

EMD Shale Gas and Liquids Committee



2015 EMD Shale Gas and Liquids Committee Mid-Year Report

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Bureau of Economic Geology
The University of Texas at Austin

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EXECUTIVE SUMMARY

Shale gas and liquids have been the focus of extensive drilling for the past 10+ years due to improved recovery and high oil and gas prices all over the world. Although there is international interest in exploiting hydrocarbons from these unconventional reservoirs, with active exploration projects on most continents, much of the successful exploitation from shales continues to be in North America, particularly in the United States but increasingly so in Canada. While shale-gas production has been declining for the past years some areas saw a revival (e.g., Haynesville Shale) due to LNG facilities being built along the East Coast of the USA. New plays in shale liquids contributed to a reversal in oil production after a general decline over the last 20 years. However, the frantic drilling in shale plays in the USA and Canada, and to a limited extent in international plays, came to an abrupt halt in July of this year due to a 60% decrease in the price of oil. Although rig counts fell by 60%, oil production still remained strong at 9.2 MMB/D due to improvements in drilling techniques. Overall, Europe remains relatively unexplored as compared to North America and many parts of Asia remain relatively unexplored for unconventional shale gas and oil, but interest in these plays is certainly high. South America's potential as unconventional shale gas and oil province is currently assessed in Argentina, but exploration and exploitation of these reservoirs is not as mature as that in North America

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

INTRODUCTION

As the new chair of the shale gas and liquids committee, it is a pleasure to submit the Mid-year report from the EMD Shale Gas and Liquids Committee 2015. This report contains information about specific shales with recent activities in the US, Canada, Europe, and China. Given the intense interest in shales as "unconventional" hydrocarbon reservoirs, this report contains information available at the time of its compilation, and the reader is advised to use links provided herein to remain as up-to-date as possible.

This report is organized so that the reader can examine contributions from members of the EMD Shale Gas and Liquids Committee on various shales in the United States (presented in alphabetical order by shale name or region; Fig. 1), Canada, China, and Europe. Additional sections of the report include Valuable Links, Additional Sources of Information, and a Gas Shales and Shale Oil Calendar.

Please feel free to submit any comments or improvements to the committee chairs or contact Ursula Hammes (Ursula.hammes@beg.utexas.edu).

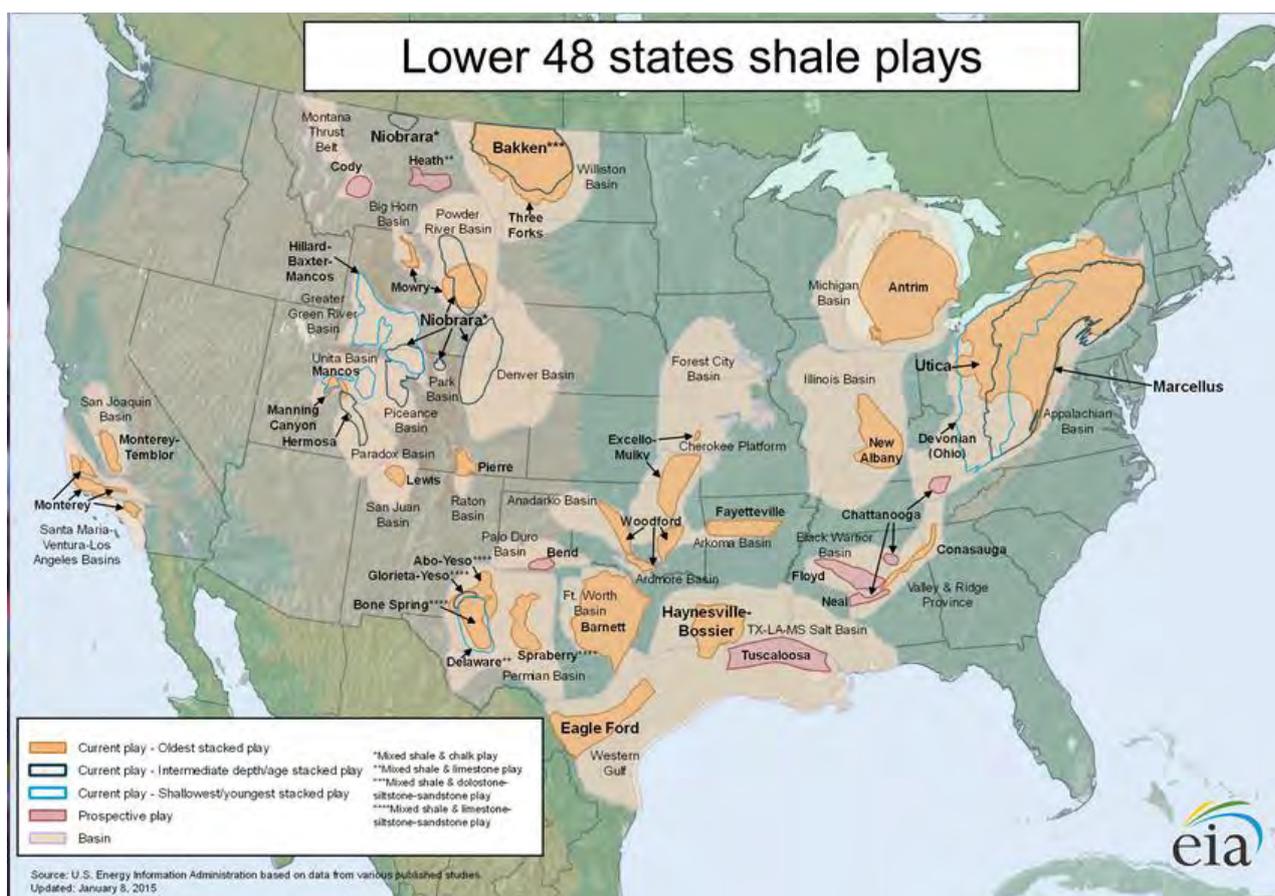


Figure 1: Current shale-gas and liquids unconventional plays in the Lower 48 States

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

US SHALES

[Antrim Shale](#)

[Bakken Shale](#)

[Barnett Shale](#)

[Eagle Ford Shale](#)

[Fayetteville Shale](#)

[Haynesville/Bossier Shale](#)

[Marcellus Shale](#)

[Niobrara Shale](#)

[Utah Shales](#)

[Utica Shale](#)

[Woodford Shale](#)

INTERNATIONAL SHALES

[Canadian Shales](#)

[Chinese Shales](#)

[European Shales](#)

STATUS OF U.S. ACTIVITIES

ANTRIM SHALE (DEVONIAN), MICHIGAN BASIN, U.S. (ORIGINALLY REPORTED 4/2013)

William B. Harrison, III (Western Michigan University)

The Michigan Basin Antrim Shale play is currently 25 years old, having begun the modern phase of development in 1987. The total number of producing wells drilled in the play through end of April, 2012 is approximately 11,500 with about 9,787 still online.

Total cumulative gas production reached 3.138TCF by the end of April, 2012. Michigan Antrim production is reported by project rather than by individual well or lease. Projects may be only a few wells or more than 70 wells. There were 788 separate projects at the end of April, 2012. Cumulative production for first 4 months of 2012 was 36,271,448 MCF of gas. That was a 3.9% decline from the same period in 2011.

There were 30 operators with production at the end of April, 2012. There were 9,787 wells online at the end April, 2012. There were 111 new wells drilled in 2009, only 58 in 2010 and 10 drilled so far in 2012. That is a 48% decrease in wells drilled from 2009 to 2010, a continuing drop of 33% in 2011 and an 82% drop in 2012. Overall drilling activity in Michigan was down 16% in 2011 compared to 2010. Most of the production comes from a few operators. The top 10 operators produced 82.4% of total Antrim gas in 2011.

Although some wells can initially produce up to 500 MCF/day, generally wells settle at less than 100 MCF/day. Play wide average production at the end of April, 2011 was 30 MCF/day per well. Many Michigan Antrim wells begin with high water production and begin to increase gas production as the water is pumped off. Water production generally continues throughout the project life, although it usually declines through time. Play wide gas to water production ratio reached almost 3 MCF/BBL in 1998, in 2004 it was 2.21 MCF/BBL, the 2009 ratio is 1.56 MCF/BB, the 2011 the ratio was 1.57 MCF/BBL and the ratio was 1.54 MCF/BBL through April, 2012. Play wide water ratios have begun to decrease relative to gas production as old wells are dewatered and very few new wells are being drilled.

CO₂ is also an issue in the produced Antrim gas that is mostly of biogenic origin. Most wells begin with very low amounts of CO₂ in the produced gas; however, the percentage of CO₂ increases through time. Some projects that have a long production history may now exceed 30% CO₂ in the produced gas. The play wide average was just over 12.4% CO₂ in 2008.

Wells produce from depths as shallow as 350 feet to just over 3,000 feet, although the vast majority of wells are completed from 1,000 to 2,500 feet deep. Wells are typically drilled with water and an attempt is made to keep the well in balance or slightly under-balanced. Wells are fraced with water and sand. Some wells are fraced using nitrogen or foam.

Production and well data is available online at the Michigan Public Service Commission at <http://www.cis.state.mi.us/mpsc/gas/prodrpts.htm>

Various kinds of oil and gas information is also available at the Michigan Office of Geological Survey site at http://www.michigan.gov/deq/0,1607,7-135-3311_4111_4231---,00.html

Cores, samples and other kinds of data are available at the Michigan Geological Repository for Research and Education at Western Michigan University. That website is <http://wst023.west.wmich.edu/MGRRE%20Website/mgrre.html>

Significant Trends –Gas production has been in steady decline since 1996 (<http://www.dleg.state.mi.us/mpsc/gas/pesec2.htm>, accessed 11/2015).

BAKKEN SHALE, WILLISTON BASIN, NORTH DAKOTA

Julie Lefever (North Dakota Geological Survey) and Stephan Nordeng (University of North Dakota)

Assessments performed by the United States Geological Survey (USGS) and the North Dakota Department of Mineral Resources in 2008 demonstrated that significant reserves were present in the Bakken Petroleum System in the entire Williston Basin (Pollastro and others, 2008; Bohrer and others, 2008; Nordeng and Helms, 2008). The area was re-assessed in 2013 due to an increase in the number of wells, longer production histories on existing wells, and new technologies and completion techniques (Gaswirth and Marra, 2015). Once again the assessment increased the undiscovered technically recoverable reserves to 3.65 billion barrels (bbls) for the Bakken and 3.73 billion bbls for the Three Forks formations of the U.S. Williston Basin.

Development of the Elm Coulee Field in 1996 resulted from the first significant oil production from the middle member of the Bakken Formation. Production from the middle member was established in the Kelly/Prospector #2-33 Albin FLB following an unsuccessful test of the deeper Birdbear (Nisku) Formation. Subsequent porosity mapping outlined a northwest-southeast trending stratigraphic interval containing an unusually thick dolomitized carbonate shoal complex within the middle member. Horizontal wells drilled through this shoal complex in 2000 resulted in the discovery of the giant Elm Coulee Field in eastern Montana. As with the previous Bakken producing fields, production at Elm Coulee depends on fracturing but in this case the productive fractures are found in the middle member of the formation. Since its discovery, more than 1100 horizontal wells have been drilled in the 450-square-mile field from which more than 169 MMBbls of oil have been recovered. The productive portions of the reservoir contains between 3 and 9 percent porosity with an average permeability of 0.04 md. A pressure gradient in the Bakken of 0.53 psi/ft indicates that the reservoir is overpressured. Laterals are routinely stimulated by a variety of sand-, gel- and water-fracturing methods. Initial production from these wells is between 200 and 1900 BOPD (Sonnenberg and Pramudito, 2009).

The Bakken middle member play moved across the line into North Dakota in 2004. Wireline logs of the Bakken Formation along the eastern portion of the Williston Basin in Mountrail County, North Dakota resembled those from Elm Coulee. The presence of free oil in DSTs and some minor Bakken production encouraged pursuit of the Bakken play in Mountrail County (Durham, 2009). In 2005, EOG Resources demonstrated with the #1-24H Nelson-Farms (SESE Sec. 24, T156N, R92W) that horizontal drilling coupled with large scale hydraulic fracture stimulation of the middle Bakken Formation could successfully tap significant oil reserves along the eastern flank of the Williston Basin. In the following year the play gained prominence when EOG Resources

drilled the #1-36 Parshall and #2-36 Parshall which resulted in wells with initial production rates in excess of 500 BOPD resulting in the discovery of Parshall Field.

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

Cores have played an important role in the understanding to this unconventional source system-play. There have been 167 cores cut on the North Dakota portion of the basin since the start of this play. Exploratory cores from the start of the play with extensive oils saturations have encouraged operators to drill, core, and produce from deeper portions of the source system. Production has been established from 3 separate horizons within the Three Forks Formation as well as the Middle Member of the Bakken. Thirty cores cut the complete Three Forks section adding to the understanding of a formation previously considered to be a trap.

Well stimulation of the early wells typically involved a large single stage fracture stimulation treatment using over 2 million pounds of proppant and over a million gallons of water. These single stage treatments have evolved into multistage treatments averaging 30 to 40 stages on the 10,000 ft laterals with a 50-50 split on plug and perf versus ball and sleeve (R. Suggs, 2015, Pers. Comm.). Fluid volumes range from 20,000 to 450,000 bbls with proppant amounts ranging from 80,000 to 3,500,000 lbs. Exceptions exist with laterals having 60 or more separate stages and proppant amounts as high as 10,000,000 lbs. The combination of horizontal drilling coupled with staged fracture stimulation has resulted in wells with IPs averaging in excess of 1100 BOPD per lateral.

Over 1.05 billion bbls of oil have been recovered from the 6665 wells in the 302 middle Bakken producing fields put into service since 2004. The 3503 horizontal wells drilled into the Three Forks Formation since 2006 have produced a total of 403 million bbls of oil. Currently there are 249 fields with Three Forks production. Seventy-seven wells have been completed in both the Bakken and Three Forks Formations. The majority of these wells were drilled in 2010.

After an all-time high of 218 rigs running on May 29, 2012, the rig count has decreased steadily with the drop in the price of oil. Sixty-five rigs are currently running in the North Dakota portion of the Williston Basin. The top 10 producers in the play are:

1. Whiting Oil and Gas Corporation (1331 wells)
2. Continental Resources, Inc. (1183 wells)
3. Hess Bakken Investments II, LLC (1128 wells)
4. XTO Energy Inc. (724 wells)
5. Burlington Resources Oil & Gas Company LP (513 wells)
6. EOG Resources (616 wells)
7. Marathon Oil Company (502 wells)
8. Oasis Petroleum North America LLC (604 wells)

9. Statoil Oil & Gas, LP (522 wells)
10. QEP Energy Company (287 wells).

Additional Information:

North Dakota Industrial Commission, Department of Mineral Resources, Oil and Gas Division
Director's Cut: <https://www.dmr.nd.gov/oilgas/informationcenter.asp>

North Dakota Geological Survey Website:
<https://www.dmr.nd.gov/ndgs/bakken/bakkenthree.asp>

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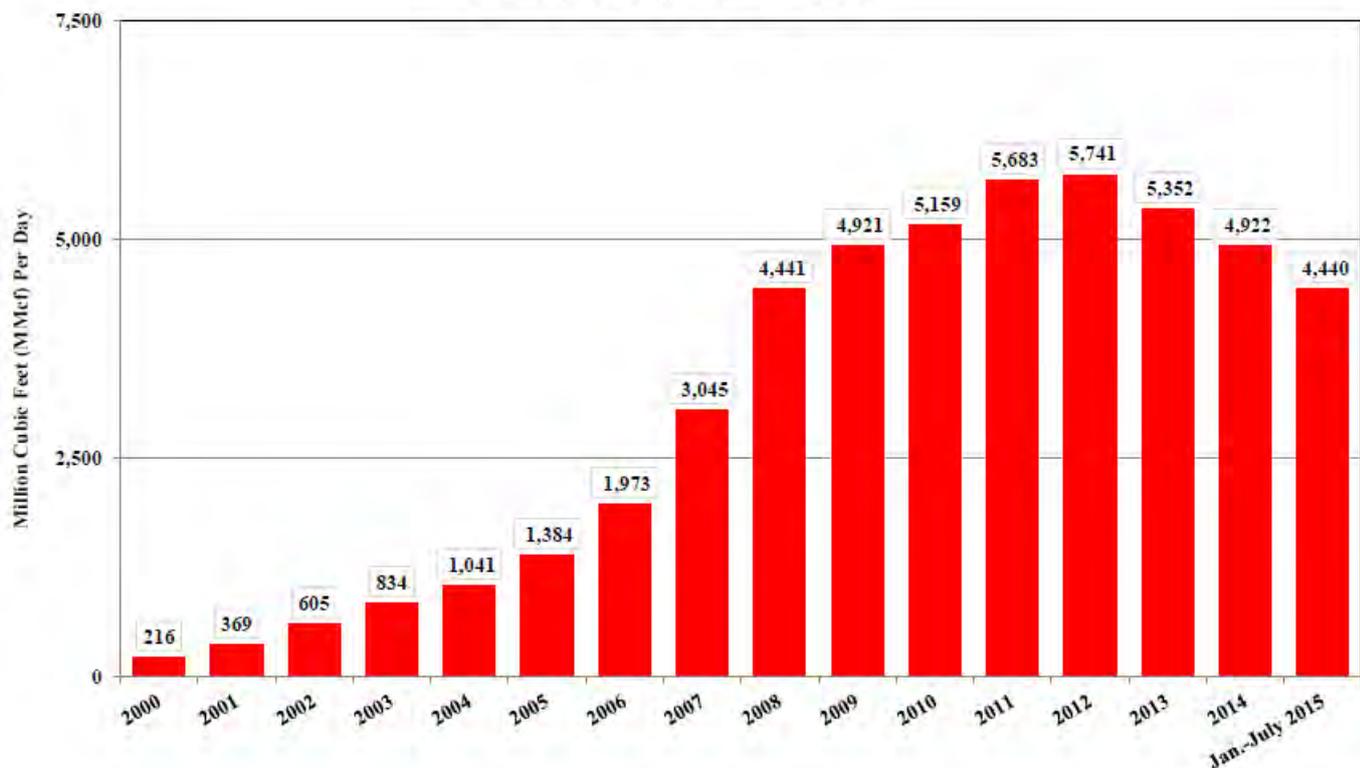
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BARNETT SHALE (MISSISSIPPIAN), FORT WORTH BASIN, TEXAS

Kent A. Bowker (Bowker Petroleum, LLC)

Daily gas production from the Barnett Shale continues to decline and has now dropped below 4.5 BCF/day. The current daily gas production is right at 4.4 BCF, while oil production is at 1900 B/D and condensate production is at 10,200 B/D. To June 1, 2015, 21,000 Barnett wells have produced 17.7 TCF of gas and 64,985,000 barrels of condensate/oil since 1983.

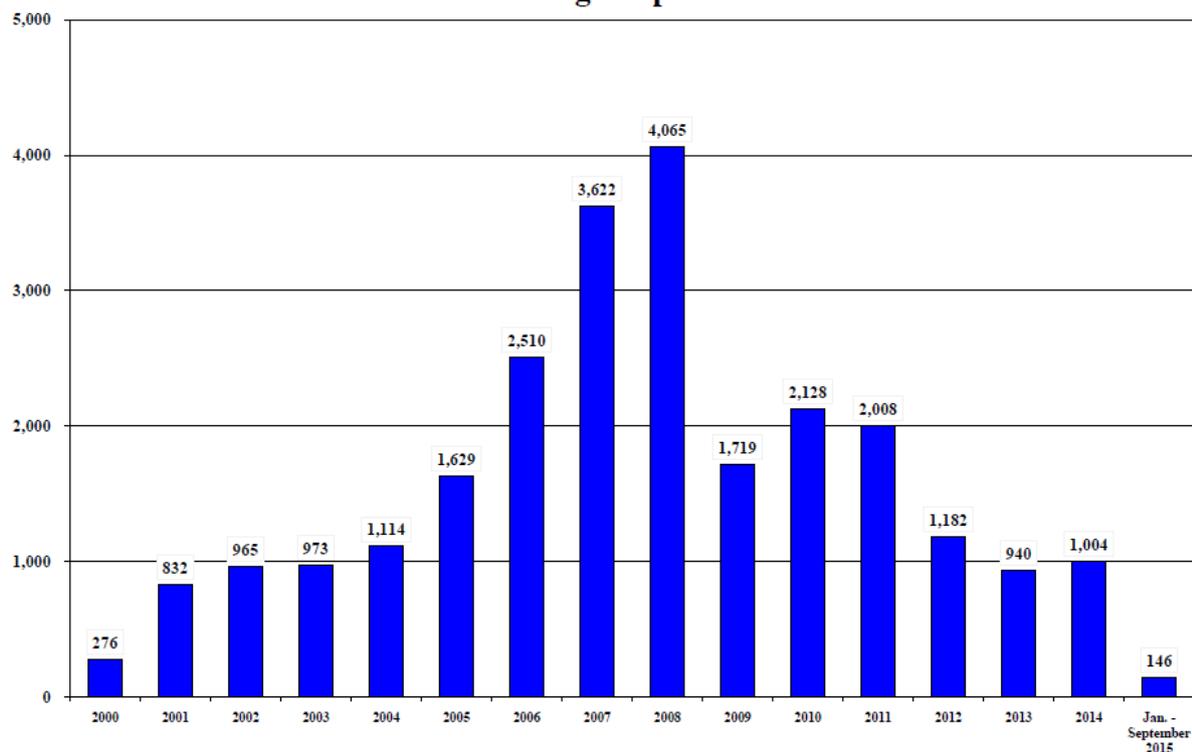
Texas Barnett Shale Total Natural Gas Production 2000 through July 2015



http://www.rrc.state.tx.us/media/22204/barnettshale_totalnaturalgas_day.pdf

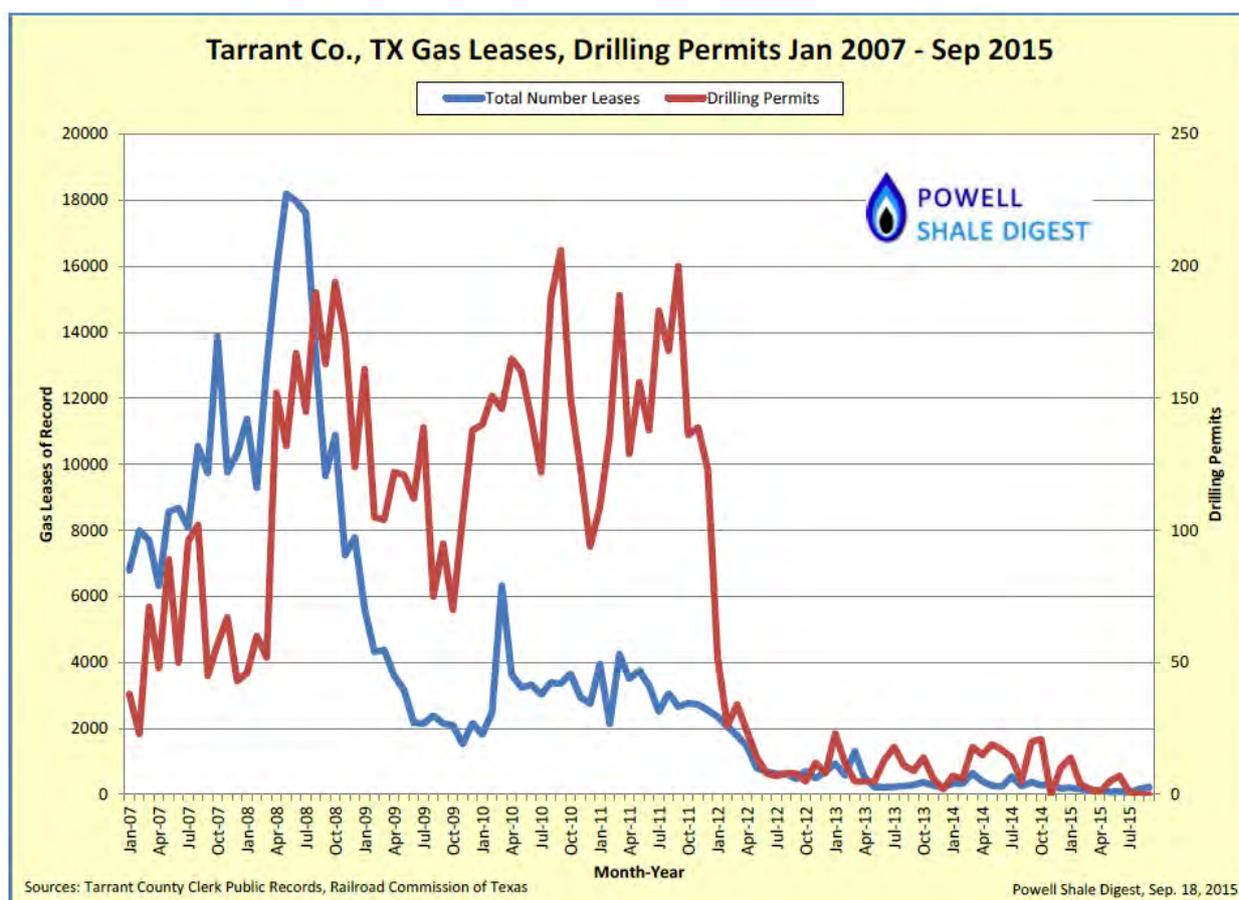
Permit applications and the play's rig count have been at pre-2000 levels for at least the past six months. The total number of active rigs in the play has averaged five or less since January 2015, well off the 180 or so rigs active in the play during 2008. The chart below shows the number of drilling permits issued by the Texas Railroad Commission for the Newark, East field (the primary producing field in the Barnett play). Most of the current permits are for wells in the core of the field in Tarrant, Wise, and Johnson counties.

**Texas Newark, East (Barnett Shale)
Drilling Permits Issued
2000 through September 2015**



<http://www.rrc.state.tx.us/media/14482/barnettshaledrillingpermitsissued.pdf>

Tarrant County (Fort Worth is the county seat) has the largest cumulative production of all the 18 counties in the play. But, as can be seen in the graph below, leasing and permit activity is moribund in the county. The effects of the late-2008 crash are seen in the leasing curve, while the drilling activity continued for another couple of years as companies drilled up leases so that they didn't expire.



Used with permission of Gene Powell.

Devon Energy announced in August that the company is experimenting with re-stimulations (aka, refracs) of existing horizontal wells in the Barnett. They also announced that the company has re-stimulated 50 vertical Barnett wells that had previously been refraced (refracs of refracs). In the horizontal refracs, the company revealed some economic success using finer sand as a diverting agent (see SPE paper number 154669 by Craig et al., 2012). Experiments are also underway in the Eagle Ford, west Texas vertical Wolfberry, and Haynesville plays. Chesapeake is also experimenting with refracing horizontal Barnett wells, but results of these tests haven't been released.

EAGLE FORD SHALE AND TUSCALOOSA MARINE SHALE

Russell F. Dubiel (U.S. Geological Survey)

The Cretaceous (Cenomanian-Turonian) Eagle Ford Shale of southwest Texas continues to be an important play producing thermogenic gas, oil, and condensate. The Eagle Ford play trends across Texas from the area of the Maverick Basin, northeast through the Karnes Trough towards the East Texas Basin, where it is a target for dry gas, wet gas/condensate, or oil. From January to August 2015, Texas Eagle Ford oil production was more than 1 MMBO per day, and natural gas production was more than 5 BCFG per day (<http://www.rrc.state.tx.us/oil-gas/major-oil-gas-formations/eagle-ford-shale/>), making it perhaps the largest oil producing play in the US. Completed wells display a steady decline in production similar to those in other

shale plays. Recently drilled shale oil wells have shown initial production rates of several hundred to as much as 1,000 barrels of oil per day (BOPD). As of October 2015, there were more than 9,300 oil wells and more than 4,600 gas wells in the Eagle Ford Shale in southwest Texas (<http://www.rrc.state.tx.us/oil-gas/major-oil-gas-formations/eagle-ford-shale/>). The trend occurs at an average depth of 11,000 feet.

Similar to other shale oil producing units in the US, the Eagle Ford is a viable target for hydrocarbon exploitation because of advances in the application of horizontal drilling and hydraulic fracturing. Lithology of the Eagle Ford is somewhat different than other gas shales, however, in that where it is being explored, the Eagle Ford contains significant marlstone and limestone beds that are brittle and enhance the opportunity for induced fractures. Most operators are drilling horizontal well laterals of 3,500 to more than 5,000 feet and are stimulating the wells with slick water or acid in at least 10 different fracture stages. For more information on Eagle Ford production, please refer to the Texas Railroad Commission web site (<http://www.rrc.state.tx.us/oil-gas/major-oil-gas-formations/eagle-ford-shale/>).

The industry term “Eaglebine” has been used locally for that part of the Eagle Ford Shale that interfingers with Woodbine Group sandstones in the northeast extension of the play south of the East Texas Basin. Adams et al. (2014), however, provide convincing arguments for the extension and application of formal stratigraphic nomenclature that has historical precedence, such as the Eagle Ford and Woodbine, to the extension of the Eagle Ford Shale northeast of the San Marcos arch and the Woodbine in the area south of the East Texas Basin.

Activity and success in the Eagle Ford Shale in Texas has generated renewed interest in the laterally equivalent Cenomanian-Turonian strata of the Tuscaloosa marine shale in eastern Louisiana and southern Mississippi. Initial exploration in the Tuscaloosa marine shale in the 1970’s has been followed by minimal exploration and production in the 1980’s, 1990’s and early 2000’s. Since 2010, several companies have begun significant leasing in eastern Louisiana and southern Mississippi. Over the last five years, those companies have begun exploration and initial development drilling in the Tuscaloosa marine shale. This activity is based in part on the historical record of hydrocarbon generation and proven, but minimal, oil production from the unit, the temporary high price for oil, corresponding low price for natural gas, and the significant success of horizontal drilling in the Eagle Ford in Texas. The Tuscaloosa marine shale trend averages about 12,000 to 15,000 feet in depth in the region north of the Lower Cretaceous shelf edge. South of the Lower Cretaceous shelf edge, the clastic shelf-margin deltas and laterally equivalent marine shales of the lower Tuscaloosa extend to more than 25,000 feet. Since 2010, several companies have drilled successful horizontal wells in Louisiana and southern Mississippi north of the Lower Cretaceous shelf edge, with about 45 wells currently producing oil in eastern Louisiana and southern Mississippi (<http://dnr.louisiana.gov/>; <http://www.sonris.com/>). This production trend is comparable to the approximately 40 wells that were current in the Eagle Ford in early 2009 (<http://www.rrc.state.tx.us/oil-gas/major-oil-gas-formations/eagle-ford-shale/>). Reported IPs are encouraging, in the neighborhood of several hundred BOPD, but currently only minimal yearly production data is available to evaluate the Tuscaloosa marine shale future success.

The marine source rocks of the Eagle Ford and Tuscaloosa have total organic carbon (TOC) contents as high as 5 to 6%. Thermal modeling based on vitrinite reflectance identifies an oil generation window that trends subparallel to the Lower Cretaceous shelf edge, with an adjacent gas generation window downdip and deeper toward the modern coast. Recent studies indicate that the

source rock interval in the Eagle Ford Shale in the Maverick Basin area and northeast to the San Marcos arch of southwest Texas lies in the lower part of the Cenomanian section, rather than in the Turonian strata (Donovan and Staerker, 2010; Donovan et al., 2012). Stratigraphic correlation of the Cenomanian and Turonian section of the Eagle Ford Shale in southwest Texas to Louisiana and Mississippi indicates that the Tuscaloosa marine shale currently being drilled north of the Lower Cretaceous shelf edge may be entirely upper Cenomanian and Turonian in age. The corresponding lower Cenomanian strata would lay south of the Lower Cretaceous shelf edge, distal to the Cenomanian shelf-margin delta sandstones of the lower Tuscaloosa, and within the gas window (Dubiel and Pitman, 2003, 2004).

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FAYETTEVILLE SHALE, ARKOMA BASIN, ARKANSAS

Marc Charette (Arkansas Geological Survey)

The Upper Mississippian Fayetteville Shale play is the current focus of 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.

Multiple news outlets reported that major companies within the Fayetteville have slashed budgets and manpower in 2015, with low natural gas pricing being the major driving force. Southwestern Energy (SWN) laid off 80 people working in the Fayetteville in August.¹ Both SWN and BHP have slashed budgets in the region, with the former cutting investment by 40% to only \$560 million for the fiscal year 2015 and the latter cutting to \$100 million.^{2,3}

U.S. Energy Information Administration (EIA) reports in 2013 that the Fayetteville contains 31.96 Tcf of technically recoverable gas resource, in which 27.32 Tcf is attributable to the core

producing area (aka eastern area) and 4.64 Tcf for the uncore producing area (aka 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 is economically recoverable reserves by 2050 (OGJ, 2014). EIA also reports that the proved gas reserves of the Fayetteville Shale in 2013 is 12.2 Tcf, an increase over the 2012 estimate of 9.7 Tcf. Estimated ultimate recovery (EUR) for a typical horizontal Fayetteville gas well decreases from 3.2 Bcf in 2011 to 3 Bcf in 2013 (OGJ, 2014).

