Energy and Minerals Division Tight Oil and Gas Committee

Activities and Commodity Report for 2019-2020

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- Kent Bowker, Bowker Petroleum, The Woodlands, TX [Barnett Shale]
- Ben Burke, HighPoint Resources, Denver, CO [Niobrara and Codell]
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Executive Summary

Contributions by Lucy Ko, Ursula Hammes and Justin Birdwell

In 2019, total daily tight oil and gas production increased in the United States month over month, with annualized growth of 14% for oil and 12% for gas. Those gains leveled off in the first quarter of 2020 due to aggressive price competition and increases in international production. Then came the pandemic with a substantially larger dose of economic turmoil, driving down demand due in part to shelter in place orders and safety concerns around travel. Between March and May, tight oil and gas production dropped by nearly 2 million bpd and almost 5 Bcf/day before beginning to recover. Production has continued to increase for the most part through the second half of 2020, but drilling remains subdued throughout most of the U.S. and uncertainty around long term demand along with the current price environment and general state of the economy has contributed to layoffs throughout the industry.

Some shale-gas production has declined recently, but a few areas have seen expansion due to construction of LNG facilities along the East Coast of the U.S. (e.g., the Haynesville Formation). Current U.S. shale-gas production is still higher now than in 2019, with daily production of almost 71 Bcf as of October 2020 driven in large part by increased production from the Marcellus Shale in the Appalachian Basin and shales within the Permian Basin. Shale liquids production is down by around a million bpd to approximately 7.1 million (September 2020; U.S. EIA) from pre-pandemic production levels at the end of 2019 and beginning of 2020. Tight oil production remains dominated by plays in the Permian Basin as well as the Bakken and Eagle Ford Formations.

On the development and production front, new enhanced oil recovery approaches for tight shale reservoirs are being more widely implemented. Natural gas or CO_2 injection is currently being utilized in the Bakken Formation, Eagle Ford Formation, Anadarko Basin, and the Permian Basin to optimize injection sequences and boost recovery. Refracturing of existing wells to reduce drilling costs, improve production, and prolong well productive life has also begun to occur more widely in developed plays.

International interest in exploiting hydrocarbons from unconventional reservoirs continues to develop, with active exploration projects on most continents. Europe remains relatively underexplored as compared to North America, although a total of 141 exploration and appraisal wells with a possible shale-gas exploration component have been spudded, including horizontal legs from vertical wells. Shale exploration has made a breakthrough in China with shale gas output in 2019 of 10 billion cubic meters (35.3 Bcf), 60% of which was produced from Sinopec's Fuling Shale Gas field. Lacustrine shale oil exploration has also been successful in the Sichuan and Ordos Basins in central China, Junggar and Tarim Basins in northwest China, and Songliao Basin in north China, and Bohai Bay Basins in northeast China as of 2018.

South America's potential as an unconventional shale gas and oil province is mainly in Argentina and Brazil, where the production from Neuquen Basin's tight shale of the Vaca Muerta Formation has been steadily increasing since 2016, but only 4% of the shale resource has been developed thus far. According to International Energy Agency's report in 2013, Brazil holds the 9th largest unconventional gas reserves. Brazil has shale oil and gas potential in the Parana, Solimoes and Amazon Basins and is actively producing from the oil shale unit of the Irati Formation. In 2019, the Brazil energy ministry launched REATE 2020 to boost onshore investments that include the expectation of drilling an experimental unconventional well in the northeast region.

For this inaugural report, the new AAPG EMD Tight Oil and Gas Committee (TO&G; formerly the Shale Gas & Liquids and Tight Gas Sands committees) has developed new commodity report requirements for contributors. This includes shorter annual reports focused on new developments, play concepts, along with the typical updates on production and new drilling in the play areas they cover. We are also asking contributors to collect background geologic and production related information into a document that summarizes important features of the plays they cover that will be stored on the TO&G webpage along with our commodity reports.

TO&G is currently working to expand the number of contributors to cover more play areas and replace committee and advisory board members that have recently stepped down. Changes to committee leadership occurred in October as recent chairs transition to EMD elected positions.

Summary of Committee News

- New AAPG Memoir 120 "Mudstone Diagenesis: Research Perspectives for Shale Hydrocarbon Reservoirs, Seals, and Source Rocks" published with chapters from several TO&G contributors and former leaders (Wayne Camp, Kitty Milliken, Joe MacQuaker, Paul Hackley, Neil Fishman)
- New background documents for resources covered in TO&G annual commodity reports
- Website updates submitted – new resources and links, updates coming more regularly
- Recruiting new contributors to cover more U.S. and international resource plays
- New committee leadership (Lucy Ko –chair starting Oct. 2020, with Vice-Chairs Allison Gibbs and Ming Suriamin)

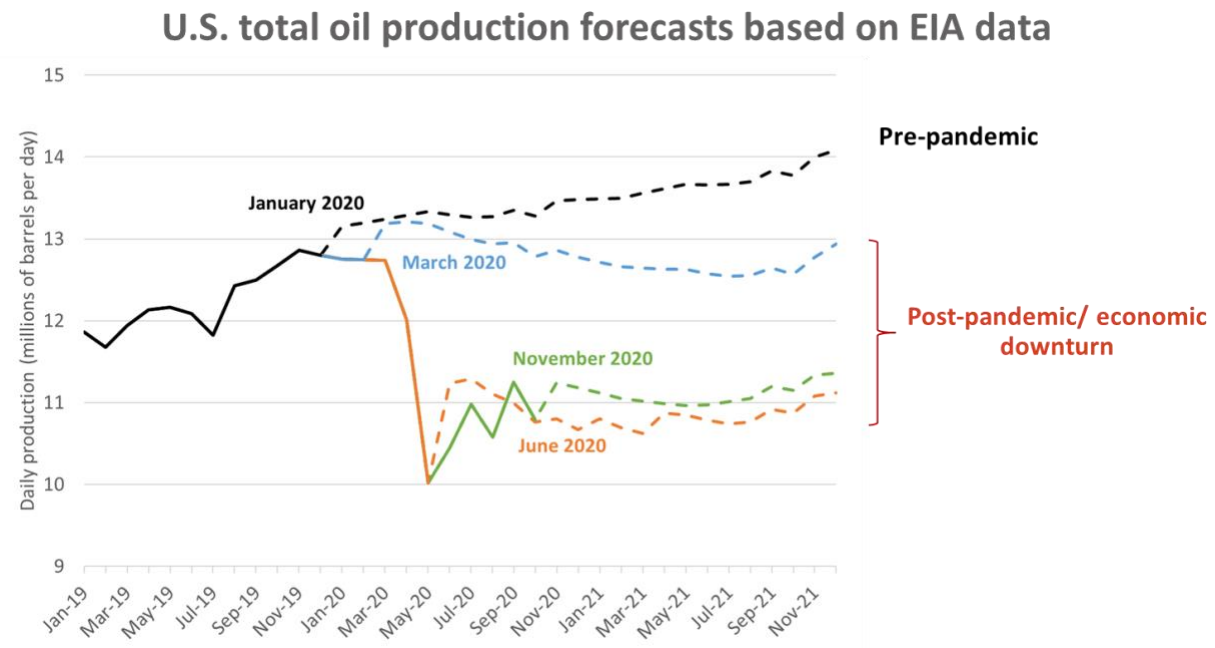


Figure 1. U.S. total oil production forecasts. Solid lines indicate actual production, dashed lines show forecast production through the end of 2021. Data Source: U.S. Energy Information Administration.

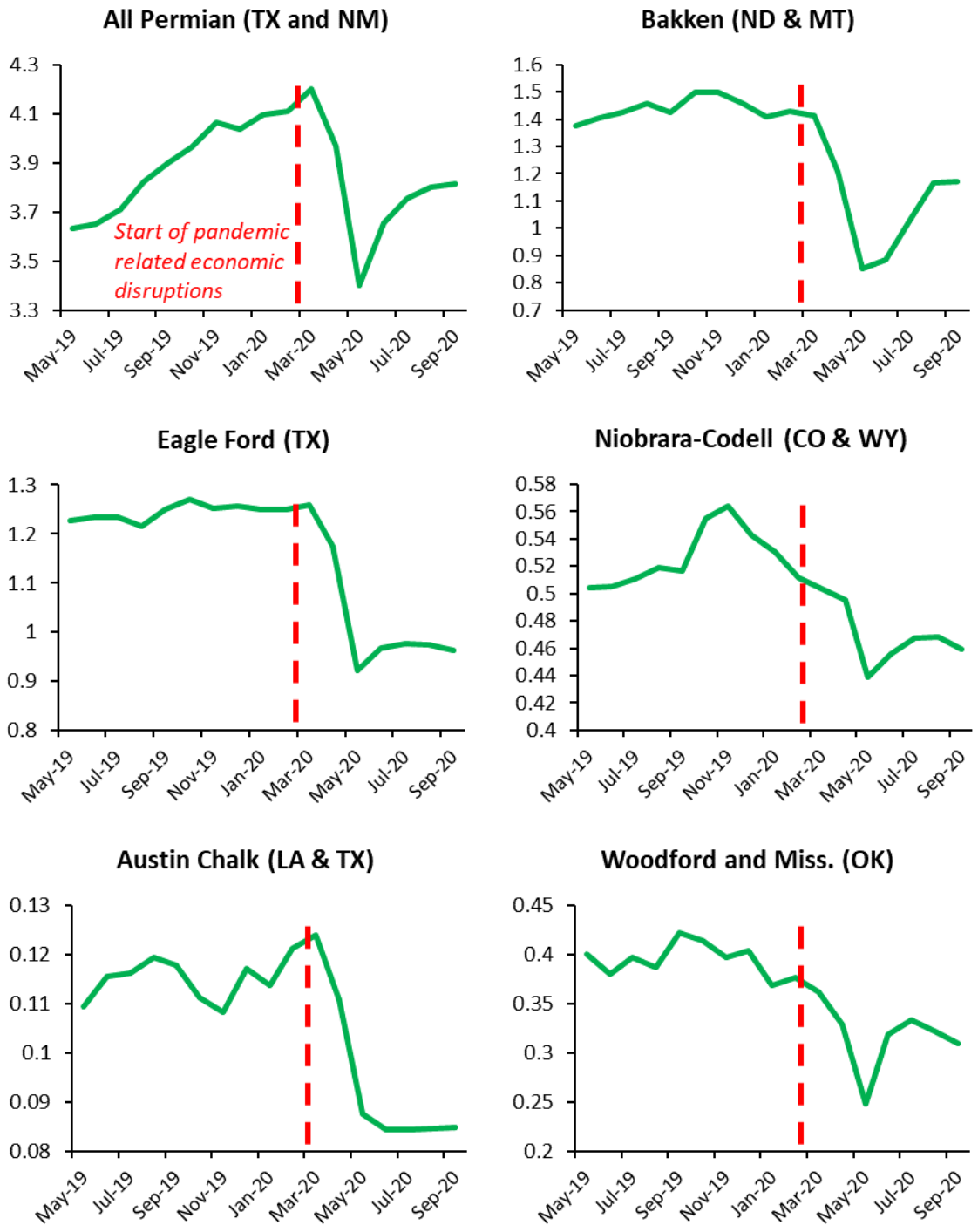


Figure 2. Status of major U.S. tight oil plays. Data source: U.S. EIA, U.S. Tight oil production report (all y-axis values in millions of bbls/day).

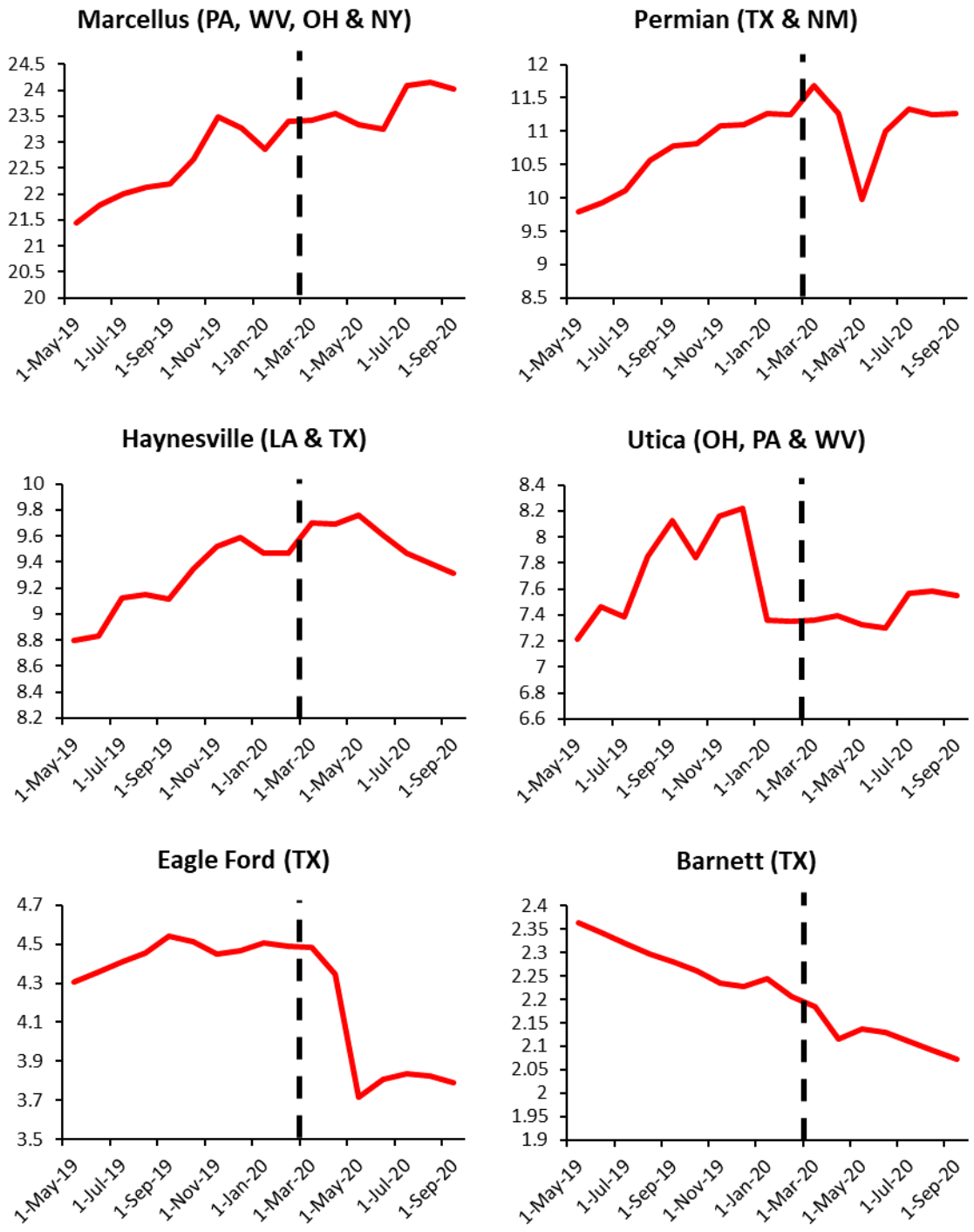


Figure 3. Status of major U.S. tight gas plays. Data source: U.S. EIA, U.S. Tight gas production report (all y-axis values in billions of scf/day).

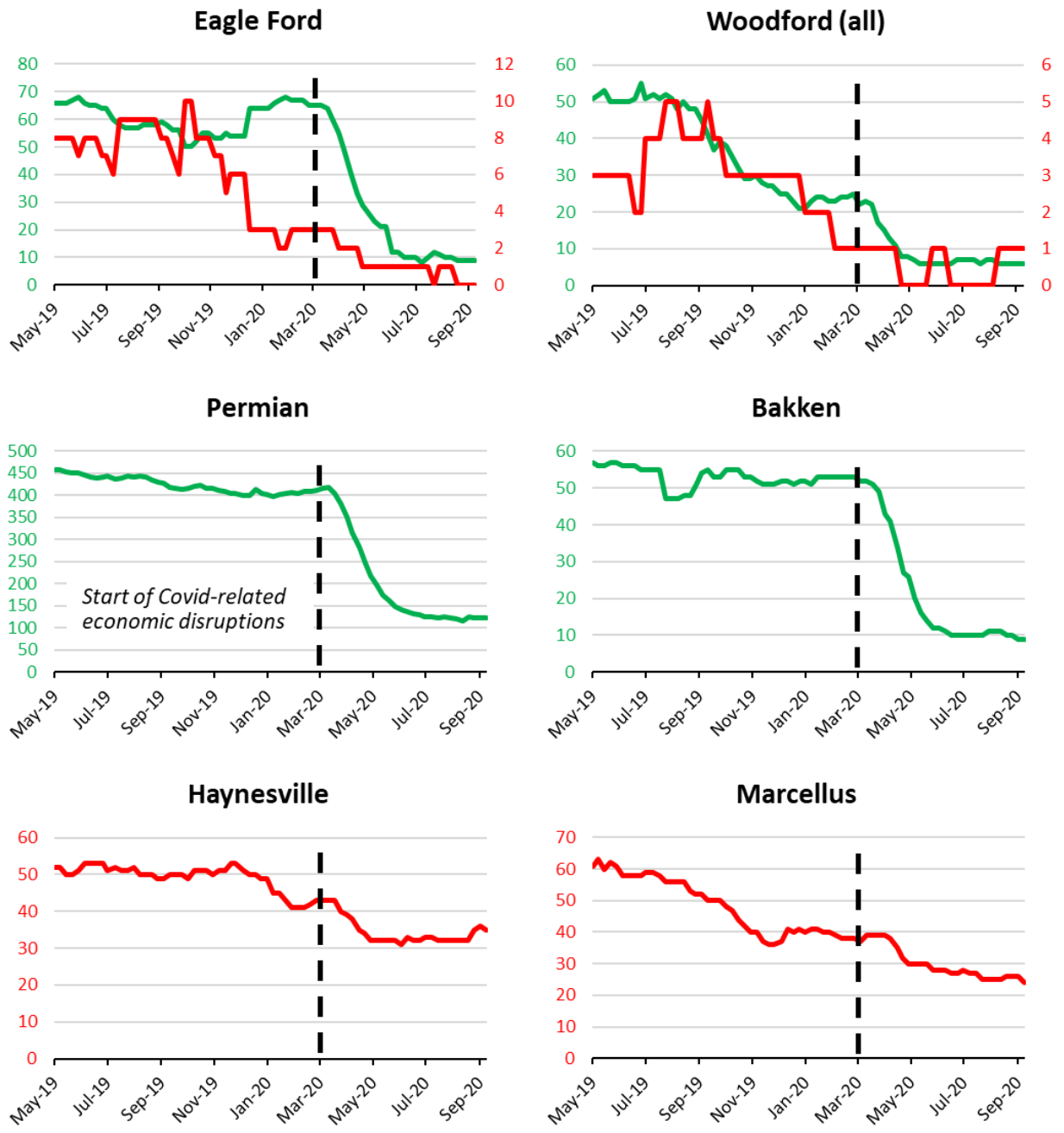
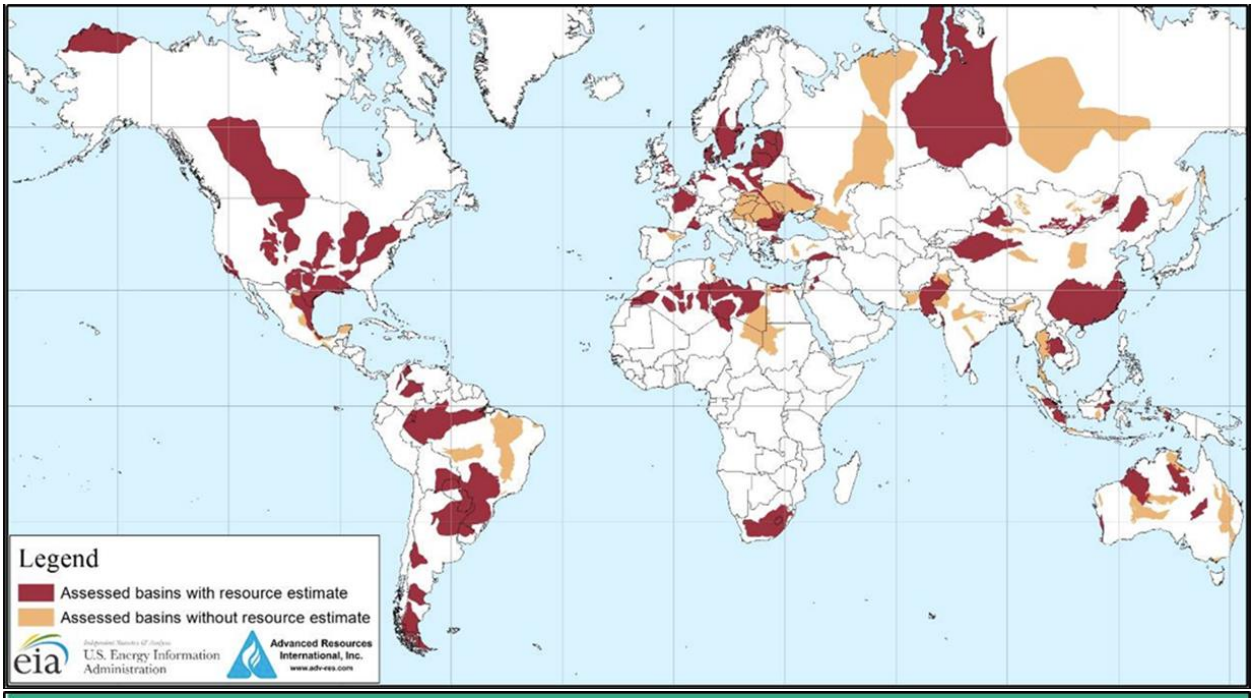


Figure 4. Status of major U.S. tight oil & gas plays: Rig counts over the last 12 months according to Baker Hughes (oil wells in green, gas wells in red); https://rigcount.bakerhughes.com/na-rig-count



Area	Last Count	Count	Change from Prior Count	Date of Prior Count	Change from Last Year	Date of Last Year's Count
U.S.	18 Sept 2020	255	+1	11 Sept 2020	-613	20 Sept 2019
Canada	18 Sept 2020	64	+12	11 Sept 2020	-55	20 Sept 2019
International	Aug 2020	747	+4	July 2020	-391	Aug 2019

Figure 5. Global tight oil and gas resources.

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Austin Chalk, Tokio, and Eutaw Formations, U.S. Onshore Gulf Coast

Justin E. Birdwell, U.S. Geological Survey, Denver, CO

Since the early 1920s, oil and gas production from the Austin Chalk has been ongoing in Texas. A total of nearly one billion barrels of oil and nearly 6 trillion cubic feet of natural gas have been produced to date, much of that from the well-known Giddings Field. The Austin Chalk in Texas overlies and is mainly charged by the prolific underlying Eagle Ford Group. The Tokio and Eutaw Formations are time-equivalent stratigraphic units located east of the Texas-Louisiana border and are also productive for oil and gas. The Tokio, located mainly in southern Arkansas and northern Louisiana, contains sandstone and lignitic shales rather than chalk or limestone, and the Eutaw, located mostly in Mississippi and Alabama, consists of sandstone and carbonaceous shale (**Fig. 1**).

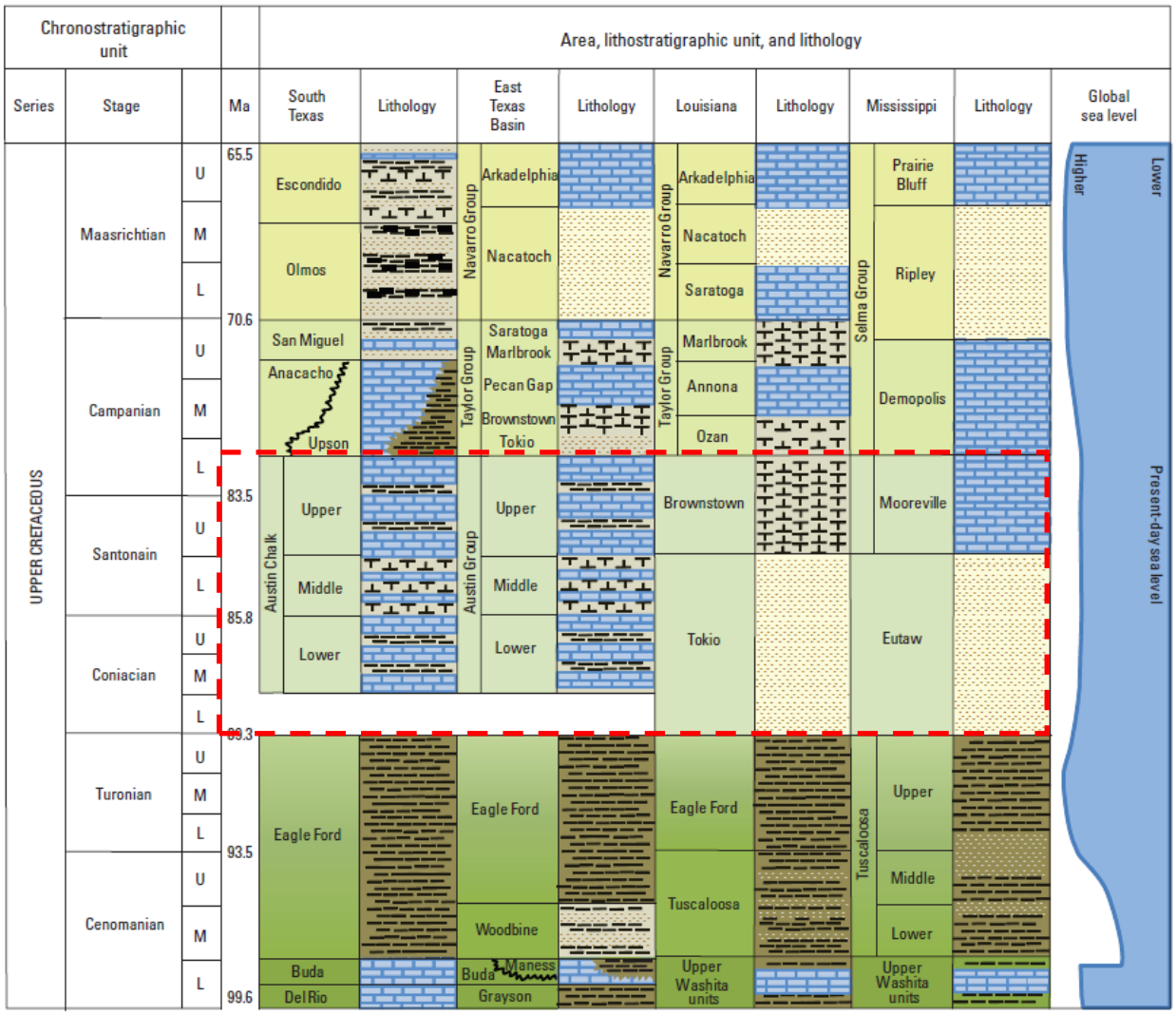

Figure 1. Stratigraphic columns for Upper Cretaceous rocks from South Texas to Mississippi (Pearson, 2012). Shows reservoir rocks (Austin Chalk, Tokio and Eutaw Formations outlined in red), source rocks (Eagle Ford Group and Smackover Formation - not shown), and seals (Anacacho, Upson, Brownstown, and Mooreville Formations and Taylor Group.

The Austin Chalk and equivalent units to the east are reservoirs for oil and gas generated by the Eagle Ford in Texas but sources of oil and gas in these units vary spatially across the onshore Gulf Coast and include the Lower Smackover, Haynesville, and Tuscaloosa Marine Shale. Regional and local-scale faults and salt diapirs facilitate migration into these units and act as reservoir, trap, and seal in conventional fields (Nehring Associates, Inc., 2020). Where it overlies the Eagle Ford and other Cenomanian-Turonian source rocks in Texas, Louisiana, and Mississippi, the Austin Chalk exhibits continuous reservoir behavior. Pressure transmission through faults and fractures in the brittle basal Austin enables petroleum migration into the unit, leading to an areally extensive continuous accumulation of resource. Chalk and marlstone are the dominant lithologies in the Austin, which was deposited on a broad, low relief marine shelf that deepened during the Coniacian-Santonian marine transgression to the south and west. The depositional environments for the Tokio and Eutaw Formations were shallow- to marginal-marine at the leading edge of the marine transgression (Pitman et al., 2020).

Oil migration into the Austin appears to have been through microfractures connected to larger tectonic fractures and the porous chalk matrix. Until the widespread adoption of horizontal drilling and hydraulic fracturing, naturally fractured zones within the chalk were the primary targets and petroleum stored in the rock matrix was initially ignored due to the low permeability of the chalk. Continued improvements in drilling technology and the application of modern drilling methods has made it possible to identify and target porous intervals in the Austin chalk using horizontal wells and multi-stage fracturing jobs. These efforts have significantly increased production from the Austin over the last five years (**Fig. 2**).

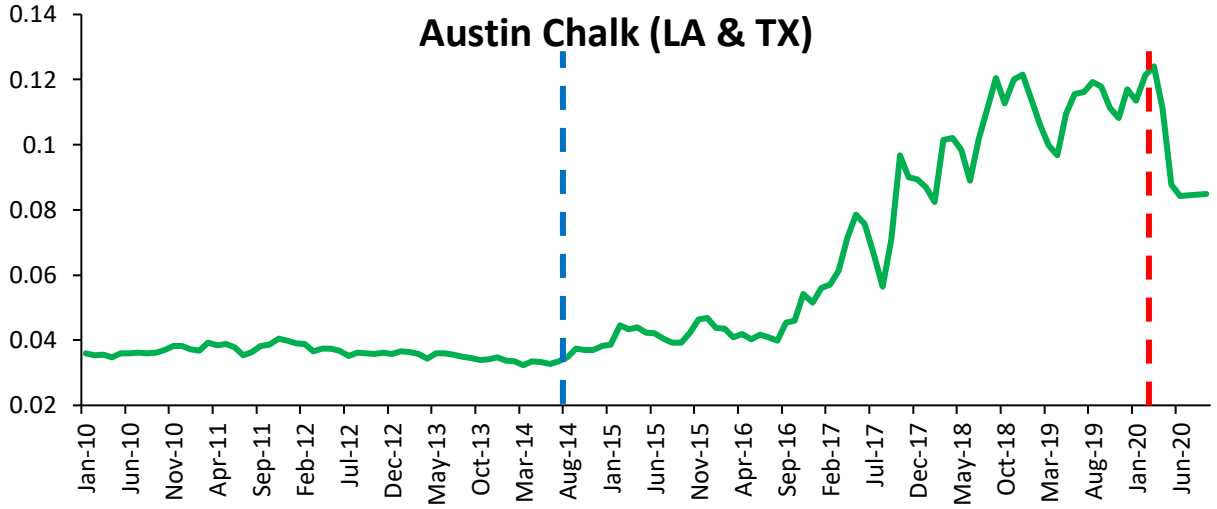

Figure 2. Austin Chalk production (combining Texas and Louisiana) from January 2010 through September 2020 in millions of barrels per day. Blue line shows the onset of increased production from the Austin due to the application of modern drilling methods and the red line indicates the onset of pandemic-related production declines in the U.S. (Source: U.S. EIA, 2020).

The U.S. Geological Survey recently completed an updated assessment of oil and gas resources in the Austin Chalk and Tokio and Eutaw Formations (Pitman et al., 2020). Five conventional and three continuous assessment units were defined (**Fig. 3**) with total estimated mean undiscovered, technically recoverable oil and gas resources of 6.9 billion barrels of oil and 41.5 trillion cubic feet of natural gas.

Like the Eagle Ford, the Austin play differs from many other U.S. shale plays in that it is productive for both oil and gas.

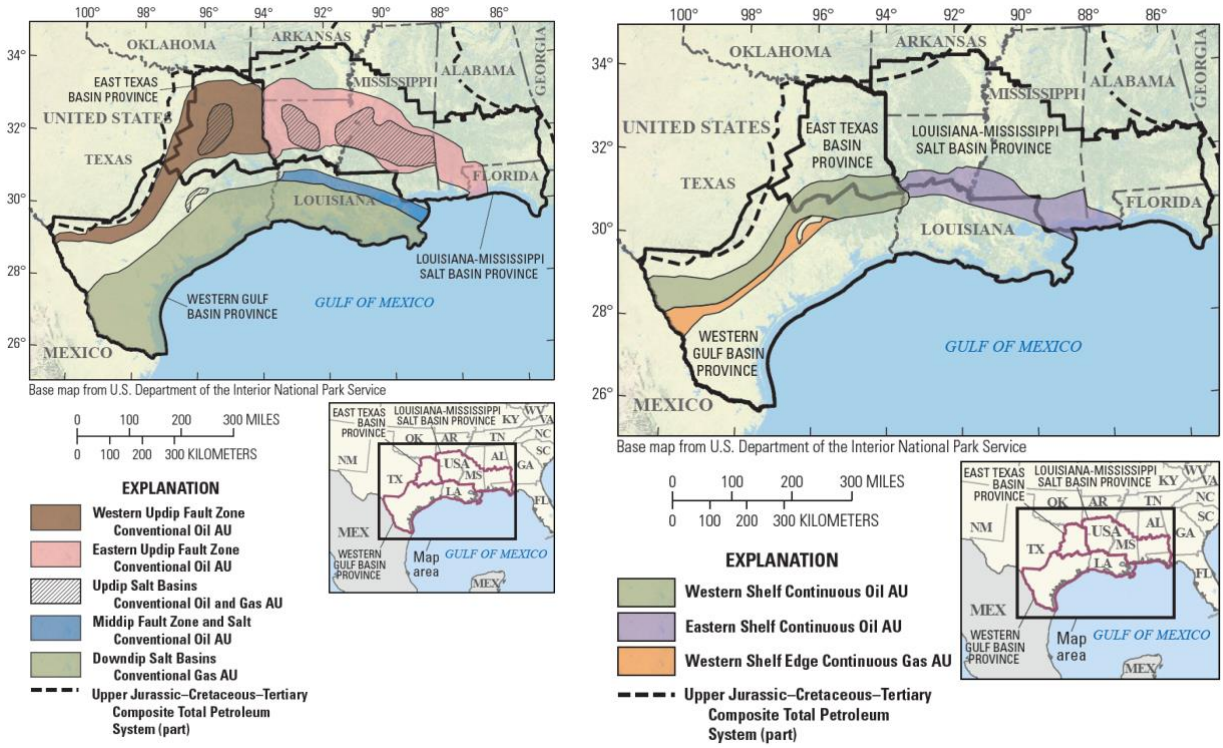

Figure 3. Conventional (left) and continuous (right) assessment unit boundaries determined as part of the 2019 USGS assessment of undiscovered, technically recoverable oil and gas resources in the Austin Chalk and related units in Texas and Louisiana. (Pitman et al., 2020).

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Bakken and Three Forks Formations, Williston Basin, North Dakota and Montana

Kristen Marra, U.S. Geological Survey, Denver, CO

The Bakken Petroleum System of the Williston Basin (North Dakota and Montana) includes the Bakken Formation, the underlying Three Forks Formation, and the overlying Lodgepole Formation (lower part). The Bakken Formation comprises 4 distinct units: the Pronghorn Member (formerly defined as the "Sanish sand") and three informal members: 1) lower shale member, 2) middle Bakken member, and 3) upper shale member. The source rocks of the system are the organic-rich upper and lower shales of the Bakken, which average approximately 11% total organic carbon and consist of type-II kerogen. The primary reservoir targets are low-porosity and low-permeability members of the middle Bakken and Three Forks (upper part), with continued exploration into the middle and lower intervals of the Three Forks and the intervening Pronghorn Member. Bakken oil is also found in limestones of the Lodgepole Formation (Gaswirth and Marra, 2015; Sonnenberg, 2017).

Production in the Bakken and Three Forks Formations began in the early 1950s at Antelope Field. Drilling later shifted to the Billings Nose area (North Dakota), where the upper Bakken shale member was exploited. The first horizontal Bakken well was drilled in this region in 1987. Major sweet spot discoveries include Elm Coulee Field in 2000 and Parshall Field in 2005–2006. Since that time, exploration and production has expanded across the basin, resulting in over 11,000 productive wells in the Bakken to date. Successful horizontal tests of the underlying Three Forks Formation were completed in Divide County (North Dakota) in 2005–2006. Drilling into the Three Forks Formation has expanded north and south along the main structure of the Nesson anticline, along with expansion into the central Williston Basin (North Dakota) and eastward into the region of Parshall Field. More than 5,000 Three Forks wells were in existence by mid-2020. Although the upper Three Forks interval is the primary target due to proximity to the organic-rich lower Bakken shale member, drilling and exploration of the middle and lower Three Forks continues across the basin (Sonnenberg and Pramudito, 2009; Gaswirth and Marra, 2015; Nesheim, 2019; IHS Markit®, 2020).

The Bakken and Three Forks Formations were assessed by the U.S. Geological Survey (USGS) in 2013, resulting in undiscovered, technically recoverable resource estimates of 3.65 billion barrels of oil (BBO) for the Bakken and 3.73 BBO for the Three Forks Formation (total mean resource estimate of 7.38 BBO; Gaswirth and Marra, 2015). The USGS is currently conducting a revised resource assessment of the Bakken and Three Forks Formations.

