radiolarians, mostly recrystallized. This unit is interpreted to have been deposited under dysaerobic and anaerobic conditions and the farthest from Mowry shorelines (Davis et al., 1989). According to their mapping, the Powder River basin is dominated by lithofacies 3 and 4. Sedimentation rates for the Mowry have been estimated to be 25 mm/1,000 yr.

Average XRD mineral content for the Mowry excluding bentonites from the Wild West Unit # 1 well (Figure 4) is as follows: quartz, 56%; feldspar, 6%; pyrite, 5%; apatite, 1%, clay 31%; and carbonate, 1% (Hollon, 2014). Most of the quartz in the Mowry in biogenic in origin (Hollon, 2014). Quartz in the Mowry has several origins: detrital silt, replacement of skeletal debris, overgrowths on detrital quartz, replaced radiolarian, pore filling in intergranular pores, and authigenic microquartz that is dispersed in the clay matrix (Milliken and Olson, 2017). Detrital silt-sized feldspars are also present. Radiolaria are reported in cores and outcrops.

Reservoir properties for the Mowry in the Wild West Unit # 1 well are as follows: average porosity of 9.3% and average permeability of 6.96E-05 md.

Mowry thickness trends

The total Mowry ranges in thickness from over 225 ft to less than 150 feet across the study area (Figures 6, 7). The thickest Mowry occurs to the west which had the greatest detrital input into the area or the highest sedimentation rate. Thickening on the east side also suggests higher rates of sedimentation associated with detrital input. The northeast trending thin area (Figure 6) in the Mowry Shale (less than 150 ft) has been interpreted by some authors to represent a forebulge related to the Wyoming Idaho thrust belt (Modica and Lapierre, 2012). This paper does not support the forebulge interpretation.

Figure 7 is a west to east cross section across the study area. Drilling depths and Mowry maturity increase to the west or left on the diagram. Note the dramatic increase in resistivity associated with increased drilling depth, increased maturity of the Mowry source rock (possibly indicating presence of oil), and increased silica diagenesis. The middle Mowry has been the main target for both vertical and horizontal wells to date.

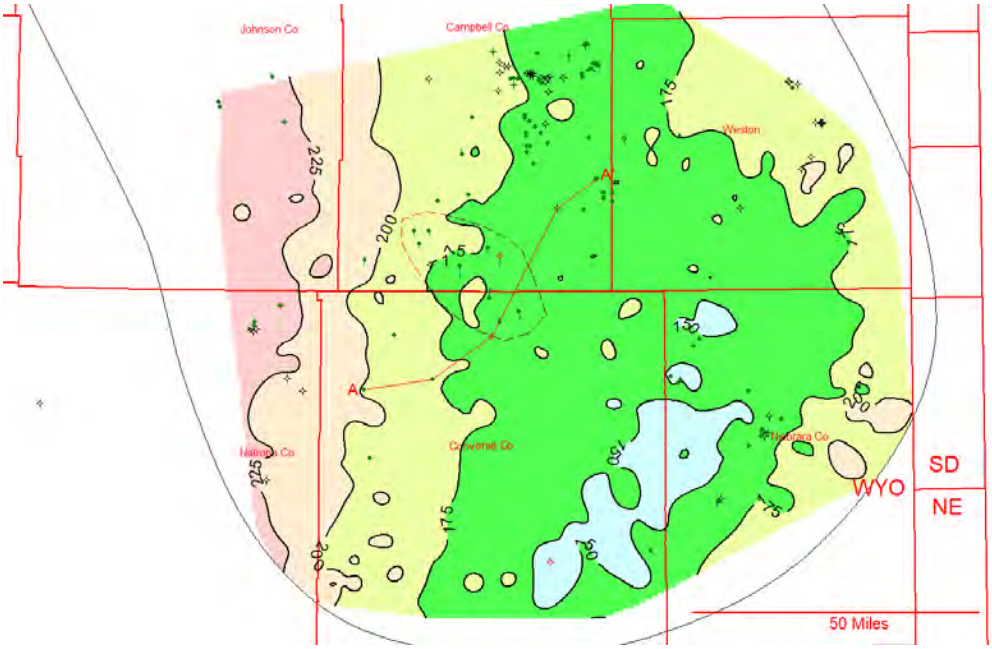

Figure 6. Isopach map of Mowry Shale, southern Powder River Basin. Contour interval = 25 ft. Dashed line is location of new Mowry drilling in Crossbow field. Cross section A-A' shown in Figure 7.

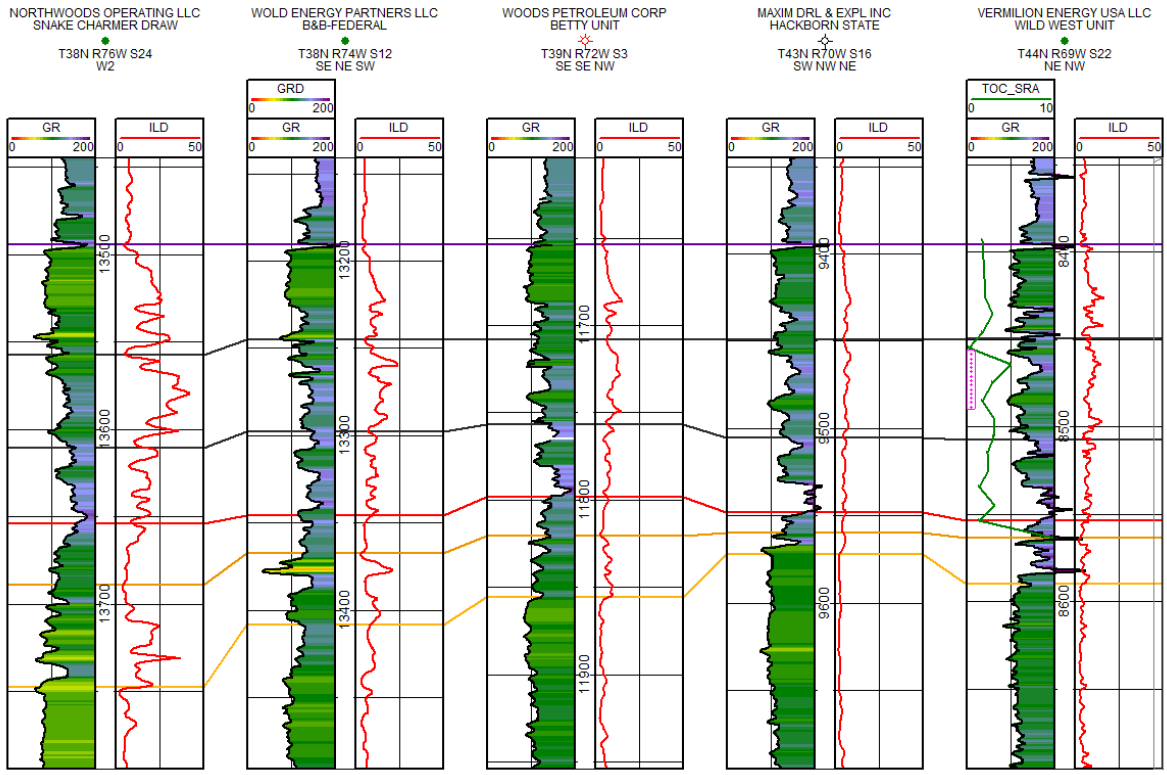

Figure 7. Cross Section A-A'. Datum is top of Mowry Shale. Note increase in resistivity in Mowry with depth. Primary target for drilling both vertical and horizontal is middle Mowry.

The Mowry in this study was subdivided into lower, middle, and upper units. The lower Mowry ranges in thickness from over 60 ft to less than 20 feet across the mapped area (Figure 8). Thick areas are present on both the west and east sides of the mapped area. These thick areas are interpreted to be due to higher rates of sedimentation in these areas. The thin area (less than 30 ft in thickness) in the mapped area is interpreted to be where the lowest rates of sedimentation are located.

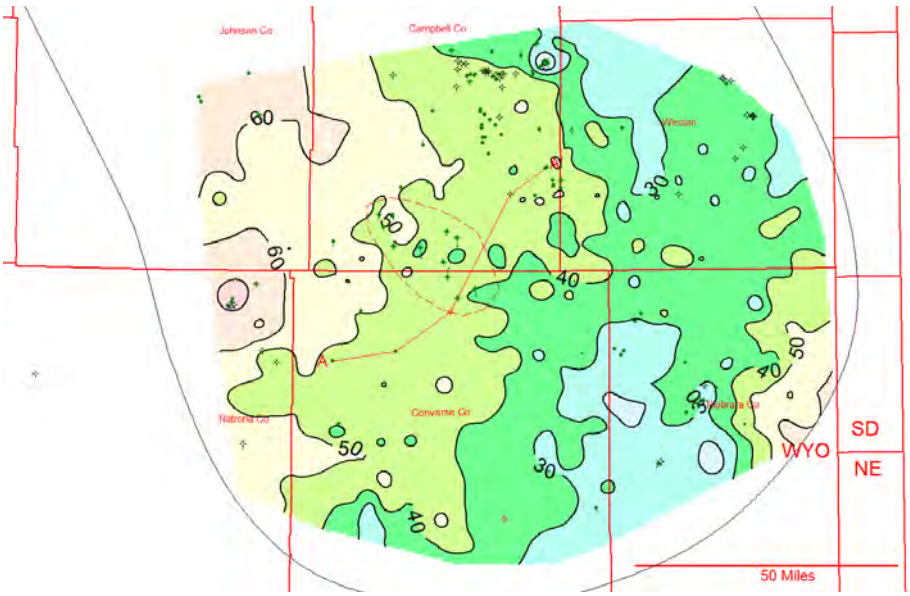

Figure 8. Isopach lower Mowry Shale, southern Powder River Basin. Contour interval = 10 ft.

The middle Mowry ranges in thickness from over 100 ft to less than 50 ft in the mapped area (Figure 9). The thin areas are interpreted to be where the lowest rates of sedimentation occurred. The middle Mowry represents the maximum inundation during Mowry time. It is the most organic rich of the Mowry units and represents a time of terrestrial sediment starvation. The middle Mowry has the highest resistivity and highest average gamma radiation of the three Mowry units.

The upper Mowry ranges in thickness from 60 to less than 30 ft in the mapped area (Figure 10). The thickness trends observed in the mapped area are like the lower Mowry Shale.

The shifting of the axis of thinning or thickening in the Mowry units reflects the effects of compensatory sedimentation. Thick areas beget overlying thin areas and vice versa.

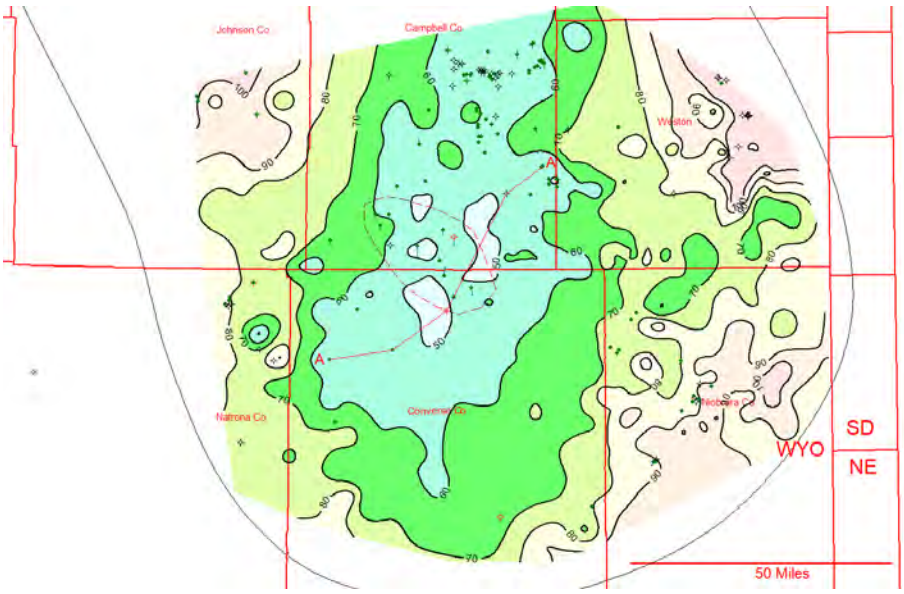

Figure 9. Isopach middle Mowry Shale, southern Powder River Basin. Contour interval = 10 ft. In the Mowry Shale play, middle Mowry is primary target for vertical and horizontal drilling. Dashed line is location of new horizontal drilling in Crossbow field.

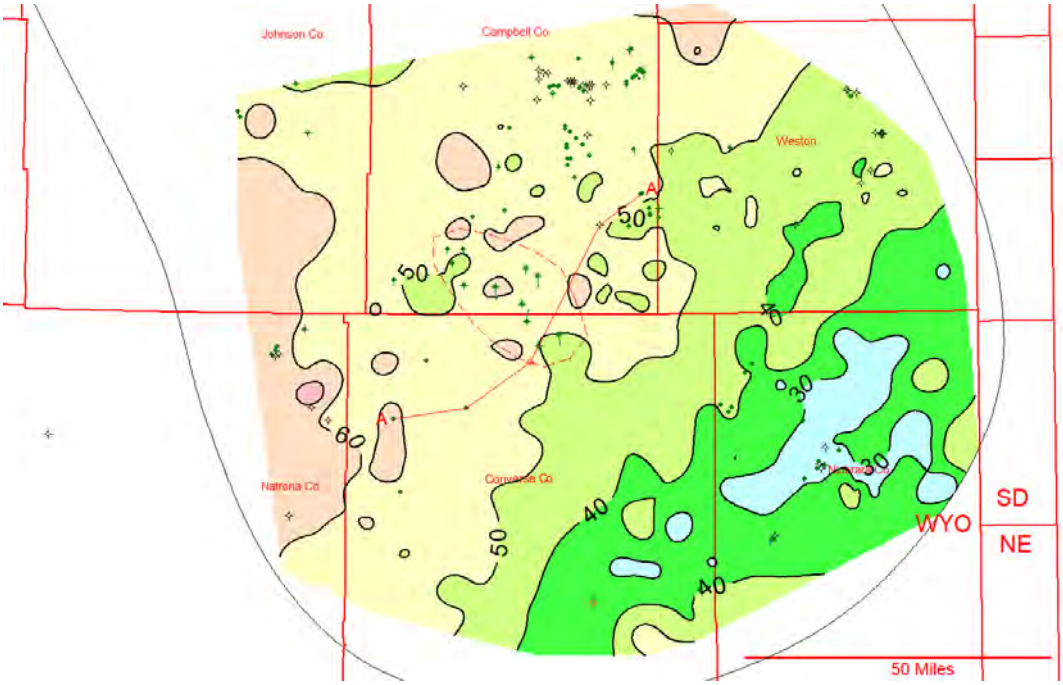

Figure 10. Isopach map of upper Mowry Shale, southern Powder River Basin. Contour interval = 10 ft.

Mechanical Stratigraphy of the Mowry

Dipole sonic logs are commonly used to calculate Poisson's ratio (PR) and Young's modulus (YM). Figure 11 illustrates PR and YM curves for the Mowry section in the Wild West Unit # 1 well. The highest brittleness (YM/PR) occurs in the middle and upper Mowry. The presence of significant volumes of silica cement, detrital silt-sized quartz and recrystallized radiolaria impacts the mechanical properties in the Mowry Shale (Milliken and Olson, 2017). The highly siliceous nature of the Mowry Shale makes the entire interval mechanically brittle.

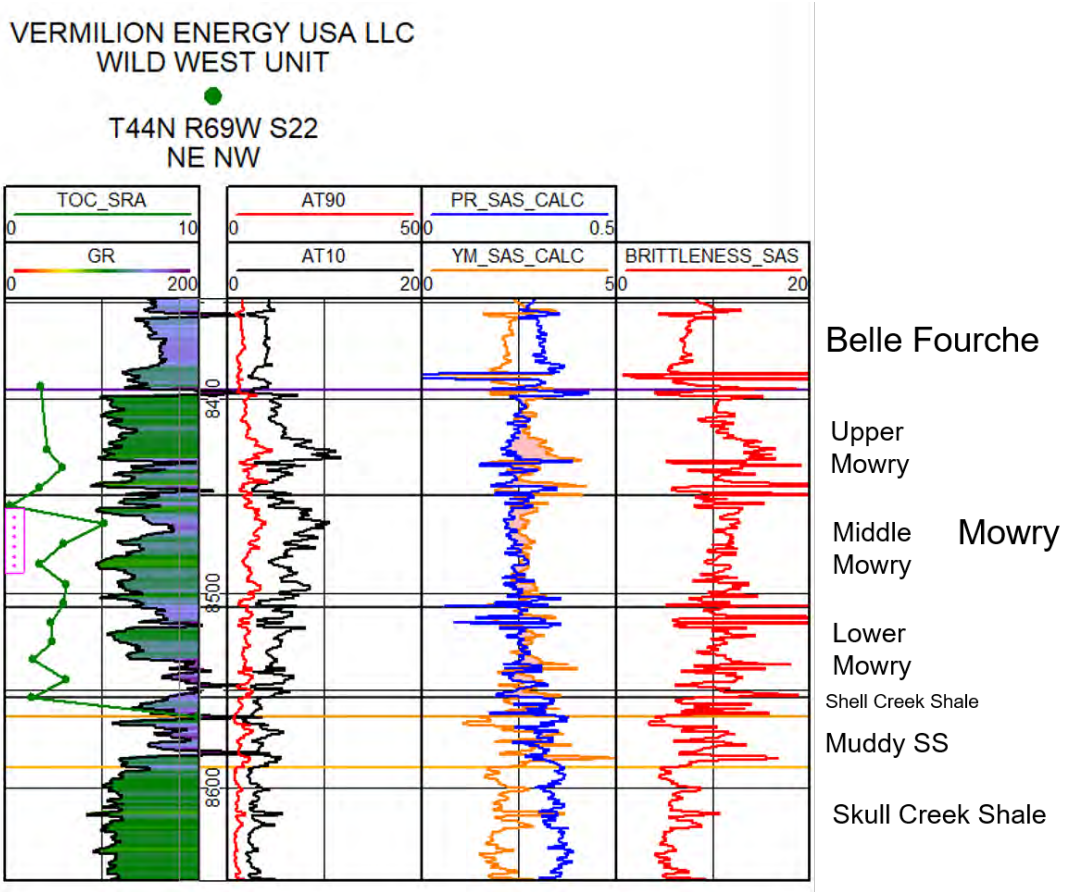

Figure 11. Poisson's ratio (PR) and Young's modulus (YM) curves compared to gamma ray (GR), resistivity curves (AT90). Also shown is calculated "brittleness" curve. The Mowry Shale illustrates high Young's modulus and brittleness in all three units.

Reservoirs for the Mowry Source Rocks

The Mowry is long thought to be one of the most important source rocks in the Rocky Mountain Region (Nixon, 1973; Momper and Williams, 1984; Burtner and Warner, 1984, 1986; Davis, 1970; Davis et al., 1989; Anna, 2009). The Mowry sources intervals both above and below the formation. The Mowry is thought to source the following reservoirs: Lakota, Fall River, Muddy Sandstone, Frontier Formation, and Turner Sandstone (Figure 2). Within the Powder River basin most of the Mowry oil is in stratigraphic traps. On basin margins, combination traps and structural traps dominate.

Abnormal pressure

Abnormal pressure in the Rocky Mountain region is generally related to hydrocarbon generation (Meissner et al., 1984). Drill stem test (DST) data is fairly common for the Muddy Sandstone. Drill stem test data for the Mowry Shale is very uncommon. Drill stem tests are a tool designed to obtain reservoir fluids, pressures, and temperatures. Figure 12 shows final shut in pressures converted to a pressure gradient in order to illustrate areas of overpressure in the Muddy Sandstone. The same overpressure is expected to occur in the Mowry Shale. An area of significant overpressure occurs in a

northwest trend across Converse County and into Campbell County. The area of strongest overpressure (>0.6 psi/ft) occurs in the southwest corner of Campbell County and northwest corner of Converse County. The highest overpressures are located south of the Belle Fourche Arch. Several new Mowry wells in this area (Crossbow Field area) had initial production of greater than 1,000 barrels of oil per day. Areas of overpressure in the deeper parts of the basin may be prospective for future Mowry drilling (Figure 12).

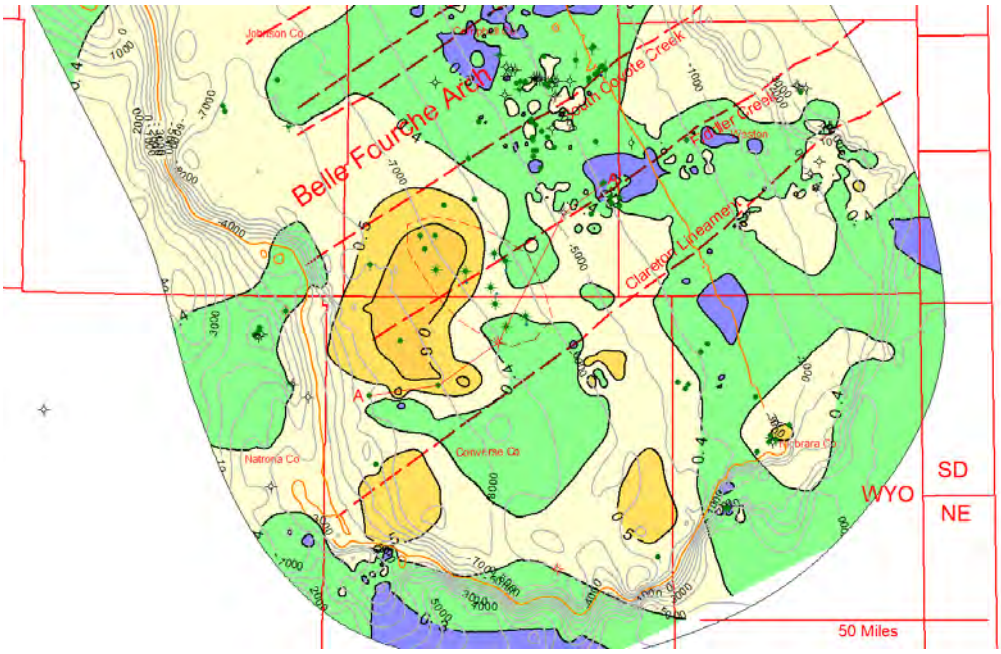

Figure 12. Pressure gradient map for Muddy Sandstone based on DST data. Also shown structure contour map top Muddy Sandstone. Dashed line shows location of new Mowry drilling in Crossbow field.

Production Deep Basin (Crossbow Field)

The Crossbow field area is recently drilled and completed in the Mowry Shale (Figure 1; Table 1). The field is located in Townships 41 and 42 North, Ranges 72 to 73 West (Figure 1). Drilling depths to the Mowry range from 11,049 ft to 12,585 ft. Average per well initial production for the area is 449 bbls oil per day and 2.3 MMCFGPD. Average per well estimated ultimate recovery is 140 MBO and 1.1 BCFG. Results are quite variable between wells. Production results are encouraging and future improved drilling and completion technologies should improve total production and overall economics. Most wells in the field area classify as gas wells based on their gas-oil ratios. Up dip from Crossbow the producing Mowry wells have lower gas-oil-ratios and are considered to be oil wells. Thus, an inverted petroleum system exists in the Mowry in the Powder River basin. A shallow up dip water leg passes down dip into an oil leg which transitions into a deeper wet gas leg.

Well #	Completion Date	Location (Sec., T, R)	IP Oil (bbls)	IP Gas (mcf)	IP GOR (ft3 per bbl)	Cum oil (bbls)	Cum gas (mcf)	Cum GOR (ft3 per bbl)	EUR OIL (bbls)	EUR GAS (mcf)
1-4MH	July 2014	S4-T42-R74	701	1104	1575	92299	303936	3293	158235	521067
1-2MH	Aug. 2015	S2-T42-R74	1103	1399	1268	148899	455577	3060	331935	1015721
1-15MH	July 2015	S19-T42-R74	289	513	1775	50902	264774	5202	89548	465828
Bates 36-2	April 1978	S36-T42-R74	78	643	8244	49313	385947	7826	49313	385947
204-1102H	June 2018	S11-T41-R73	1004	9207	9170	50092	531298	10606	NA	NA
1-21MH	Feb. 2015	S21-T42-R72	367	3261	8886	77233	1416545	18341	109423	200692
248-16H	Aug. 2012	S16-T41-R72	135	1687	12496	59743	1600152	26784	82354	220576
1-3526H	June 2013	S35-T42-R72	273	1755	6429	154737	3263215	21089	198684	4192232
26-2234H	Aug. 2014	S22-T41-R72	265	1480	5585	105332	1860045	17659	152553	2693933
210-23H	July 2013	S23-T40-R72	134	1800	13433	64212	858557	13371	82823	1238030
200-2116H	Oct. 2013	S21-T40-R71	587	2088	3557	109034	749764	6876	131601	904888
AVERAGE			449	2267	6583	87436	1062710	12192	138647	1183891

Table 1. Results from selected wells from Crossbow field area. Most wells in this field classify as gas wells based on gas oil ratio.

Unconventional Potential

Expulsion efficiency for the Mowry was calculated by Momper and Williams to be 7%. The 7% number was calculated by comparing the amount of generated volumes (170 billion barrels oil) with the discovered in-place oil, estimate of undiscovered oil, dispersal, escape, and thermal cracking volumes. Total Mowry oil expelled is estimated to be 11.9 billion barrels. A very small part of this expelled volume has been produced in fields sourced from the Mowry petroleum system (5%). Cumulative production from the Mowry petroleum system is estimated to be 630 million barrels of oil (Anna, 2009). Remaining undiscovered conventional oil was estimated by Anna (2009) to be 111 million barrels. Technically recoverable resources for the possible continuous or unconventional play area located in the deeper parts of the Powder River Basin was estimated to be 198 million barrels of oil and 198 billion cubic feet of gas (Anna, 2009). Investor presentations by EOG (2018) and Chesapeake (2018) estimate gross recoverable resource numbers for the Mowry Shale of 1.7 billion barrels equivalent and 570 million barrels equivalent, respectively, on their acreage positions in the Powder River Basin. The resource estimates, source rock maturity, Mowry thickness and facies, and geopressuring suggest the opportunity for a relatively large undiscovered continuous accumulation of large regional extent.

Summary

The Mowry Shale is one of the most important source rocks units in the Rocky Mountain region. The Mowry has sourced significant accumulations in Upper and Lower Cretaceous reservoirs. These reservoirs have been largely targeted using vertical wells.

New technology (horizontal drilling, multistage hydraulic fracture stimulation) are now commonly being applied to source rock plays. The Mowry represents a source rock play that is in the early stages of investigation. Keys to production will include: source rock maturity, reservoir brittleness, overpressure, TOC content, reservoir thickness, and presence of matrix and fracture porosity and permeability. The Mowry appears to possess these key attributes.

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PERMIAN BASIN SHALES

Beau Tinnin (EOG Resources) and Bo Henk (Pioneer Resources); updated by Ursula Hammes 2019 (Hammes Energy & Consultants)

The Permian Basin of southeast New Mexico and west Texas (Fig. 1) is currently one of the most prolific oil producing regions in the United States. It has produced more than 29 billion barrels of oil and 75 trillion cubic feet of gas (Texas RRC) since the early 1920s. Numerous experts agree that the Permian Basin contains significantly more recoverable resource in place than what has previously been produced to date. Overall, the Permian Basin spans an area of approximately 250 miles wide by 300 miles long. The basin can be divided into several distinct structural and tectonic regions with current drilling activity focused in two sub-basins, the Midland Basin and the Delaware Basin, which are both separated by the Central Basin Platform (Fig. 1). In a cross sectional view, the Permian Basin is highly asymmetric with the western Delaware Basin comprised of thicker and more structurally-deformed sediments than the eastern Midland Basin.

The Permian Basin is comprised of numerous vertically-stacked conventional reservoirs and organic-rich source rocks intervals with a vast majority of production coming from Permian and Pennsylvanian-aged units (Fig. 1). Traditionally, these formations have been developed with vertical wells and small hydraulic stimulations but more recently there has been a dramatic shift to horizontal drilling and large multi-stage hydraulic stimulations. As of May 8, 2019, there were 459 rigs running in the Permian Basin (data from Baker Hughes). But even with the falling rig count in the Permian Basin (Fig. 2), the basin's production has continued to climb (Fig. 3). Based on the U.S. EIA April 2019 Drilling Productivity Report, oil production has been steadily rising since 2010 when it was at approximately 900,000 barrels of oil per day and is now currently at approximately 2.4 million barrels of oil and 8.5Bcf of gas per day in 2018 (RRC, 2019; Fig. 3).

The substantial rise in oil production in the Permian Basin is directly tied to the uptick in horizontal well activity targeting tight oil formations. From 2008 to 2019 the horizontal rig count increased from 30% to 88% of all rigs drilled (Baker Hughes, 2019). Oil and gas companies are actively drilling horizontal wells targeting the Clear Fork, Spraberry, and Wolfcamp formations in the Midland Basin and targeting the Brushy Canyon, Bone Spring, Wolfcamp, Cisco, and Canyon formations in the Delaware Basin (Fig. 1).

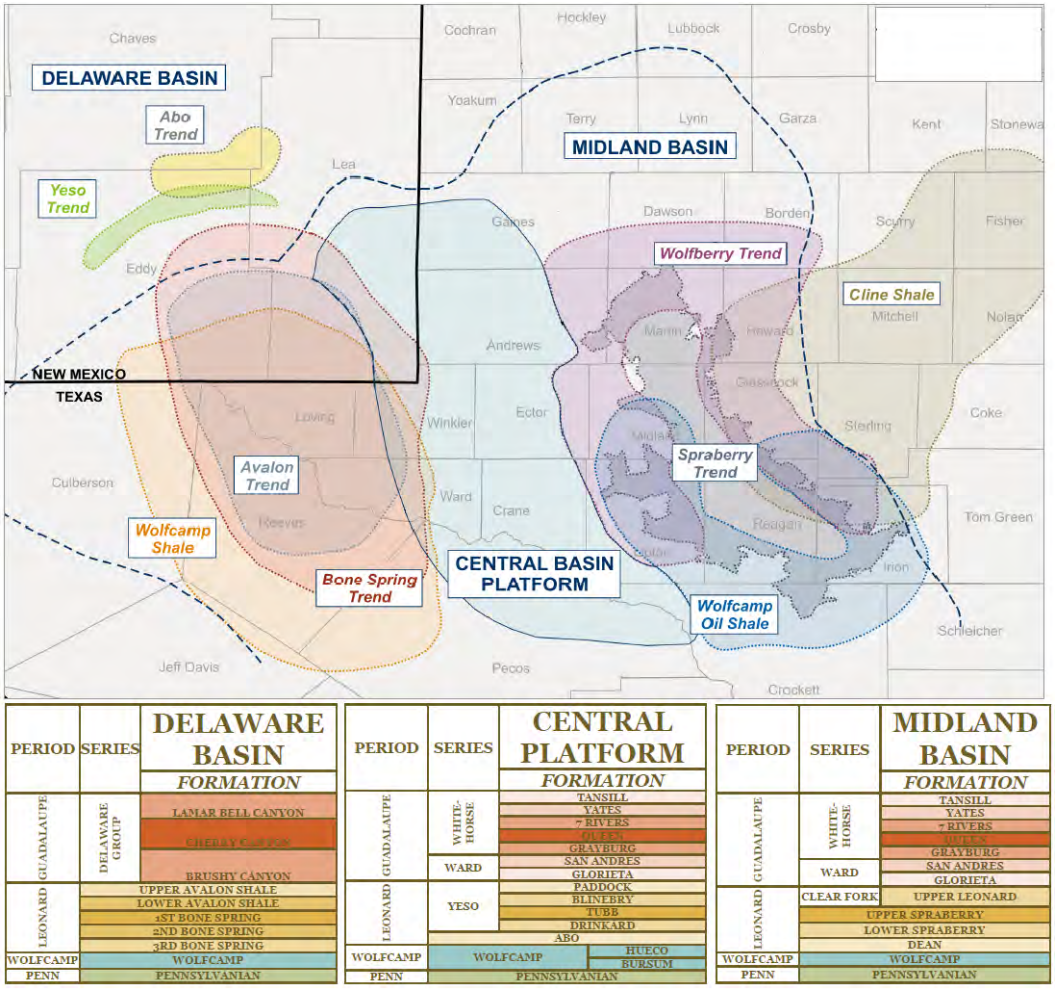

Figure 1: Map of the Permian Basin in southeast New Mexico and west Texas showing the major geologic and tectonic boundaries of the region with stratigraphy for each of the basins and the Central Basin Platform separating the Midland and Delaware Basins (from www.shaleexperts.com; accesses 5/8/2019).