According to the Arkansas Oil and Gas Commission data, estimated cumulative production of gas from the Fayetteville Shale as of June 2015 has totaled 6,151,412,461 Mcf from 5,776 wells. Annual production of Fayetteville Shale for January to June 2015 is 472,581,672 Mcf from 5,510 wells. Thirty-day initial production rates of horizontal wells have recently averaged about 4.4 MMcf/day. For more Fayetteville Shale production information, please refer to the Arkansas Oil and Gas Commission (AOGC) web link at <http://www.aogc.state.ar.us/Fayproinfo.htm>.

Like other dry gas plays, the Fayetteville has seen a dramatic decline in its rig count. According to Baker Hughes (BHI), the number of gas-directed rigs active in the play has dropped from 33 rigs in February 2011 to just 4 rigs in October 2015. SEECO (SWN) is the operator of these 4 remaining rigs. The continued production, in spite of the sharply lower rig count, is explained by the truly remarkable gains in rig productivity and operating efficiencies as the transition towards the full development mode in many areas is beginning to bear fruit. In 2014, Southwestern Energy has drilled its average well in just 6.8 days, re-entry to re-entry, compared to 11 days in 2010. The comparison is even more impressive given that the average length of the lateral increased from 4,532 feet in 2010 to 5,440 feet in 2014.

Fayetteville Shale reports from the AOGC have noted well increases from 24 in 2004, 33 in 2005, 129 in 2006, 428 in 2007, 587 in 2008, 839 in 2009, and 874 in 2010. Since then the numbers of new completed wells declined in three consecutive years, with 829 in 2011, 675 in 2012, and 557 in 2013. As of June 30, 2015, there were a total of 5,776 producing gas wells in the Fayetteville Shale play. Most Fayetteville Shale wells are drilled horizontally and have been fracture stimulated using slickwater or cross-linked gel fluids. Baker Hughes' FracPoint Multi-stage fracturing system has provided most of the hydraulic fracturing completions in the Fayetteville Shale. Fayetteville Shale gas production generally ranges over a depth between 1,500 to 6,500 feet. The thickness of Fayetteville Shale varies from 50 feet in the western portion of the Arkoma Basin of Arkansas (fairway area) to 550 feet in the central and eastern regions (primary producing area).

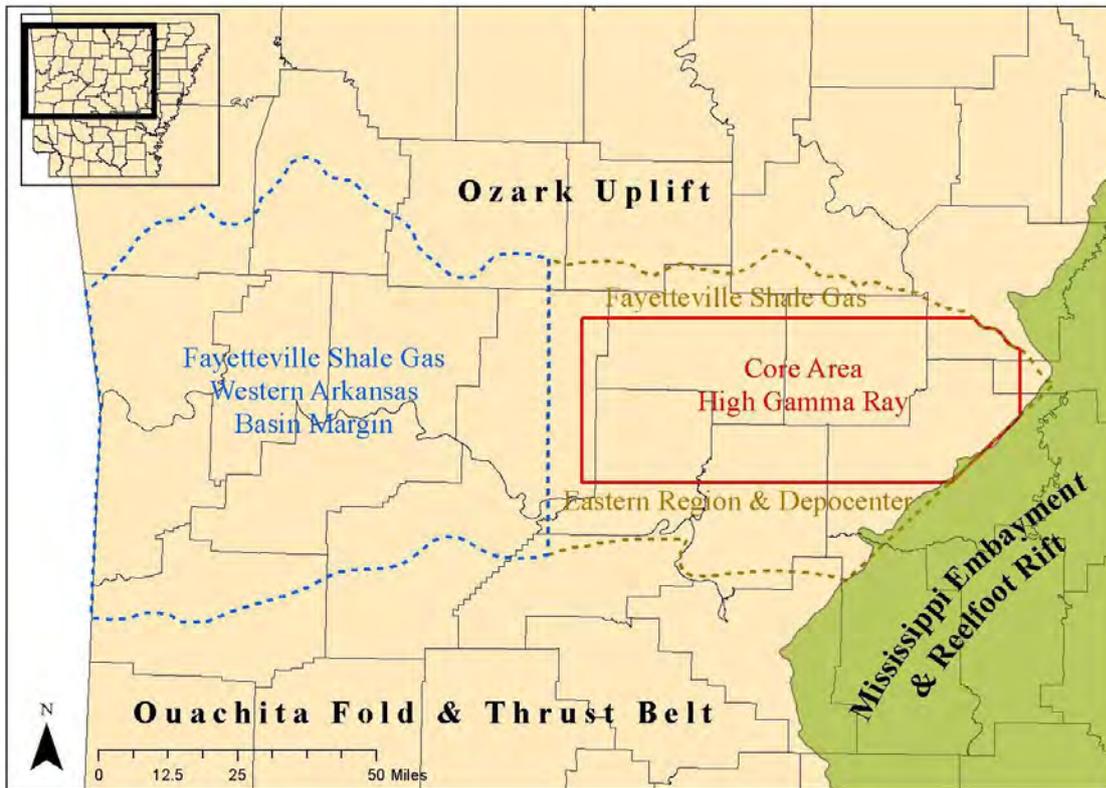


Figure 1. Primary area of the Fayetteville Shale exploration and development in Arkansas.

Since the play's inception, the Fayetteville Shale play has been dominated by a small number of large players. Three operators – Southwestern Energy, BHP Billiton, and XTO Energy (a subsidiary of Exxon Mobil) – account for over 99% of gross operated production from the field. The three companies hold close to 2 million net acres under lease in the play. Southwestern, with 888,161 net acres and more than four thousand producing wells, is by far the largest operator among the three companies, and accounts for over two-thirds of the field's total production volume. Exxon and BHP are approximately equal in terms of their acreage and gross operated production. During 2014, Southwestern contributed 749.9 Bcf in Fayetteville gas sales, good for 73.2% of the play's total sales that year. BHP sold 140.2 Bcf (13.7%) and XTO Energy sold 131.8 Bcf (12.7%). The remaining 0.4% of sales, or 2.67 Bcf, was spread out among ten companies.

The top three operators of the Fayetteville gas shale play as of June 2015 based on numbers of producing wells are as follows (Figure 2):

- 1) SEECO Inc. (an exploration subsidiary of Southwestern Energy) (3,781 wells)
- 2) BHP Billiton Petroleum (938 wells)
- 3) XTO Energy, Inc. (a subsidiary of ExxonMobil) (870 wells)

Two different maps are available that illustrate the location and types of wells located in the Fayetteville Shale producing area. Web links for the Fayetteville Shale maps and the associated federal and state agencies are listed below:

(1) The home page of the Arkansas Geological Survey (AGS) website is:
<http://www.geology.arkansas.gov/home/index.htm>

(2) The home page of the U.S. Energy Information Administration (EIA) website is:
<http://www.eia.doe.gov/> and the EIA Fayetteville Shale map is available at
http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm.

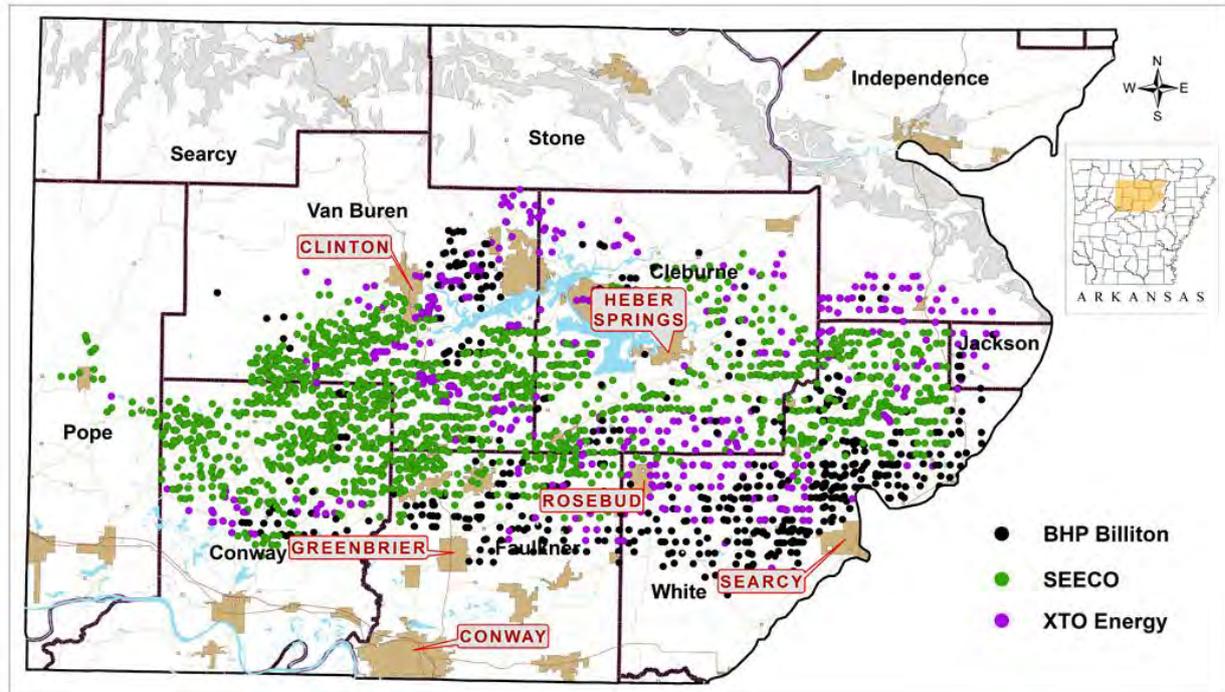


Figure 2. Location map of the Fayetteville Shale producing wells by top 3 operators as of June 2015.

Disposal of production well wastewater through injection wells has gradually mounted concern in the Fayetteville Shale play area given thousands of recent area earthquakes. Most of the seismic events have been too small to be felt, and a majority of the epicenters form a northeast-southwest trending linear feature near the towns of Guy and Greenbrier in Faulkner County. These earthquakes have become known as the Guy-Greenbrier Swarm. It was recently discovered that the Guy-Greenbrier Swarm earthquakes occurred along and illuminate a previously unknown sub-surface fault, the Guy-Greenbrier Fault, located near the disposal wells. The fault, nearly 7.5 miles long, could theoretically generate an earthquake of around 6.0 in magnitude. In January 2011, the AOGC imposed a six-month moratorium on new injection wells in a portion of the Fayetteville Shale production area to determine what relationship, if any, there is between the wastewater injection and the earthquakes. The quakes intensified during the last two weeks of February 2011, culminating with a 4.7-magnitude earthquake near Greenbrier on February 27, 2011, the most powerful reported seismic event in Arkansas in 35 years. AOGC held a special meeting on March 4, 2011 to issue an emergency order immediately shutting down all injection operations of two disposal wells through the last day of the regularly scheduled hearing in March 2011. At the March 2011 hearing, AOGC ordered the companies to continue the cessation of all injection operations of these two wells for a period of an additional sixty days. During the July 2011 hearing, the AOGC requested an immediate and permanent moratorium on any new or additional disposal wells or disposal well permits in the moratorium

area (Figure 3). At the time of the hearing, there were four disposal wells within the moratorium area, including the two wells that were shut down since March 2011. The frequency of the quakes within the moratorium area saw a significant decrease, about 75%, since the cessation of the injection operation of the disposal wells. This, in turn, gave more evidence to confirm a potential relationship between the injection activities and the earthquakes. Geohazards geologists at the AGS that monitor the earthquakes in the state provide the relevant information to the public and the AOGC.

Concerns about the effect of Fayetteville gas exploration and production on public health, air, water and land are increasing with the spread of hydraulic fracturing technology that is utilized in well completions. Expanded production and potential environmental impacts have increased the need for additional regulations related to all aspects of exploration and production. Arkansas joins Wyoming as the only states that require the full disclosure of all chemical constituents in all frac fluids and additives on a well-by-well basis and the release of these reports to the public. The AOGC's Rule B-19 (available on the AOGC website), which also protects the trade secrets behind proprietary compounds, went into effect January 15, 2011. AOGC also issued a revised surface casing and production casing cementing requirements for all Fayetteville Shale wells. All operators of such wells since June 1, 2011 are required to set surface casing to a depth equal to 500 feet below the lowest ground surface elevation occurring within 1 mile of the proposed well, with a minimum of 1000 feet of surface casing to be set and cemented to surface. In addition, cement shall be circulated to the surface on all production casings, so as to isolate from all strata encountered in the wellbore above the Fayetteville Shale horizon.

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. These studies are available at the Arkansas Geological Survey as Information Circular 37 (Ratchford et. al., 2006) and Information Circular 40 (Li et al., 2010) and integrate surface and subsurface geologic information with organic geochemistry and thermal maturity data.

The AGS continues to partner with the petroleum industry to pursue additional Fayetteville Shale related research. Ongoing AGS research is focused on the chemistry and isotopic character of produced gases, mineralogy of the reservoir, and outcrop to basin modeling.

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²<http://talkbusiness.net/2015/03/southwestern-energy-slashes-fayetteville-shale-budget-41/>

³<http://www.thecitywire.com/node/36581#.Vie8JH6rTcs>

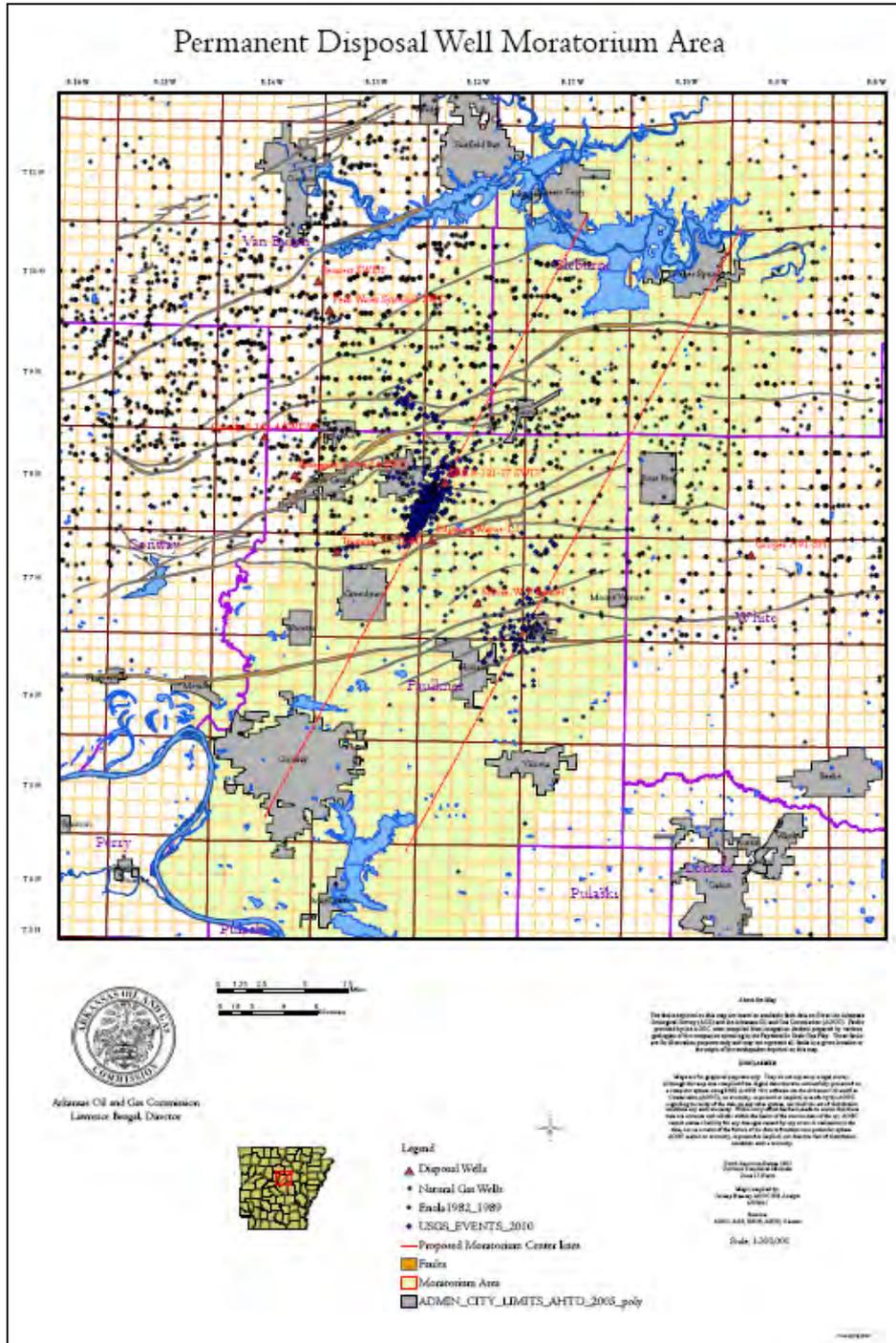


Figure 3. Permanent moratorium area for disposal wells in the Fayetteville Shale Play, Arkansas (from the AOGC website).

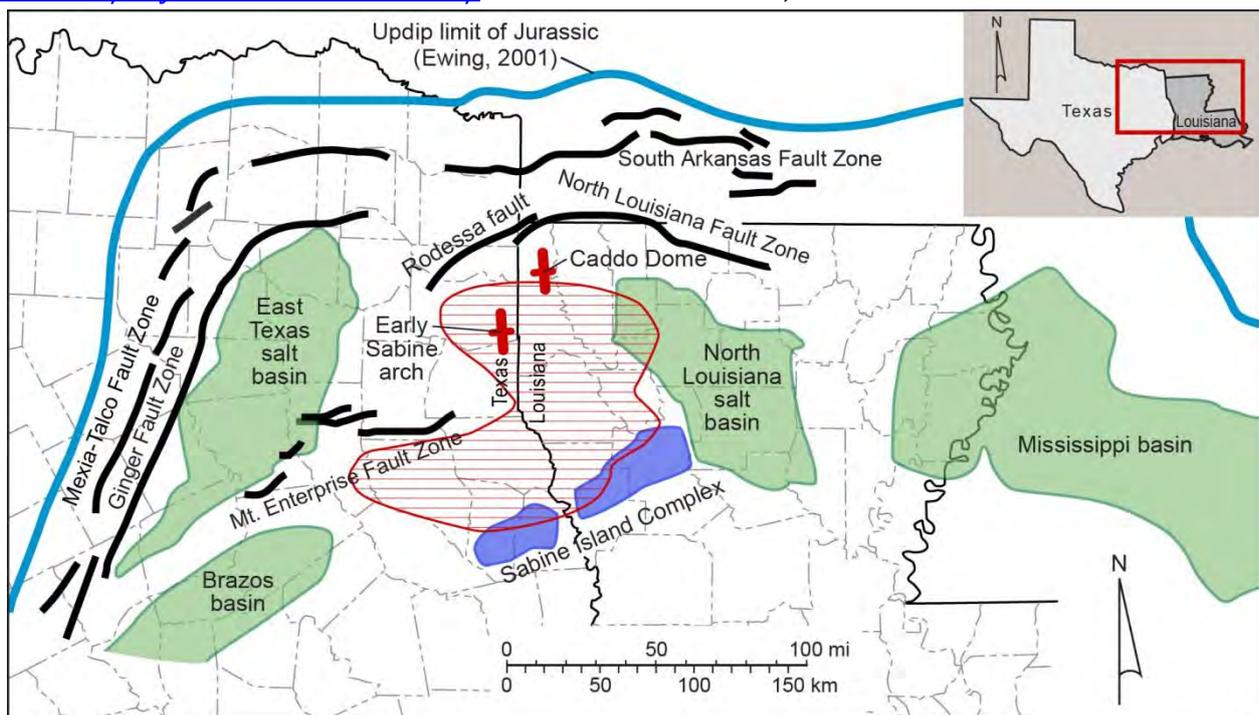
HAYNESVILLE/BOSSIER SHALES, EAST TEXAS BASIN, TEXAS

Ursula Hammes (Bureau of Economic Geology, The University of Texas at Austin)

The Kimmeridgian Haynesville Shale spans 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 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 mudrocks contain a spectrum of facies ranging from more calcareous in the southern part of the productive area to more siliceous and argillaceous rich in the northern and eastern part of the productive area (Fig. 1; Hammes et al., 2011). Haynesville reservoirs are characterized by overpressuring, porosity averaging 8–12%, 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 are 3000– 5000 ft (1000–1700 m). Optimal frac stages are 12–16 with an optimum number of 15 with multiple perforation clusters (Wang et al., 2013).

Haynesville drilling permits and rig count showed more wells were drilled in Texas over Louisiana and an overall decrease in rigs from last 6 months but increased by 12.5% within the last week (Figs, 2, 3). However, the Haynesville Shale in Texas and Louisiana is starting to experience a slight revival due to construction of LNG and gas-power plants being built along the TX Gulf coast. 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. New technologies learned from other shale plays might also assist in additional production as well as refracing of 5–6 year old wells drilled in the early phase of the play. Production fell to about half from what was produced at its peak in 2012 (Fig. 4). Liquids and gas production in Texas fell slightly from last year (Figs. 5, 6). Additional information on the Haynesville can be found at the Louisiana Oil and Gas association <http://dnr.louisiana.gov/index.cfm?md=pagebuilder&tmp=home&pid=442> and from the Texas Railroad Commission <http://www.rrc.state.tx.us/oil-gas/major-oil-gas-formations/haynesvillebossier-shale/> accessed November 3, 2015.



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

October 9, 2015			
All Haynesville/MBS Wells			
Operator	LA	TX	Total
Chesapeake	5	0	5
Vine Oil & Gas	4	0	4
Anadarko	3	0	3
EXCO Resources	0	3	3
XTO Energy	0	1	1
BP America	0	1	1
Comstock Oil & Gas	1	0	1
Total	13	5	18

Parish/County	9-Oct	2-Oct	25-Sep
Red River, LA	5	1	1
DeSoto, LA	4	5	7
Shelby, TX	1	1	1
Bossier, LA	2	3	3
Caddo, LA	2	2	1
Panola, TX	1	1	1
San Augustine, TX	3	3	3
Total	18	16	17

Figure 2: Rig counts in Louisiana and Texas for October 2015 (www.haynesvilleplay.com; accessed November 4, 2015)

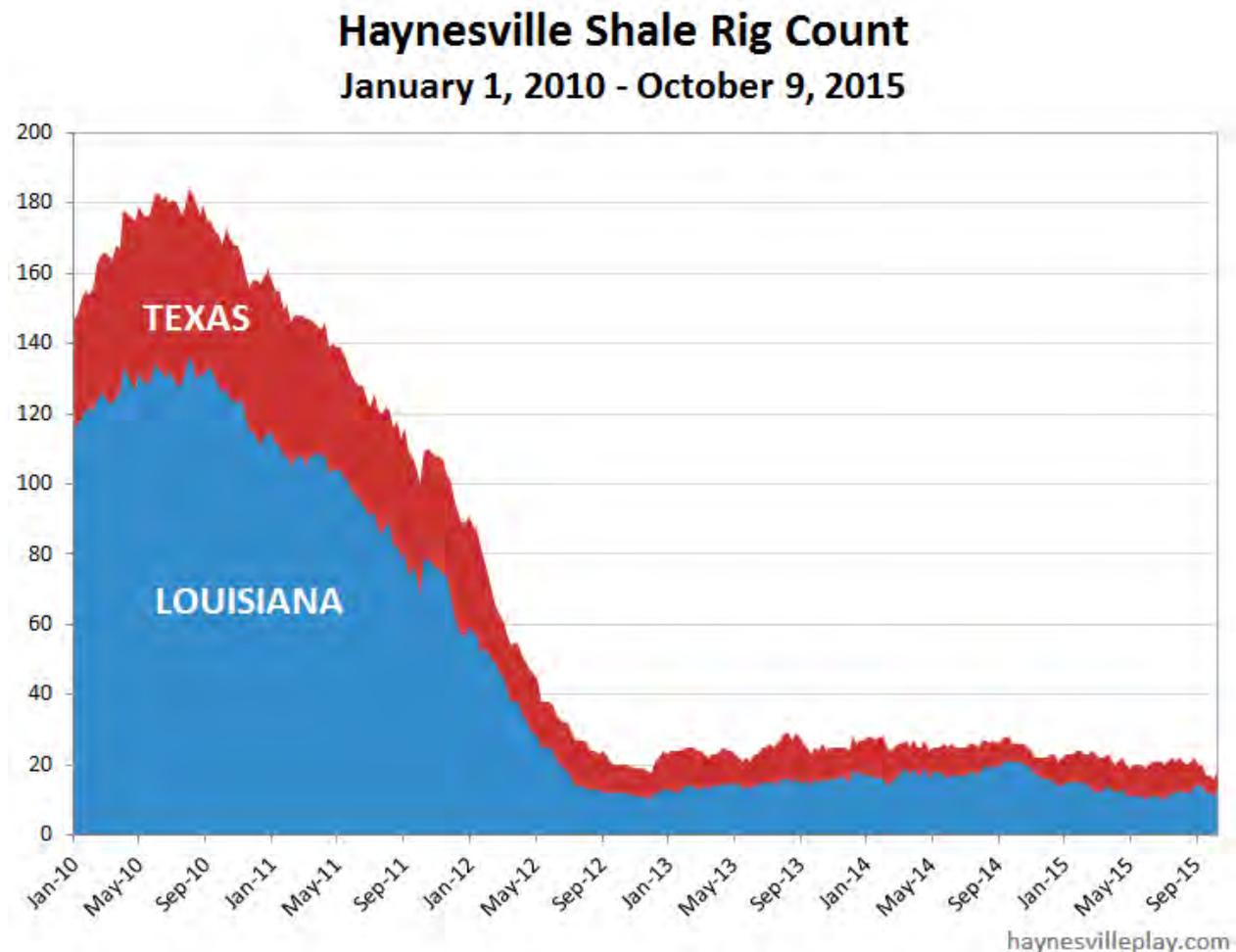


Figure 3: Louisiana and Texas Haynesville rig count through September 2015 (from www.haynesvilleplay.com).

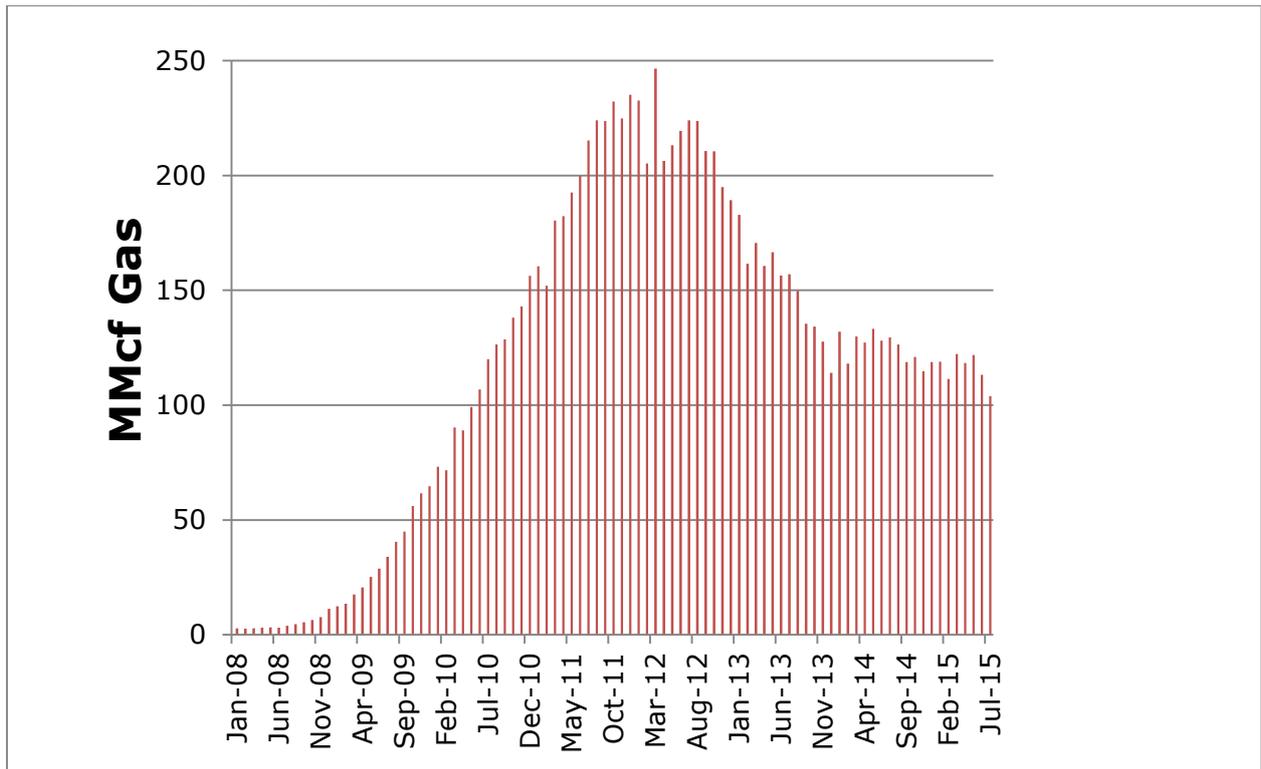


Figure 4: Monthly gas production (in MMcf) through July 2015 of the Haynesville Shale (data from IHS Enerdeq).

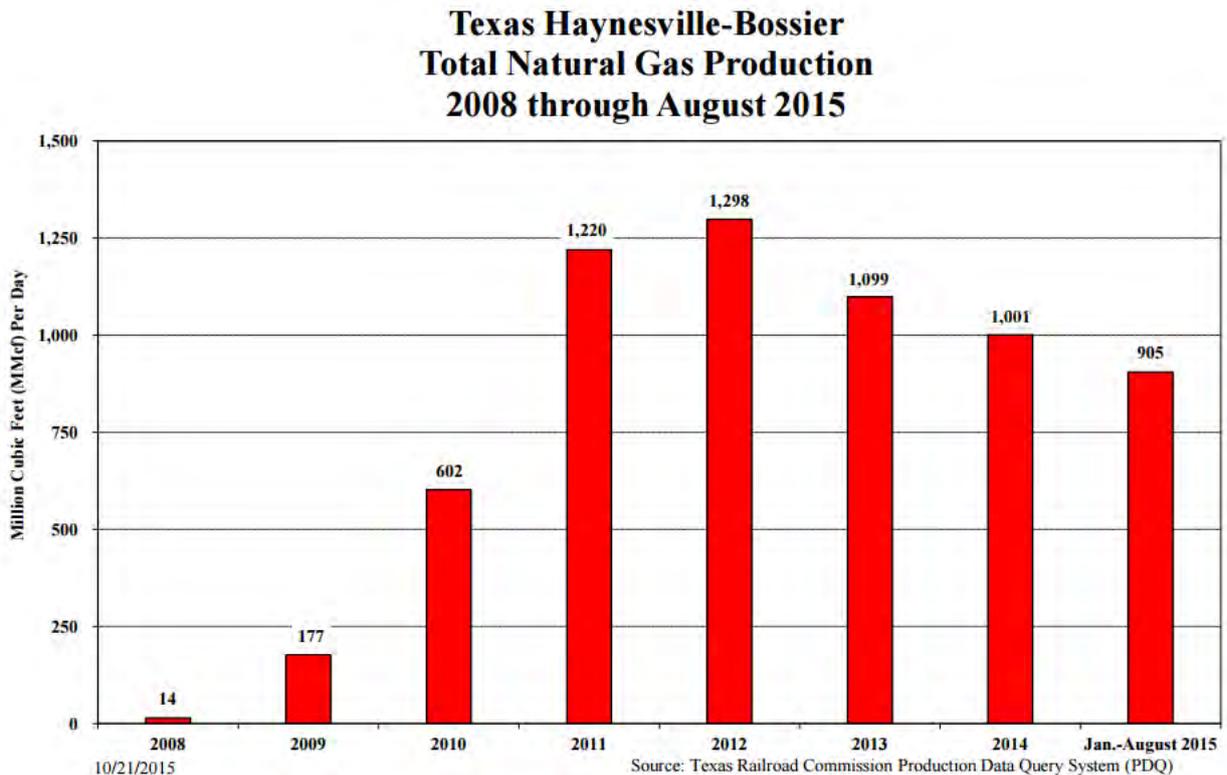


Figure 5: Yearly gas production chart (MMCF/day) through January 2015 for Haynesville Shale (from RRC TX).