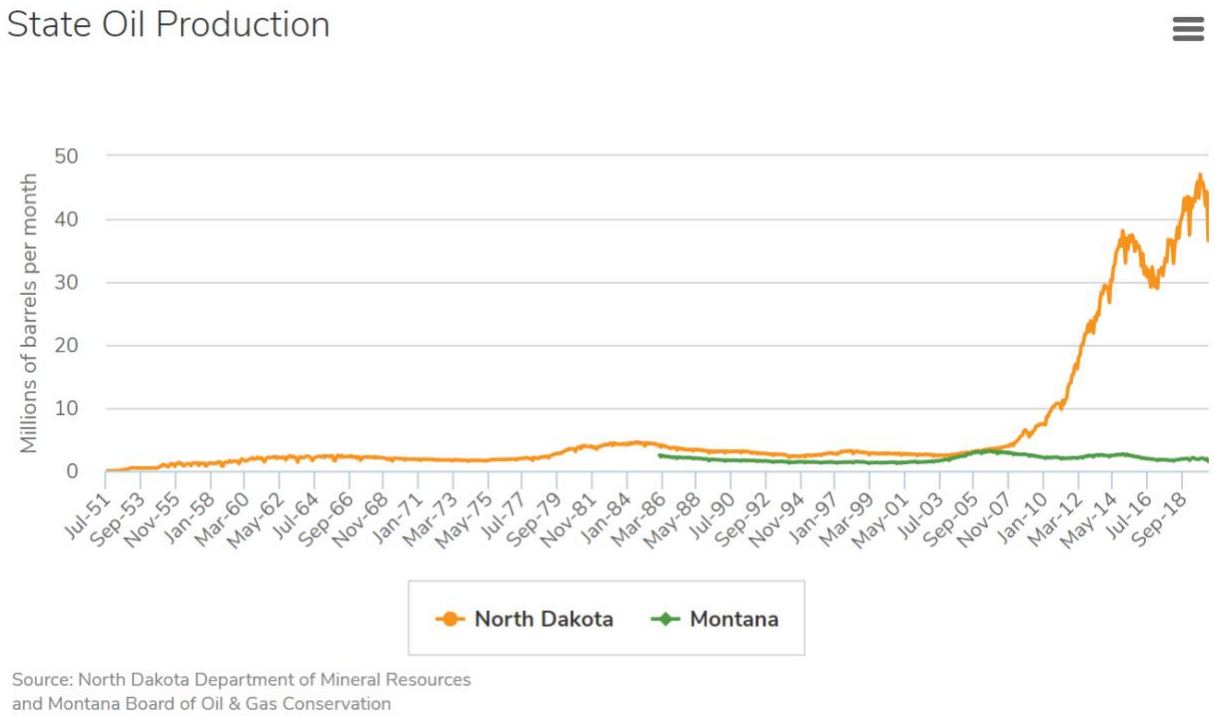
Additional recent assessments of the Bakken and Three Forks Formations include:

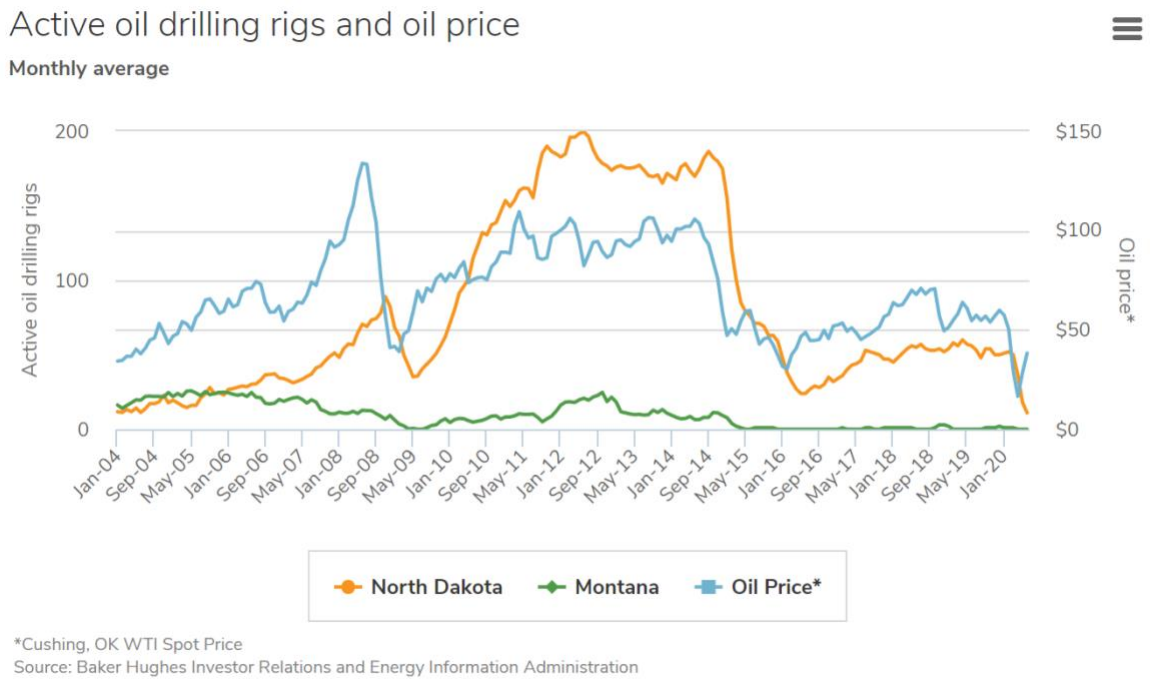
• Texas Bureau of Economic Geology (Gherabati et al., 2017): 262 BBO generated (oil in place) in the Bakken, Three Forks, Pronghorn, and Scallion units

• Platte River Associates (Theloy et al., 2017): 3.4–4.0 BBO technically recoverable in the Bakken and Three Forks Formations (North Dakota region only)

• Saputra et al. (2019): 8 BBO technically recoverable (plus addition of 5 BBO from existing wells) in the Bakken and Three Forks Formations

Since 2010, production in the Bakken has generally increased, with notable declines beginning in 2014 due to a drop in oil prices and in mid-2020 due to the decrease in demand during in the ongoing COVID-19 pandemic. Overall, oil production has remained high, and North Dakota continues to be the second largest oil producing state in the country. (https://www.minneapolisfed.org/region-and-community/bakken)





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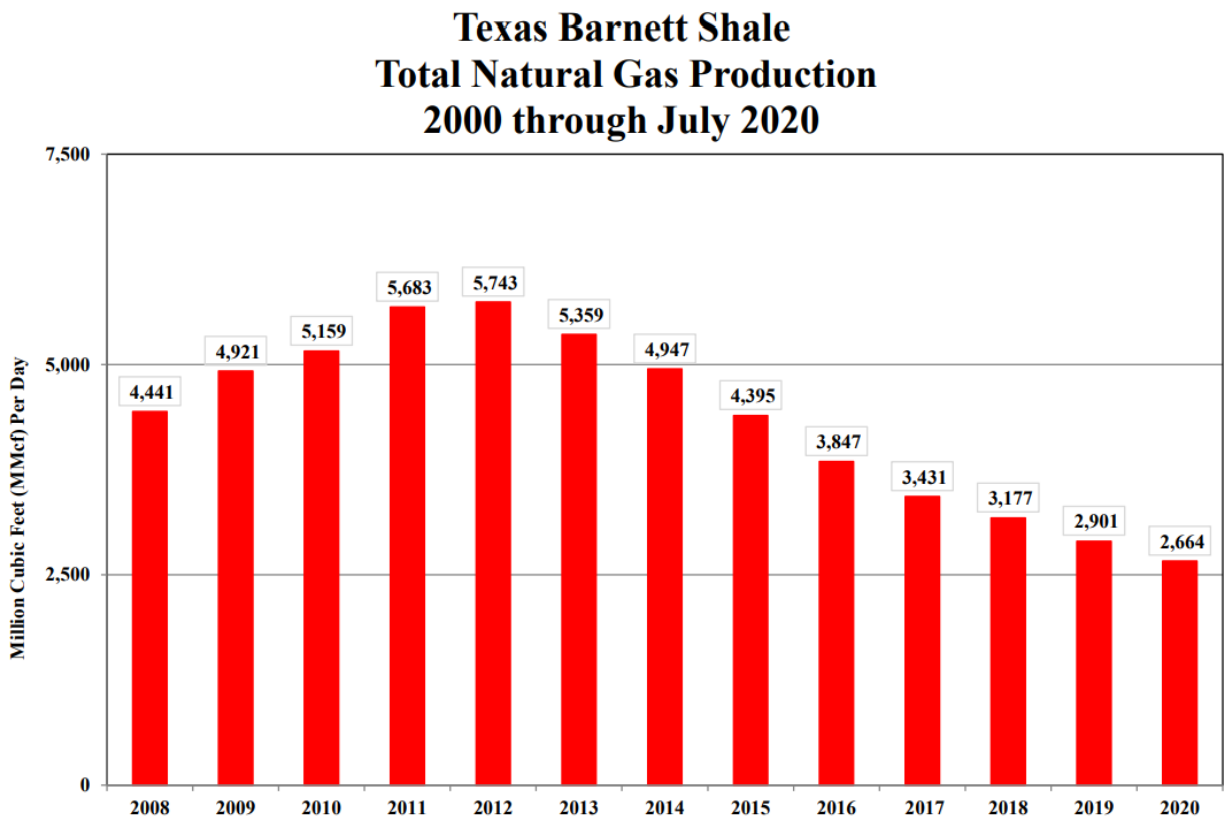
Barnett Shale (Mississippian), Fort Worth Basin, Texas

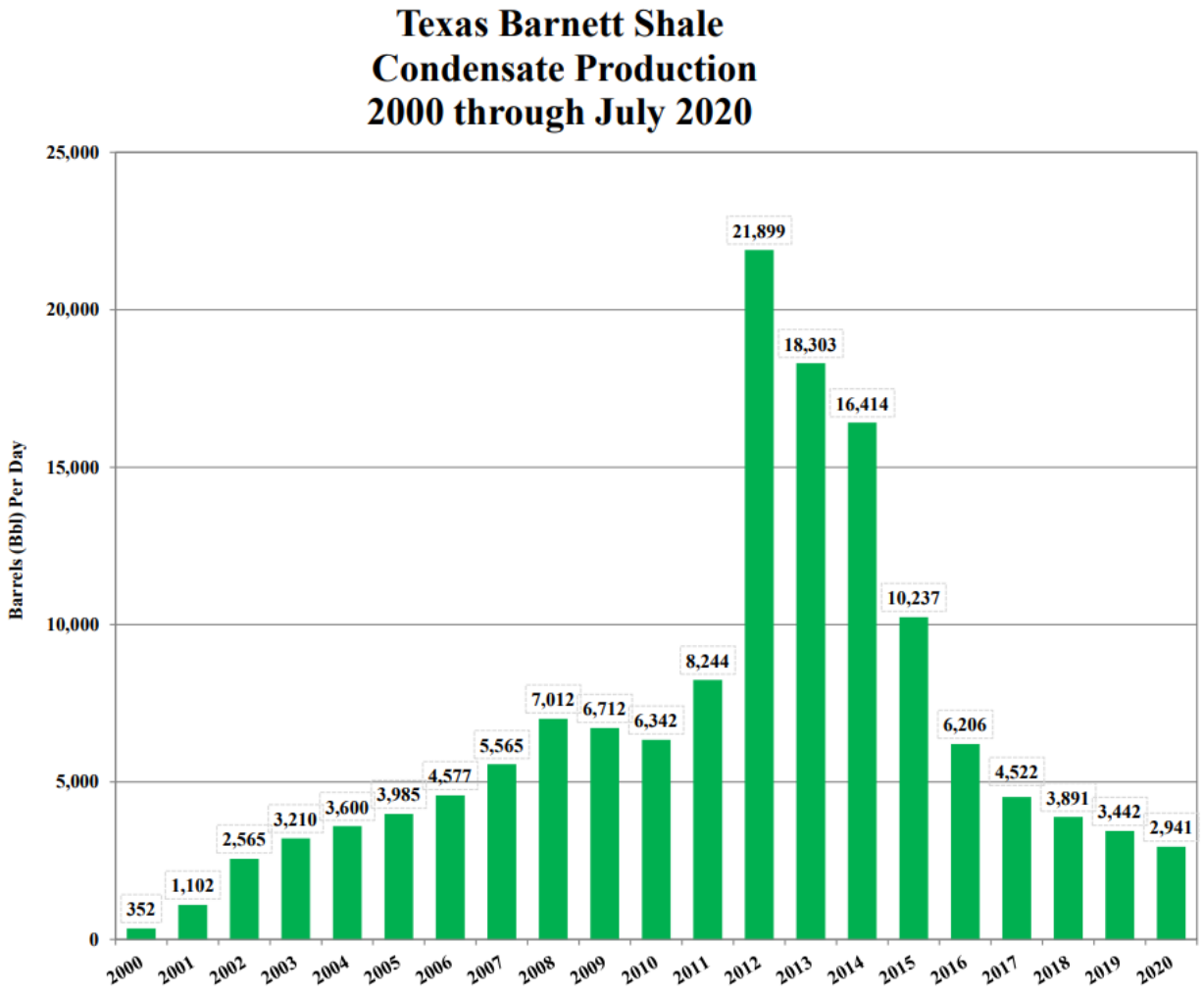
Kent A. Bowker, Bowker Petroleum, LLC

In December 2019, Devon Energy sold its remaining interests in the Barnett Shale to BKV Oil & Gas, a subsidiary of Banpu Pcl (a Thailand-based coal-mining and power-generating firm), for $770 million. This acquisition will make BKV the largest producer in the Barnett (Total, XTO/ExxonMobil, and EOG Resources round out the top four producers).



https://www.rrc.state.tx.us/media/58307/barnett-gas.pdf

Daily gas production from the Barnett Shale continues to decline and has recently dropped to near 2.6 BCF/day, but at a rate less than might have been expected given the massive decrease in drilling and completion activity over the past eight 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 oil/condensate production is at 2941 bbls (with condensate making up the bulk of the Barnett's liquids production; daily oil production is currently around 560 bbl).



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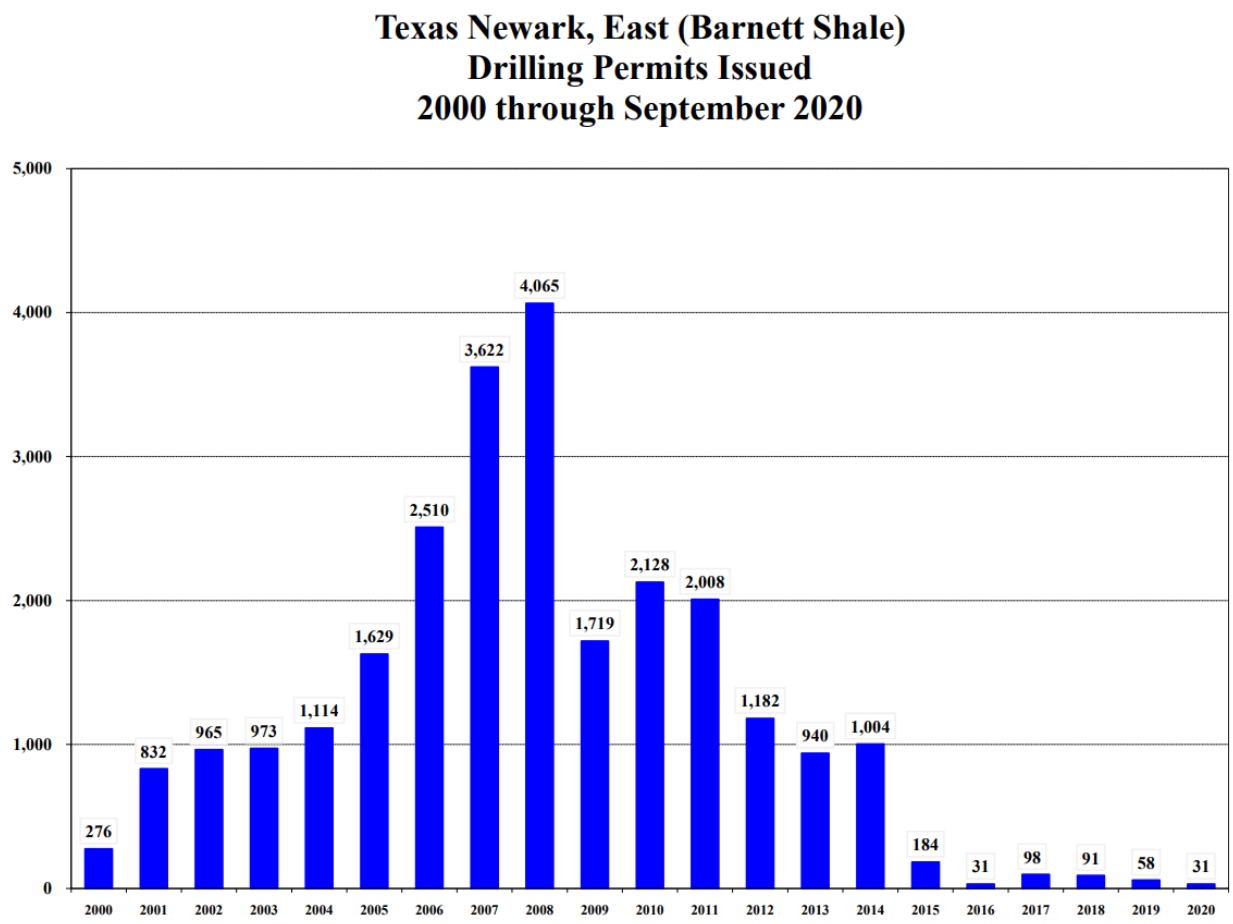

https://www.rrc.state.tx.us/media/59960/barnett-drilling-permits-sept-2020.pdf

The graph above illustrates the precipitous decline in the number of drilling permits issued in the Barnett over the last five years. Though at the beginning of 2020 there was a relative flurry of permit applications (thirteen in total) from TEP Barnett USA (a Total subsidiary) in Tarrant County, the following months have seen a lack of new permitting. The city of Arlington has rejected three of early 2020 applications (too close to a day-care facility), but Total is expected to drill several wells this year.

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.

There are twenty-three named Barnett fields in the Fort Worth basin, and as of April 2020 they have produced a total of 23.7 trillion cubic feet of gas and 76.9 million barrels of oil/condensate (Texas Railroad Commission data).

Eagle Ford Group in southwest Texas

Justin E. Birdwell, U.S. Geological Survey, Denver, CO

Background

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, with some development extending to and just beyond the San Marcos Arch. The area included in the Eagle Ford is approximately 50 miles wide and 400 miles long with thicknesses varying from less than 100 ft, to over 600 ft thick in 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, calcareous lower Eagle Ford. The Turonian upper Eagle Ford also contains source potential. It is calcareous in much of the play area, but contains more siliciclastic material moving southwest to northeast.

The organic matter content and quality in the Eagle Ford varies stratigraphically primarily due to variability in the depositional environment. Geographic variation may have been affected by localized depositional conditions and detrital inputs. Kerogen is mainly represented by oil-prone Type II and Type II-S (French et al., 2020 and references therein). Production trends in the Eagle Ford correspond to geologic structure. Production distributions from wells are related to depth, which range from ~4,000 to over 14,000 ft deep in a trend north to south across the play (**Fig. 1**). Eagle Ford oil is also widely produced in Texas and parts of Louisiana from wells in 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 the Eagle Ford facilitates this development approach, as the high carbonate content of marlstone, limestone, and other mudstones (as much as 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 increasing 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. Initial production rates have increased over the last decade with improvements in production technology, but decline rates for production are also steeper. In the last few years improvements in ultimate recovery have been realized through well re-stimulation or the application of secondary recovery techniques (e.g., huff-and-puff).

The U.S. Geological Survey assessment in 2018 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 east Texas and southern Louisiana distributed among seven assessment units (Whidden et al., 2018). The Eagle Ford is somewhat unique among U.S. shale plays in that production data show and assessed resources further indicate it is prolific for both oil and gas, with assessed oil resources comparable to the Bakken Formation in the Williston Basin and natural gas resources essentially equivalent to the Mancos Shale in the Piceance Basin. Condensate is also an important product in the Eagle Ford, with annualized daily production rates averaging over 250,000 barrels per day over the last five years (Texas Railroad Commission, 2020).

Production Updates

New wells and rig counts in the Eagle Ford play during 2019 showed a general but slight decline with some fluctuations for both oil and gas wells (**Fig. 2**). In late 2019 and early 2020, there was a slight uptick in drilling that subsequently decreased precipitously, first due to the so-called Russian-Saudi price war that led to oil price reductions and second was exacerbated in the spring as the COVID-19 pandemic caused substantial drop in demand. Over 2000 permits were issued in 2019, and nearly all permitted wells were drilled (Texas Railroad Commission, 2020; IHS Markit, 2020).

Daily oil production fluctuated around 1.2 million bpd through 2019, peaking at 1.27 million bpd in October, dropping slightly after that through the end of the year (**Fig. 3**). Gas production averaged 4.36 billion scf/day in 2019. Slight drops in oil and gas production occurred in the first three months of 2020, and with the onset of the pandemic production decreased substantially from March to May (27% for oil, 17% for gas) recovering slightly after.

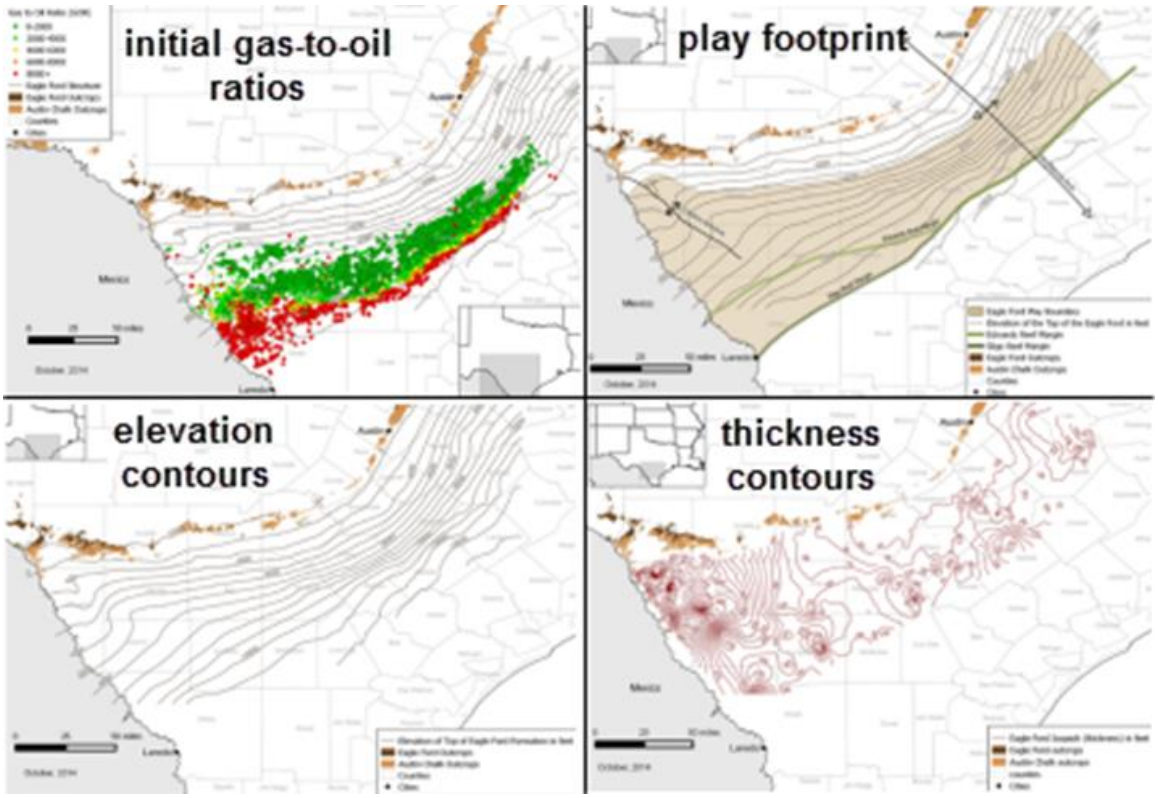

Figure 1. Initial gas-to-oil ratios, play footprint, elevation contours, and thickness contours for the Eagle Ford play in southwest Texas. Source: U.S. Energy Information Administration, DrillingInfo, Inc., Texas Natural Resources Information, U.S. Geological Survey, University of Texas Bureau of Economic Geology (from U.S. EIA, January 21, 2015).

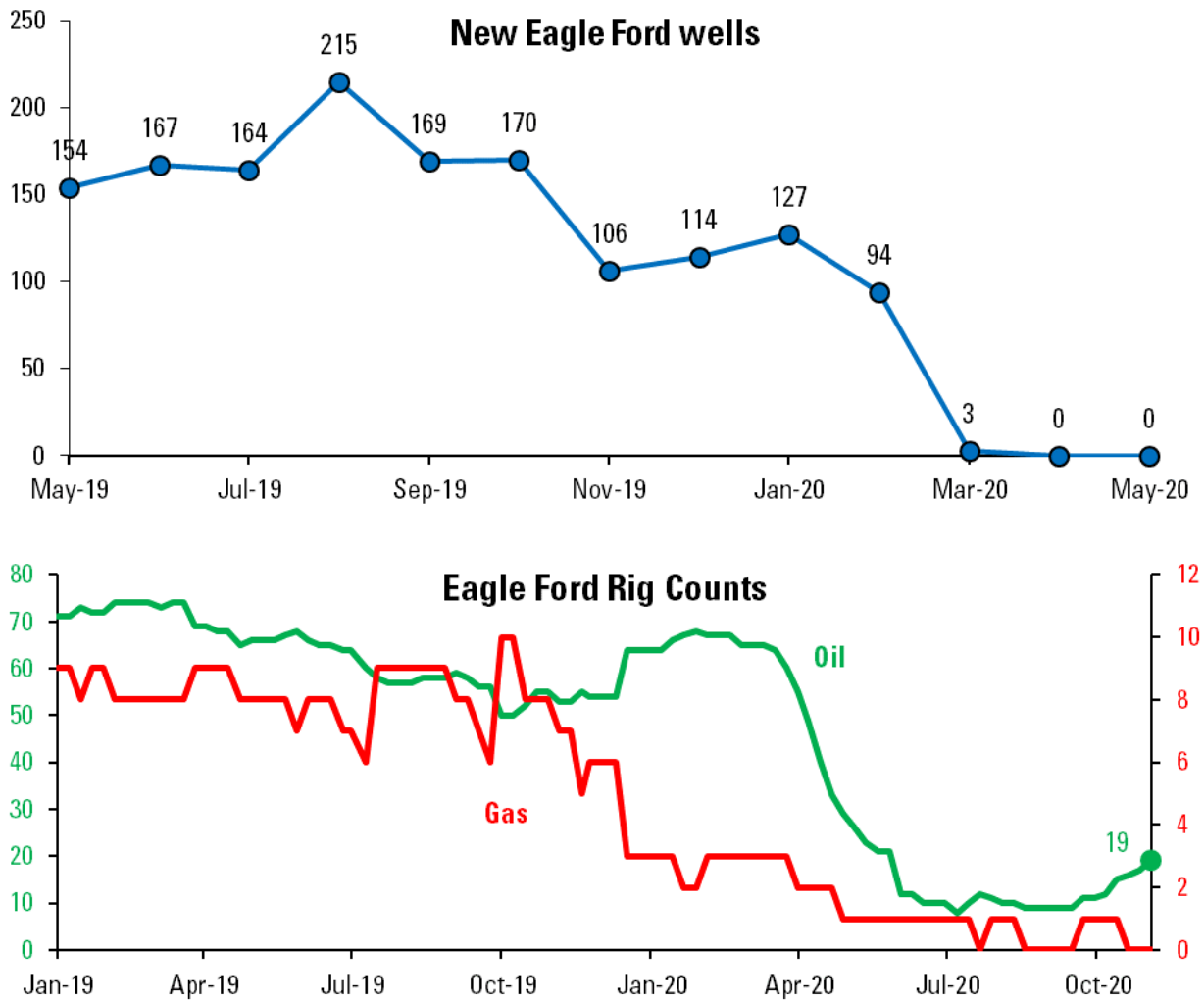

Figure 2. Top: Eagle Ford wells with production in IHS Enerdeq from May 2019 through May 2020 (accessed May 27, 2020). Bottom: rig counts in the Eagle Ford from May 2019 through November 2020 (source: Baker Hughes, 2020).

Eagle Ford Water Assessment

In 2019, the U.S. Geological Survey completed an assessment of water and proppant use and produced waters volumes needed to develop the undiscovered, technically recoverable oil and gas resources associated with the Eagle Ford Group assessed in 2018 (Gianoutsos et al., 2020). This is only the second application of the USGS produced waters assessment methodology (Haines, 2015), which is meant to provide an estimate of the volume of water needed to drill wells and amount of hydraulic fracturing fluids (water and proppant) required to recover the oil and gas resources assessed in the most recent USGS Eagle Ford oil and gas assessment (Whidden et al., 2018). Total produced waters from the formation are also estimated. Flowback water was not assessed due to insufficient data availability.

For the four assessment units considered, the mean estimated total volume of water that would be required for drilling, cementing, and hydraulic fracturing the wells needed to access the mean USGS assessed oil and gas resource estimates is 687.6 billion gallons and the mean estimated quantity of

proppant is 420 million tons. The mean total volume of formation water estimated to be produced in extracting the assessed petroleum resources is 177 billion gallons.

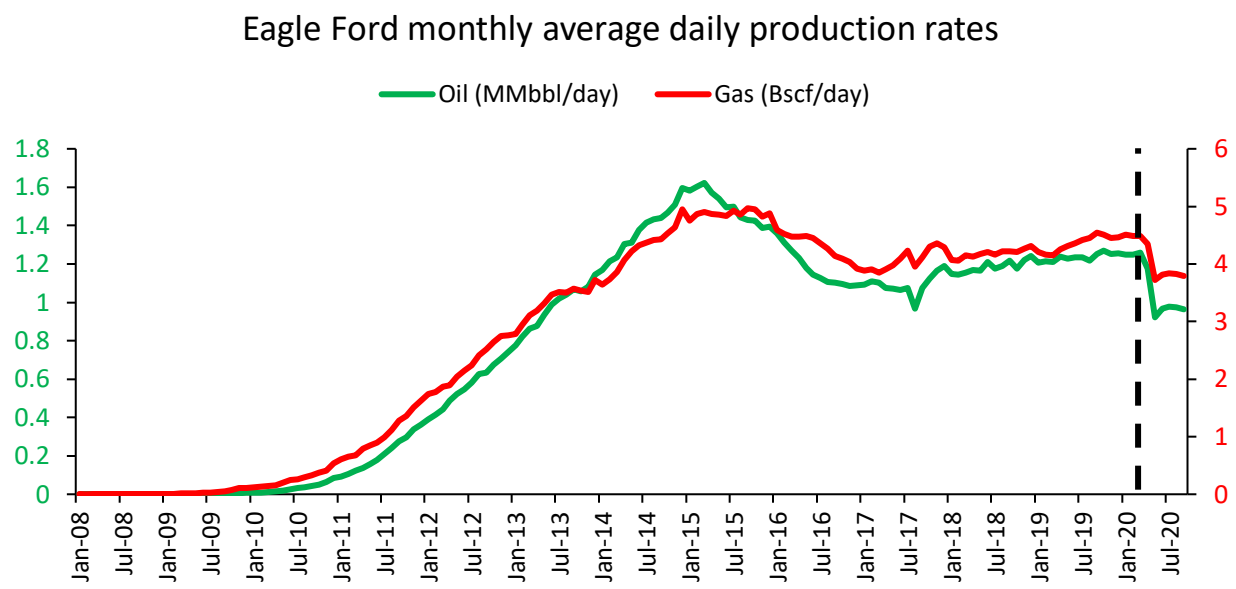

Figure 3. Average monthly daily production rates for crude oil from the Eagle Ford (U.S. EIA, Jan. 2008 through Sep. 2020).

Other Research

According to Scopus, in 2019 there were 59 articles, conference papers, or book chapters that referenced the "Eagle Ford" in their title, and in 2020 the number of new articles was 54 as of November 11. Google Scholar had nearly 4000 hits for mentions of "Eagle Ford" anywhere in an article for 2019 through November 11 (this likely includes many cited references), with over 150 publications including "Eagle Ford" in the title. AAPG Datapages Archive shows 46 articles with "Eagle Ford" in the title between 2019 and 2021, many of which were proceedings papers on engineering aspects of enhanced recovery presented at the 2019 and 2020 Unconventional Resources and Technology Conferences. Notable publications from the USGS include several on Eagle Ford source rock geochemistry and thermal maturity trends (French et al., 2020; Jubb et al., 2020a,b) and produced waters chemistry (Engle et al., 2020).

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Update for Fayetteville Shale Gas Play in Arkansas, 2019

Peng Li, Arkansas Geological Survey, Little Rock, AR

Overview

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.

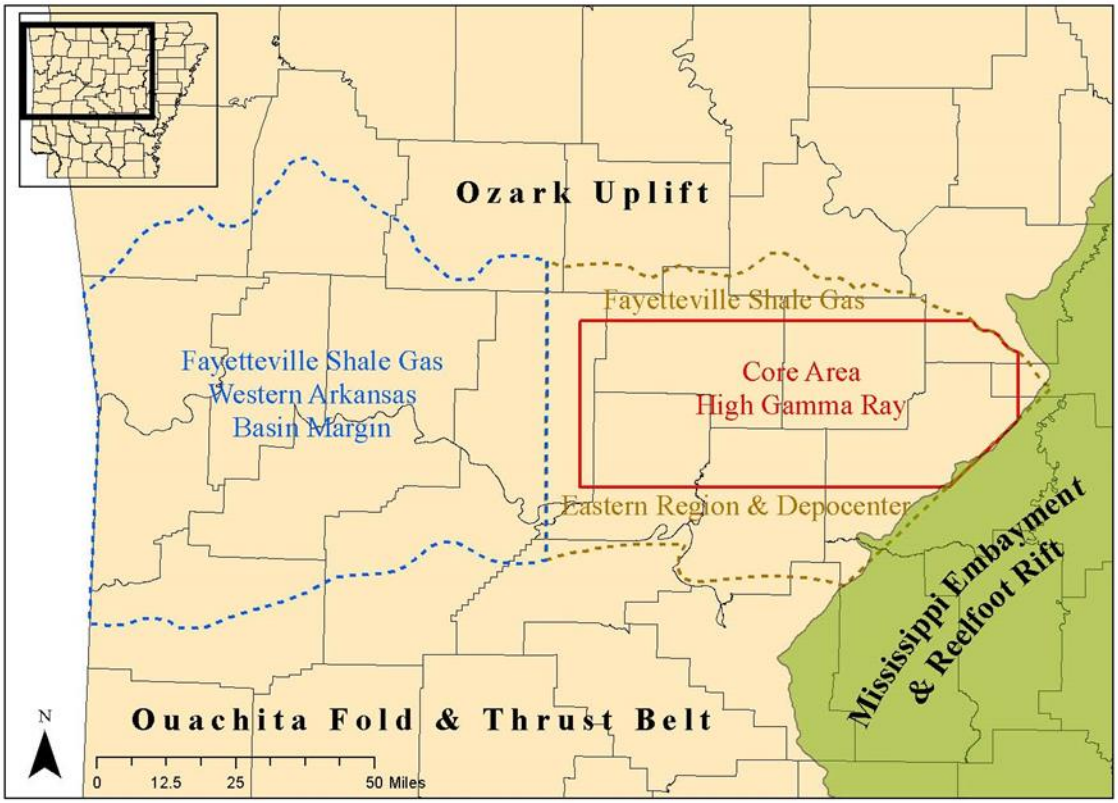

Figure 1. Primary area of the Fayetteville Shale exploration and development in Arkansas.

The U.S. Energy Information Administration (EIA) reported in 2013 that the Fayetteville Shale contained 31.96 Tcf of technically recoverable gas resource, of which 27.32 Tcf was 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 reported that the proven gas reserves of the Fayetteville Shale in 2017 were 7.1 Tcf, an increase over the 2016 estimate of 6.3 Tcf.

Most Fayetteville Shale wells are drilled horizontally and have been fracture stimulated using slickwater or cross-linked gel fluids. 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 to 550 feet in the central and eastern regions.

Due to a decline in drilling activity driven by lower natural gas prices, Fayetteville Shale gas production has decreased since peaking in 2013. In 2019, approximately 465 Bcf of gas was produced in the play, a 11% decline over the last year. Estimated cumulative production of gas as of 2019 has totaled 8.95 Tcf (Figure 2). Initial production rates of horizontal wells in 2017 averaged about 5.3 MMcf/day. For more Fayetteville Shale information, please refer to the Arkansas Oil and Gas Commission's web link at http://www.aogc.state.ar.us/sales/default.aspx.

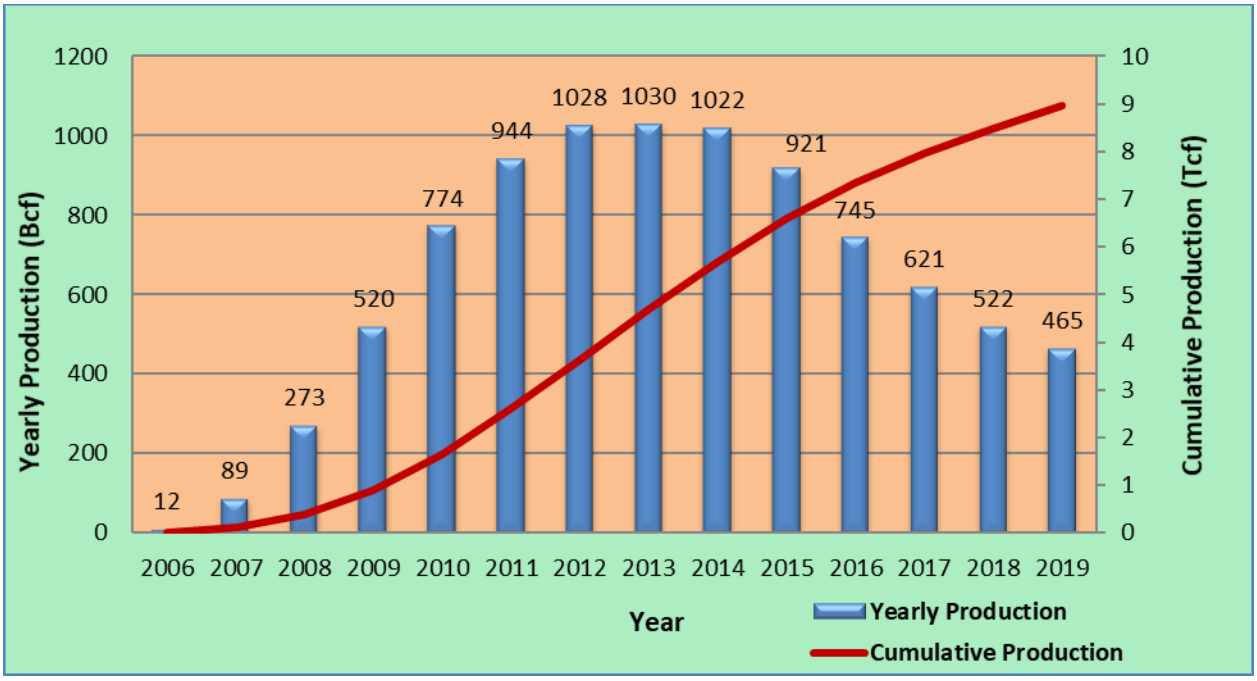

Figure 2. Annual and cumulative gas production of the Fayetteville Shale gas play.

In the entire year of 2019, no rigs worked in the Fayetteville Shale gas play (Figure 3), demonstrating a rapid downward trend in well completion since 2015 (Figure 4). Approximately 39 gas wells were plugged and abandoned.

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.