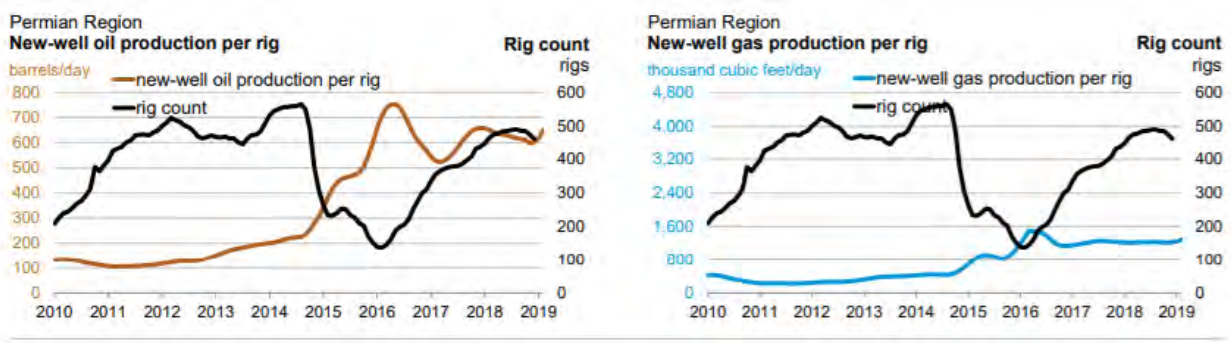

Figure 2: Permian Basin new well oil (left) and gas (right) production and rig count ranging from 2010 to 2019 (EIA, 2019). Rig count has steadily increased since the downturn 2014-2016. The spike in oil and gas production in 2016 is most likely relate to more efficient completion techniques and longer laterals.

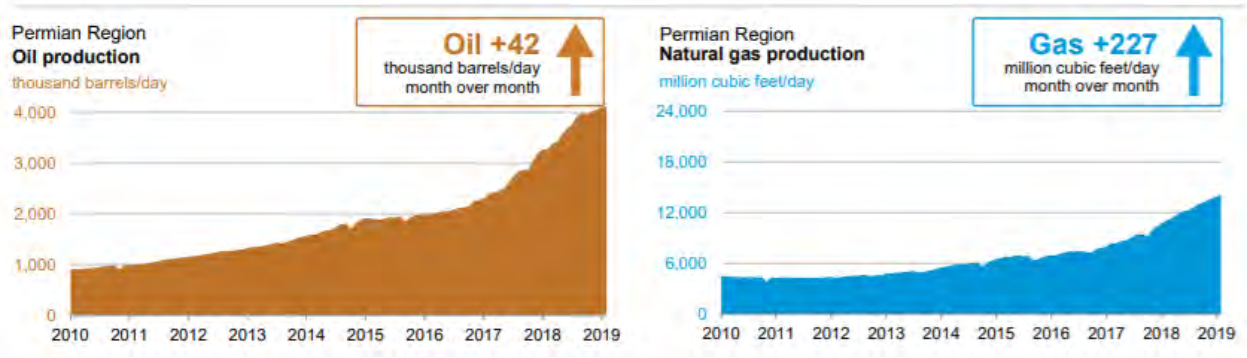

Figure 3: Oil (left) and gas (right) production in the Permian Basin from 2010 to 2019 has shown a steady increase to 4,000,000 barrels/day and 13+Bcf of gas per day to 2019 (from EIA, 2019).

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Tight-Oil Plays and Activities in Utah

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The dramatic crash of crude oil that occurred towards the end of 2014 continuing through 2018, coupled with ongoing low natural gas prices, has severely affected exploration and development of shale gas and liquids in Utah. Following on the success of the past shale gas boom elsewhere and employing many of the same well completion techniques, numerous petroleum companies had been exploring for liquid petroleum in shale formations in the state. In fact, many shales or low-permeable ("tight") carbonates targeted for natural gas include areas in which the zones are more prone to liquid production. Organic-rich shale zones in the Uinta and Paradox Basins have been the source for significant hydrocarbon generation, with companies traditionally targeting the interbedded sands or porous carbonate buildups for their conventional resource recovery. With the advances in horizontal drilling and hydraulic fracturing techniques, operators in these basins explored the petroleum production potential of the shale and interbedded tight sand and carbonate units themselves. Much of this potential remains and waits for oil and gas prices to rebound. However, some drilling activity occurred during 2017 and 2018 as well as research targeting shale gas and liquids plays in Utah.

Uinta Basin

Overview

The Uinta Basin is the most prolific petroleum province in Utah (Fig. 1). The basin is asymmetrical, paralleling the east-west trending Uinta Mountains. The basin is a major depositional and structural basin that subsided during the early Cenozoic along the southern flank of the Uinta Mountains. The north flank dips 10–35º southward into the basin and is bounded by a large north-dipping, basement-involved thrust fault. The southern flank gently dips between 4–6º north-northwest. Producing units include the Paleocene Flagstaff Limestone, Paleocene-Eocene Wasatch Formation (included with the Flagstaff in many company reports), Eocene Green River Formation (Fig. 2), and the Cretaceous Mesaverde Group; minor production is found in the deeper Cretaceous Mancos Shale. Zones within the Flagstaff through Green River, and the Mancos represent the main targets or potential for shale liquids and shale gas production in the Uinta Basin.

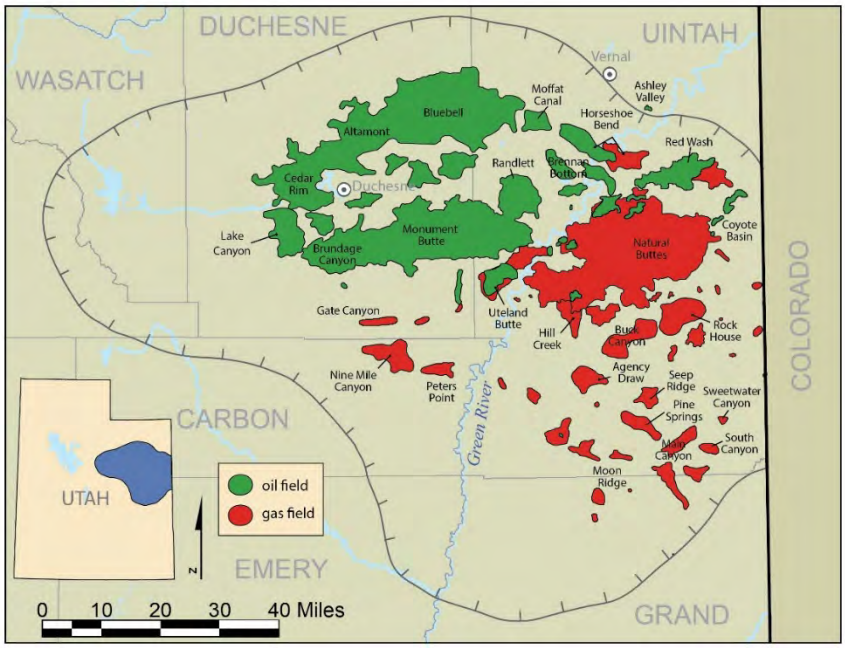


Figure 1. Oil and gas fields in the Uinta Basin of Utah and Colorado. Modified from Wood and Chidsey (2015).

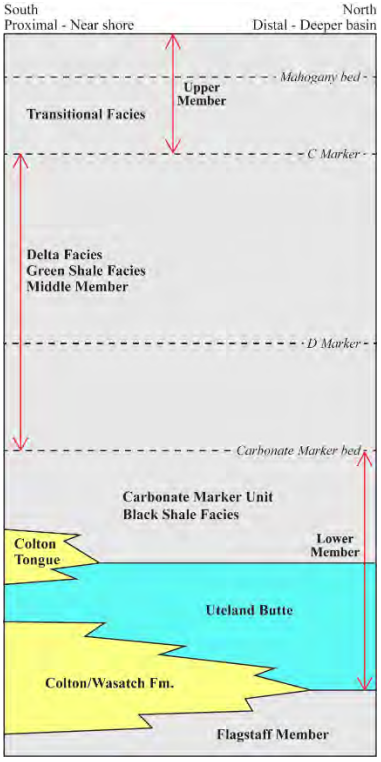


Figure 2. General stratigraphy of the Green River Formation in the western Uinta Basin (not to scale). The Uteland Butte Member, the primary horizontal drilling target in the basin, and its relationship to the Colton/Wasatch Formation is shown.

Paleocene Flagstaff Limestone

Lake deposits filled the Uinta basin between the eroding Sevier highlands to the west and the rising Laramide-age Uinta Mountains, Uncompahgre uplift, and San Rafael Swell to the north, east, and south, respectively. The upper Paleocene Flagstaff Limestone (Fig. 3A) was deposited in a large freshwater lake (Lake Flagstaff) that extended from the central part of the Uinta Basin through central and southwestern Utah. These strata included alluvial, marginal lacustrine, and open lacustrine carbonate facies (Fig. 3B). Lenticular sandstone bodies in the Flagstaff represent fluvial deposits associated with the lake system as clastic material was into the along all of its margins. Clastic deposits gradually displaced Lake Flagstaff northward until all that remained was a crescent-shaped lake, partially within the Uinta Basin (Fouch, 1975).

Paleocene-Eocene Colton / Wasatch Formations

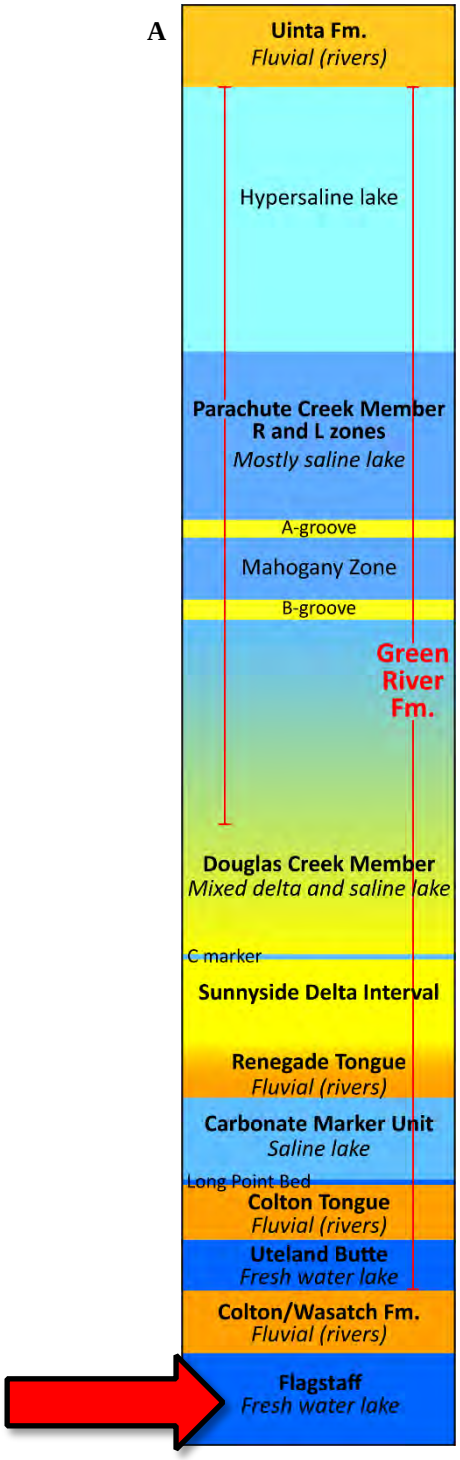
The Paleocene-Eocene Colton in the western Uinta Basin and Wasatch Formations in the eastern part of the basin are equivalent (Fig. 4A). The Colton and Wasatch Formations are often undivided in the Uinta Basin, but in the central and east parts of the basin the Wasatch is more distinguishable where it consists of red, yellow, and light gray friable sandstone, siltstone, mudstone, conglomerate, and minor interfingering limestone of the Flagstaff Limestone. The Colton consists of variegated mudstone and shaly siltstone interbedded with fine- to medium-grained quartzose sandstone (Fig. 4B). Producing reservoirs in both formations are typically thin and lenticular in sandstone bodies.

As the Uinta Mountains continued to rise during the late Paleocene and early Eocene, the alluvial Colton and Wasatch Formations began to fill the adjacent subsiding Uinta Basin, reaching a thickness of up to 3200 feet (Hintze and Kowallis, 2009). The Colton is mainly of alluvial origin, but also contains fluvial, deltaic, and marginal lacustrine deposits. It is referred to as the Colton fan-delta, which was associated with both freshwater Lake Flagstaff and the later Eocene-age Lake Uinta that occupied the Uinta Basin. The Wasatch Formation was deposited predominantly in a non-lacustrine alluvial plain environment, significantly beyond the margins of Lakes Flagstaff and Uinta (Fouch, 1975). This alluvial plain included fluvial channels, overbanks, and small lakes and ponds. Channels were eventually sand filled and commonly encased by thin clay beds, creating small traps for hydrocarbons suppled later when regional fracturing provided migration pathways from Cretaceous source rocks below.

Eocene Green River Formation and the Wasatch/Colton Tongue

Lake Uinta formed during the Eocene within Utah's Uinta Basin and Colorado's Piceance Creek Basin and is represented by the Green River Formation. The Green River consists of as much as 6000 ft of sedimentary strata (Hintze and Kowallis, 2009; Sprinkel, 2009) and contains three major depositional facies associated with Lake Uinta sedimentation: alluvial, marginal lacustrine, and open lacustrine (Fouch, 1975). The marginal lacustrine facies, where most of the hydrocarbon production is found, consists of fluvial-deltaic, interdeltaic, and carbonate flat deposits, including microbial carbonates. The open-lacustrine facies is characterized by nearshore and deeper water offshore muds, including the famous Mahogany oil shale zone which represents Lake Uinta's highest water level.

A



B

Figure 3. Flagstaff Limestone: A – stratigraphic section, B – core from the 9-4B1 Ute Tribal well. Note the abundant shell fragments indicating deposition in a freshwater lacustrine environment.

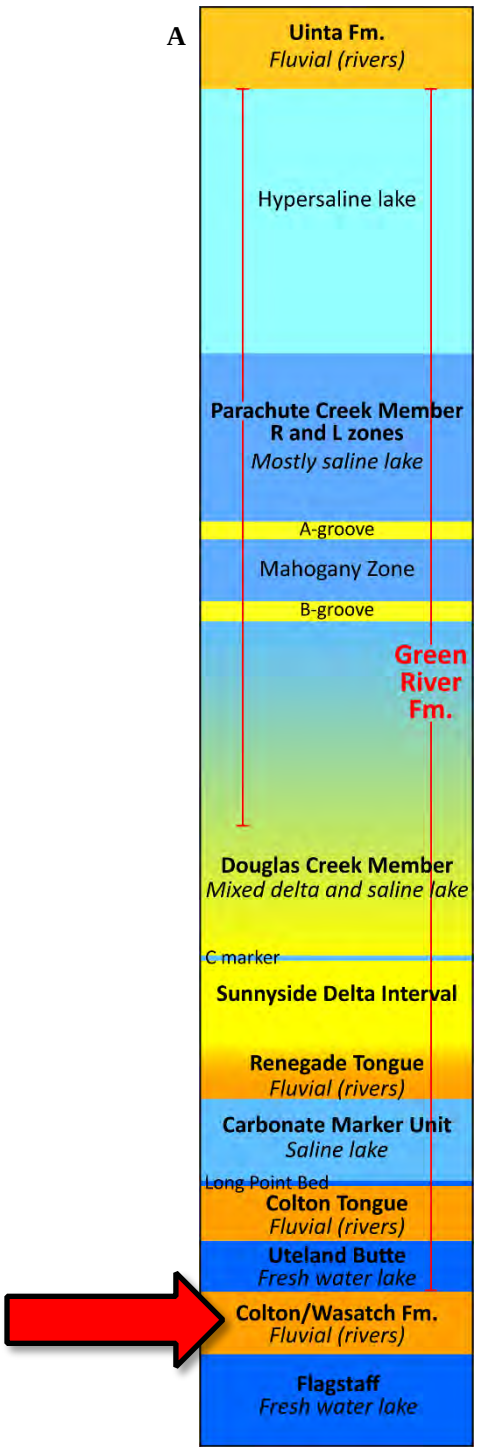


Figure 4. Colton/Wasatch Formation: A – stratigraphic section, B – typical outcrop, Nine Mile Canyon.

The Uteland Butte Member of the lower Green River Formation (Fig. 5A) records the first major transgression of Eocene Lake Uinta after the deposition of the alluvial Colton Formation, and thus it is relatively widespread in the basin. The oil-bearing, low-permeability, Uteland Butte is being exploited with horizontal drilling techniques and has similar in characteristics to the Late Devonian to Early Mississippian Bakken Shale of the Williston Basin. The Uteland Butte ranges in thickness from less than 60 ft to more than 200 ft, and consists of limestone, dolomite, organic-rich calcareous mudstone, siltstone, and rare sandstone (Figs. 5B and 5C). The thin dolomite (Figs. 5C and 5D), the

horizontal drilling target, often has more than 20% porosity, but is so finely crystalline that the permeability is very low (single mD or less).

The Wasatch/Colton Tongue or Castle Peak overlies the Uteland Butte (Figs. 2 and 6A) and consists of fluvial sandstones, siltstones, mudstones, and red beds (Fig. 6B). It represents a regression of Lake Uinta along a shallow margin in the south and a very steep margin in the north. Sandstones are fine grained, cross-bedded to planar-bedded, lenticular, and discontinuous.

Upper Cretaceous Mancos Shale

Although much older and representing deposition before creation of the Uinta Basin, the Upper Cretaceous Mancos Shale represents an important target for the development of shale gas and liquids in the basin. The shallow marine, 3400 to 5500-ft-thick Mancos, including its subunits (Fig. 7), was deposited in the Western Interior Seaway in the foredeep basin east of the Sevier orogenic belt, and intertongues westward with coarser-grained clastic sediments shed from the belt. The Mancos consists of dark gray calcareous mudstone with interbeds of silt to very fine sandstone. However, some units have high total organic carbon with dense, non-fissile, dark gray claystone and scattered, light gray silt laminae and bivalve fragments. Average porosities range 3.5% to 8.7% and do not vary with depth or geographical location in the basin; average permeabilities range from 0.03 to 164 nanodacies (Ressetar, 2017).

Activity

Tight-oil drilling and exploration activities in the Uinta Basin have focused on the Uteland Butte Member of the Green River Formation, particularly in an area referred to as the “Central Basin region” between Altamont-Bluebell field to the north and Monument Butte field to the south (Figs. 1 and 8A). The Uteland Butte has historically been a secondary oil objective of wells tapping shallower overlying Green River reservoirs and deeper fluvial-lacustrine Colton Formation sandstone units in the western Uinta Basin. Other major horizontal drilling targets include the Castle Peak and the upper Wasatch (Flagstaff Limestone) Formations. Horizontal drilling began in earnest in 2010 and the first long-reach (10,000 ft plus) horizontal well in the Uinta Basin was drilled in 2013. By the close of 2018, there were approximately 285 horizontal wells in the basin. The use of slick-water hydraulic fracturing techniques has greatly improved completion and recovery results estimated between 20 and 60 million bbls per section or 350,000 to 400,000 BO/well. Initial production ranges from less than 150 BO/D to greater than 2000 BO/D (Fig. 8). Well spacing ranges from 2 to 8 wells per section depending on the objectives. The acquisition of three-dimensional seismic data, microseismic programs on wells, oil/water/proppant determination, and cores have provided the input for better rock mechanics and fracturing modeling.

Several companies (Newfield Exploration, LINN, Bill Barrett Corporation, Crescent Point Energy Corporation, QEP Resources, Petroglyph Energy, Inc., and Axia Energy II) targeted the Uteland Butte with horizontal wells in both the central, normally pressured part of the basin near Greater Monument Butte field, and farther north in the overpressured zone in western Altamont field (Fig. 8B).

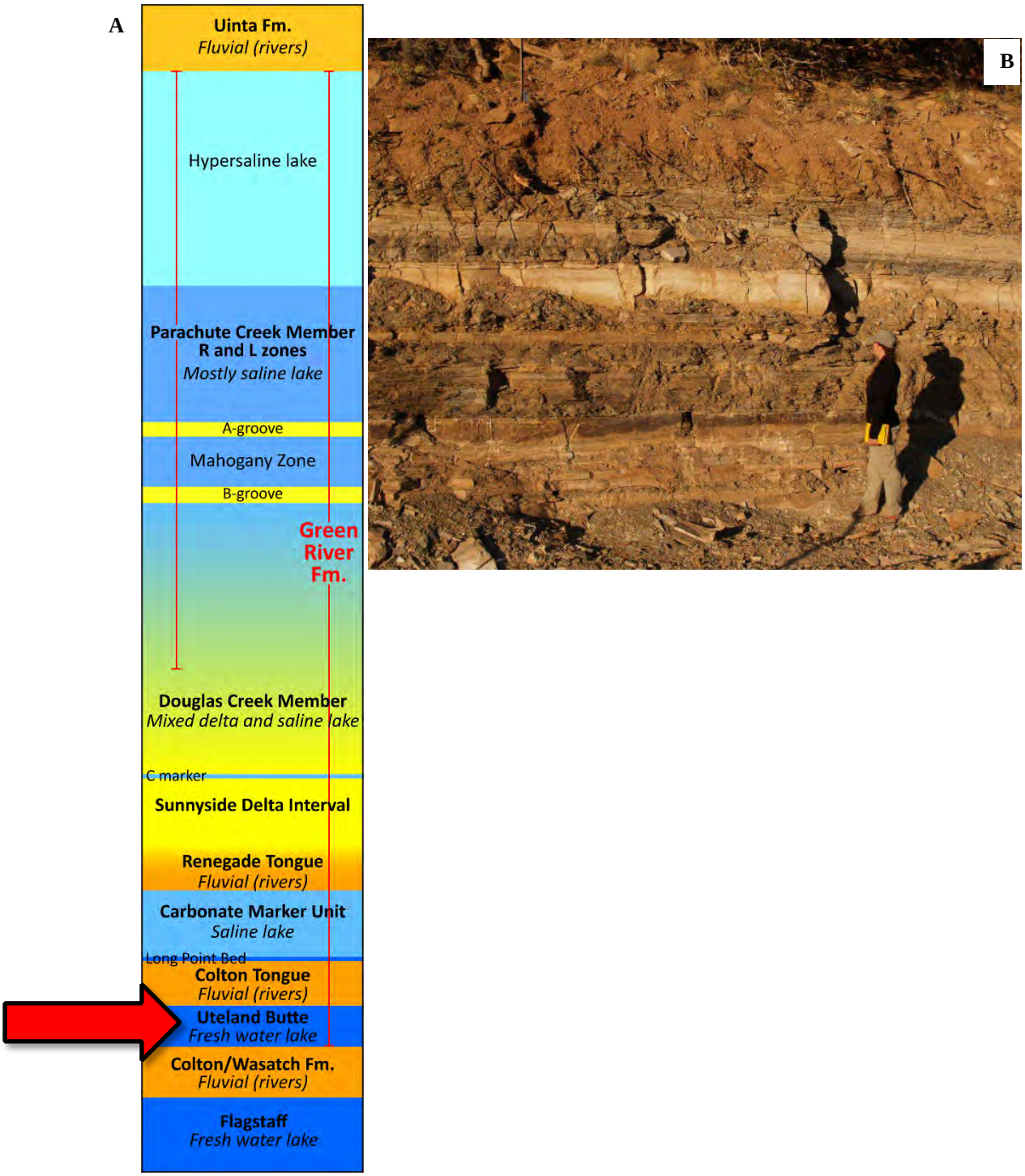


Figure 5. Uteland Butte Limestone: A – stratigraphic section, B – typical outcrop, Nine Mile Canyon. Porosity ranges from 15 to 30% and permeability averages 0.06 mD. The dolomite is interbedded with organic-rich shale, mudstone, and limestone averaging between 1% and 3% TOC. Note the abundant shell fragments in C and D indicating deposition in a freshwater lacustrine environment.

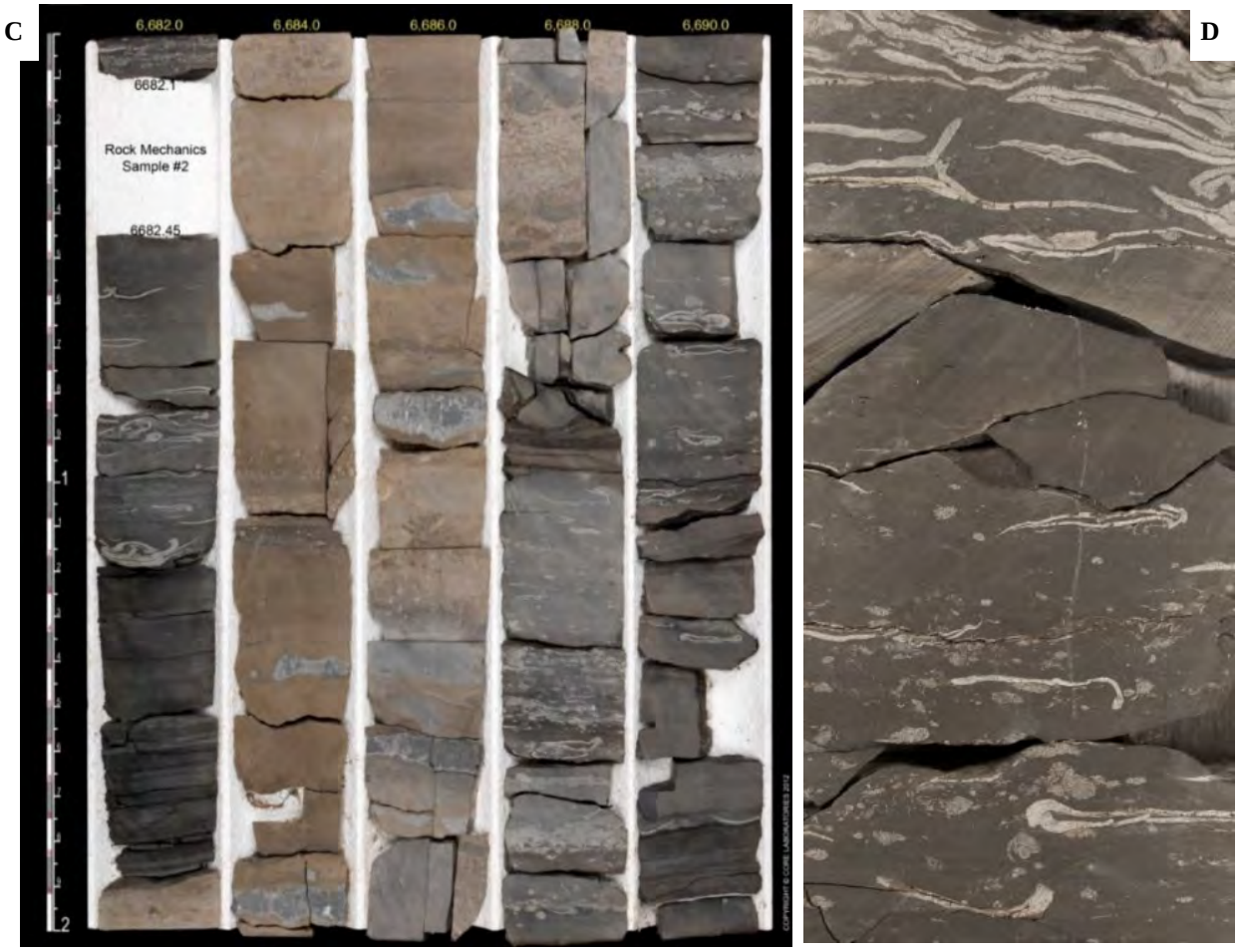


Figure 5 continued. Uteland Butte Limestone: C – core from the Bill Barrett 14-1-46 well. The horizontal drilling target is the roughly 5-ft-thick, light brown dolomitic interval, and D – closeup of dolomite reservoir. Porosity ranges from 15 to 30% and permeability averages 0.06 mD. The dolomite is interbedded with organic-rich shale, mudstone, and limestone averaging between 1% and 3% TOC. Note the abundant shell fragments in C and D indicating deposition in a freshwater lacustrine environment.