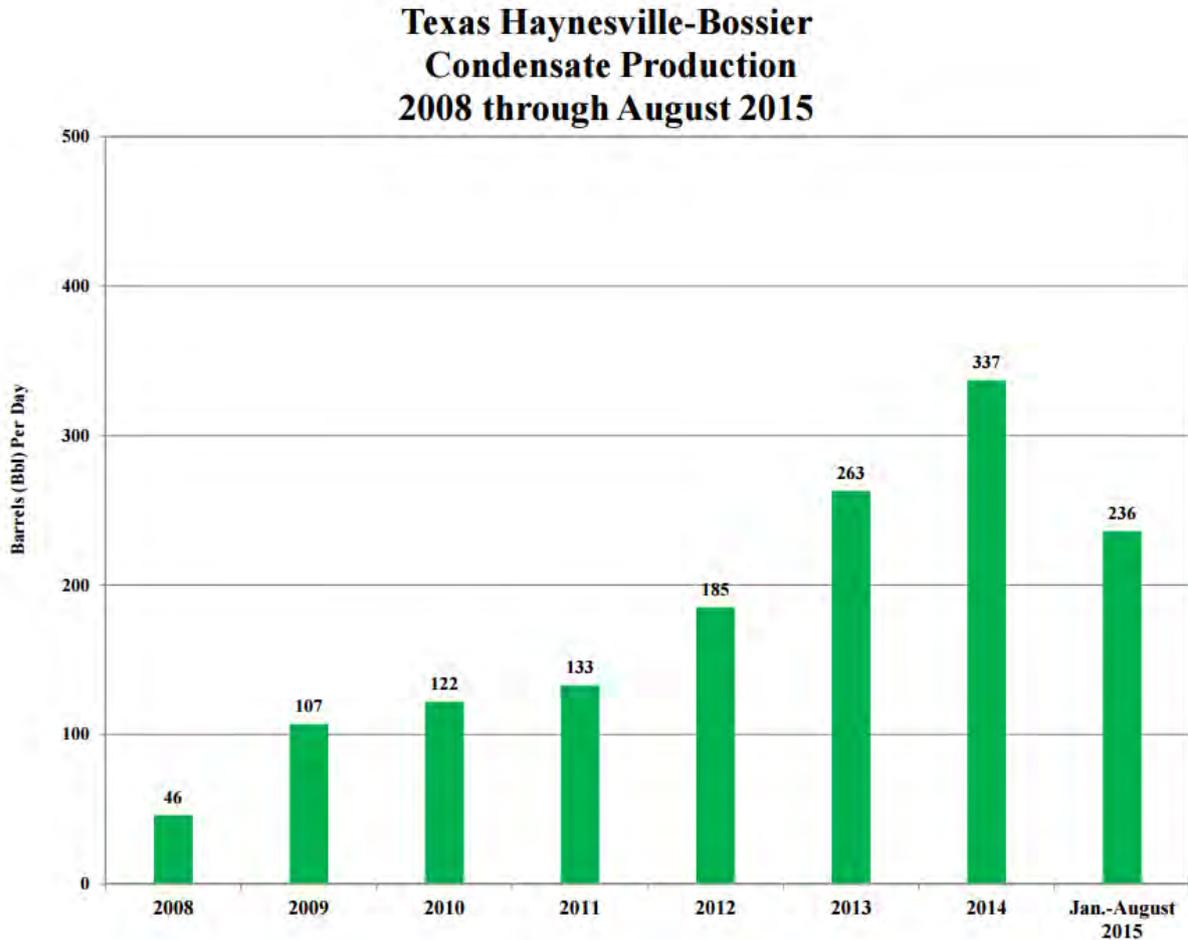


Figure 6: Texas Haynesville Shale condensate production (in barrels per day) through August 2015 shows a decline in liquids production for the first half of 2015.

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MARCELLUS SHALE, 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 (Milici and Swezey, 2006; Wrightstone, 2009). The organic-rich zone of the Marcellus Shale has a net thickness of 50 to over 250 feet, and exists at drilling depths of 2,000 to 9,000 feet ((Milici and Swezey, 2006; Wrightstone, 2009). 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. 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. However, in southwest Pennsylvania, eastern Ohio, and northern West Virginia, reported production included condensate and oil from wells in the 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 in other shale plays, horizontal drilling and hydraulic fracturing increase production rates of petroleum, which improves the commerciality of hydrocarbon production from this formation. The orientation of the horizontal sections of the wells and the design of the staged hydraulic fracturing operations enhance the natural fracture trends in the Marcellus Shale. "Slick-water fracs" have provided the best method for recovering large volumes of natural gas efficiently. These use sand as a proppant and large volumes of freshwater that have been treated with a friction reducer such as a gel. The slick-water frac maximizes the length of the induced fractures horizontally while minimizing the vertical fracture height (Harper, 2008). Water supply for large volume fracturing is a concern, as are the potential environmental impacts related to handling and management of produced formation water and used hydraulic fracturing fluid, called "flow-back" fluid (Engle and Rowan, 2014; Skalak and others, 2014; Capo and others, 2014). The management of produced formation water and used hydraulic fracturing fluid have been addressed with a variety of approaches including 1) treatment followed by discharge into receiving basins or streams, 2) injection into subsurface disposal wells, or 3) treatment to remove solids and unwanted contaminants followed by reuse.

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

cubic feet (bcf) of gas per day and about 60,000 barrels (bbls) of oil and condensate per day, in July, 2015, according to the EIA (U.S. Energy Information Administration, 2015b).

In August, 2011, the U.S. Geological Survey (USGS) published Fact Sheet 2011-3092, "Assessment of undiscovered oil and gas resources of the Devonian Marcellus Shale of the Appalachian Basin Province" (Coleman and others, 2011). According to this publication, the USGS estimated a mean undiscovered, technically recoverable natural gas resource of about 84 trillion cubic feet (tcf) and a mean undiscovered, technically recoverable natural gas liquids resource of 3.4 billion bbls in continuous-type accumulations in the Marcellus Shale. The estimate of natural gas resources ranged from 43 to 144 tcf (95 percent to 5 percent probability, respectively), and the estimate of natural gas liquids (NGL) resources ranged from 1.6 to 6.2 billion bbls (95 percent to 5 percent probability, respectively). This re-assessment of the undiscovered continuous resources in the Marcellus Shale updated the previous assessment of undiscovered oil and gas resources in the Appalachian Basin performed by the USGS in 2002 (Milici and others, 2003), which estimated a mean of about 2 tcf of natural gas and 11.5 million bbls of NGL in the Marcellus Shale .

The new 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.

The increase in undiscovered, technically recoverable resources is due to new geologic information and engineering data. 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 new 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.

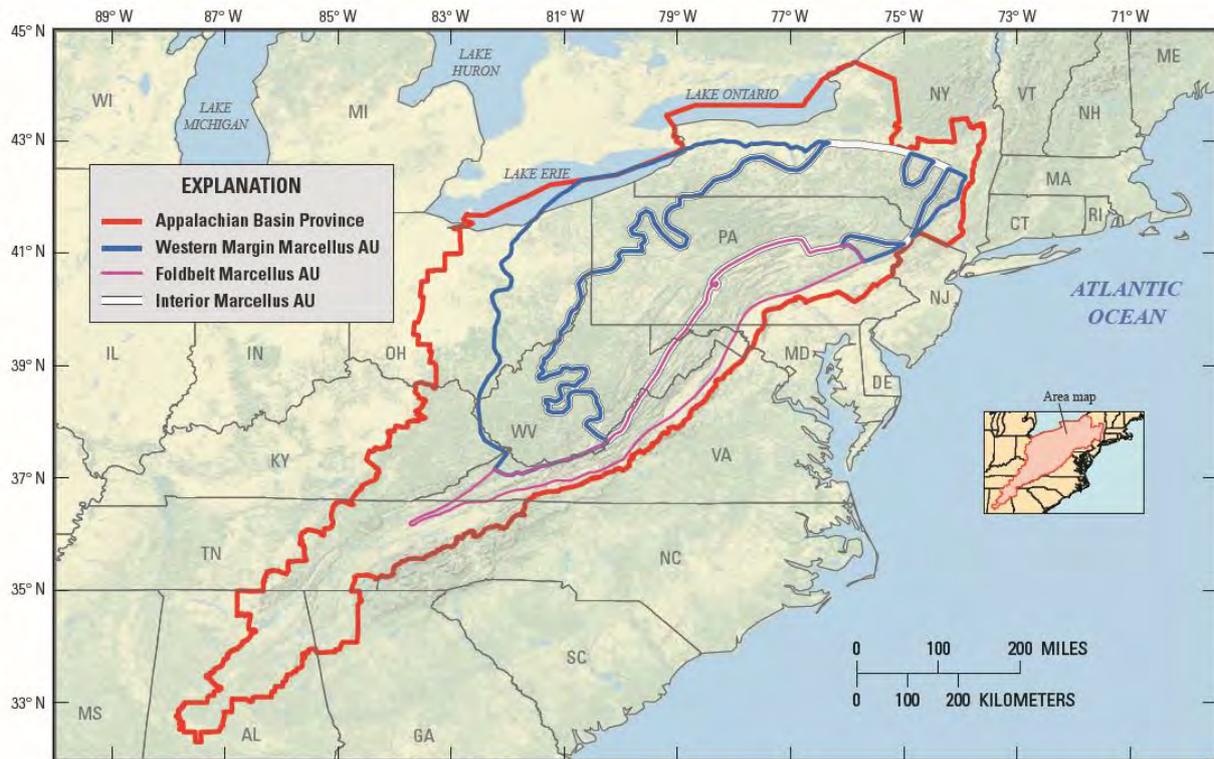


Figure 1. Map of the Appalachian Basin Province showing the three Marcellus Shale assessment units (Coleman and others, 2011).

Maryland: According to the Maryland Geological Survey (MGS), there were no exploration wells drilled in Maryland between 1996 and 2015. There is currently (2015) no reported production from the Marcellus Shale in Maryland. 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. The permit process to drill and produce natural gas from the Marcellus Shale in Maryland is under review. On June 6, 2011, the Governor of Maryland signed an Executive Order establishing the Marcellus Shale Safe Drilling Initiative. The Order required the Maryland Department of the Environment (MDE) and Department of Natural Resources (DNR) to undertake a study of drilling for and extracting natural gas from shale formations. In December, 2011, the MDE and DNR developed four recommendations regarding revenue and three recommendations regarding standards of liability. The final draft “Assessment of Risks from Unconventional Gas Well Development in the Marcellus Shale of Western Maryland” was released on January 20, 2015; it is available at http://www.mde.state.md.us/programs/Land/mining/marcellus/Pages/Risk_Assessment.aspx. Proposed revised oil and gas exploration and production regulations were published in the January 9, 2015, edition of the Maryland Register. The 30-day comment period closed February 9, and the MDE is reviewing the comments received. The new regulations can be accessed at <http://www.mde.state.md.us/programs/Land/RecyclingandOperationsprogram/SpecialProjects/Documents/Oil%20and%20gas%20reg%20proposal%20-%20MD%20Register%20notice%2001-9-15.pdf>.

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 in the eastern part of basin in south-central New York (Smith and Leone (2010)). According to the New York State Department of Environmental Conservation (DEC) in October, 2015, there were 25 vertical wells with Marcellus Shale listed as the producing formation in 2014, but only 14 reported production in 2014; 10 wells had “shut-in” status. Natural gas production from the Marcellus Shale in 2014 was 14.3 Mcf, down from the high of 64 Mcf reported for 2008. There was no reported oil production. According to the DEC, there were almost 284 Mcf of gas produced from the Marcellus Shale between 2000 and 2014. 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#2015>. 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: The Ohio Department of Natural Resources (DNR) reported that about 4.3 bcf of gas and over 167,000 bbls of oil were produced from the Marcellus Shale from 2007 through 2014. There were about 13 wells that reported production from the Marcellus Shale in 2014. According to DNR, there were about 3 bcf of gas and about 145,700 bbls of oil produced in 2014. As of October, 2015, 43 Marcellus Shale horizontal well permits were issued, 28 horizontal wells had been drilled into the Marcellus Shale, and 19 horizontal wells were producing from the Marcellus Shale, according to the Ohio DNR. The horizontal Marcellus Shale wells reported as productive were in Belmont, Carroll, Jefferson 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 3,000-5,000 feet. The Ohio Geological Survey published a map of the area of potential production from the Marcellus Shale (http://geosurvey.ohiodnr.gov/portals/geosurvey/Energy/Utica/Utica_Marcellus_Ohio_8x11.pdf), which included the counties of Ashtabula, Lake, Trumbull, Mahoning, Columbiana, Carroll, Jefferson, Harrison, Belmont, Guernsey, Monroe, Stark, Tuscarawas, and Washington. The DNR Division of Oil and Gas Resources Management published new draft rules pertaining to horizontal well site construction, which are available for review and comment at <http://oilandgas.ohiodnr.gov/laws-regulations/opportunities-for-involvement#PPR>.

Pennsylvania: The Marcellus Shale is deepest in north-central Pennsylvania, and the deepest wells to test the Marcellus Shale have been drilled to 8,500 feet in Clinton County

(Harper and Kostelnik, undated). The organic-rich, high gamma ray portion of the Marcellus Shale is thickest in southwestern and north-central Pennsylvania (Perry and Wickstrom (2010), and Harper (2008)), reaching about 400 feet thick in Susquehanna and Wyoming counties (Erenpreiss and others (2011)). The areas of greatest drilling activity in the Marcellus Shale were in southwestern and northeastern Pennsylvania. The production of oil and condensate from fields in southwest Pennsylvania made this area attractive to operators. Pennsylvania has continued to be the state with the most drilling into, and production from, the Marcellus Shale. According to the Pennsylvania Department of Conservation and Natural Resources (DCNR) and Department of Environmental Protection (DEP), the counties with the most natural gas production in 2014 from the Marcellus Shale were Greene, Washington, Lycoming, Tioga, Bradford, Wyoming and Susquehanna. The counties with the most condensate and/or oil production in 2014 from the Marcellus Shale were Washington, Mercer, and Butler.

According to DCNR and DEP, by the end of 2014, over 4,600 wells reported production from the Marcellus Shale, and about 90% of those productive wells were horizontal wells. According to DCNR and DEP, almost 3 tcf of gas, about 1.7 million bbls of condensate, and about 133,000 bbls of oil were produced from the Marcellus Shale in 2014. During the last 6 months of 2014, Chesapeake Appalachia LLC was the largest producer of natural gas from the Marcellus Shale, followed by Cabot Oil & Gas Corporation, Range Resources Appalachia LLC, Southwestern Energy Production Company, EQT Production Company, and Chief Oil & Gas LLC. Range Resources was the largest producer of condensate and/or oil from the Marcellus Shale during the last 6 months of 2014. Other operators with significant liquids production included Chesapeake Appalachia, Hilcorp Energy Company, Noble Energy Inc., RE Gas Development LLC, and Chevron Appalachia LLC.

Beginning in January, 2015, the Pennsylvania DEP began reporting production from unconventional wells on a monthly basis. According to the Pennsylvania DEP, in August, 2015, there were 8,000 active wells listed as horizontal completions in the Marcellus Shale. From these wells, in August, 2015, about 371.5 bcf of gas, and about 406,000 bbls of condensate and oil were produced.

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 2015. It is possible that natural gas was produced from the Marcellus Shale commingled with other zones in vertical wells in Virginia, but the quantity is unknown. A significant fraction of potentially productive acreage in Virginia is on national forest land. The U.S. National Forest Service (NFS) updated the George Washington National Forest (GWNF) Plan in November, 2014. The NFS chose Alternative I regarding lands administratively available for oil and gas leasing. The approximately 10,000 acres of mineral rights under current federal oil and gas leases will

continue to be legally available for federal oil and gas leasing. None of these are currently active, but those lands will remain available for leasing after the current leases expire, terminate or are relinquished. All other areas of the GWNF are now administratively unavailable for federal oil and gas leasing, which includes about 1,056,000 acres. The Final GWNF Plan documents, including the revised forest plan, maps, and the final environmental impact statement, can be accessed at the following link:

http://www.fs.usda.gov/detail/gwj/landmanagement/?cid=fsbdev3_000397.

West Virginia: West Virginia is second to Pennsylvania in cumulative production of hydrocarbons from the Marcellus Shale. Total production from wells completed in the Marcellus Shale from 1979 through 2014 was over 2 tcf of gas, over 11.3 million bbls of oil, and about 2 million bbls of NGL, according to information from the West Virginia Geological and Economic Survey (WVGES). In the vertical wells, production volumes are commingled from multiple formations and were reported. The first production reported from a horizontal well completed in the Marcellus Shale in West Virginia was in 2007. Between 2007 and 2014, about 1.9 tcf of gas were produced from horizontal wells completed in the Marcellus Shale, as well as about 11 million bbls of oil and about 2 million bbls of NGL. According to the WVGES, there were 1420 horizontal wells reporting production from the Marcellus Shale, and 1458 vertical wells reporting production from the Marcellus Shale in 2014. There were over 8.3 million bbls of liquids produced (oil and natural gas liquids) and about 852 bcf of gas produced from the Marcellus Shale in 2014, the most recent year that data were available. In 2014, the companies reporting the most gas production from the Marcellus Shale were Antero Resources Corporation, EQT Production, Chesapeake Energy Appalachia, Noble Energy, Inc., Stone Energy Corporation, and CNX Gas/Consol Gas. The companies reporting the most liquids production from the Marcellus Shale in 2014 were Chesapeake Energy Appalachia, LLC, Noble Energy, Inc., Jay-Bee Oil & Gas, Triad Hunter LLC, and Stone Energy Corporation.

In 2014, the counties from which most of the liquids were produced were Marshall, Ohio, Tyler, Brooke, Wetzel, Ritchie, and Doddridge. The counties from which most of the natural gas was produced were Doddridge, Harrison, Wetzel, Marshall, Tyler, Ritchie, Ohio, Taylor, Marion and Barbour. Most of the completed Marcellus Shale wells that are reported as “deviated”, meaning horizontal, are located in Brooke, Marion, Marshall, Wetzel, Ohio, Taylor, Harrison, Doddridge, and Upshur counties. In these counties, the thickness of the Marcellus Shale with high gamma-ray readings is 30 to 100 feet, according to WVGES Marcellus Shale interactive map web page. The depth to the base of the Marcellus Shale ranges from about 4,200 feet in Brooke County to about 7,000 feet in Harrison County.

Visit the following web sites for more information on the Marcellus Shale:

http://www.eia.gov/oil_gas/rpd/shale_gas.pdf

<http://geology.com/articles/marcellus-shale.shtml>

<http://www.wvgs.wvnet.edu/www/datastat/devshales.htm>

<http://www.dep.wv.gov/oil-and-gas/databaseinfo/Pages/default.aspx>

http://www.mgs.md.gov/geology/minerals_energy_resources/marcellus.html

http://www.mgs.md.gov/geology/minerals_energy_resources/natural_gas.html

<http://www.mde.state.md.us/programs/Land/mining/marcellus/Pages/index.aspx>

<http://www.dec.ny.gov/energy/75370.html>
<http://www.dec.ny.gov/energy/36159.html>
<http://www.dec.ny.gov/energy/1603.html>
<http://www.nysm.nysed.gov/nysgs/>
<http://geosurvey.ohiodnr.gov/energy-resources/marcellus-utica-shales>
<http://oilandgas.ohiodnr.gov/>
<http://oilandgas.ohiodnr.gov/shale>
<http://www.dcnr.state.pa.us/topogeo/econresource/oilandgas/marcellus/index.htm>
http://www.portal.state.pa.us/portal/server.pt/community/marcellus_shale/20296
<https://www.paoilandgasreporting.state.pa.us/publicreports/Modules/DataExports/DataExports.aspx>
<http://www.dmme.virginia.gov/DGO/HydraulicFracturing.shtml>
<http://www.dmme.virginia.gov/DGO/pdf/NaturalGasFAQs.pdf>
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NIORARA/CODELL RESOURCE PLAYS IN THE WATTENBERG FIELD, DENVER BASIN, COLORADO (EXCERPT FROM SONNENBERG, IN PRESS)

Stephen A. Sonnenberg (Colorado School of Mines)

The Niobrara Formation and Codell Sandstone are one of nine horizons that are productive in the giant Wattenberg Field area (GWA) of Colorado (Fig. 1). GWA covers approximately 3200 square miles. The field was discovered in 1970 (J Sandstone) and first significant Codell

production from vertical wells was established in 1981 followed by Niobrara production in 1986. Horizontal Niobrara/Codell drilling began in the field in 2009.

Wattenberg straddles the Denver Basin synclinal axis and is regarded as a basin-center petroleum accumulation. The Niobrara/Codell is overpressured and drilling depths are 6200 to 8200 ft. The Wattenberg area is a “hot spot” or positive temperature anomaly. Temperature gradients range from 16 – 18°F/1000 ft on the edges of the field to about 28 to 29°F/1000ft in high GOR areas.

The Niobrara consists of four limestone (chalk) units and three intervening marl intervals. The lower limestone is named the Fort Hays and the overlying units are grouped together as the Smoky Hill member. The chalk units are referred to in descending order as the A, B, C, and Fort Hays. Erosional unconformities exist at the top and base of the Niobrara. The upper unconformity removes the upper chalk bed in some areas of the Wattenberg Field. The B and C chinks are the main focus of horizontal drilling by operators in the field. The underlying Codell Sandstone/Fort Hays is also targeted with horizontal wells. Recent horizontal completions in the Niobrara have initial production of approximately 100 to 700 BOPD with a GOR of 500 to 10,000 cu ft per barrel. Estimated ultimate recovery per well is greater than 300,000 BOE.

The Upper Cretaceous Codell Sandstone is also a major pay in the giant Wattenberg Field of the Denver Basin. The vertical wells have a history of successful hydraulic refracturing. New horizontal wells (2011 to P) with initial production of 100 to 700 BOPD (GOR ~10,000 cf/bbl) indicate substantial remaining reserves in the formation (Fig. 2). The sandstone is very fine to fine grained and bioturbated. Thin (< 1 ft thick) hummocky cross stratified beds are present in the Codell. Depositional environment is interpreted to be a shallow marine shelf setting. Clay content within the pay interval is approximately 20% and consists of 40-45% mixed layer illite-smectite, 30-40% illite, 10-30% chlorite, and up to 7% glauconite. The Codell is a low-resistivity, low-contrast pay.

The Wattenberg area has a resource estimate from the Niobrara/Codell of 3-4 billion barrels equivalent. The combined technologies of horizontal drilling and multistage fracture stimulation have brought significant new life into this 45 year old field.

New horizontal wells are being drilled in the Wattenberg Field in both the Niobrara Formation (B and C chalk intervals) and Codell Sandstone. These wells are being drilled in the same areas where vertical Niobrara and Codell wells were drilled. Operators are suggesting up to sixteen wells can be drilled in sections in a pattern which alternates Niobrara and Codell laterals (Fig. 3). Pilot well studies show very little if any interference between wells. The existing drainage areas in both the Niobrara Formation and Codell Sandstone are very small.

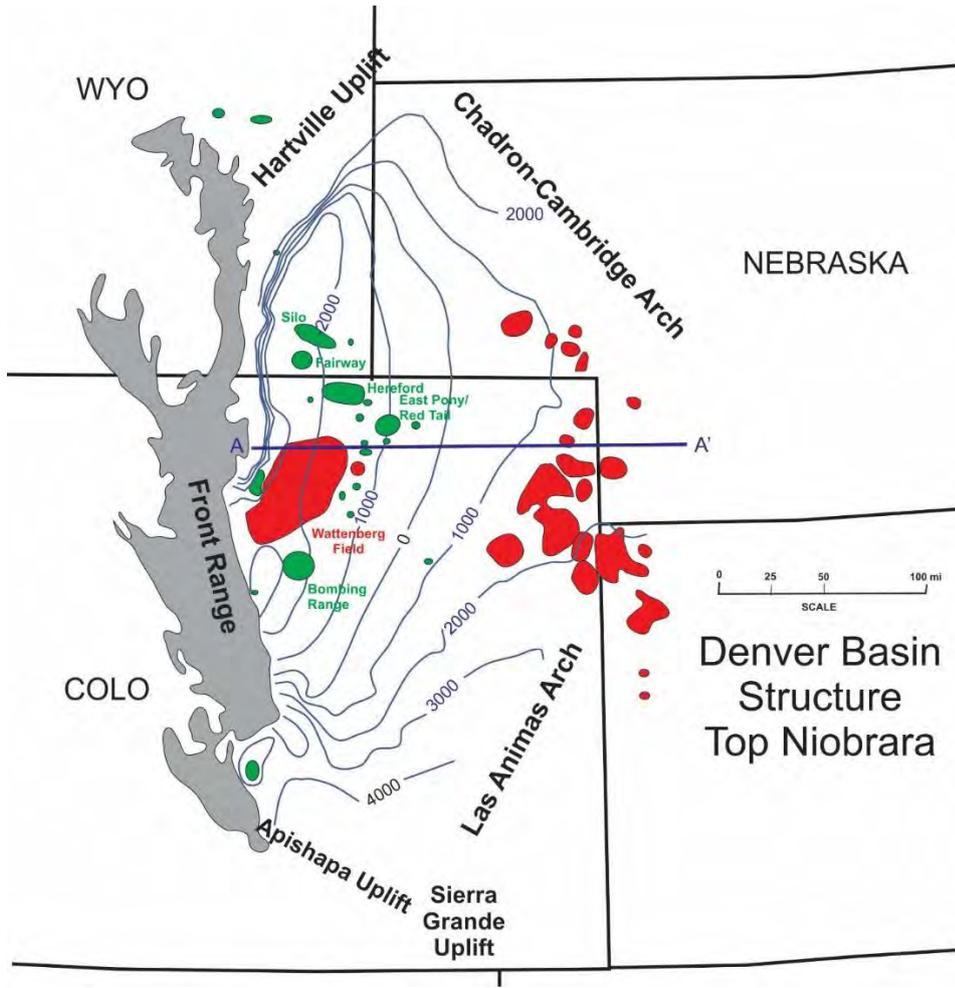


Figure 1: Location of Wattenberg Field.

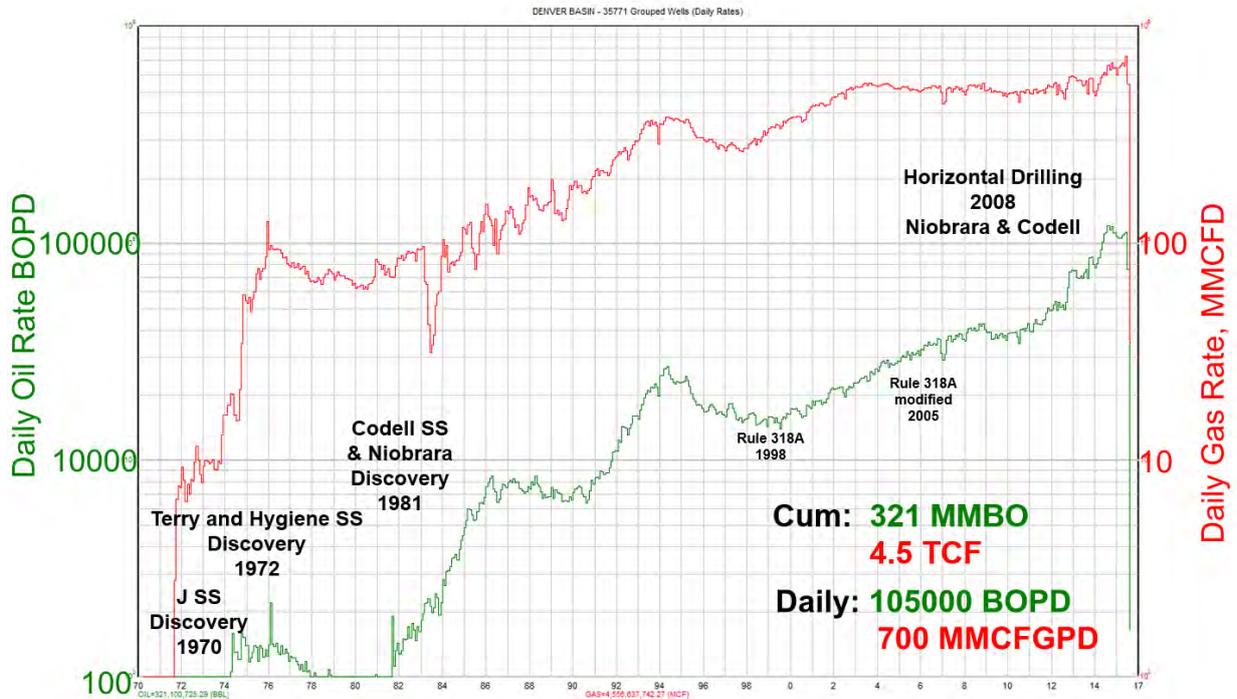


Figure 2. Production curve for Wattenberg Field.

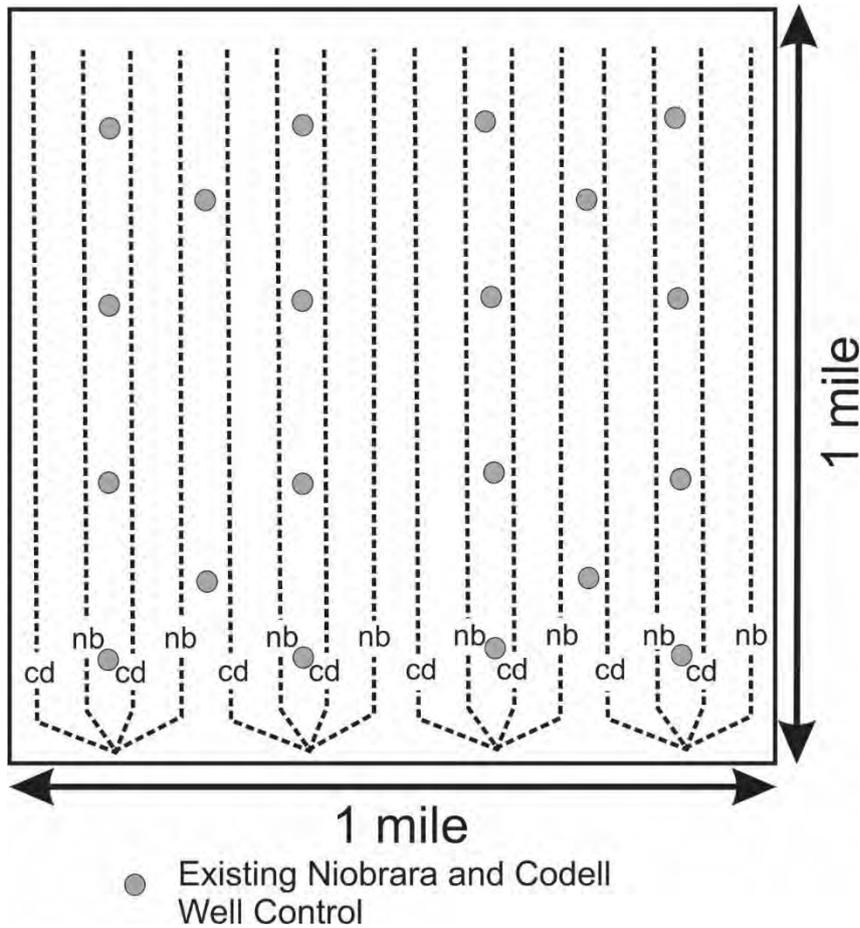


Figure 3. Sketch of drilling and spacing units showing a possible 16 horizontal wells per section with alternating Niobrara and Codell laterals. These horizontal laterals in many cases are drilled in the same sections that were developed with vertical wells using 32 acre spacing (gray dots, subsurface location). The extremely tight nature of the Niobrara and Codell illustrate that drainage areas are very small.

UTAH SHALES

Tom Chidsey, Utah Geological Survey

The tight oil/shale gas activity in Utah has been put to a halt due to current prices. Utah's big play, the Uteland Butte Limestone of the Eocene Green River Formation in the Uinta Basin that requires horizontal drilling but is currently too expensive. Therefore, drilling has been shut down. The Utah Geological Survey (UGS) is wrapping up a major study of the shale-gas potential of the Cretaceous Mancos Shale and set to publish their Paleozoic shale gas study early next year. The UGS continues to work on a tight oil project on the Uteland Butte and Paradox Basin Cane Creek shale.