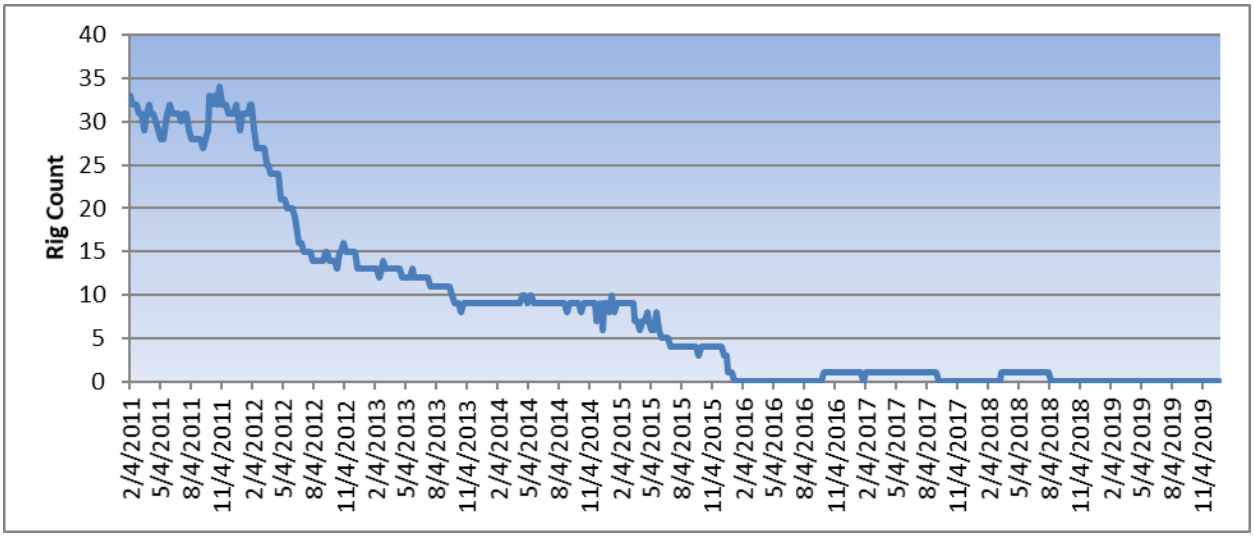

Figure 3. Weekly drill rig numbers in the Fayetteville Shale gas play (2011-2019).

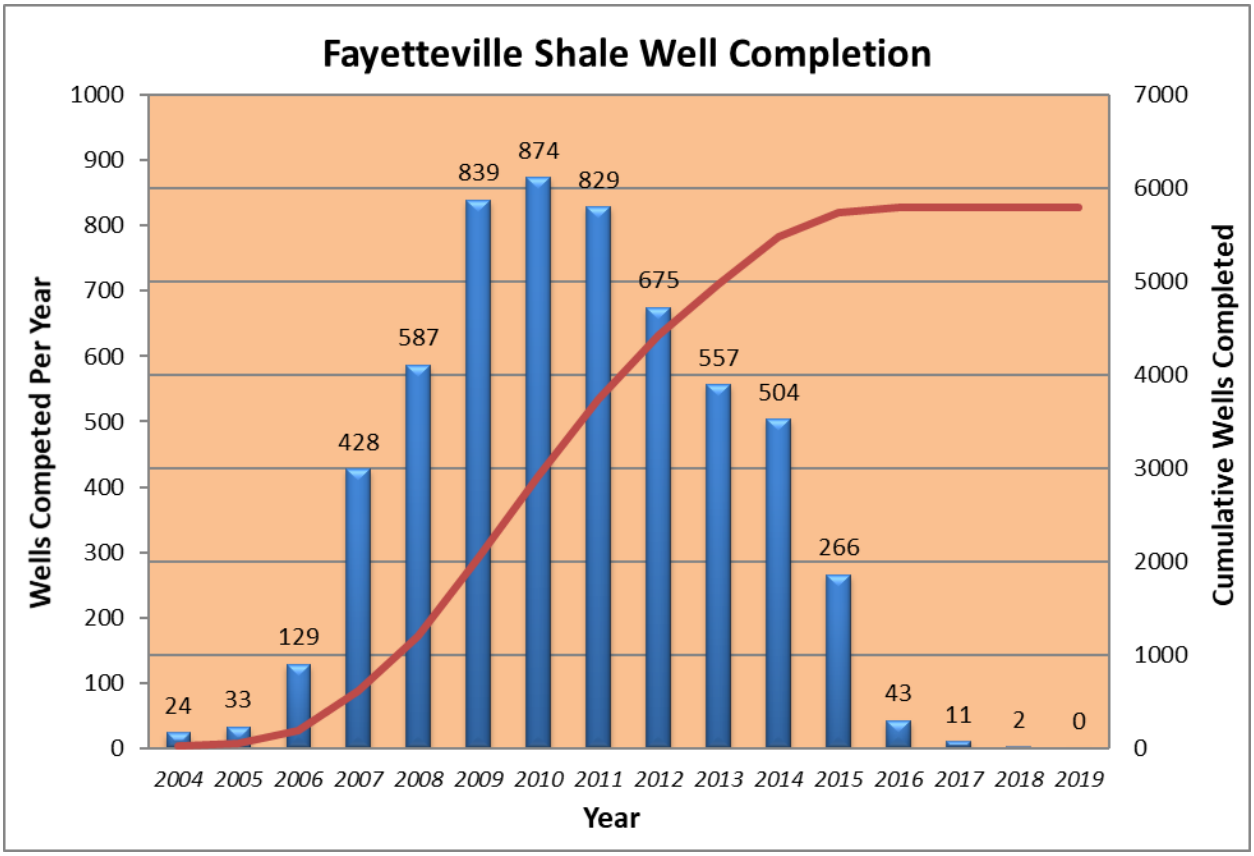

Figure 4. Fayetteville Shale well completion numbers.

Haynesville and Bossier Shales (Upper Jurassic), East Texas and Northwest Louisiana, USA

Ursula Hammes, Hammes Energy & Consultants, 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).

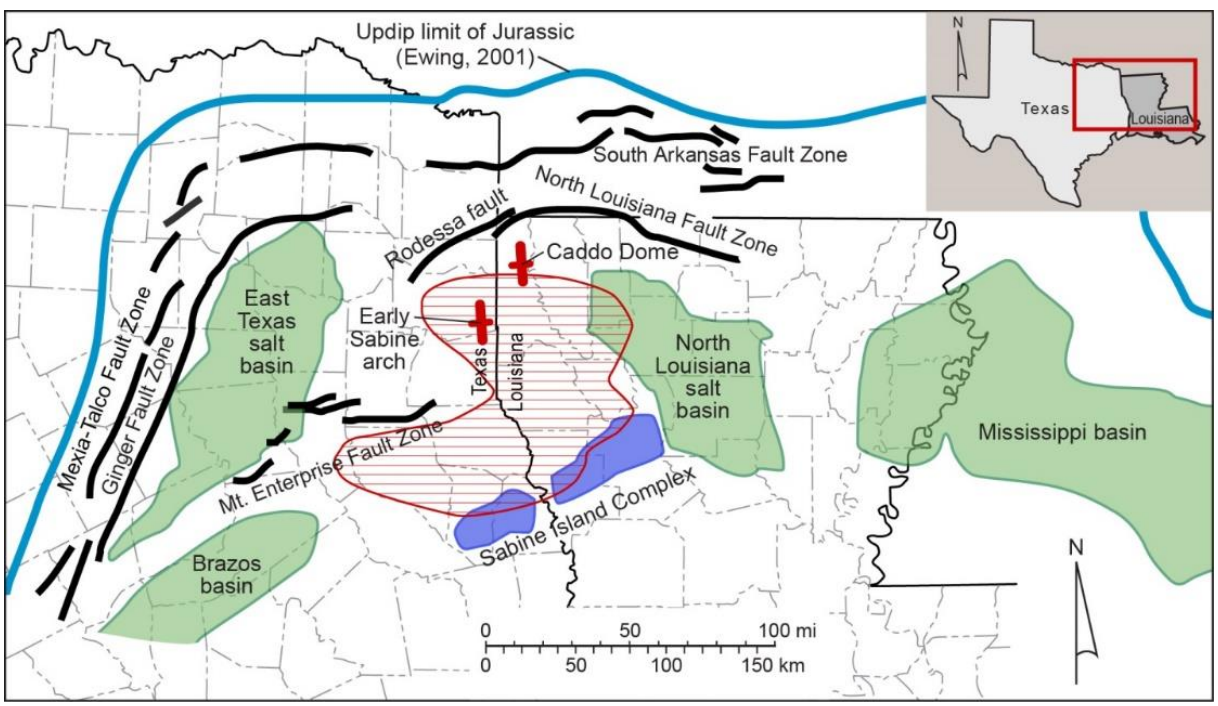

Figure 1. Location of Haynesville Basin and productive zone of Haynesville Shale (red stippled pattern; from Hammes et al., 2011).

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. Despite the recent downturn due to oversupply and global pandemic, the play has had its highest production since inception 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 2.6 Bcf/day recording the highest production since inception of the play while condensate production has increased to 468 B/d (Fig. 2). 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 4 shows drilling permit activity for 2020. 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 2020 (Fig. 2). 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).

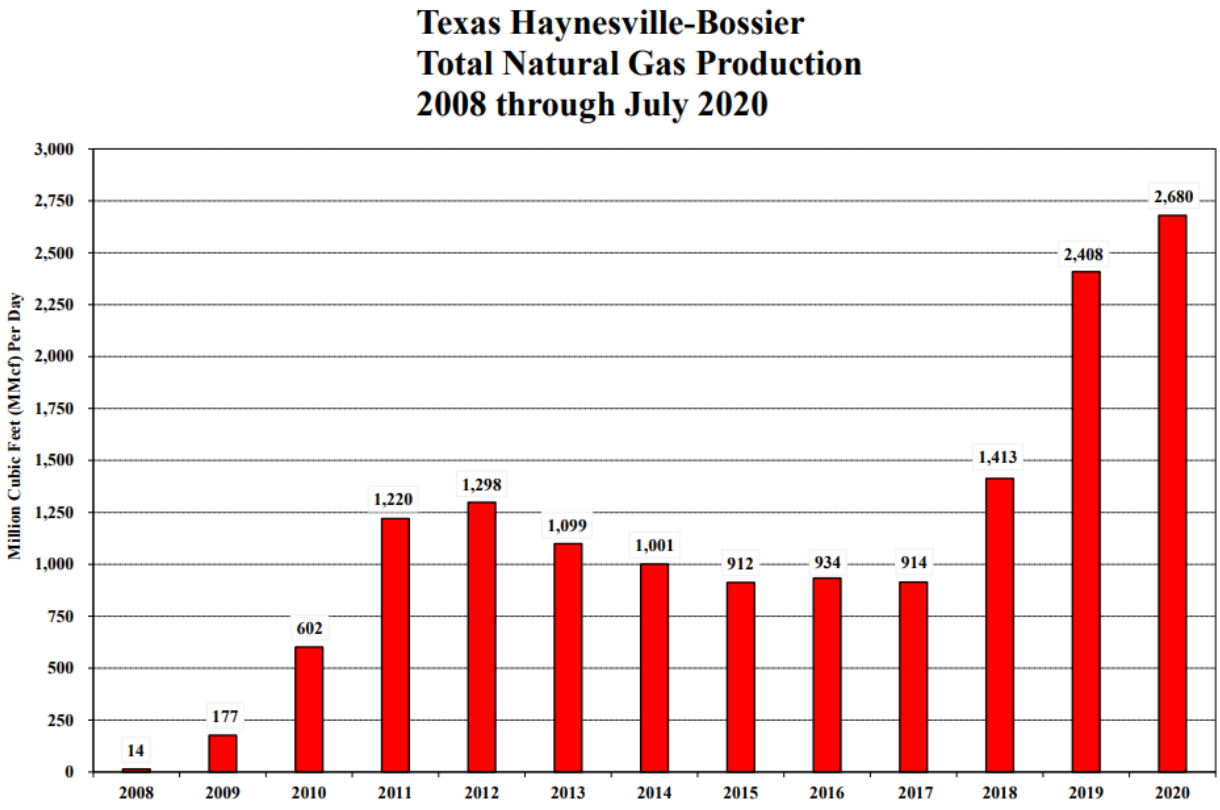

Figure 2. Yearly gas production chart (MMCF/day) through July 2020 shows a steady increase in gas production over the last four years.

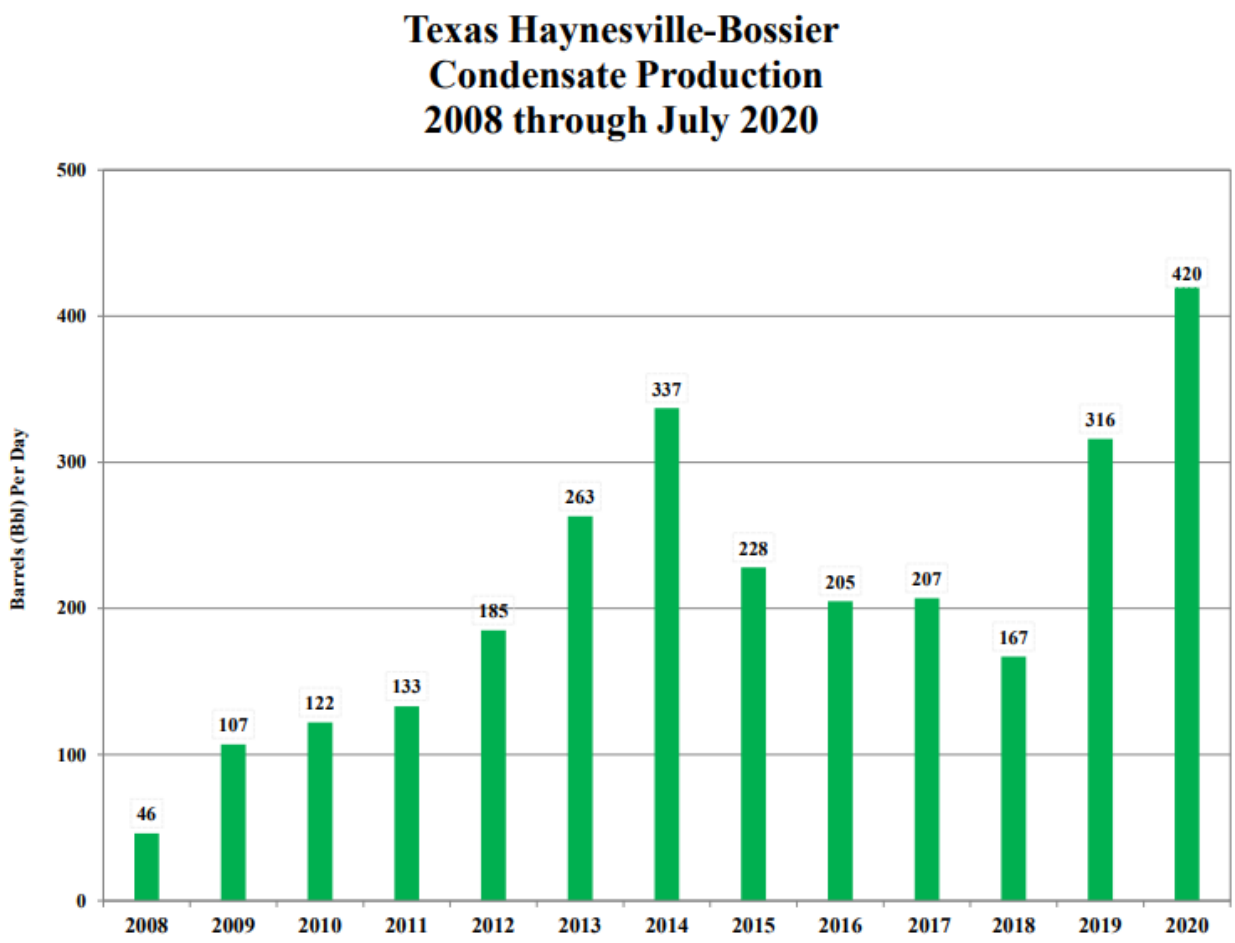

Figure 3. Yearly condensate production (in barrels per day) through July 2020 shows a steady decline in liquids production until 2019.

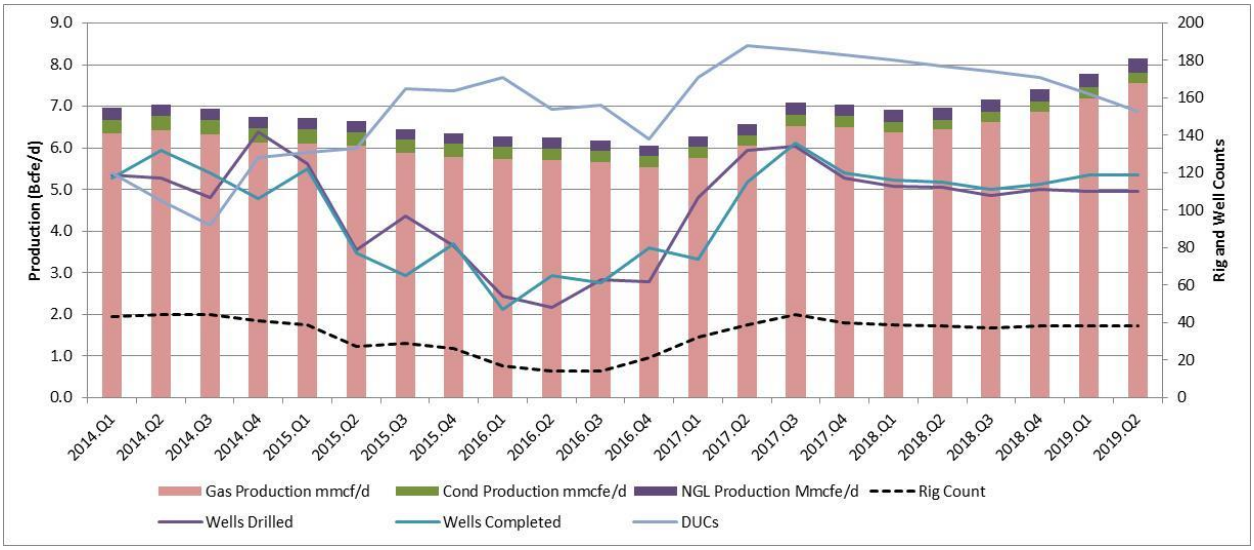

Figure 3. Haynesville production has risen to 7.5 billion cubic feet equivalent per day (Bcfe/d) by year-end 2018, an increase of 4% from the 7.2 Bcfe/d reported for September 2017 (from Hart Energy, 2019).

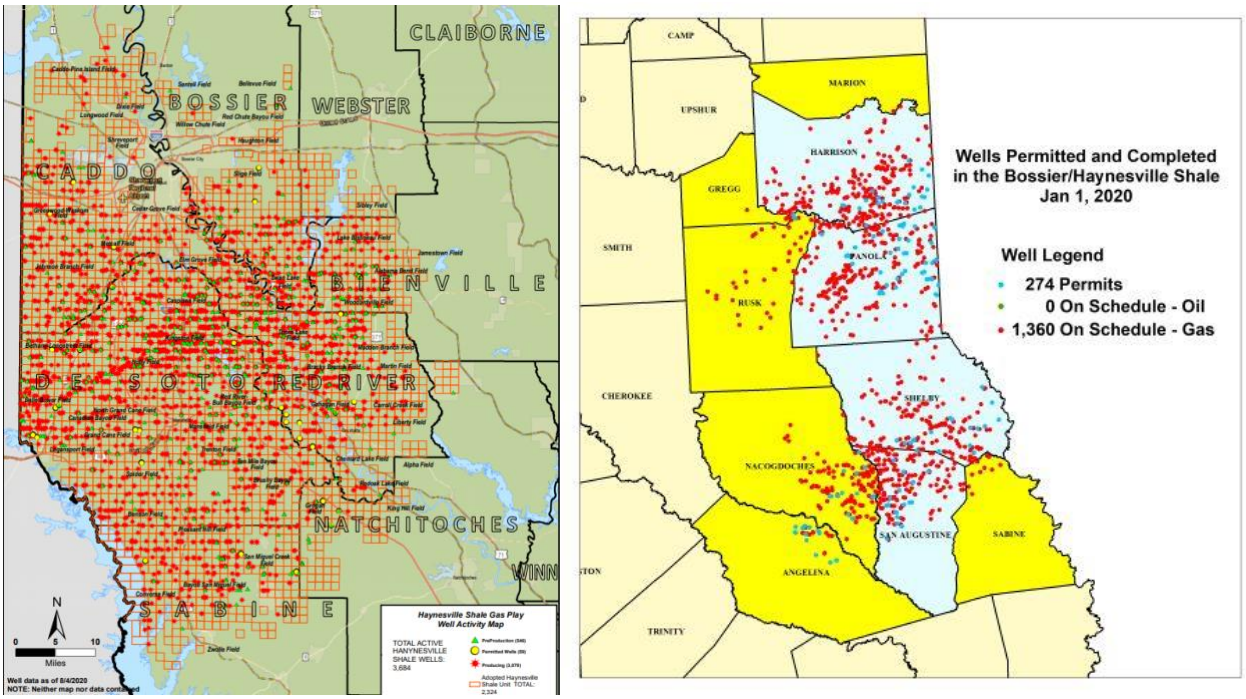

Figure 4. Haynesville shale permit activity (Louisiana left - Aug. 2020 and Texas right, July 2020).

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Marcellus Shale (Devonian) -- Appalachian Basin, U.S.A.

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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. In Pennsylvania, 85% of the flowback fluid was recycled in 2019. Companies have proven that recycling can be very cost effective and environmentally friendly (Yoxtheimer, 2020).

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).

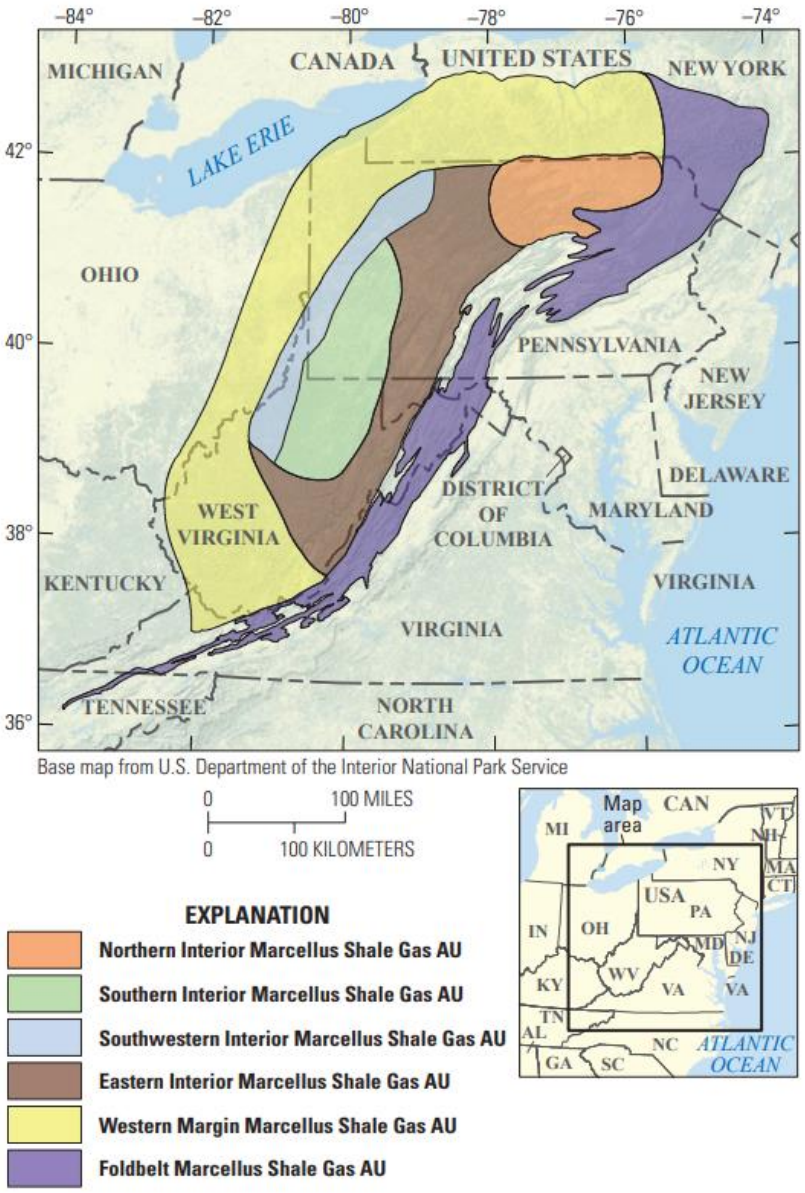

Figure 1. Map showing boundaries for six assessment units (AUs) in the Middle Devonian Marcellus Shale of the Appalachian Basin Province (Higley et al., 2019a).

In October 2019, the U.S. Geological Survey (USGS) completed an updated assessment of the undiscovered, technically recoverable oil and gas resources in the Marcellus Shale of the Appalachian Basin Province and published a fact sheet and two articles summarizing the results of the assessment and its geological underpinnings (Higley et al., 2019a,b; Higley and Enomoto, 2019). The USGS estimated a mean undiscovered, technically recoverable natural gas resource of about 96.5 trillion cubic feet (tcf) and a mean undiscovered, technically recoverable natural gas liquids resource of 1.5 billion bbls in continuous-type accumulations in the Marcellus Shale. These values represent an increase in gas resource (~10 tcf) but a nearly 50% decrease in NGL from the previous USGS assessment of the Marcellus in 2011 (Coleman et al., 2011). The change is attributed to changes in technology and improved data coverage due to increased drilling (Higley et al., 2019b).

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.

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 (2019) no production from the Marcellus Shale in Maryland. There were no exploration wells drilled to the Marcellus Shale in Maryland between 1996 and 2019. 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. There is currently a moratorium on drilling unconventional wells in Maryland.

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, 12 were listed as active in 2018. Production reported from the Marcellus Shale from the 12 active wells in 2018 (most recent data available) was 12.4 Mcf of gas, down from the high of 64 Mcf reported for 2008. There was no reported oil or condensate production. In 2018, most of the productive wells were located in Steuben County, with some also in Allegany, Chautauqua, and Livingston counties. According to the DEC, there were over 340 Mcf of gas produced from the Marcellus Shale between 2000 and 2018. 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), over 21.5 bcf of gas and 850,000 bbls of condensate and/or oil were produced from the Marcellus Shale from 2007 through 2019 (most recent data available). There were 13 wells that reported production from the Marcellus Shale in 2019. According to the DNR completion reports, there were about 3.6 bcf of gas and about 99,000 bbls of oil and/or condensate produced in 2019. 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 well is in Lycoming County and has a true vertical depth of 9,088 feet. 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 2019, 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 2019 from the Marcellus Shale was Susquehanna County. After Susquehanna, the other counties with the most natural gas production in 2019 were Bradford, Washington, Greene, Lycoming, and Tioga. The counties with the most condensate production in 2019 from the Marcellus Shale were Washington and Butler. Forest County was the only county to report oil production in 2019.

According to DCNR and DEP, by the end of 2019, about 6,950 wells reported production from the Marcellus Shale, with most production from horizontal wells. Almost 3.2 tcf of gas, about 1.8 million bbls of condensate and 1,544 bbls of oil were produced from the Marcellus Shale in 2019. In 2019, the largest producers of natural gas from the Marcellus Shale were Cabot Oil & Gas Corporation, Chesapeake Appalachia LLC, Range Resources Appalachia LLC, SWN (Southwestern Energy) Production Company LLC, and Rice Drilling LLC. Range Resources was the largest producer of condensate from the Marcellus Shale in 2019.

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 2019, about 8.5 tcf of gas were produced from horizontal wells completed in the Marcellus Shale, as well as about 55 million bbls of oil and/or condensate, and about 136.7 million bbls of NGL. According to the WVGES, there was reported production from the Marcellus Shale in 1,989 horizontal wells and 1,428 vertical wells in 2019. Production was co-mingled in the vertical wells, thereby making it difficult to separate Marcellus Shale production figures for those wells. In 2019, there were about 15 million bbls of oil and/or condensate, almost 61 million bbls of NGL, and over 1.7 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 2019, the counties from which most of the liquids were produced from the Marcellus Shale were Tyler, Marshall, Ohio, Brooke, and Ritchie (Dinterman, 2020). The counties from which most of the natural gas was produced were Tyler, Doddridge, Ritchie, Ohio, and Marshall (Dinterman, 2020).

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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Mowry Shale, Powder River Basin, WY

Zachary Hollon, Workhorse Geologic LLC

The Albian-aged Mowry Shale in the Powder River Basin of northeastern Wyoming and southeastern Montana (Figure 1) is a siliceous, organic-rich, dark-gray to black marine mudstone interbedded with bentonite, sandstone, and silt. (Nixon, 1973; Burtner and Warner, 1984; Davis et al., 1989). Radiolaria tests, fish scales, fish teeth, fish bones, fecal pellets, inoceramus debris, and ammonites are found in the bedding planes and silt-laminae of the Mowry Shale throughout Wyoming (Davis, 1970; Anderson and Kowallis, 2005). Calcareous cone-in-cone concretions are seen in core and outcrop (Hollon, 2014). Numerous bentonite beds up to 3 ft thick in the Mowry Shale allow for the precise recognition of time equivalent strata over vast areas (Nixon, 1973). In outcrop, the Mowry Shale has a distinct profile and weathers to a dark to light gray, is hard, and often has large jointing sets. The Mowry Shale ranges in thickness from 150 to 250 ft and is a significant source rock for the Cretaceous reservoirs in the Powder River Basin.

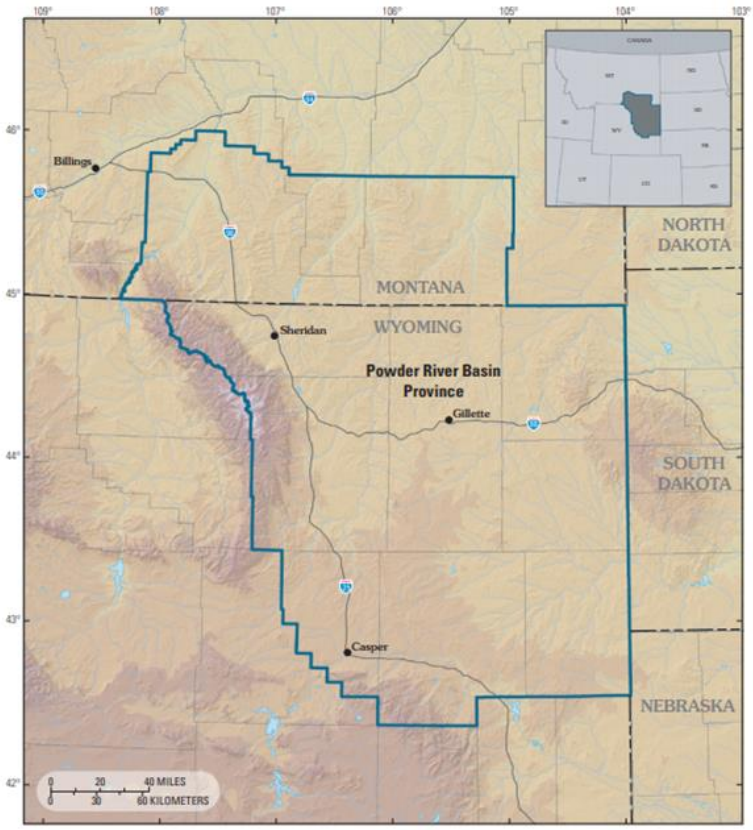

Figure 1. Map showing boundary of Powder River Basin Province in Wyoming and Montana. Province boundary is shown as heavy blue line.

Figure 1. General outline of the Powder River Basin (Anna, 2009).

Exploration and production from the Mowry Shale has been periodic and slow. As the writing of this summary, there are 41 horizontal wells in the Mowry, 14 of which have been drilled since 2018, and most of the wells are south of the Belle Fourche Arch in Campbell and Converse Counties. The 2006-

2015 one-mile laterals rarely made commercial wells, plagued by drilling and completion issues from the thick bentonites that are found throughout the Mowry. EOG's return to the Mowry Shale in 2018 with modern slickwater completions designs and two-mile laterals proved the Mowry to be a commercial oil play in their core acreage, renewing interest from basin operators. In 2019, the Mowry had its largest production, producing ~986,000 BO, ~9.4 BCF, and ~1,800,000 BW (Figure 2) (WOGCC, 2020).

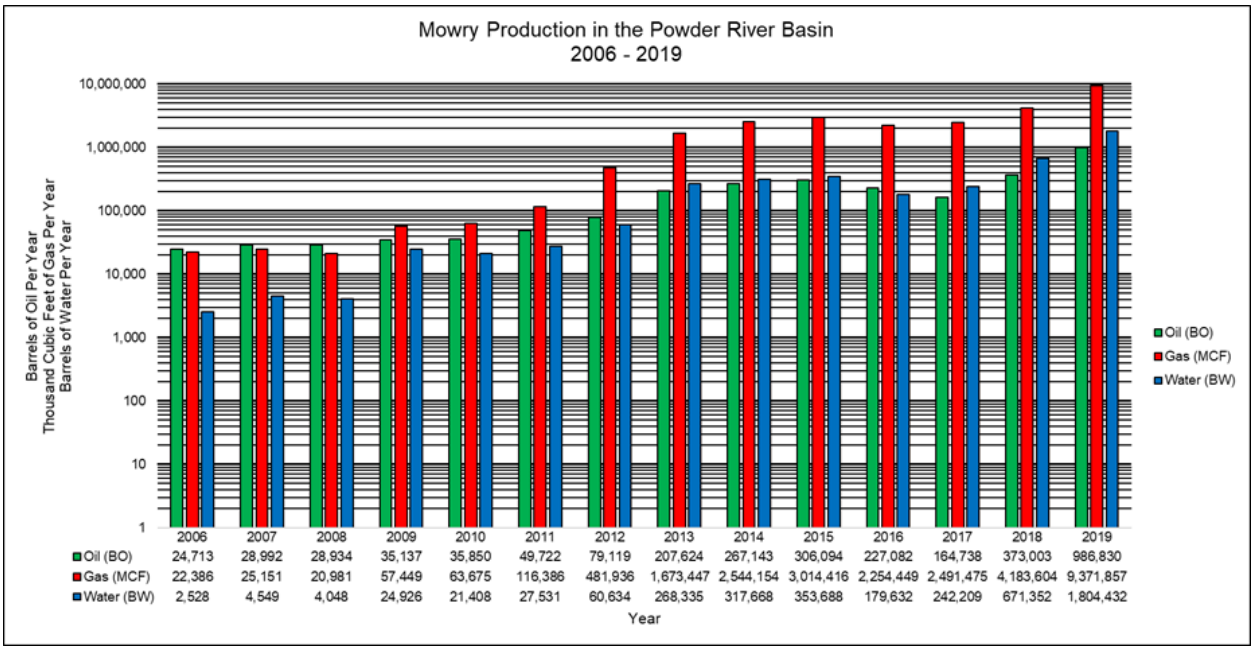

Figure 2. Mowry production in the Powder River Basin 2006-2019 (data from WOGCC, 2020)

The Mowry's depth and mixed Type II/III kerogen makes it more gas and condensate prone than the shallower, Type II kerogen Niobrara. The prevalence of several shallower, oilier reservoirs above the Mowry reduces the likelihood of full-scale development any time soon. Operators recognize how prolific the Mowry Shale can be but will develop other reservoirs first while delineating the Mowry Shale with one-off wells until it can be proven over a larger area. It should be noted that Wyoming is a "first to file" state for well permits and operators have been engaged in permitting battles to capture operatorship across all potential reservoirs. The 8,900 Mowry permits filed to control leasehold are unlikely to be drilled soon.

As of July of 2020, there are zero rigs drilling in the Powder River Basin, and it is expected for the Mowry Shale's production to decline until commodity prices recover.

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Wyoming Oil and Gas Conservation Commission - http://pipeline.wyo.gov/legacywogcce.cfm

Niobrara & Codell of the Denver-Julesburg Basin

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Geologic Setting

The Cretaceous Niobrara Formation and Codell Member of the Carlile Formation are the top producing unconventional zones in the Denver-Julesburg Basin. The basin encompasses eastern and northeastern Colorado, southeastern Wyoming, southwestern Nebraska, and far western Kansas. The Codell member of the Carlile Formation is a tight sandstone 4 to 35 ft in thickness across the basin. It its unconformably above the very dark colored Fairport Chalk member of the Carlile. It is variously composed of three facies: a lower bioturbated zone, a middle laminated sand zone containing many small shale drapes and cross beds, and an upper bioturbated zone. It conformably grades into the lowest-most member of the Niobrara Formation, the Fort Hays Limestone. Above the Fort Hays, the cyclic sedimentation of the chalks and marls of the Smokey Hill member of the Niobrara are 250-350 ft thick. In most parts of the basin, Niobrara reservoir targets are the chalks, named, the C, B, and A from bottom to top. The top of the Niobrara sits unconformably on the Sharon Springs member of the Pierre Shale (Higley and Cox, 2007). Across the basin, up to 100 feet of the upper Niobrara has been eroded.

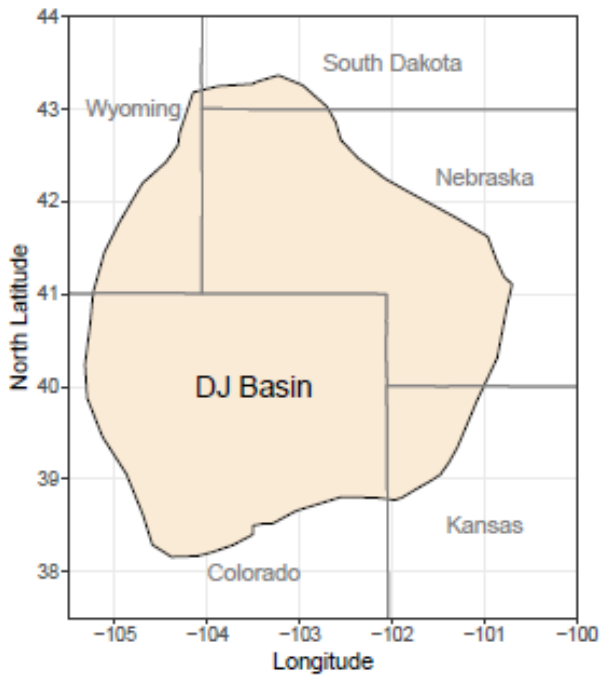

Figure 1. Location of DJ Basin

Produced fluid type follows maturity in the DJ Basin. In southeastern Wyoming as well as the front range counties of Colorado, thermally mature Niobrara source rocks produce oil and gas (Higley and Cox, 2007). Further east in Colorado, as well as in southwestern Nebraska and far western Kansas, Niobrara production is limited to biogenic gas. In all three areas, zones deeper than the Cretaceous produce thermogenic oils and gases, but migration upwards into the Niobrara and Codell is very limited to non-existent.