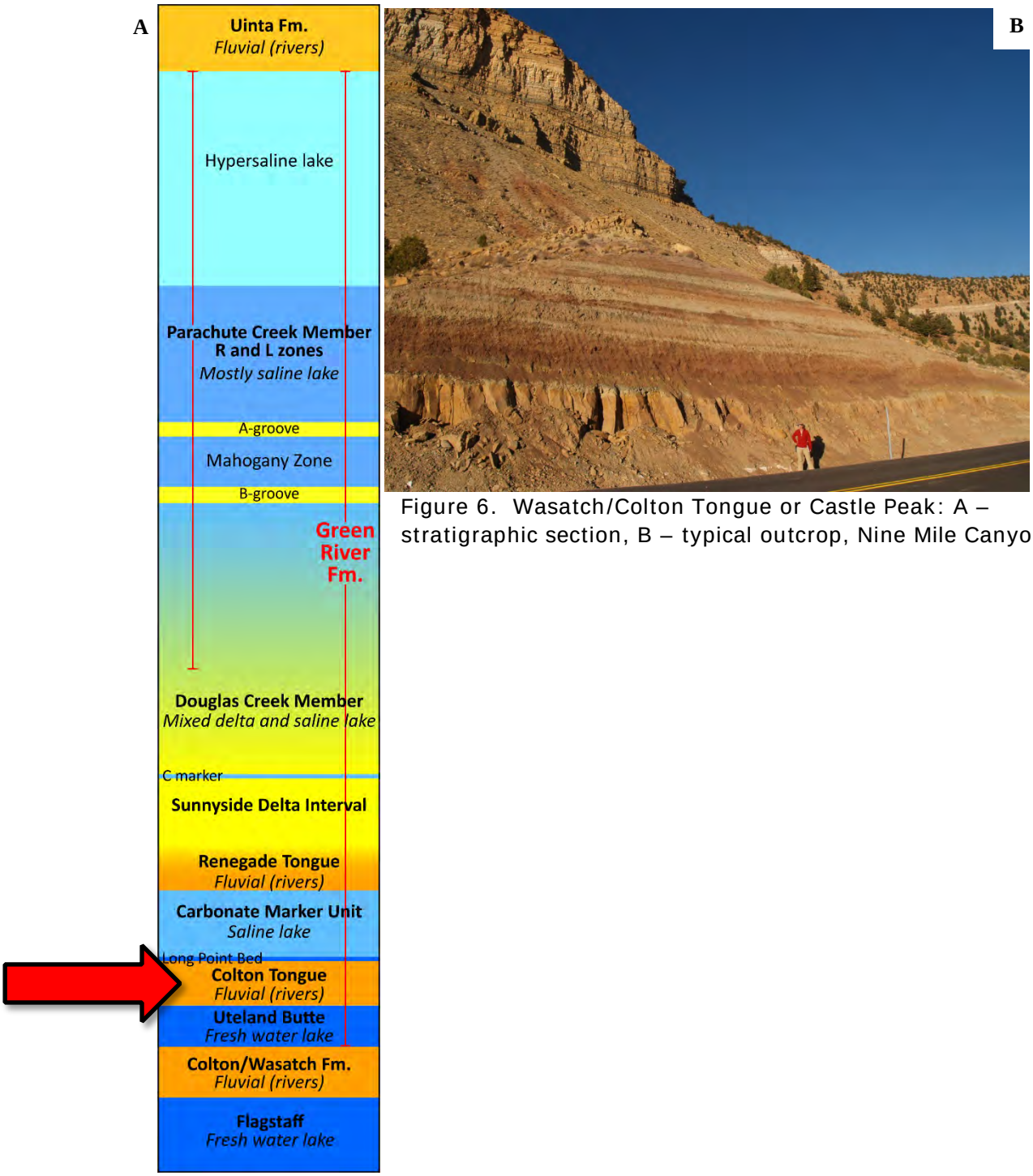


Figure 6. Wasatch/Colton Tongue or Castle Peak: A – stratigraphic section, B – typical outcrop, Nine Mile Canyon.

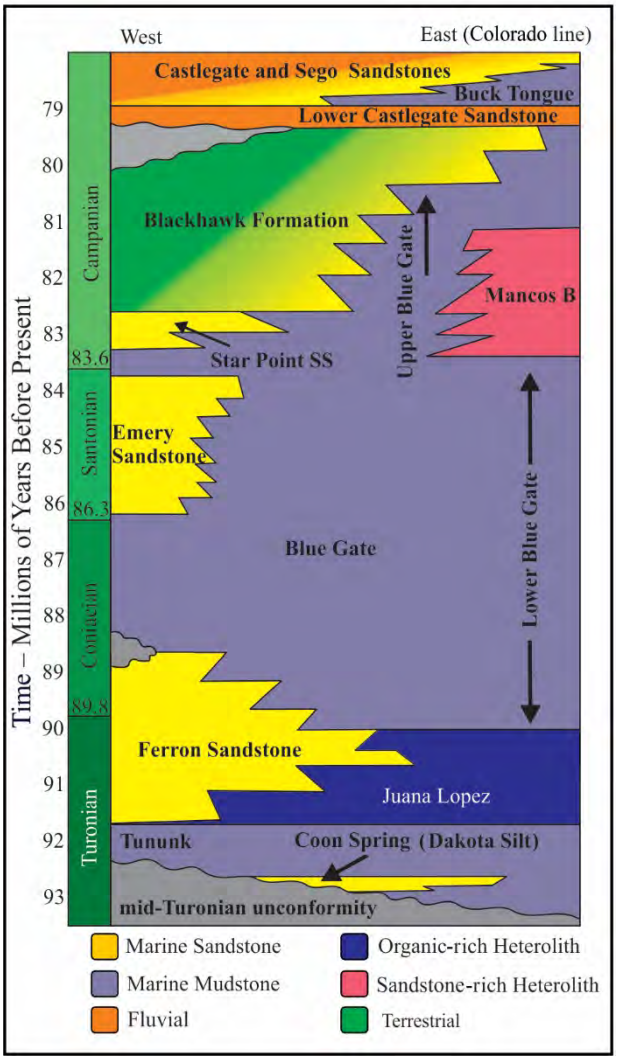


Figure 7. Stratigraphic relations of the Mancos Shale, its subunits, and adjacent formations in the Uinta Basin. After Birgenheier and others (2015).

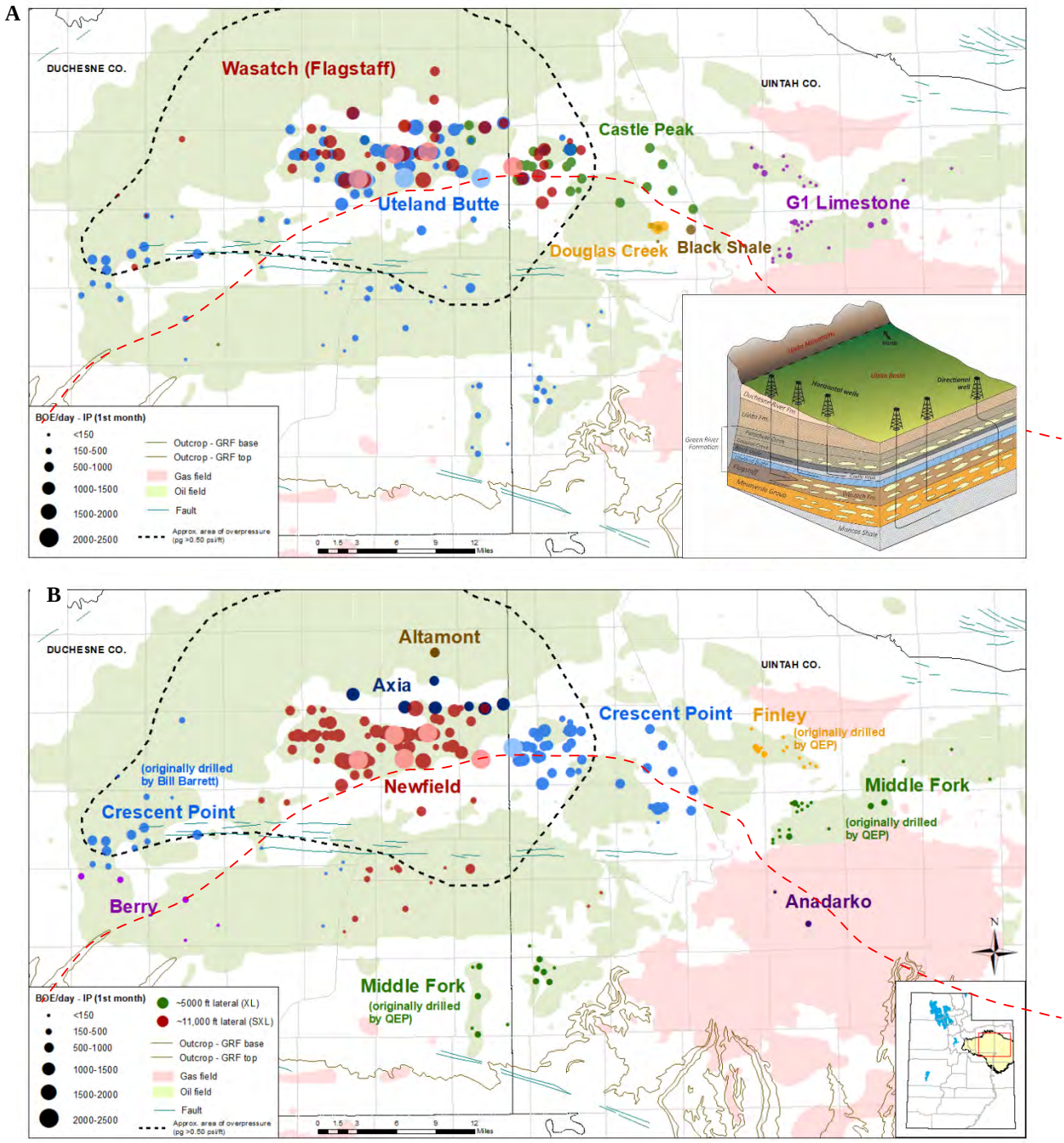


Figure 8. Initial production (first month BOE/day) of horizontal wells in the Uinta Basin by A – drilling target (inset schematic of horizontal drilling targets), and B – by operator.

During 2017 and 2018, there were 115 and 188 wells, respectively, spudded in the Uinta Basin (over 100 more wells than in 2016) some of which had the Uteland Butte as the primary objective. In 2016, Axia proposed 15 long-reach horizontal wells in the Central Basin region. They were designed to evaluate the Uteland Butte from two common drillpads (10 wells – SESE section 32, T. 2 S., R. 2 W., and 5 wells – NWNW

section 4, T. 3 S., R. 1 W., Uintah Baseline & Meridian [UBL&M], Duchesne County). Two wells were drilled in 2016 from the pad in section 4, but no details have been provided. In 2017, the Butcher Butte No. 32-144H-21 was drilled from the pad in section 32; again no information is available (Rocky Mountain Oil Journal, 2017a). In 2018 Newfield completed the Oats UT No. 2-26 3-3-23-14-1H (NWNE section 26, T. 3 S., R. 3 W., UBL&M, Duchesne County), in the Uteland Butte for 2432 BOPD, one of the highest initial production (IP) rate horizontal well in the Uinta Basin (Rocky Mountain Oil Journal, 2018a). Newfield also completed a second horizontal test, the Oats UT No. 2-26 3-3-23-14-12H, from the same drillpad in the Wasatch Formation (Flagstaff Limestone) for 1387 BOPD. Crescent Point drilled 23 horizontal wells in the Uinta Basin in 2018. For example, along the flank of Independence field, Crescent Point completed the Kendall No. 2-18-3-1E-H4 (SWSE section 7, T. 3 S., R. 1 E., UBL&M, Uintah County), in the Uteland Butte for 310 BOPD (Rocky Mountain Oil Journal, 2018b). The operator completed the Kendall No. 2-18-3-1E-H2 from the same pad in 2017 in the Castle Peak; the well as produced over 126,000 BO as of December 31, 2018 (Utah Division of Oil, Gas and Mining, 2019). Crescent Point also targeted the Castle Peak in 2017 with a long-reach horizontal well: the CPG No. 1-26-35-3-1 W-H1 (NWSE section 26, T. 3 S., R. 1 E., UBL&M, Uintah County) (Rocky Mountain Oil Journal, 2019) with an IP of 158 BOPD and cumulative production of more than 274,000 BO as of December 31, 2018 (Utah Division of Oil, Gas and Mining, 2019).

Limited activity for the Mancos Shale has occurred in the eastern part of the basin. The Mancos has produced oil and gas where it also has mainly been a secondary objective in wells targeting tight-gas sands in the Mesaverde and Wasatch sections above. In 2017, KGH Operating partnered with Whiting Oil and Gas to drill the Bonanza State No. 20-15H well (SWSE section 20, T. 9 S., R. 25 E., Salt Lake Baseline & Meridian [SLBL&M], Uintah County, Utah) to presumably test the Mancos Shale as well as Mesaverde zones above; results have not been reported. A mile to the southwest is KGH's No. 28-13 State well (SWSW section 28, T. 9 S., R. 25 E., SLBL&M, Uintah County) that has produced 5812 BO and 36.2 MMCFG as of December 31, 2018, from the Mancos B (Fig. 7) (Rocky Mountain Oil Journal, 2017b; Utah Division of Oil, Gas and Mining, 2019a). In 2018, Del-Rio Resources of Vernal, Utah, staked a horizontal Mancos test, the State No. 4H-36-13-11 (NWNW section 36, T. 13 S., R. 22 E., SLBL&M, Uintah County), near Seep Ridge field (Fig. 1) in the southeastern part of the Uintah Basin (Rocky Mountain Oil Journal, 2018c); no activity has been reported.

Future drilling in the Uinta Basin may be affected by the 2018 merger of Newfield, the major operator of Monument Butte field and the Central Basin region, with Calgary-based Encana Corporation. Encana will now control 220,000 net acres and operate about 1500 wells. Also in 2018, QEP announced the sale of its oil and gas producing properties, undeveloped acreage, and related assets to Denver-based Middle Fork Energy Partners, LLC.

Paradox Basin

Overview

The Paradox Basin is located mainly in southeastern Utah and southwestern Colorado with small portions in northeastern Arizona and the northwestern corner of New Mexico. The Paradox Basin is an elongate, northwest-southeast-trending, evaporitic basin that predominately developed during the Pennsylvanian, about 330 to 310 Ma. The basin was bounded on the northeast by the Uncompahgre Highlands as part of the Ancestral Rockies. As the highlands rose, an accompanying depression, or foreland basin, formed to the southwest—the Paradox Basin. Rapid basin subsidence, particularly during the Pennsylvanian and continuing into the Permian, accommodated large volumes of evaporitic and marine sediments that intertongue with non-marine arkosic material shed from the highland area to the northeast. Deposition in the basin produced a thick cyclical sequence of carbonates, evaporites, and organic-rich shale of the 500- to 5000-ft-thick Pennsylvanian Paradox Formation (Hintze and Kowallis, 2009).

Rasmussen (2010) divided the middle part of the Paradox Formation in the evaporite basin into as many as 35 salt cycles, some of which onlap onto the basin shelf to the west and southwest (Fig. 9). Each cycle consists of a clastic interval/salt couplet. The clastic intervals are typically interbedded dolomite, dolomitic siltstone, anhydrite, and black, organic-rich shale—the sources of the petroleum in the basin. The clastic intervals typically range in thickness from 10 to 200 ft and are generally overlain by 200 to 400 ft of halite.

The Paradox Basin can generally be divided into three areas: the Paradox fold and fault belt in the north, the Blanding sub-basin in the south-southwest, and the Aneth platform in the southernmost part in Utah. The area now occupied by the Paradox fold and fault belt was the site of greatest Pennsylvanian/Permian subsidence and salt deposition. Folding in the Paradox fold and fault belt began as early as the Late Pennsylvanian as sediments were laid down thinly over, and thickly in areas between, rising salt. Spectacular salt-cored anticlines extend for miles in the northwesterly trending fold and fault belt. Reef-like buildups or mounds of carbonates consisting of algal bafflestone and oolitic/skeletal grainstone fabrics in the Desert Creek and Ismay zones of the Paradox Formation are the main hydrocarbon producers in the Blanding sub-basin and Aneth platform. Oil in these zones is sourced above, below, or within the organic-rich Gothic, Chimney Rock, Hovenweep, and Cane Creek shales (Fig. 9).

The Cane Creek shale records an early stage of a transgressive-regressive sequence (cycle 21) in the Paradox Formation and consists of organic-rich marine shale with interbedded dolomitic siltstone and anhydrite (Fig. 10). The unit is up to 160 ft thick and aerially extensive within the Paradox Basin. It is divided into the A, B, and C zones, with the shale and silty carbonates of the B zone considered both the source rock and reservoir. The A and C zones are anhydrite rich and provide an upper and lower seal to the B zone. The unit is

highly overpressured, with measurements ranging between 5000 and 6200 psi, which is probably the result of hydrocarbon generation between very impermeable upper and lower anhydrite seals. The B zone is naturally fractured, and oriented cores show that fractures trend northeast-southwest, matching the regional structural trend.

Activity

The Cane Creek shale of the Paradox Formation has been a target for tight-oil exploration on and off since the 1960s and produces oil from several small fields (Fig.11). The play generated much interest in the early 1990s with the successful use of horizontal drilling. Currently, ten active fields produce from the Cane Creek in the Paradox Basin fold-and-fault belt. Cumulative production from active, shut-in, and abandoned Cane Creek fields is over 8.7 million bbls of oil and 8.6 BCF of gas as of December 31, 2018 (Utah Division of Oil, Gas, and Mining, 2019b). The Cane Creek and other Paradox shale zones have been targeted for exploration using horizontal drilling.

The U.S. Geological Survey (2012), Whidden and others (2014), and Anna and others (2014) re-assessed the undiscovered oil resource in the Cane Creek shale at 103 million barrels at a 95% confidence level and 198 million barrels at a 50% confidence level. In addition to the Cane Creek, several other organic-rich shale zones are present in the Paradox Formation, creating the potential for significant resource base additions. The Gothic, Chimney Rock, and Hovenweep shales (Fig. 9) in the Blanding sub-basin and Aneth platform are estimated to hold an undiscovered oil reserve of 126 million barrels at a 95% confidence level and 238 million barrels at a 50% confidence level (U.S. Geological Survey, 2012; Anna and others, 2014; and Whidden and others, 2014).

Fidelity Exploration & Production Company, the major operator in the Cane Creek play for several years, estimated that with extended horizontal drilling the estimated ultimate recovery could be as much as 1.7 million bbls of oil per well (IHS Inc., 2014). Fidelity completed the 24-mile, 12-inch diameter Dead Horse Lateral gas pipeline gathering system and Blue Hill gas plant so gas produced from the Cane Creek is now being sold instead of being flared as it was for many years. In 2016, Fidelity sold their holdings to Wesco Operating Incorporation. Joint-venture partners Kirkwood Resources and NERD Energy, under the name of Wesco Operating Company, bought leases (more than 50,000 acres of state and federal lands), 14 producers, and other interests in 2016 from Fidelity Exploration & Production in the Big Flat field area (Fig. 11) (Rocky Mountain Oil Journal, 2017c).

Cane Creek drilling activity reported in 2017 and 2018 was limited due to continued depressed oil prices and lower than expected flow rates in recent wells. In late 2017, Wesco horizontally drilled the No. 8-2-26-20 well (SENW section 8, T. 26 S., R. 20 E., SLBL&M, Grand County) in Big Flat field, the first well in the area in several years flowing 364 BOPD (Rocky Mountain Oil Journal, 2018d). Wesco received approval to drill the TMU No. 21-21D well (NESW section 21, T. 29 S., R. 22 E., SLBL&M, San Juan County) targeting the

Mississippian Leadville Limestone and presumably the Cane Creek shale, both of which produce at nearby Hatch Point field (Fig. 11). A drilling permit for Liberty Pioneer Energy Sources Lippincott No. 32 ST 1H well (NENW section 32, T. 30 S., R. 24 E., SLBL&M, San Juan County), originally permitted in 2015, was rescinded due no drilling or other activity at the wellsite (Rocky Mountain Oil Journal, 2017d). In 2018, Wesco staked the La Sal No. 2 well (SWSW section 22, T. 29 S., R. 23 E., SLBL&M, San Juan County) offsetting the 2011 horizontal Cane Creek discovery made by the La Sal No. 29-28 well (SESE section 22, T. 29 S., R. 23 E., SLBL&M, San Juan County) which has produced about 6100 BO as of December 31, 2018 (Rocky Mountain Oil Journal, 2018e; Utah Division of Oil, Gas and Mining, 2019). Rose Petroleum permitted two wildcats in the northern part of the Paradox Basin targeting the Cane Creek with horizontal drilling: the GVU No. 29-1 (NESE section 29, T. 22 S., R. 18 E., SLBL&M, Grand County) and GVU No. 21-1 (NWSW section 22, T. 22 S., R. 17 E., SLBL&M, Grand County). The nearest Cane Creek production is at Greentown field (Fig. 11) which has produced over 92,000 BO as of December 31, 2018 (Rocky Mountain Oil Journal, 2018f; Utah Division of Oil, Gas and Mining, 2019).

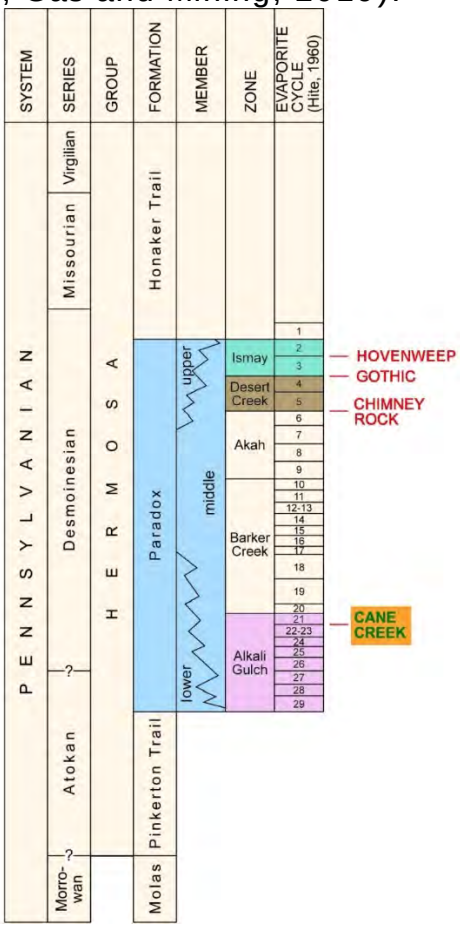


Figure 9. Pennsylvanian stratigraphic chart for the Paradox Basin, informal organic-rich shale units are highlighted. Note the position of the Cane Creek shale. Modified from Hite (1960), Hite and Cater (1972), and Reid and Berghorn (1981).

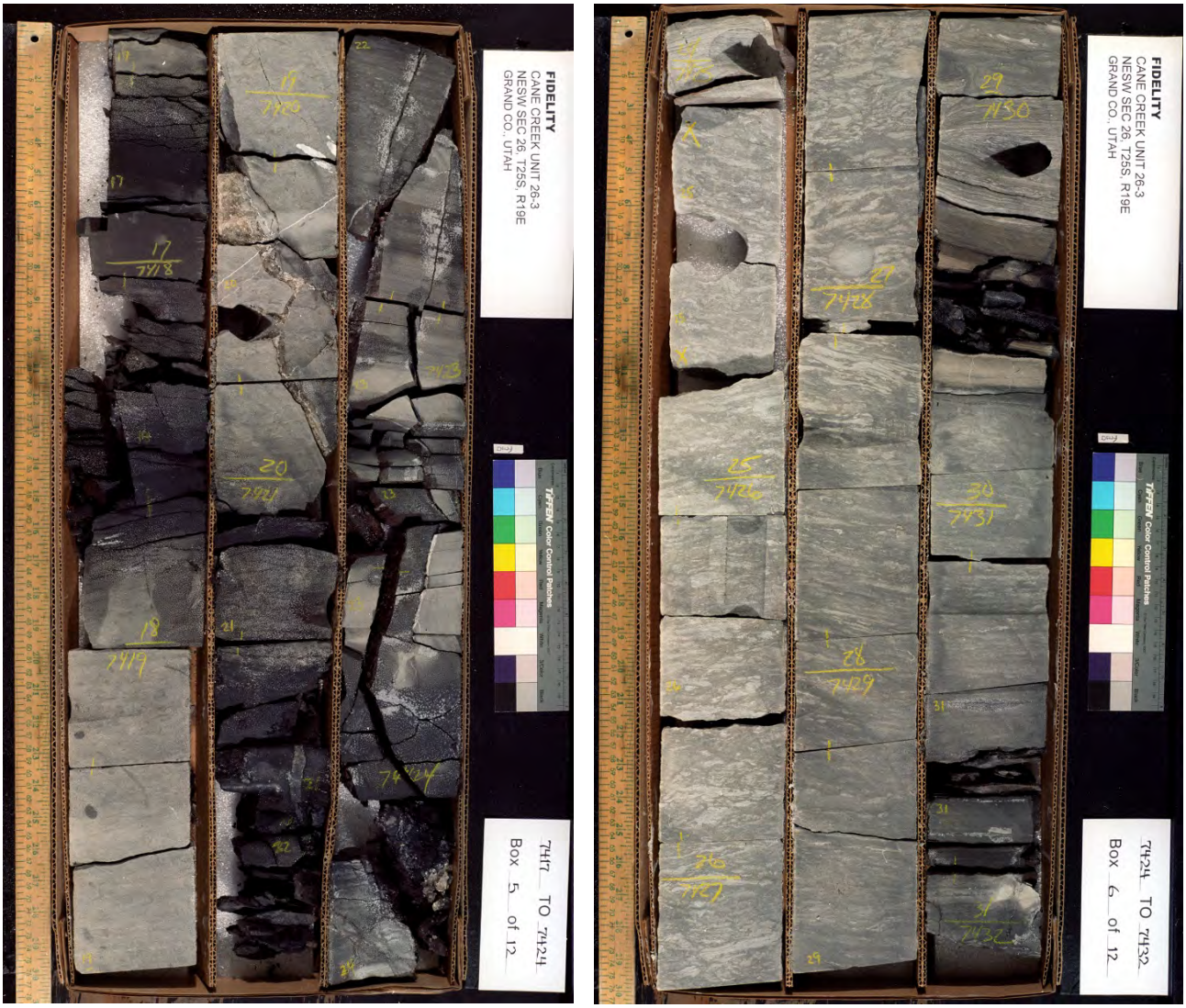


Figure 10. Typical fractured, silty to muddy dolomite (finely crystalline) with thin siltstone and back organic-rich shale beds of the productive B interval in the Cane Creek shale; also present is mottled light gray to white anhydrite. Cane Creek Unit No. 26-3 well (section 26, T. 25 S., 19 E., SLBL&M), Big Flat field, San Juan County, Utah, slabbed core from 7418 to 7432 ft. Core photography by Triple O Slabbing, Denver, Colorado, provided courtesy of Fidelity Exploration & Production Company.

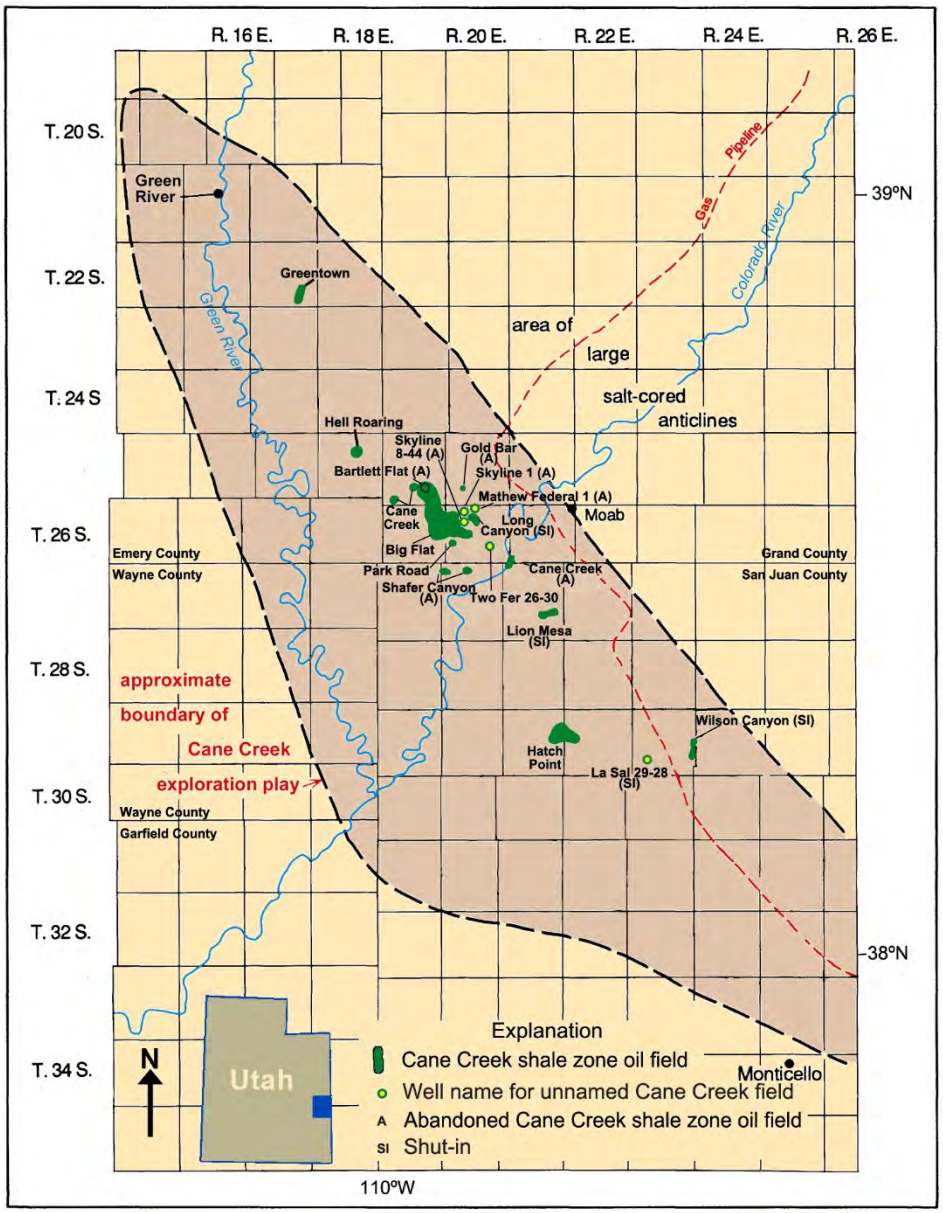


Figure 11. Location of fields that produce oil from the Cane Creek shale of the Pennsylvanian Paradox Formation, northern Paradox Basin, Utah. Play area shown in light brown.

Resent Research

The Utah Geological Survey (UGS), with funding from the National Energy Technology Laboratory, U.S. Department of Energy (DOE), completed a four-year project titled "Liquid-Rich Shale Potential of Utah's Uinta and Paradox Basins: Reservoir Characterization and Development." The overall goals of this study are to provide reservoir-specific geological and engineering analyses of the (1) emerging Green River Formation tight-oil plays (such as the Uteland Butte Limestone Member, Black Shale facies, deep Mahogany zone, and other deep

Parachute Creek member high-organic units) in the Uinta Basin, and (2) the established, yet understudied Cane Creek shale (and possibly other shale units such as the Gothic and Chimney Rock shale zones) of the Paradox Formation in the Paradox Basin. To accomplish these goals, the project:

- Characterized geologic, geochemical, and petrophysical rock properties of target zones in the two designated basin areas by compiling various sources of data and by analyzing newly acquired and donated core, well logs, and well cuttings.
- Described outcrop reservoir analogs of Green River Formation plays and compared them to subsurface data (not applicable in the Paradox Basin since the Cane Creek shale is not exposed).
- Mapped major regional trends for targeted liquid-rich intervals and identified “sweet spots” that have the greatest oil production potential.
- Suggested techniques to reduce exploration costs and drilling risks, especially in environmentally sensitive areas.
- Improved drilling and fracturing effectiveness by determining optimal well completion design.
- Suggested techniques to reduce field development costs, maximize oil recovery, and increase reserves.