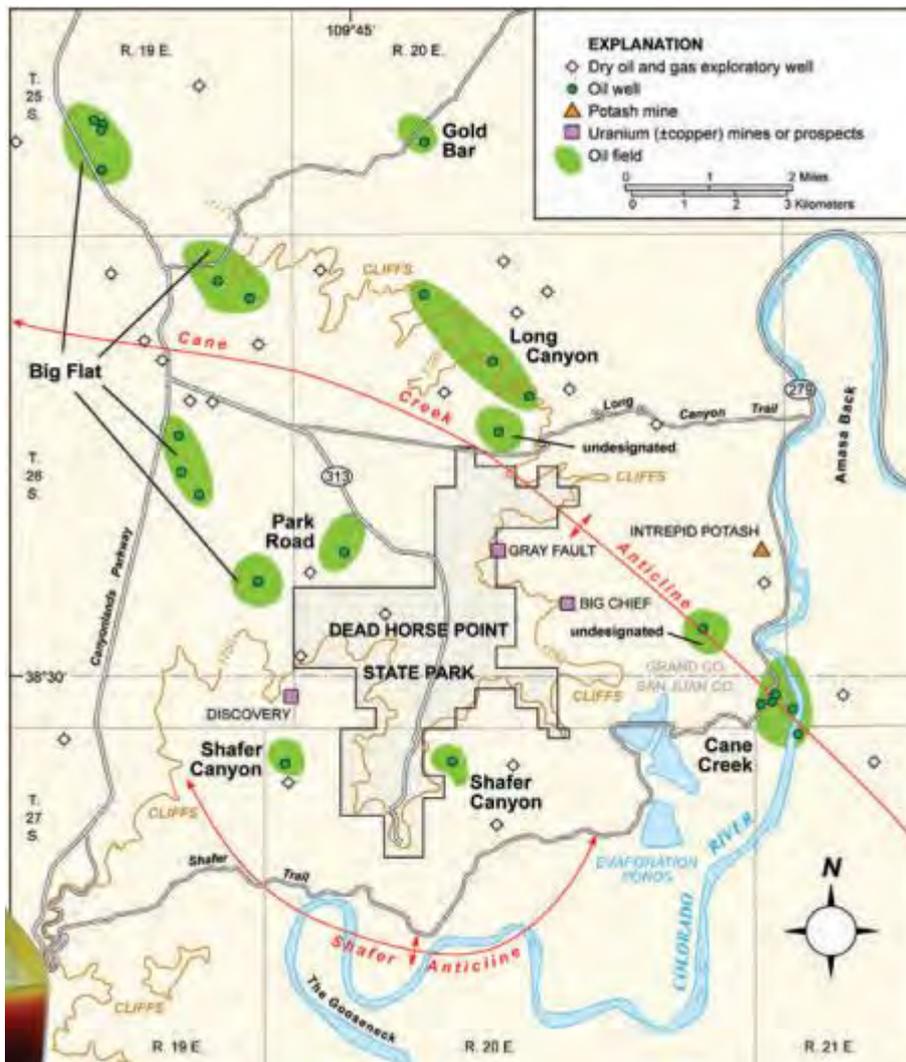


Figure 1: Location of fields producing shale oil from Cane Creek shale in the Dead Horse Point area, Utah.

UTICA SHALE, OHIO, PENNSYLVANIA, WEST VIRGINIA, KENTUCKY

Richard Nyahay, Nyahay Geosciences, LLC, New York

OVERVIEW:

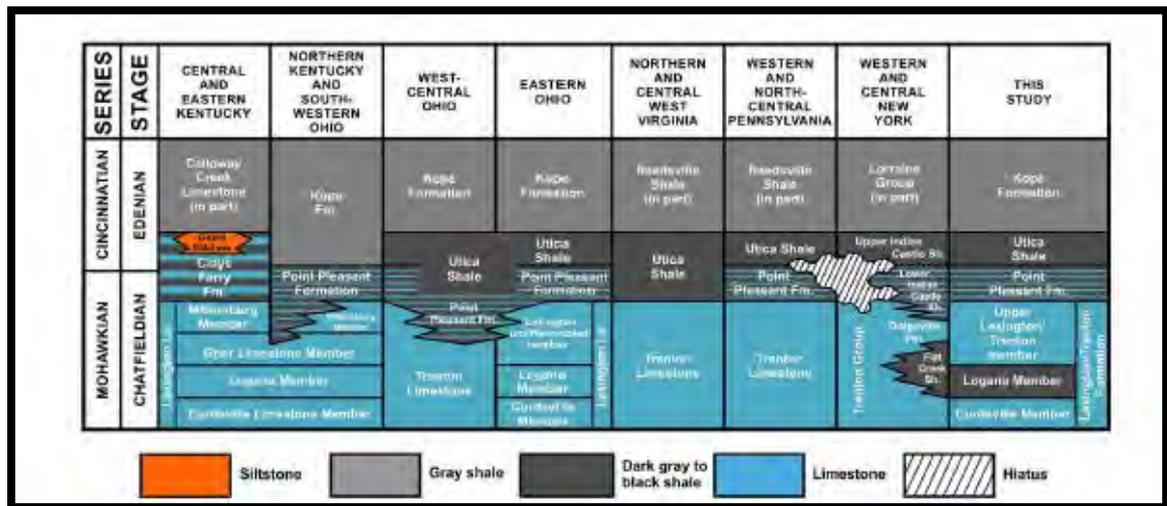
The Ordovician Utica (Indian Castle), Dolgeville, and Flat Creek are the formations of interest. These shales and interbedded limestones range in TOC from 1- 5% in the dry gas window. They cover an area from Mohawk Valley south to the New York State boundary line with Pennsylvania and extend west to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

In Ohio, Pennsylvania, and West Virginia, the Utica is underlain by organic rich Point Pleasant Formation that is in part the lateral equivalent of the upper portion of the Trenton

limestone and is in the gradational relationship with the overlying Utica shale which thickens into the Appalachian Basin. (Wickstom, 2011). The Utica –Point Pleasant interval is up to 300 feet thick in Ohio and over 600 feet thick in southwestern Pennsylvania. The TOC in this interval ranges from 1 to 4 % (Harper, 2011). In Ohio, gas prone areas will be found in the deeper parts of the basin well as appreciable amounts of oil (Ryder, 2008).

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

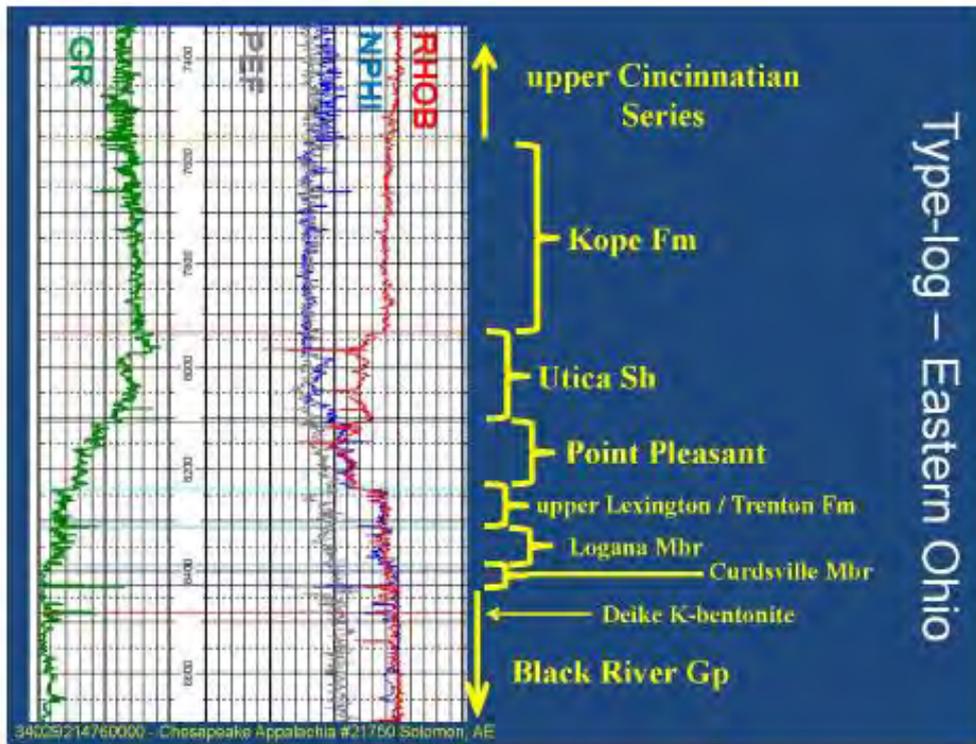
In Michigan, the Utica is underlain by the Collingwood Formation in the northern central part of the state. This formation consist of shales that are black to brown and dark gray in color, with a thickness between 25 to 40 feet and TOC range between 2-8 percent (Snowdon, 1984).



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

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

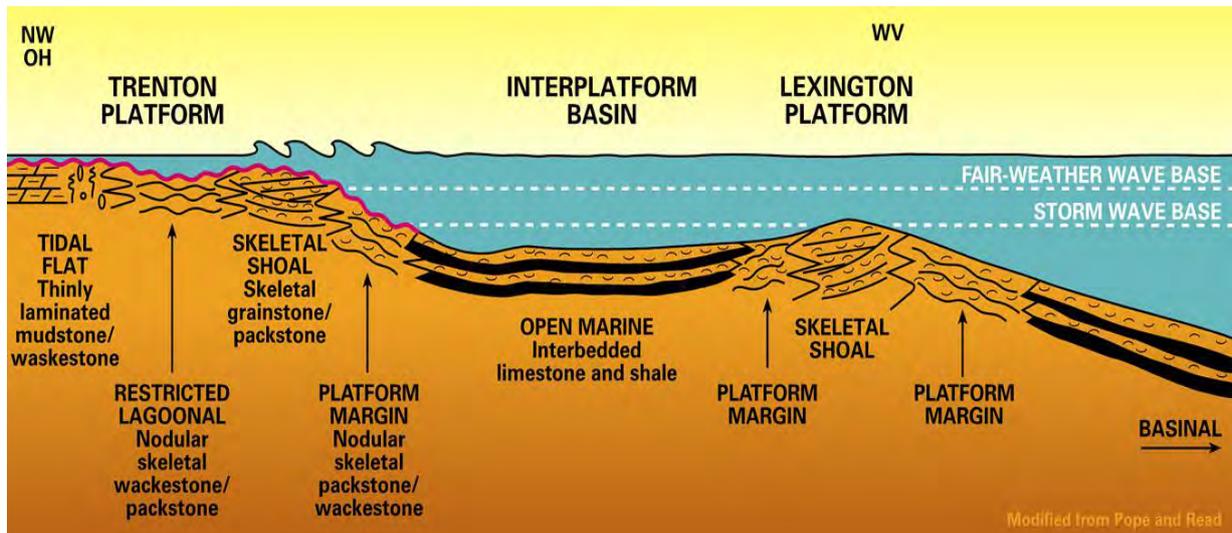
The Kope Formation is an organic poor interbedded gray shale and siltstone. The Utica Formation would be a laminated organic and clay rich shale with thin limestone beds. The Point Pleasant Formation is an interbedded limestone and shale, the upper section would be organic poor, and the lower section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



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

GEOLOGY:

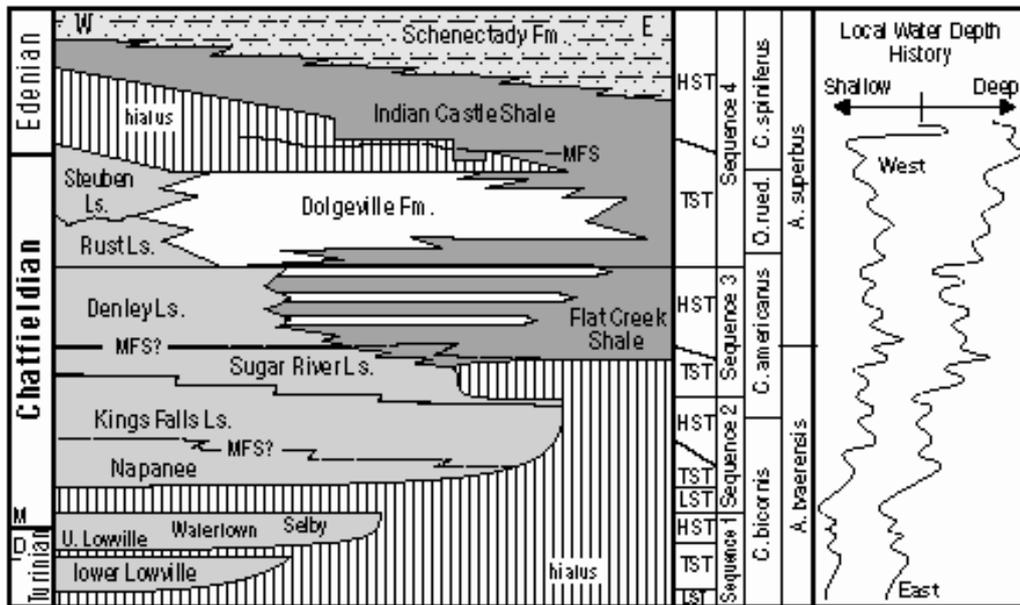
The Late Ordovician Utica shale was deposited in a foreland basin setting adjacent to and on top of, the Trenton and Lexington carbonate platforms. Initial deposition of the Trenton and Lexington platform began on a relatively flat Black River passive margin. Early tectonic activity from the Taconic orogeny created the foreland bulge that would become the Trenton and Lexington platforms. Carbonate growth was able to keep up with the overall rise in seal level while areas stayed relatively deeper until increased subsidence in the foreland basin lowered the ramps out of the photic zone and inundated the passive margin with fine grained clastics (Willan et al. 2012).



(Riley & Baranowski, 2011)

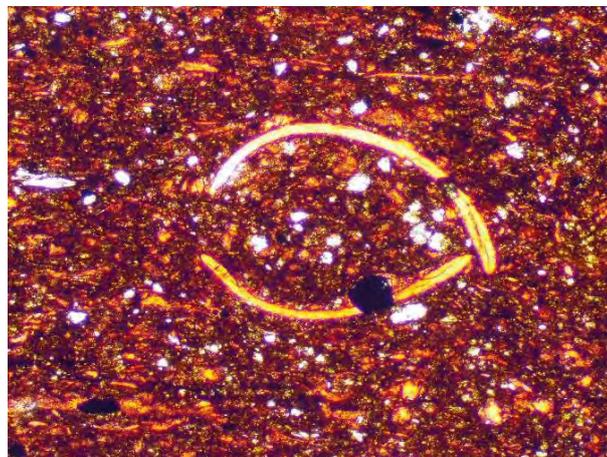
The Trenton/Lexington limestone through the Utica Shale comprise the transgressive systems tract (TST) of a large second-order sequence, superimposed with four, smaller scale third-order composite sequences. Third order sequences are regional correlative, aggradational,

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



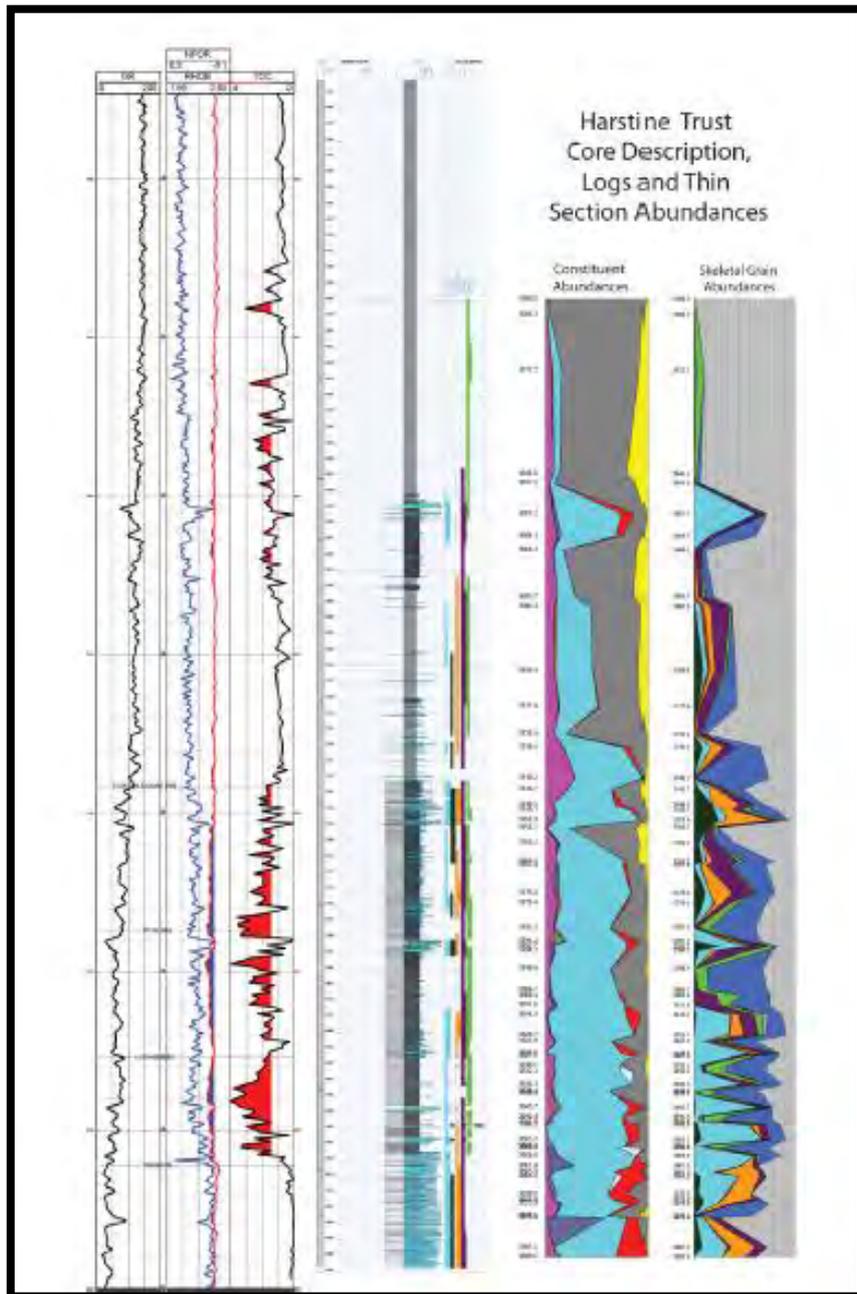
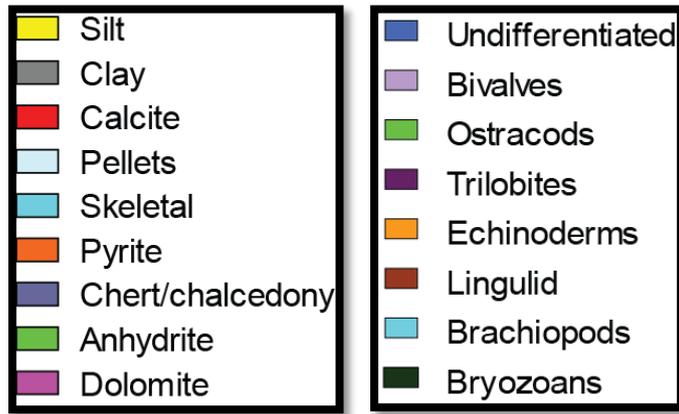
(Joy et al. 2000)

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



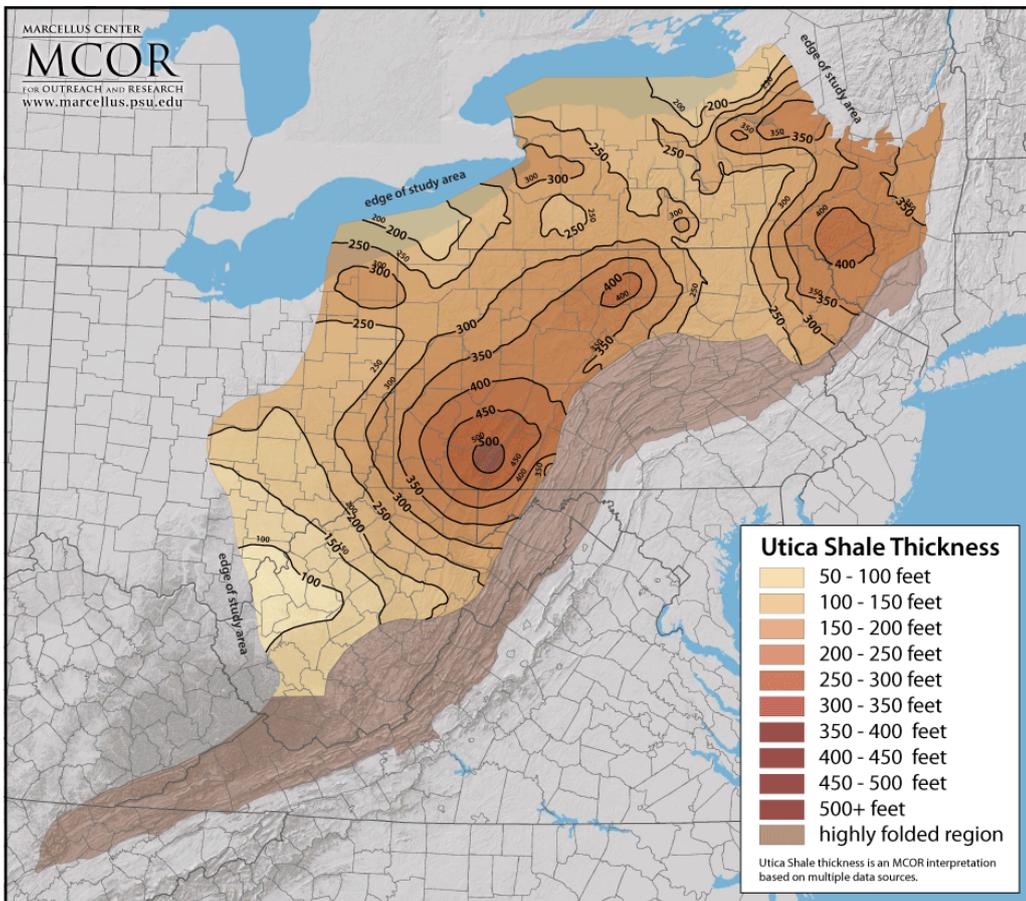
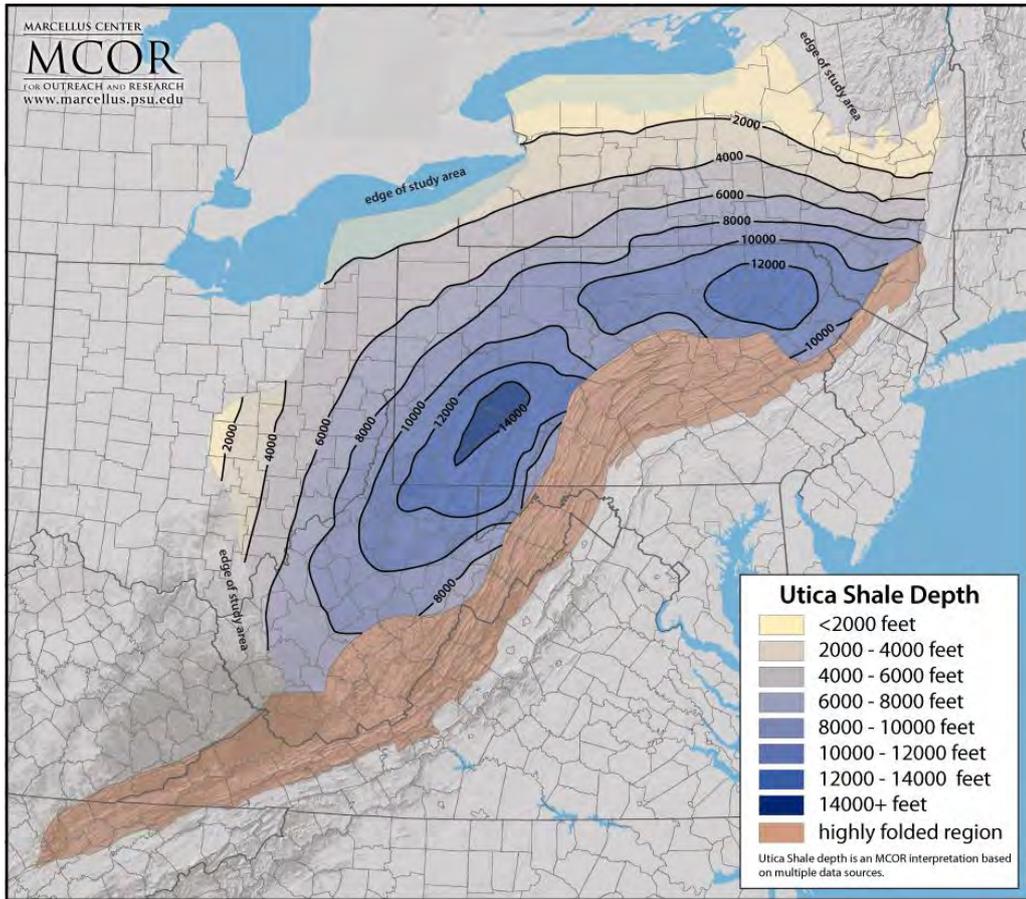
(Smith, 2015a)

An ostracod in organic rich Logana member of the Lexington Formation.



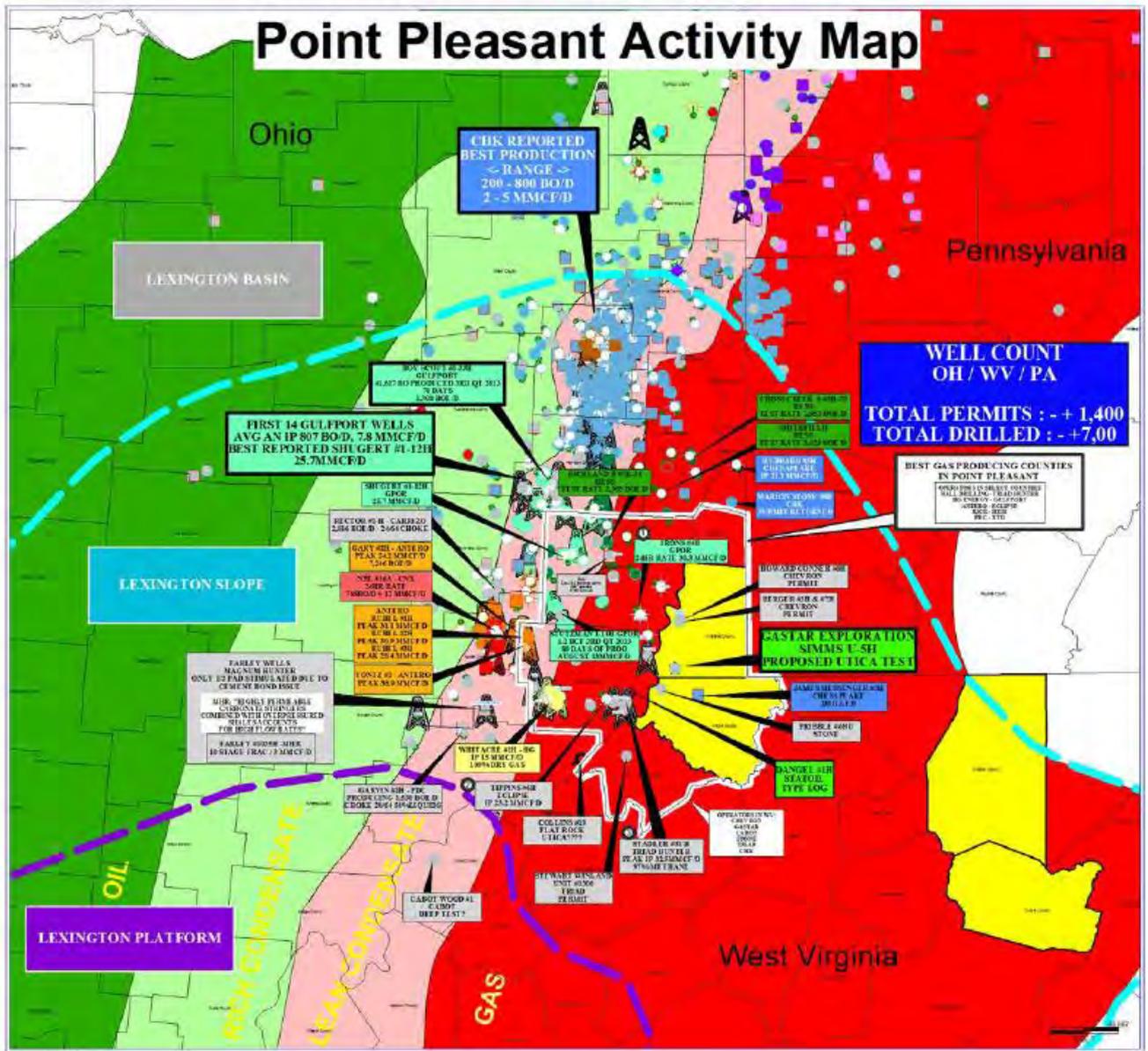
(Smith, 2015a)

One of the five Devon Cores studied in Ohio



General Maps of the Utica not subdivided

Well Activity:

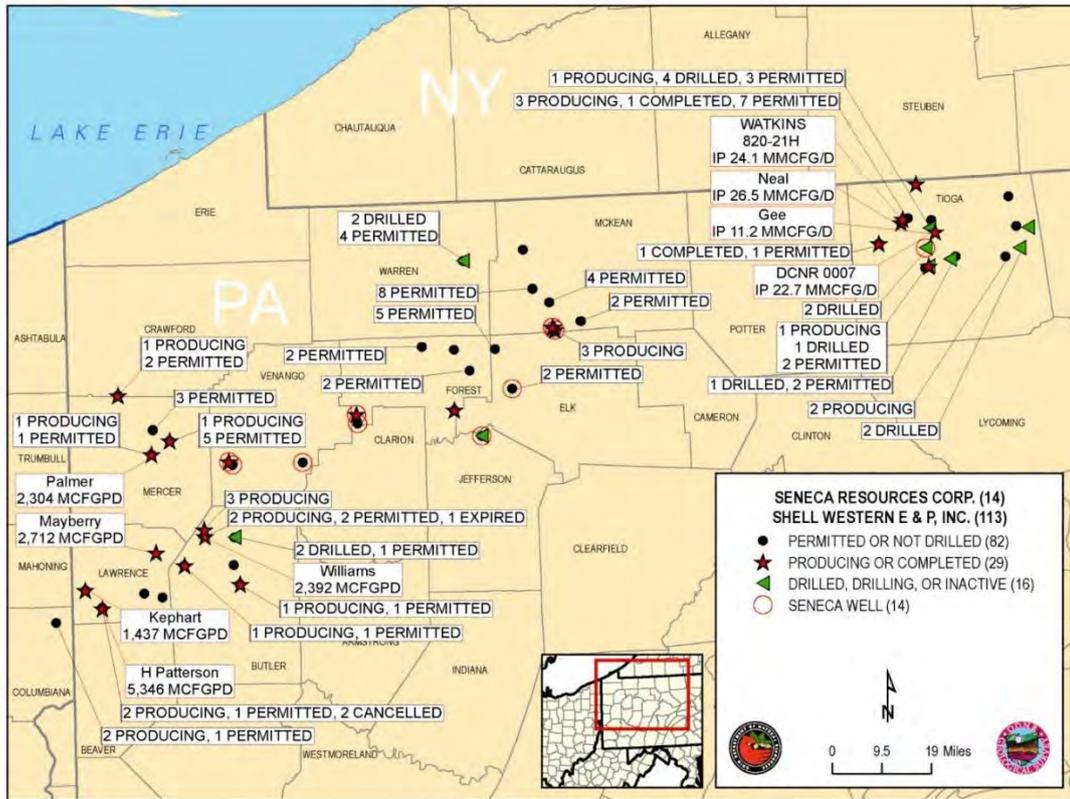


(Gastar Exploration Inc, 2014)

With the current regulatory moratorium in place in New York, activity has been focused in eastern Ohio, western Pennsylvania and western West Virginia. No drilling has been done in Kentucky to date. Ohio current drilling activity as of October 10, 2015 lists 2041 Utica permits, 1608 wells drilled and 1017 producing wells (ODNR, 2015). Exploration activity has been concentrated in a triangle area of southeastern Ohio, the northern pan handle of West Virginia and southwestern Pennsylvania. The map above highlights the area of the best producing Point Pleasant wells. The thermal maturity windows are delineated from the gas to lean then rich condensate and finally the oil window.

Most of the activity has taken place in Eastern Ohio. Chesapeake Energy is the operator who has the majority of permits. Shell Appalachia has concentrated their efforts in the dry gas area in Pennsylvania from Lawrence County eastward to Tioga County and has permitted 75 Utica/Point Pleasant horizontal wells. Of these, 18 are reported as completed, two are drilled or drilling, and 55 are not drilled. There are no annual production data available for these wells.