Development History

Throughout the early and mid-twentieth century, shows and the occasional overpressure were noted in the Niobrara and Codell while producers drilled to deeper formations for oil and gas production. Several wells were drilled and completed in both zones through the 1970s and 1980s (Montgomery, 1983). Beginning in the mid-1990s, large-scale vertical development began with a switch to horizontal development around 2010, first with one-mile mile and then two-mile laterals and evolving completion fluid volumes and sand loads (Ladd, 2001; Birmingham et al, 2006; Milne and Cumella, 2014).

2019 Production Update

Oil and gas production data from the Colorado Oil and Gas Conservation Commission (COGCC, 2020), Wyoming Oil and Gas Conservation Commission (WOGCC, 2020), Nebraska Oil and Gas Conservation Commission (NOGCC, 2020), and the Kansas Geological Survey (KGS, 2020) gives a full scope of basin-wide production across the four states. The four states hydrocarbon production was collected and aggregated using R or manual methods (R Core Team, 2020) and visualized with ggplot2 (Wickham, 2016). Total oil broken out by zone and state is shown in Figure 2.

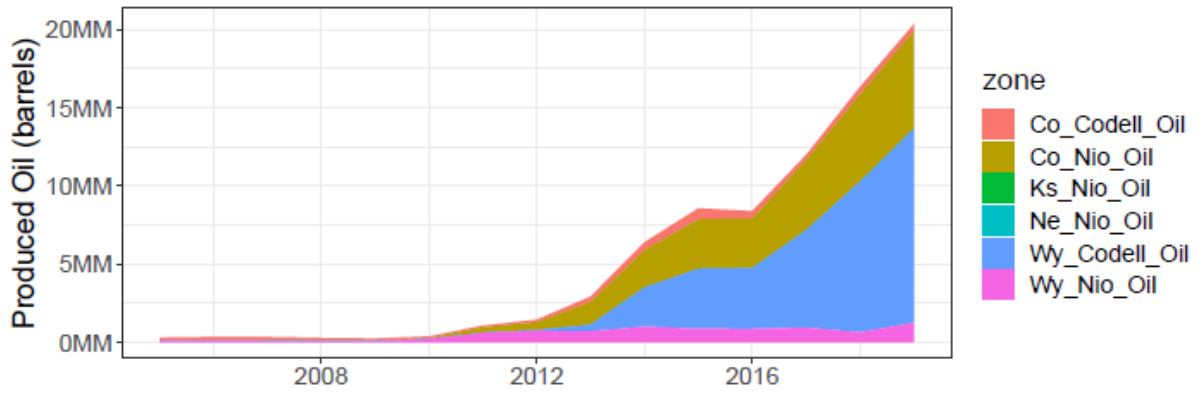

Figure 2. Basinwide Oil Production.

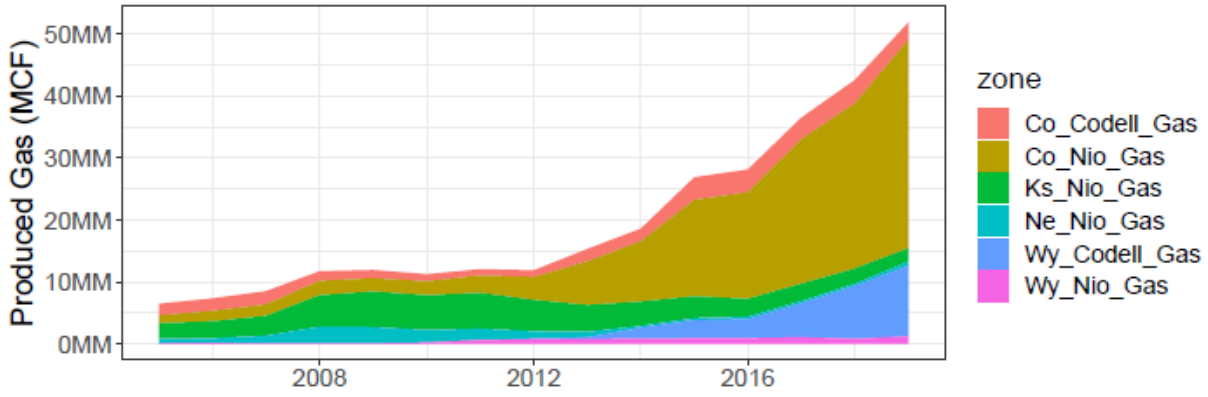

Figure 3. Basinwide Gas Production.

Basin-wide, oil production continued a steady multiple year-on-year increase led by higher volumes produced from the Codell sandstone in Wyoming. Colorado Niobrara production showed a slight rise

from 2018, as did Wyoming Niobrara oil. Colorado production from the Codell remained essentially flat. While some oil has been produced from the shallow Niobrara in Kansas in past year, none was reported for 2019.

Gas production from across the basin followed a similar trend, shown in Figure 3, following the same steady multiple year-on-year increases. Niobrara gas from Colorado and Codell gas from Wyoming led the basin-wide increases. Wyoming and Nebraska Niobrara gas showed a slight increase but overall minimal production while Kansas Niobrara gas and Colorado Codell gas showed slight decreases.

Best Niobrara & Codell Wells in the Colorado DJ Basin

Table 1 and Table 2 show the ten best Niobrara and ten best Codell wells in the Colorado DJ Basin ranked by average oil per production day during the calendar year. Aggregated per-well production data for Wyoming was not available and wells from Kansas and Nebraska did not rank highly enough to make the lists. The best wells have gas/oil ratios (GORs) and water cuts that varies significantly. The Niobrara wells are oil dominant, whereas some of the Codell as gas dominant, as suggested by the GOR values greater than 10,000. The wells span the thermal maturity region of the giant Wattenberg in the DJ Basin in Colorado from 1N to 6N and 62W to 66W.

Table 1. The 10 Best Niobrara Wells in the Colorado DJ Basin

Operator	API Number	API Grav (deg)	Gas BTU	Avg Oil/Day (bbls)	Avg Gas/Day (mcf)	Avg Water/Day (bbls)	Avg GOR	Ave Water Cut
EXTRACTION OIL & GAS INC	05-123-47996	50.8	1295	694	1736	79	2500	0.10
NOBLE ENERGY INC	05-123-44948	53.0	1484	671	1422	304	2121	0.31
NOBLE ENERGY INC	05-123-47687	52.1	1302	582	2370	362	4068	0.38
NOBLE ENERGY INC	05-123-48166	55.4	1573	576	660	432	1148	0.43
NOBLE ENERGY INC	05-123-47590	51.7	1340	543	2261	468	4161	0.46
PDC ENERGY INC	05-123-45067	51.0	1338	526	1822	177	3467	0.25
NOBLE ENERGY INC	05-123-48565	51.5	1346	520	2311	231	4448	0.31
NOBLE ENERGY INC	05-123-48563	51.5	1346	515	2459	196	4769	0.28
HIGHPOINT OPERATING CORPORATION	05-123-48495	46.4	1268	485	1940	207	3999	0.30
KERR MCGEE OIL & GAS ONSHORE LP	05-123-46256	43.6	1405	472	1260	193	2670	0.29

Table 2: The 10 Best Codell Wells in the Colorado DJ Basin

Operator	API Number	API Grav (deg)	Gas BTU	Avg Oil/Day (bbls)	Avg Gas/Day (mcf)	Avg Water/Day (bbls)	Avg GOR	Avg Water Cut
NOBLE ENERGY INC	05-123-44963	53.0	1457	468	1153	319	2460	0.40
EXTRACTION OIL & GAS INC	05-123-45995	49.6	1360	406	993	299	2448	0.42
KERR MCGEE OIL & GAS ONSHORE LP	05-123-46522	42.1	1401	290	742	116	2555	0.28
KERR MCGEE OIL & GAS ONSHORE LP	05-123-46443	48.0	1362	246	869	80	3526	0.24
KERR MCGEE OIL & GAS ONSHORE LP	05-123-43820	47.1	1349	157	684	129	4346	0.45
PDC ENERGY INC	05-123-39842	46.2	1332	46	142	12	3050	0.20
NOBLE ENERGY INC	05-123-41529	66.9	1353	44	499	10	11286	0.18
NOBLE ENERGY INC	05-123-41531	67.2	1327	44	512	23	11691	0.34
KERR MCGEE OIL & GAS ONSHORE LP	05-123-43362	51.9	1321	37	598	13	16160	0.25
KERR MCGEE OIL & GAS ONSHORE LP	05-123-43210	52.9	1316	33	412	16	12426	0.33

Technological & Research Challenges

As with other North American basins, operators in the DJ Basin have moved from one-off wells in the past few years to full drill spacing unit (DSU) developments. A DSU in the DJ Basin is typically one section

wide and one or two sections long and are usually oriented either east-west or north-south. An important decision for operators when drilling full DSUs are the vertical and horizontal spacing of wells. Operators are also moving away from the "bigger is always better" completions approach to tailoring the fluid volume, fluid chemistry, and sand loading of completions to specific geochemical, petrophysical, and fracture domains (e.g., Kamruzzaman et al., 2019; Zhu et al., 2019; Uzun et al., 2019; Grau et al., 2019).

Regulatory & Business Framework

Two operators dominated the Niobrara and Codell in the DJ Basin in 2019: Occidental Petroleum with their legacy Anadarko Petroleum assets and Noble Energy, which at the time of writing in mid-2020 is merging with Chevron. Other operators with large contiguous lease positions include PDC, Crestone Peak Energy, Crescent Point, Bonanza Creek Energy, High Point Resources, EOG, Extraction Oil & Gas, Great Western, Whiting, Bayswater, and Samson Exploration. A number of small, private-equity backed companies operate in the Niobrara and Codell, including Confluence Resources, Mallard Exploration, Bison Oil & Gas II, Edge Energy, Boomtown, and Clear Creek Resource Partners.

The regulatory framework applied to the DJ Basin varies considerably by state. Kansas and Wyoming are both considered to be petroleum friendly states for investment, ranking 3rd and 4th respectively, while Colorado was ranked 59th and Nebraska was not ranked in the Fraser Institute Global Petroleum Survey (Glennon, 2018). In the months leading up to the defeated Colorado proposition 112, which would have imposed a 2500 foot setback on all wells from habitations and wetlands, operators applied for and received large numbers of permits. In April 2019, the Colorado senate approved Senate Bill 19-181 (SB 181), which brought significant changes to Colorado's regulatory framework for oil and gas, including increasing local control, changing forced pooling, drilling, and operating requirements, creating professional oil and gas commissioners, and changing the mandate of the COGCC to place public health, safety, and environmental concerns ahead of promoting oil and gas development. The slowdown in permitting that occurred following the passage of SB 181 but before the rewriting of many COGCC regulations did not seem to affect the upward trajectory of Niobrara and Codell production because of banked permits.

Whereas much of Colorado is private land and regulated by the state, Wyoming's DJ Basin is dominantly public land regulated by the US Bureau of Land Management in addition to the WOGCC. Across both Colorado and Wyoming, state and federal regulatory bodies added regulations around air quality, tank venting, and flaring.

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Potential Self-Sourced Accumulations, North Slope, Alaska

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Overview

Prudhoe Bay and Kuparuk River fields of northern Alaska are the two largest conventional oil fields in North America (Fig. 1; Hosford Shierer and Bird, 2020). Three major source rocks have been typed as the source of hydrocarbons in Prudhoe Bay, Kuparuk River and associated fields: the Triassic Shublik Formation, the Jurassic Kingak Shale, and the Cretaceous Hue Shale (Fig. 1; Peters et al., 2006 and references therein). The Shublik, Kingak and Hue source rocks also are being investigated for their potential as self-sourced resource plays (Houseknecht et al., 2012; Duncan and Bird, 2013; Hosford Scheirer et al., 2014; Whidden et al., 2018; Hosford Scheirer and Bird, 2020).

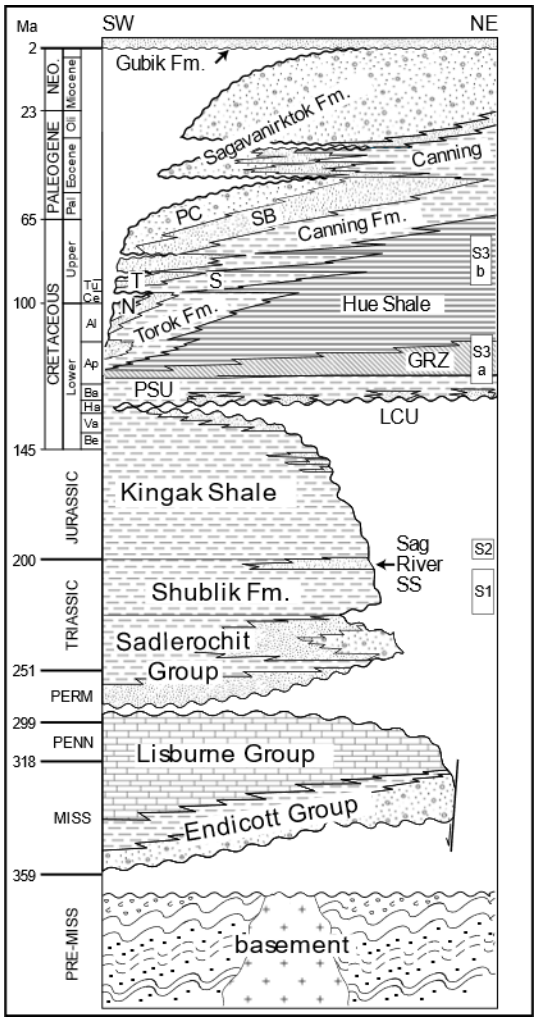

Figure 1. Stratigraphy of northern Alaska. The three major source rocks discussed in the text are the Shublik Formation (S1), the Kingak Formation (S2), the GRZ (S3a) and the Hue Shale (S3b). Figure courtesy of D. Houseknecht, USGS.

Houseknecht and others (2012) assessed the continuous hydrocarbon resource potential of the Shublik, Kingak and Brookian strata (which include the lower part of the Hue Shale and the underlying pebble shale unit; Fig. 1) using geologic and engineering analogs from the lower 48 states since no production data were available. They noted that the Shublik Formation has limestone, phosphatic limestone and chert, and the Hue Shale has sandstone, siltstone, concretionary carbonate and silicified tuff, all of which provide brittle lithologies necessary for hydraulic fracturing. The Kingak Formation, however, is largely a ductile mudstone. The assessed mean undiscovered, technically recoverable oil and gas resources for Shublik oil was 463 MMBO and for gas was 38,405 BCFG. The mean undiscovered, technically recoverable oil and gas resources for Kingak oil was 28 MMBO; Kingak gas was not assessed. The mean undiscovered, technically recoverable oil and gas resources for Brookian oil was 449 MMB and for gas was 2184 BCFG. The range of uncertainty on these numbers was captured by the F5 and F95 values, as shown in Table 2 of Houseknecht and others (2012).

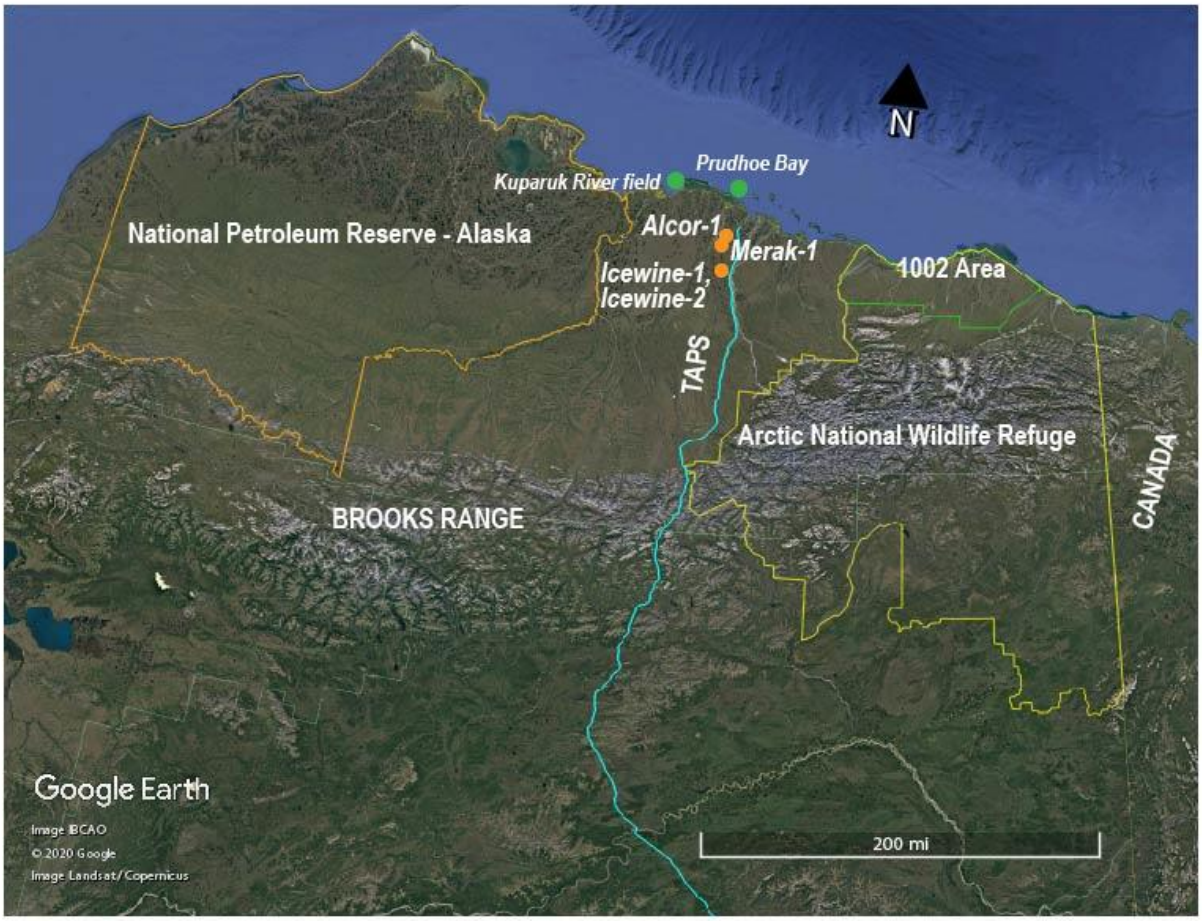

Figure 2. Map of northern Alaska illustrating the locations of the four wells drilled to date to test the potential of the Shublik and Hue Shale as continuous resource plays. TAPS = Trans-Alaska Pipeline System, which approximates the location of the Dalton Highway.

Exploration for conventional reservoirs in northern Alaska has been ongoing for several decades; however, exploration for continuous (unconventional) resources has barely begun – a total of four wells have been drilled to test continuous plays across the whole of the North Slope (Fig. 2). Great Bear

Petroleum Operating LLC drilled Merak-1 and Alcor-1 along the Dalton Highway, which follows the Trans-Alaska pipeline system (TAPS; Fig. 2) in 2012 to evaluate the continuous potential of the Hue Shale, Kingak Formation, and specifically the Shublik Formation. Both vertical wells were completed in 2017 as dry and abandoned without having been flow tested. Cores collected through all three formations are part of ongoing evaluations of the continuous potential of these units.

The Hue Shale was the target for two wells drilled along the Dalton Highway (Fig. 2) by Accumulate Energy Alaska Inc. Icewine-1 was drilled in 2015, while Icewine-2 was drilled in 2017. Icewine-1 was not flow tested, and flow tests on Icewine-2 were inconclusive. Cores drilled through different units within the Hue Shale are part of ongoing evaluations of the continuous potential of these units.

Source Rock Geology of Northern Alaska

The Triassic Shublik Formation is a heterogeneous siliciclastic-carbonate-phosphatic unit that was deposited on a low-angle shelf in Arctic Alaska during the Middle and Late Triassic (Fig. 1; Kupecz, 1995; Hulm, 1999; Parrish et al., 2001; Whidden et al., 2018). Organic-rich intervals occur throughout the Shublik, with the middle unit having many of the highest measured total organic carbon (TOC) values, as well as common brittle, carbonate-rich and chert-rich lithologies (Whidden et al., 2018).

The Jurassic Kingak Shale was deposited as a southward thinning wedge of strata above the Shublik Formation (Fig. 1). Although oils have been typed to the Kingak (Peters et al., 2006), it is not well understood as a source rock interval. Houseknecht and Bird (2004) interpreted the basinal condensed section of the oldest sequence set within the Kingak as the likely organic-rich section. TOC data from core and cuttings suggest that there may be multiple source rock intervals in the Kingak Formation (Hosford Sheirer and Bird, 2020; Whidden, USGS, unpublished data). More work is needed to understand the spatial and temporal development across the North Slope of organic-rich sequences within the Kingak Shale.

The Hue Shale was deposited in a basinal setting during Aptian – Campanian time (Fig. 1; Molenaar, 1983; Molenaar et al., 1987; Whidden et al., 2019). The lower part of the Hue Shale, informally known as the gamma-ray zone (GRZ) or high-resistivity zone (HRZ), has long been recognized as an important organic-rich interval that was deposited across the North Slope. Recent USGS field work and analytical data indicate that there is a second significant source interval within the Hue Shale above the GRZ, spatially limited to the eastern part of the North Slope, that is age-correlative with other Cenomanian-Turonian source rocks of the Western Interior Seaway (Whidden et al., 2019). Further USGS field and analytical studies are ongoing to better understand the spatial and temporal development of organic-rich sequences in the Hue Shale.

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Oklahoma Shale Gas/Tight Oil Plays, U.S.A.

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Note: no update was submitted by the contributors for 2019-2020 due to limited activity

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).

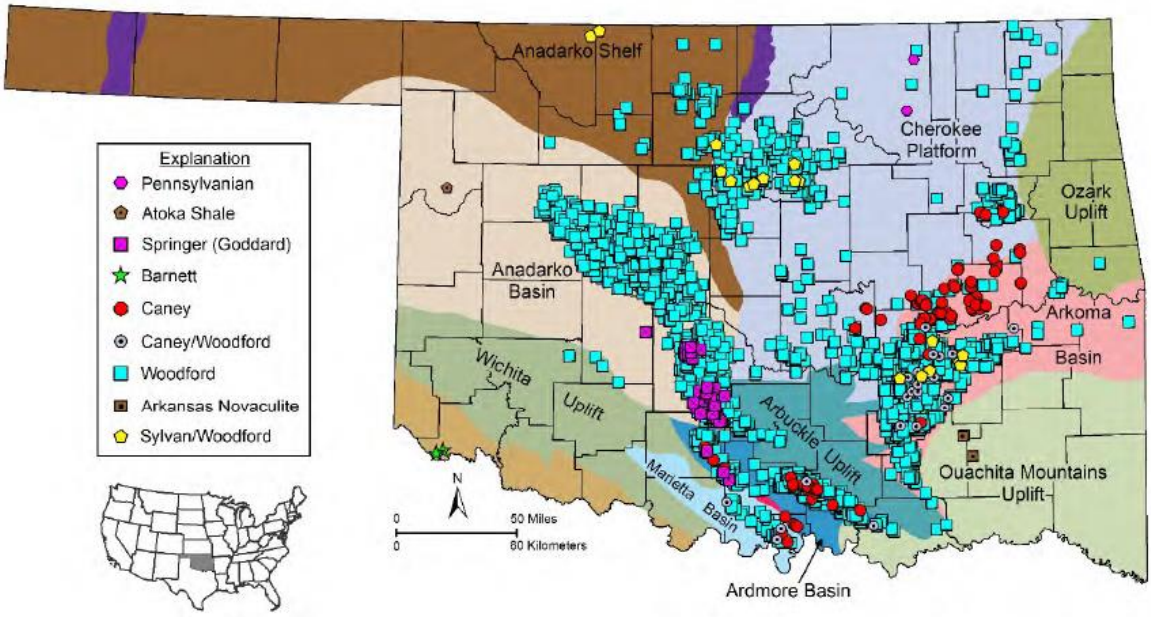

Figure 1. Map showing Oklahoma shale gas and tight oil well completions (1939-2018) on a geologic provinces map of Oklahoma (OU, 2018; base map modified from Northcutt and Campbell, 1998).

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.

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).

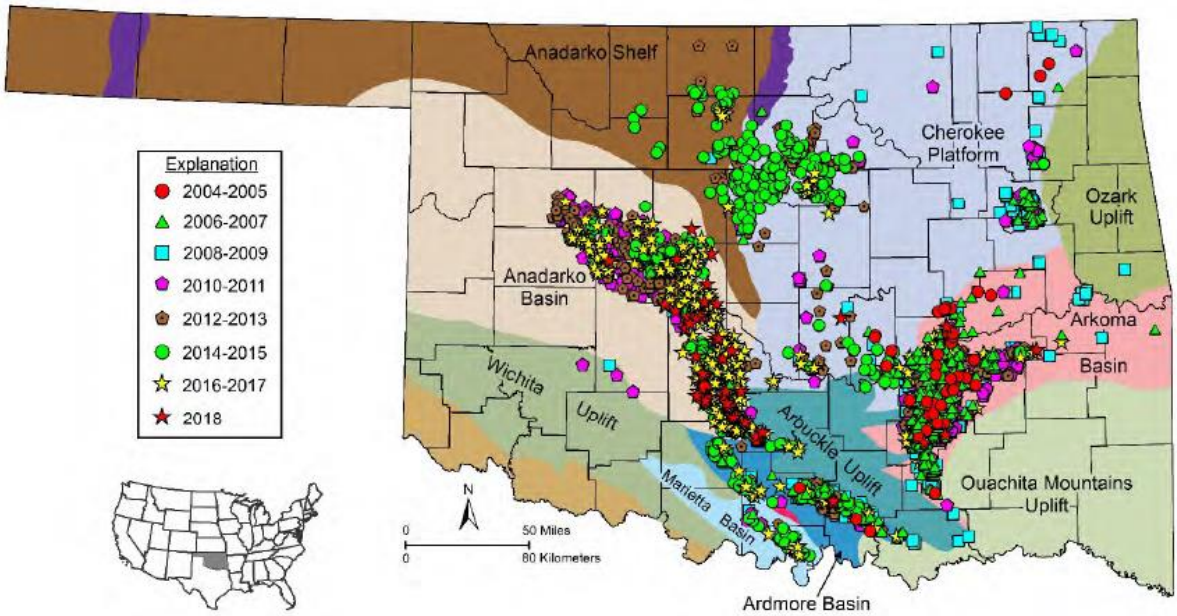

Figure 2. Map showing Woodford Shale well completions, 2004-2018 (OU, 2018_2).

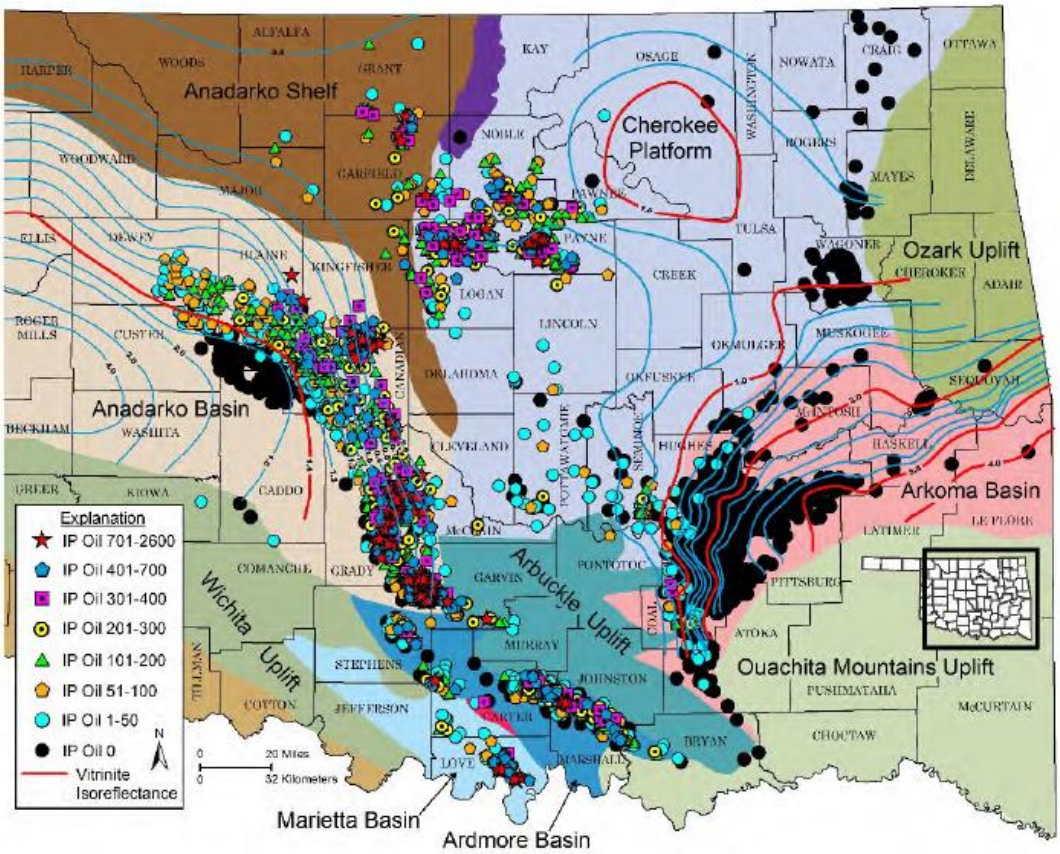

Figure 3. Map showing initial potential oil/condensate rates of Woodford Shale well completions 2004-2018 (OU, 2018_3).

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)

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Permian Basin Shales

Beau Tinnin, EOG Resources, and Bo Henk, Pioneer Resources

Updated for 2019-2020 by Justin E. Birdwell, U.S. Geological Survey, Denver, CO

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 Railroad Commission, 2020) since the early 1920s. Numerous experts agree that the Permian Basin contains significantly more recoverable hydrocarbon resource in place than previously has been produced. To date, the U.S. Geological Survey has conducted assessments of three Permian-aged resources: the Wolfcamp shale and Bone Spring Formation of the Delaware Basin (Gaswirth et al., 2018); the Spraberry Formation of the Midland Basin (Marra et al., 2017); and the Wolfcamp shale of the Midland Basin (Gaswirth et al., 2016). These have combined mean total undiscovered, technically recoverable resource of 70.5 billion barrels of oil and 300.1 trillion cubic feet of natural gas.

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 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.

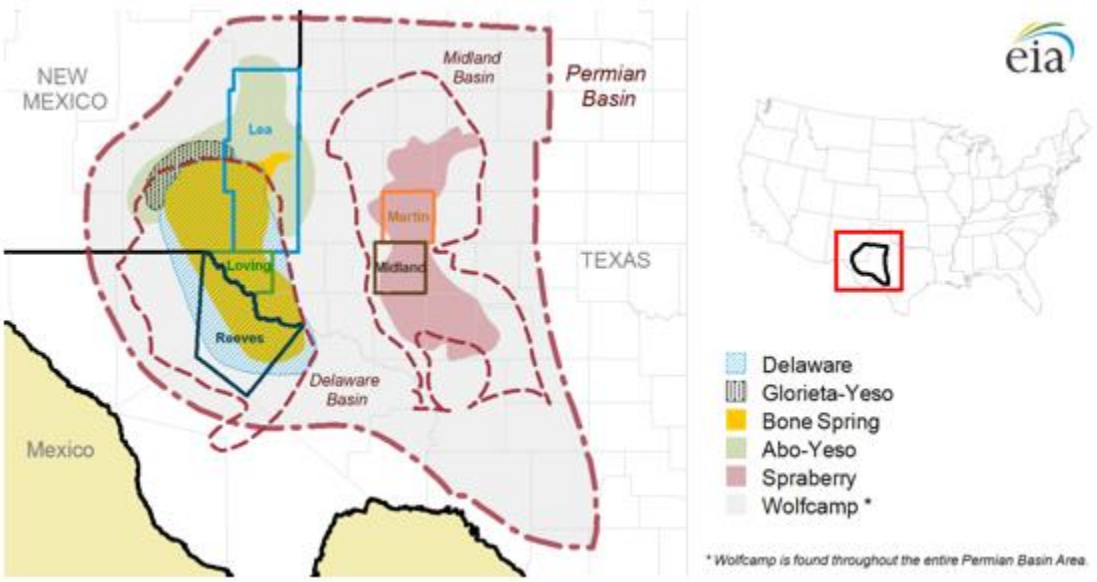

Figure 1. Map of the Permian Basin (see inset map on the right) in southeast New Mexico and west Texas showing major plays currently under development in the Delaware and Midland Sub-Basins (Source: U.S. Energy Information Administration, U.S. Geological Survey, University of Texas Bureau of Economic Geology, and Drillinginfo).

The Permian Basin comprises numerous vertically stacked conventional reservoirs and organic-rich source-rock intervals with a vast majority of production coming from Permian- and Pennsylvanian-aged

units. 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. From January 2019 through April 2020, the number of rigs operating in the Permian Basin ranged from 400 to 500 but dropped precipitously as of June 2020 to less than 150 when the decline in drilling leveled off (**Fig. 2**). Permian production has also declined as a result of declining prices and the COVID-19 pandemic depressing demand. Oil production rose steadily from 2010 (approximately 900,000 bpd), reached a peak of around 4.2 million bpd in March 2020, and as of September 2020 had dropped to 2.8 million bpd, with 11.27 Bcf of daily gas production (U.S. EIA, October 2020).

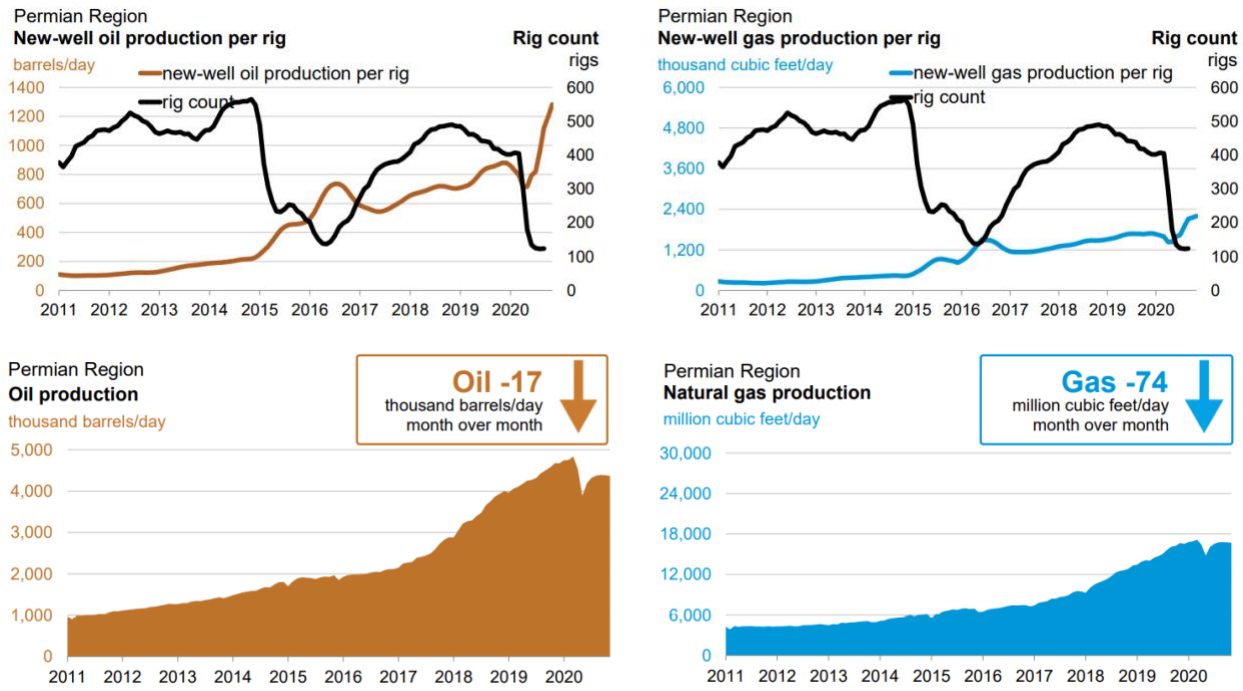

Figure 2. US EIA data new well production per rig, rig counts, and total regional daily production for oil and natural gas in the Permian Region (from U.S. EIA Drilling Productivity Report, 2020).

Annualized production of oil, natural gas, and condensate/natural gas liquids from the Texas Railroad Commission are summarized below (**Figs. 3** through **5**). Drilling permits issued from 2006 through August 2020 are also presented (**Fig. 6**). Despite fluctuations in new drilling permits, until 2020 production of all products reported to the Texas Railroad Commission increased year over year on an annualized daily production basis. Discussions of the growth in U.S. shale oil production generally indicate that the majority or perhaps all substantial growth from resource plays is expected to come from the Permian Basin for the foreseeable future.

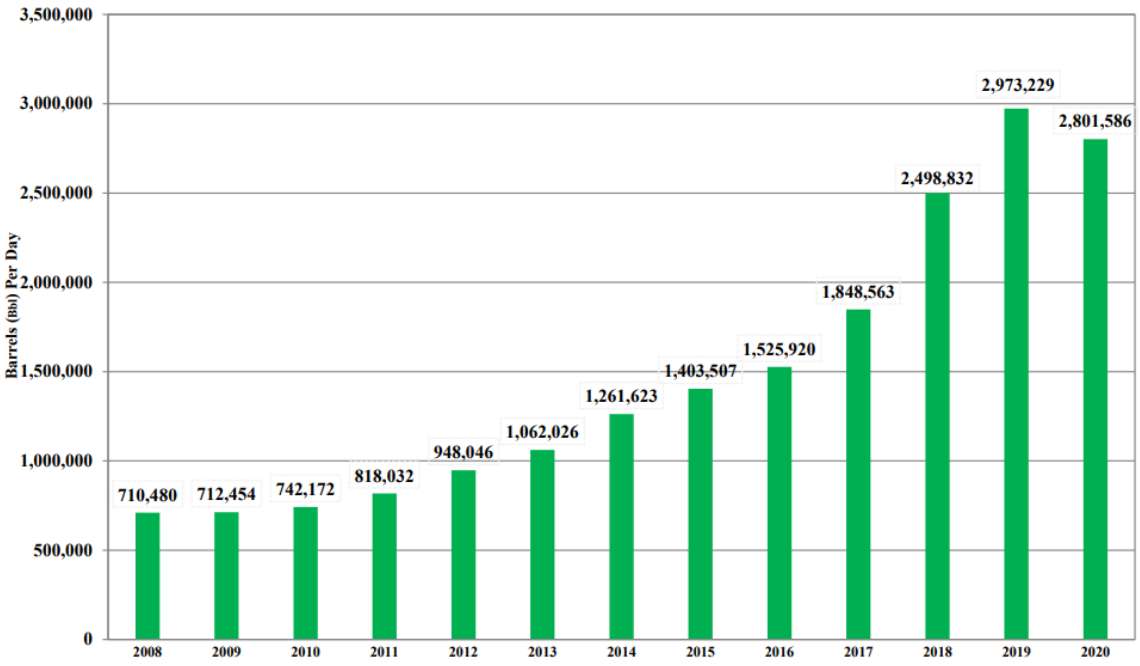

Figure 3. Texas Permian Basin Average Daily Oil Production for 2008 through July 2020 (Texas Railroad Commission, accessed 11/11/2020).