The project developed and made available geologic and engineering analyses, techniques, and methods for exploration and production from the Green River Formation tight-oil zones and the Paradox Formation shale zones where operations encounter technical, economic, and environmental challenges.

In addition to a thorough geologic characterization of the target zones, tests were performed to characterize the geomechanical properties of the zones of interest to inform/guide well completion strategies. The brittle characteristics of the target intervals were studied in detail using energy-based calculations. This approach acknowledges both mechanical properties and in-situ stress conditions, as well as geometric lithologic constraints and the mineralogy that regulates fracturing. The study established a template for more effective well planning and completion designs by integrating the geologic characterization and formation evaluation with state-of-the-art rock mechanical analyses. This will help companies access oil they know is present, but technically difficult to recover.

To aid in the identification of hydrocarbon “sweet spots,” novel concepts for exploration were employed, such as the use of low-cost, low-environmental impact, epifluorescence analysis of regional core and well cuttings. Epifluorescence microscopy is a technique used to provide information on diagenesis, pore types, and organic matter (including “live” hydrocarbons) within sedimentary rocks. It is a rapid, non-destructive procedure that uses a petrographic microscope equipped with reflected-light capabilities, a mercury-vapor light, and appropriate filtering. Epifluorescent intensities obtained from core and cuttings were mapped to help identify areas with potential for significant hydrocarbon production. The detailed reservoir characterization and

rock mechanics analyses provided the basis for identification of "sweet spots" and improve well completion strategies for these undeveloped and under-developed reservoirs.

For more information about this project, including available posters and talks (in pdf), refer to the Utah Geological Survey's project website: https://geology.utah.gov/resources/energy/oil-gas/shale-oil.

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UTICA SHALE, OHIO, PENNSYLVANIA, WEST VIRGINIA, KENTUCKY

Richard Nyahay, Nyahay Geosciences, LLC, New York

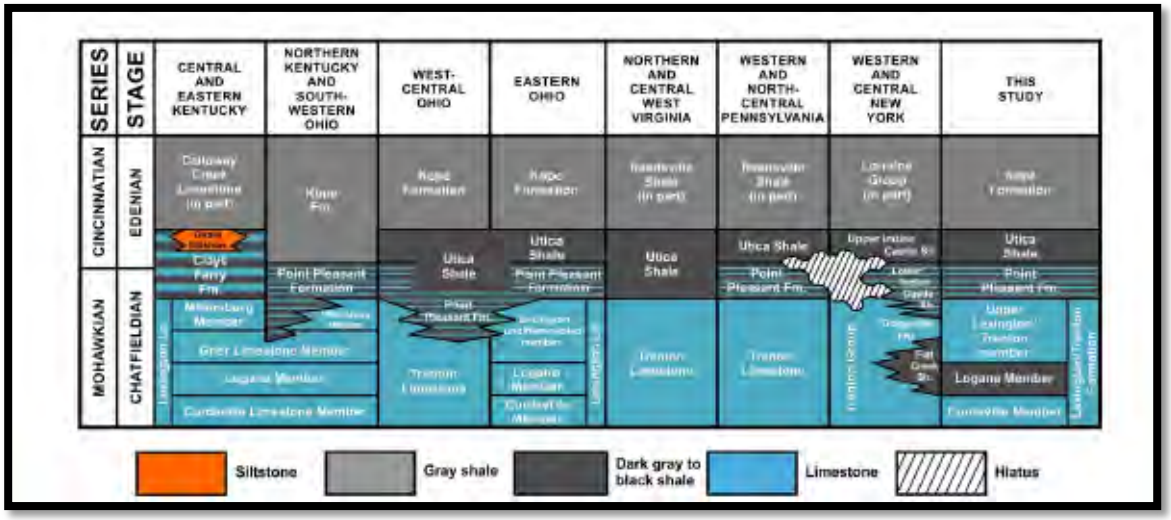
OVERVIEW

The Ordovician Utica (Indian Castle), Dolgeville, and Flat Creek are the formations of interest. These shales and interbeded limestones range in TOC (Total Organic Content) from 1- 5% in the dry gas window. They cover an area from Mohawk Valley south to the New York State boundary line with Pennsylvania and extend west to the beginning of the Finger Lakes region and east to the Catskill Mountain region. These three formations have a total thickness from 700 to 1,000 feet.

In Ohio, Pennsylvania, and West Virginia, the Utica is underlain by organic rich Point Pleasant Formation that is in part the lateral equivalent of the upper portion of the Trenton limestone and is in the gradational relationship with the overlying Utica shale which thickens into the Appalachian Basin. (Wickstom et al, 2012). The Utica Point Pleasant interval is up to 300 feet thick in Ohio and over 600 feet thick in southwestern Pennsylvania. The TOC in this interval ranges from 1 to 4 % (Harper, 2011). In Ohio, gas prone areas will be found in the deeper parts of the basin well as appreciable amounts of oil (Ryder, 2008).

In Kentucky, the Utica is equivalent to the Clays Ferry formation and individual members of the Trenton/Lexington formation, one organic rich, the Logana member and the other organic poor, the Curdsville member.

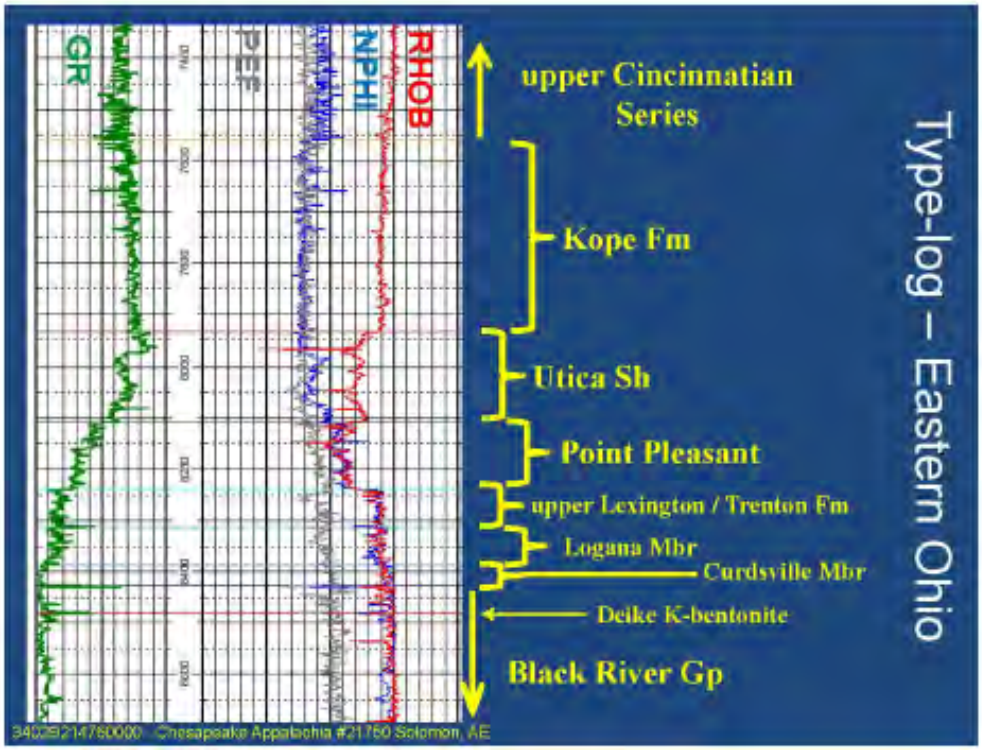
In Michigan, the Utica is underlain by the Collingwood Formation in the northern central part of the state. This formation consist of shales that are black to brown and dark gray in color, with a thickness between 25 to 40 feet and TOC range between 2-8 percent (Snowdon, 1984).



(Patchen, D.G. and Carter, K.M., 2015)

Correlations from the Utica outcrop sections in the Mohawk Valley to subsurface in Ohio, Pennsylvania, Kentucky, and West Virginia would be as follows: the Lorraine to Upper Indian Castle would be equivalent to the Kope Formation, Lower Indian Castle would be equivalent to the Utica, the Dolgeville would be equivalent to the Point Pleasant, the Flat Creek would be equivalent to the Logana (Smith, 2015). See the type log for the Utica section below.

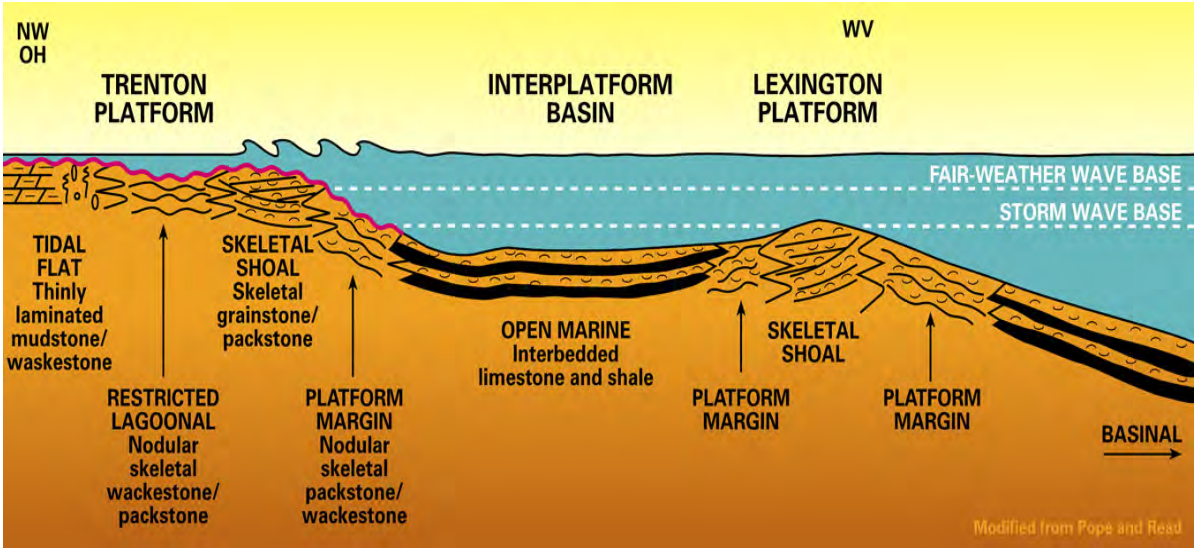
The Kope Formation is an organic poor interbedded gray shale and siltstone. The Utica Formation would be a laminated organic and clay rich shale with thin limestone beds. The Point Pleasant Formation is an interbedded limestone and shale, the upper section would be organic poor, and the lower section is a storm-bedded and laminated black shale and limestone. The Logana Formations is an organic rich interbedded calcareous shales and limestones with abundant ostracods in the organic facies.



(Patchen, D.G. and Carter, K.M., 2015)

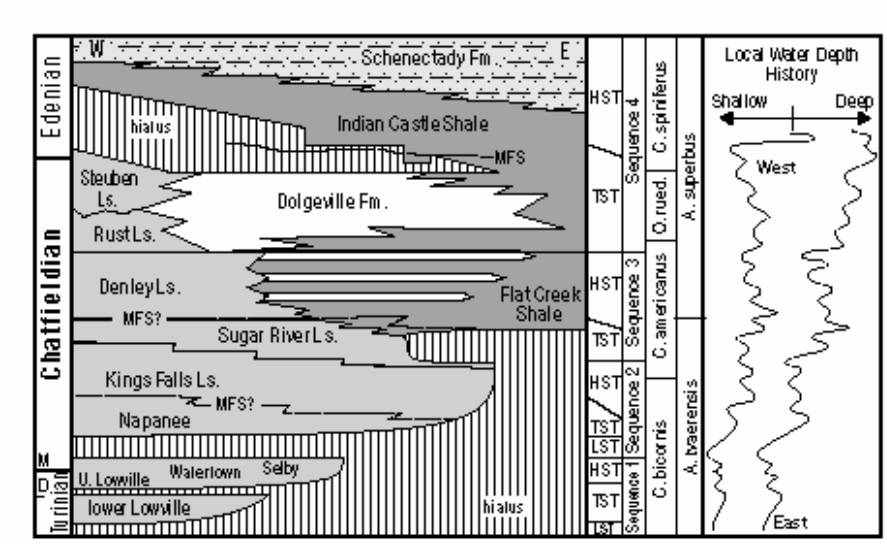
GEOLOGY:

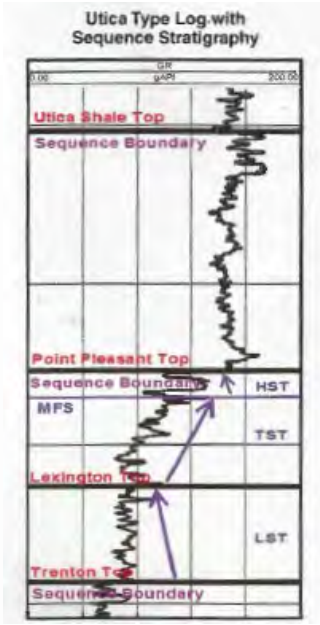
The Late Ordovician Utica shale was deposited in a foreland basin setting adjacent to and on top of, the Trenton and Lexington carbonate platforms. Initial deposition of the Trenton and Lexington platform began on a relatively flat Black River passive margin. Early tectonic activity from the Taconic orogeny created the foreland bulge that would become the Trenton and Lexington platforms. Carbonate growth was able to keep up with the overall rise in seal level while areas stayed relatively deeper until increased subsidence in the foreland basin lowered the ramps out of the photic zone and inundated the passive margin with fine grained clastics (Willan et al. 2012). The Trenton/Lexington limestone through the Utica Shale comprise the trangressive systems tract (TST) of a large second-order sequence, superimposed with four, smaller scale third-order composite sequences. Third order sequences are regional correlative, aggradational,



(Riley & Baranowski, 2011)

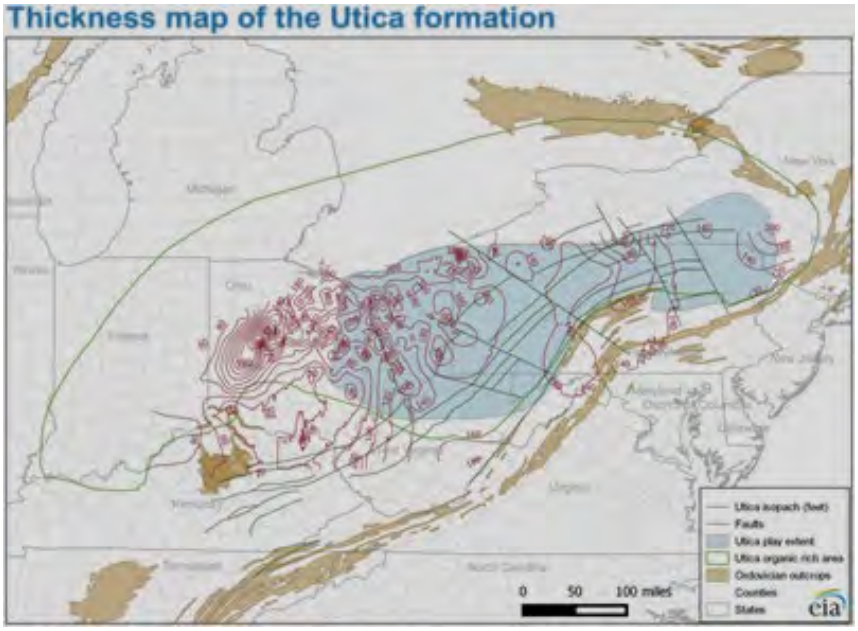
and lack lowstand deposits. Sequences are separated by type 3 sequence boundaries that amalgamate with trangressive surfaces and separate underlying highstand system tracts(HST's) from overlying TST's(McClain, 2012).





(Joy et al. 2000) (Belyadi, et al, 2017)

Smith, 2013 proposes the organic rich section were deposited in shallow water to the west and becomes progressively less organic rich approaching what was the deepest part of the basin due to progressively more dilution from clay and silt that are sourced from the highlands to the east, but it may be the longest duration of anoxic conditions occurred in the shallowest water. The environment was relatively shallow, less than 30 meters deep, with storm dominated carbonate shelfs that experienced frequent algae blooms. A study of five cores taken in Ohio show an abundance of fossils that indicates the environment was oxygenated much of the time. There are delicate trilobites and articulated ostracods that could not have been transported any significant difference. The silt sized skeletal debris was probably reworked and of unknown origin. A core description from one of the five cores below (Smith, 2015).

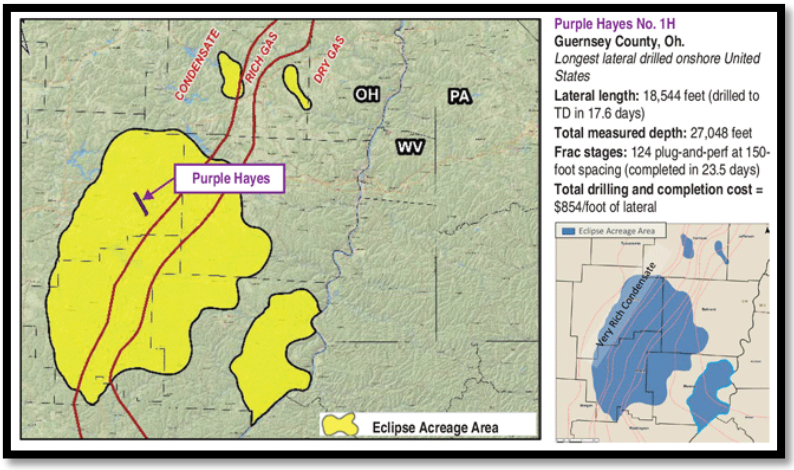


(EIA, 2017)

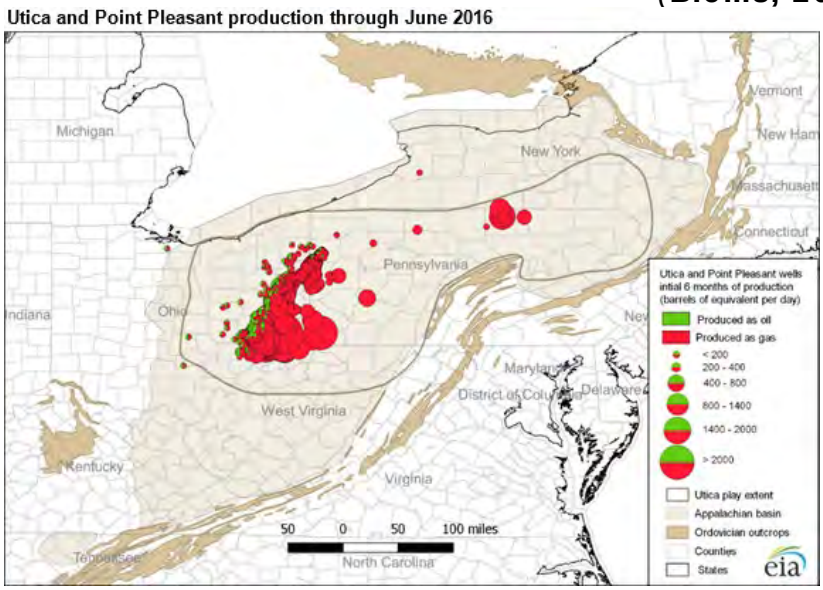
Well Activity:

With the current regulatory moratorium in place in New York, activity has been focused in eastern Ohio, western Pennsylvania (250 wells) and western West Virginia (50 wells) (Kallanish Energy News, November, 30 2018). No drilling has been done in Kentucky to date. Ohio current drilling activity as of April 13, 2017 lists 3059 Utica permits, 2591 drilled and 2179 producing wells (ODNR, 2019). Exploration activity has been concentrated in a triangle area of southeastern Ohio, the northern pan handle of West Virginia and southwestern Pennsylvania.

In May 2016, Eclipse Resources Corporation drilled the Purple Hayes 1H well, the longest lateral ever drilled onshore in the United States. The length of the lateral was 18,544 feet, it was completed in 24 days and produces natural gas and condensate. Initial Production from the Purple Hayes 1H is 5 million cubic feet per day and 1,200 barrels of condensate a day. Compared to earlier wells Eclipse has drilled, the super-lateral Purple Hayes 1H has three times the reservoir interval than those of the first 10 horizontals at one third the cost and in less time than 7,000 foot laterals drilled earlier (Beims, 2016). Most of the activity has taken place in Eastern Ohio. Chesapeake Energy is the operator who has the majority of permits. Shell Appalachia has concentrated their efforts in the dry gas area in Pennsylvania from Lawrence County eastward to Tioga County and has permitted 75 Utica/Point Pleasant horizontal wells. Of these, 18 are reported as completed, two are drilled or drilling, and 55 are not drilled.



(Biems, 2016)



(EIA, 2016)

Completion Techniques:

Average well cost ranges from 8 to 30 million dollars per well. The basic completion concept is to drill with long laterals, have short stages, and shut in the well for a determined resting period.

A new technique used to test the possible productivity of a new well is to set a permanent plug isolating the final stage or the stage closest to the well head while letting the other stages rest, usually three or more months (Energy in Depth, 10/10/2012).

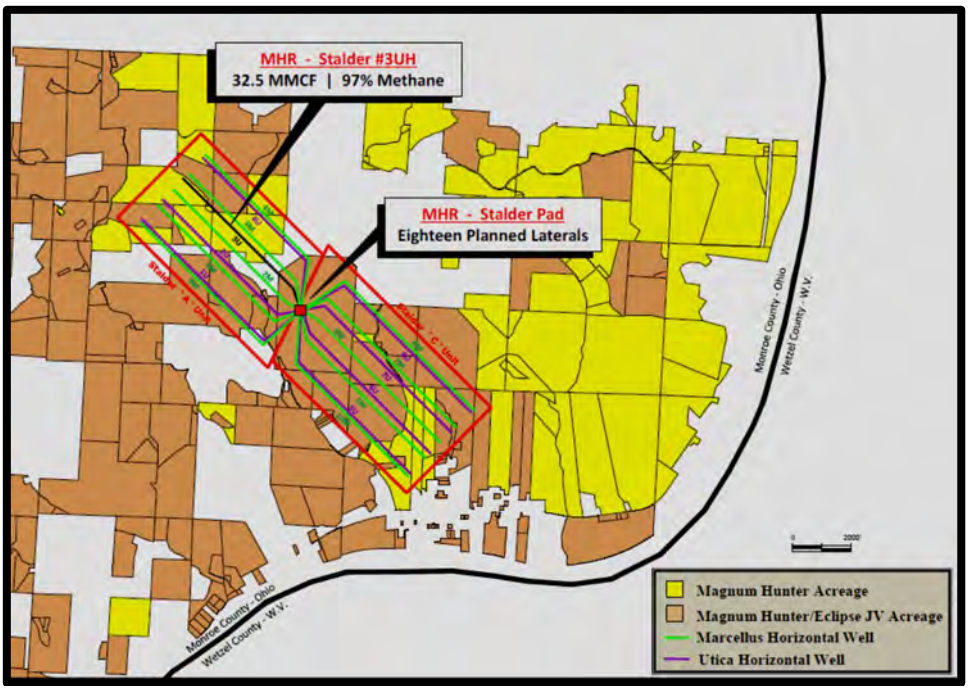
Production:

In 2018-2019, US natural gas production will reach roughly 97 Bcfpd with the Marcellus and Utica production combining to equal 33perecent of that total (Kallanish Energy News, 2019). Utica production has increased steadily from 2012, Last quarter of 2018 showed an increase of 34 percent from last quarter 2017 up to 6.5 bcfpd (The Business Journal, 2019).

Production is mostly dry gas in the southeast Ohio, Pennsylvania, and Northwestern West Virginia. Oil is produced east of the of the southeastern Ohio dry gas production. The oil window in the Utica Play is -4,000 to -8,000 feet and the corresponding gas window is -7,000 feet to -12,000 feet (EIA, 2017).

Stackable Reservoirs:

Magnum Hunter Resources has been exploiting this area with stackable reservoirs most notably the Ordovician Utica and Devonian Marcellus see the design below in Monroe County, Ohio.



(Magnum Hunter Resources Inc., 2014)

The Consol Energy Gaut 4IH well in Westmoreland County, PA, one of the top three Utica producers, was drilled off the Gaut pad, which includes seven Marcellus wells (Pickett, 2015). Upper Devonian Genesee play area may exist in Northcentral Pennsylvania counties (Ultra Petroleum Corp., 2014). In Tyler County, WV Magnum Hunter Resources had successful tests in the Marcellus and Utica to extend the stackable reservoirs further south and east (Magnum Hunter Resources Inc., 2014).

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OKLAHOMA SHALE GAS/TIGHT OIL PLAYS, U.S.A.

Brian Cardott (Oklahoma Geological Survey, Oklahoma City, OK)

Information on Oklahoma shale resource plays is available on the Oklahoma Geological Survey web site (http://www.ou.edu/ogs/research/energy/oil-gas). The site includes an Oklahoma shale gas and tight oil well completions database, currently containing 5,280 records. Wells completed during 2018 include 226 Woodford Shale, 1 Caney Shale (Johnston County), and 30 Goddard Shale (lower Springer shale; Fig. 1).

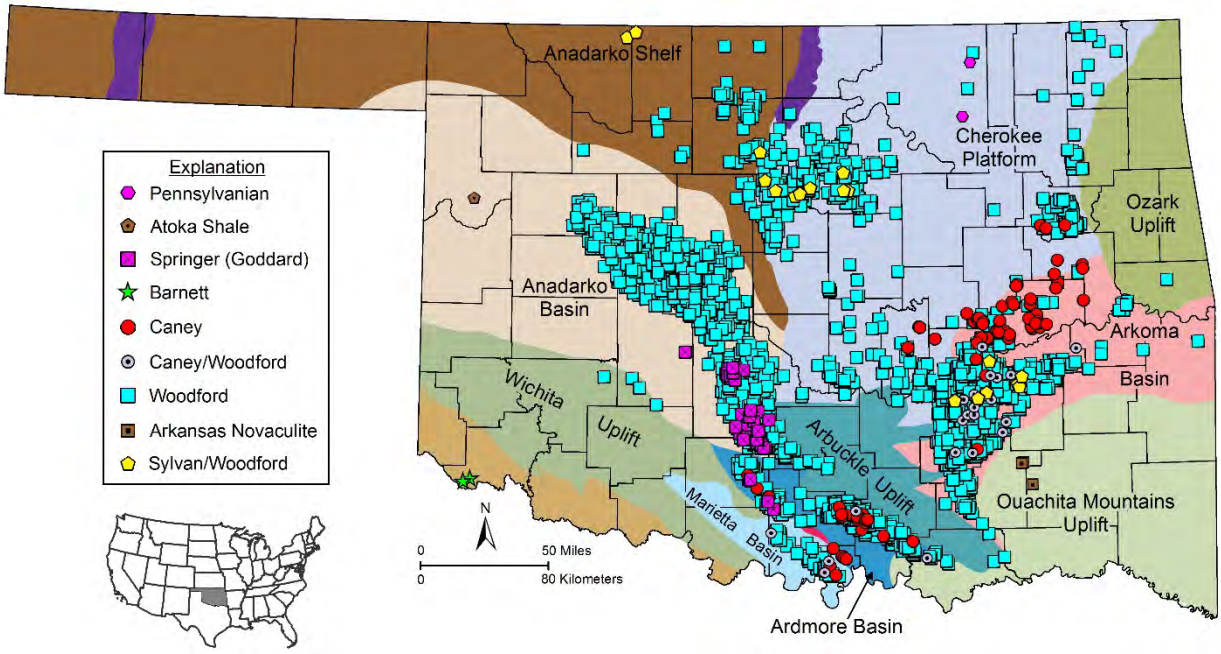

Figure 1: Map showing Oklahoma shale gas and tight oil well completions (1939-2018) on a geologic provinces map of Oklahoma (OU, 2018; base map modified from Northcutt and Campbell, 1998).

A Woodford Shale completions map showing wells by year illustrates wells in the STACK (Sooner Trend Anadarko Canadian Kingfisher), SCOOP (South Central Oklahoma Oil Province), Cherokee Platform, Arkoma Basin, and Ardmore Basin areas.

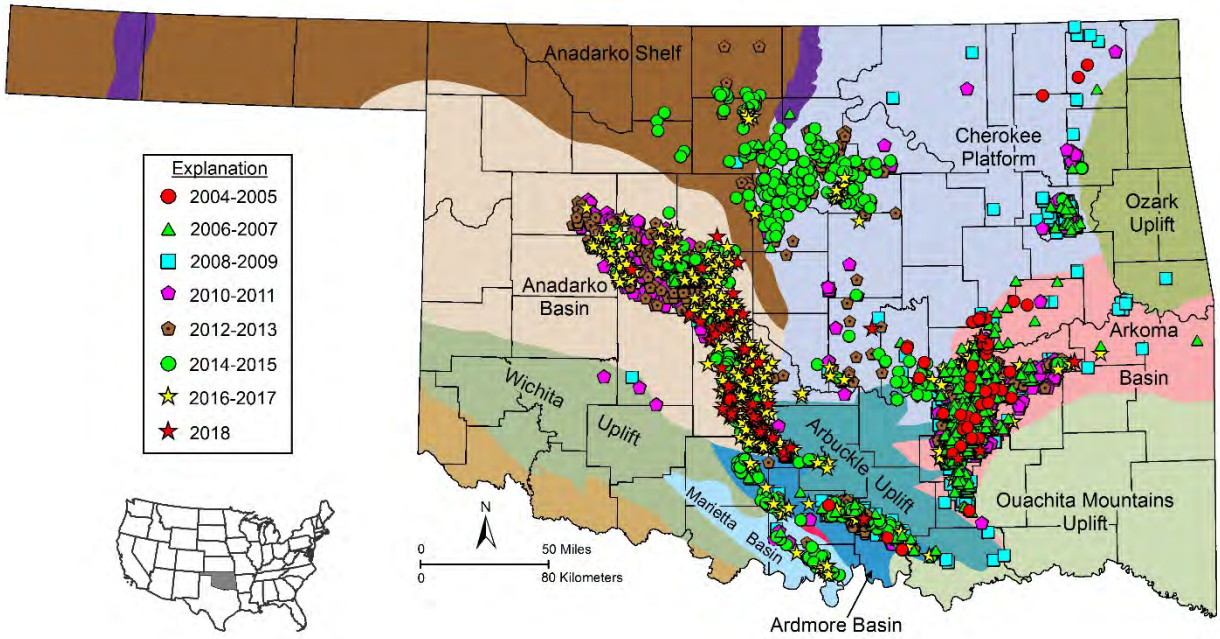

Figure 2: Map showing Woodford Shale well completions, 2004-2018 (OU, 2018_2).

Initial potential oil/condensate rates of Woodford Shale horizontal wells completed during 2018 range from a trace to 1,673 barrels of oil per day (bopd) at up to 1.5% vitrinite reflectance. Six of the highest rate wells (1,128-1,673 bopd) were in Grady County at vertical depths of 10,844 to 14,438 ft and lateral lengths of 1,362 to 5,459 ft. Woodford Shale-only wells in north-central Oklahoma may be in fracture contact with Mississippian-age reservoirs above (Wang and Philp, 2019).