Pennsylvania Activity



(Riley and Fakhari, 2015)

Ohio Production Data	Utica-Point Pleasant Production			Total Production		
	Oil (Barrels)	Gas (Mcf)	No. of Wells	Oil (Barrels)	Gas (Mcf)	No. of Wells
2011	46,326 (1%)	2,561,524 (3.5%)	9	4,853,000	73,290,000	50,192
2012	635,874 (13%)	12,831,292 (15%)	87	4,974,000	86,770,000	~50,000
2013	3,643,141 (45.5%)	99,532,124 (59.4%)	36	8,006,000	167,293,000	~50,000
2014	10,847,211 (70%)	445,466,231 (85%)	78	15,300,000	518,000,000	~50,000
2015 (1 st Qtr)	4,401,687	183,585,256	87			
Cumulative Production	19,574,239	743,976,427	87			

(Riley and Fakhari, 2015)

The table below lists some of the major companies and their net acreage in the Utica in 2014.

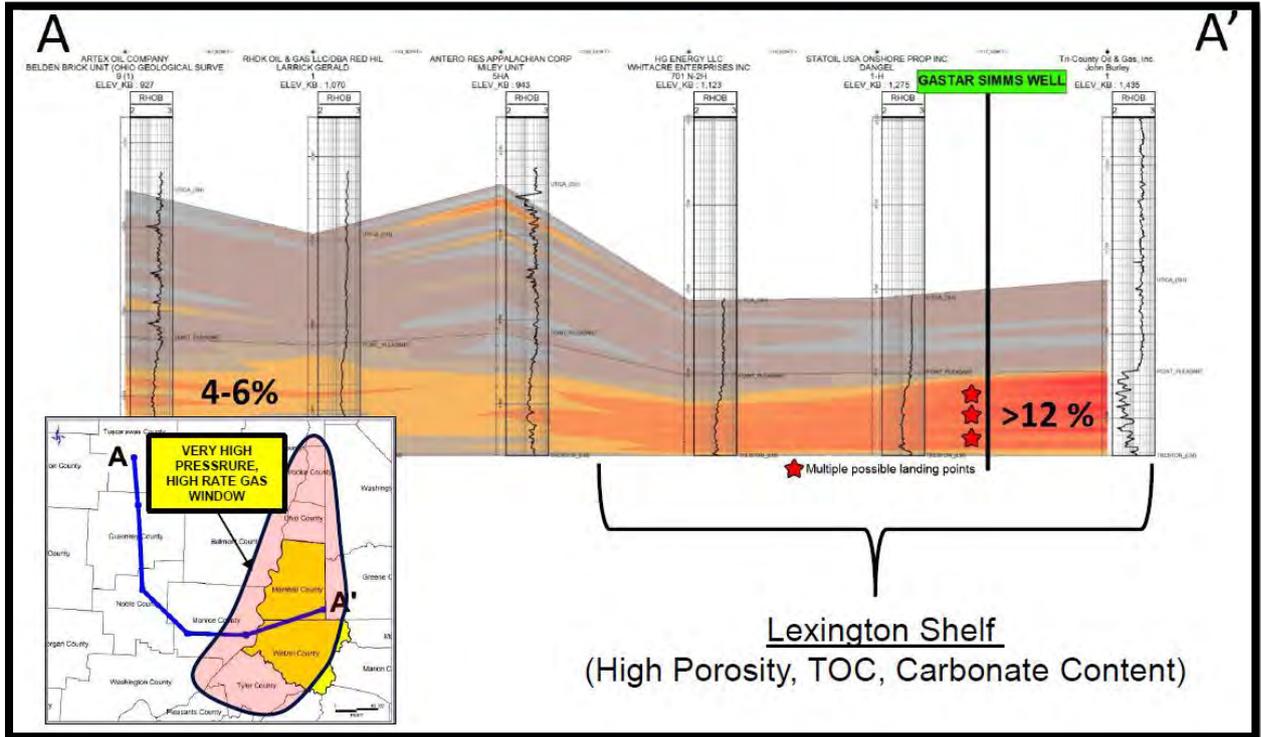
Company	Ticker	Net Acres
Chesapeake Energy	CHK	1,000,000
Chevron	CVX	600,000
Anadarko Petroleum	APC	267,000
Devon Energy	DVN	195,000
Range Resources	RRC	190,000
Hess Corporation	HES	185,000
EV Energy	EVEP	177,000
Gulfport Energy	GPOR	147,350
Halcon Resources	HK	142,000
Antero Resources	AR	104,000
Magnum Hunter	MHR	99,000
BP	BP	84,000
Consol Energy	CNX	80,000
ExxonMobil	XOM	75,000
PDC Energy	PDCE	48,000
Carrizo Oil & Gas	CRZO	21,700
Rex Energy	REXX	21,000
EQT Resources	EQT	13,600

(Magnum Hunter Resources, 2014)

Best Well Attributes:

From the cross section and table below, the Range Resources Claysville Sportman's Club 1 1H comes in at the highest IP rate thus far in the dry gas window of the Utica/Point Pleasant play. If you inspect the cross-section below closely it shows the density logs decreasing as wells trend to the east in the Point Pleasant sweet spot. With decreasing density logs, the TOC content increases. From the table below lateral length ranges from 3605 to 8235 feet though increasing IP is not correlating with increasing lateral length. With TOC greater than 12 % in some of these wells, production must be related to TOC. From Gastar type log (Dangle 1H) in Monroe County, Ohio, the lower density log values correlates to increasing TOC.

Cross-section of wells with very high pressure and high gas rates.



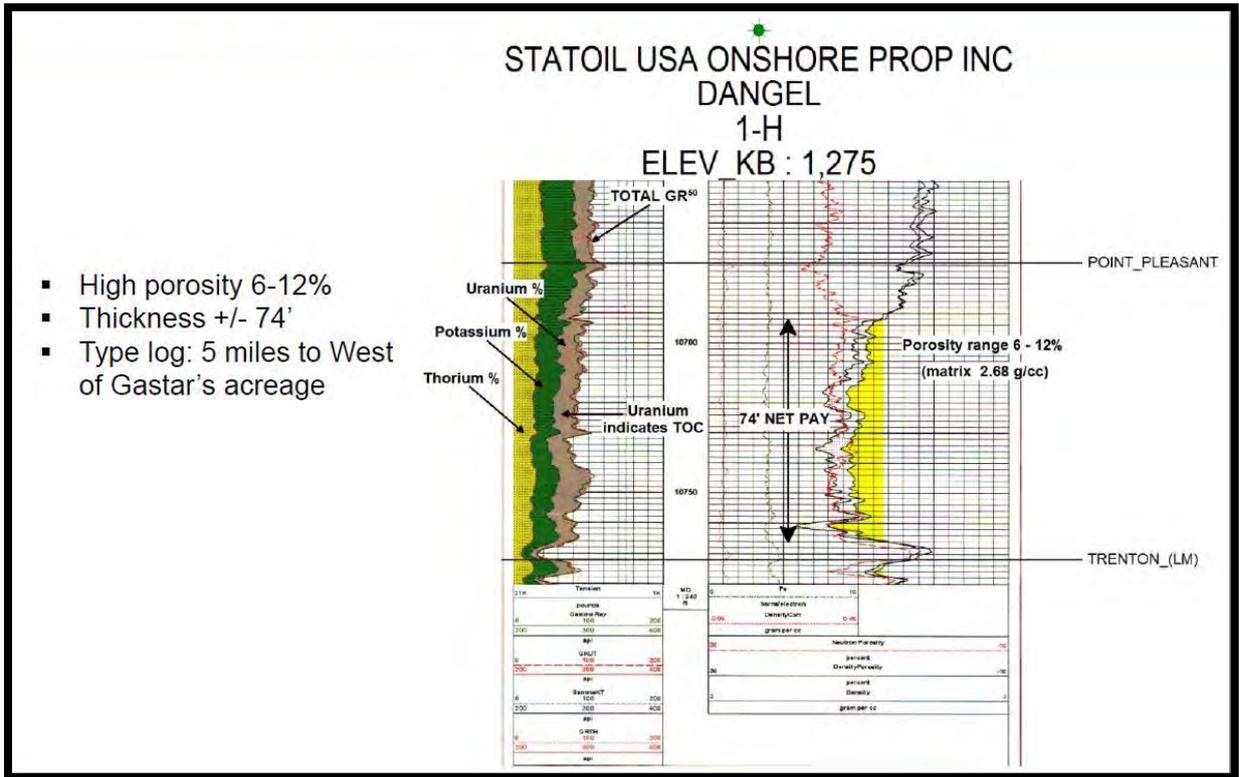
(Gastar Exploration Inc., 2014)

Top Tier Utica Point Pleasant Wells – PA, OH, WV

Well	Operator	State	County	IP (Mmcf/d)	Lateral Length (Ft)	IP/1000' LL
Claysville Sportsman's Club 11H	Range Resources	PA	Washington	59.0	5420	10.9
Stewart Winland Unit 1300U	Magnum Hunter	WV	Tyler	46.5	5289	8.8
Bigfoot 9H	Rice	OH	Belmont	41.7	6957	6.0
Stadler Unit A 3UH	Magnum Hunter	OH	Monroe	32.5	5050	6.4
Irons 1-4H	Gulfport	OH	Belmont	30.3	6630	4.6
Shroyer 2H	Eclipse	OH	Monroe	30.1	8235	3.7
Pribble 6HU	Stone	WV	Wetzel	30.0	3605	8.3
Simms 5H	Gastar	WV	Marshall	29.4	4447	6.6
Conner 6H	Chevron	WV	Marshall	25.0	6451	3.9
Shroyer 4H	Eclipse	OH	Monroe	23.7	6608	3.6
Tippens 6H	Eclipse	OH	Monroe	23.2	5858	4.0
Porterfield 1H-17	Hess	OH	Belmont	17.2	5154	3.3
Hubbard BRK 3H	Chesapeake	WV	Brooke	14.7	3550	4.1

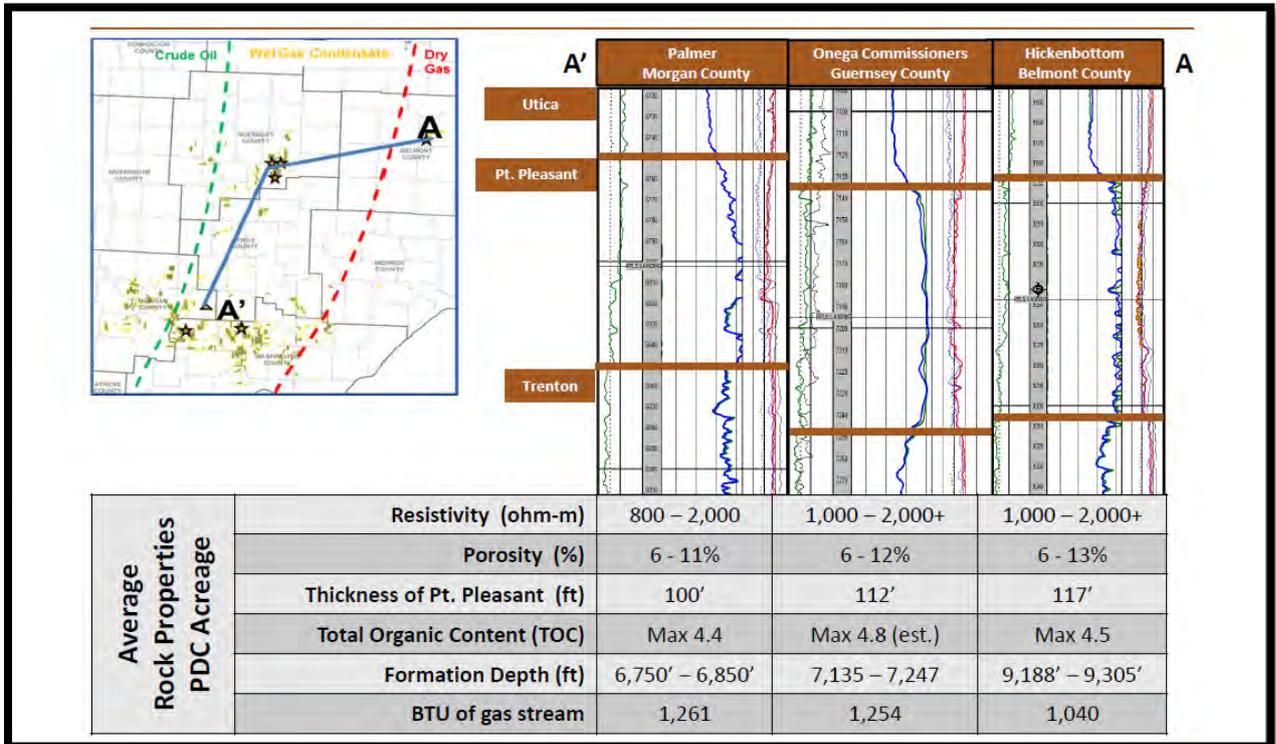
(Range Resource, 2015)

Gastar's Exploration type log in Monroe County, Ohio for the Simm's Well in West Virginia.



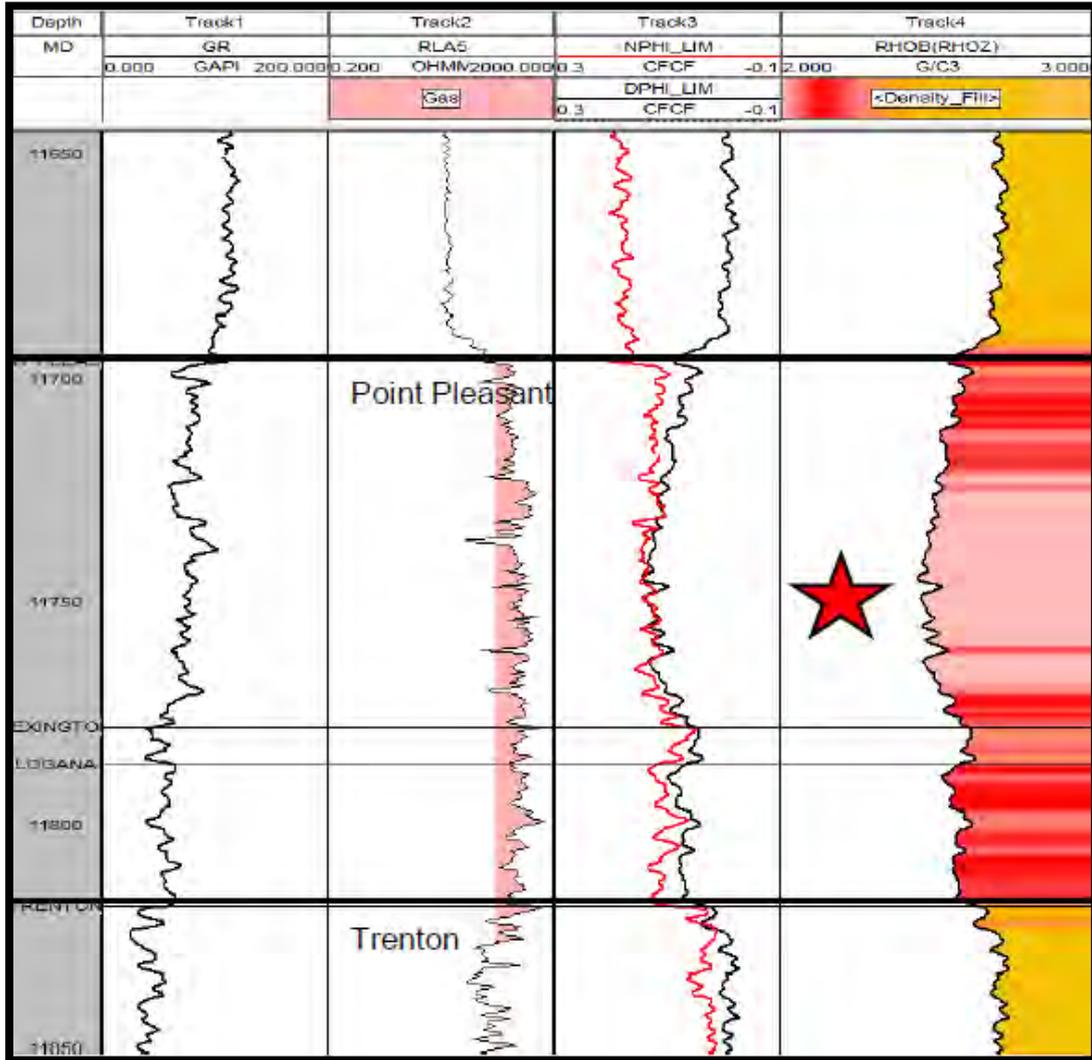
(Gastar Exploration Inc, 2014)

All logs in the highlighted southeastern Ohio, PA and West Virginia area all show increasing resistivity and decreasing density which correlates to higher TOC values and increasing porosity.



(PDC Energy, 2014)

Log from Range Resources in Washington County, PA with an IP of 59 mmcf/d with 32 stage 5420 feet lateral completion



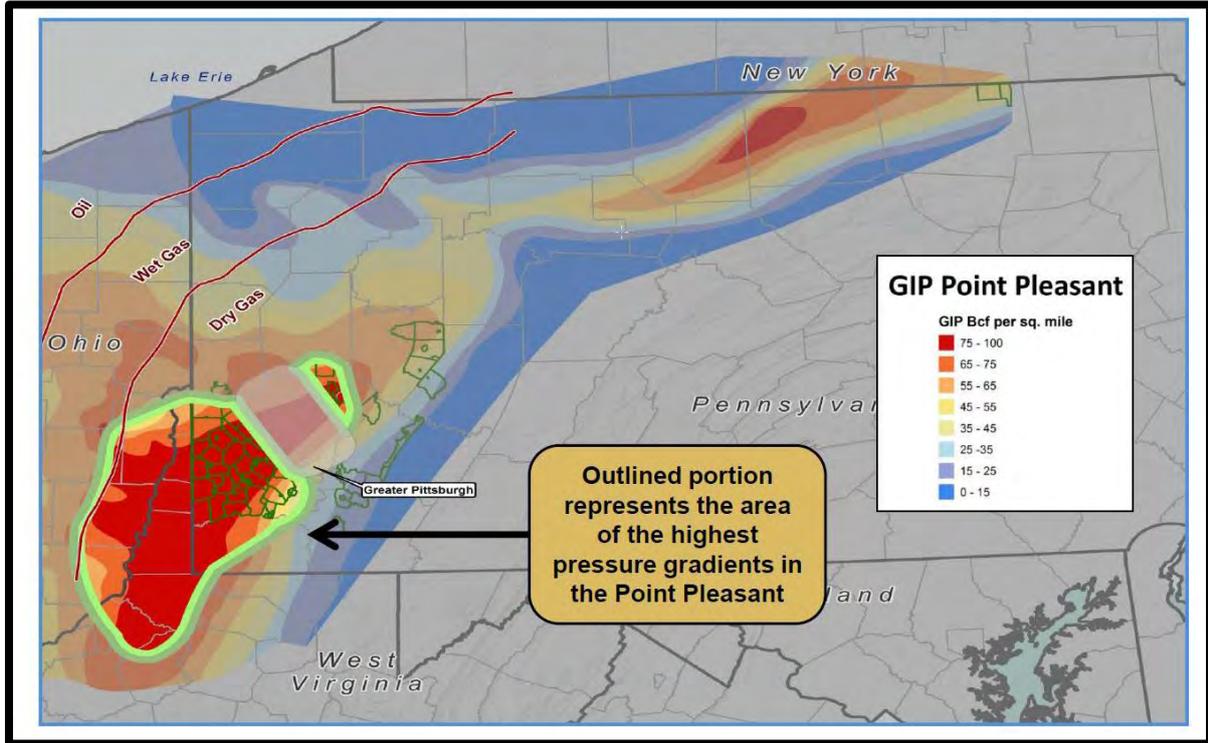
(Range Resources, 2015)

Most of the gas in place is in free gas, according to Range Resources 20% to 40 % more than best areas in eastern Ohio.

GAS IN PLACE ANALYSIS: Claysville Sportsman 11H					
		Bulk Density (g/cc)	Gas Content (scf/ton)	GIP (scf/acre-ft)	GIP (BCF/section)
Utica to Trenton	Free Gas	2.64	240.4	863,811	140.9
	Sorbed Gas		23.5	84,488	13.8
	Total Gas in Place		263.9	948,299	154.7
GAS IN PLACE ANALYSIS: Claysville Sportsman 11H					
		Bulk Density (g/cc)	Gas Content (scf/ton)	GIP (scf/acre-ft)	GIP (BCF/section)
Utica	Free Gas	2.73	148.2	549,663	46.3
	Sorbed Gas		9.9	36,534	3.1
	Total Gas in Place		158.1	586,197	49.3
GAS IN PLACE ANALYSIS: Claysville Sportsman 11H					
		Bulk Density (g/cc)	Gas Content (scf/ton)	GIP (scf/acre-ft)	GIP (BCF/section)
Point Pleasant	Free Gas	2.56	338.5	1,177,676	93.0
	Sorbed Gas		38.1	132,404	10.5
	Total Gas in Place		376.5	1,310,080	103.5

(Range Resources, 2015)

With high gas in place values, Range Resources is also reporting highest pressure gradients along South East Ohio, the pan handle of West Virginia and south western Pennsylvania.



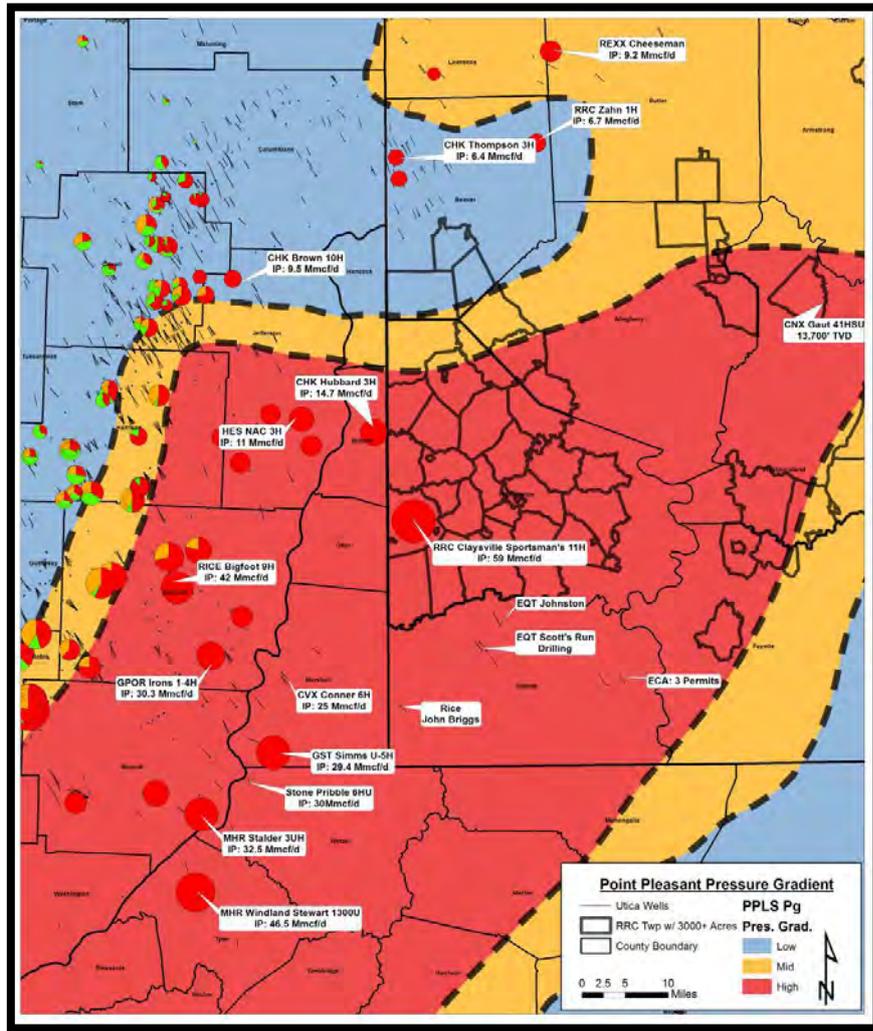
(Range Resources, 2015)

Table of Pressure Gradients for States

State	Pressure Gradient (psi/ft)		Note(s)
	Low	High	
New York (NY)	0.433	0.5	0.433 for most of NY; 0.5 for very small portion of southern NY
Ohio (OH)	0.6	0.9	0.6 for most of OH; 0.7-0.9 for narrow region in east central OH
Pennsylvania (PA)	0.6	0.9	0.6 for most of PA; 0.7 in small portion of central PA; 0.7-0.9 in southwestern PA
West Virginia (WV)	0.6	0.9	0.6 for most of WV; 0.7-0.9 for northern WV panhandle

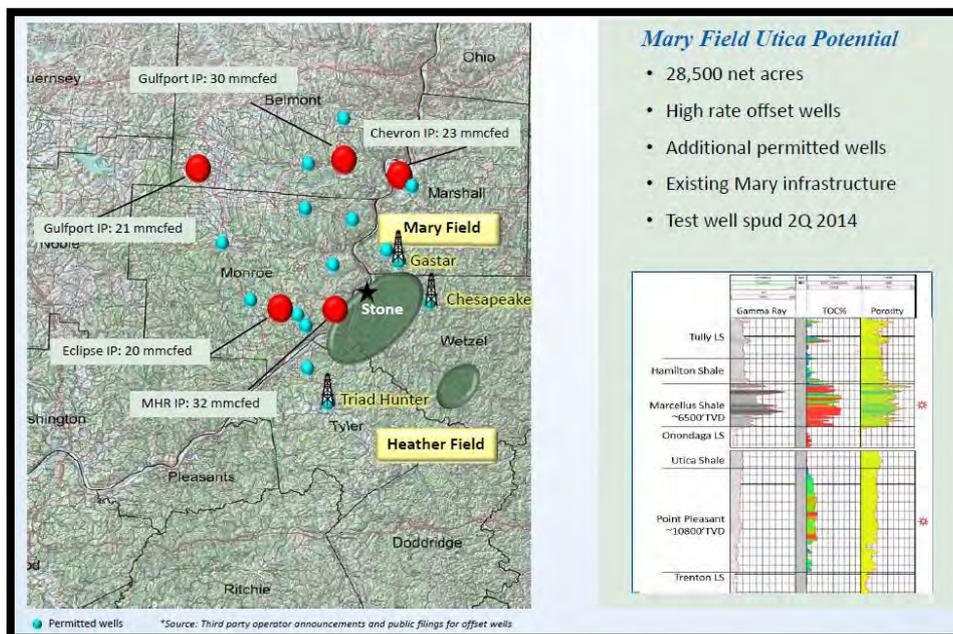
(Patchen, D.G. and Carter, K.M., 2015)

Below is a graphic from a Range Resources presentation delineating pressure gradients found in the area with high volume wells.



(Range Resources, 2015)

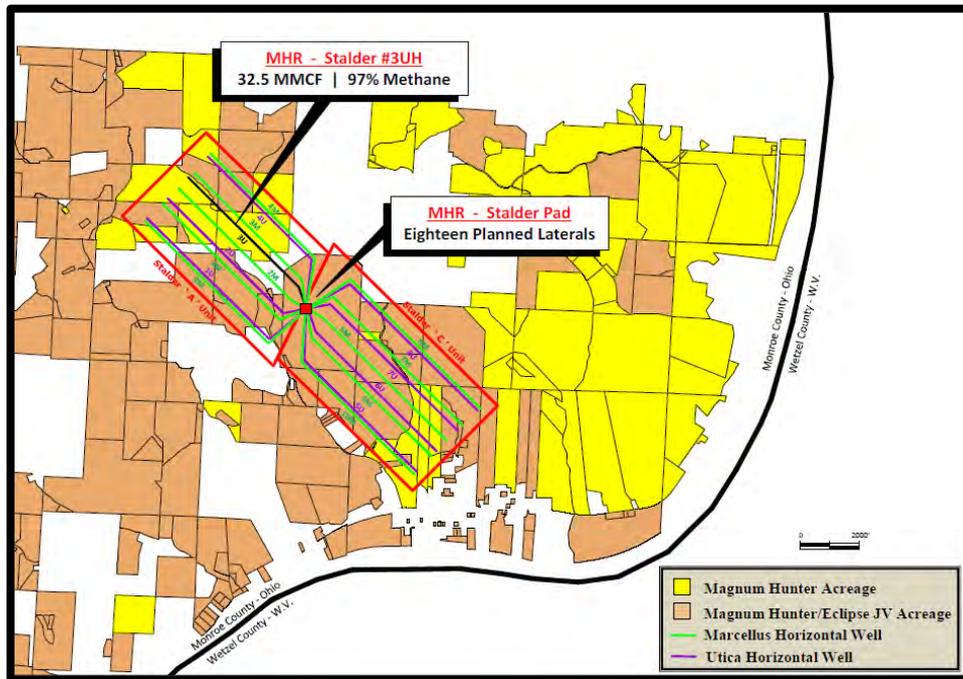
Stone Energy also had a successful test in Wetzel County, WV extending the high IP and pressure gradient area and possibly looking to extend the area further to the southeast.



(Stone Energy, 2014)

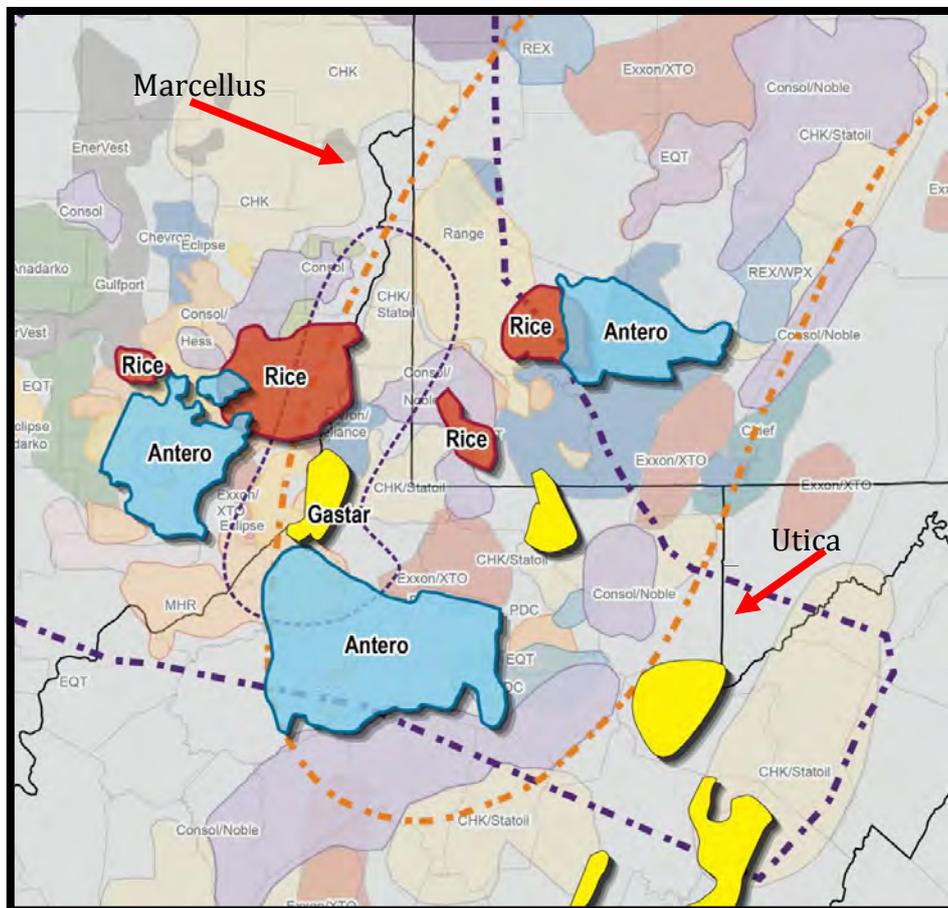
Stackable Reservoirs:

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



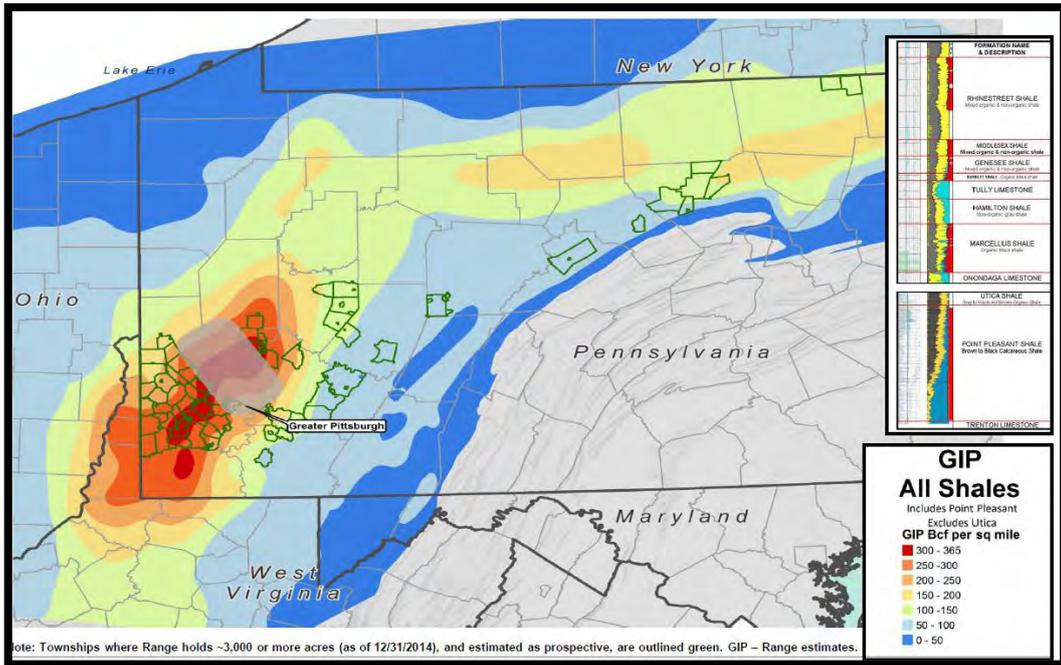
(Magnum Hunter Resources Inc., 2014)

Companies with acreage in stackable play area.