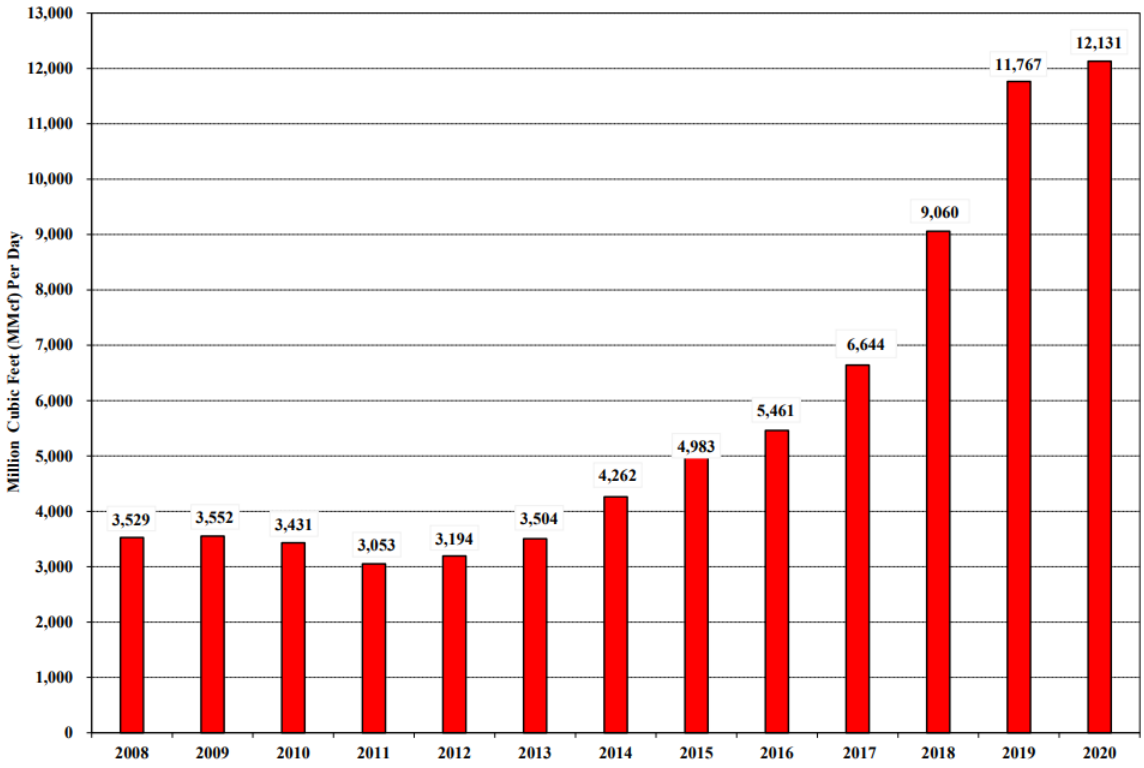

Figure 4. Texas Permian Basin Average Daily Natural Gas Production for 2008 through July 2020 (Texas Railroad Commission, accessed 9/29/2020).

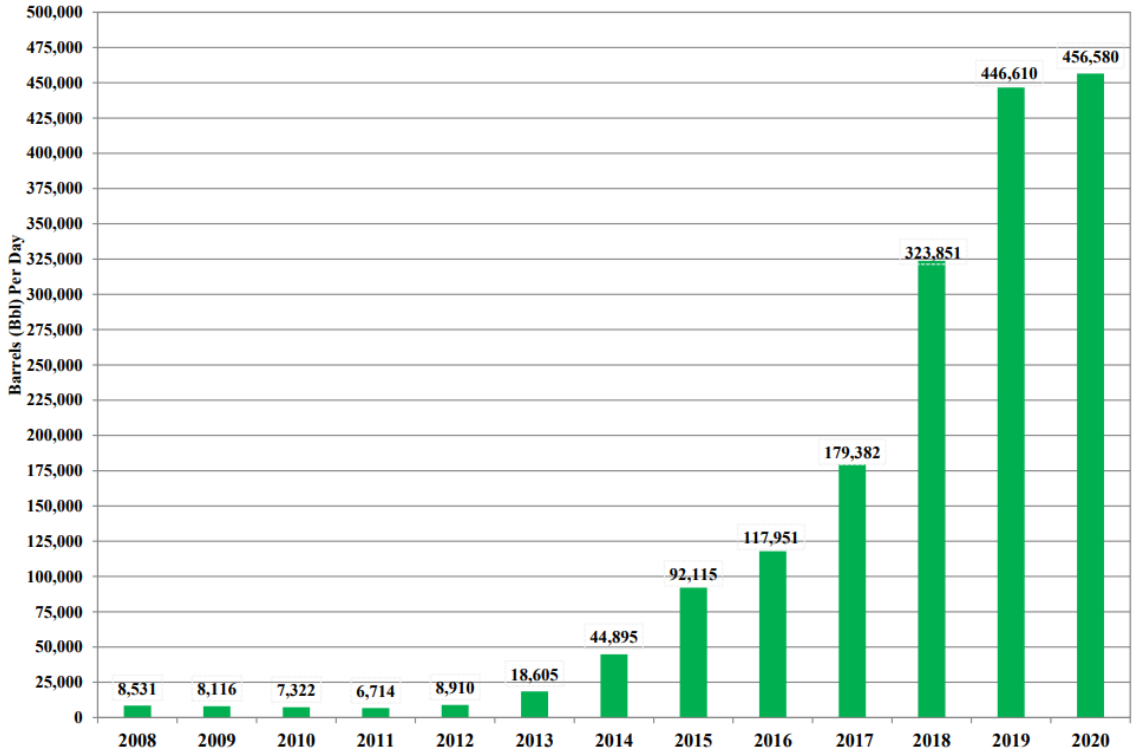

Figure 5. Texas Permian Basin Average Daily Condensate Production for 2008 through July 2020 (Texas Railroad Commission, accessed 11/11/2020).

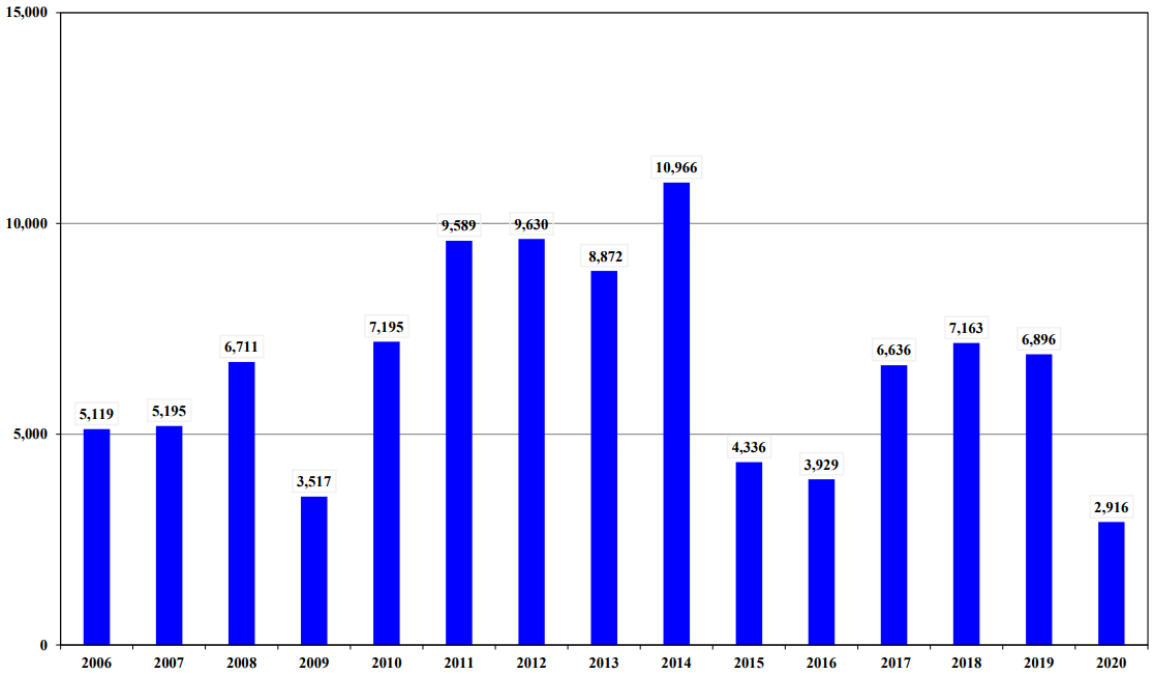

Figure 6. Texas Permian Basin (District 7C, 08, & 8A) Drilling Permits Issued between 2006 through September 2020 (Texas Railroad Commission, accessed 11/11/2020).

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Tuscaloosa Marine Shale, Gulf Coast Basin, Louisiana and Mississippi

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Upper Cretaceous (Cenomanian–Turonian) strata 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 97.5 to 90 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; Dubiel et al., 2011). Though both of these units have been demonstrated to contain substantial hydrocarbon 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, whereas development of the Tuscaloosa Marine Shale has been more limited due to several factors related to drilling costs and limited infrastructure.

The Tuscaloosa Marine Shale (TMS) is currently a minor shale oil play in Louisiana, Mississippi, and Alabama. Though it is thought to contain substantial unconventional oil and gas resources, the TMS has been largely undeveloped. This is evident by comparing well counts and production values for the TMS and the stratigraphically equivalent Eagle Ford. The number of active wells in the TMS is less than 100, with around two thirds in Mississippi and the remainder in Louisiana.

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 (**Fig. 1**). This area is around 300 miles (east to west) and 100 miles (north to south). TMS thickness averages about 500 ft at depths between 11,000 and 15,000 ft. Since 2009, approximately 100 wells have been drilled, 90% of which are horizontals, and as of June 2020 records from IHS Markit indicated 77 active TMS wells in 2019 and 76 as of March 2020 produced mainly oil. The top operators (Australis, Goodrich Petroleum, and Backwater Energy Partners) continue to account for over 70% of active wells. Total oil production in 2019 (1.22 million barrels) was up slightly compared to 2018 (0.99 million barrels; **Fig. 2**). Data was only compiled for the first few months of 2020, but the monthly production numbers through February (March data was incomplete at the time of collection) show a slight drop in oil production and slight increase in gas production relative to December 2019 (**Fig. 2**).

Despite substantial potential estimated in the TMS (John et al., 1997; Hackley et al., 2018), it has not been developed to the same extent as the Eagle Ford. The main reason for this disparity seems 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 than other U.S. plays ($80+/bbl; Weatherly, 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 1; Hackley et al., 2018). This is much less than an estimate of 7 billion barrels of oil in the TMS by John et al. (1997).

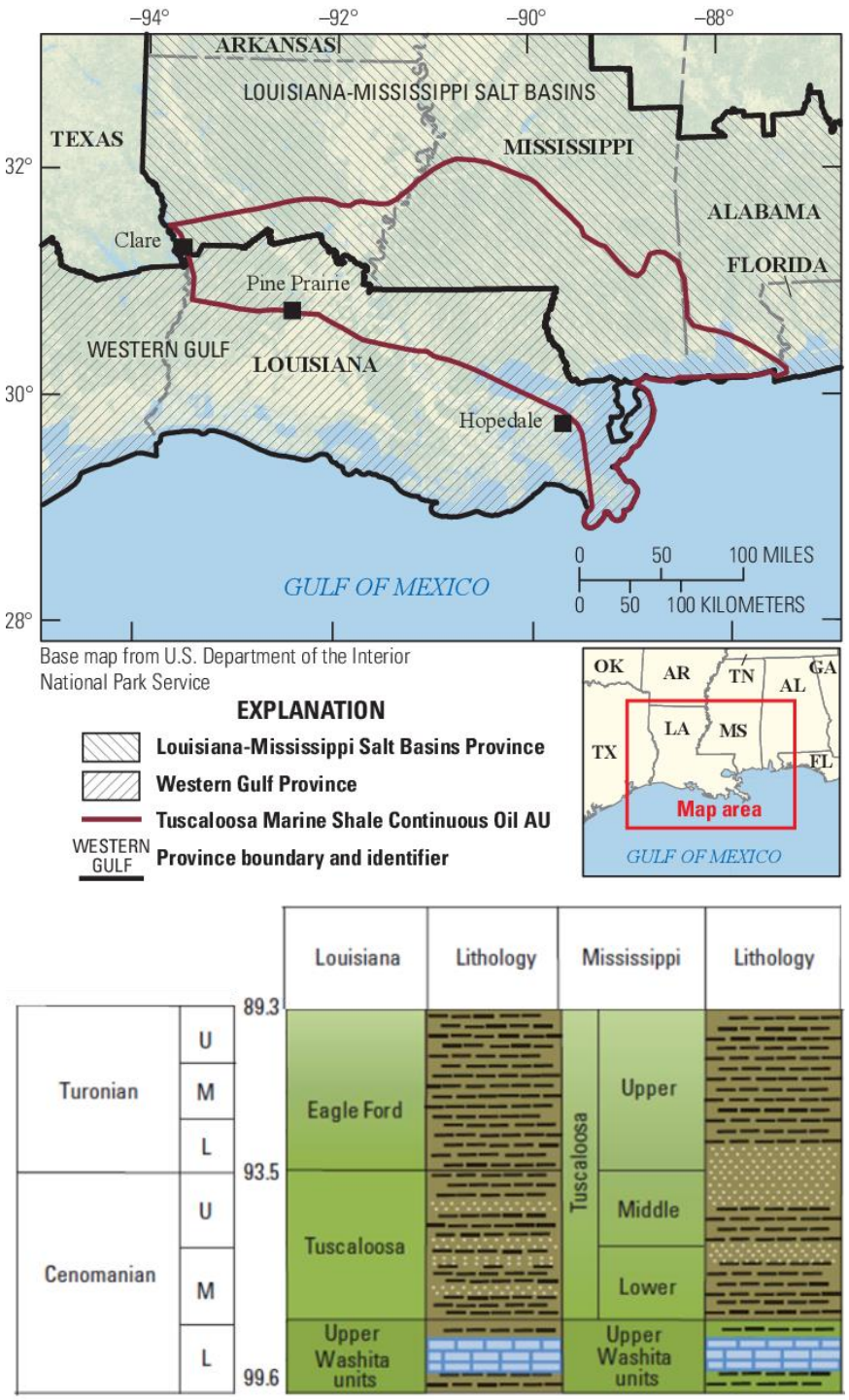

Figure 1. Map (top; Hackley et al., 2018) and stratigraphic column (bottom; after Pearson, 2012) for Tuscaloosa Marine Shale.

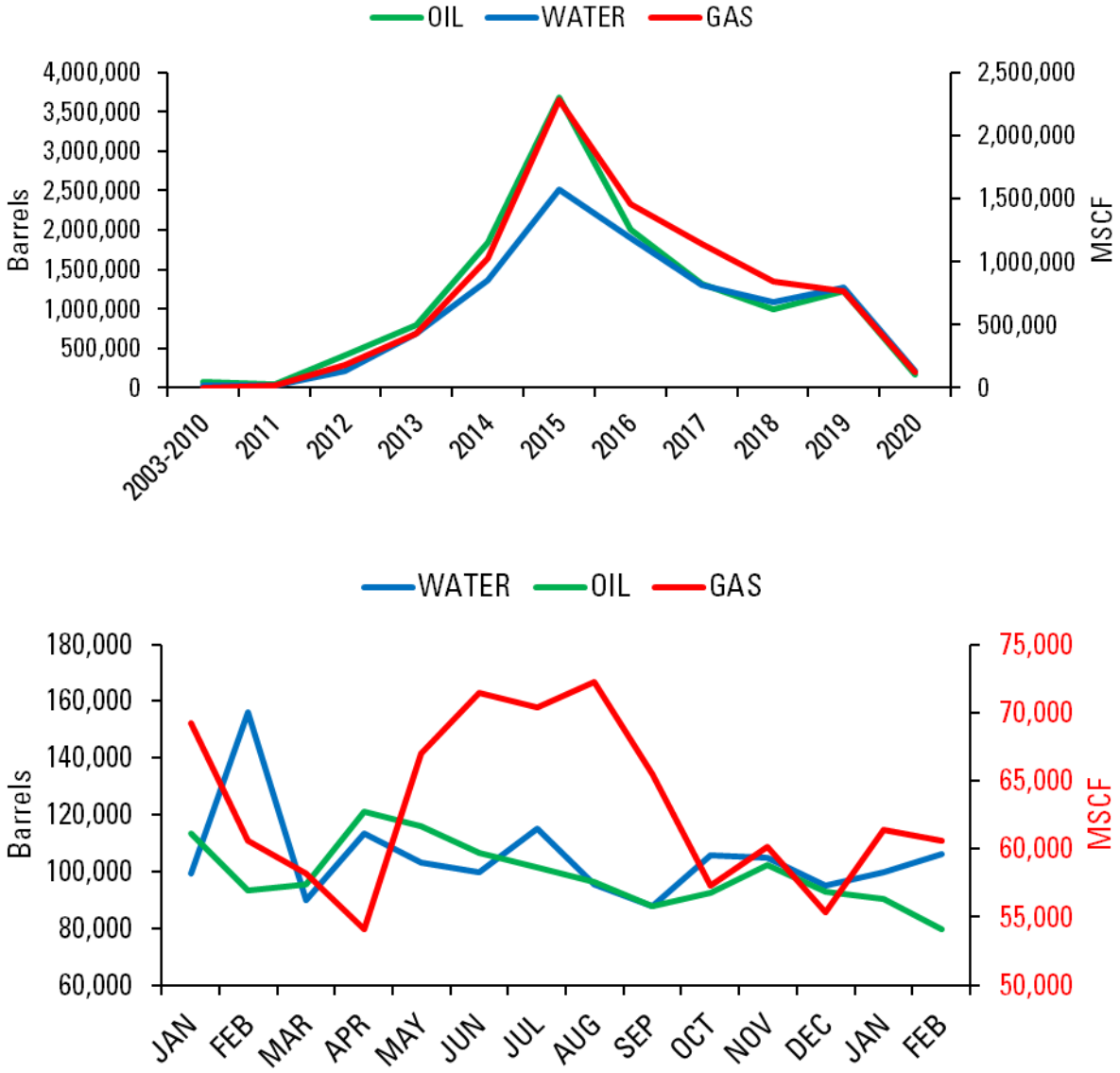

Figure 2. Top: Annual production summaries for gas and liquid products from the Tuscaloosa Marine Shale including oil+condensate, natural gas, and water, 2009 through 2019. Bottom: Monthly production for gas and liquid products for January 2019 through February 2020. Data from IHS Markit® (accessed June 3, 2020).

Several recent research articles have been published on TMS source rock geochemistry, mineralogy and petrography (Borrok et al., 2019; Lohr et al., 2020), along with oil-source correlation (Hackley et al., 2020) and produced waters geochemistry (Hoffmann and Borrok, 2020). Researchers at the University of Louisiana at Lafayette also published three papers on TMS physical properties in the joint SEG-AAPG journal *Interpretation* (Mlella et al., 2020; Ahmadov and Mokhtari, 2020; Ruse and Mokhtari, 2020). In general, since the start of 2019, Google Scholar shows 121 publications mentioning TMS, Scopus has 9 articles, conference papers and book chapters with TMS in the title, and AAPG Datapages archive shows two URTeC papers with TMS in the title.

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Tight-Oil Plays and Activities in Utah

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Note: no update was submitted by the contributors for 2019-2020 due to limited activity

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.

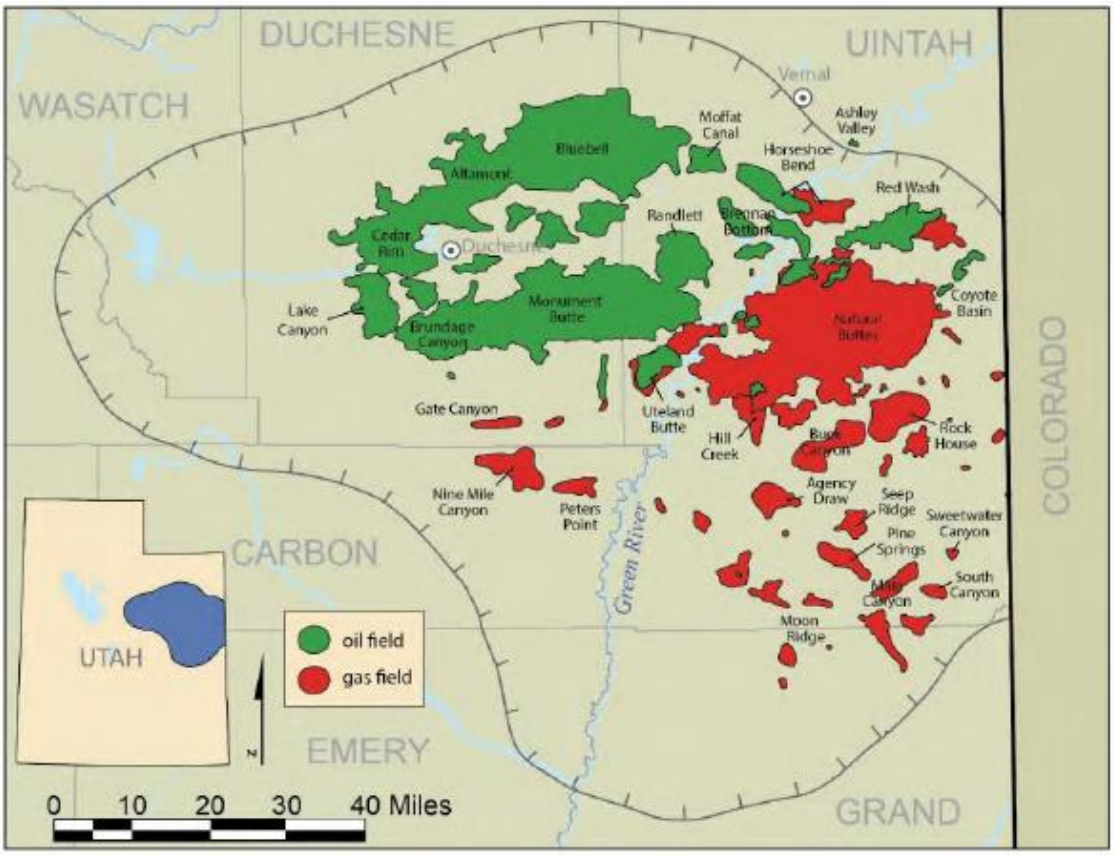

Figure 1. Oil and gas fields in the Uinta Basin of Utah and Colorado. Modified from Wood and Chidsey (2015).

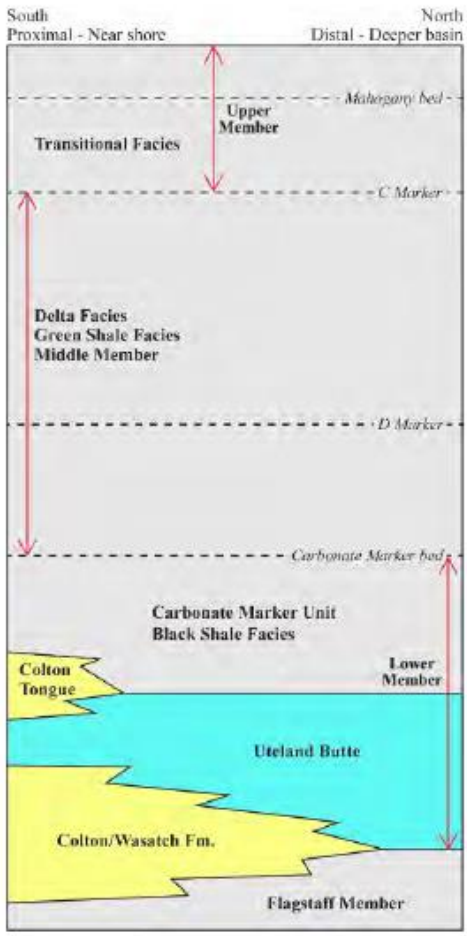

Figure 2. General stratigraphy of the Green River Formation in the western Uinta Basin (not to scale). The Uteland Butte Member, the primary horizontal drilling target in the basin, and its relationship to the Colton/Wasatch Formation is shown.

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.

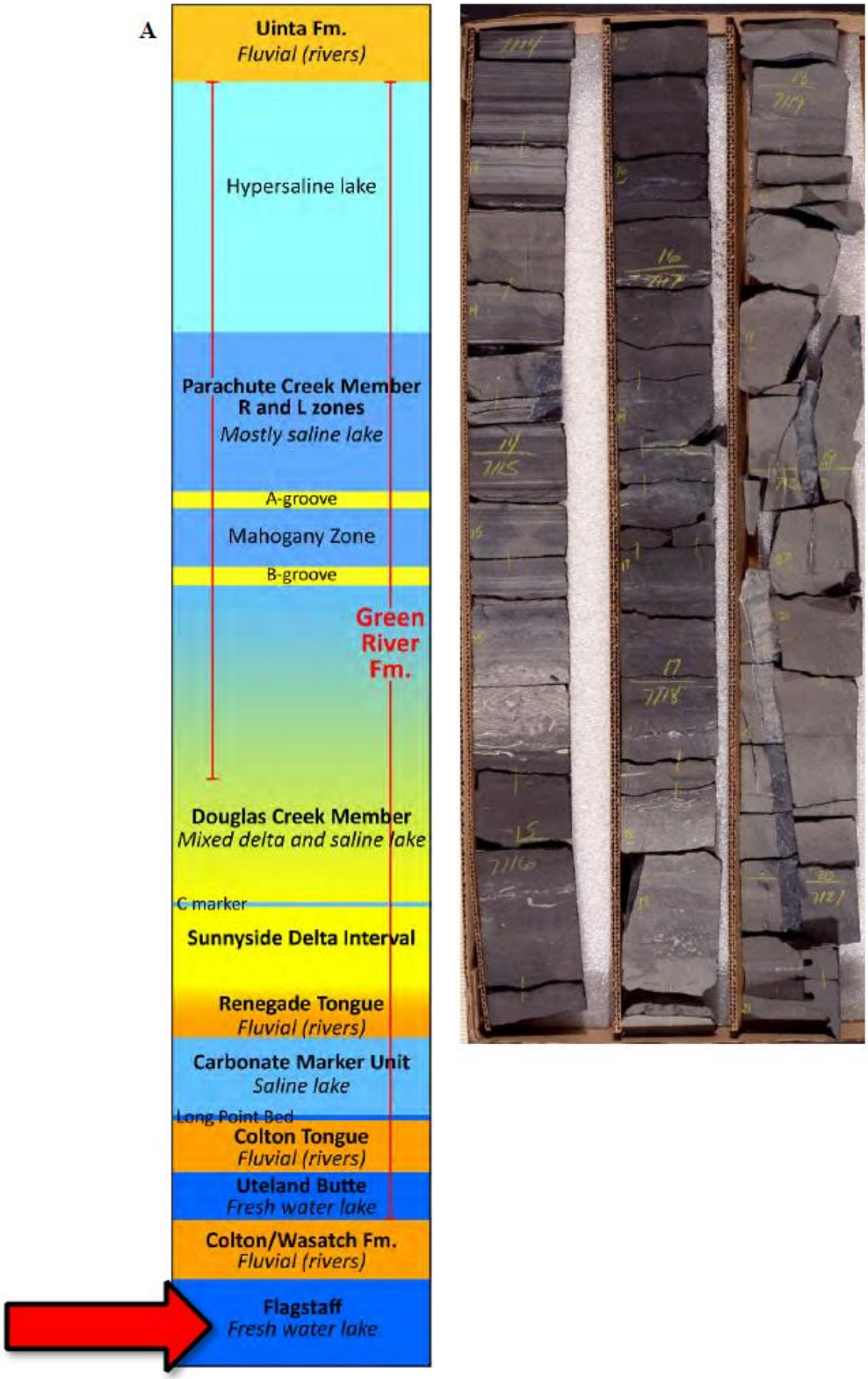

Figure 3. Flagstaff Limestone: Left – stratigraphic section, Right – core from the 9-4B1 Ute Tribal well. Note the abundant shell fragments indicating deposition in a freshwater lacustrine environment.

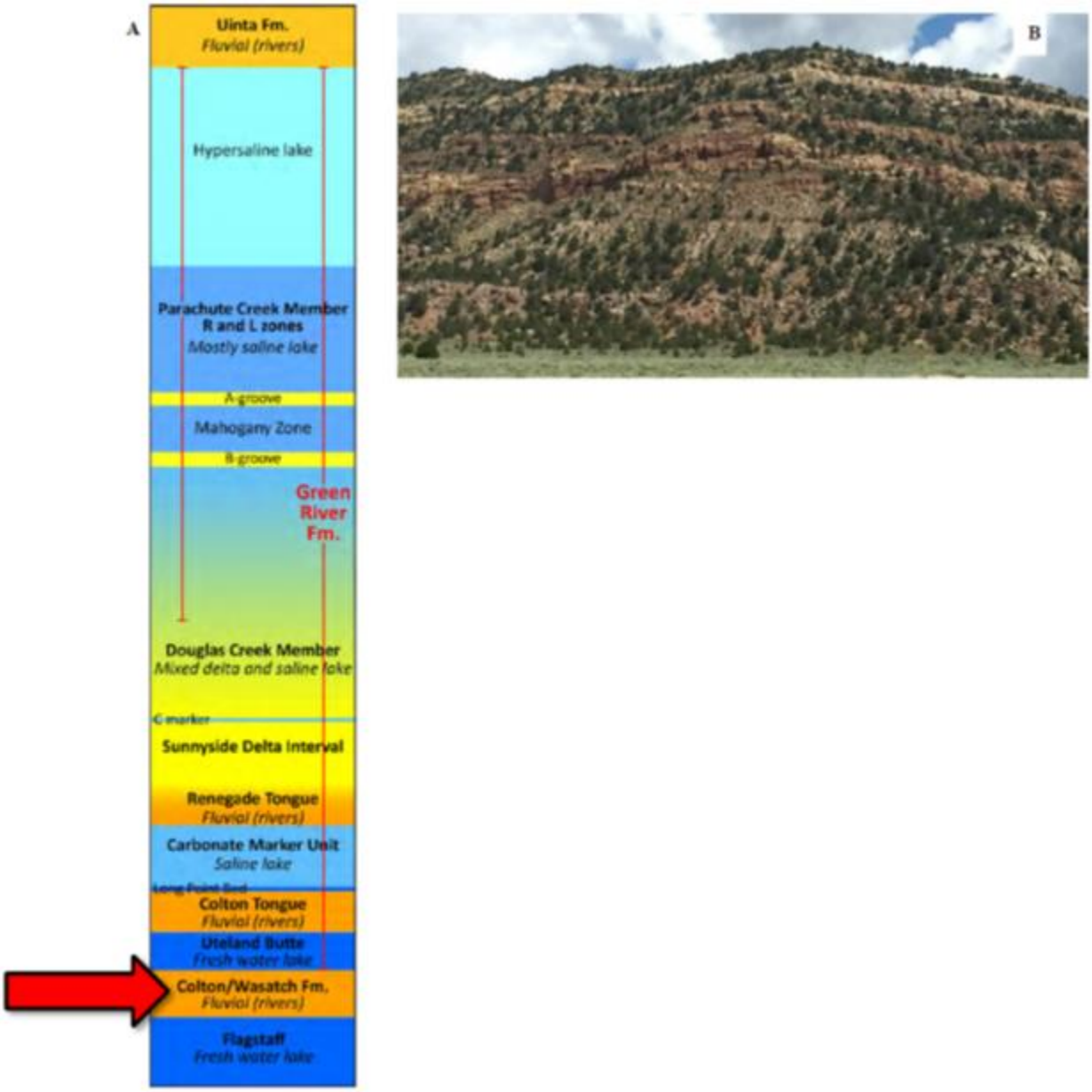

Figure 4. Colton/Wasatch Formation: A – stratigraphic section, B – typical outcrop, Nine Mile Canyon.

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 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).

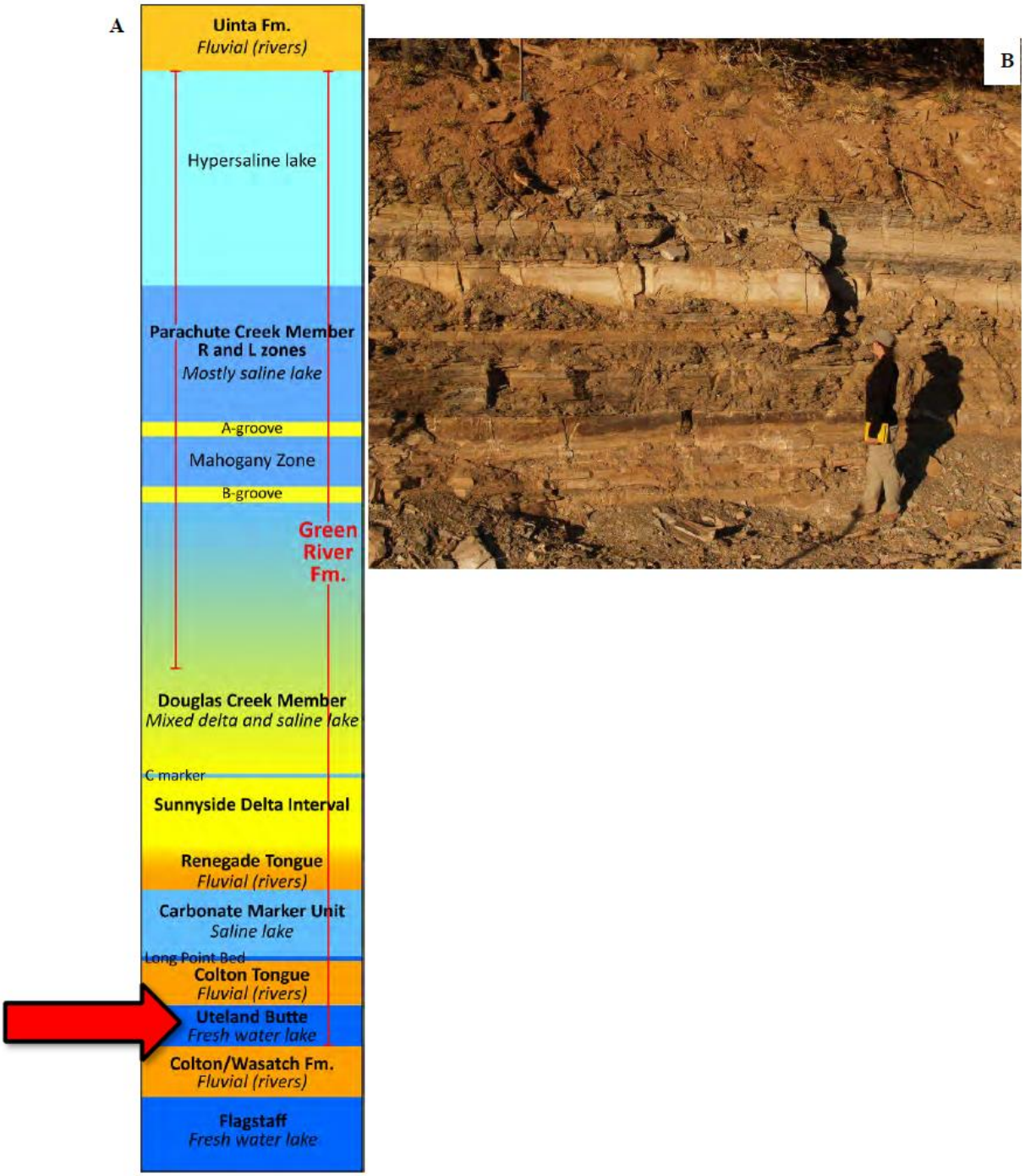

Figure 5. Uteland Butte Limestone: A – stratigraphic section, B – typical outcrop, Nine Mile Canyon. Porosity ranges from 15 to 30% and permeability averages 0.06 mD. The dolomite is interbedded with organic-rich shale, mudstone, and limestone averaging between 1% and 3% TOC. Note the abundant shell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

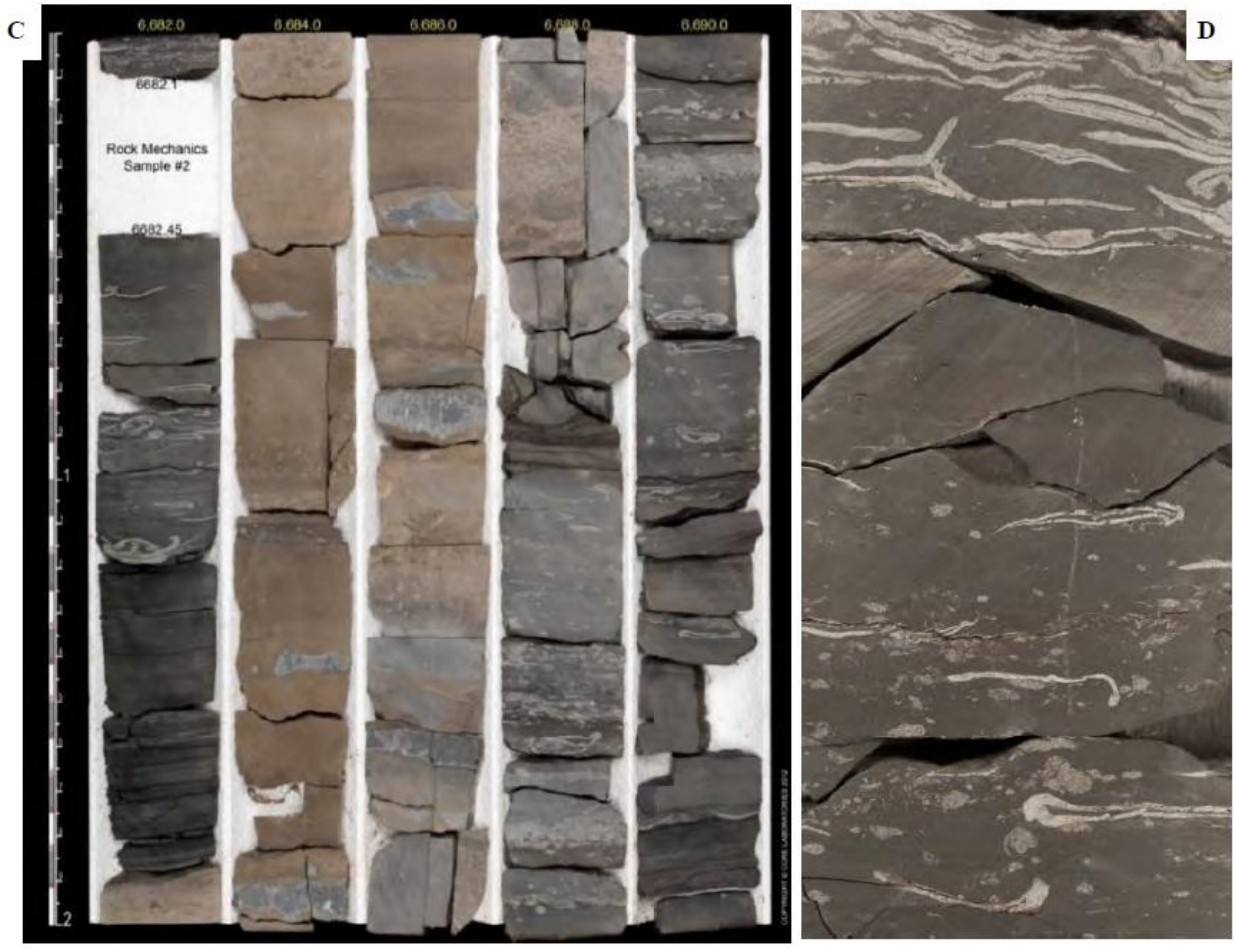

Figure 5 continued. Uteland Butte Limestone: C – core from the Bill Barrett 14-1-46 well. The horizontal drilling target is the roughly 5-ft-thick, light brown dolomitic interval, and D – closeup of dolomite reservoir. Porosity ranges from 15 to 30% and permeability averages 0.06 mD. The dolomite is 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.