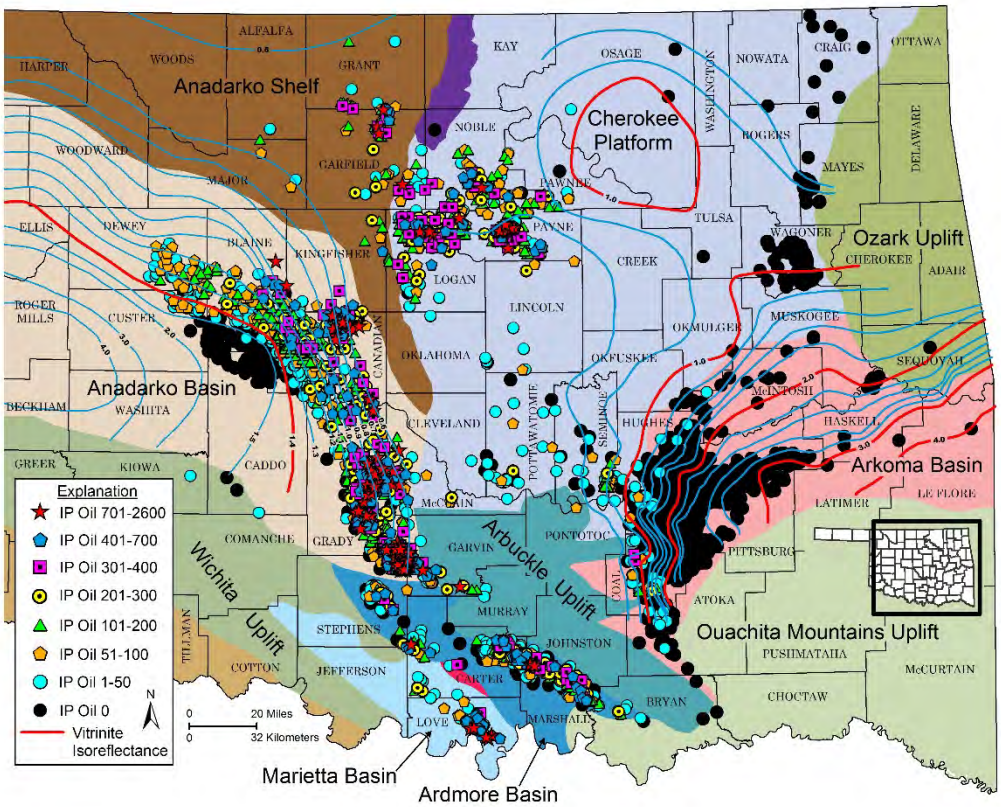

Figure 3: Map showing initial potential oil/condensate rates of Woodford Shale well completions 2004-2018 (OU, 2018_3).

Of 34 operators active in Oklahoma shale resource plays during 2018, the top nine operators (for number of wells drilled during 2018) are:

(1) Continental Resources (44)
(2) Trinity Operating USG (29)
(3) Newfield Exploration Mid-Continent Inc. (23)
(4) BP America Production Company (19)
(5) EOG Resources (19)
(6) XTO Energy (13)
(7) Marathon Oil (13)

(8) Gulfport Midcon LLC (12)
(9) Rimrock Resource Operating (10)

Bibliographies at http://www.ou.edu/ogs/research/energy/oil-gas include Oklahoma gas shales, Caney Shale, and Woodford Shale.

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STATUS OF INTERNATIONAL ACTIVITIES

CANADIAN SHALE GAS AND LIQUIDS

Jock McCracken (Egret Consulting, Vancouver)

Canada has an abundance of both conventional oil and natural gas and unconventional gas, liquids and oil. Most of these shale and tight rock opportunities lie within the Western Canadian Sedimentary Basin (WCSB) which is a vast sedimentary basin underlying 1,400,000 square kilometres (540,000 sq. mi) of Western Canada including southwestern Manitoba, southern Saskatchewan, Alberta, northeastern British Columbia, southeast corner of the Yukon and the southwest corner of the Northwest Territories. It consists of a massive wedge of sedimentary rock extending from the Rocky Mountains in the west to the Canadian Shield in the east. This wedge is about 6 kilometres (3.7 mi) thick under the Rocky Mountains, but thins to zero at its eastern margins. The WCSB, an immense petroleum system with multiple source rocks, contains one of the world's largest reserves of petroleum and natural gas.

The National Energy Board (NEB) estimate of Western Canada natural gas ultimate potential could be over 1000 TCF (2017-01-12) and oil (all of Canada) with an estimated remaining ultimate potential of 339 BBO (oil sands included) (2012-12) and supplies much of the North American market, producing about 4.3 MM BOPD and 15.7 BCFD gas. Of the provinces and territories within the WCSB, Alberta has most of the oil and gas reserves and almost all of the oil sands.

The first Canadian tight gas production that resulted from horizontal drilling and multi-stage hydraulic fracturing came from the Montney Formation in British Columbia in 2005. The first modern Canadian shale gas production came from the Horn River Basin in 2006, also found in northeast British Columbia. About 72% (2014) of Canada's natural gas is coming from unconventional which would include shale, tight sands and CBM. The state of development for the shale plays range from speculative to exploratory to emerging to developing and under increasing commercial production. Typically, production numbers from government websites are up to one year or more behind. Additional production numbers and exploration statistics for this report are therefore gathered from press releases and presentations from some of the key companies involved with the plays. As a result of the low natural gas prices operators have been focusing exploration and production into the liquids-rich hydrocarbons. The following plays are under development and maintaining production yearly. Production has gone down in a number of areas because of the price. The key plays are Horn River and Montney in N.E. B.C., Cardium, Duvernay in Alberta and the Bakken oil play (tight oil play encased in shale) in Saskatchewan and Manitoba.

There have been other shales that have been disappointments for technical and regulatory reasons. Significant shale gas wells have been drilled and tested in the St. Lawrence Lowlands of Québec but a government freeze on fracking because of environmental concerns will slow or stop any future exploration and production. The positive announcements that came out of New Brunswick had been tempered by disappointing results, low gas prices and anti-fracking regulations.

To date there is shale exploration activity in 9 provinces of Canada out of the 10 with Prince Edward Island being the exception. One of the three Territories of Canada, the Northwest Territories, with the drilling and fracking of their first wells into a possible oil-bearing shale section. The Yukon is evaluating their shale plays as well. The oil price fluctuation and pipeline bottleneck has had significant effects on industry production and exploration.

As a further note, there has been significant public concern in the press about hydraulic fracturing in various locations across Canada which is hindering or slowing down exploration and/or production. More discussion about these concerns is occurring in Provinces where there is limited oil and gas exploration and production. Industry and governments are becoming more transparent and self-imposed guidelines are being drawn up. http://www.capp.ca/

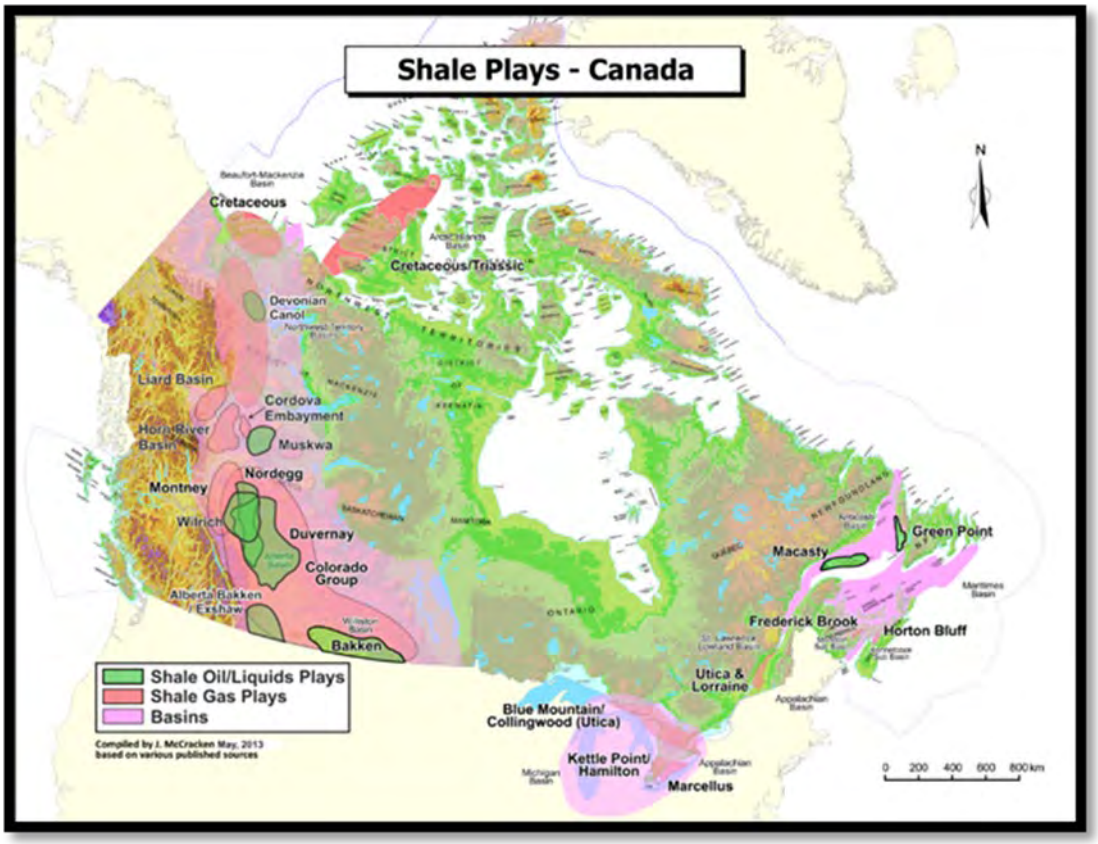
Nova Scotia, New Brunswick, Newfoundland and the Yukon effectively have put hydraulic fracking under partial or full moratorium. Quebec may be changed their regulations with the new government and it might be possible to frack in the Northwest Territories. Alberta recently updated their regulations. It is hopeful, at the end of this discussion, hydraulic fracturing will be managed such that it will minimize potential risks and allow the public to have a balanced and realistic sense of the costs and benefits.

https://www.csur.com/wp-content/uploads/2018/08/Where-are-we-with-FrackingAug2018.pdf

https://www.petrelrob.com/wp_install/wp-content/uploads/2018/08/Hayes-HF-Public-Policy.pdf

One other recent problem is the lack of pipelines to get the hydrocarbons out of the land-locked western provinces of Alberta, Saskatchewan and Manitoba. The current price differential according to Oilprice.com is WTI $62.24 with a low of $42.53 around Dec 2018 and the Canadian Western Select is $47.18 with a low of $10.29 around Dec 2018. These low prices and lack of pipelines is detrimental to the Canadian Industry and is reflected in exploration and production activity.

https://oilprice.com/Energy/Energy-General/Why-Canadian-Crude-Selling-For-20.html



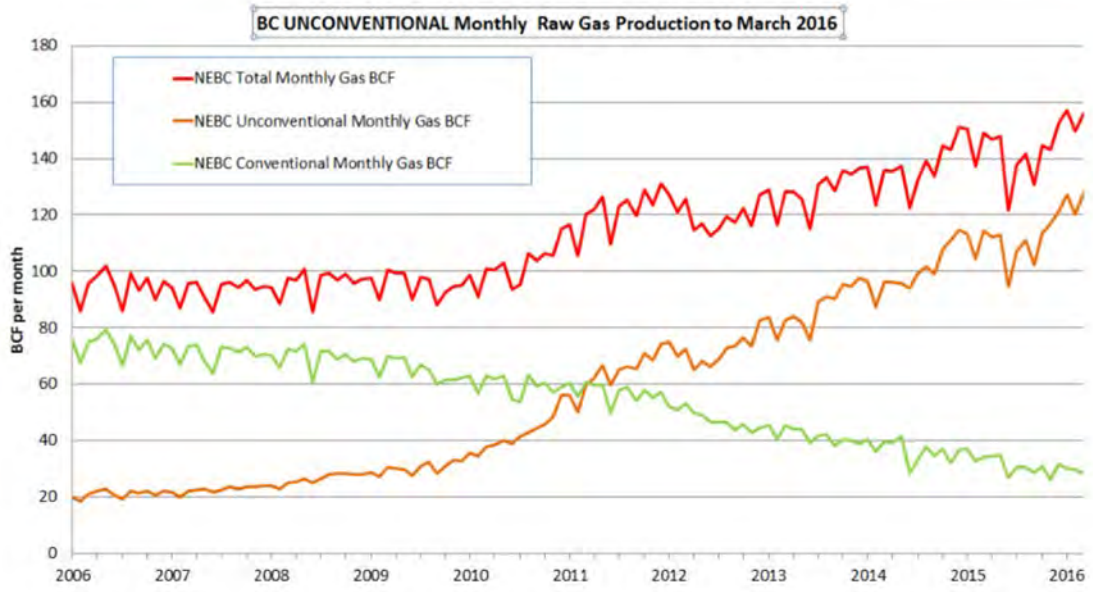
British Columbia

Northeast British Columbia contains Cretaceous to Devonian aged shale deposits that potentially could contain 2900 TCF of natural gas in place of which over 400 TCF is estimated to be marketable with about 70% being unconventional. The unconventional gas production ramped upward to about 120 BCF per month in March 2016.

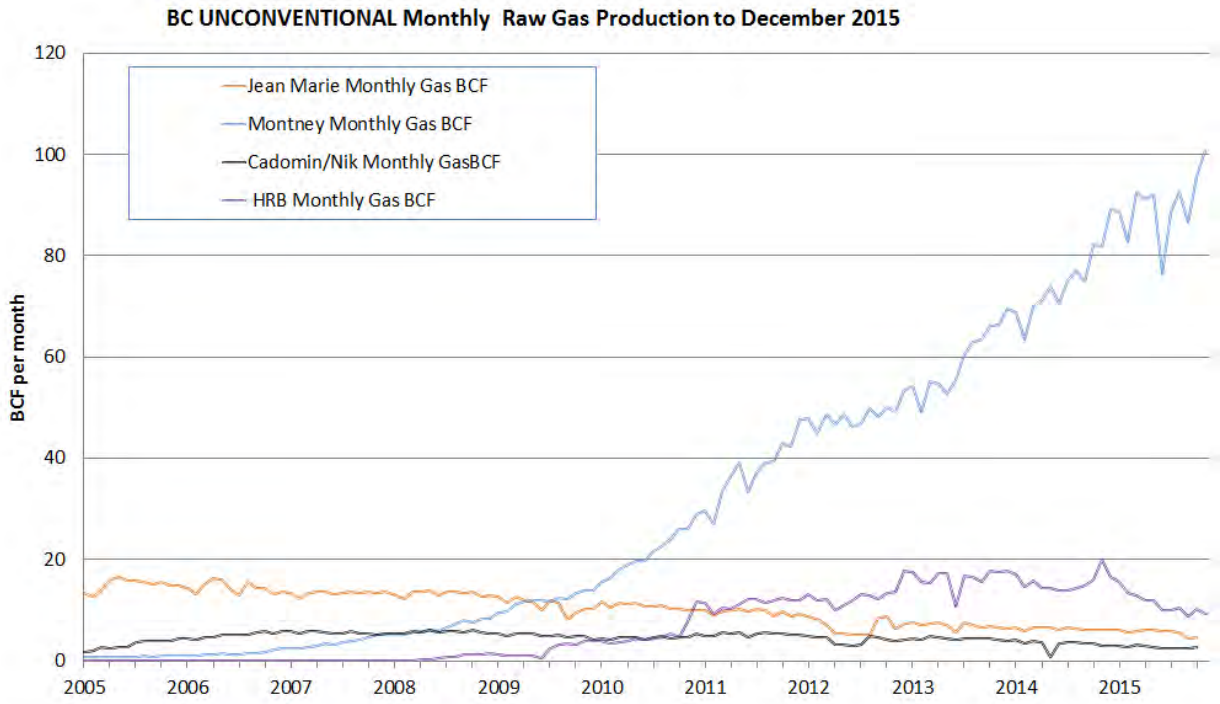
In 2017 4.7 billion - cubic feet per day of natural gas production in 2017 with $4 billion - in industry spending on exploration and development (both conventional and unconventional). Advances in horizontal drilling and completion techniques have largely contributed to these advances in all the play areas.

British Columbia is summarized by the Natural Resources Canada of which these two diagrams were extracted. http://www.nrcan.gc.ca/energy/sources/shale-tight-resources/17692

B.C. Unconventional Monthly Raw Gas Production to March 2016 – BCF Per Month

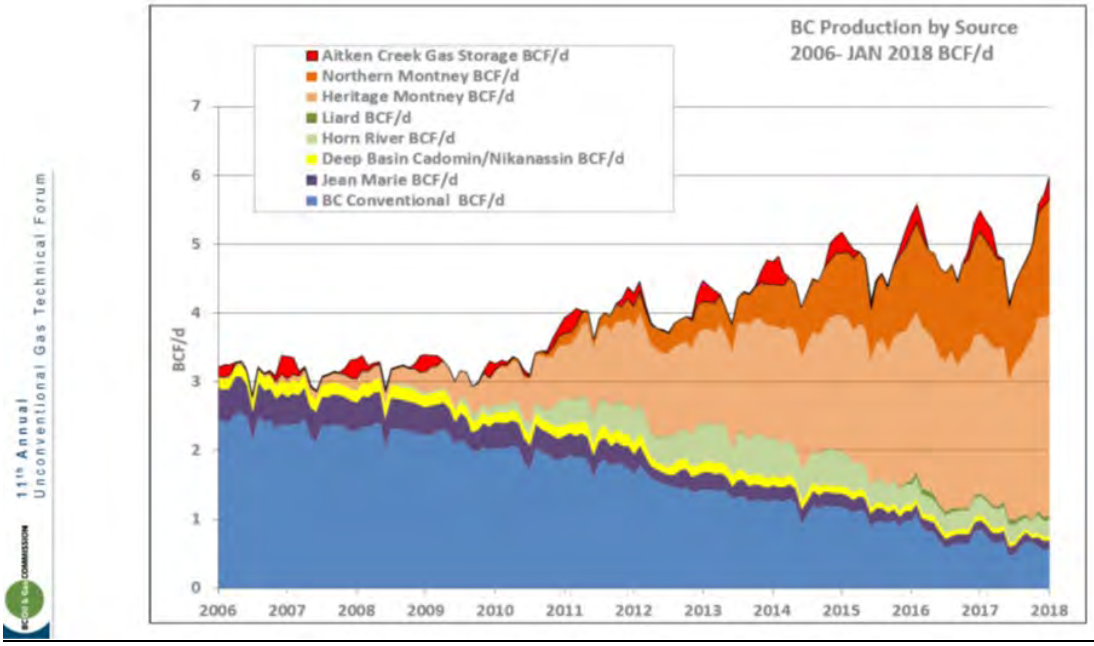


By year-end 2015, BC's unconventional gas production accounted for about 80 percent of total gas production. Compares unconventional versus conventional gas production.



The above graph illustrates, over the same time period, the relative rise of Montney unconventional gas production compared to the other major unconventional plays in

northeast BC. HRB is the Horn River Basin production. Montney is by far the largest contributor.



https://bcogc.ca/node/15405/download

Of note the Horn River production is declining while Montney is rising.

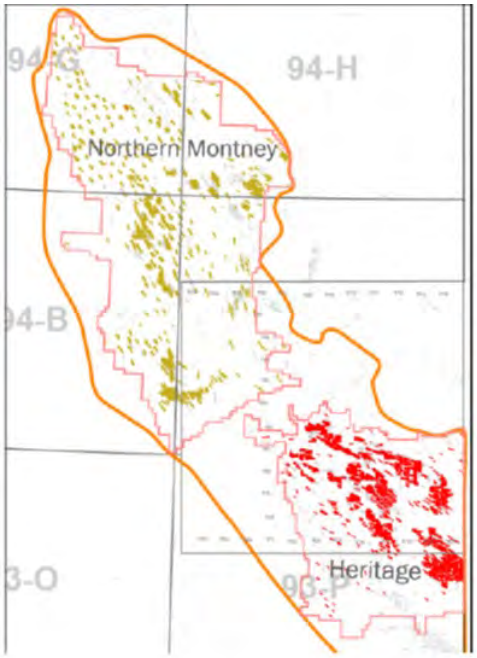
Triassic Doig and Montney Fort St. John / Dawson Creek Area

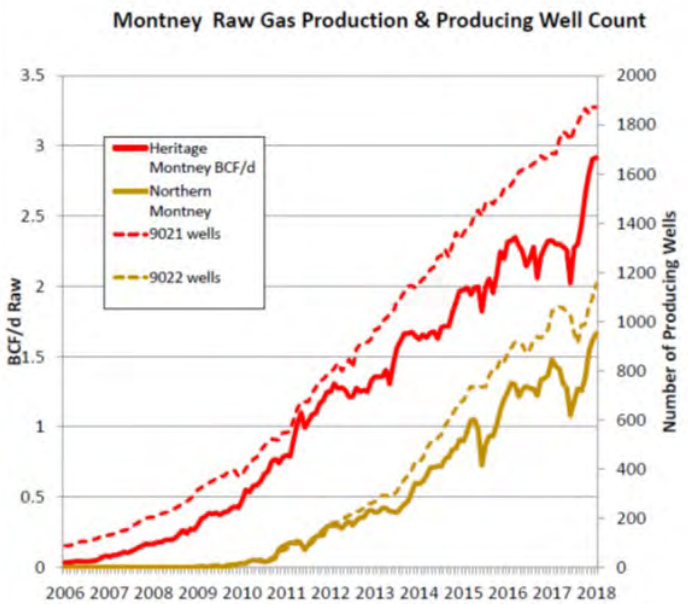
The Montney is a liquids-rich tight gas/shale gas play, producing at 3.64 BCFD and 9,588 BOPD as of March 2016. This Montney Play Trend, 29,850 sq.km.is now one of the most active natural gas plays in North America. The primary zones are the Upper Middle and Lower Montney as well as the Doig and Doig Phosphate. The major facies include fine-grained shoreface, shelf siltstone to shale, fine-grained sandstone turbidites, and organic rich phosphatic shale**.** This play varies from the traditional distal shale facies along the Alberta/British Columbia border to a tight calcareous siltstone and sandstone in Central Alberta. The current trend for companies is to explore up dip towards the “oil window” in search of liquids-rich gas. The top six Montney players out of the more than twenty two, in order of rig utilization, are Progress Energy Ltd., ARC Resources, Shell Canada Ltd, Canadian Natural Resources, Encana Corp., and Tourmaline Oil Corp as March 2014.

The following table is from Adams, 2013 showing a comparison of Montney with the US gas plays.

Parameter	Shale Gas Play					
	Horn River Basin	Montney (B.C. only)	Barnett	Marcellus	Haynesville	Fayetteville
Basin Area (km^2)	11 500	1 600 to 10 000	1 900	95 000	9 000	9 000
Depth (m)	1 800 to 3 000	1 000 to 3 500	2 000 to 2 600	2 500 to 3 000	3 000	350 to 2 300
Thickness (m)	50 to 350	50 to > 300	15 to 182	12 to 275	75	16 to 180
Porosity (%)	2 to 8	1 to 6	4 to 5	10	8 to 9	2 to 8
Total Organic Content (%)	1 to 8	1 to 7	4.5	3 to 12	0.5 to 4.0	4.0 to 9.8
Reservoir hydrocarbons	dry gas	wet gas, dry gas	wet gas, dry gas	wet gas, dry gas	dry gas	dry gas
Natural Fracturing	Yes	Yes	Yes	Yes	Yes	Yes
Pressure regime	Overpressured	Overpressured	Overpressured	Normal to overpressured	Overpressured	Normally pressured
Proximity to major consuming markets	Distant	Distant	Close	Very close	Close	Close
GIP (billion m^3)	12 629 (10 466 to 14 894)	2 270 to 19 800	9 263	42 492	2 0311	1 473
GIP (Tcf)	448 (372 to 529)	80 to 700	327	1 500	717	52
Marketable (billion m^3)	2 198 (1 715 to 2 714)	Uncertain	1 246	7 422	7 110	1 178
Marketable (Tcf)	78 (61 to 96)	Uncertain	44	262	251	41.6
State of development	very early	early	medium	early	medium	medium
Notes:		hybrid shale/tight-gas				

Source: U.S. data from U.S. Department of Energy Modern Shale Gas Development in the United States: A Primer





The two above diagrams came from Mark Hayes presentation in 2017.
https://bcogc.ca/node/15405/download

Evolving technology is a key driver of performance in modern gas wells: a look at the Montney Formation, one of North America's biggest gas resources

https://www.neb-one.gc.ca/nrg/ntgrtd/mrkt/snpsht/2018/04-04-1vlvngtchnlg-eng.html

Figure 8: Montney 2015 Dry/Wet/Oil Distribution

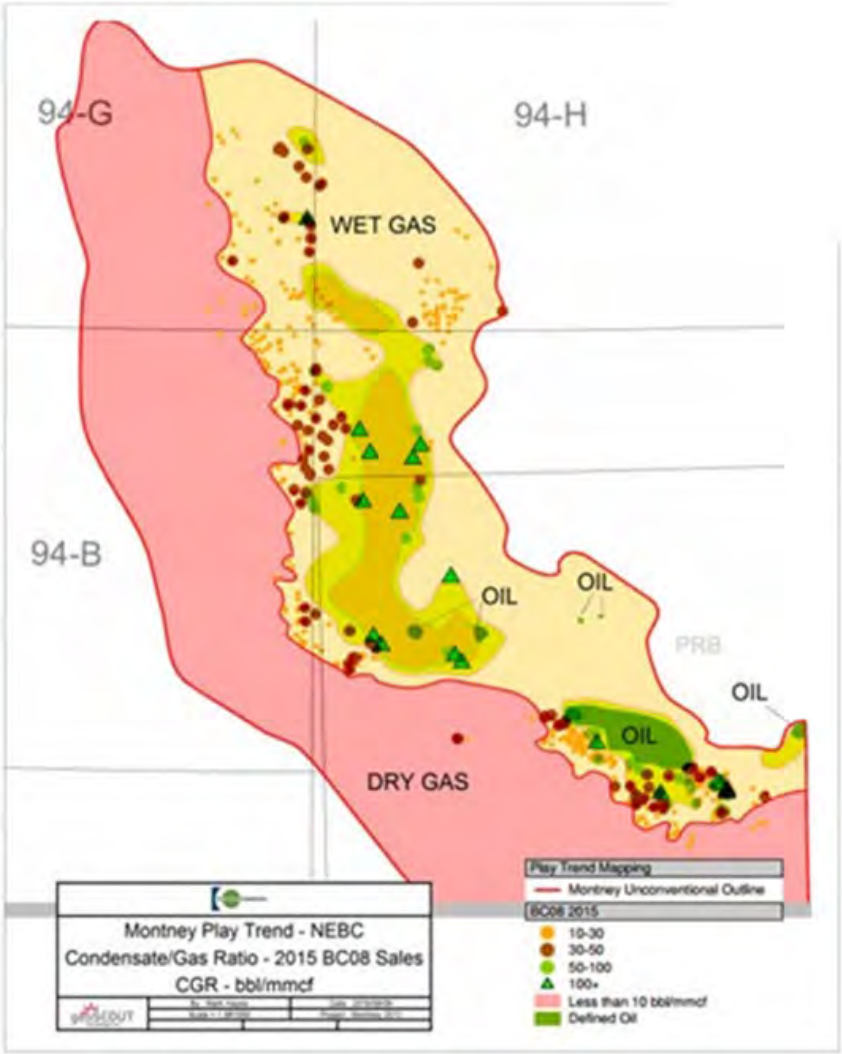


Table 1. Ultimate potential for Montney unconventional petroleum in British Columbia and Alberta.

Hydrocarbon Type	In-Place			Marketable		
	Low	**Expected**	High	Low	**Expected**	High
Natural Gas – billion m^3	90,559	**121,080**	153,103	8,952	**12,719**	18,257
(trillion cubic feet)	(3,197)	**(4,274)**	(5,405)	(316)	**(449)**	(645)
NGLs – million m^3	13,884	**20,173**	28,096	1,540	**2,308**	3,344
(million barrels)	(87,360)	**(126,931)**	(176,783)	(9,689)	**(14,521)**	(21,040)
Oil – million m^3	12,865	**22,484**	36,113	72	**179**	386
(million barrels)	(80,949)	**(141,469)**	(227,221)	(452)	**(1,125)**	(2,430)

[19] NEB. *Canada Energy Overview 2012*, 2013. Available at: www.neb-one.gc.ca.

[20] NEB. *Natural Gas Supply Costs in Western Canada in 2009*, 2010. Available at: www.neb-one.gc.ca.

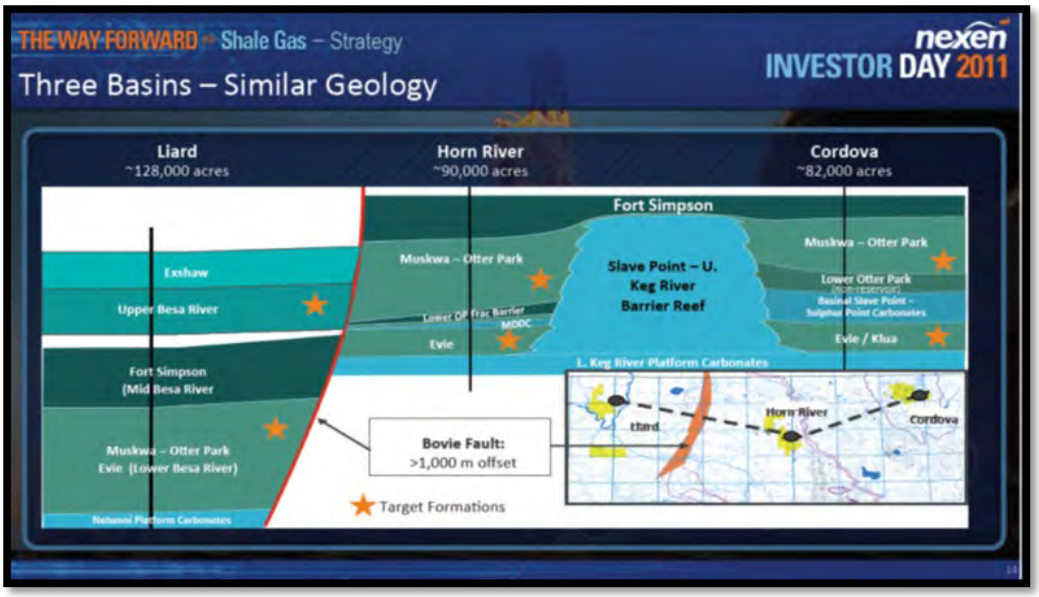
[21] NEB. *Short-term Canadian Natural Gas Deliverability 2013-2015*, 2013. Available at: www.neb-one.gc.ca.