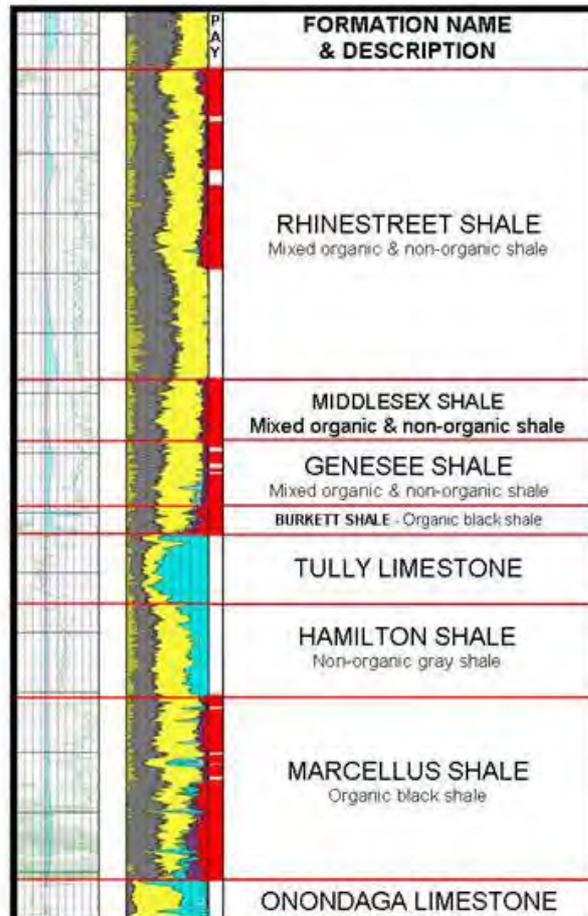


(Gstar Exploration Inc., 2014)

Gas in place estimates for stackable plays from Range Resources.

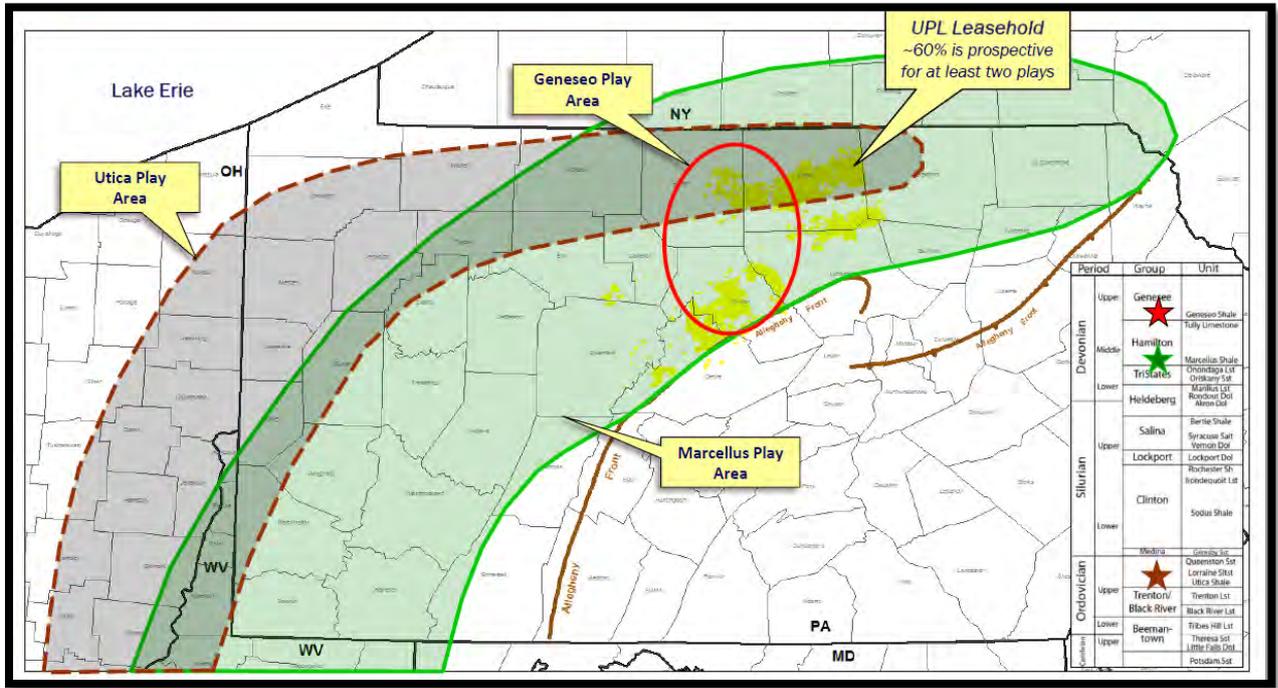


(Range Resources, 2015)



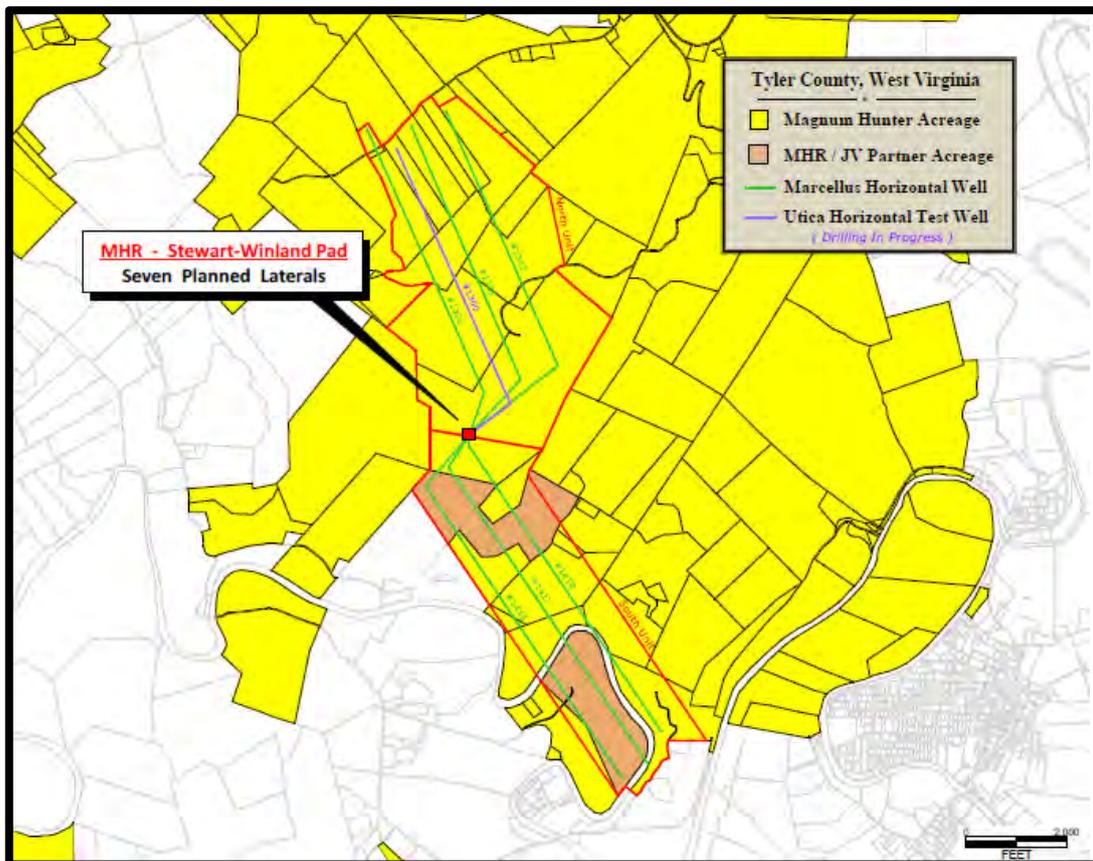
(Range Resources, 2015)

*Stratigraphic Section and Log responses formations targeted.
The figure below indicates where the Genesee play area might be located.*



(Ultra Petroleum Corp., 2014)

In Tyler County, WV Magnum Hunter Resources had successful tests in the Marcellus and Utica to extend the stackable reservoirs further south and east.



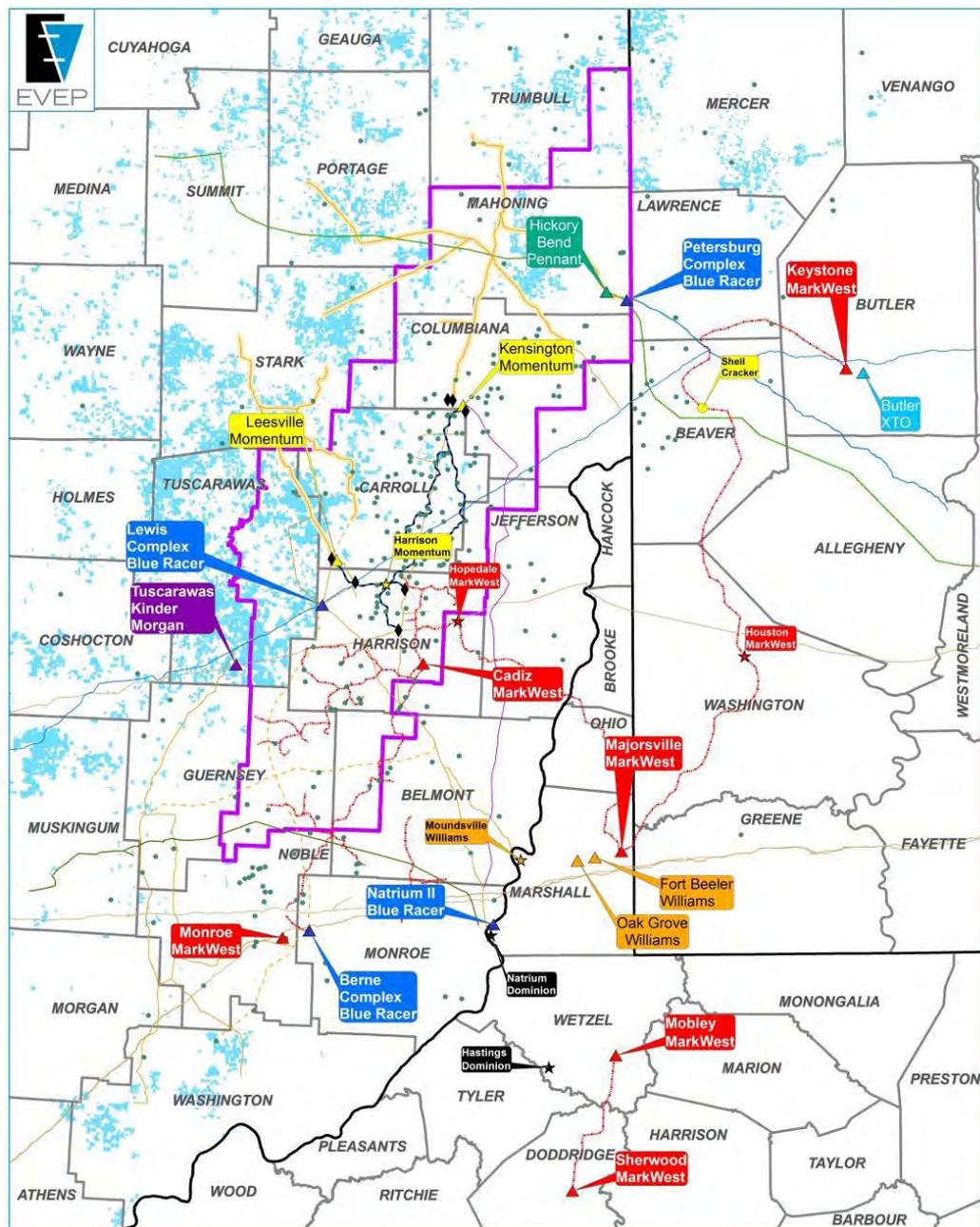
(Magnum Hunter Resources Inc., 2014)

Infrastructure:

Earlier expectations have been dampened by larger companies selling large acreage parcels, pipeline infrastructure not in place, and construction of gas processing units. This concern may be changing because at the current activity has doubled the number of producing wells again from the latest 3rd quarter production reports of 2013. Three cryogenic natural gas plants have been added in Columbia, Harrison, and Noble counties to separate and purify natural gas. (Downing, 2013).

Kinder Morgan Energy Partners LP and Mark West Energy Partners LP are planning a Utica-Marcellus Pipeline to Texas. This project has a target date of second quarter 2016. Spectra Energy Corp is also planning a Utica to Gulf Coast pipeline to operational by November 2015 (Knox, 2014).

From the figure below it seems that this pipeline bottleneck is starting to disappear with increasing infrastructure and processing units being built.

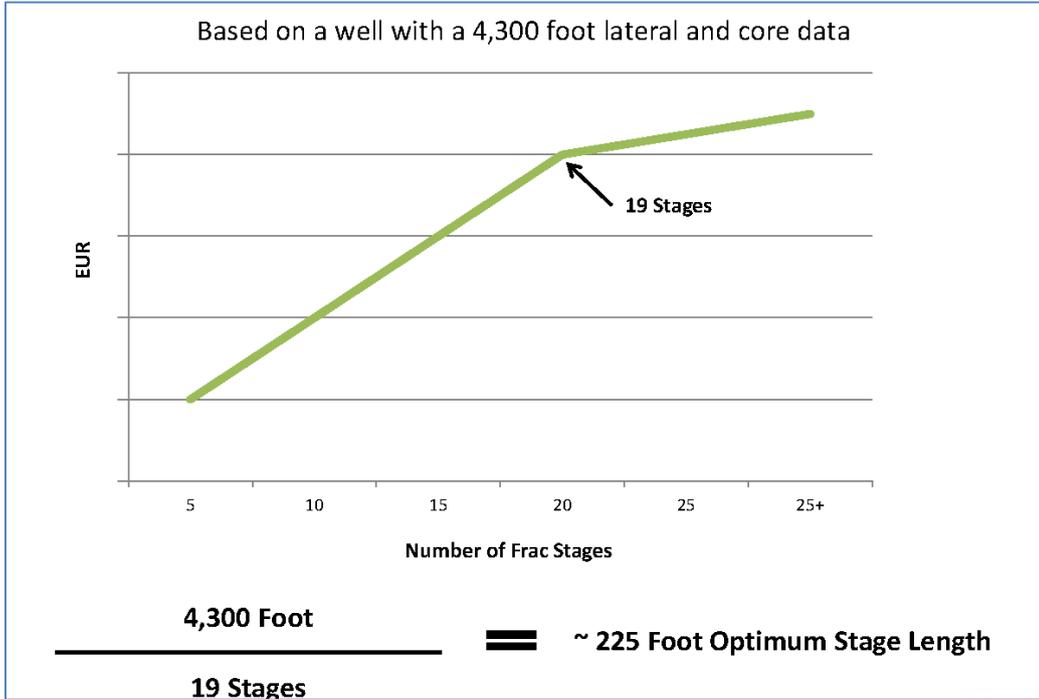


(ODNR, 2015)

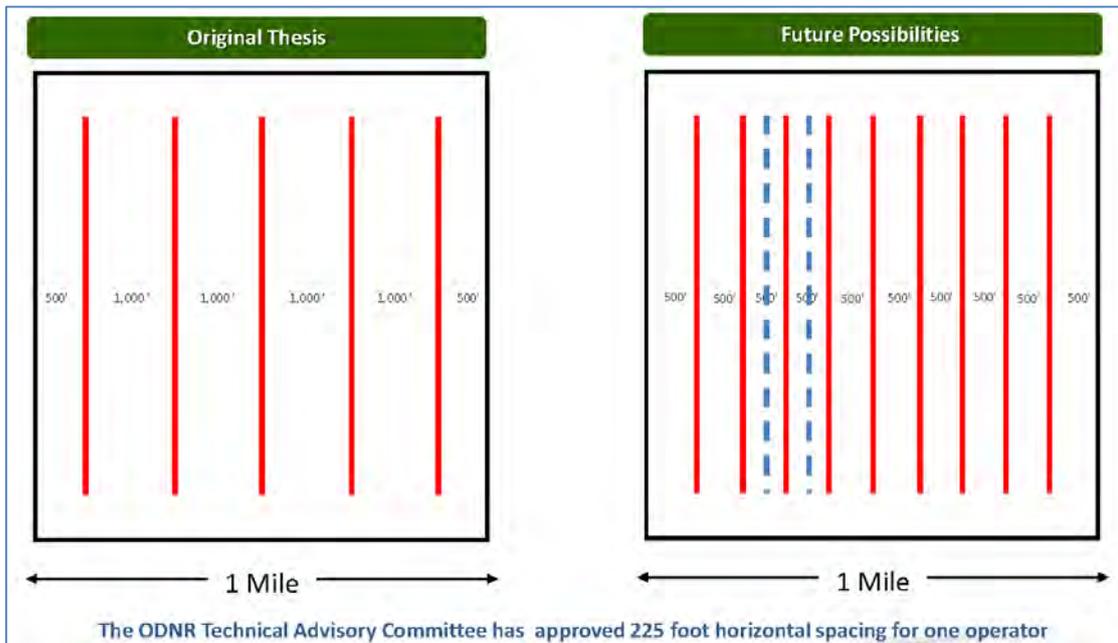
Completion Techniques:

Average well cost range from 8 to 14 million dollars per well. The basic completion concept is to drill with long laterals, have short stages, and shut in the well for a determined resting period.

A new technique used to test the possible productivity of a new well is to set a permanent plug isolating the final stage or the stage closest to the well head while letting the other stages rest, usually three or more months (EID, 10/10/2012). Gulfport Energy found a 225 foot optimum stage length and is now thinking about 250 ft between laterals.

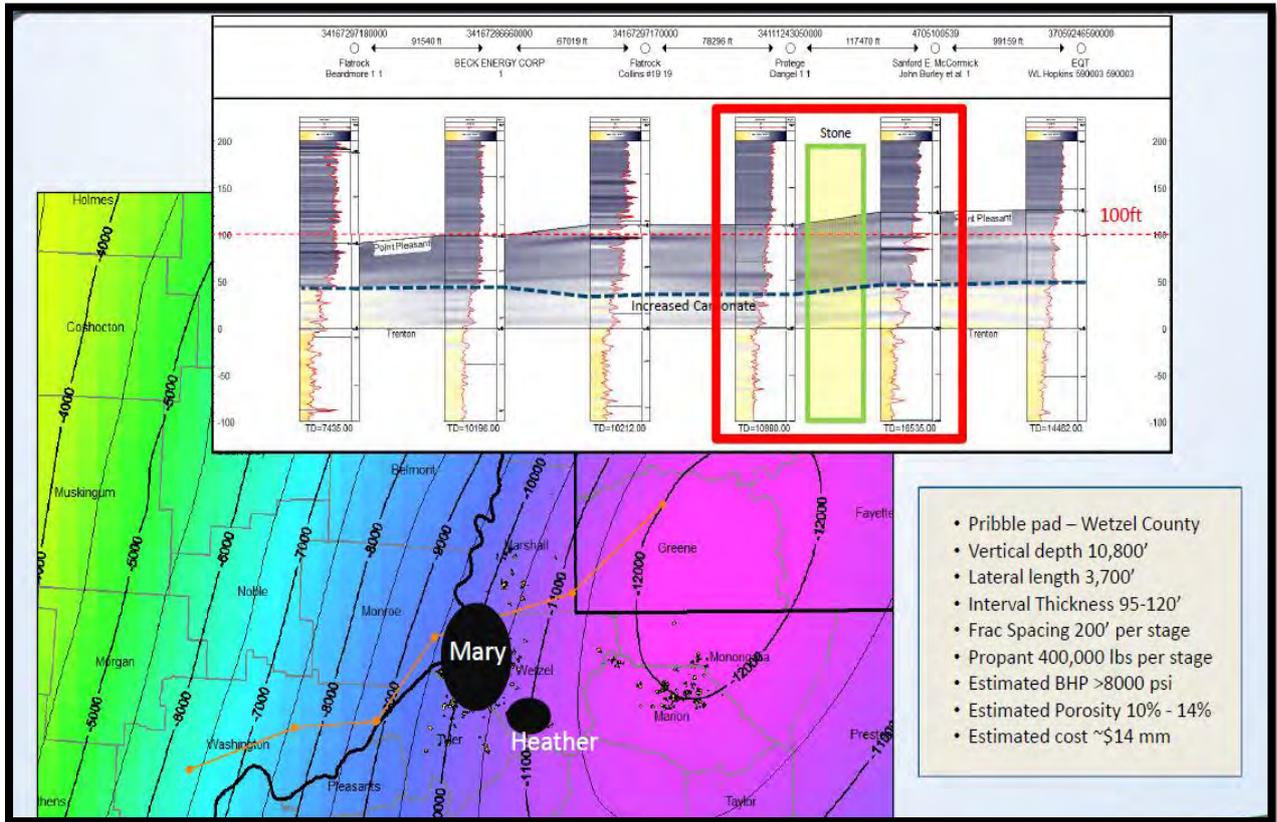


(Gulfport Energy Inc DUG East 11-14-2012)



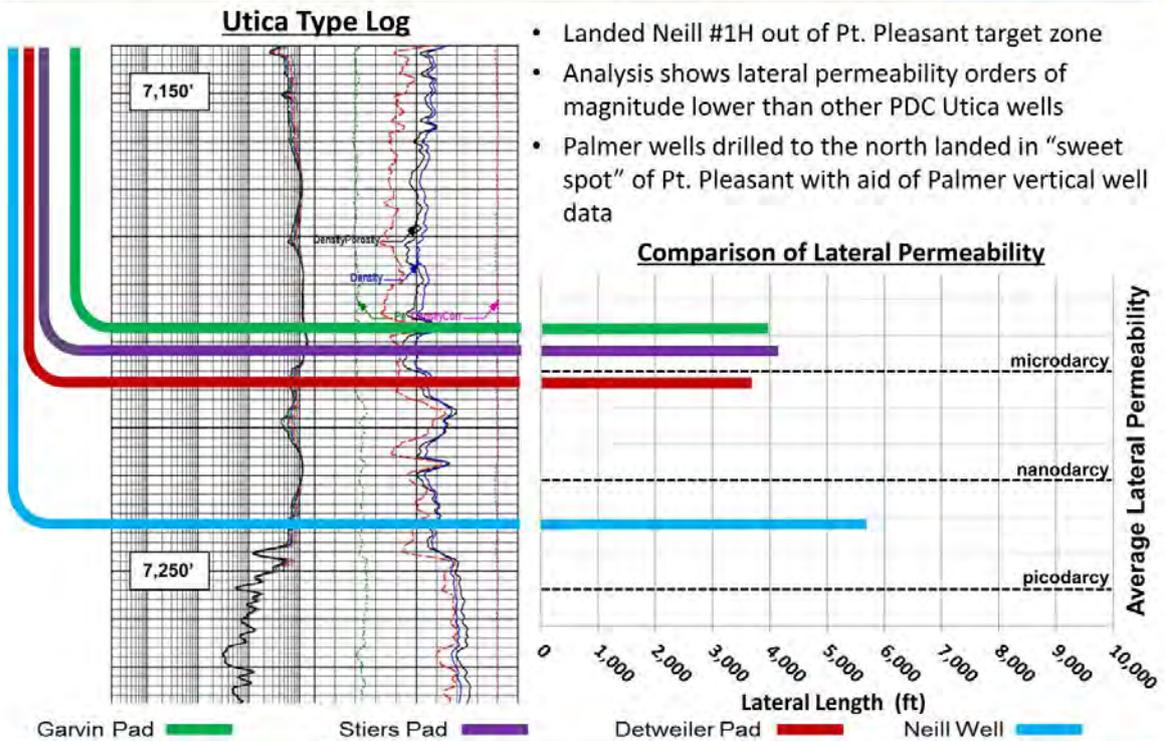
*Lateral spacing consideration of Gulfport Energy Inc
(Gulfport Energy Inc DUG East 11-14-2012)*

Estimated Cost and Completion Parameters for a WV well



(Stone Energy, 2014)

Neill #1H Learnings: Landing Zone is Critical



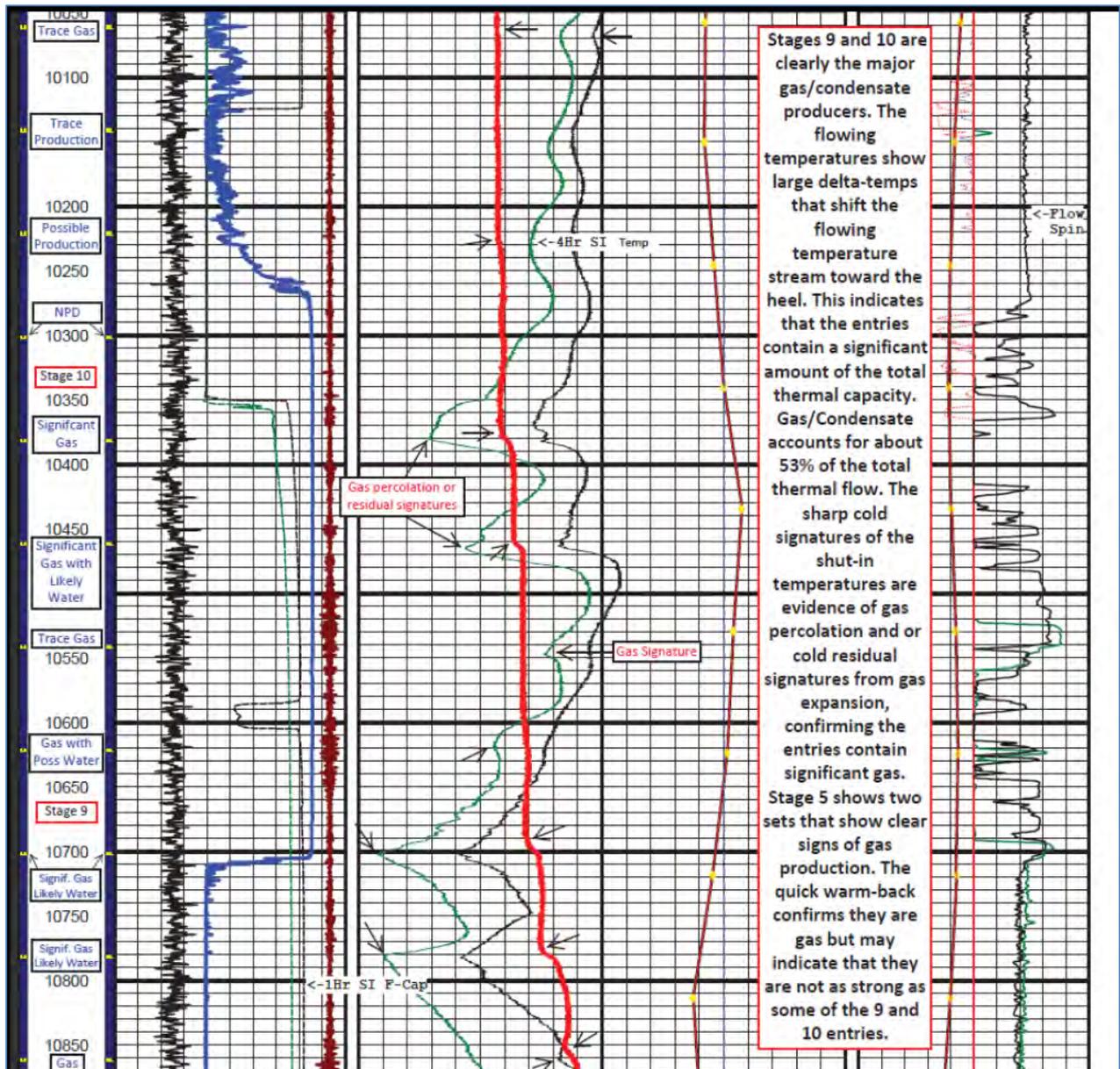
(PDC presentation, 2015)

Table 8-3. Legacy porosity and permeability data for selected Ohio wells.

API No.	Well Identification	No. Samples	He ϕ (%)	Hg ϕ (%)	Hg k (md)
34101201960000	Prudential 1A	7		0.03-1.31	1.0E-7 to 1.0E-6
34157253340000	OGS CO2-1	2		0.64-1.25	1.2E-6 to 5.1E-6
34139206780000	Copper Shelby	3		0.85-3.34	2.3E-6 to 1.93E-3
34133208670000	K Vasbinder	4		0.11-0.89	1.0E-7 to 2.9E-6
34151254750000	PSR1	3		0.29-1.01	4.0E-7 to 3.1E-6
34167286660000	Strass 1	2		0.37-0.55	1.0E-7 to 6.0E-7
34169248500000	Davis View 1	2		0.26-1.08	3.0E-7 to 3.5E-6
34005241600000	Eichelberger	25	2.2-8.2	0.03-1.31	1.0E-7 to 1.0E-6

Porosity - ϕ , measured in percent (%) using He (helium pycnometry) or Hg (mercury injection) techniques
 Permeability - k, measured in md

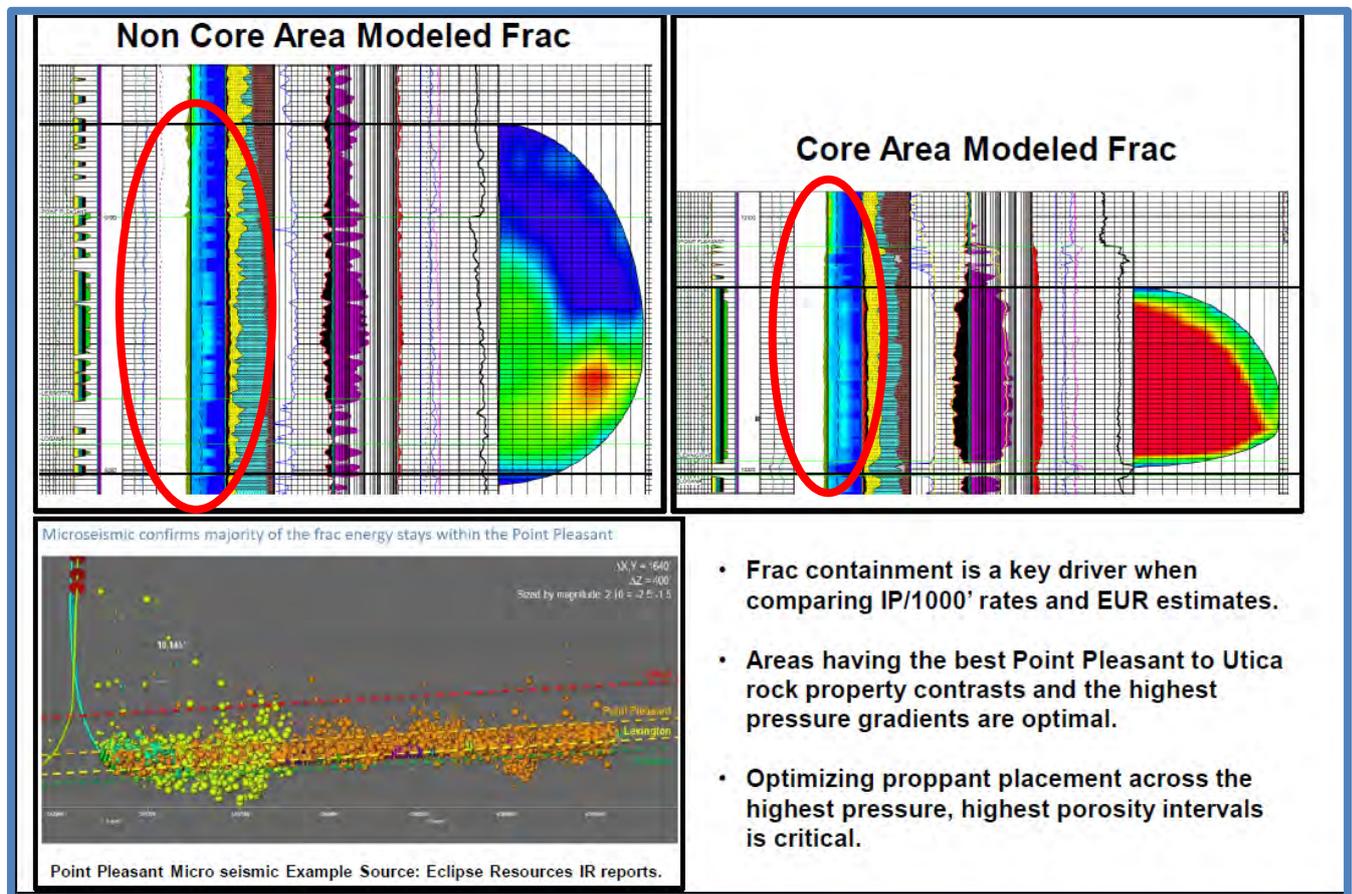
(Patchen, D.G. and Carter, K.M., 2015)



Production Log from a Gulfport Energy well (Gulfport Energy Inc DUG East 11-14-2012)

PDC Energy has noted that flowback management of Utica/Point Pleasant wells is critical to the success of this unconventional resource play (PDC presentation, 2014). Preliminary data indicate that applying back pressure during initial flowback can significantly increase reserves and economics of Utica/Point Pleasant wells. Their initial performance results demonstrated longer-term productivity and a lower decline rate in wells simply by decreasing the choke size. PDC Energy also noticed differences in permeability depending on where they landed their laterals, see figure above.