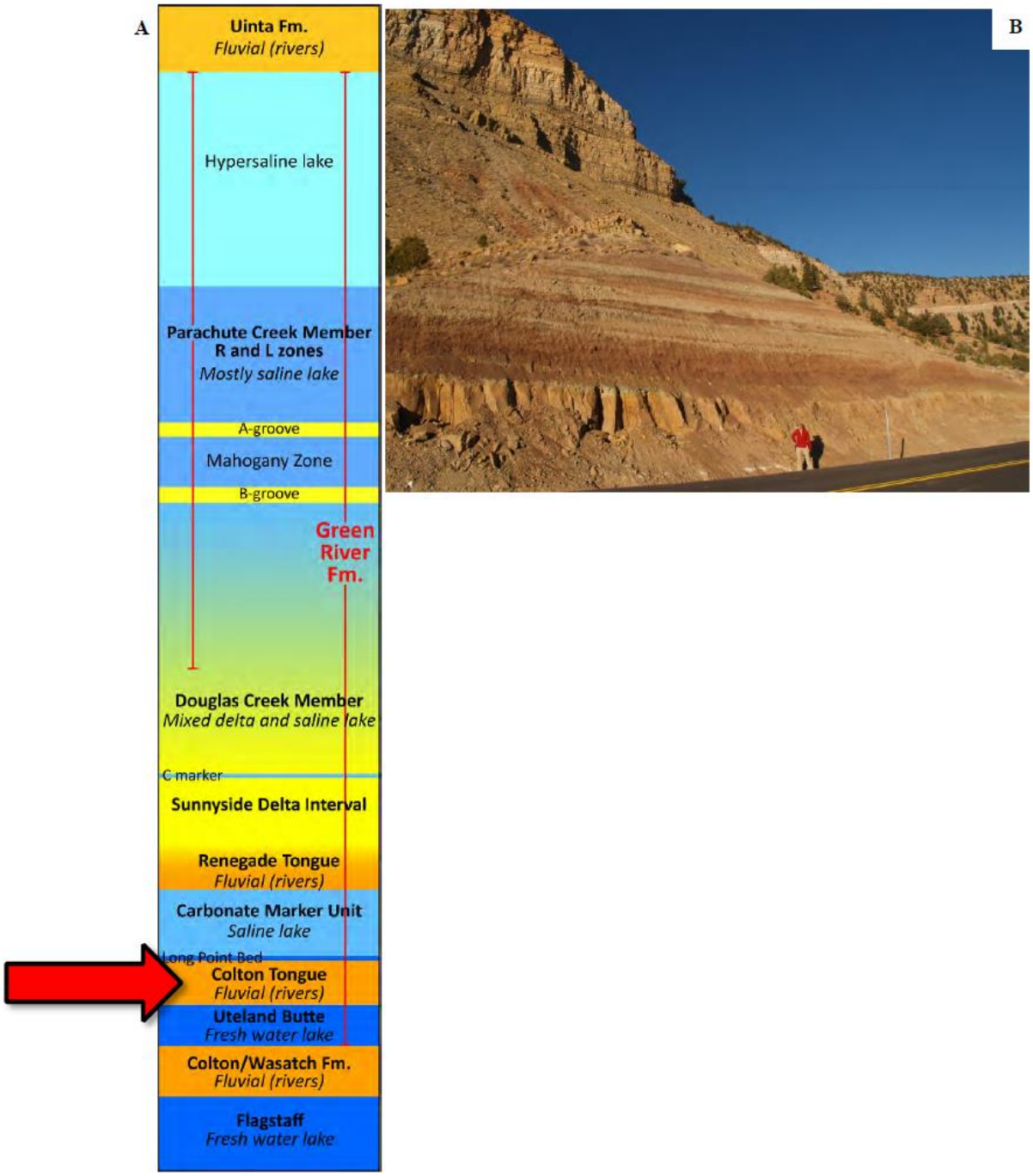

Figure 6. Wasatch/Colton Tongue or Castle Peak: A – stratigraphic section, B – typical outcrop, Nine Mile Canyon.

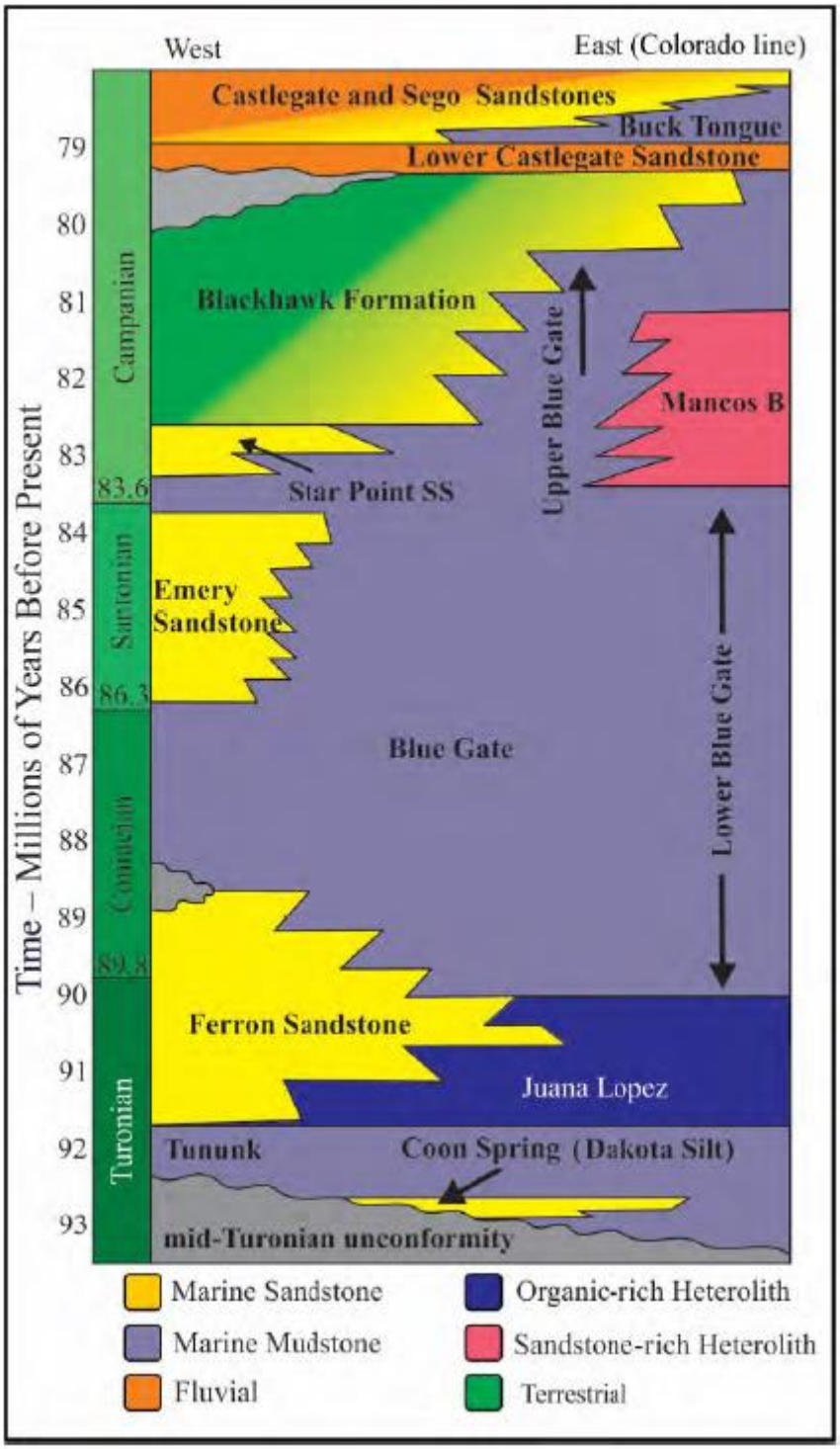

Figure 7. Stratigraphic relations of the Mancos Shale, its subunits, and adjacent formations in the Uinta Basin. After Birgenheier and others (2015).

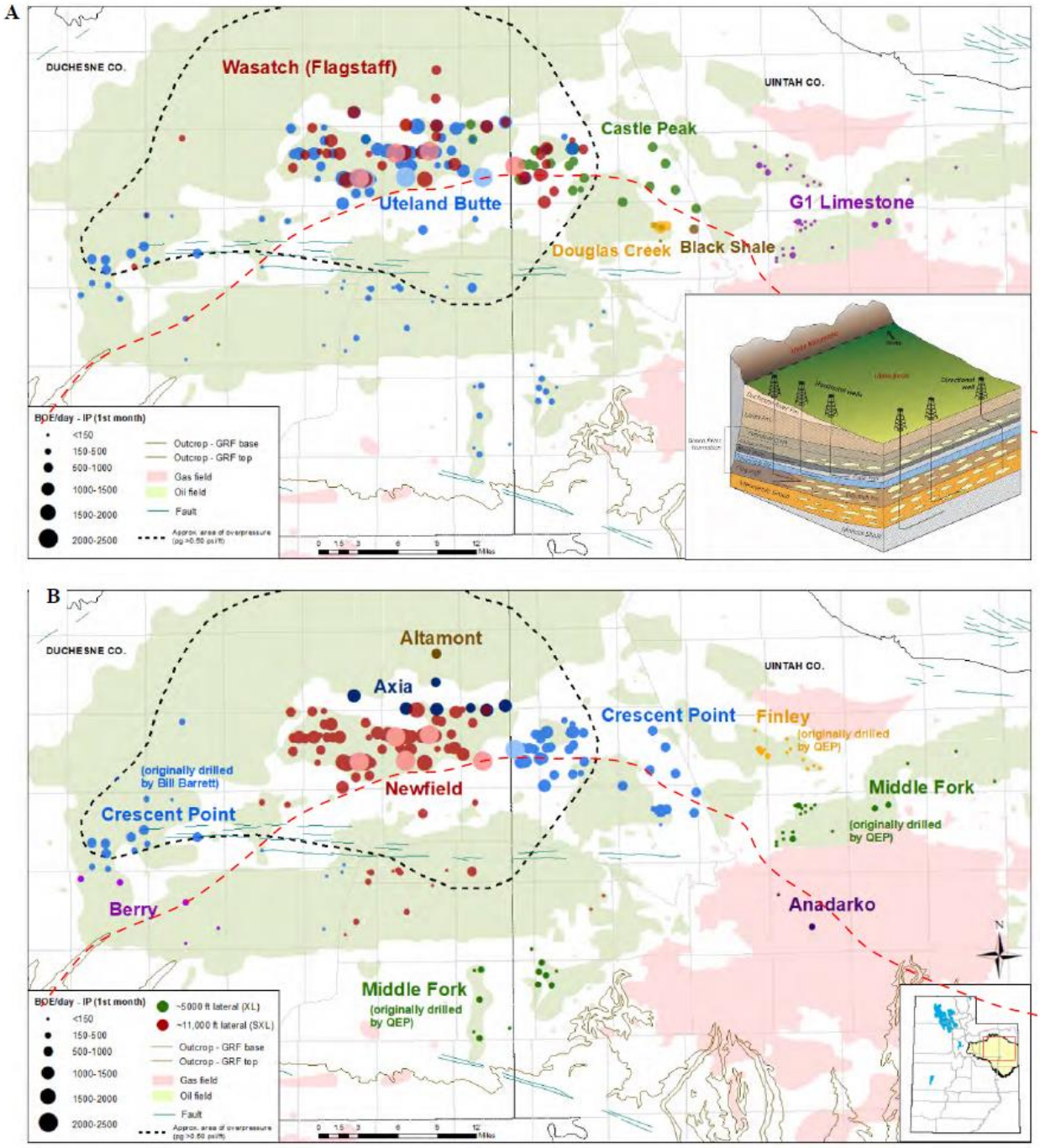

Figure 8. Initial production (first month BOE/day) of horizontal wells in the Uinta Basin by A – drilling target (inset schematic of horizontal drilling targets), and B – by operator.

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 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).

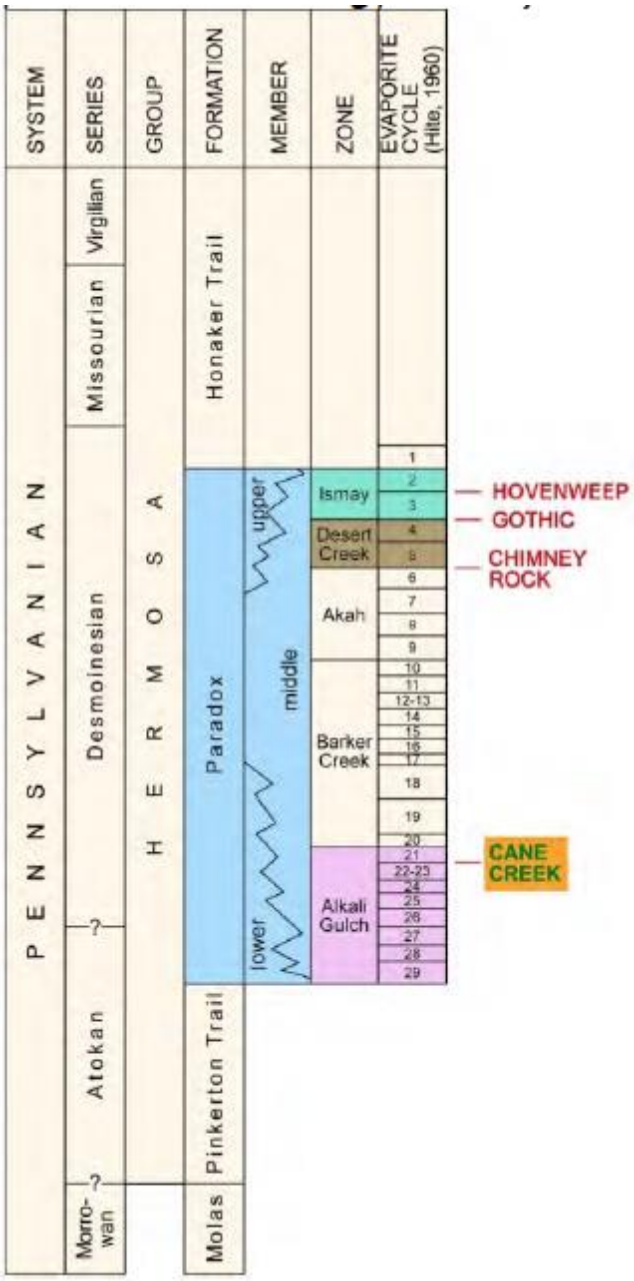

Figure 9. Pennsylvanian stratigraphic chart for the Paradox Basin, informal organic-rich shale units are highlighted. Note the position of the Cane Creek shale. Modified from Hite (1960), Hite and Cater (1972), and Reid and Berghorn (1981).

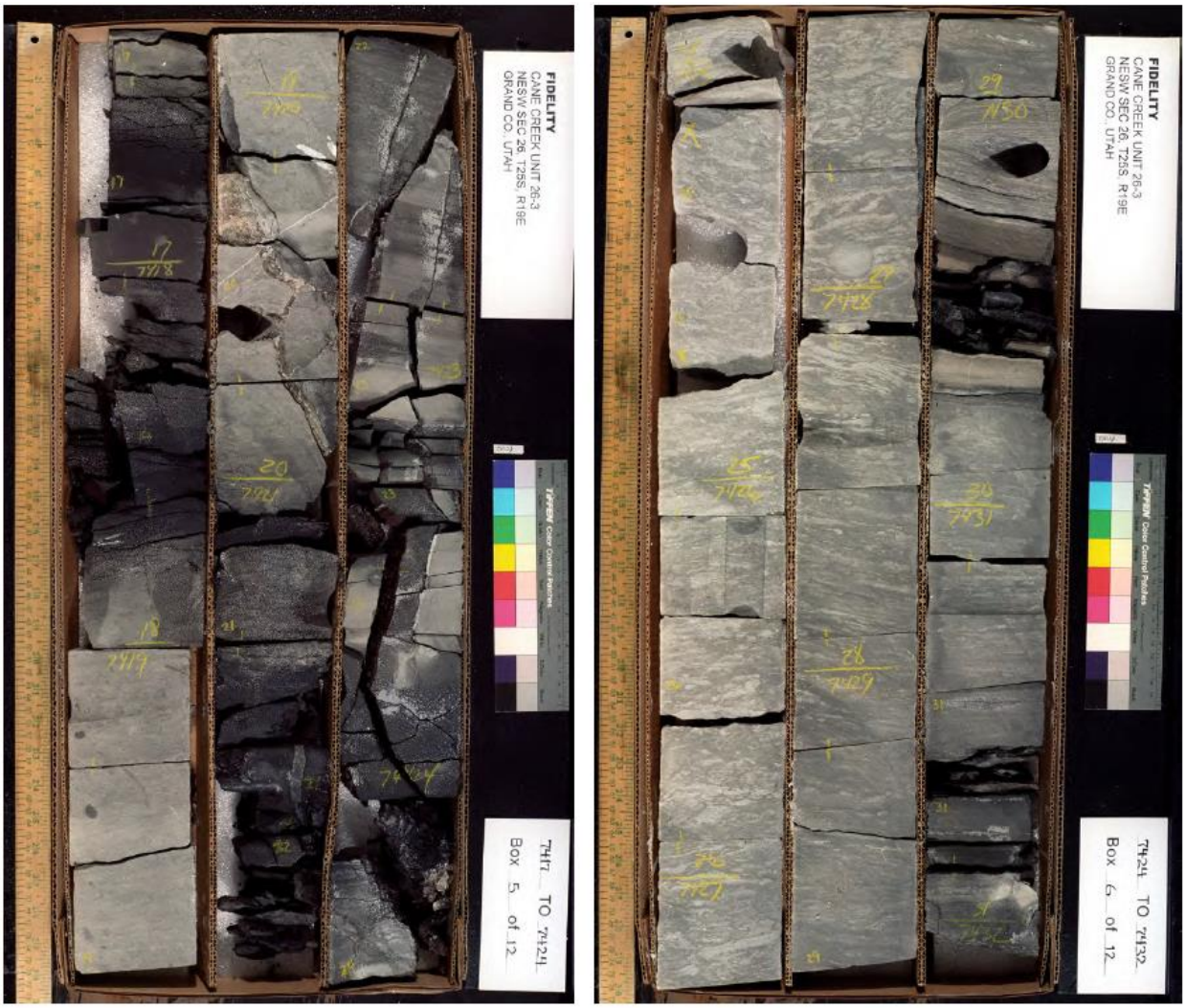

Figure 10. Typical fractured, silty to muddy dolomite (finely crystalline) with thin siltstone and back organic-rich shale beds of the productive B interval in the Cane Creek shale; also present is mottled light gray to white anhydrite. Cane Creek Unit No. 26-3 well (section 26, T. 25 S., 19 E., SLBL&M), 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.

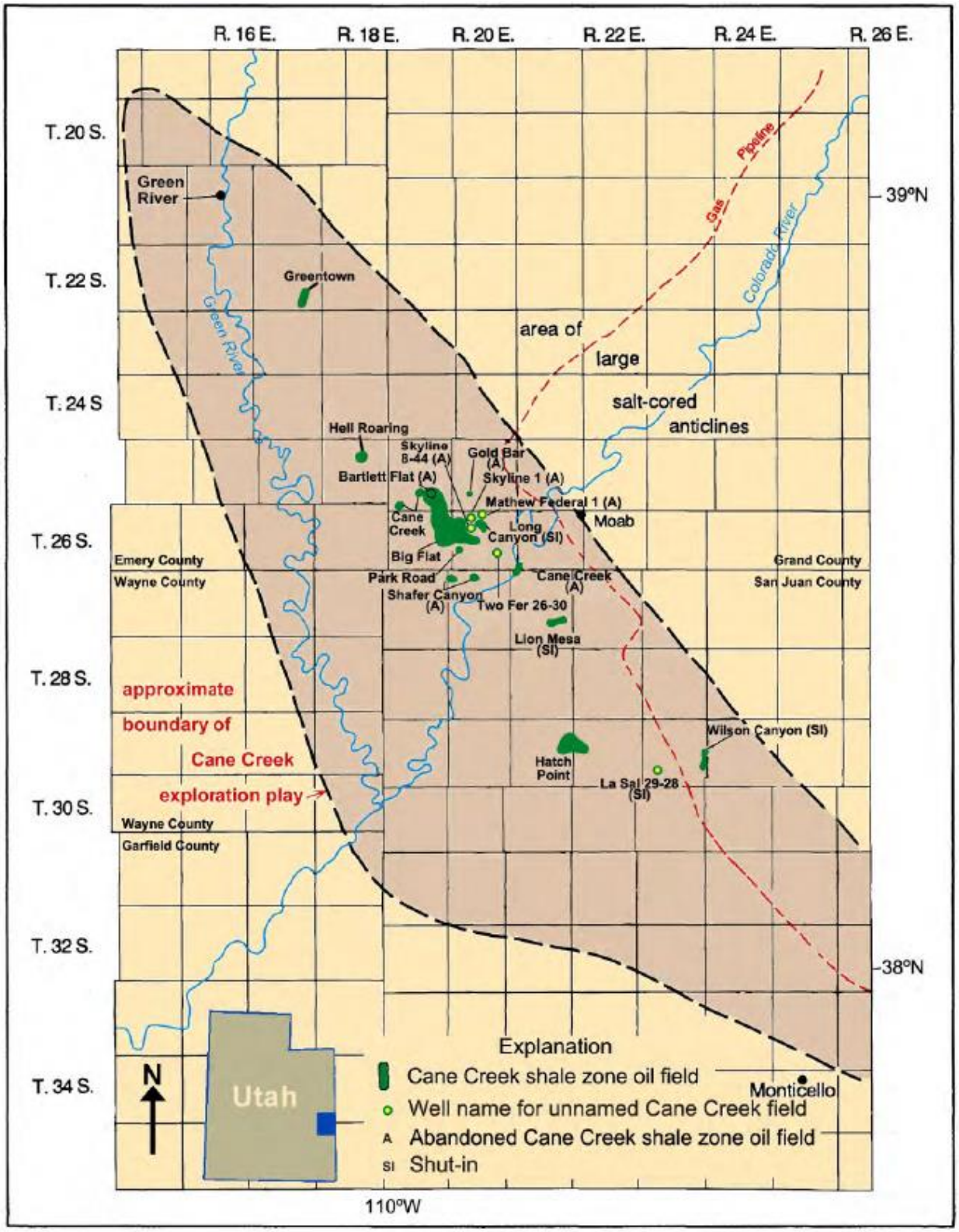

Figure 11. Location of fields that produce oil from the Cane Creek shale of the Pennsylvanian Paradox Formation, northern Paradox Basin, Utah. Play area shown in light brown.

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 in Ohio, Pennsylvania, West Virginia and Kentucky

Richard Nyahay, Nyahay Geosciences, LLC, New York

The Utica Shale should be more aptly named the Point Pleasant Play. Most of the production is coming from the lower organic rich section Point Pleasant interval a lateral equivalent of the upper portion of the Trenton Limestone. The Point Pleasant play extends from eastern Ohio east to the southern tier in New York, where the play was discovered in 2007, to southwestern Pennsylvania and into the pan handle of West Virginia.

The Point Pleasant play has shown a steady increase of production of oil, natural gas and natural gas liquids in Ohio since coming online in 2011. Production from gas wells with prolific IP's near the pan handle of West Virginia and southwestern Pennsylvania is proving the play is living up to it's potential as a Giant underneath the Marcellus above.

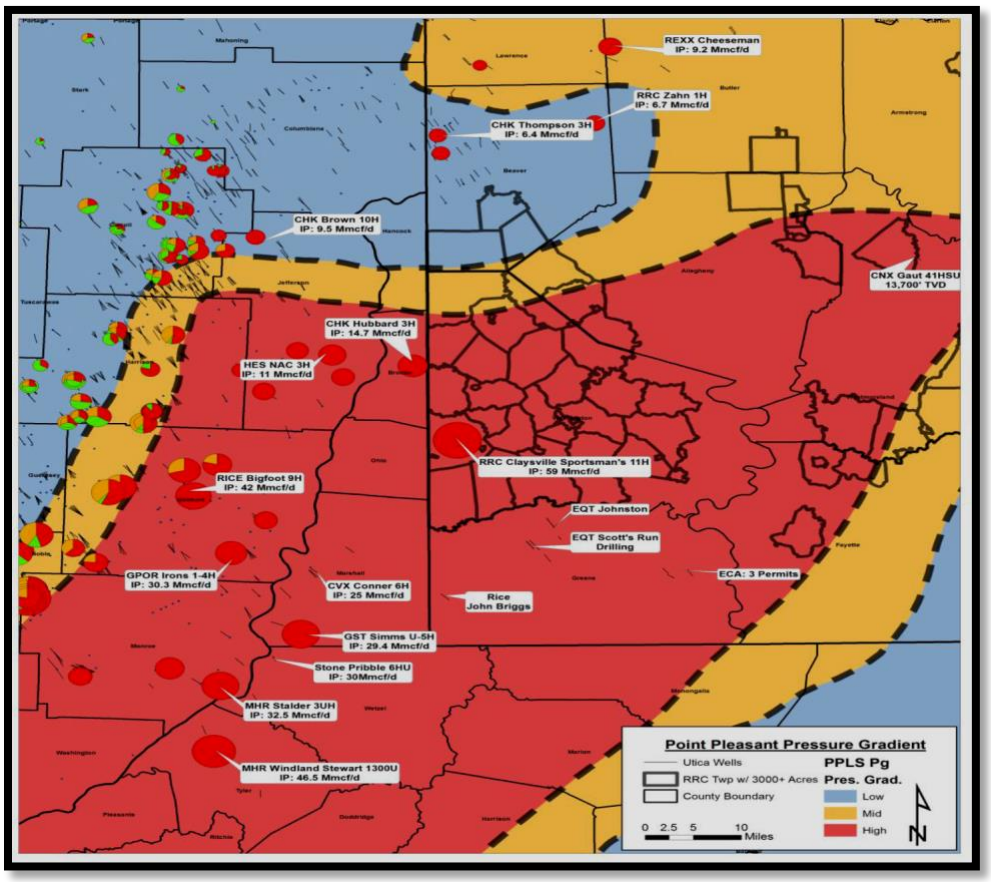
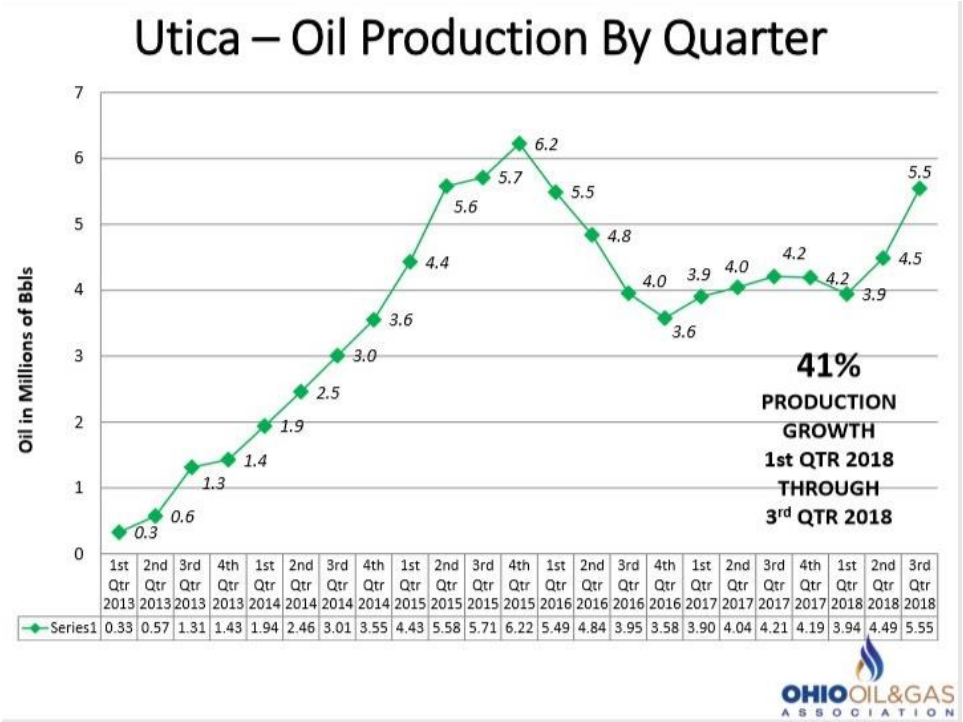


Figure 1. Range Resources map of Point Pleasant pressure gradients.



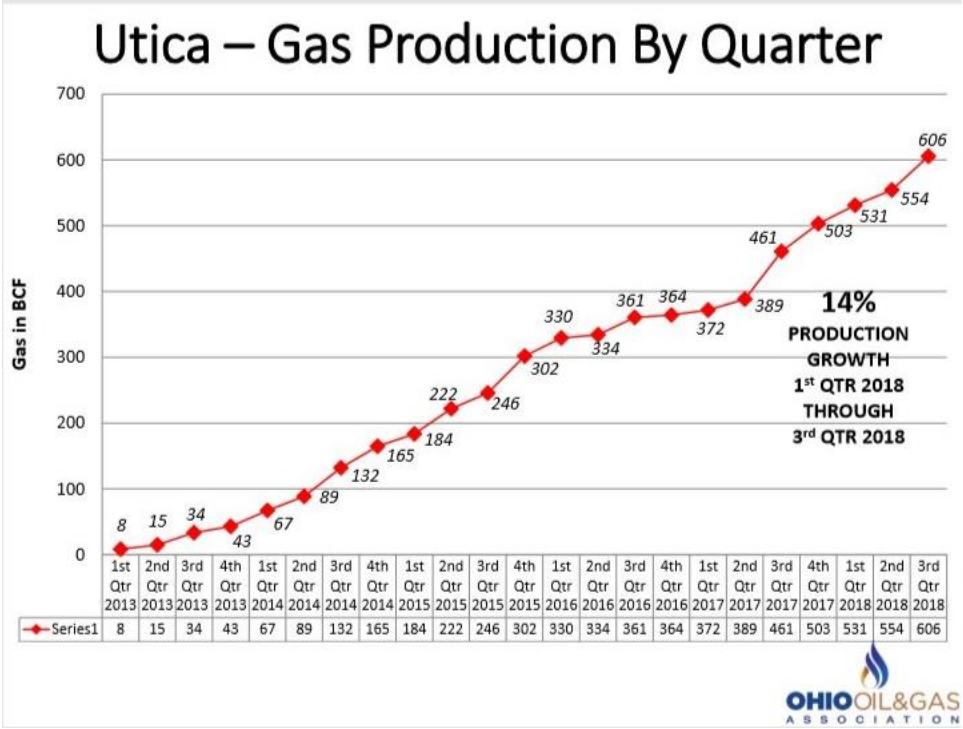


Figure 2. Top: Oil production by quarter; Bottom: Gas production by quarter (Shumway et al., 2019).

The Point Pleasant Play thickens to the southeast up to 300 feet in Ohio, up to 600 feet in Pennsylvania. Thermal maturity can be divided into the oil window, wet gas window, and dry gas zone which increases in maturity to the east and to southeast direction.

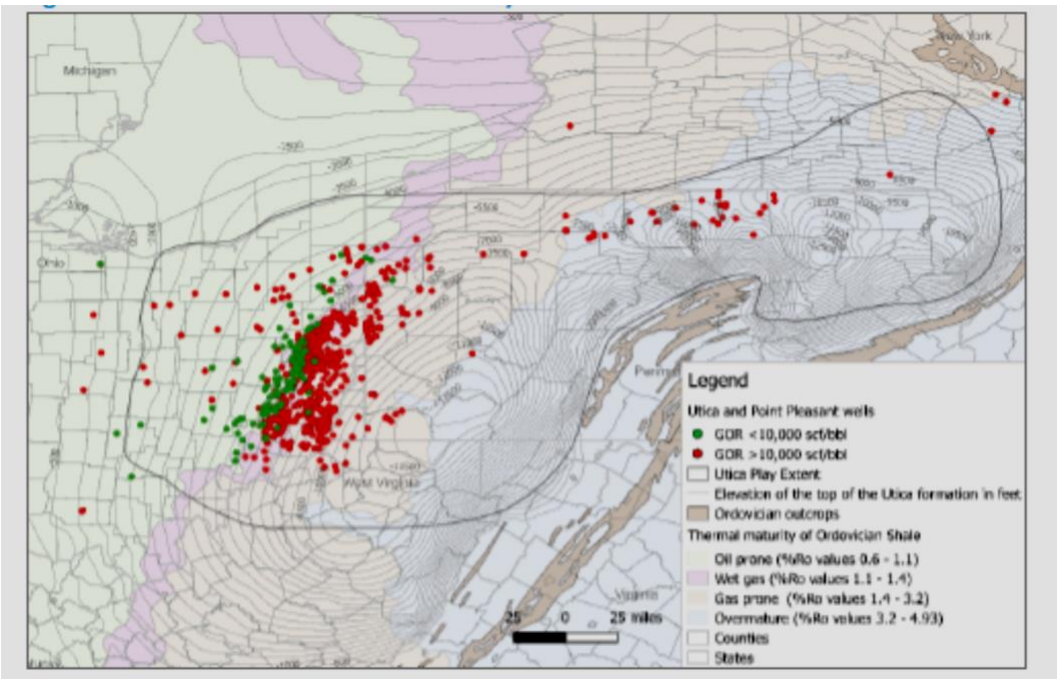


Figure 3. Well locations, gas-oil ratios, play extent, outcrop distribution, depth contours, and thermal maturity windows (U.S. EIA, 2017).

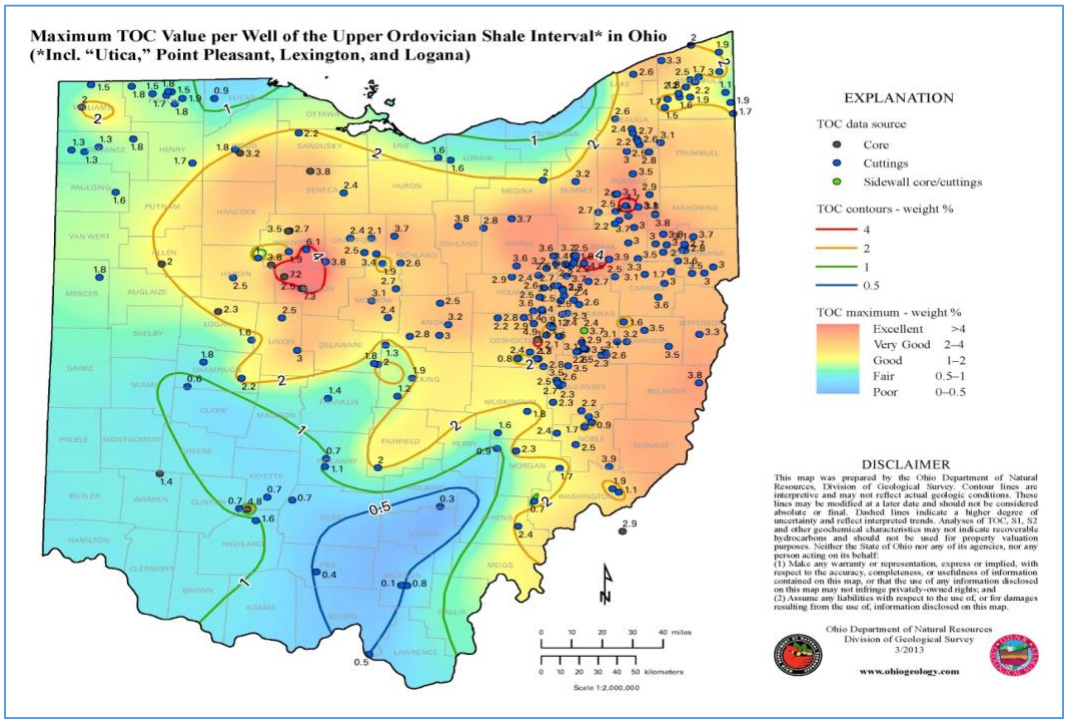


Figure 4. Total organic carbon map for the Utica-Point Pleasant from the Ohio Department of Natural Resources (2013).

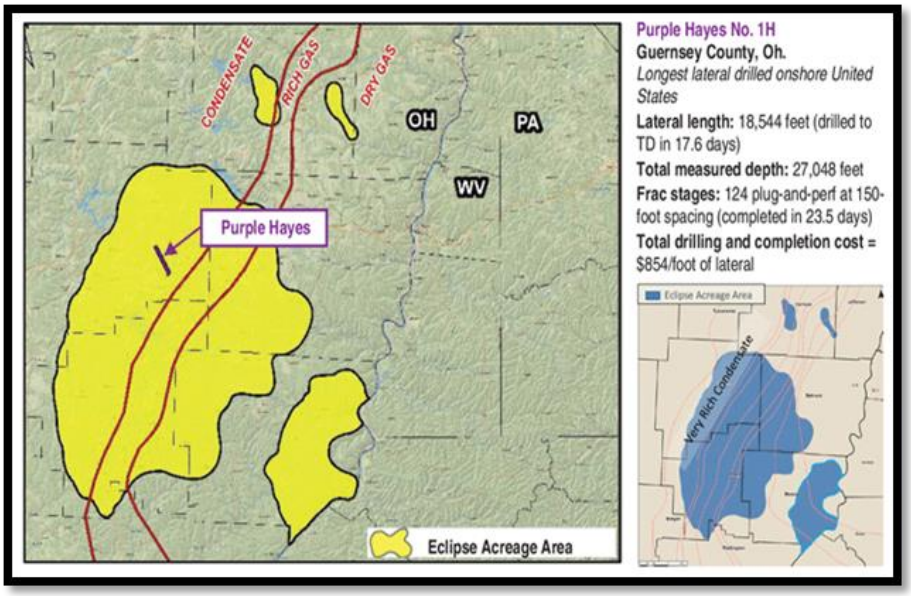


Figure 5. Location of the Purple Hayes No. 1H well, the longest lateral well in the U.S. (Beims, 2016).