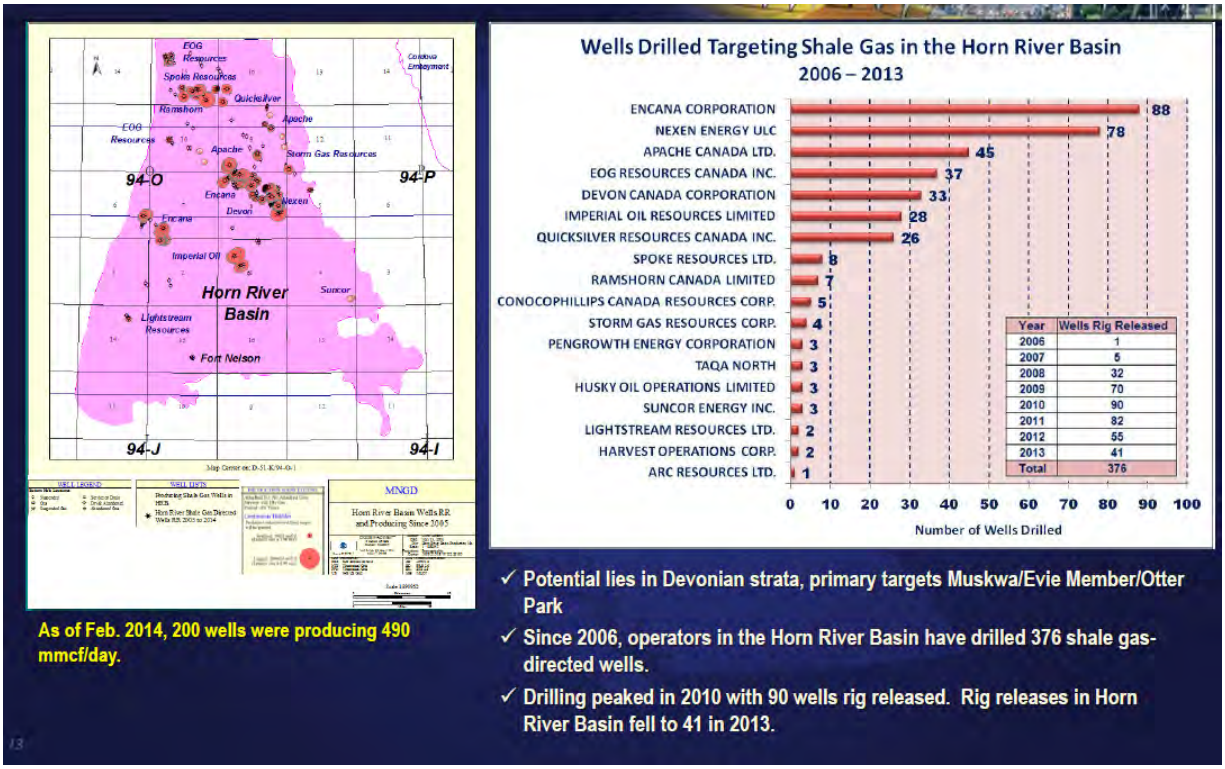
[22] NEB. *Canada's Energy Future: Energy Supply and Demand Projections to 2035*, 2011. Available at: www.neb-one.gc.ca.

BC Oil and Gas Commission | 2015 Oil and Gas Reserves and Production Report

Upper and Middle Devonian, Evie (Klua), Otter Park and Muskwa members of the Horn River Formation Horn River Basin, Laird Basin and Cordova Embayment.

The resource estimate is 448 TCF OGIP. As of Dec. 2015 there were 175 wells producing 274 MMCF/D. increasing from roughly 80 MMCFD at the end of 2009 and a cumulative gas production of 929 BCF. Production and new well drilling in this play have dropped off and wells shut in awaiting a better gas price.





The **Laird Basin**, straddling the Yukon, North West Territory and British Columbia, has great potential with 9,340 sq. km and 5 kilometres of vertical section from the Cambrian to the Upper Cretaceous. The resource potential is 848 TCF OGIP. There only 4 producing wells with a daily production of 82.7 MMCF/D and a cumulative production of 21.1 BCF. Houston-based independent Apache Corp. called the Lower Besa River black shale "the best unconventional gas reservoir evaluated in North America with excellent vertical and lateral reservoir continuity." As of 2014 Chevron and Woodside also became bigger players in the basin as Apache divested. Seven wells were evaluated in 2017 to contribute to reserves.

Liard Basin.

http://www.ogj.com/articles/print/vol-110/issue-8b/regular-features/journally-speaking/liard-and-the-besa-river.html

The two diagrams below are from an Apache presentation Jun 2012. This information provides a very good background to the play and the rocks.

http://files.shareholder.com/downloads/APA/2148221537x0x577564/d3ace688-47ba-48e4-8179-83b15adb6881/Apache_Investor-Day_20120614.pdf

In 2012, Apache reported that one of their wells (Apache HZ Patry d-34-K/94-O-5) recorded a 30 day initial production rate of 21.3 MMCF/D on a six-stage fracturing operation (3.6 MMCF/D per hydraulic fracture). The well was drilled in 2010 to a vertical depth of 3843 m with a horizontal leg of 885 m and has an estimated ultimate recovery (EUR) of 17.9 BCF. It is considered to be one of the best shale gas resource tests in any of North America's unconventional reservoirs (Apache Canada Ltd., 2012).

Apache was targeting the Upper Devonian Lower Besa River Black Shale. The shale is 400-1,000 ft. thick lying at depths of 9,500-15,000 ft. Porosity range is 3-8% and water saturation is 15-20%. Total organic carbon values are 3-6 wt. %. Apache showed a development model that would involve recovery of 54 TCF of raw gas using 731 well locations on 61 pads with two drilling rigs per pad.

The company's vertical C-86-F well went to 15,000 ft. and had a 30-day initial potential of 9.8 MMCFD, and the vertical D-28-B well went to 13,200 ft. and flowed 4.6 MMCFD. The two vertical wells had only a single frac apiece. Net pay thickness is 1,024 ft. at C-86-F and 708 ft. at D-28-B. In its development model, Apache envisions drilling horizontal wells with 7,050-8,040-ft laterals with 18 fracs per lateral. The company estimates 400 ft. spacing between fracs and 600 m between wells. Drilling time was expected to be 110-120 days/well.

In March 2016 a joint government's report "Laird Basin, one of the larger one of the largest shale gas resources in the world" was published by the NEB on the potential of the Laird Basin.

http://news.gc.ca/web/article-en.do?mthd=tp&crtr.page=1&nid=1040329&crtr.tp1D=1

The results from this report are directly quoted below:

- "The Liard Basin is expected to contain 219 trillion cubic feet (TCF) of marketable, unconventional natural gas, making it Canada's second largest gas resource behind the Montney Formation (449 TCF) to the southeast in B.C. and Alberta
- Canada's total natural gas usage in 2014 was 3.2 TCF, making the Liard Basin unconventional gas resource equivalent to more than 68 years at Canada's 2014 consumption rate.
- Canada has more than 850 TCF of remaining, marketable gas in areas already served by major pipeline systems. This is the equivalent of 267 years of supply based on Canada's 2014 consumption rate."

The **Cordova Embayment** area, an area of 2,690 sq.km. where most blocks of land were purchased in 2007 and 2010, now has16 wells. Daily production is 18.4 MMCF/D with a cumulative production of 41.8 BCF. As of 2014 Nexen and its partner INPEX (IGBC) started early stage development. Penn West had some interests but had blocks on the auction block as of 2014.

Table B-1: Summary of Unconventional Plays

	Montney	Horn River	Liard	Cordova
PROSPECTIVE RESOURCES				
Potential Resource (TCF)	1,965	448	Evaluation ongoing	Evaluation ongoing
Source	Joint 2013 report: Commission, Alberta Energy Regulators, BC Ministry of Natural Gas Development, National Energy Board	Joint 2011 report: National Energy Board, BC Ministry of Energy and Mines	Commission evaluation ongoing (limited data)	Preliminary Commission estimate
PROVEN RESERVES				
OGIP (TCF)	241.3	46.9	1.0	0.4
RR (TCF)	25.7	11.0	0.09	0.08
Cum Gas (TCF)	3.2	0.8	0.012	0.03
Existing Wells Drilled	2520	375	12	39
RESERVES METHODOLOGY				
Evaluation Method	Decline Statistics	Decline	Decline	Volumetric
Average Reserves per HZ Well (BCF)	4.5	6.4	8.0	4.0
Recovery Factor (%)	12	25	10	25
RESERVOIR DATA				
Depth Range (m)	1,400-3,200	1,900-3,100	3,900-4,800	1,500-2,300
Gross Thickness (m)	30-300	140-280	100-200	70-120
TOC Range (%)	~2	1-5	3-6	2-5
Porosity (%)	2-9	3-6	3-6	3-6
Water Saturation (%)	25	25	15-20	25
Pressure (MPa)	14-86	20-53	75-85	5-22
Pressure Regime	Over Pressure	Over Pressure	Over Pressure	Under to Normal Pressure
Temperature (°C)	50-110	80-160	150-180	50-180
Average H_2S (%)	0-1.5	0 Muskwa-Otter Park 0.02 Evie	0.002	0.004
Average CO_2 (%)	< 1.0 (max 5)	10 Muskwa-Otter Park 13 Evie	7	8
COMPLETION DATA (based on 2010-2014 results)				
Average Proppant Placed per Stage (t)	120	170	193	220
Total Fluid Pumped (m^3)	11,648	79,920	20,431	43,513
Number of Stages	16	25	10	14
Completed Length (m)	1,726	2,232	1,200	1,794
Average Frac Spacing (m)	145	103	133	147
Six Month Gas Rate per Stage (Mcf/d)	195	227	158	134

BC Oil and Gas Commission 2014 Hydrocarbon and By-Product Reserves Report

Lower Cretaceous – Gething and Buckinghorse N.E. British Columbia

Shale gas activity directed towards Cretaceous horizons was being assessed in several areas of the Fort St. John and Northern Foothills regions. The Blair Creek and Farrell Creek areas in the Northern Foothills region were the target areas. Lower Cretaceous sequences are the exploration focus in the Beg/Jedney areas and further south in the Blair Creek and Farrell Creek areas. Each of these areas has unique characteristics in terms of its shale gas potential. Companies currently operating in these areas are evaluating fracture stimulation programs and continue to optimize completion methods that could potentially increase well productivity. The Buckinghorse Formation is about 1000m thick in some places. There has not been much information on whether this play has worked economically especially with the successful gas/liquids Montney in the area.

Other Plays

A new report by Brad Hayes et al (2018), commissioned by Geoscience BC, looked at 19 potential intervals for future consideration. Nine were deemed worthwhile for further work with the Triassic Halfway and Lower Cretaceous Chinkeh formations seen as highest in the ranking.

http://cdn.geosciencebc.com/project_data/GBCReport2018-20/GBCR2018-20_Resource_Oil_Report.pdf

With all these gas resources, which are mostly unconventional, the Asian gas market was targeted by 19 (11 in 2013) joint venture export groups with the building of LNG terminals and their pipeline routes to Kitimat, Prince Rupert and Grassy Point BC, 643 kilometers north of Vancouver. There currently is only one LNG active – LNG Canada and three proposed – Kitimat LNG, Tilbury LNG and Woodfibre LNG.
https://www2.gov.bc.ca/gov/content/industry/natural-gas-oil/lng/lng-projects

Table 1: Unconventional Gas Resource, Reserves and Cumulative Production

	Resource		Reserve			
Basin/Play	Basin Total GIP Resource (Tcf)	Ultimate Potential (Marketable, Tcf)	Initial Raw Gas Reserves (Raw, Tcf)	Remaining Reserves (Raw, Tcf)	Cumulative Production (Raw, Tcf)[6]	% Reserve per Resource
Montney[1]	1,965	271	34.08	29.77	4.31	1.73%
Liard Basin[2]	848	167	0.10	0.09	0.01	0.01%
Horn River Basin[3]	448	78	11.72	10.82	0.90	2.62%
Cordova[4]	67	9	0.11	0.07	0.04	0.16%
Deep Basin Cadomin, Nikanassin[5]	9	7	1.04	0.43	0.61	11.56%
Total	3,337	532	47.05	41.18	5.87	1.41%

1. NEB/OGC/AER/MNGD Energy Briefing Note - The Ultimate Potential for Unconventional Petroleum from the Montney Formation of BC and Alberta (Nov. 2013).
2. NEB/OGC/ NWT/Yukon Energy Briefing Note - The Unconventional Gas Resources of Mississippian-Devonian Shales in the Liard Basin of British Columbia, The Northwest Territories and Yukon (March 2016).
3. NEB/MEM Oil and Gas Reports 2011-1, Ultimate Potential for Unconventional Natural Gas in Northeastern BC's Horn River Basin (May 2011).
4. MNGD/OGC Cordova Embayment Resource Assessment (June 2015).
5. MEMPR/NEB Report 2006-A, NEBC's Ultimate Potential for Conventional Natural Gas.
6. Cumulative production to Dec. 31, 2015.

B.C Shale information link: There is a wealth of data on this website.

http://www2.gov.bc.ca/gov/content/industry/natural-gas-oil/petroleum-geoscience/unconventional-oil-gas

http://www2.gov.bc.ca/gov/content/industry/natural-gas-oil/petroleum-geoscience/statistics-industry-activity

http://www2.gov.bc.ca/gov/content/industry/natural-gas-oil/petroleum-geoscience/petroleum-geoscience-publications/petroleum-maps-and-figures

Adams, C., Janicki, E., Balogun, A. (2016): Summary of shale gas activity in Northeast British Columbia 2013; in Oil and Gas Reports 2016, British Columbia Ministry of Natural Gas Development, pages 1–39

http://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/natural-gas-oil/petroleum-geoscience/oil-gas-reports/oil_and_gas_report_2016-1.pdf

Chris Adams the principal author of these yearly reports (above) sadly passed away in November 2015. His reports were instrumental in this report.

Geoscience BC is an industry-led, industry-focused, applied geoscience organization. Their mandate is to encourage mineral and oil & gas exploration investment in British Columbia. http://www.geosciencebc.com/about-us/

Other sources

National Energy Board et al., The Unconventional Gas Resources of Mississippian-Devonian Shales in the Liard Basin of British Columbia, the Northwest Territories, and Yukon http://www.emr.gov.yk.ca/oilandgas/pdf/Unconventional-Gas-Resources-in-Liard-Basin.pdf

The Ultimate Potential for Unconventional Petroleum from the Montney Formation of British Columbia and Alberta, November 2013 NEB https://www.neb.gc.ca/nrg/sttstc/ntrlgs/rprt/ltmtptntlmntnyfrmtn2013/ltmtptntlmntnyfrmtn2013-eng.html

BC Oil and Gas Commission | 2017 Oil and Gas Reserves and Production Report http://www.bcogc.ca/publications/reports

Alberta

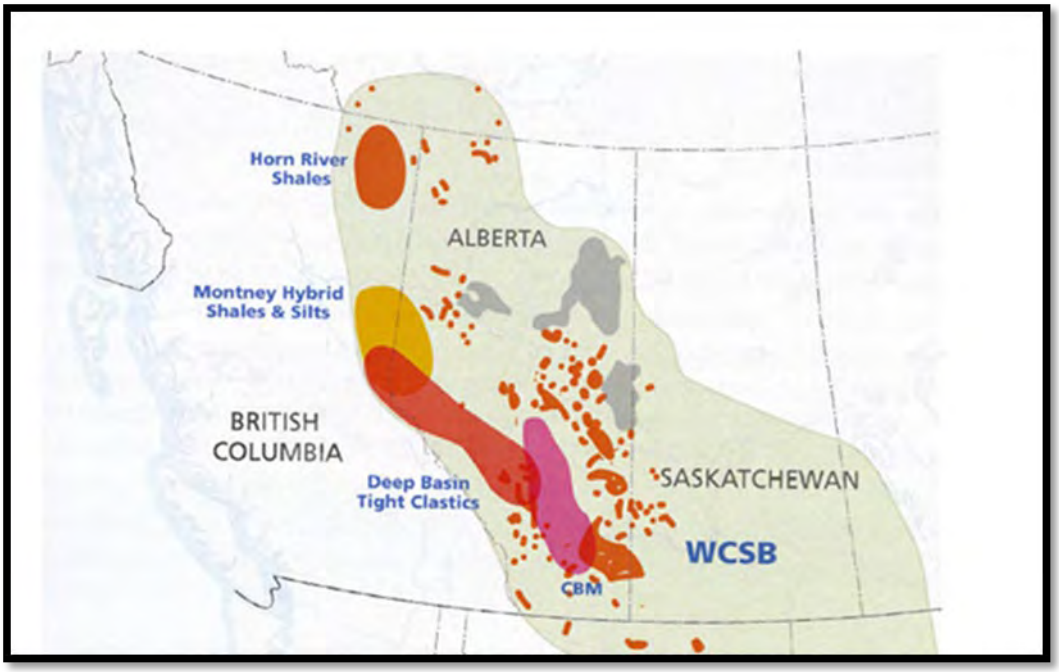
Note that the recent oil price collapse as well as the pipeline bottleneck has changed the dynamics of this industry dramatically, especially for Alberta, creating a challenge in the updating for this report but I have tried to remain current as possible.

The shales and tight rocks of the Western Canada Sedimentary Basin have been under investigation for the last number of years. The Alberta portion of this basin, Alberta Basin, has been studied thoroughly by Alberta Energy Regulator (AER), Alberta Geological Survey (AGS), Geological Survey of Canada (GSC) and National Energy Board (NEB).

Alberta has extensive experience in the development of energy resources and has a strong regulatory framework already in place. Shale gas and liquids is regulated under the same legislation, rules and policies required for conventional natural gas. The Alberta Energy Regulator (AER) regulates exploration, production, processing, transmission and distribution of natural gas within the province.

Estimates of shale resources within the Western Canada Sedimentary Basin (see map below) vary from 86 to 1000 TCF. This early estimate did not include liquid phase. There is a huge potential in Alberta and commercial shale production is now being produced with additional new plays emerging. 10.4 billion - cubic feet per day of marketable natural gas (Conventional and Unconventional) was produced in 2017.
According to the Alberta Energy Regulator (AER), in 2016, Alberta produced 67 per cent of Canada's natural gas and 81 per cent of Canada's oil and equivalent. More than 60 per cent of Canada's total oil and equivalent production was marketable bitumen. Conventional crude oil production in 2016 was an estimated 441,000 bbls/d, a decrease of about 16 per cent from 2015 due to lower crude oil prices, which resulted in fewer wells placed on production. Overall marketable natural gas production in Alberta, which includes growing liquids-rich shale/tight gas volumes, increased for the second year in a row in 2015, growing by 2.2 per cent to 298.6 million cubic metres per day from 292.1 million cubic metres, due to the lag effect from high drilling levels in 2014.

However, in 2016 production of natural gas declined year over year for the first time since 2013, with production estimated to have decreased by 1.8 per cent to 291.9 million cubic metres a day.



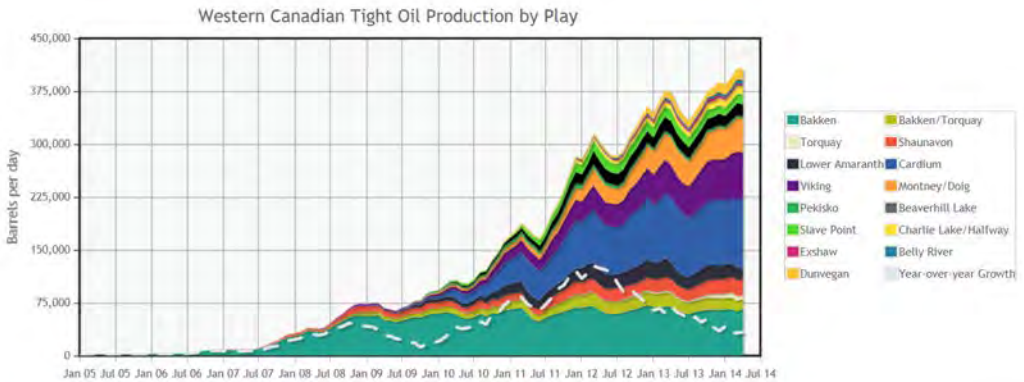


Figure Sources and Description

Sources: Divestco data, NEB calculations

Description: This stacked cake chart shows Western Canadian tight oil production by play, from 2005 to early 2014. Tight oil production grows from near zero in 2005, with production from 15 plays. These are the Bakken, Bakken/Torquay, Torquay, Shaunavon, Lower Amaranth, Cardium, Viking, Montney/Doig, Pekisko,Beaverhill Lake,Slave Point,Charlie Lake/Halfway, Exshaw, Belly River, and Dunvegan. Of these, larger amounts of production come from the Bakken, Cardium and Viking plays. Also, overlaying the cake chart is a line, representing year over year production growth. This line grows until early 2012, at which point it begins to decline.

These charts (above and below), to 2014, show tight oil production from the four Western Provinces. A number of the plays overlap provincial boundaries with the larger contributors and the trend being obvious. Note the newer play Duvernay has not contributed at this time.
https://www.neb-one.gc.ca/nrg/ntgrtd/mrkt/snpsht/2014/10-01tghtl-eng.html

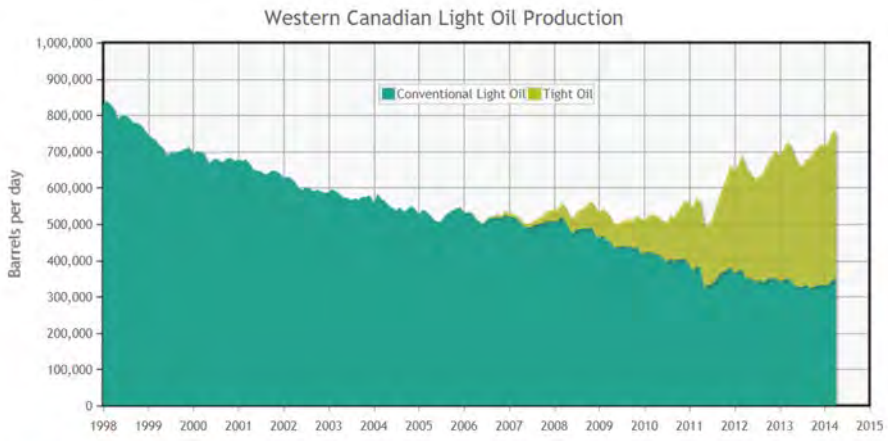


Figure Sources and Description

Sources: Divestco data, NEB data and calculations

Description: This stacked cake chart shows Western Canadian light oil production (conventional and tight oil) from 1998 to early 2014. Conventional oil production declines steadily from 1998 to 2014. Tight oil production is zero until 2005, and grows thereafter. By early 2014, tight oil represents a majority of Western Canadian light oil production.

Following are tables of resource numbers for the Western Canada Sedimentary Basin and Alberta Formations.

Table 1. Ultimate potential for Montney unconventional petroleum in British Columbia and Alberta.

Hydrocarbon Type	In-Place			Marketable		
	Low	**Expected**	High	Low	**Expected**	High
Natural Gas – billion m^3	90,559	**121,080**	153,103	8,952	**12,719**	18,257
(trillion cubic feet)	(3,197)	**(4,274)**	(5,405)	(316)	**(449)**	(645)
NGLs – million m^3	13,884	**20,173**	28,096	1,540	**2,308**	3,344
(million barrels)	(87,360)	**(126,931)**	(176,783)	(9,689)	**(14,521)**	(21,040)
Oil – million m^3	12,865	**22,484**	36,113	72	**179**	386
(million barrels)	(80,949)	**(141,469)**	(227,221)	(452)	**(1,125)**	(2,430)

[19] NEB. *Canada Energy Overview 2012*, 2013. Available at: www.neb-one.gc.ca.

[20] NEB. *Natural Gas Supply Costs in Western Canada in 2009*, 2010. Available at: www.neb-one.gc.ca.

[21] NEB. *Short-term Canadian Natural Gas Deliverability 2013-2015*, 2013. Available at: www.neb-one.gc.ca.

[22] NEB. *Canada's Energy Future: Energy Supply and Demand Projections to 2035*, 2011. Available at: www.neb-one.gc.ca.

Table 2. NEB Estimate of Ultimate Potential for Marketable Natural Gas in the WCSB – Year-end 2015

		10^9 m³			Tcf		
Area	Gas Type	Ultimate Potential	Cumulative Production	Remaining	Ultimate Potential	Cumulative Production	Remaining
Alberta	Conventional	6 276	**4 712**	**8 610**	221.6	**166.4**	**313.4**
	Unconventional	7 046			248.8		
	CBM portion	101			3.6		
	Montney portion	5 042			178.1		
	Duvernay portion	2 168			76.6		
	Alberta Total	**13 587**			**479.8**		
British Columbia	Conventional	1 462	**811**	**15 505**	51.6	**28.6**	**547.6**
	Unconventional	14 854			524.6		
	Horn River portion	2 198			77.6		
	Montney portion	7 677			271.1		
	Cordova portion	248			8.8		
	Liard portion	4 731			167.1		
	British Columbia Total	**16 316**			**576.2**		
Saskatchewan	Conventional	297	**227**	**152**	10.5	**8.0**	**5.4**
	Unconventional	82			2.9		
	Bakken portion	82			2.9		
	Saskatchewan Total	**379**			**13.4**		
Southern NWT	Conventional	132	**14**	**1 368**	4.7	**0.5**	**48.3**
	Unconventional	1 250			44.1		
	Liard portion	1 250			44.1		
	Southern NWT Total	**1 382**			**48.8**		
Southern Yukon	Conventional	61	**6**	**271**	2.2	**0.2**	**9.6**
	Unconventional	215			7.6		
	Liard portion	215			7.6		
	Southern Yukon Total	**276**			**9.8**		
WCSB Total		**31 941**	**5 770**	**26 172**	**1128**	**204**	**924**

Notes:
– Determined from reliable, published assessments by federal and provincial agencies.
– Cumulative production is determined from provincial and territorial gas reserves reports.
– For this table, "unconventional" is defined as natural gas produced from coal (CBM) or by the application of multi-stage hydraulic fracturing to horizontal wells.
– The ultimate potential for natural gas should be considered an estimate that will evolve over time. Additional unconventional potential may be found in unassessed formations.

Table 1. Summary of estimates of Alberta shale- and siltstone-hosted hydrocarbon resource endowment.

Unit	Adsorbed Gas Content %*	Natural Gas (Tcf)	Natural-Gas Liquids (billion bbl)	Oil (billion bbl)
Duvernay P50	6.8	443	11.3	61.7
Duvernay P90–P10	5.6–8.5	353–540	7.5–16.3	44.1–82.9
Muskwa P50	6.9	419	14.8	115.1
Muskwa P90–P10	4.1–10.5	289–527	6.0–26.3	74.8–159.9
Montney P50	17.7	2133	28.9	136.3
Montney P90–P10	10.8–26.0	1630–2828	11.7–54.4	78.6–220.5
Basal Banff/Exshaw P50 (preliminary data; see Section 5.1)	5.7	35	0.092	24.8
Basal Banff/Exshaw P90-P10	3.2–10.0	16–70	0.034–0.217	9.0–44.9
North Nordegg P50 (preliminary data; see Section 5.1)	18.2	148	1.4	37.8
North Nordegg P90–P10	4.6–34.8	70–281	0.487–3.5	19.9–66.4
Wilrich P50 (preliminary data; see Section 5.1)	33.7	246	2.1	47.9
Wilrich P90–P10	6.2–59.2	115–568	0.689–4.449	20.2–172.3
Total P50 (medium estimate) resource endowment	n/a	3424	58.6	423.6

* The percentage of adsorbed gas represents the portion of natural gas that is stored as adsorbed gas.

The resource estimates listed above provide an estimate of total hydrocarbons-in-place. Geological and reservoir engineering constraints, recovery factors, and additional economic factors, as well as social and environmental considerations, will ultimately determine the potential recovery of this large resource.

Duvernay Shale

Since 2011, companies have been testing the Duvernay Shale of Alberta for shale gas and shale oil. Importantly, the Duvernay Shale is also rich in NGLs, including condensate.

The estimates for the total in-place resources in the Duvernay Formation are 784 to 858 Trillion Cubic Feet) of raw gas, with a best estimate of 820 Tcf; 91.7 to 99.4 billion barrels [Bbbls] of natural gas liquids, with a best estimate of 95.9 Bbbls; and 198 to 220 Bbbls of oil, with a best estimate of 208 Bbbls.

https://ags.aer.ca/document/OFR/OFR_2017_02.pdf

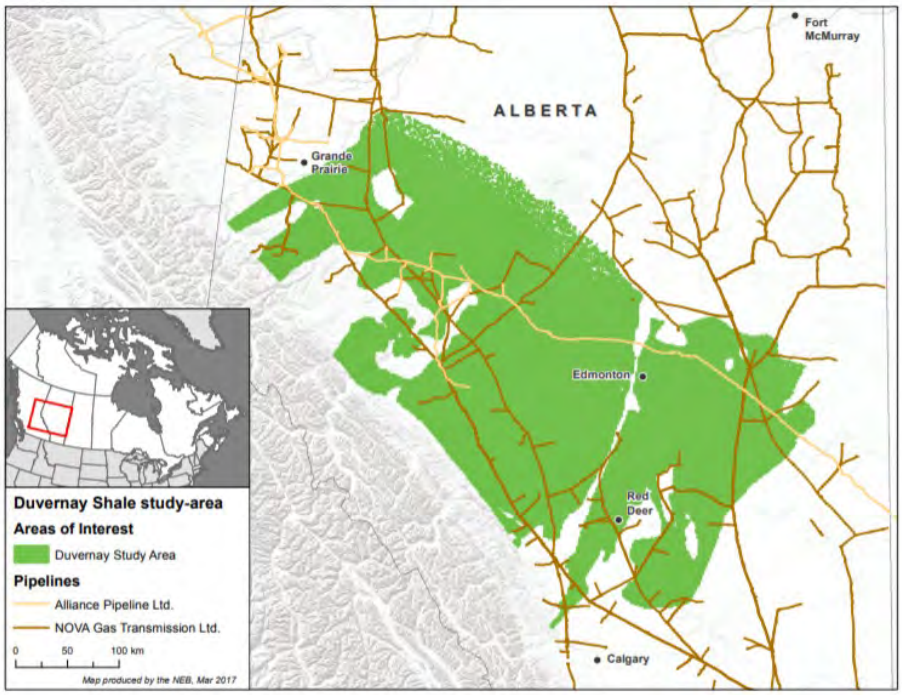
https://www.neb-one.gc.ca/nrg/sttstc/crdlndptrlmprdct/rprt/2017dvrncnmcs/2017dvrncnmcs-eng.pdf

Chevron is moving ahead with commercial development on its Duvernay shale acreage, six years after commencing exploration activities in the play.

The company says the Duvernay — an early-stage liquids rich natural gas resource in west-central Alberta — is “considered one of the most promising shale opportunities on the continent.” The program will utilize long-term infrastructure development and service agreements with Pembina Pipeline and Keyera, with service expected to be available during the second half of 2019.