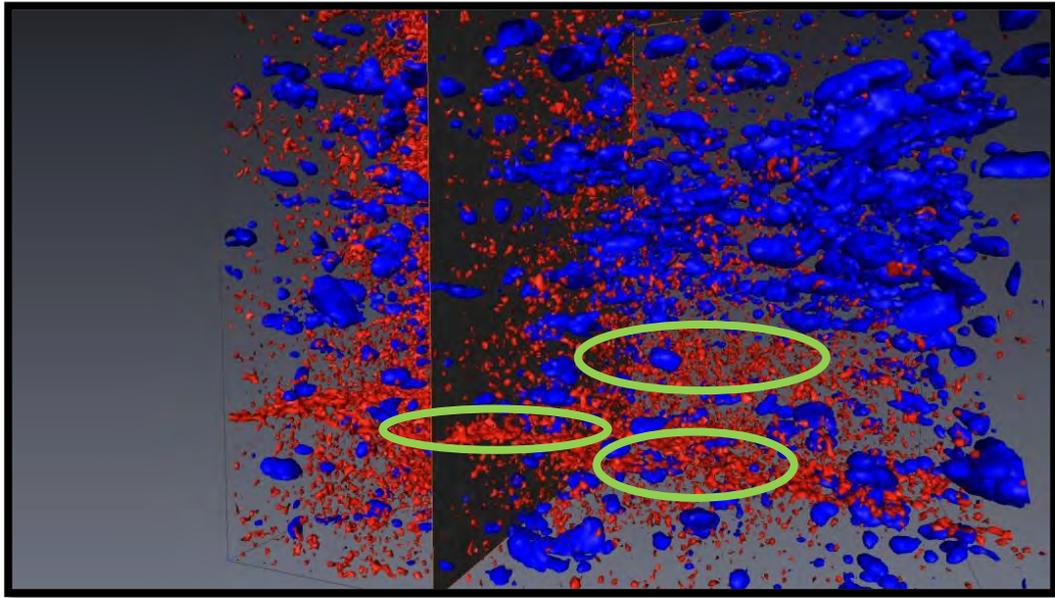
With more development of the Utica/Point Pleasant play, the figure below becomes more interesting. What is different in the high pressure gradient area as opposed to the area in the eastern Ohio? Three things stand out, the density logs are decreasing as you go east and there seems to be a subtle increase in the clay content and a subtle decrease in calcite to the east, and a subtle increase in quartz. TOC increases as does porosity as you go east. See the figure below from Range Resources showing the differences in the two areas. In the core area the bulk mineralogy is different than the non-core area.



(Range Resources, 2015)

A conclusion from a paper by Swift, et al (2014) which looked at nano- to micro-scale pore characterization of the Utica Shale found that mudstones with abundant clasts and clay reduces anisotropy more at the nanometer scale of clay folia than at the microscale of clasts themselves. Swift et al. (2014), conclude that wrapping of clay folia around clasts of every size may be expected to mediate local diffusivity and permeability, and potentially enhance the ability of fractures to propagate in directions other than horizontal. The figure below shows micro CT imagery of a Utica core showing the blue higher density minerals such as calcite, in the form of fossils and the red being voids, organics and low density minerals. The green highlighted areas would indicate where porosity may be and areas of permeability. The blue areas would indicate containment.

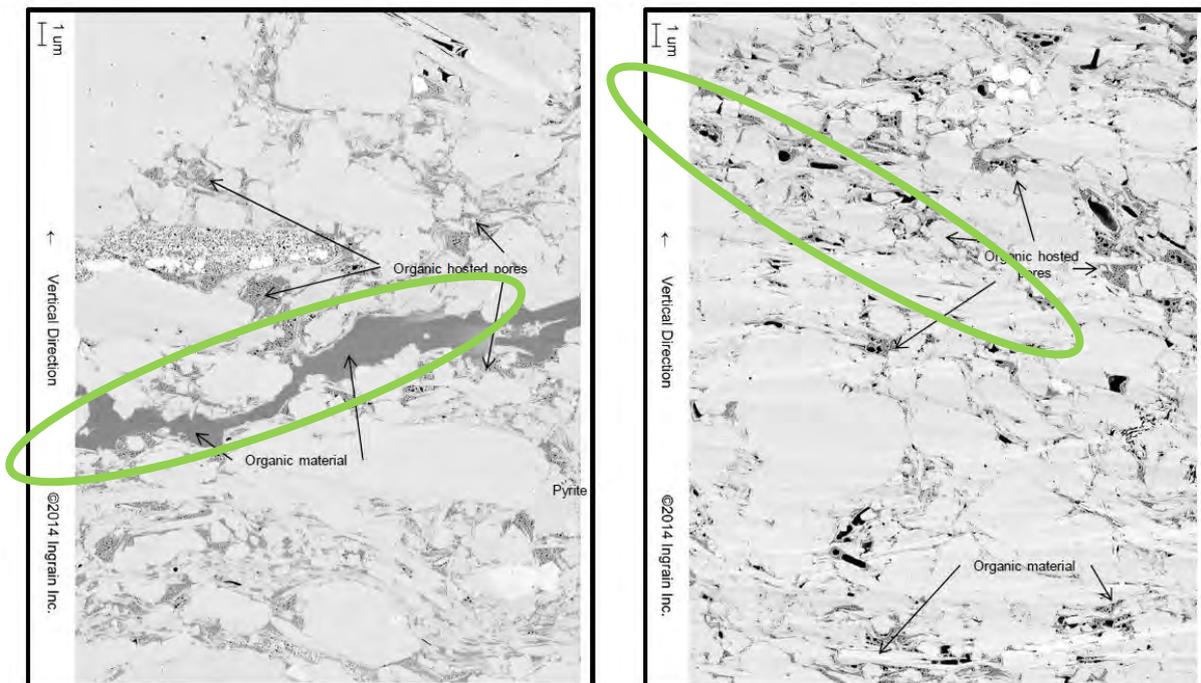
Micro CT Image of a Utica Core



(Swift, et al, 2014)

TOC and Porosity:

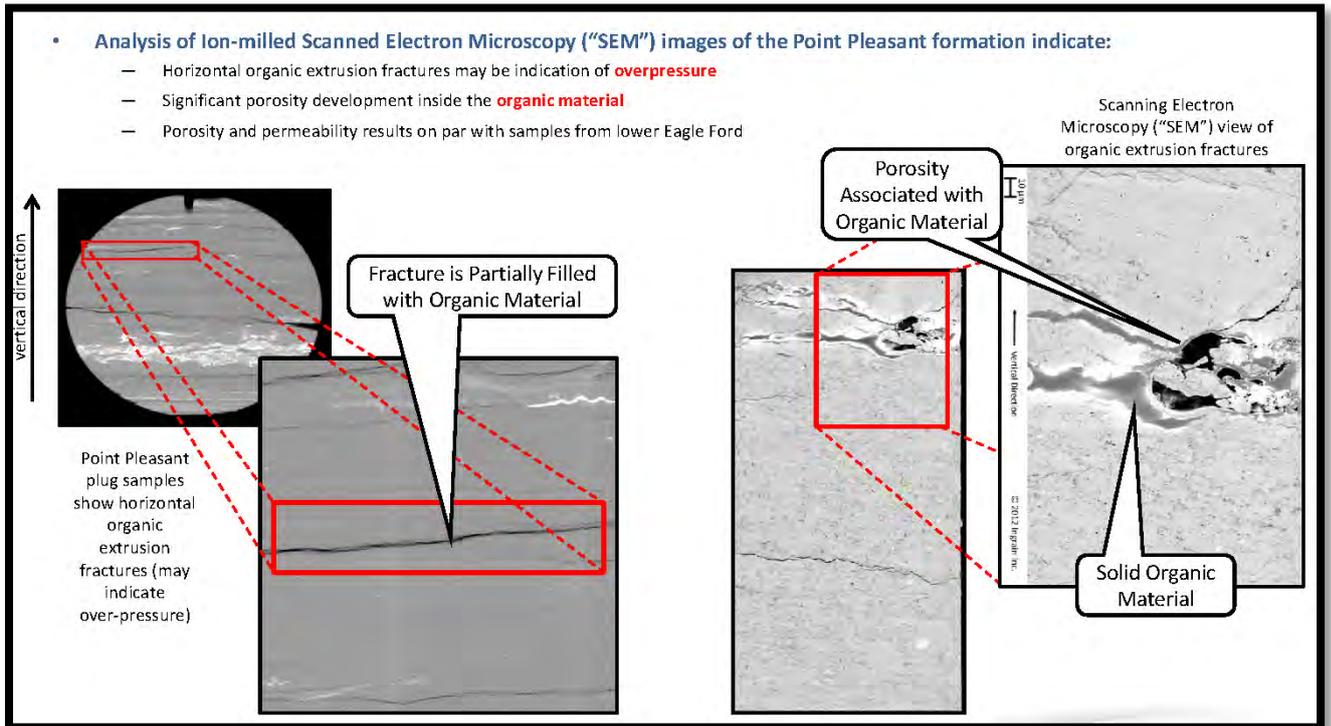
Claysville 11H Point Pleasant Pore Systems



FIB SEM examples from lateral target interval. Note TOC content and well developed pore network.

(Range Resources, 2015)

Comparison of ion milled SEM images from the high IP and Pressure gradient area and the Point Pleasant outside that area. The left image would show increased permeability in areas of organic matter and the right side would demonstrate area of porosity and lower permeability with a pore network that could create more permeability when the organic matter is fraced.



(Gulfport Energy Inc DUG East 11-14-2012)

As SEM imaging has shown that matrix porosity is minor to non-existent in these rocks, it is the organic matter pores that are the major contributor to hydrocarbon production in the Utica/Point Pleasant play (Smith, 2015). Below are two examples where organic matter can be tied to hydrocarbon production and porosity.



Figure 8-5. Photomicrograph of specimen from a depth of 566 ft in 74NY5 Mineral Core, Herkimer County, New York, analyzed by Juergen Schieber using ion milling and SEM imaging techniques. Qtz=quartz, CC=calcite. Area 1 shows development of large bubble pores in organic matter; Area 2 shows development of bubble pores into deep, connected channels/tubes; Area 3 shows a completely open framework pore defined by calcite grains. One could envision progressive development of organic matter pores from foam to bubbles to tubes in the organic matter, and finally completely emptying of framework pore spaces due to out-migration of liquid hydrocarbons.

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

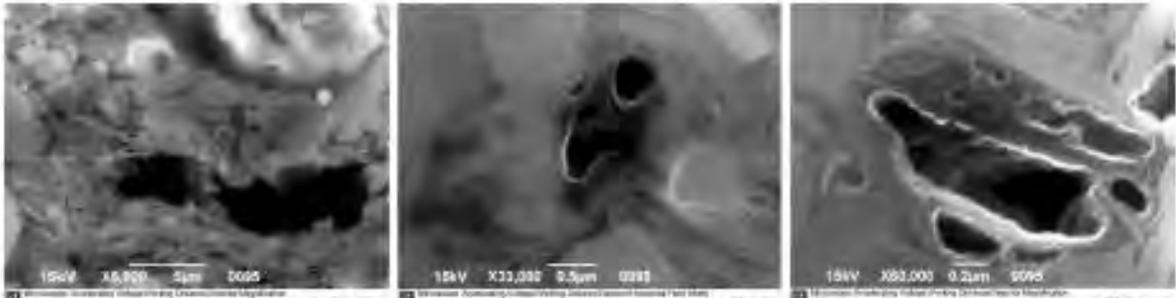
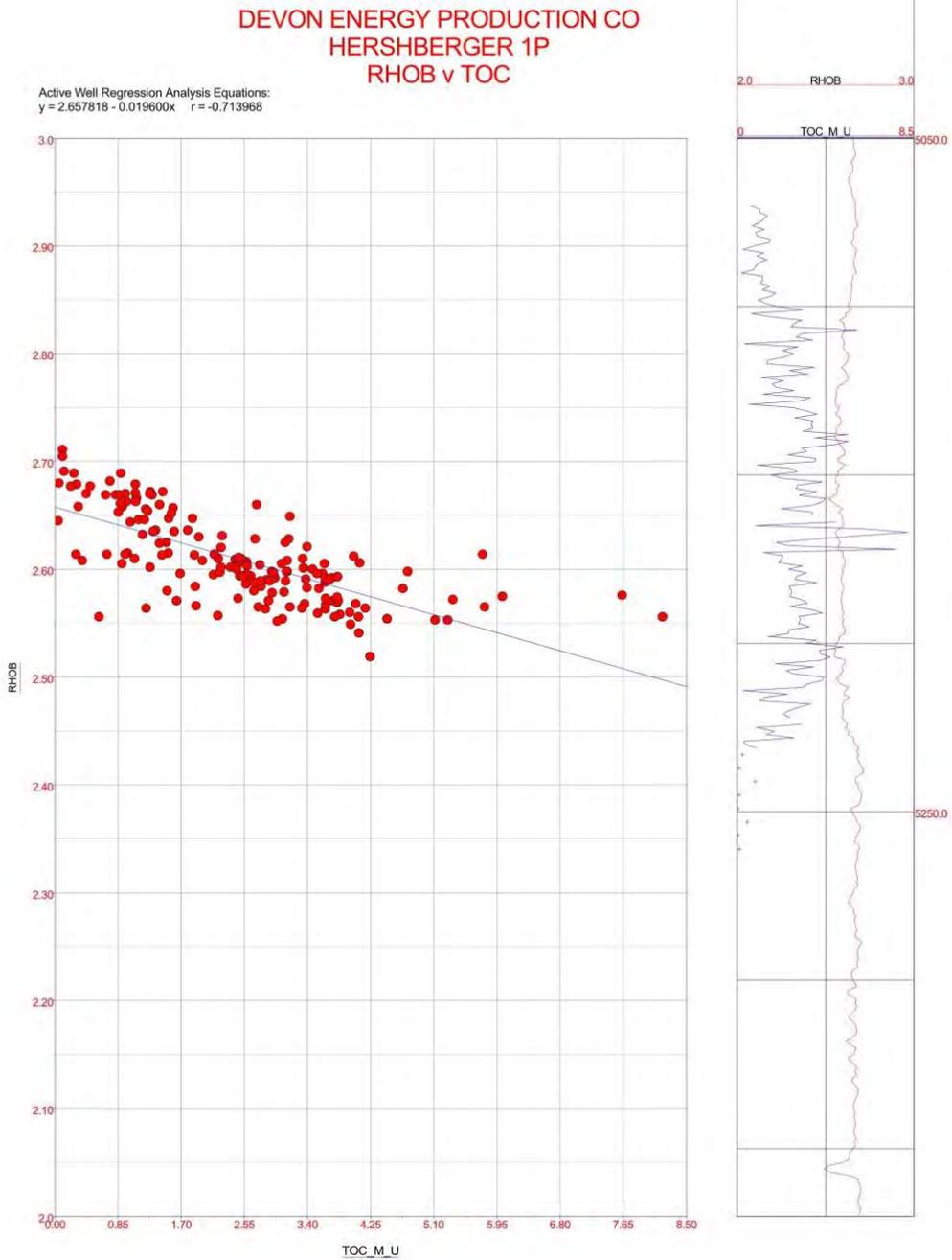


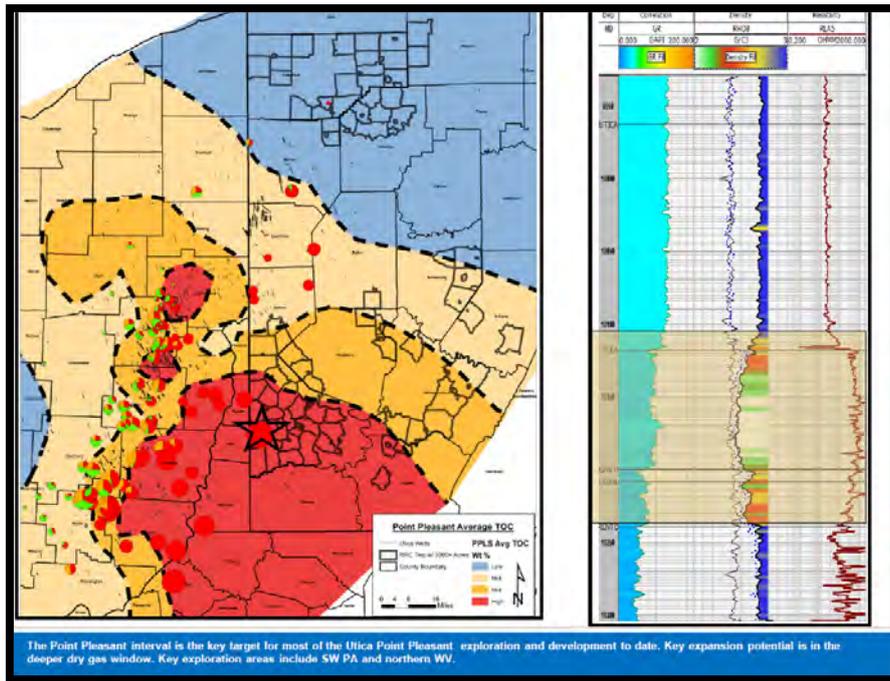
Figure 8-1. Selected SEM photomicrographs of organic matter and pores observed in the Point Pleasant Formation of the Fred Barth No. 3 well, Coshocton County, Ohio.

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



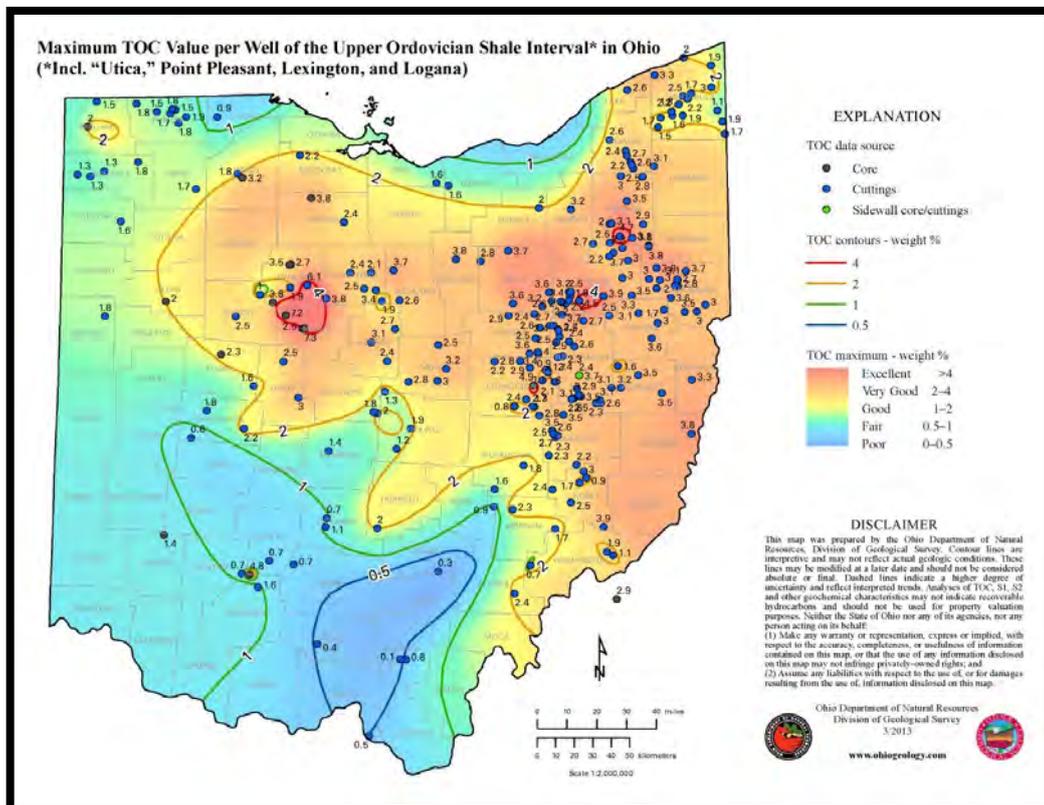
(Erenpreiss, 2015)

In the above figure in one of the five Utica cores taken by Devon Energy in Ohio we see a strong correlation between RHOB and TOC just as we saw in the Gastar's Exploration's cross section of increased pressure gradients and volumes.



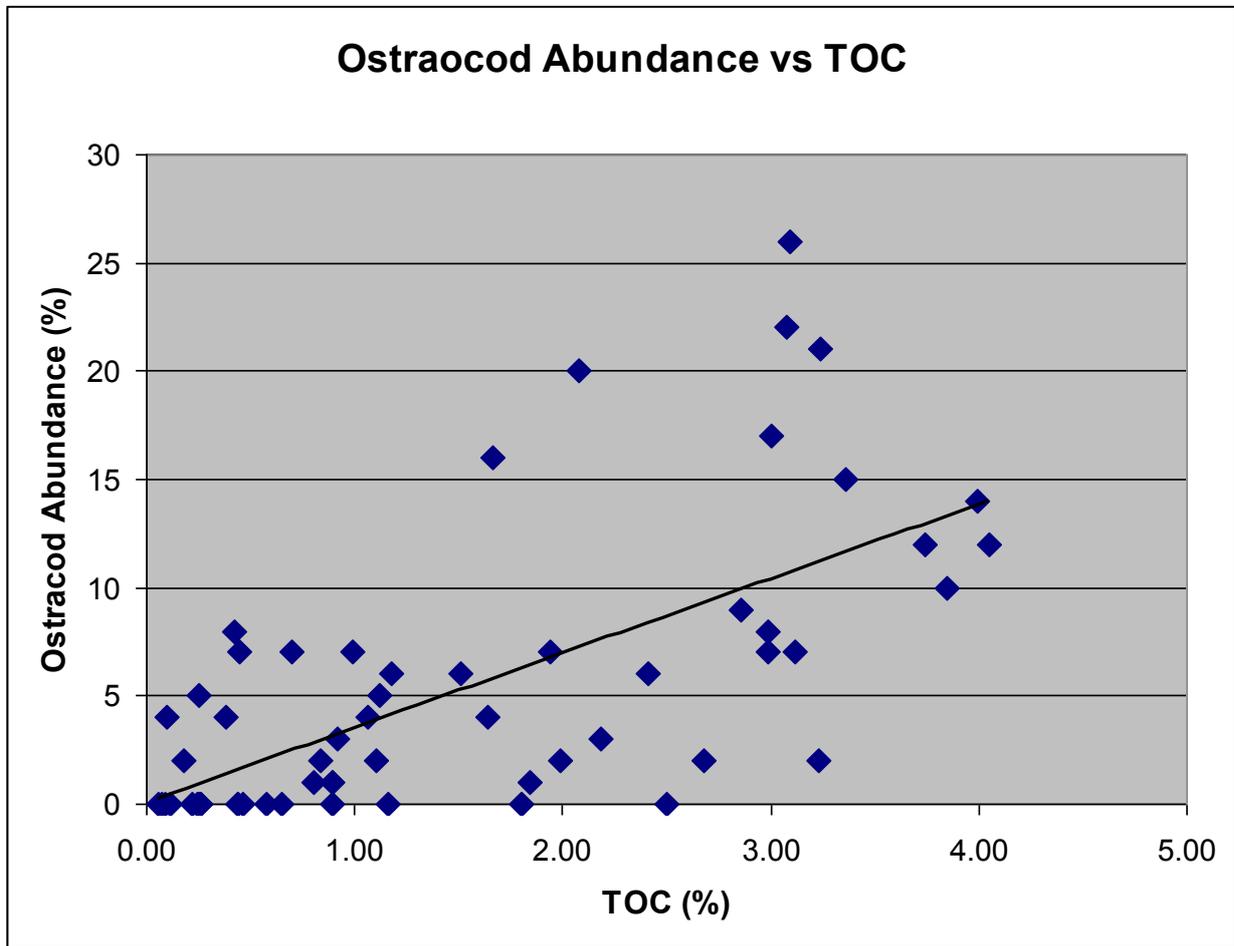
(Range Resources, 2015)

This figure above show an increase in TOC to the southeast and it tends to agree with a revised Ohio Geological Survey Map below.



(ODNR, March 2013)

In May of 2012, a TOC (Total Organic Content) map generated by the Ohio Geological Survey caused a fall out between the State Geologist and critics from southeastern counties of Ohio. The main criticism of the map was the limited amount data points in the southeastern part of the state which may have caused limited interest and lower lease and bonus prices offered to landowners.



(Smith, 2015b)

One last word about TOC, Smith 2015, from his five core study found a correlation between ostracod abundance and TOC. This line of evidence would support a shallow depositional environment

ISSUES: The Ohio Division of Natural Resources confirmed 11 low magnitude earthquakes that occurred near Hilcorp Energy Corp's well pad operations in Poland Township Ohio. The series of earthquakes were recorded by both the USGS and Columbia University's Lamont-Doherty Earth Observatory. The USGS confirmed five earthquakes ranging from 2.1 - 3.0 magnitude and Columbia University's Lamont-Doherty Earth Observatory registered six lower magnitude shocks in other places in the region (McParland, T., 2014)

The first quake occurred at a depth of 1.2 miles and the second quake was recorded at a depth of 3 miles (Obrien, D., 2014). The Precambrian basement is at 9000 feet and the vertical depth of the Hilcorp Energy well in the area is at a depth of 7900 feet.

These earthquakes have brought attention to whether fracking causes these earthquakes or are they naturally occurring. Ohio records show that the area between 1950 and 2009 averaged 2 earthquakes annually with magnitude 2.0 or greater. Between 2010 and 2014 the average rose to nine (Drabold, W., 2014). The Ohio Division of Natural Resources has halted operations and have been petitioned by local residences to set up a seismic network in the area

to monitor operations. The area is close to the Youngstown where an injection well was determined to cause earthquakes in 2011.

Governor Kasich has proposed a flat tax of 2.75% on producer's gross receipts (Provance, J., 2014).

Additional Information:

<http://www.wvgs.wvnet.edu/Utica> This website will lead you to the Utica Shale Appalachian Basin Exploration Consortium's three year study on the Utica Shale in five States pertinent to the play. This website has three parts DATA, INTERACTIVE MAP, and Downloads Section that contain the following data outlined below.

The "Data" section of the website contains all data collected, processed and analyzed during the course of the project's research. Website users may access these data via a well document file search which links to the project database. This document search allows users to create a custom search of the project database. A search may utilize one or more of the following criteria:

- API number
- File category
- State
- County

Results of the data search may also be exported to Excel, where the data are able to be further sorted. Hyperlinks to the individual files are embedded in the Excel file, which allows users to link back to the project webpage to retrieve the data without performing a duplicate search.

The Utica Shale Play Book Study's "Interactive Map" application utilizes ESRI ArcGIS Server technology and is designed to allow users to visualize geologic data in spatial context (Figure 1).

1). Data include the following:

- Wells
 - With Supplemental Data :
 - Digitized Well Logs
 - Scanned Well Logs
 - Source Rock Analyses
 - Total Organic Carbon (TOC) Data
 - Core Photographs
 - Scanning Electron Microscopy (SEM) Images-Data
 - Thin Section Images
 - Thin Section Descriptions
 - All Wells with Data (i.e. a file on the FTP server)
 - With Formation Tops²:
 - Upper Ordovician
 - Kope
 - Utica
 - Point Pleasant
 - Lexington/Trenton (includes Logana and Curdsville members)
 - Black River
- Cross-Sections³
 - Lines
 - Wells
- Maps
 - Faults

- Play Areas
 - Utica
 - Ordovician Outcrops

The “Downloads section “contains the Playbook, Presentations, Shapefiles, Petra Utica File, Well Files and a Utilize Mapping Services Section.

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

<http://geosurvey.ohiodnr.gov/major-topics/interactive-maps> This website will lead you downloadable oil and gas data in Ohio as well as information on type logs, cores and instructions on how to download digital and raster geophysical logs.

<http://esogis.nysm.nysed.gov> This is the website to go for information on well logs, formation tops, core, and well samples. At this website many studies on New York reservoirs sponsored by NYSERDA can be downloaded for free.

<http://oilandgas.ohiodnr.gov/shale#SHALE> This is the website to get weekly activity and yearly production information in Ohio.

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WOODFORD SHALE (LATE DEVONIAN-EARLY MISSISSIPPIAN), OKLAHOMA, U.S.A.

Brian Cardott (Oklahoma Geological Survey)

Three recent U.S. Geological Survey oil and gas assessments have included the Woodford Shale. Houseknecht and others (2010) conducted an assessment of the natural gas resources of the Arkoma Basin Province in which they determined a Woodford Shale Gas assessment unit total undiscovered resource of 10.7 trillion cubic feet of gas (Tcf). Higley and others (2014) conducted an oil and gas assessment of the Anadarko Basin Province in which they determined a Woodford Shale Oil assessment unit total undiscovered oil resource of 393 million barrels of oil (MMbo) and a Woodford Shale Gas assessment unit total undiscovered gas resource of 16.0 Tcf. Drake and others (2015) conducted an oil and gas assessment of the Cherokee Platform Province of Kansas, Missouri, and Oklahoma. The Woodford/Chattanooga Total Petroleum System included the Woodford Shale Oil assessment unit (total undiscovered oil resource of 460 MMbo and total undiscovered gas resource of 644 billion cubic feet (Bcf)) and Woodford Biogenic Gas assessment unit (total undiscovered resource of 416 Bcf).

Figure 1 illustrates 4,123 Oklahoma shale gas and tight oil well completions (1939–2015) on a geologic provinces map of Oklahoma. The Oklahoma Geological Survey has a database of all Oklahoma shale gas and tight oil well completions (<http://www.ogs.ou.edu/level3-oilgas.php>). The database of 4,324 well completions from 1939 to October 2015 contains the following shale formations (in alphabetical order) and number of completions: Arkansas Novaculite (3), Atoka Group shale (1), Barnett Shale (2), Caney Shale or Caney Shale/Woodford Shale (120), Excello Shale/Pennsylvanian shale (2), Goddard Shale (lower Springer shale)(47), Sylvan Shale or Sylvan Shale/Woodford Shale (20), and Woodford Shale (3,915). Shale wells commingled with non-shale lithologies are not included. Exceptions include 20 Sycamore Limestone/ Woodford Shale, 11 Mississippian/Woodford Shale, and 3 Hunton Group carbonate/Woodford Shale horizontal completions where non-Woodford perforations were minimal. The database was originally restricted to shale-gas wells. Tight-oil wells have been added since 2005.

The clay-rich Mississippian Caney Shale (age equivalent to the Barnett Shale and Fayetteville Shale) well completions in 2001–2008 in the Arkoma Basin in eastern Oklahoma resulted in poor wells while recent drilling (2012–present) in the Caney Shale in southern Oklahoma has been successful (initial potential (IP) gas of 57–2,801 thousand cubic feet (Mcf) and IP oil/condensate (39–54° API gravity) of 12–642 barrels of oil per day (bopd)).

The newest shale play in Oklahoma (2013–present) is the Mississippian lower Springer shale (Goddard Shale) in the South Central Oklahoma Oil Province (“SCOOP”) in the southeastern Anadarko Basin (Figure 1). Of 47 horizontal Springer/Goddard shale well completions in Garvin, Grady, and Stephens counties in 2013–2015, IP gas rates were 93–2,713 Mcf and IP oil rates (43–54° API gravity) were 143–2,785 bopd at vertical depths of 11,332–14,618 feet. The Springer/Goddard shale play is held by production so operators in the play have indicated no new drilling is planned for the year thereby holding on for higher oil prices (Toon, 2015b). Summaries of the play are in Bates (2015), Darbonne (2015), Nash (2014), and Toon (2015a).