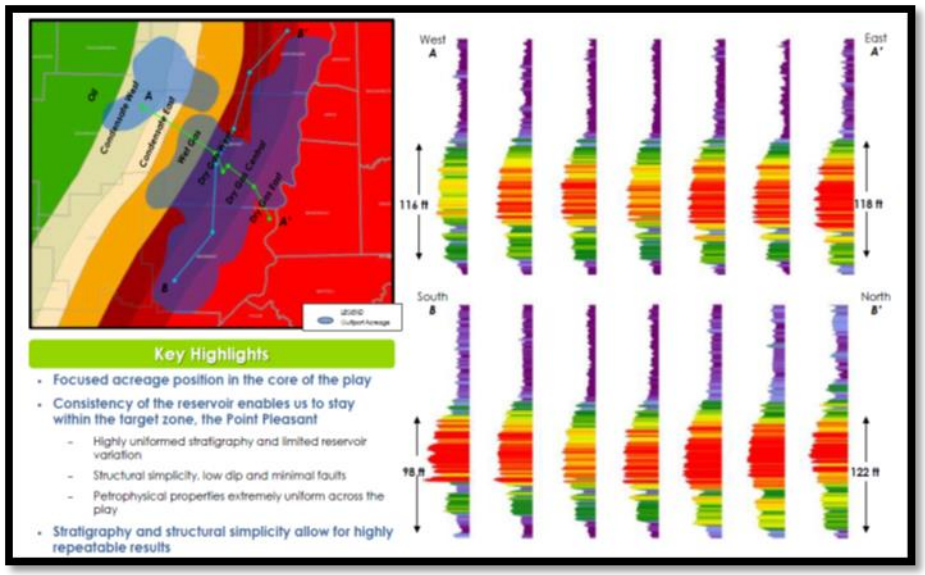


Figure 6. Gulfport Presentation showing gamma log similarities across the Point Pleasant play.

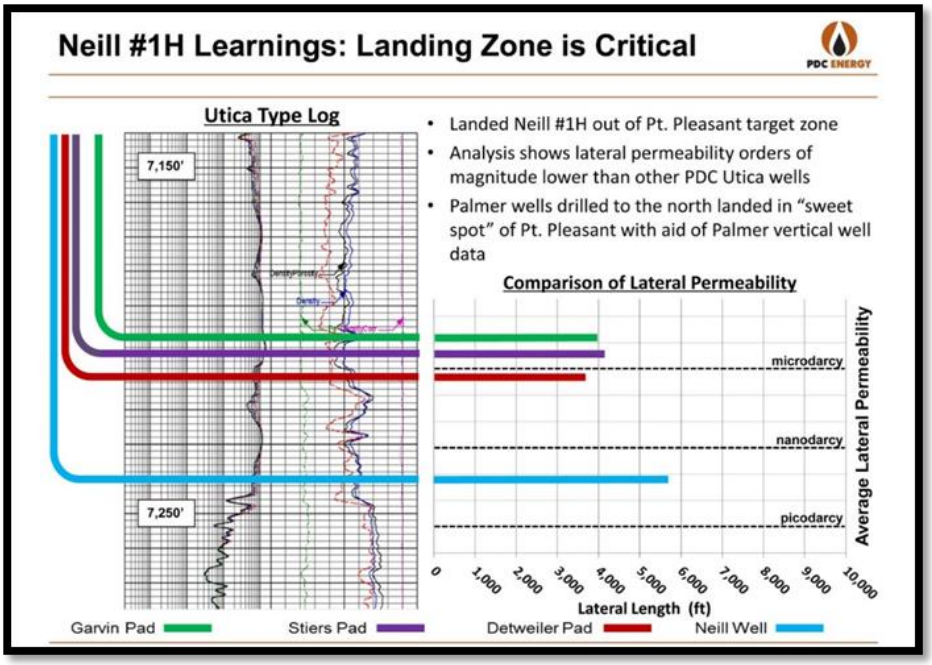


Figure 7. PDC presentation showing landing zone optimization targeting a Point Pleasant sweetspot.

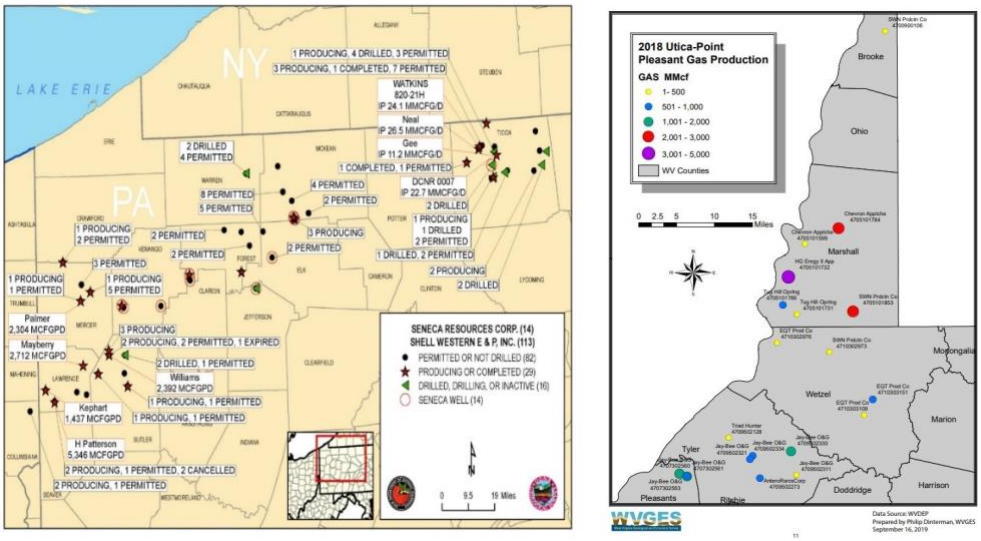


Figure 8. Permitting map and Utica-Point Pleasant gas production (Riley and Fakhari, 2015).

TOC is highest in the organic rich Point Pleasant interval ranging from 3% to 12%. The TOC increases to the east and to the southeast. This same interval is an organic rich calcareous shale with a high carbonate content making it a good candidate for hydraulic fracturing.

Longer laterals, short stages and shut in rest periods are the basic completion concept. The Purple Hayes 1H drilled in 2016 in Guernsey County was the longest drilled lateral in the United States with a lateral length of 18,544 feet. It had an initial production rate of 5MMcf/d and 1,200bbl/d while being choked

back. With the completion of this well Eclipse Resources Corp proved it could drill a superlateral in shorter amount of time and for less money than the 6500 ft. laterals it drilled earlier.

The Gulfport cross sections show the stratigraphy and petrophyical properties of the Point Pleasant in Southeast Ohio are uniform and are structurally quiet. This would speak to the success Eclipse Resource Corporation is having with its superlateral the Purple Hayes 1H. Eclipse Resources corporation believes it could drill a 22,000 foot lateral well effectively.

Steering a well is equally important in this interval because differences in amplitude will result in variable economics that could be a result of different lateral permeability.

Figure 9. Map showing the boundaries of the two assessment units (AUs) that were quantitatively assessed in the Point Pleasant Formation and Utica Shale of the Appalachian Basin Province (U.S. Geological Survey, 2002).

The Utica shale Appalachian Basin Exploration Consortium Reports in 2015 using the USGS method revised recoverable resources for the play at 782.2 Tcf, and 1960MMbo. In October 2019, the USGS published result of their most recent assessment of the Upper Ordovician Point Pleasant Formation and Utica Shale of the Appalachian Basin Province and reported mean undiscovered, technically recoverable resources of 117.2 trillion cubic feet of natural gas, 1.8 billion barrels of oil, and 985 million barrels of natural gas liquids in two assessment units (Enomoto et al., 2019). These estimates seem feasible

because of the early activity in Pennsylvania (approximately 270 wells) and the development starting to take place in West Virginia.

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Canada Tight Oil and Gas Resources Update

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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. It ranks in the world as 4th largest producer of both natural gas and oil.

The Canadian Energy Regulator (CER) (previously National Energy Board, NEB) estimate of Western Canada natural gas ultimate potential could be over 1,220 TCF (Dec 2017) and oil at 168.5 BBO (all of Canada, Newfoundland included and ~ 97% from the oil sands) (Dec 2018). Canada supplies much of the North American market, producing about 4.6 MM BOPD and 16.7 BCFD gas (71% unconventional). Alberta, within the WCSB, has most oil and gas reserves and almost all of the oil sands. Data from the Energy Fact Book - Canada 2019-2020.
https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/energy/pdf/Energy%20Fact%20Book_2019_2020_web-resolution.pdf

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 (B.C.). About 72% (2014) of Canada's natural gas is coming from unconventional which would include shale, tight sands and CBM. As a result of the low natural gas prices operators have been focusing exploration and production into the liquids-rich hydrocarbons. Production has gone down in a number of areas because of the commodity prices. The significant plays are Montney, straddling B.C. and Alberta, Horn River (on hold because of economics) in N.E. B.C., Cardium, Duvernay in Alberta and the Bakken oil play 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 and New Brunswick but a government freeze on fracking because of environmental concerns slowed and then stopped any future exploration and production.

To date there is or was shale and tight reservoir exploration activity in 9 provinces of Canada out of the 10 with Prince Edward Island being the exception and 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 was/is evaluating their tight reservoir plays as well. The oil price fluctuation and pipeline bottleneck has had significant effects on industry production and exploration.

Significant public concern in the press and social media about hydraulic fracturing in various locations across Canada has hindered, slowed down and some cases stopped exploration and/or production. Industry and governments are becoming more transparent and self-imposed guidelines are being drawn up. https://www.capp.ca/explore/hydraulic-fracturing/

Nova Scotia, New Brunswick, Newfoundland and the Yukon effectively have put hydraulic fracking under partial or full moratorium. Quebec based laws in 2011 to limit oil and gas exploration. In 2014 these laws were extended and in 2018 more restrictions were announced but these orders died after the results of the election. The Northwest Territories has also had studies done but there has not been any activity since 2015. 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

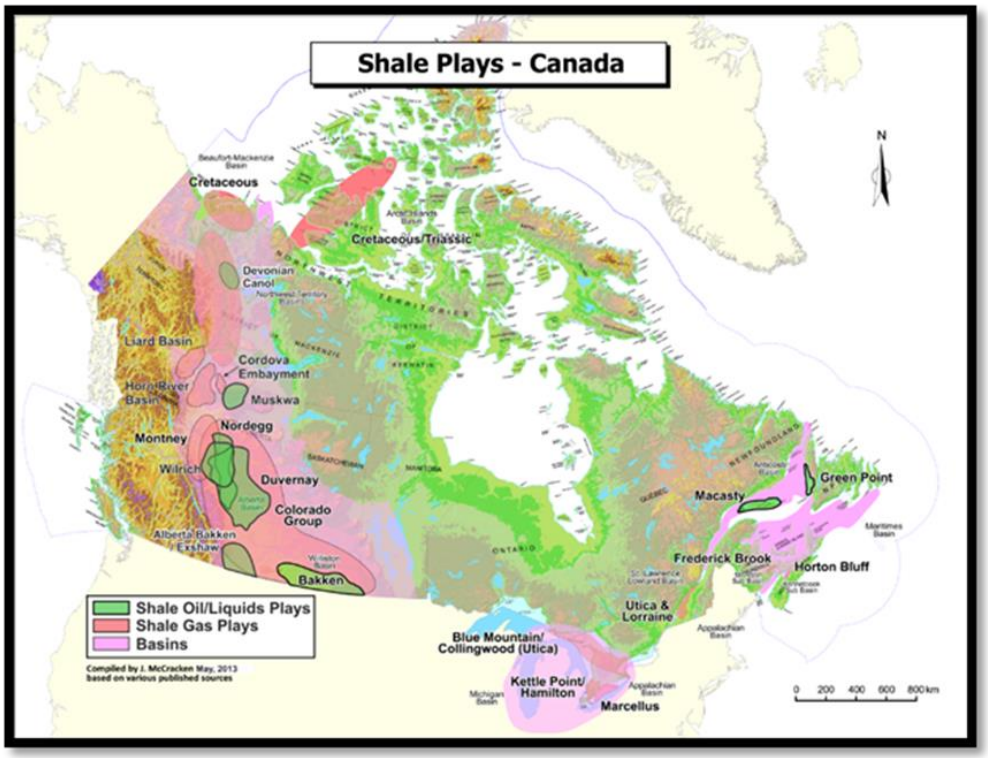
https://www.petrelrob.com/wp_install/wp-content/uploads/2018/08/Hayes-HF-Public-Policy.pdf

One other recent problem is the lack of pipelines to transport the hydrocarbons out of the land-locked western provinces of Alberta, Saskatchewan and Manitoba. According to the Alberta Government, https://economicdashboard.alberta.ca/OilPrice, a comparison of the WTI versus WCS (Western Canada Select) in $US for the month of April 2020 was $16.55 and $3.50 respectively (at the low of the oil price collapse). These low prices and lack of pipelines is detrimental to the Canadian Industry and is reflected in exploration and production activity.

Canada Energy Regulator (CER) (previously NEB) provides a good summary per Province and Territory on this following website.

https://www.cer-rec.gc.ca/nrg/ntgrtd/mrkt/nrgsstmprfls/index-eng.html

This Report will be including five spreadsheets that will summarize these tight formations: British Columbia's Montney, Alberta's Montney, Cardium and Duvernay and Saskatchewan's Bakken. The next update will include some of the other tight plays.

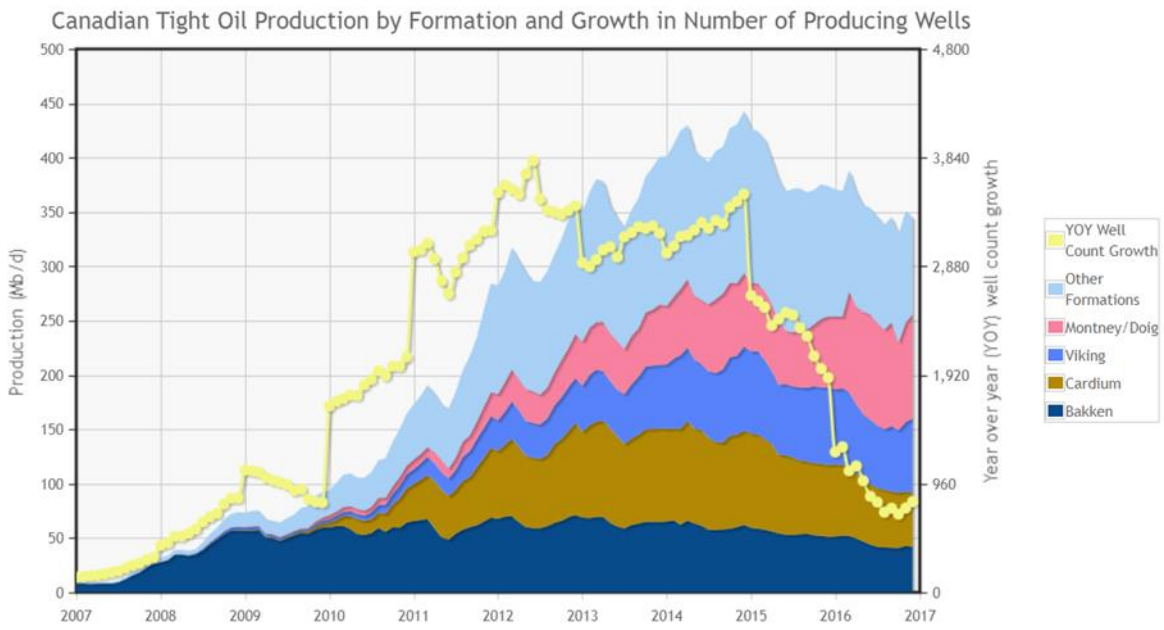


Canada Tight Oil and Gas – in General

Canada Energy Regulator (CER) which was partially the National Energy Board (NEB) prior to August 28, 2019, regulates pipelines, energy development and trade in the Canadian public interest. They publish energy related reports and statistics on this site, https://www.cer-rec.gc.ca/index-eng.html.

This section covers Western Canada gas production and its forecast to 2040. Alberta Deep Basin Tight, Alberta Montney Tight, Duvernay Shale and WC (Western Canada) Tight which would cover a multitude of intervals. Natural gas liquids in some gas plays has driven gas drilling and production despite low gas prices. For example, production of Montney tight gas increased from no production prior to 2006 to almost 149 × 10^6 m^3 /d (5.3 Bcf/d) in 2017, or 34% of total Canadian natural gas production. The majority of Canadian production growth over the projection period comes from the Montney, with its production reaching 344 × 10^6 m^3/d (12.1 Bcf/d) in 2040, or 58% of total Canadian gas production. The Duvernay is an emerging shale play in Alberta that contains natural gas, NGLs and crude oil.

https://www.cer-rec.gc.ca/nrg/ntgrtd/ftr/2019cnvntnll/nrgftrs2019spplmntscnvntnll-eng.pdf

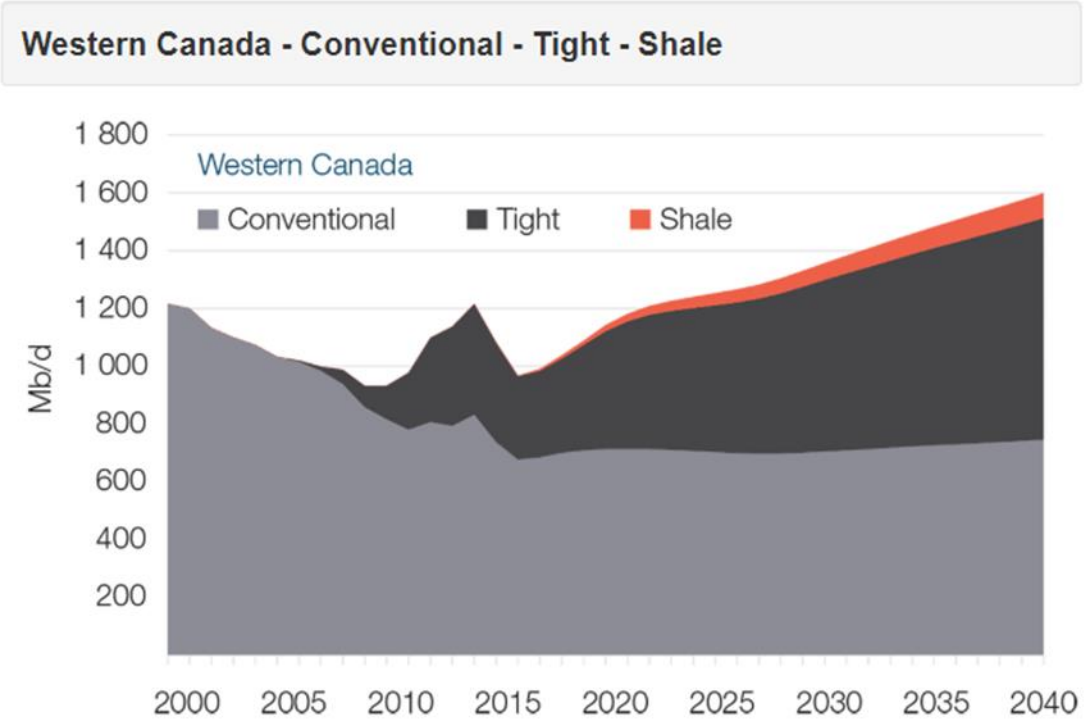


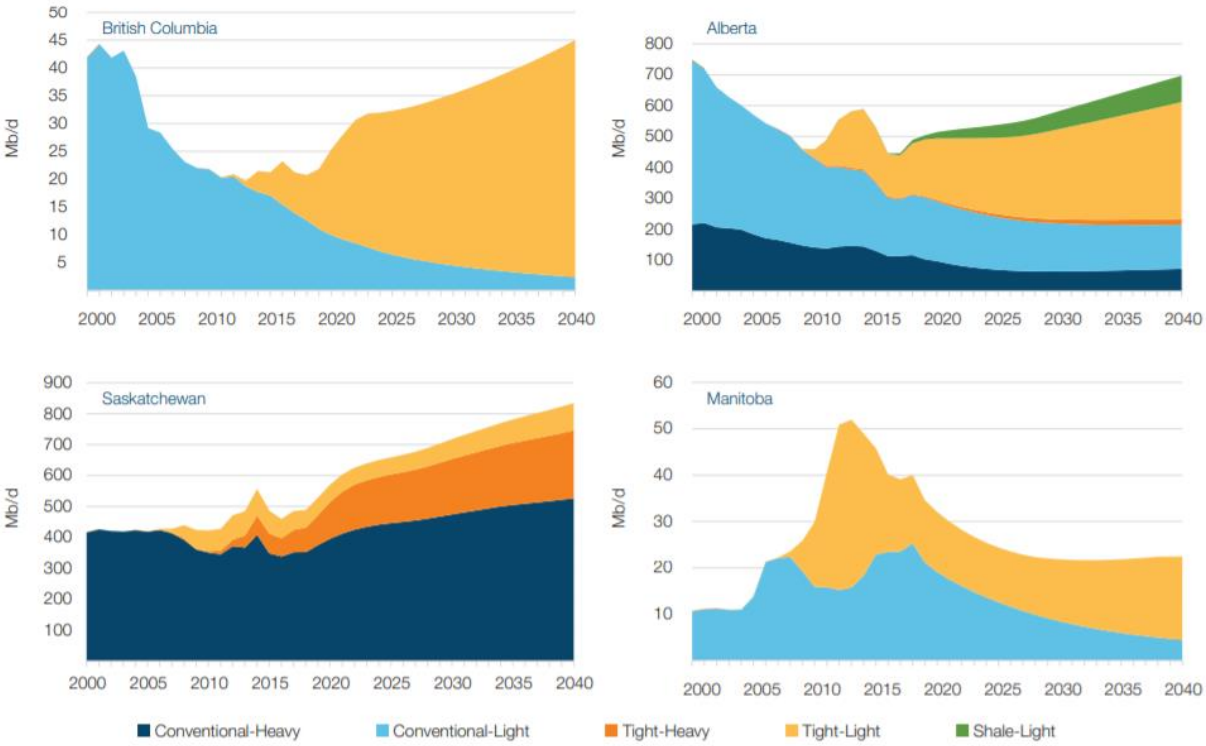
Source: Divestco, NEB calculations

The above stacked area chart shows Canadian tight oil production by formation from January 2007 to December 2016. An overlaid line series shows the year-over-year well count growth. Tight oil production grew from less than 9 Mb/d in 2007 to almost 445 Mb/d in 2014 and then declined to less than 345 Mb/d in 2016. This production came from various formations, led by the Montney/Doig, Cardium, Viking, and Bakken formations. Well count growth increased from 132 in January 2007 to 3,517 in December 2014, after which it declined to 798 in December 2016.

The overall decline in tight oil production is from fewer new wells being added as drilling activity slowed in response to decreasing prices. Tight-oil wells typically produce a large amount of oil in their first month but decline quickly thereafter, which means that new wells must be continually added to maintain production levels. In 2014, the number of producing wells grew annually by over 3,200. In

2015, the number of producing wells grew by about 2 300, and production started to decline. By 2016, less than 1000 new wells were added. The following information and figures come from this reference.





The next chart summarizes the increase of tight oil drilling in Western Canada

https://www.cer-rec.gc.ca/nrg/ntgrtd/mrkt/snpsht/2014/10-01tghtl-eng.html

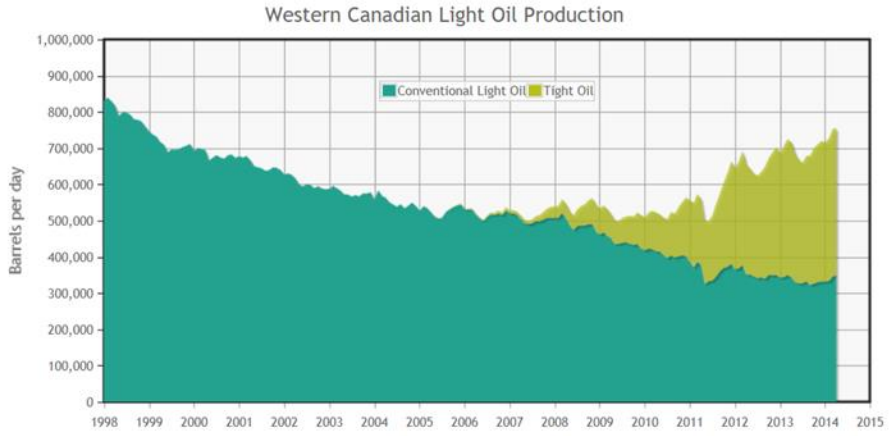


Figure Sources and Description

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.

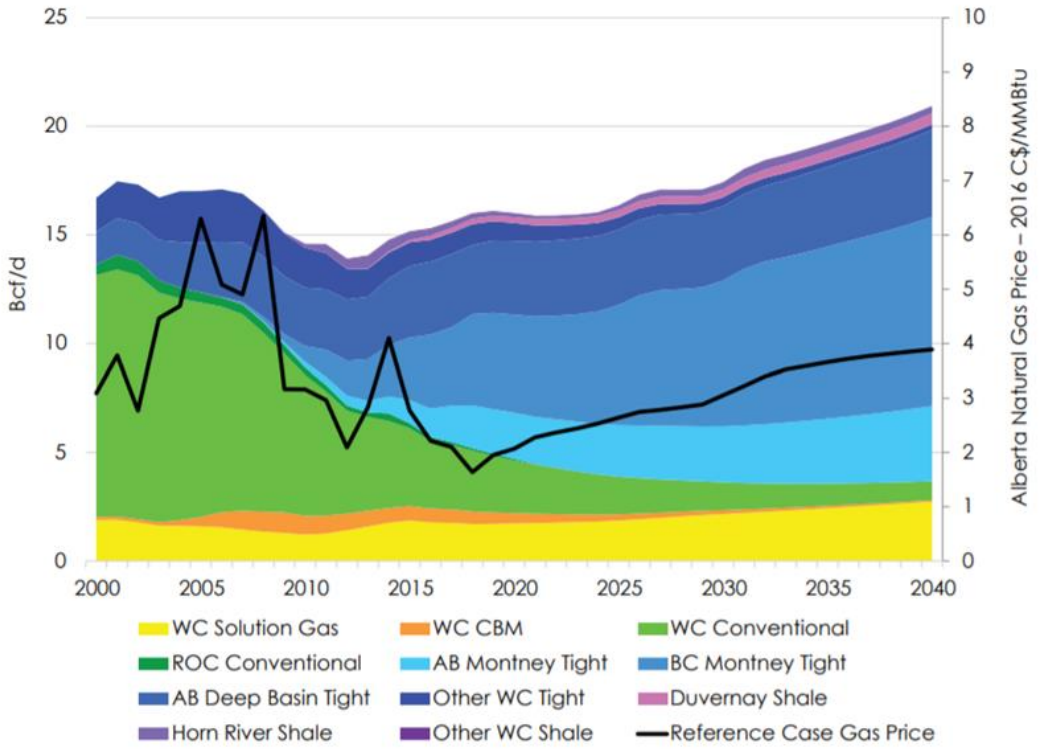
The next two charts show the current and future trend in tight gas. Information is from the following sources.

https://www.cer-rec.gc.ca/nrg/ntgrtd/ftr/2018/2018nrgftr-eng.pdf

http://www.cer-rec.gc.ca/nrg/ntgrtd/ftr/2018ntrlgs/nrgftrs2018spplmntsntrlgs-eng.pdf

https://www.cer-rec.gc.ca/nrg/ntgrtd/ftr/2018cnvntnll/nrgftrs2018spplmntscnvntnll-eng.pdf

Figure 2.1 Reference Case Production and Gas Price



Note: WC = Western Canada (British Columbia, Alberta, Saskatchewan, Manitoba)

Figure 3.16: Natural Gas Production by Type, Reference Case

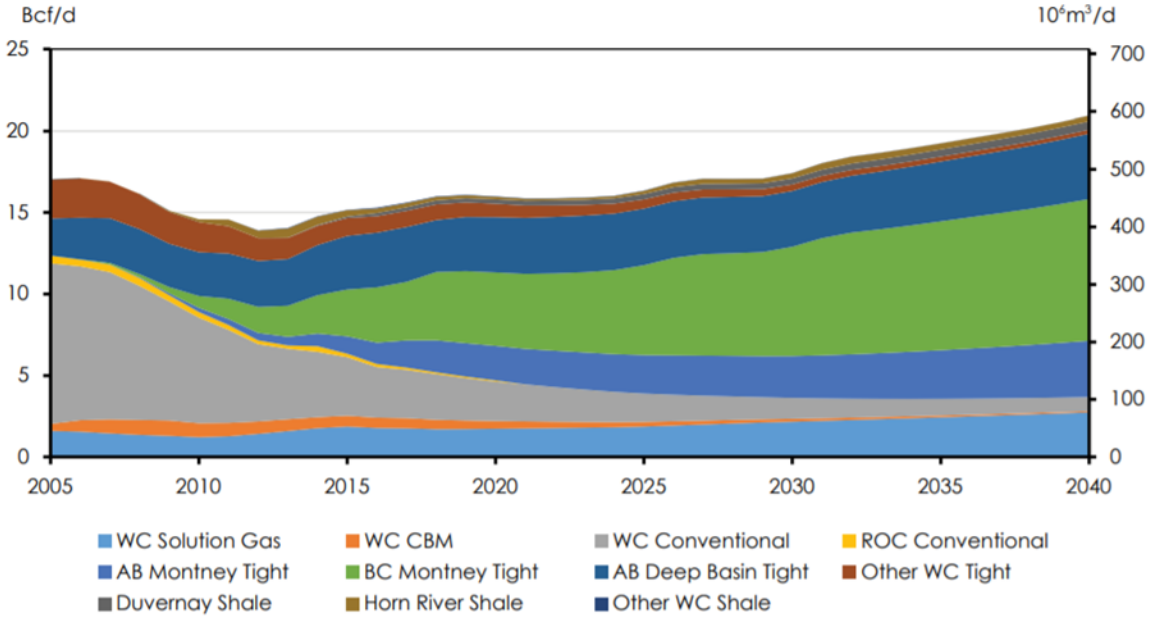


Table 2. NEB Estimate of Ultimate Potential for Marketable Natural Gas in the WCSB – Year-end 2015

Area	Gas Type	10^9 m³			Tcf		
		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.

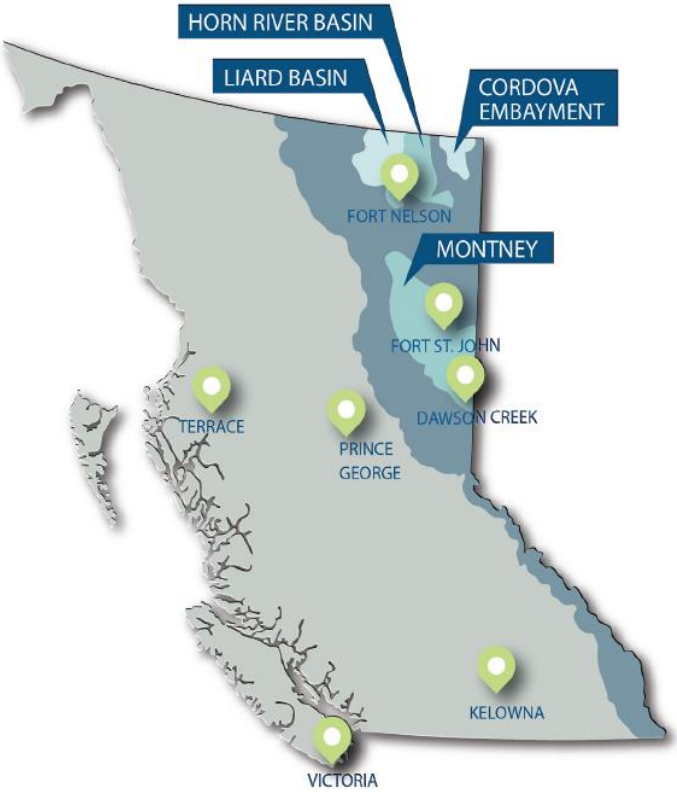
British Columbia

Northeast British Columbia contains Cretaceous to Devonian-aged unconventional deposits that potentially could contain 3,337 TCF of natural gas in place of which over 532 TCF is estimated to be marketable. Raw gas production in Dec of 2018 was 6.1 Bcf/d of which 89.6% was unconventionally sourced. The Montney is supplying about 83 % in 2018. Gas production has increased 26 % in the last 5 years. The once prolific Horn River development has essentially ceased until there is an improvement in the economics.

Advances in horizontal drilling and completion techniques have largely contributed to these advances in all the play areas. 444 wells were drilled in 2018, a decrease from the 621 wells in 2017. There is also a significant shift to capturing the liquids-rich component in the wet gas zones.

The next three figures come from the annual BC Oil and Gas Commission, 2018 Oil and Gas Reserves Production Report. https://www.bcogc.ca/files/reports/Technical-Reports/2018-oil-and-gas-reserves-and-production-reportfinal.pdf

The following figure shows the four focus areas for British Columbia.



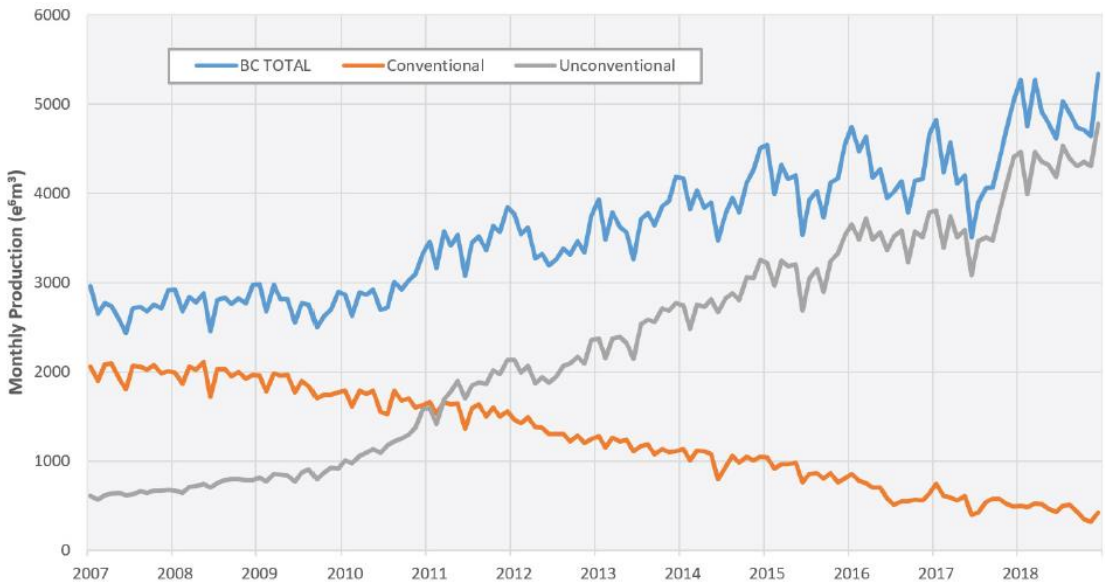
The following table shows the unconventional gas resources, reserves and cumulative production and the following graph shows the increase of the unconventional gas production in this province.

Table 1: Unconventional Gas Resource, Reserves and Cumulative Production

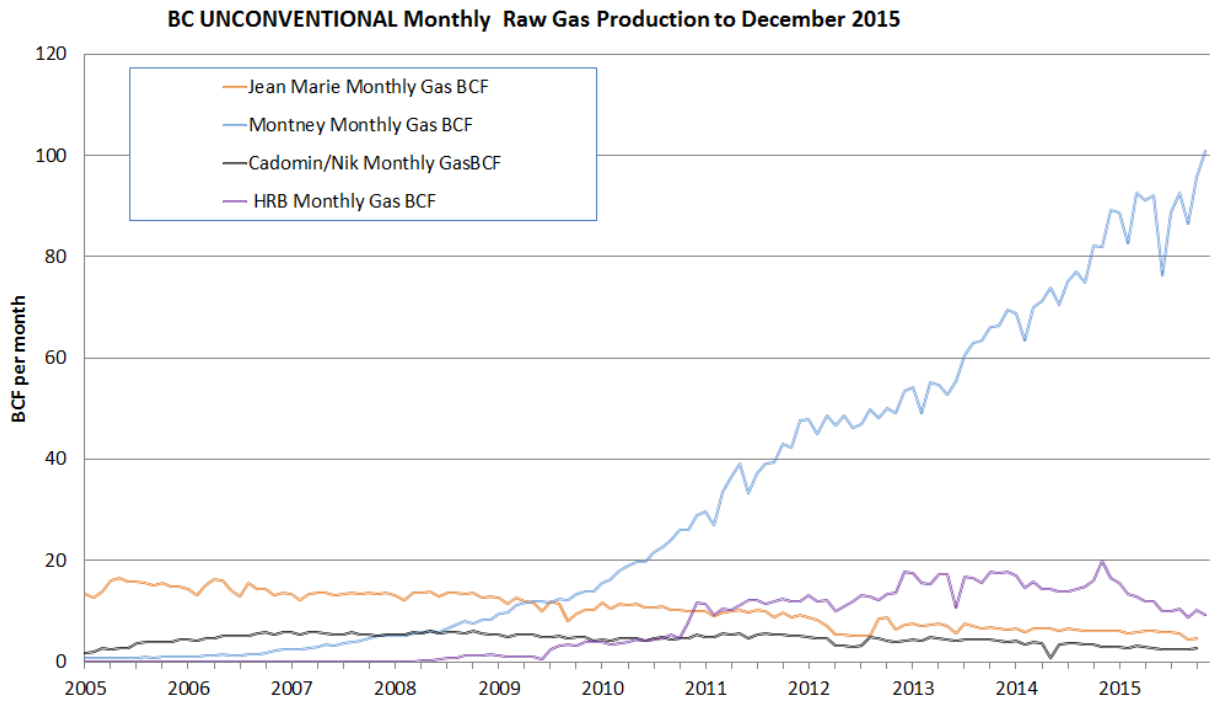
Basin/Play	Resource				Reserve						
	Basin Total GIP Resource		Ultimate Resource Marketable		Initial Raw Gas Reserves		Remaining Reserves (Raw)		Cumulative Production (Raw)[6]		% Reserve per Resource
Unit	10^9m^3	Tcf	10^9m^3	Tcf	10^9m^3	Tcf	10^9m^3	Tcf	10^9m^3	Tcf	
Montney[1]	55,610	1,965	7,669	271	1,347.6	47.6	1,102.6	39.0	245.1	8.7	2.42%
Liard Basin[2]	23,998	848	4,726	167	2.8	0.1	1.4	0.1	1.4	0.1	0.01%
Horn River Basin[3]	12,678	448	2,207	78	79.0	2.8	48.1	1.7	30.8	1.1	0.62%
Cordova[4]	1,902	67	249	9	3.1	0.1	1.7	0.1	1.4	0.1	0.16%
Deep Basin Cadomin, Nikanassin[5]	255	9	207	7	29.7	1.1	11.0	0.4	18.7	0.7	11.67%
Total	94,443	3,337	15,058	532	1,462.3	51.7	1,164.8	41.2	297.4	10.5	1.55%

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, 2018.