FIGURE 1

Location of the Duvernay Shale in Alberta and Canada



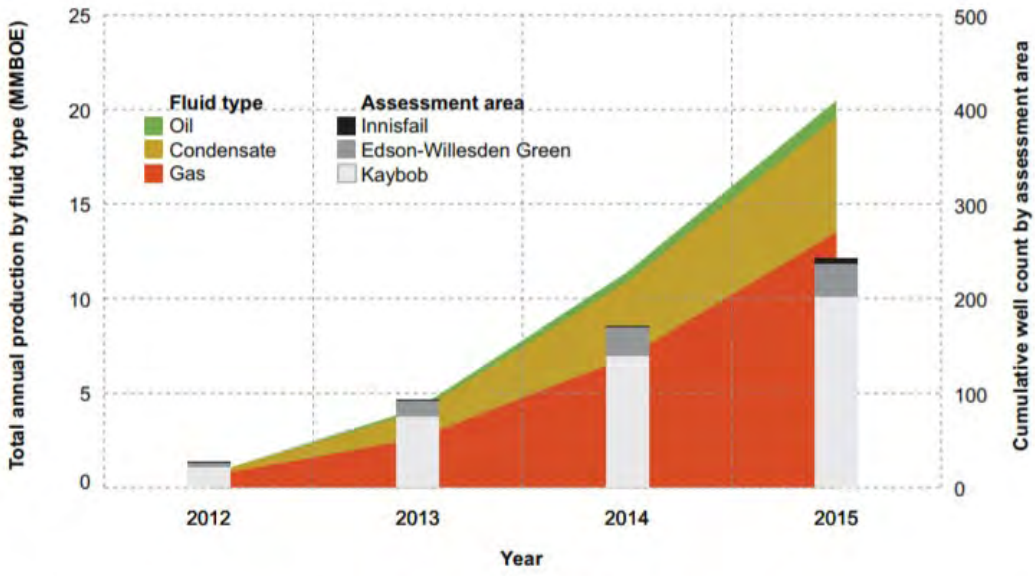


Figure 8. Annual Duvernay production by fluid type and cumulative well count by assessment area

https://www.aer.ca/documents/reports/DuvernayReserves_2016.pdf

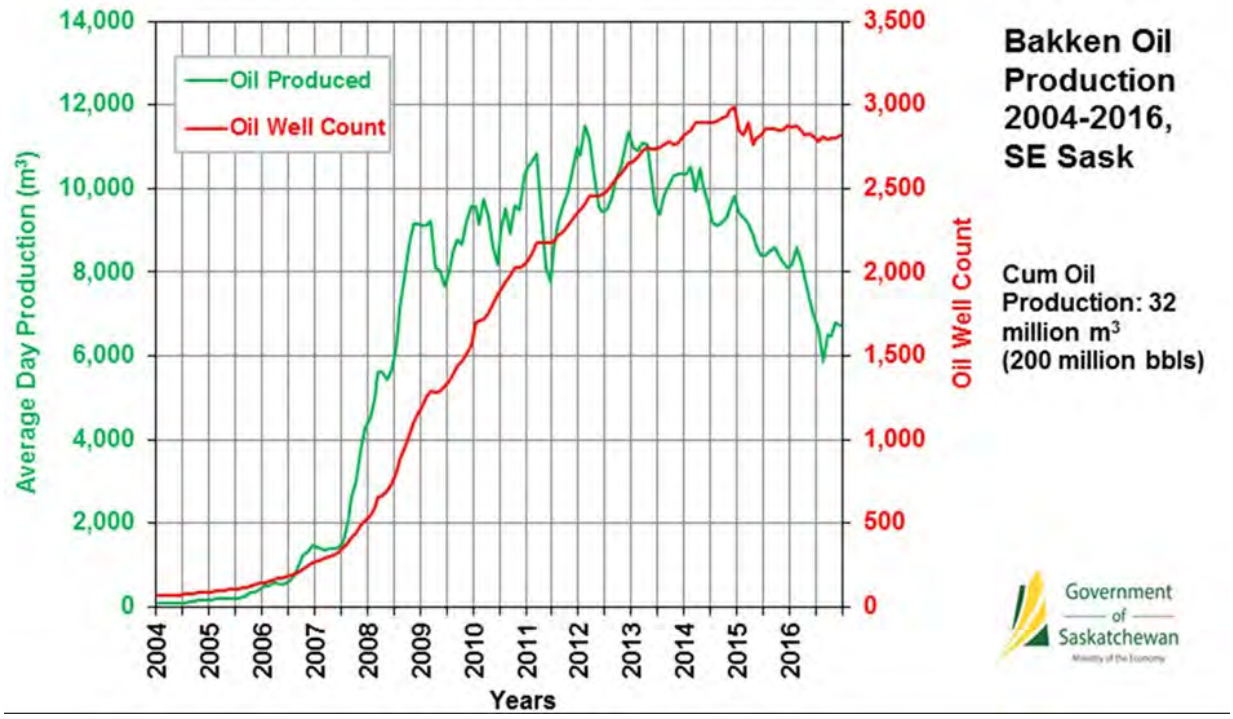
Saskatchewan

Saskatchewan has about seven billion barrels of crude oil and about 9.5 trillion cubic feet of natural gas. To date, over six billion barrels of oil and 7.2 trillion cubic feet of natural gas have been produced.

Saskatchewan is #2 in the amount of oil produced among Canadian provinces, accounting for 12 per cent of Canada's oil production.

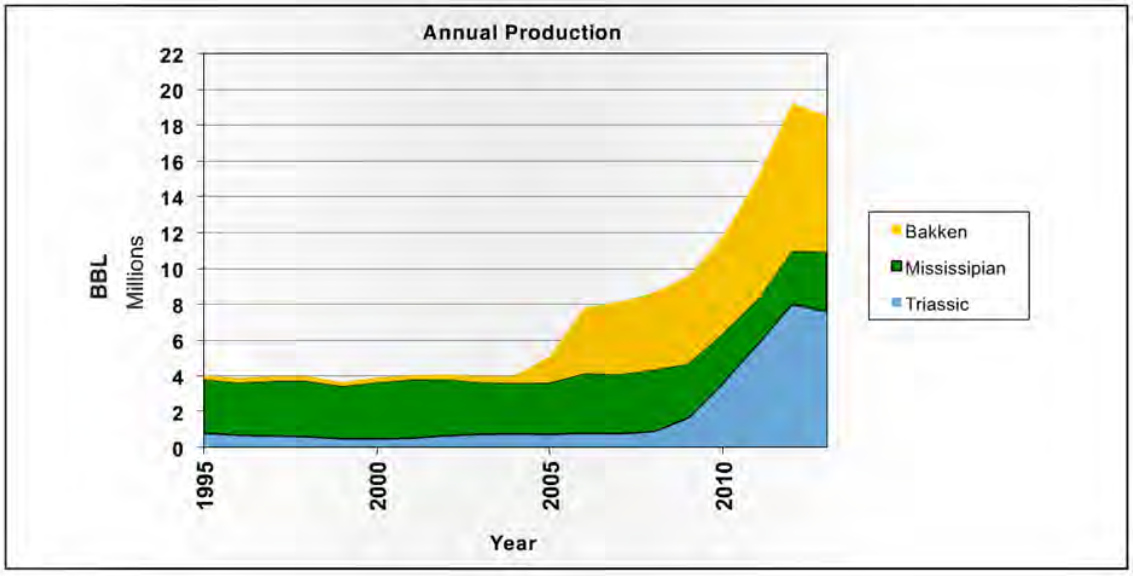
The marketable unconventional oil and natural gas potential of the Bakken Formation in Saskatchewan has been jointly evaluated by the National Energy Board and the Saskatchewan Ministry of the Economy. Located in the southeast corner of the province, the unconventional, marketable resources of the Bakken are expected to be 223 million m^3 (1,401 million barrels) of marketable oil and 81.2 billion m^3 (2.9 trillion cubic feet (Tcf)) of marketable natural gas.

https://www.neb-one.gc.ca/nrg/sttstc/crdlndptrlmprdct/rprt/2015bkkn/index-eng.html



Manitoba

With the development of the Sinclair field, Manitoba has increased its crude oil production from the Mississippian Bakken—Torquay (co-mingled) almost four-fold since 2000 and is now almost 40,000 barrels per day in 2017. There is the potential of Cretaceous Colorado Group shale gas in Manitoba, but no activity or production



Ontario

Although Ontario is not a significant producer of petroleum, the province has almost 2,400 producing oil and gas wells. There has been discussion of drilling the shale sections of Upper Devonian Kettle Point Shale (Antrim Shale Equivalent), Middle Devonian Marcellus Shale, Upper Ordovician Blue Mountain and Collingwood Shale (Utica Equivalent) but shale gas or shale oil are not being extracted anywhere in Ontario. Fracking has been talked about up by each change of government but no action as of yet.
http://www.ogsrlibrary.com/downloads/Ontario_Shale_Gas_OPI_2009_Nov11.pdf

Québec

The other potential bright light in Canadian shale exploration in 2008 was in Quebec, within a 300 km by 100 km fairway between Montreal and Quebec. The Upper Ordovician Utica and Lorraine shales were the targets. Québec has enough natural gas, 20 trillion cubic feet (tcf) of recoverable natural gas, enough to meet Quebec's natural gas demands for more than 100 years or more. Industry drilled 29 wells between 2006 to 2010 and spent $200 million on this play.

In addition, the Upper Ordovician Macasty Shale (Utica Equivalent) on Anticosti Island in the Gulf of St. Lawrence has seen some interest for oil. Corridor reported the results of an independent resource assessment of the Macasty Shale which resulted in a best estimate of the Total Petroleum Initially-In-Place 33.9 billion barrels of oil equivalent (BBOE) for Corridor's land holdings with the low estimate at 21.4 BBOE and the high estimate at 53.9 BBOE.

Corridor and Petrolia completed by 2015 an exploration program of 12 wells with fracking to take place in 2016 but in 2017 a new ministerial order was passed to ban drilling on the island.

After six years of debate on the merits and risks of fracking, Quebec's advisory office of environmental hearings published a report in Dec 2014 that found shale gas development in the Montreal-to-Quebec City region wouldn't be worthwhile. The Bureau d'audiences publiques sur l'environnement (BAPE) warned of a "magnitude of potential impacts associated with shale gas industry in an area as populous and sensitive as the St. Lawrence Lowlands." No fracking is taking place.

New Brunswick

New Brunswick is home to the Frederick Brook Shale, estimated to contain 67.3 Tcf of shale gas in-place which roughly stretches across the southeastern part of the province and is part of the Maritimes Basin. From 2009 to 2013 there have been various operators working this play.

In December 2014, the Government of New Brunswick introduced a moratorium on hydraulic fracturing in the province and indicated that five conditions must be met in order for the moratorium to be lifted. There was another study in February 2016 and finally the moratorium was extended indefinitely in Jan 2017.

Nova Scotia

The government of Nova Scotia estimates Nova Scotia's offshore resource potential at more than eight billion barrels of oil and 120 trillion cubic feet of natural gas. Significant exploration programs are also underway. Onshore, more than 125 exploration wells have been drilled in various parts of the province, with small amounts of petroleum discovered in about one-third of these wells. To date, there has not been any commercial production of onshore oil or natural gas resources in Nova Scotia.

In 2013 the Nova Scotia Government imposed a ban on hydraulic fracturing and promised a comprehensive review by a panel of experts. The panel of experts issued a 387 page report in August of 2014 and suggested that it not proceed and made 32 recommendations. The government then announced a ban. In 2017 the Nova Scotia Dept of Energy and Mines published an Oil and Gas Onshore Atlas, on the potential of both conventional and unconventional hydrocarbons. They assess that there is a potential of 32 TCF of Shale Gas within the Mississippian Horton Bluff Shale and Siltstones based on Brad Hayes and colleagues of Petrel Robertson Consulting Limited. https://energy.novascotia.ca/onshore-atlas-version-1-2017/onshore-atlas-open-file-reports

Prince Edward Island

There are pockets of natural gas deposits under Prince Edward Island, but their exact size and location is unknown because only 20 exploratory wells have been drilled on and around the province. Prince Edward Island's oil and natural gas industry is still in its infancy. However, in excess of one million acres of land are under active exploration for oil and natural resources. There have been no exploration wells drilled in PEI since 2003

Newfoundland and Labrador

Newfoundland and Labrador is currently producing about 250,000 barrels of oil per day from its current offshore oil projects –Hibernia, Terra Nova, White Rose and Hebron. These numbers are expected to increase with the Bay du Nord discovery in 2013. It is expected to be sanctioned in 2020. It has reserves of nearly 300 million barrels of oil with first oil expected in 2025.

The Cambro-Ordovician Green Point Formation is the focus of exploration activity for oil bearing shale in the western parts of the province. This Green Point interval has been studied in outcrop by the Geological Survey of Canada and is summarized in Hamblin (2006). Oil seeps have been documented along the entire coastline and some oil production from as early as the 1900's have been recorded. A well drilled in 2008 from the onshore to the near offshore by Shoal Point Energy and partners encountered about 500 to 2000 m of shale with siltstone stringers with high gas and oil shows throughout the formation but no testing was attempted then. The geochemistry analysis indicates that this zone is in the oil window.

An independent Panel was appointed by the Minister of Natural Resources, Government of Newfoundland and Labrador, in October 2014 to conduct a public review of the socio-economic and environmental implications of hydraulic fracturing in Western

Newfoundland. The mandate of the Panel is also to make recommendations on whether or not hydraulic fracturing should be undertaken in Western Newfoundland.

The results from this Panel came out with these recommendations in May 2016. It outlined 85 supplementary recommendations for government if it wishes to further consider the possibility of hydraulic fracturing, and it emphasizes the necessity of public support in any areas that would be affected by the activity. http://nlhfrp.ca/. There has been no activity since this report.

Northern Canada

Yukon

In Yukon, a committee of six MLA's could not reach a consensus in 2014 around allowing or even addressing hydraulic fracturing. The government subsequently banned fracking across the territory in 2016 except for a small area in the SE corner, and now faces litigation from Northern Cross Energy, which cannot develop its properties without the ability to frac.

Northwest Territories

The Northwest Territories, Nunavut and Yukon have large, untapped resources of crude oil and natural gas. With modern technology and higher prices for oil and natural gas, the North is attracting a growing number of petroleum producers. Considerable exploration and development is underway, especially in the southern part of the territory. The oil and natural gas industry has acquired offshore oil and gas interests and there are some active exploration programs in the Northwest Territories and Yukon.

In November 2016, the Norman Wells pipeline was shut-in because of safety concerns regarding slope stability on the south bank of the Mackenzie River. As a result, production at Norman Wells was suspended and an NEB hearing for the replacement of the affected segment concluded in late October 2017. Effective October 2018 production has resumed.

The slowdown in the global oil and gas sector continued in 2017, impacting all operations and projects in the NWT. A number of oil and gas projects in the onshore areas of the NWT did, however, maintain low activity levels, reflecting an interest by companies in being positioned for the expected upturn in the industry.

Canol and Bluefish Shales as well as the Exshaw and Horn River are the unconventional targets in the NWT.

Table 2: Unconventional resource assessments of Canol and Bluefish shale

	In-Place		
billion m^3 (billion barrels)	Low	Expected	High
Bluefish	4.392 (27.624)	7.366 (46.331)	11.254 (70.786)
Canol	13.129 (82.579)	23.018 (144.779)	35.095 (220.741)

National Energy Board, *An Assessment of the Unconventional Petroleum Resources of the Bluefish Shale and the Canol Shale in the Northwest Territories*, June 2015

https://www.neb-one.gc.ca/nrg/sttstc/crdlndptrlmprdct/rprt/2015shlnt/2015shlnt-eng.pdf

Table 3: Natural gas resource estimates for the Liard Basin

	In-Place		
trillion m^3 (trillion ft^3)	Low	Expected	High
Exshaw-Paltry	5.2 (184)	9.0 (318)	14.5 (514)
Horn River	2.6 (91)	5.3 (187)	9.0 (317)

National Energy Board, *The Unconventional Gas Resources of Mississippian-Devonian Shales in the Liard Basin of British Columbia, the Northwest Territories, and Yukon*, March 2016

https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/ltmtptntlbcnwtkn2016/ltmtptntlbcnwtkn2016-eng.pdf

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In 2013 ConocoPhillips drilled two vertical wells into the Canol Formation and in 2014 they drilled two horizontals. These wells were then hydraulically fractured and extended flow tests were conducted. This play area was then granted a Significant Discovery License.

In Northwest Territories, some First Nations seek out shale exploration, while others have rejected fracking – and the Federal government has taken a non-supportive position. For the first time in decades, petroleum legislation in the Northwest Territories is getting a makeover which is to be tabled in the summer of 2019.

Nunavut

Petroleum exploration in Nunavut began in 1962 and occurred throughout the territory until 1986. Oil production that took place at the Bent Horn oil field on Cameron Island from 1985 to 1996 produced approximately three million barrels of oil. Nunavut which covers approximately 20 per cent of Canada's area territory is estimated to potentially hold a third of Canada's total petroleum resource endowment. Nunavut's discovered resources are held in 20 licensed fields, mostly in the Sverdrup Basin in the high Arctic, and total nearly two billion barrels of crude oil and 27 trillion cubic feet of natural gas.

There has been no consideration of unconventional drilling in this jurisdiction.

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CHINA SHALE GAS AND SHALE LIQUIDS PLAYS

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The shales spanning from Pre-Cambrain Sinian (a period right before Cambrian) to Quaternary are wildely distributed in China. The Pre-Cambrian to Upper Paleozoic organic rich marine and transitional shales with maturity in gas window and shallow Quaternary shales have shale gas potentials and Mesozoic to Cenozoic organic rich shales with maturity in oil window have shale oil potentials (Fig.1, Fig. 2). In 2010, The Strategic Research Center of Oil and Gas, Ministry of Land and Resources and China University of Geosciences at Beijing used an analog assessment regime to announce that China Shale Gas resource is predicted to be about 30 BCM (billion cubic meter or 1050 TCF). in March 2012, China Ministry of Land and Resources announced China had 25.08 trillion cubic meters (886 TCF) of recoverable onshore shale gas reserve. In 2013, EIA's report indicates China has recoverable shale gas reserve of 1115 TCF and recoverable shale oil of 32 Billion Barrel, which means China has the largest shale gas resource and 3rd largest shale oil resource in the world. China is currently the largest natural gas importer in the world and 45.3% natural gas relies on import. At the same time, China has been emulating the successful U.S. shale gas production experiences and models in order to power its economy and reduce greenhouse gas emissions. The Chinese shale gas output in 2019 is 10 billion cubic meters, 60% of which is produced from Sinopec's Fuling Shale Gas field. Lacustrine tight/ shale oil exploration has also made breakthrough in Junngar Basin in NW China and Bohai Bay Basin in NE China in 2018.

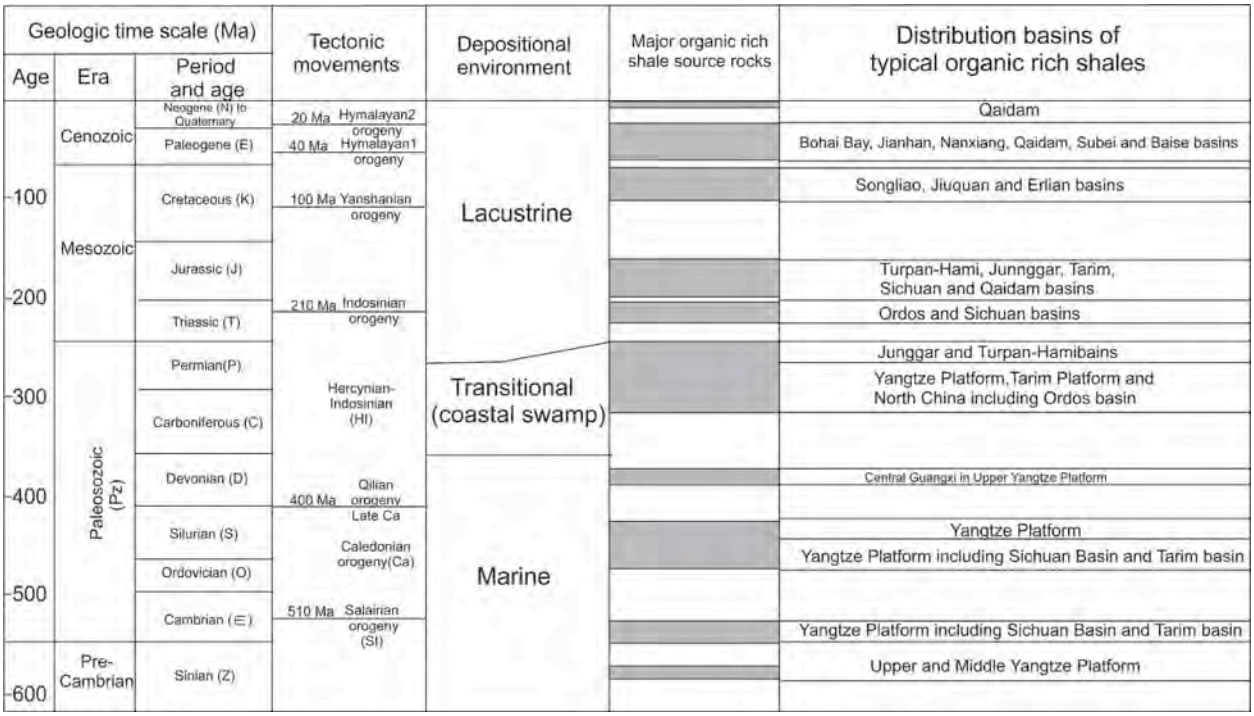

Figure 1. Geologic history and organic rich shale development in China

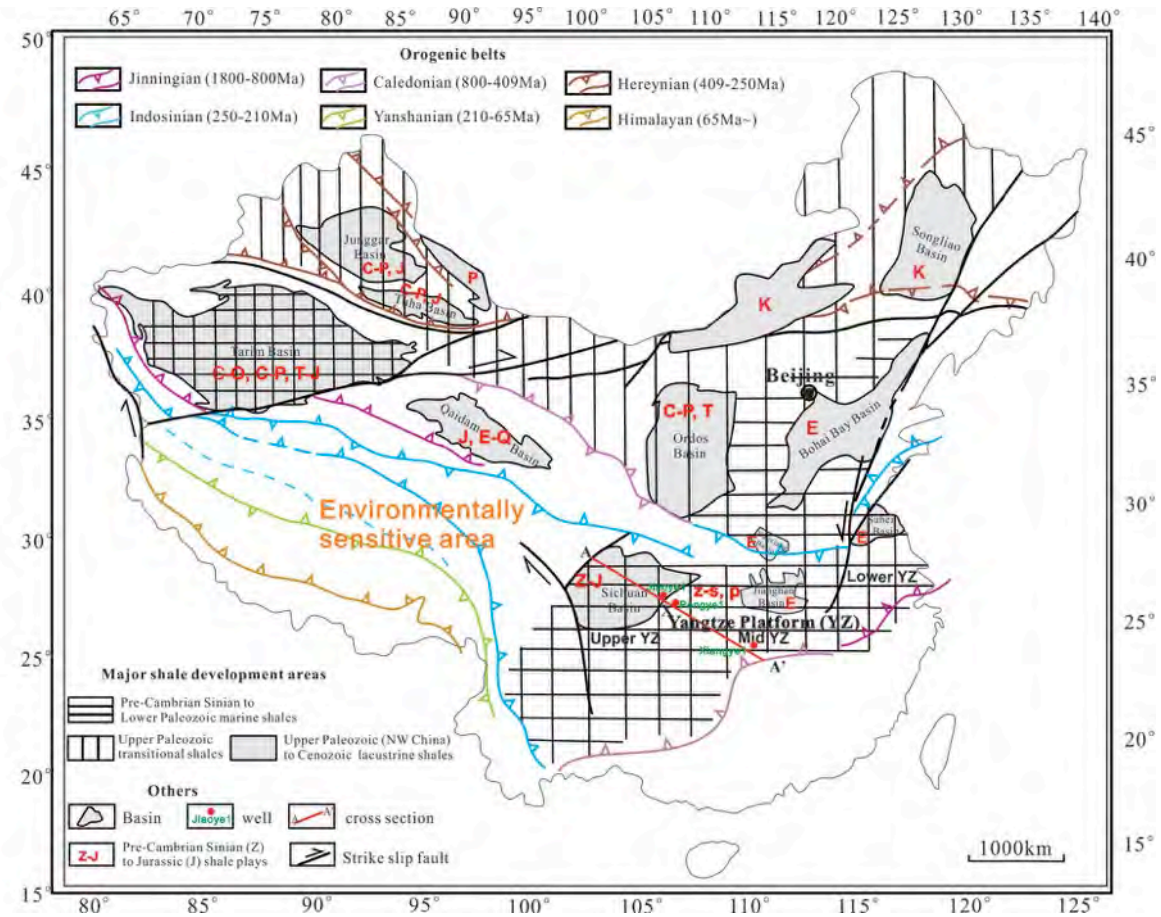

Figure 2. The distribution of organic rich shales in China. Z=Pre-Cambrian Sinian; ∈=Cambrian; O=Ordovician; S=Silurian; C=Carboniferous; P=Permian; T=Triassic;J=Jurassic; K=Cretaceous; E=Paleogene. Q=Quaternary

Shale gas

Commercial shale gas production in China is only from the Silurian marine Longmaxi shale in the Sichuan Basin and its margin in the Upper Yangtze region. Since the discovery and production of Fuling shale gas field in the SE Sichuan Basin, several breakthroughs have been made in the geologically complex areas outside basin, e.g. Pengshui, Zhaotong. The shale gas production rate and formation pressure generally decrease from areas inside Sichuan Basin to areas outside the Sichuan Basin (Fig. 3). In 2018, 143 drilling rigs were deployed to produce shale gas in southern Sichuan Province.

In March 2019, PetroChina Southwest Brach successfully struck daily shale gas flow of 1.38 million cubic meters from the deep Lu203 well in the southern Sichuan Basin. This reservoir is characterized by deep burial of >4000 m, fracturing pressure of >110 MPa, high temperature of 140 ºC, and large stress constrast of 20 MPa. In March 2019, Sinopec discovered Weiyuan-Rongchang Shale Gas Field with reserve of 124.7 billion cubic meters. This indicates the huge potentials of deep shale gas in China. Recently, high-yielding shale gas flow has been obtained in geological formation systems of Sinian, Cambrian and Silurian in Western Hubei in Middle Yangtze region. At present, great breakthroughs or progress have been successively made in Zunyi,Guizhou Province,Yichang, Hubei Province and Xuancheng,Anhui Province while two shale gas

resource bases, Zheng'an, Guizhou Province and Yichang, western Hubei Province, have been initially formed. It's estimated that the geological resource quantity of shale gas in Western Hubei reaches 11.68 trillion cubic meters, which has the annual production capacity of 10 billion cubic meters.

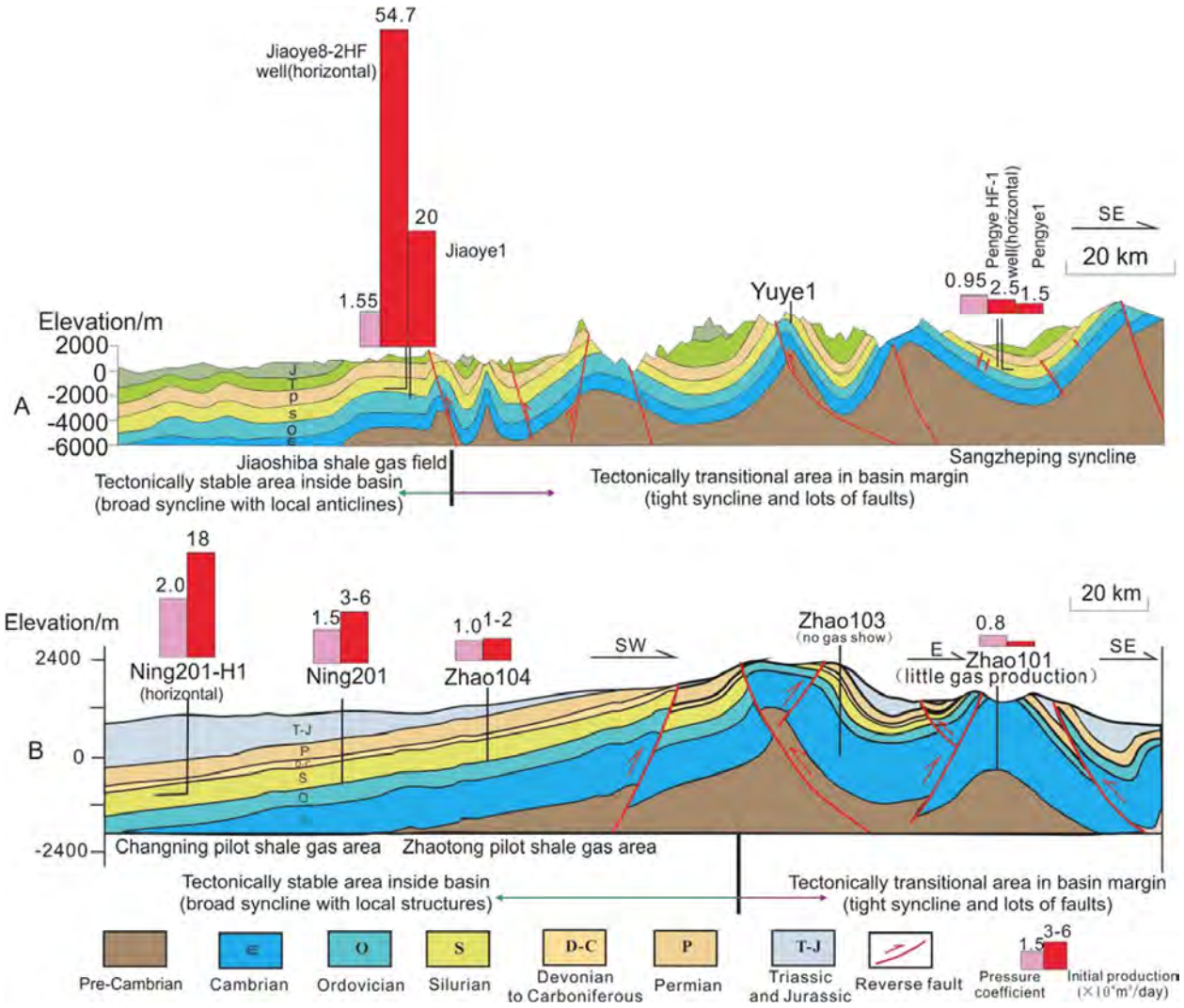

Figure 3. Schematic cross sections demonstrating the variations in formation pressure and initial shale gas production rates from the tectonically stable area inside the Sichuan Basin to the tectonically transitional area with tight synclines and many faults.