Figure 5: Unconventional vs. Conventional Raw Gas Production 2007 to 2018



The next 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. http://www.nrcan.gc.ca/energy/sources/shale-tight-resources/17692



Triassic Montney Fort St. John/Dawson Creek Area

The Montney is a liquids-rich tight gas/shale gas play, producing 1,694 Bcf of gas in 2018 and 2.5 MMB Oil and 40.3 MMB Pentanes+ and Condensate (BC Oil and Gas Commission, 2018 Oil and Gas Reserves Production Report). This Montney Play Trend, 26,000 sq.km.is now one of the most active natural gas plays in North America. This trend is divided into two areas, Northern Montney and Heritage Montney. 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 five Montney players are Encana (now Ovintiv as of 2020 and moving of headquarters from Calgary to Denver), Petronas Energy Canada, ARC Resources Corporation, Shell Canada Ltd. and Tourmaline Oil Corp. There were 22 companies in total in 2014. **See the included BC Montney Spreadsheet.**

Other Areas: Horn River Basin

The Upper and Middle Devonian, Evie (Klua), Otter Park and Muskwa members of the Horn River Formation are the productive zones**.** 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. But as of Dec 2018, the production was down at 210 MMCF/D. New well drilling in this play has stopped and wells are shut in awaiting a better economics.

Other Areas: Laird Basin

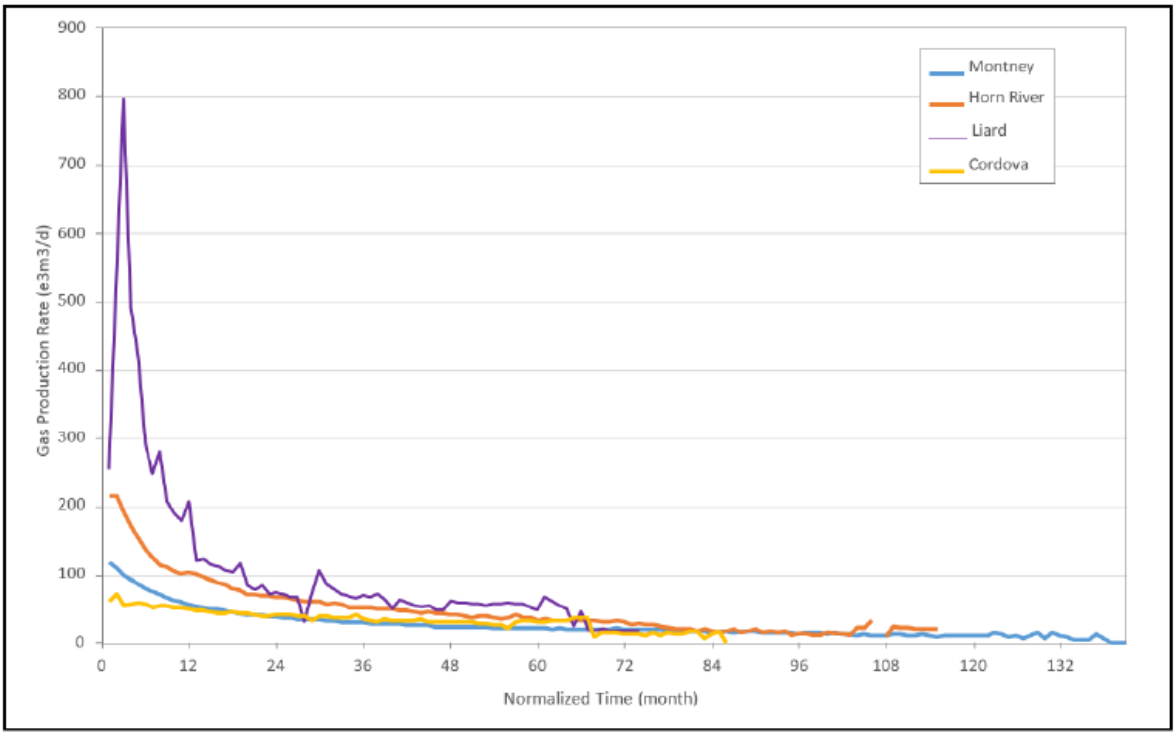
The Laird Basin in the far north and straddling into the Yukon has the ultimate potential of 848 TCF in place. There were 7 wells drilled starting in 2008. These Devonian Exshaw/Patry siliceous Shales are

deeper at 3.5 to 5 kilometres and are extremely overpressured and thick, up to 250 metres. One well was production tested at 55.7 MMCF/D with a potential of 92 BCF from this well alone. The deep pay zones and remote area has made them very expensive to drill and produce so therefore has limited development.

Other Areas: Cordova Embayment

By the end of 2018 there were 17 wells with a production rate of 15 MMCF/D. Development ended in this basin in 2014.

The following figure from the BC 2018 report shows the typical well response from the above Basins.



BC Oil and Gas Commission | 2018 Oil and Gas Reserves and Production Report

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

Marketing and Pipelines

With the gas production increasing by 26% in 2018 the gas is moved and delivered by a combination of these pipeline companies: Fortis BC Pipeline, AltaGas, Enbridge, TC Energy, Alliance Pipeline and Nova Pipeline.

The Asian market was targeted earlier on with up to 19 joint venture export groups determined to move this gas to the Kitimat, Prince Rupert and Grassy Point BC and exported as LNG. Currently there is one still attempting this project LNG Canada (Shell-led consortium of PETRONAS, PetroChina, Mitsubishi and KOGAS) and three other proposals.

AltaGas Ridley Island terminal exports LPG (liquid propane) which arrives via rail. This terminal offloads 50 to 60 railcars per day which are then stored, cooled and then loaded into specialty ships and delivered with approximately 20-30 loads per year with full capacity of 40,000 BPD. Painted Pony Energy is getting a 275% premium, over domestic, by shipping this route. There is another proposed terminal at Watson Island near Prince Rupert proposed by Pembina with initial capacity of approximately 25,000 BPD of propane with an in-service date the first quarter of 2021.

B.C. There is a wealth of data available via these websites as well as with the Canada Energy Regulator (CER) (see references)

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

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

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/

BC Oil and Gas Commission | 2018 Oil and Gas Reserves and Production Report published in January 2020.

https://www.bcogc.ca/files/reports/Technical-Reports/2018-oil-and-gas-reserves-and-production-reportfinal.pdf

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 of this report but I have tried to remain as current as possible.

The shales and tight rocks of the Western Canada Sedimentary Basin have been under investigation for the last several 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), now the Canadian Energy Regulator (CER) as of 28 Aug 2019.

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

Estimates of shale and tight reservoir 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 % of Canada's natural gas and 81 % of Canada's oil and equivalent. More than 60 % 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 % 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 % 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 % to 291.9 million cubic metres a day.

Alberta produced more crude oil in 2018 than could be shipped for export by rail or pipeline. This affected storage levels, Canadian crude oil prices and other aspects of the market. To protect the value of its oil, the Government of Alberta temporarily limited production to match export capacity to prevent Canadian crude from selling at large discounts. Due to continuing pipeline delays, oil production limits remain necessary through 2020. The curtailment policy has also been adjusted to give industry more flexibility to make timely business decisions and reduce red tape for small producers.

Production limits - The oil production limit has been extended to December 31, 2020, with possible earlier termination. This limit will be monitored closely and adjusted to better match export capacity. https://www.alberta.ca/oil-production-limit.aspx

The AER puts out an annual report on the activities and production in Alberta for the previous year. This report has very little in the specifics of Shale and Tight Rock hosted Hydrocarbons. https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st98/reserves.html

The table, from this report, is shown below and note the table includes and excludes Shale Gas, Shale Oil and Tight Oil (see notes). Does not elaborate the Tight and Shale resources and reserves.

Table 1 Resources, reserves, and production summary, 2019

	Crude bitumen		Crude oil		Natural gas[a]		Raw coal	
	(million m^3)	(billion barrels)	(million m^3)	(billion barrels)	(billion m^3)	(trillion cubic feet)	(billion tonnes)	(billion tons)
Initial in-place resources	293,125	1,845	14,197	89.3	10,237	363	93.7	103.3
Initial established reserves	28,092	177	3,128	19.7	5,903	209.5	34.8	38.4
Cumulative production	2,292	14.4	2,886	18.2	5,122	181.8	1.7	1.8
Remaining established reserves	**25,800**	**162**	**269.8**	**1.7**	**781[b]**	**27.7[b]**	**33.1**	**36.6**
Annual production	179.7	1.130	28.1	0.176	109.6[c]	3.9[c]	0.019[d]	0.021[d]
Ultimate potential (recoverable)	50,000	315	3,130[e]	19.7[e]	6,276[f]	223[f]	620	683

Note: Columns may not add up due to rounding.
[a] Expressed as "as is" gas, except for annual production, which is 37.4 megajoules per cubic metre; includes coalbed methane.
[b] Measured at field gate.
[c] Includes coalbed methane and shale gas.
[d] Annual production is marketable.
[e] Does not include oil from tight oil or shale oil plays.
[f] Does not include coalbed methane and shale gas.

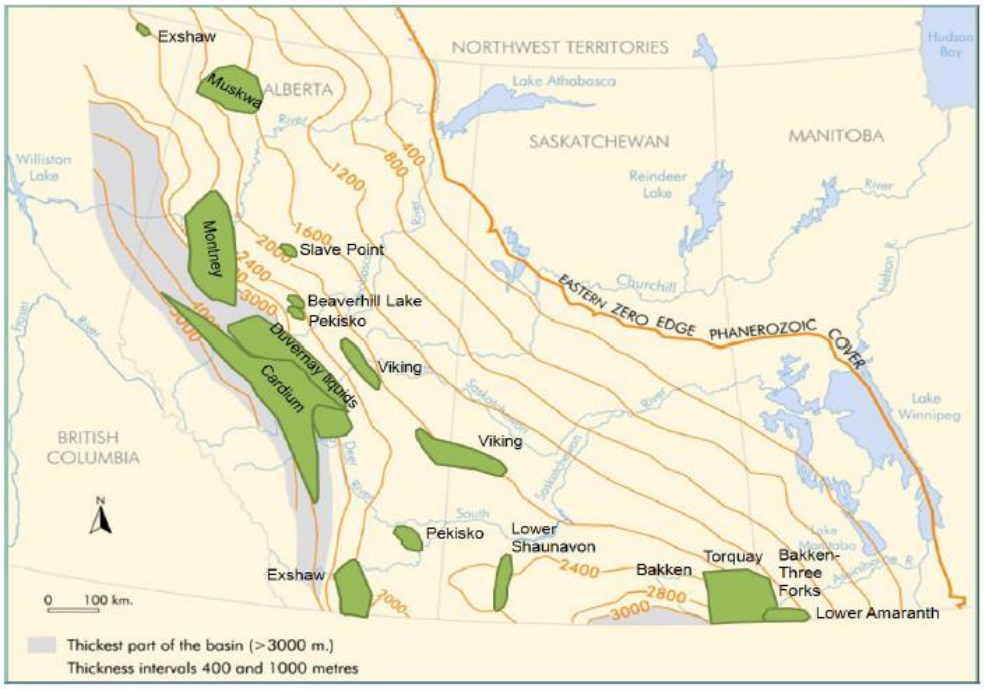
Cardium - Late Cretaceous – first discovered as a conventional play in 1953 in the Pembina Field. Since 2009 it has been targetted by industry in the Halo area where the tighter surrounding rocks are harboring hydrocarbons. Horizontal wells with multi-stage fracturing is the driving the technology. Two zones are the lower Pembina Member which is shale dominated and the upper Pembina which is more sand prone. This play is extensive with 170,000 square kilometres. The remaining reserve estimate is 10.1 million cubic metres (63.5 million bbls) oil, 1.0 million cubic metres (6.3 million bbl) NGL and 5.9 billion cubic metres (208 billion cu ft gas).(AER: ST98: Alberta Energy Outlook 2020) **See the included Cardium spreadsheet**.

Duvernay – Upper Devonian – this Shale/ Cabonate unit is both the Reservoir and Source Rock. Despite challenging commodity prices and high capital costs, activity in the condensate and oil-rich areas of the Duvernay Formation remains steady. Condensate is a key product used to dilute bitumen, allowing for flow to market. The condensate and oil also have high value as feedstock for Alberta's petrochemical industry.The remaining reserve estimate is 24.5 million cubic metres (154.1 million bbls) oil, 53.7 million cubic metres (337.8 million bbls) condensate, and 76,112 million cubic metres (2.7 trillion cu ft) natural gas. (AER: ST98: Alberta Energy Outlook 2020) **See the included Duvernay spreadsheet.**

Montney – Early Triassic - in the NW part of Alberta and continues into BC where is a significant play. It is both a conventional and unconventional target. This zone contains sandstones and dolostones in the east with mainly sandstone and siltstones to the west.

The remaining reserves estimate is 18.2 million cubic metres (114.5 million bbl oil) , 307 million cu m (1,931 million bbl) of condensate and 530 billion cu m (18,714 billion cu ft) gas. (AER: ST98: Alberta Energy Outlook 2020) **See the included Montney Alberta spreadsheet.**

Figure 1
Map of the WCSB and location of tight oil land activity and drilling



Source: Modified from University of Regina map

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.

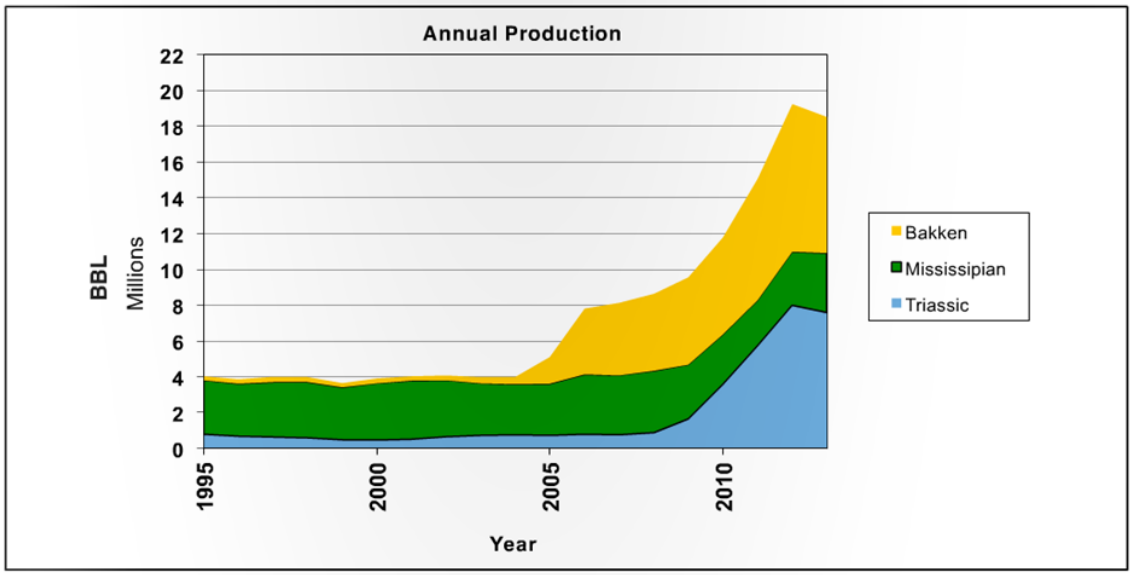
Saskatchewan is #2 in the amount of oil produced among Canadian provinces, accounting for 12 % of Canada's oil production.

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. **See the attached Bakken Spreadsheet**.

https://www.cer-rec.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.



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 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, to meet Quebec's natural gas demands for more than 100 years or longer. Industry drilled 29 wells from 2006- 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 in 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 are currently producing about 250,000 barrels of oil per day from their 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.cer-rec.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.cer-rec.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 % 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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Note: no update was submitted by the contributors for 2019-2020 due to limited activity

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.

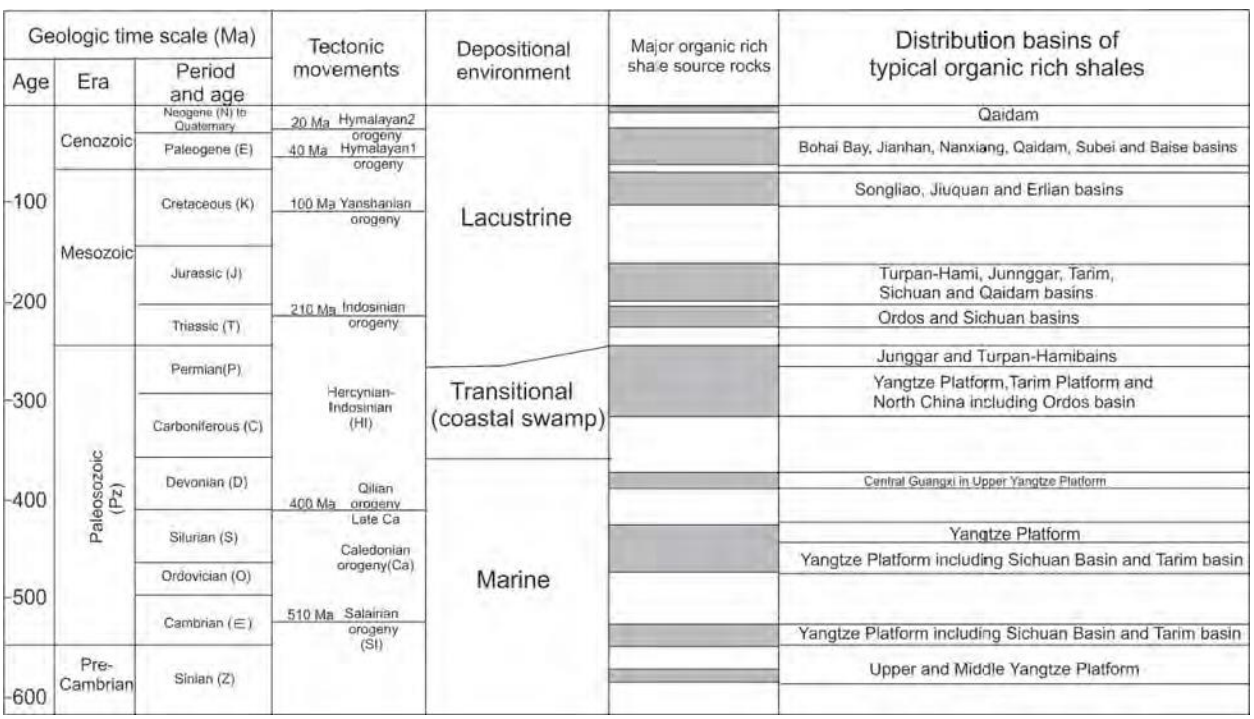

Figure 1. Geologic history and organic rich shale development in China.

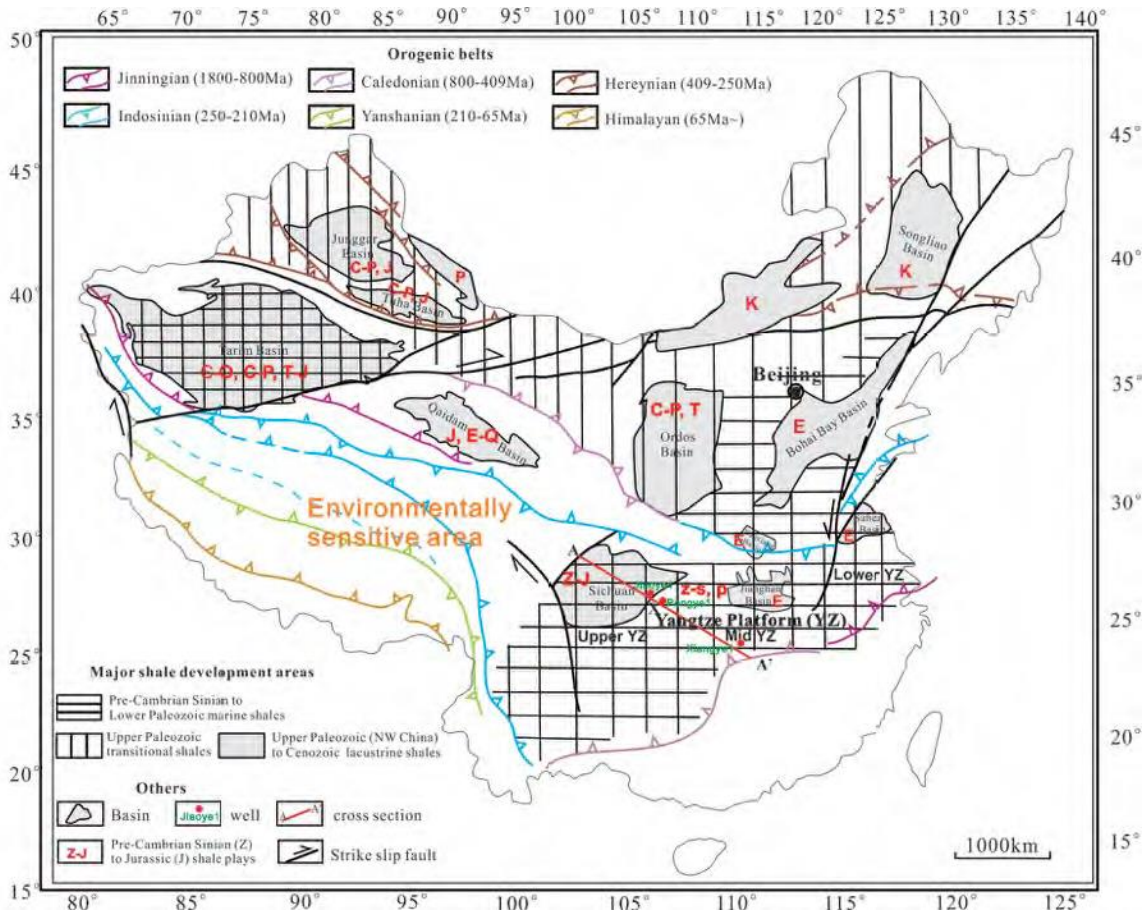

Figure 2. The distribution of organic rich shales in China. Z=Pre-Cambrian Sinian; ∈=Cambrian; O=Ordovician; S=Silurian; C=Carboniferous; P=Permian; T=Triassic;J=Jurassic; K=Cretaceous; E=Paleogene. Q=Quaternary.

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°C, 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.

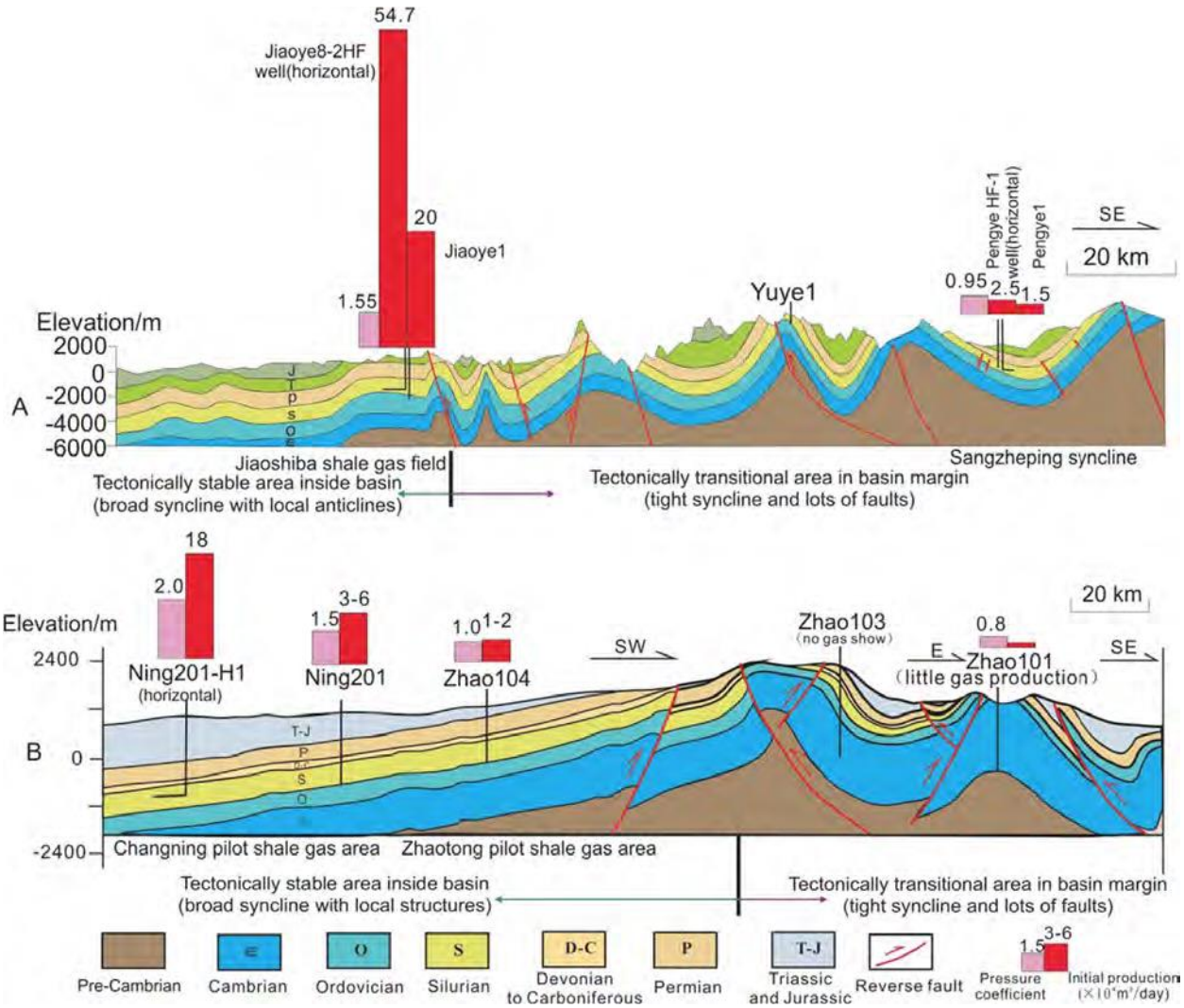

Figure 3. Schematic cross sections demonstrating the variations in formation pressure and initial shale gas production rates from the tectonically stable area inside the

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× 103 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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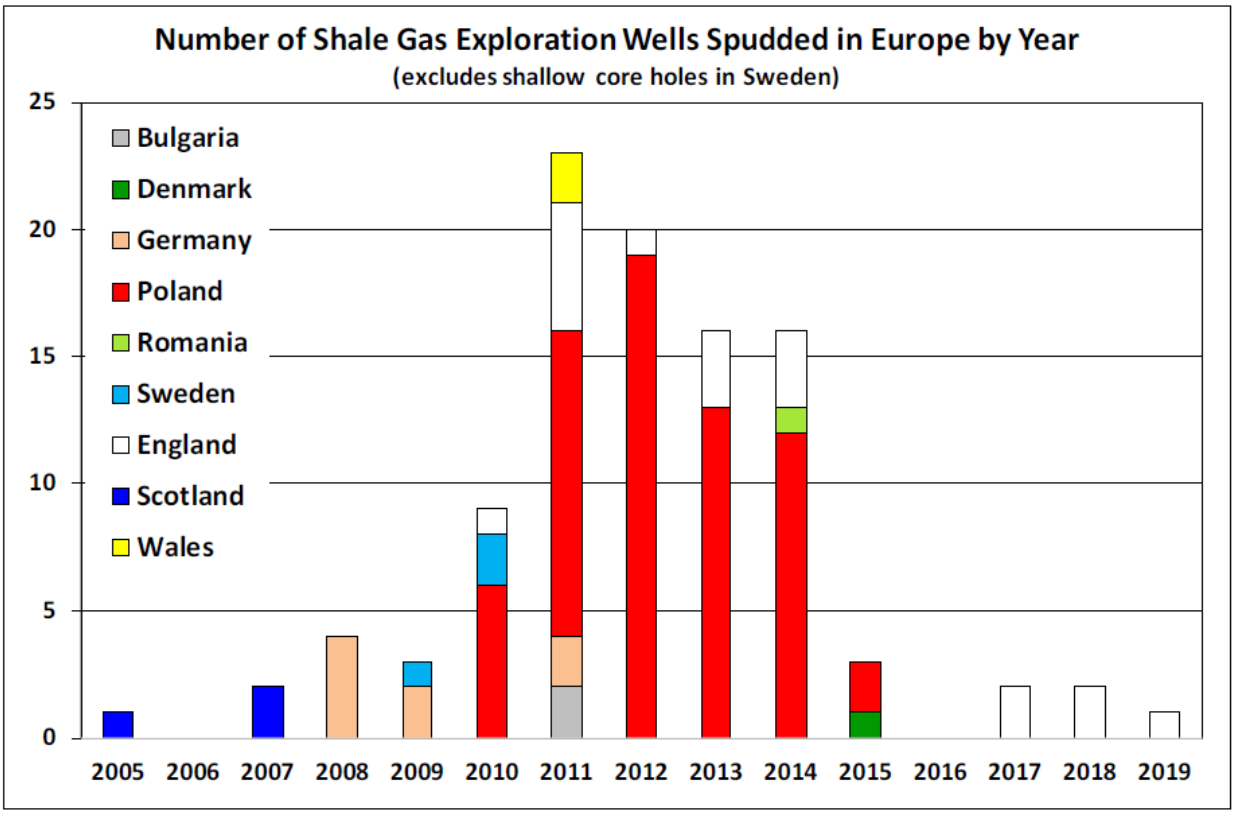
Note: no update was submitted by the contributors for 2019-2020 due to limited activity

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).

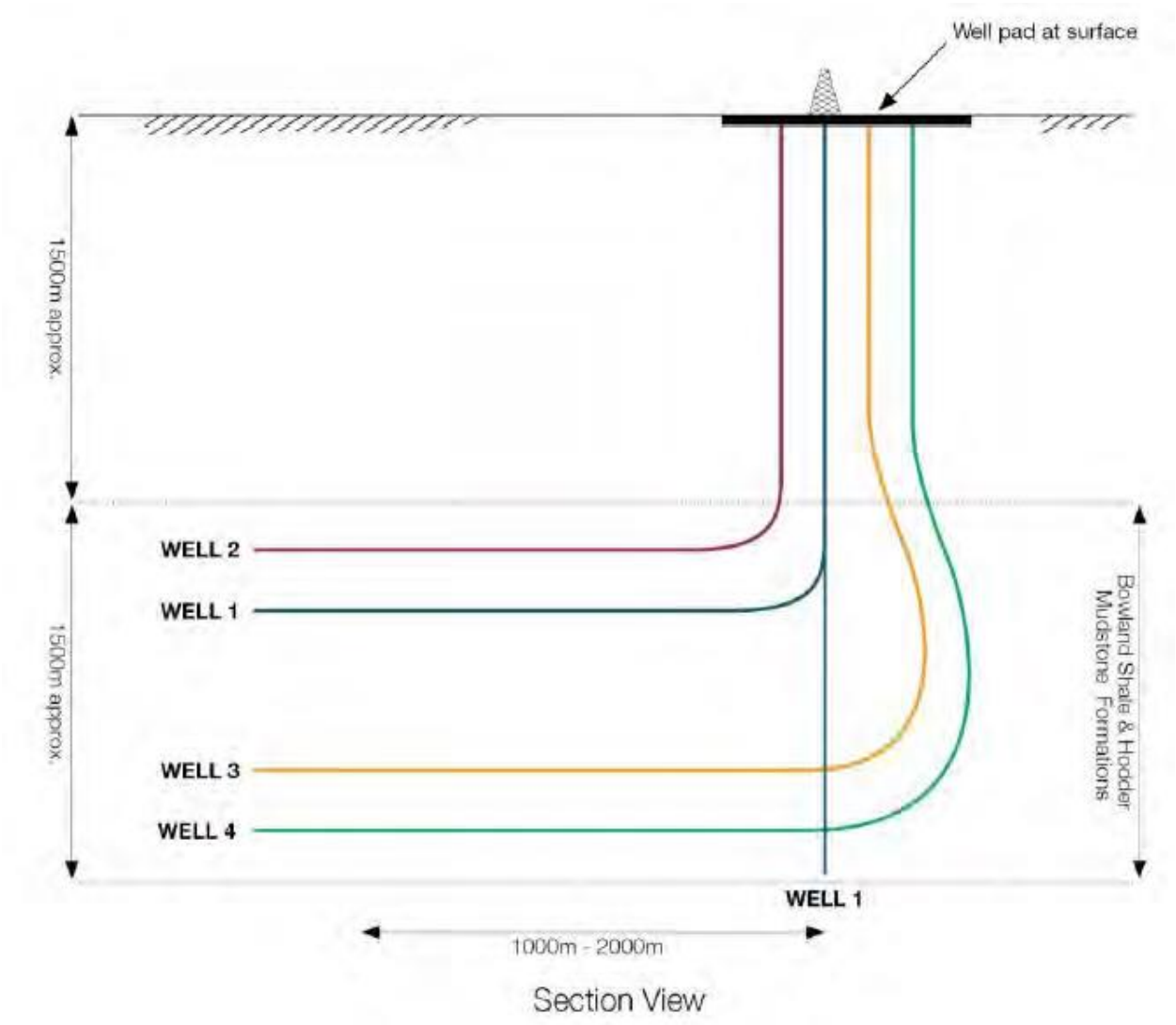
Cuadrilla appealed the decisions and a 6-week public enquiry commenced before a planning inspector on 9th February 2016. The inspector's recommendation was due to be submitted to the Secretary of State for Communities and Local Government by 4th July 2016 but the recommendation was not to be made public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

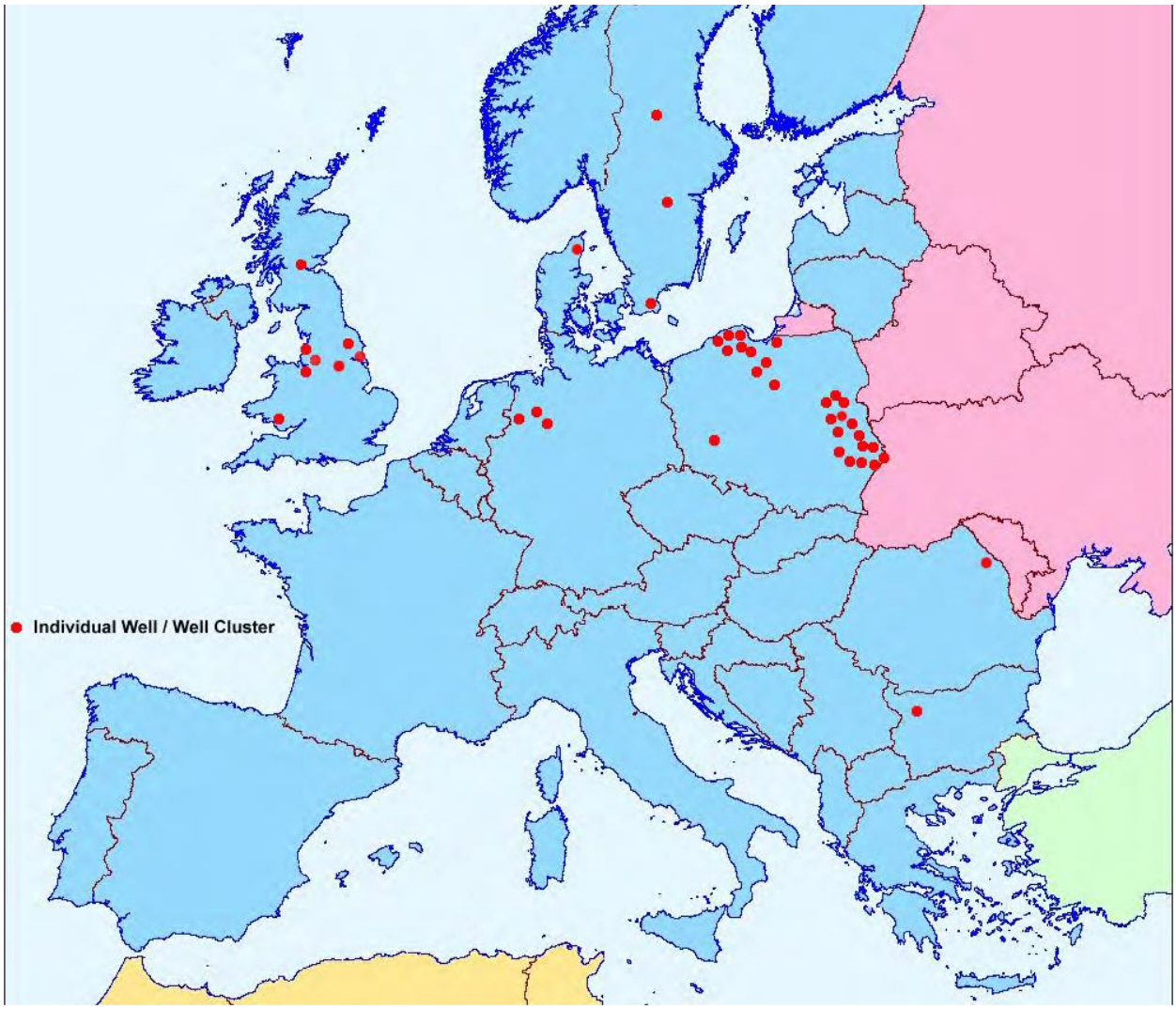
On 4th February 2019, Angus Energy announced that part of the 640' perforated interval was flowing water. On 10th May the operator announced that a bridge plug had been set to isolate the water zone. The well is now awaiting retesting.

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.



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