Shale oil and tight oil

China's shale oil and tight oil plays are mainly located in the Mesozoic to Cenozoic basins, e.g., Songliao Basin, Ordos Basin, Junggar Basin, Santanhu Bain and Bohai Bay Basin. Since 1978, oil has been producing from fractured shales in Bohai Bay Basin, Biyan Basin, Jianghan Basin, Songliao Basin, Subei Basin, and Tarim Basin. In the last five years, shale oil exploration has been focused in Songliao Basin, Bohai Bay Basin, Junggar and Santanghu Basin. Tight oil was identified from lacustrine Upper Triassic Yanchang formation in Ordos Basin in 1907. China has had some success in producing shale gas, shale oil and tight oil exploration and production has been progressing too for the world's largest crude importer. According the PetroChina's assessment, the Xin'

anbian Oilfield in the Ordos Basin has proven oil reserves of 101×10^6 ton, 3P reserves of 739×10^6 ton and an initial annual production capacity of 829×10^3 ton. The Songliao Basin has newly added probable and possible tight oil reserves of 184×10^6 ton in the Qijia, Weixing and Rangzijing blocks, and an initial annual production capacity of 100×10^3 ton. The Santaghu Basin has probable reserves of 25.06×10^6 ton in the Permian Tiaohu Formation, and an established annual production capacity of 100×10^3 ton.

Recently, many tight oil fields have been discovered from Ordos, Sichuan, Songliao, Junggar, Santanghu, and Tuha basins. In 2018, PetroChina has achieved daily output of 100 tons of oil (733 barrels) at a test well in the Jimsar field in the Junggar Basin located in the Xinjiang province in NW China, suggesting that shale oil has strong commercial potential in the nation for the first time. The Jimsa oil field has been assessed to have a recoverable oil reserve of 1 billion tons. In early 2019, PetroChina Dagang Oilfield announced the 1701H1 and 1702H horizontal wells in Bohai Bay Basin have been naturally flowing shale oil with a daily raw oil output of 20 to 30 cubic meters for more than 260 days, which indicates the massive shale oil reserves of 100 million tons could take place in this area in the Bohai Bay Basin. In early 2019, Shell signed an agreement with Sinipec to enter China's shale oil sector in Bohai Bay Basin.

SHALE GAS AND SHALE LIQUIDS PLAYS IN EUROPE

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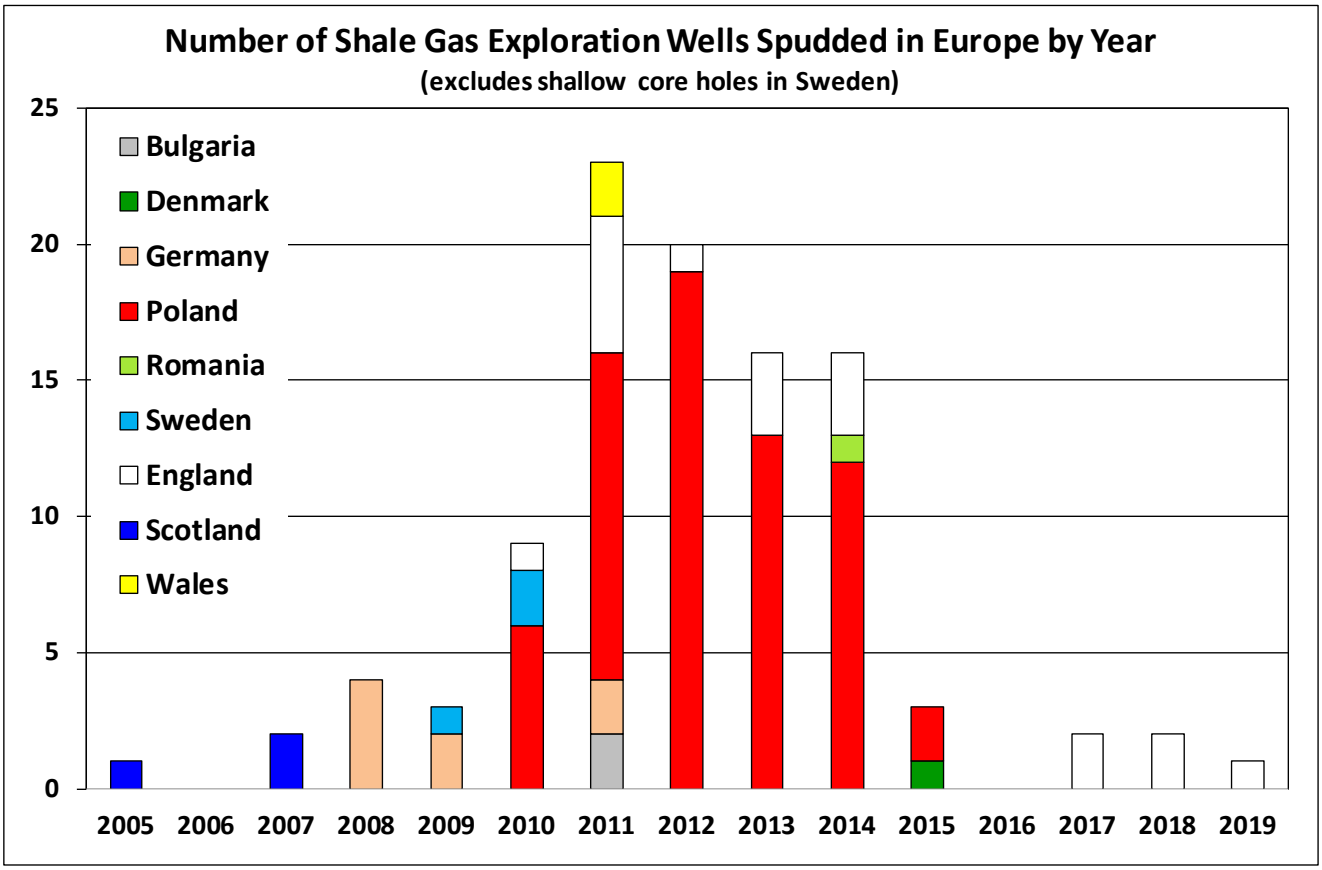
Summary of the period October 2017 – May 2019

Europe continues to be relatively unexplored for shale gas and, especially, shale liquids. Shale gas drilling has taken place in six countries and shale liquids drilling in three countries. In total some 141 exploration and appraisal wells with a possible shale gas exploration component have been spudded, including horizontal legs from vertical wells. 39 of these wells are shallow gas tests drilled in Sweden, largely using mineral exploration equipment. Some 11 wells have been drilled to target shale liquids and hybrid continuous tight oil deposits.

After 2015, when two wells were drilled in Poland and one in Denmark, significant shale gas exploration activity has been limited to England, where a pilot hole and two horizontal wells have been drilled in Lancashire. The horizontals are being hydraulically fractured in the Lower and Upper Bowland Shale (Mississippian).



In Nottinghamshire, two vertical shale gas exploration wells were drilled in the Gainsborough Trough of the English East Midlands Basin.

Opposition to hydraulic fracturing and shale oil and gas exploration at grassroots level in general remains strong. Public pressure has resulted in moratoria being placed on some or all aspects of shale gas exploration and production in Bulgaria, Czech Republic, France, Germany, Ireland and Netherlands, plus certain administrative regions in Spain, Switzerland and the UK (Scotland; Wales; Northern Ireland). Proposed environmental legislation led OMV to abandon its plans for shale gas exploration in Austria.

Exploration to date has also shown that the geology in many countries is unfavourable for shale gas production.

As a result, England is the only European country in which active shale gas exploration is taking place. Jurassic tight oil exploration is also taking place in Southern England, where a number of naturally fractured limestones within the Upper Jurassic Kimmeridge Clay source are under test.

Country Update

United Kingdom

England Shale Gas

Cuadrilla Resources. On 4th February 2014, Cuadrilla announced that it intended to apply for planning permission to drill, hydraulically fracture and flow test up to four exploration wells on each of two sites, one at Roseacre Wood, Roseacre, and the other at Preston New Road, Little Plumpton. Separate applications were also made to install two seismic arrays that will be used to monitor the hydraulic fracturing process.

Planning applications were submitted on 29th May (Preston New Road) and 16th June 2014 (Roseacre Wood). The Environment Agency granted the necessary environmental permits for shale gas exploration on 16th January (Preston New Road) and 6th February 2015 (Roseacre Wood). The company still required planning permission from Lancashire County Council before operations could proceed. In January 2015 Cuadrilla asked for a deferral of the planning applications to address noise and traffic issues that had been identified by the Council's planning officers.

In June 2015 Lancashire County Council refused planning permission for the two sites, despite a recommendation of approval for the Preston New Road site from the council's planning officer. The reasons given for refusal were noise and visual impact (Preston New Road) and traffic (Roseacre Wood).

Cuadrilla appealed the decisions and a 6-week public enquiry commenced before a planning inspector on 9th February 2016. The inspector's recommendation was due to be submitted to the Secretary of State for Communities and Local Government by 4th July 2016 but the recommendation was not to be made public until the Secretary of State had made his decision.

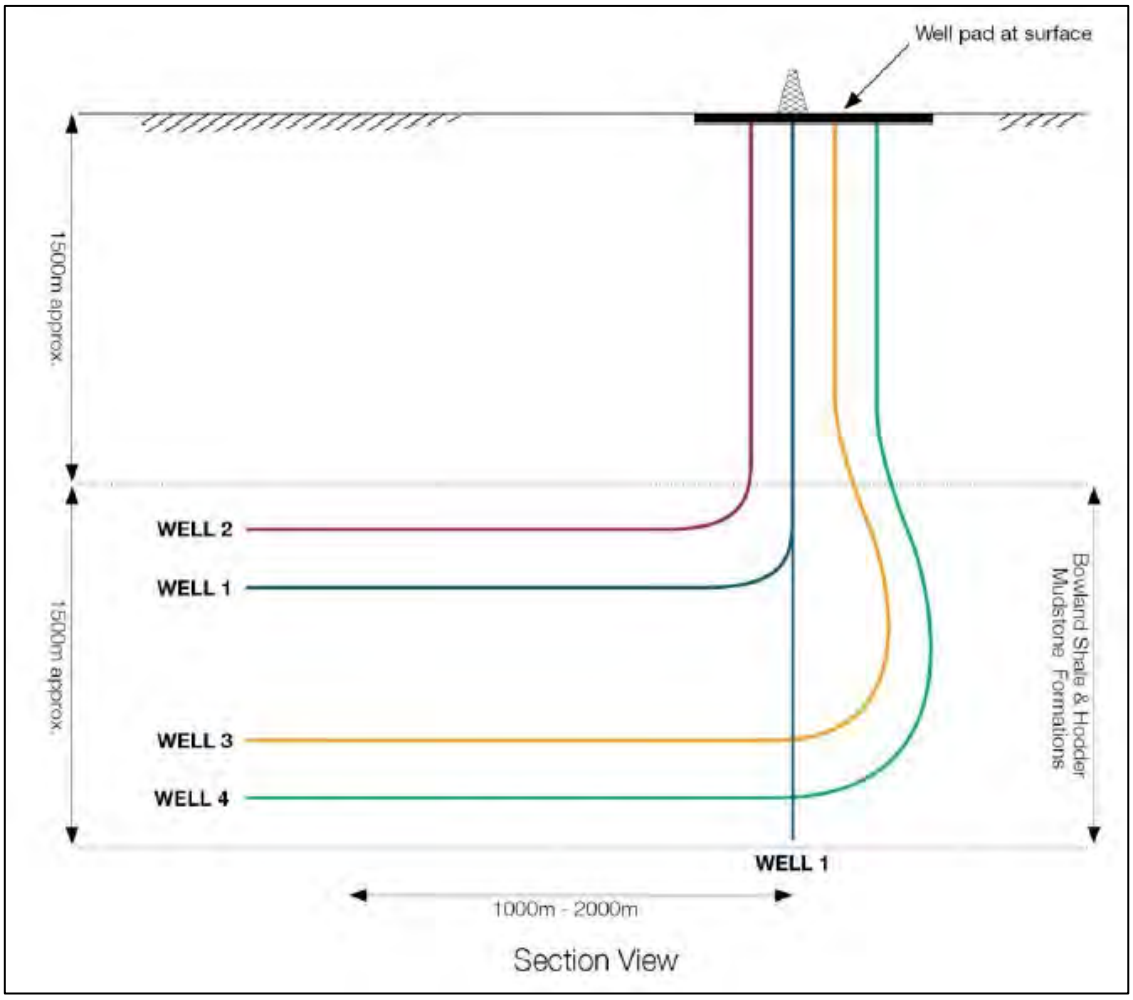
On 6th October the Secretary of State for Communities and Local Government announced approval of Cuadrilla's plan to drill and fracture 4 wells at the Preston New Road site. The Secretary of State's decision was challenged by judicial review in March 2017 but on 12th April 2017 Mr Justice Dove dismissed the claims against the Secretary

of State. Site construction work had started on the Preston New Road site in January 2017.

Current licence terms for the PEDL 165 licence require one horizontal well to be drilled and fractured by 30th June 2019 and a Field Development Plan to be submitted by 30th June 2021. The drilling rig was delivered to the Preston New Road site in July 2017 and Preston New Road-2 (Well 2 in illustration below) was spudded on 17th August. Preston New Road-1 (Well 1) was then spudded on 16th September 2017. Well 1 was drilled as a vertical pilot hole to a TD of 8,575' to determine the optimum kick-off depth for the horizontal sidetrack of Well 1, Preston New Road-1Z. The sidetrack was spudded on 18th January 2018 at a depth of about 6,600' and completed on 18th December 2018 having drilled a horizontal leg of some 2,560' through the Lower Bowland Shale at a depth of about 7,500'. Well 2 was sidetracked horizontally above Well 1 and completed on 26th June 2018 having drilled a 2,450' horizontal leg in the Upper Bowland Shale, at a depth of around 6,900'.

The UK operates a "traffic light" system for induced seismicity associated with hydraulic fracturing. Fracturing must cease when seismic events of magnitude greater or equal to 0.5 on the Richter scale are recorded. This is a very low threshold, as a result of which the Preston New Road-1Z fracturing programme has taken a considerable length of time and injected sand volumes have been constrained to 14% of plan. The well was partially tested at a peak of over 200,000 scfg/d and stabilised rate of 100,000 scfg/d. The results indicate a potential initial flow rate between 3 and 8 Mscfg/d from an 8,000' lateral if fractured effectively.

[On 27th April 2019 Natascha Engel, the Commissioner for Shale Gas, submitted her resignation after six months in post, complaining that the traffic light system requiring a halt to hydraulic fracturing when a tremor of 0.5 magnitude is recorded effectively "amounts to a *de facto* ban". She suggested that the government and politicians are "choosing to listen to a powerful environmental lobby campaigning against fracking rather than allowing science and evidence to guide our policy making".]



Drilling Plan for Cuadrilla's Preston New Road site

Viking UK Gas. Between June and October 2013, Viking UK Gas, a wholly owned subsidiary of Third Energy, which in turn is 97% owned by a private equity arm of Barclays Bank, drilled Kirby Misperton-8 as a deep Bowland Shale appraisal well on the Kirby Misperton conventional field (PL 80) in the Cleveland Basin, North Yorkshire. The neighbouring Kirby Misperton-1 had encountered ~ 2,500' of Bowland Shale when drilled in 1985. In July 2015 a planning application was submitted to hydraulically fracture Kirby Misperton-8. The application went through the public consultation process and was considered and approved by North Yorkshire's planning committee on 20th May 2016, subject to the company meeting 40 conditions. The permission was challenged by local resident group Frack Free Ryedale and Friends of the Earth and a judicial review was held in the High Court in London on 22nd and 23rd November. On 20th December 2016 Mrs Justice Lang decreed that North Yorkshire County Council had acted lawfully in approving the application to fracture test Kirby Misperton-8 and the company could proceed to meet the conditions required by the council after which it can test the well.

On 3rd July 2017 Third Energy submitted its Hydraulic Fracture Plan to the Oil & Gas Authority. Five fracture zones are planned between 7,000' and 10,000', each of 20'

thickness. If gas flow is sufficient, the well will be placed on production and gas sent to the Knapton electricity generating station. On 10th October 2017 the Environment Agency approved the Hydraulic Fracture Plan. The plan was sent to the Department for Business, Energy & Industrial Strategy to confirm that all required conditions have been met. In February 2018 the Secretary of State asked the Oil & Gas Authority to undertake a review of Third Energy's financial resilience to include the eventual decommissioning of the site. Subsequent to the review, on 25th April 2019 Third Energy agreed to sell all of its UK Onshore assets to York Energy (UK) Holdings Ltd., an affiliated company of Alpha Energy, a U.S. based energy company.

IGas. In October 2015, IGas submitted a planning application to Nottinghamshire County Council to drill one vertical well to approximately 11,500' and one adjacent horizontal well at Springs Road on PEDL 140 in the Gainsborough Trough, East Midlands. Following two periods of public consultation, on 15th November 2016 Nottinghamshire Council's planning committee approved the plans subject to certain conditions regarding heavy traffic fluid discharge. Springs Road-1 spudded on 22nd January 2019 and was completed on 28th March at a TD of 11,483'. Springs Road-1 was a basin-centre test of the Gainsborough Trough and encountered over 820' of hydrocarbon-bearing shale in the Mississippian Upper and Lower Bowland Shale, recovering 480' of shale core. Hydrocarbons were also recorded in the Arundian Shale at TD.

A further application to drill a vertical shale gas exploration well at Tinker Lane on PEDL 200 in the Gainsborough Trough was approved by Nottinghamshire Council's planning committee on 21st March 2017, subject to certain conditions. The licence terms for PEDL 200 had required one well to be drilled by 31st December 2017 and a horizontal well by June 2021. The objective of this test was to determine whether basin margin shales are prospective. Tinker Lane-1 was spudded on 27th November 2018 and completed on 29th December 2018 at a TD of 5,650'. The Bowland Shale was not present in the well but gas-bearing shale was encountered in the Millstone Grit Group (Upper Mississippian – Lower Pennsylvanian).

INEOS. On 1st November 2017, INEOS Shale announced that it had acquired Total E&P Limited's entire UK onshore exploratory licence portfolio, less a 20% stake in three 14th Round licence awards that Total will retain. The transaction includes 100% of Total's 40% participating interest in PEDLs 139 and 140, and 60% of Total's 50% interest in PEDLs 273, 305 and 316. All five licences are in Eastern England (Nottinghamshire; Yorkshire; Lincolnshire).

England Tight Oil

UK Oil & Gas Investments PLC (UKOG). Horse Hill Developments Ltd. (UKOG 49.9%), as operator, drilled Horse Hill-1 between September and November 2014 on PEDL 137 in the Weald Basin to a TD of 8,770' in Paleozoic rocks. Horse Hill Developments Ltd. has a 65% interest in PEDL 137 giving UKOG a net interest of 32.435% in the licence. A conventional oil discovery was made in the Portland Sandstone (Upper Jurassic). The well also identified potential recoverable liquids within a 653' aggregate net pay in naturally fractured argillaceous limestone and mudstone of the Kimmeridge Clay and

mudstones of the Oxford and Lower Lias intervals. The Kimmeridge section contains 511' net pay with average TOC of 2.8% and calculated oil-in-place of 115 million bbl / square mile.

The hydrocarbon occurrence appears to be analagous to Cuadrilla's Balcombe-2 discovery (below). The British Geological Survey (Andrews, 2014) has described this play as being a hybrid Bakken-type shale play (although the Balcombe-2 discovery may also have an element of structural closure). It is believed that the liquids can be developed by conventional horizontal drilling and completion techniques without recourse to hydraulic fracturing. The productive intervals are shallower than the 1,000 metre (3,280') upper permissible limit for hydraulic fracturing in the UK.

The well was placed on flow test in Spring 2016. An upper limestone interval (KL4) in the Middle Kimmeridge Clay was perforated over an 88' aggregate interval at about 2,750' and flowed in excess of 900 bo/d of 40° oil. A lower limestone interval (KL3) in the Middle Kimmeridge Clay at around 2,950' flowed in excess of 460 bo/d from an 80' perforated zone. The conventional Portland Sandstone was also tested and flowed at over 300 bo/d over an 8.5-hour period.

On 18th October 2017 Horse Hill Developments announced that Surrey County Council's Planning and Regulatory Committee had granted planning permission to enable HHDL to carry out extended flow tests at Horse Hill-1, plus drill and test both a sidetrack from the existing Horse Hill-1 well and new borehole Horse Hill-2. These wells are planned for Q2 2019. The extended well test produced 25,000 bbl of dry oil from the Kimmeridge Limestone and 15,000 bbl of dry oil from the conventional Portland reservoir.

On 29th May 2017 Kimmeridge Oil & Gas Ltd. (UKOG 100%) spudded Broadford Bridge-1 on PEDL 234 in the Weald Basin 27 km (17 miles) southeast of Horse Hill-1. The well reached a TD of 5,850'. On 29th July a mechanical sidetrack (1z) was kicked off at 2,613' and drilled to a TD of 5,757'. The wells encountered a gross vertical naturally fractured oil-bearing thickness of some 1,400' of Kimmeridge Clay within which lay six (6) fractured Kimmeridge Limestone intervals (KL0 – KL5).

With results very similar to Horse Hill-1, the Broadford Bridge wells support the presence of a major continuous tight oil play. The Broadford Bridge-1z sidetrack was perforated over an interval from 3,920' – 5,657' MD. The aggregate perforated thickness of eight (8) naturally fractured Kimmeridge Limestone and interbedded shale units was 1,064'. A 14-week extended flow test commenced on 6th September 2017. After acidizing some oil flowed to the surface from KL-5 but formation damage was suspected in KL-3 and KL-4.

Two Broadford Bridge wells are planned from other locations in 2019.

Angus Energy. On 20th January 2017 Angus Energy Ltd (operator: 55%) re-entered and sidetracked well Brockham-X4 drilled on PL 235 by Key Petroleum in 2007. The re-entry was designed to test for the presence of the naturally fractured Kimmeridge limestones and shale found in the Horse Hill well. The well was completed on 27th January 2017 at a TD of 4,564'. A gross Kimmeridge thickness of 1,265' TVD was

encountered, as were the two limestone intervals tested at Horse Hill. Three limestones in total were found within a 650' interval of naturally fractured limestone and shale in the centre of the Kimmeridge interval.

On 11th May 2017 Angus Energy submitted a Field Development Plan Addendum to the Oil & Gas Authority to produce from the Kimmeridge interval and on 23rd October 2017 announced that approval had been granted. Production from the 650' Kimmeridge interval will commence once a connection to the National Grid has been established for the distribution of excess power generated on-site.

On 4th February 2019, Angus Energy announced that part of the 640' perforated interval was flowing water. On 10th May the operator announced that a bridge plug had been set to isolate the water zone. The well is now awaiting retesting.

Cuadrilla Resources. In April 2010 Cuadrilla received planning permission to drill the Lower Stumble test of the Kimmeridge Clay using the well pad of Balcombe-1, drilled by Conoco in 1986 on the Bolney (Lower Stumble) anticline in PEDL 244.

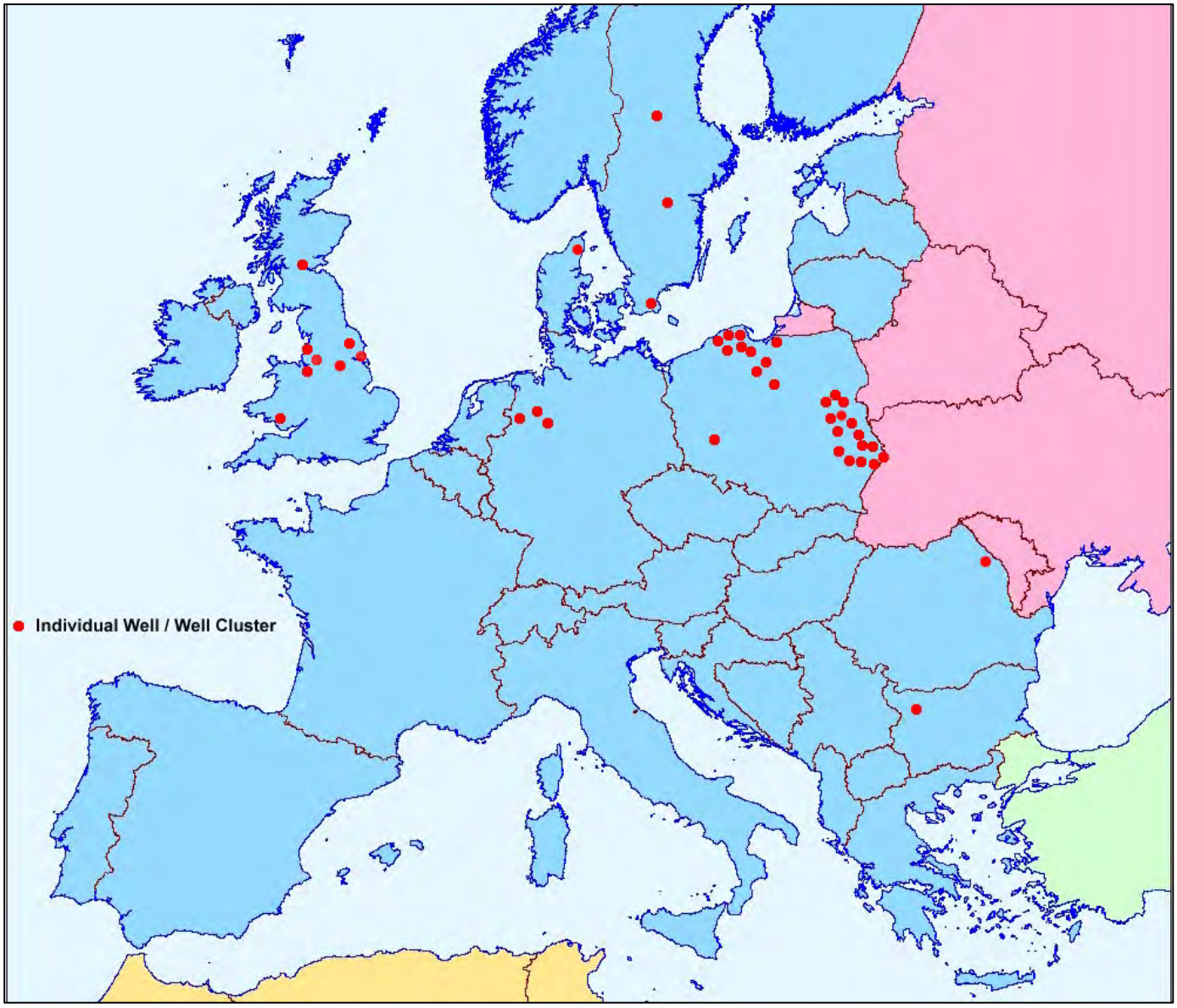
Top Kimmeridge Clay was estimated to occur at a depth of around 1,830' at this location and to lie within the relatively small sweet spot where the Kimmeridge Clay has reached oil maturity. Cuadrilla spudded Balcombe-2 on 2nd August 2013, drilling to a TD of ~2,700' on 5th September, despite interruptions caused by protesters. Balcombe-2 falls within the same Weald Continuous Tight Oil Area tested by the Horse Hill and Broadford Bridge wells. The 1,700' Balcombe-2Z horizontal leg was then drilled within the Mid-Kimmeridge "I" Micrite at 2,350' below ground level and the well completed on 22nd September 2013 at a measured depth of ~ 4,400'. The well encountered hydrocarbons and was suspended for testing.

Planning permission for testing was granted in May 2014 but that subsequently expired. In October 2017 Cuadrilla submitted a new planning application to West Sussex County Council to flow test and monitor the well. The planning application excluded hydraulic fracturing and the well is being treated as a conventional well producing from natural fractures. The application was approved in January 2018.

On 22nd January 2018, Cuadrilla announced that Angus Energy Plc would acquire a 25% interest in PEDL 244 and become operator. On 2nd October 2018 it was announced that Angus Energy had completed a seven day flow test of Balcombe-2Z, flowing at 853 Boe/d and 1,587 Boe/d on two separate tests. Both tests also (unexpectedly) flowed water which the operator believes is not from the reservoir micrite but through communicating fractures. The operator believes it can isolate the water-producing zone and produce from the reservoir using normal pumping procedures.

Appendix 1

Distribution of known shale gas drilling in Europe. *Base map courtesy of IHS*.



GAS SHALES WEB LINKS

EIA World Shale Resource Assessments (September 2019).
http://www.eia.gov/analysis/studies/worldshalegas/

EIA/ARI World Shale Gas and Shale Oil Resource Assessment: Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States (2013)
http://www.eia.gov/analysis/studies/worldshalegas/pdf/fullreport.pdf
http://www.adv-Res.com/pdf/A_EIA_ARI_2013%20World%20Shale%20Gas%20and%20Shale%20Oil%20Resource%20Assessment.pdf

EIA Shale in the United States.
http://www.eia.gov/energy_in_brief/article/shale_in_the_united_states.cfm

EIA Eagle Ford Play Maps Update
http://www.eia.gov/maps/pdf/eagleford122914.pdf

EIA Drilling Productivity Report with analysis of Bakken, Eagle Ford, Haynesville, Marcellus, Niobrara, and Permian shales. http://www.eia.gov/petroleum/drilling/

Understanding shale gas in Canada
http://www.csur.com/resources/understanding-booklets

Understanding tight oil
http://www.csur.com/resources/understanding-booklets

Unconventional Shale Reservoirs/Plays
http://explorationgeology.com/public_html/General_Geology/Geology_Unconventional_Shale.html

PTTC Unconventional Resources Tech Center
http://www.pttc.org/tech_centers/unconventional_resources.htm

Shale Gas and U.S. National Security
http://bakerinstitute.org/publications/EF-pub-DOEShaleGas-07192011.pdf

Frac Chemical Disclosure Registry
http://fracfocus.org/

EIA Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays
http://www.eia.gov/analysis/studies/usshalegas/pdf/usshaleplays.pdf

EIA Maps
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EIA World Shale Gas Resources
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http://geology.com/news/category/utica-shale.shtml

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http://geology.utah.gov/online/ofr/ofr-499.pdf

Woodford and Caney Shales (Oklahoma Geological Survey)
http://www.ogs.ou.edu/level3-oilgas.php

Canadian Society for Unconventional Gas
http://www.csug.ca/

Shale Gas and Liquids Calendar

2019

June 18-20, 2019: DUG East, Pittsburgh, PA. Hart Energy.

https://www.hartenergyconferences.com/dug-east

September 24-26, 2019: DUG Eagle Ford, San Antonio, TX. Hart Energy.

https://www.hartenergyconferences.com/dug-eagle-ford

November 19-21, 2019: DUG Midcontinent, Oklahoma City, OK. Hart Energy.

https://www.hartenergyconferences.com/dug-midcontinent

December 3-5, 2019: Marcellus-Utica Midstream Conference, Pittsburgh, PA. Hart Energy.
https://www.hartenergyconferences.com/marcellus-utica-midstream

2020

April 6-8, 2020: DUG Permian Basin, Fort Worth, TX. Hart Energy.

https://www.hartenergyconferences.com/future-events

June 16-18, 2020: DUG East, Pittsburgh, PA, Hart Energy. https://www.hartenergyconferences.com/future-events

September 8-10, 2020: DUG Eagle Ford, San Antonio, TX, Hart Energy.
https://www.hartenergyconferences.com/future-events

December 1-3, 2020: Marcellus-Utica Midstream Conference, Pittsburgh, PA. Hart Energy.
https://www.hartenergyconferences.com/future-events