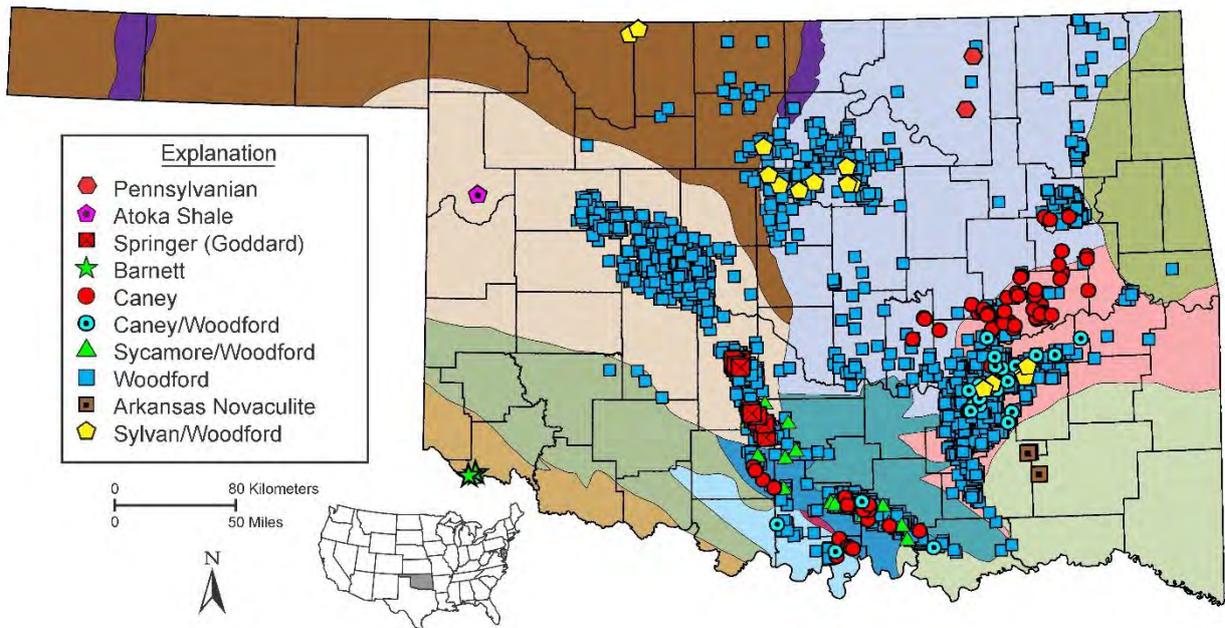


Figure 1. Map showing Oklahoma shale gas and tight oil well completions (1939–2015) on a geologic provinces map of Oklahoma (modified from Northcutt and Campbell, 1998).

Since 2004, the Woodford Shale-only plays of Oklahoma have expanded from primarily one (Arkoma Basin) to four geologic provinces (Anadarko Basin, Ardmore Basin, Arkoma Basin, and Cherokee Platform) and from primarily gas to gas, condensate, and oil wells (Figure 2). The recent low price of natural gas has shifted the focus of the plays more toward condensate (“Cana” for western Canadian County or “SCOOP” plays and western Arkoma Basin) and oil (northern Ardmore Basin, “Cana”, “SCOOP”, and north-central Oklahoma) areas. Of the 3,894 Woodford-only well completions from 2004–2015, 3,500 wells are horizontal/directional wells and 394 wells are vertical wells. 983 Woodford Shale wells are classified as oil wells based on a gas-to-oil ratio < 17,000: 1. Total vertical depths range from 368 ft (Mayes Co.) to 17,355 ft (Stephens Co.). IP gas rates range from a trace to 16.7 million cubic feet per day. IP oil/condensate rates range from a trace to 2,075 bopd (Garvin County). Reported oil gravities range from 21 to 67 API degrees.

The annual peak of 595 Woodford Shale well completions occurred in 2014 (Figure 3). Following the drop in natural gas prices in 2008, the emphasis in the Woodford Shale plays has been for oil- and condensate-producing wells. The recent drop in oil prices has resulted in a significant decline in Woodford Shale completions (282 wells during the first 3 quarters of 2015). Figure 4, showing Woodford Shale wells from 2011–2015, illustrates the expansion of the Woodford Shale condensate play in the Anadarko Basin which began in “Cana” in 2007 and “SCOOP” in 2012. There is an expansion of the play in north-central Oklahoma where the Woodford Shale is in the lower half of the oil window.

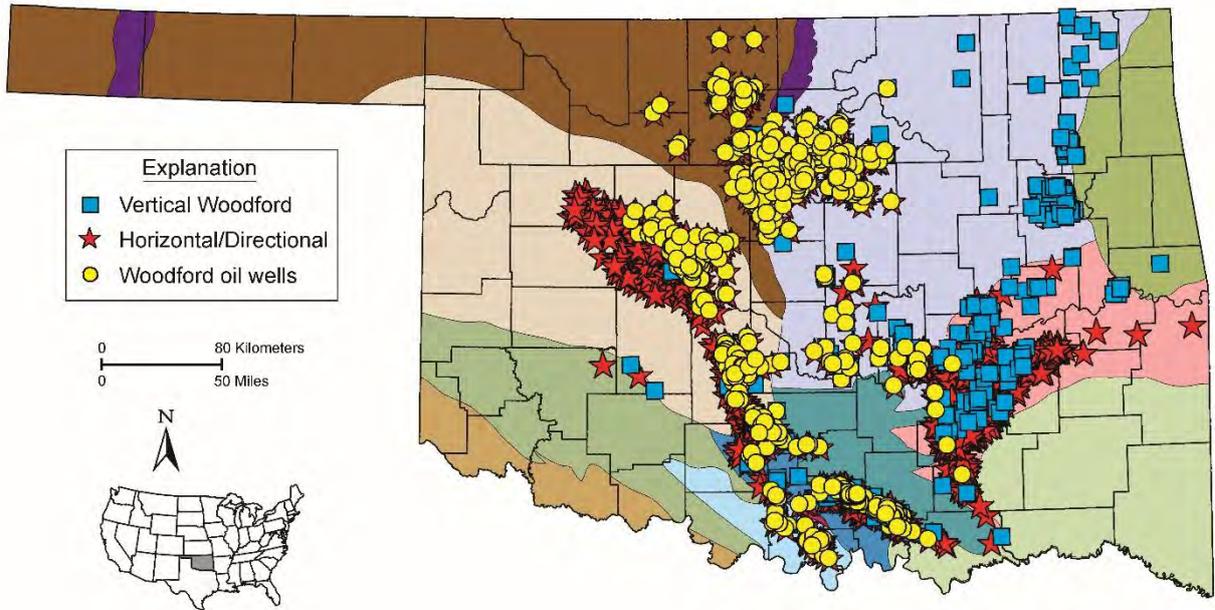


Figure 2. Map showing 3,865 Woodford Shale-only gas and oil well completions (2004–2015) on a geologic provinces map of Oklahoma.

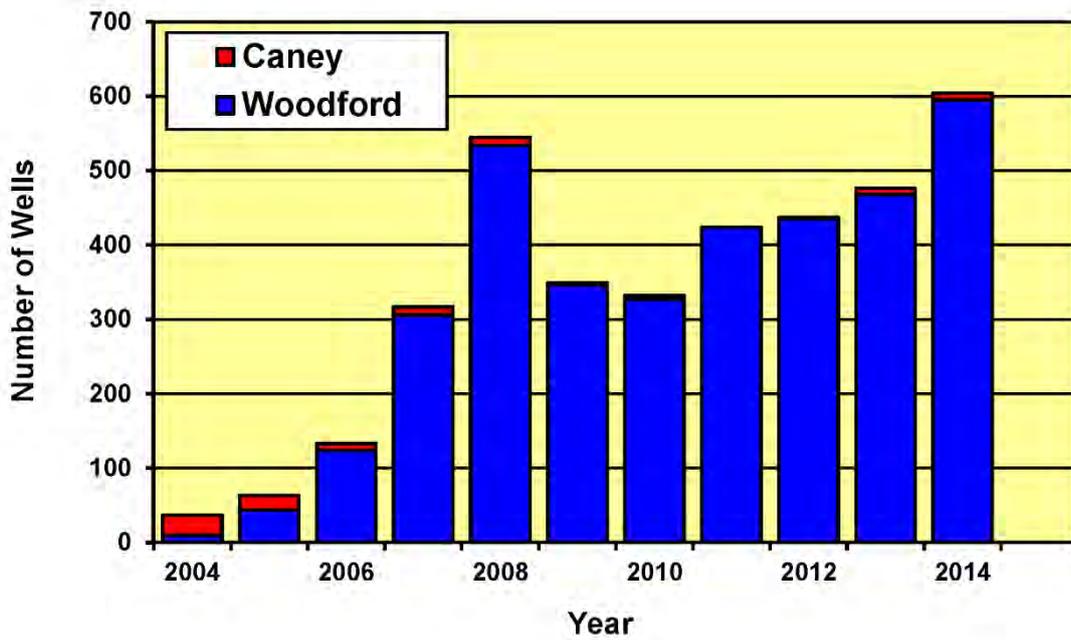


Figure 3. Histogram showing numbers of Woodford Shale and Caney Shale well completions, 2004–2014.

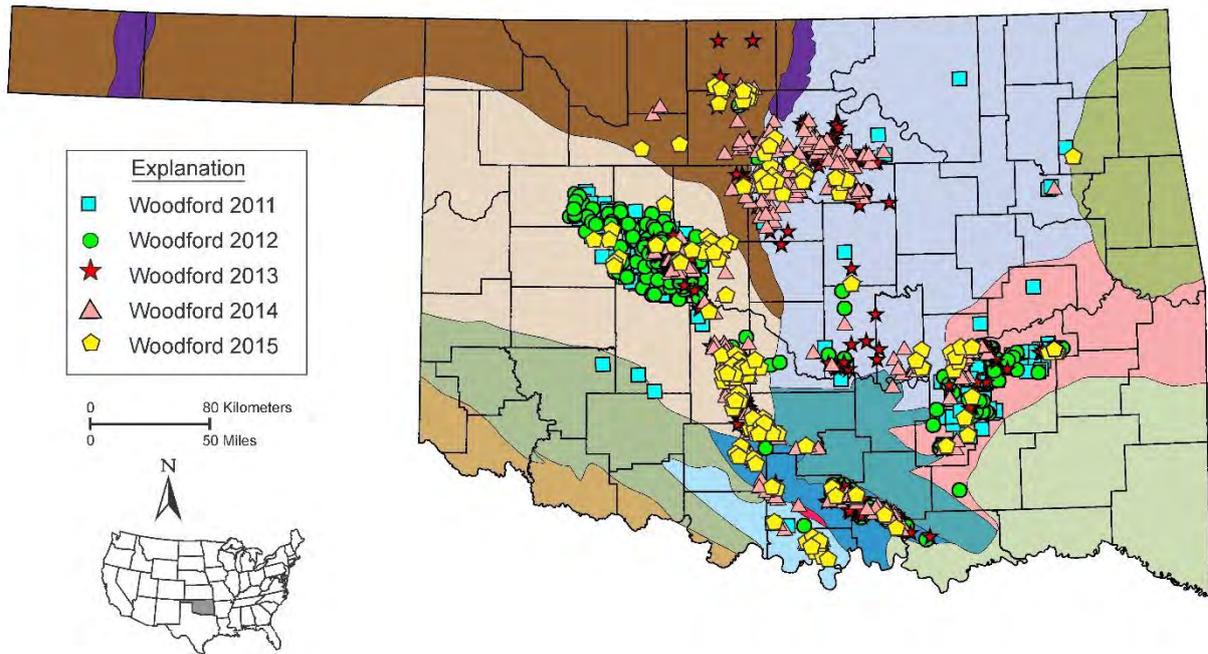


Figure 4. Map showing Woodford Shale-only gas and oil well completions (2011-2015) on a geologic provinces map of Oklahoma.

The four Woodford shale plays in Oklahoma are as follows:

1) western Arkoma Basin in eastern Oklahoma with thermogenic methane production at thermal maturities from <1% to >3% vitrinite reflectance (VRo) and oil/condensate production up to 1.67% VRo (Figure 5);

2) Anadarko Basin (“Cana” and “SCOOP” plays) in western Oklahoma with thermogenic methane production at thermal maturities from <1% to >1.6% VRo and oil/condensate production at thermal maturities up to ~1.5% VRo (Figure 6);

3) Ardmore and Marietta Basins in southern Oklahoma with oil, condensate, and thermogenic methane production at thermal maturities in the oil window (<1.8% VRo) (Figure 7);

4) north-central Oklahoma (Cherokee Platform and Anadarko Shelf) with oil and thermogenic methane production at thermal maturities <1.0% VRo (Figure 5).

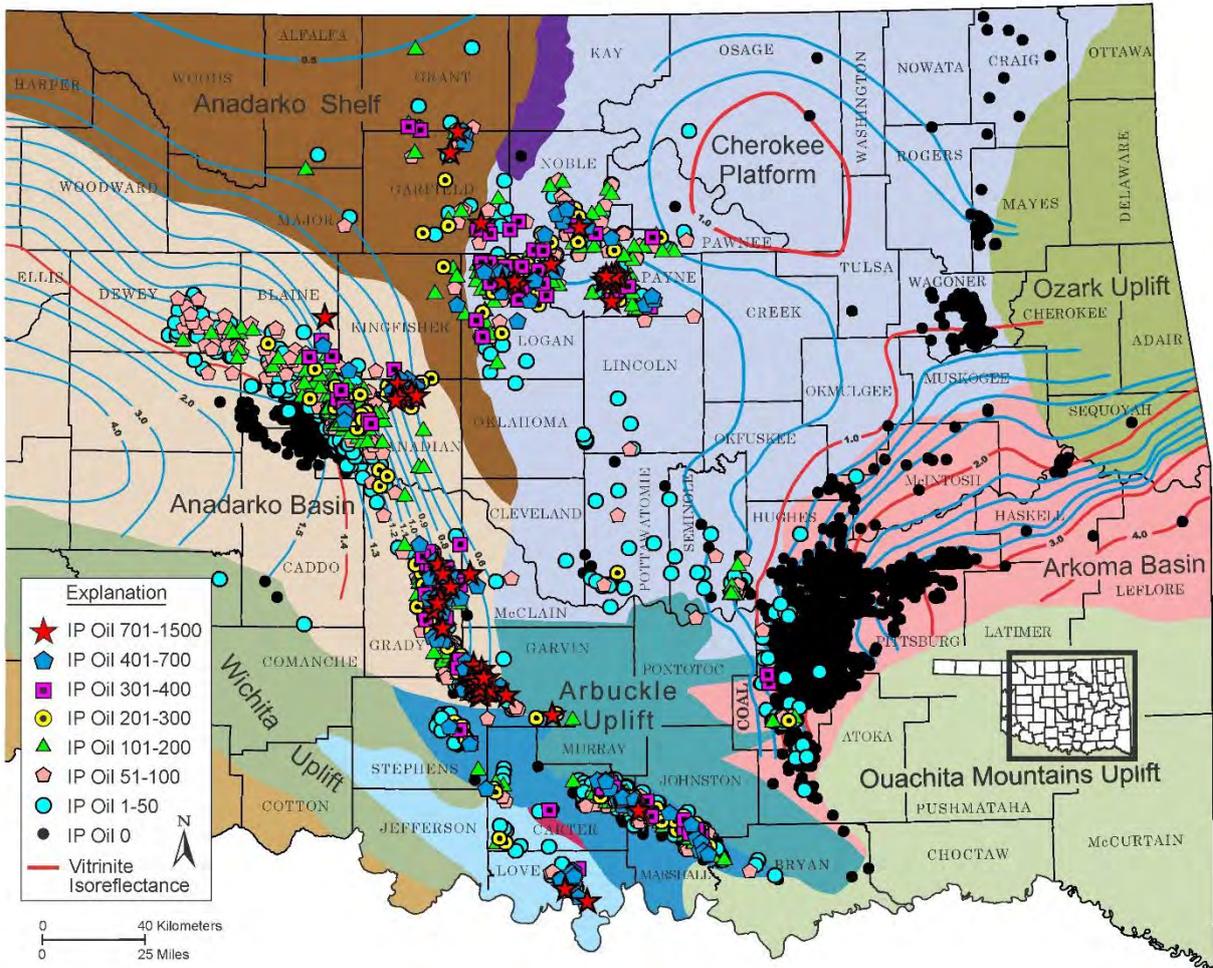


Figure 5. Map showing initial potential liquid hydrocarbon production of Woodford Shale-only gas and oil well completions (2004-2015) in Oklahoma with vitrinite isorefectance contours.

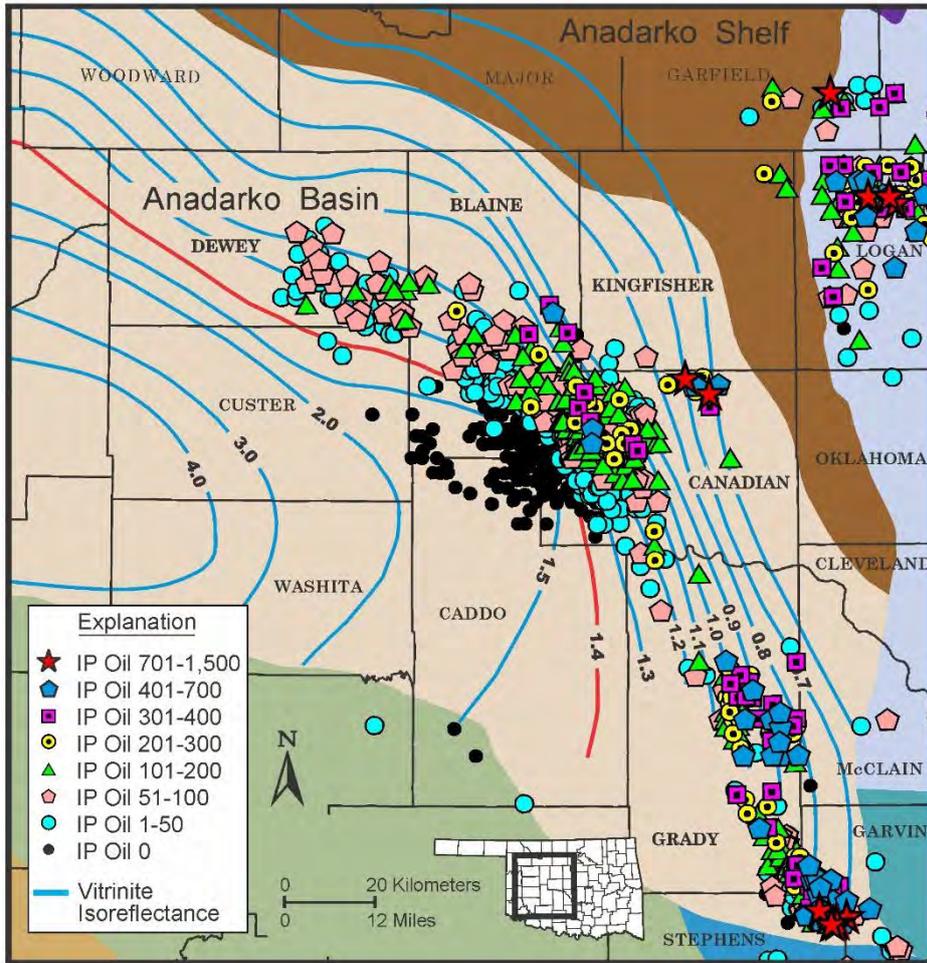


Figure 6. Map showing initial potential liquid hydrocarbon production of Woodford Shale-only gas and oil well completions (2004-2014) in the Anadarko Basin of western Oklahoma.

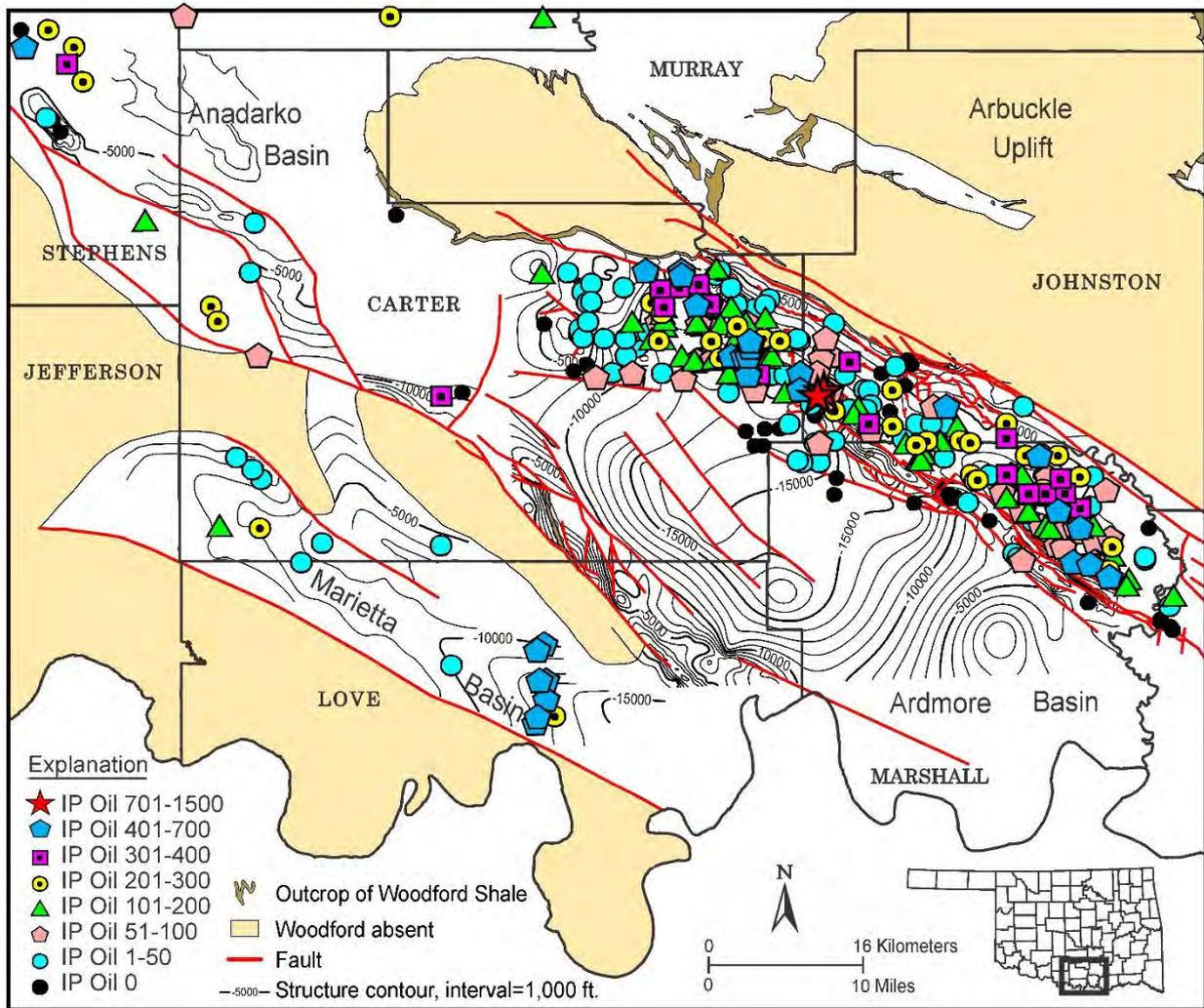


Figure 7. Map showing initial potential liquid hydrocarbon production of Woodford Shale-only gas and oil well completions (2004-2014) in the Ardmore and Marietta basins of southern Oklahoma.

Of 24 operators active in Oklahoma shales (not just the Woodford) during 2015, the top eight operators (for number of wells drilled during 2015) are:

- (1) Continental Resources (68)
- (2) Newfield Exploration Mid-Continent Inc. (38)
- (3) XTO Energy (38)
- (4) Devon Energy Production Co. LP (38)
- (5) Petroquest Energy (26)
- (6) American Energy - Woodford (19)
- (7) Silver Creek Oil & Gas (16)
- (8) Vitruvian II Woodford (14)

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STATUS OF INTERNATIONAL ACTIVITIES

CANADIAN SHALE GAS AND LIQUIDS

Jock McCracken (Egret Consulting, Vancouver)

Even though Canada has an abundance of conventional oil and natural gas, unconventional gas, liquids and oil plays dominate the headlines. Most of these shale opportunities lie within the Western Canadian Sedimentary Basin (WCSB) which is a vast sedimentary basin underlying 1,400,000 square km (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 km (3.7 mi) thick under the Rocky Mountains, but thins to zero at its eastern margins. The WCSB contains one of the world's largest reserves of petroleum and natural gas and supplies much of the North American market, producing about 658,000 BOPD and 14 MMCFD gas. Of the provinces and territories within the WCSB, Alberta has most of the oil and gas reserves and almost all of the oil sands.

The first announcement of new discoveries in shale occurred in Canada at the beginning of 2008, seven years ago. Now, about 25% of Canada's natural gas is coming from unconventional which would include tight sands. The state of development for the shale plays range from speculative to exploratory to emerging to developing and under increasing commercial production. Typically, production numbers from government websites are up to one year or

more behind. Additional production numbers and exploration statistics for this report are therefore gathered from press releases and presentations from some of the key companies involved with the plays. As a result of the low natural gas operators had been focusing exploration and production into the liquids-rich hydrocarbons. The low oil prices now complicate these plays. The following plays are under development and increasing the production yearly: Horn River and Montney in N.E. B.C., Duvernay and Alberta Bakken in Alberta and the Bakken oil play (tight oil play encased in shale) in Saskatchewan and Manitoba.

There have been other shale that have been disappointments for technical and regulatory reasons. Significant shale gas wells have been drilled and tested in the St. Lawrence Lowlands of Québec but a government freeze on fracking because of environmental concerns will slow or stop any future exploration and production. The positive announcements out of New Brunswick have been tempered by recent disappointing results, low gas prices and anti-fracking regulations. To date there is shale exploration activity in 9 provinces of Canada out of the 10 with Prince Edward Island being the exception. One of the three Territories of Canada, the Northwest Territories, is just now seeing the drilling and fracking of their first wells into a possible oil-bearing shale section. The Yukon is evaluating their shale plays as well. The recent drop in oil price has had significant effects on industry production and exploration.

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

Quebec, Nova Scotia, New Brunswick and the Yukon effectively have put hydraulic fracturing under partial or full moratorium with Newfoundland and North West Territory under review. 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.

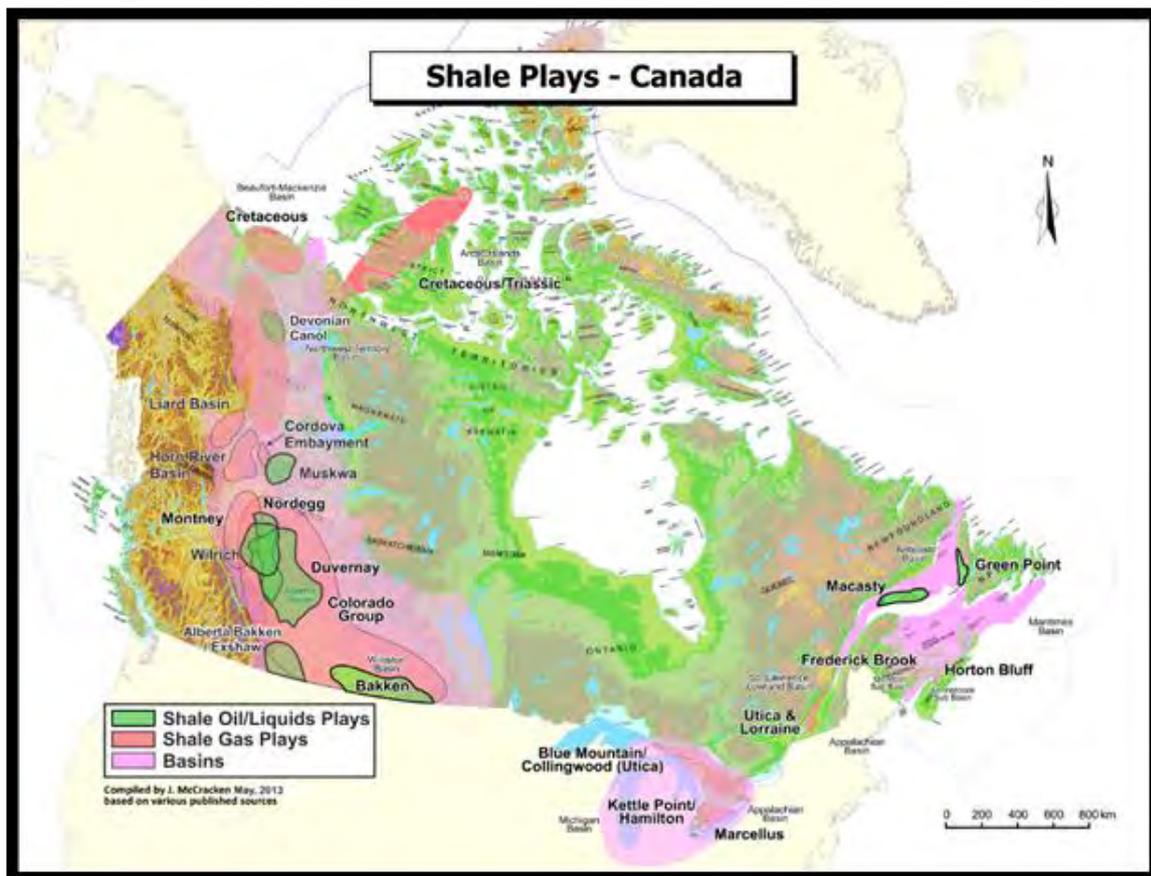
There is a good summary by Natural Resources Canada of shales and tight resources by province. <http://www.nrcan.gc.ca/energy/sources/shale-tight-resources/17669>

This next table is from the publication by EIA *Technically Recoverable Shale Oil and Shale Gas Resources: Canada, September 2015*. They are reporting that Canada has 162,000 MM BBL of oil/condensate and 2,413.2 TCF of natural gas risked resources in place with 8,840 MM BBL of oil/condensate and 572.9 TCF of natural gas risked resources recoverable. www.eia.gov

Table I-1. Shale Gas and Oil Resources of Canada

Region	Basin / Formation	Risky Resource In-Place		Risky Technically Recoverable Resource	
		Oil/Condensate (Million bbl)	Natural Gas (Tcf)	Oil/Condensate (Million bbl)	Natural Gas (Tcf)
British Columbia / Northwest Territories	Horn River (Muskwa / Otter Park)	-	375.7	-	93.9
	Horn River (Eve / Klua)	-	154.2	-	38.5
	Cordova (Muskwa / Otter Park)	-	81.0	-	20.3
	Liard (Lower Besa River)	-	526.3	-	157.9
	Deep (Doig Phosphate)	-	100.7	-	25.2
	Sub-Total	-	1,237.8	-	335.8
Alberta	Alberta (Banff / Exshaw)	10,500	5.1	320	0.3
	E/W Shale (Duvernay)	66,800	482.6	4,010	113.0
	Deep Basin (Nordegg)	19,800	72.0	790	13.3
	N.W. Alberta (Muskwa)	42,400	141.7	2,120	31.1
	S. Alberta (Colorado)	-	285.6	-	42.8
	Sub-Total	139,500	987.1	7,240	200.5
Saskatchewan / Manitoba	Williston (Bakken)	22,500	16.0	1,600	2.2
Quebec	App. Fold Belt (Utica)	-	155.3	-	31.1
Nova Scotia	Windsor (Horton Bluff)	-	17.0	-	3.4
	Total	162,000	2,413.2	8,840	572.9

*Less than 0.5 Tcf



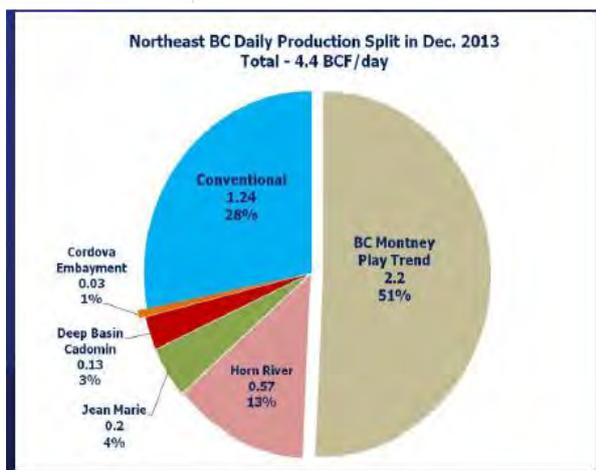
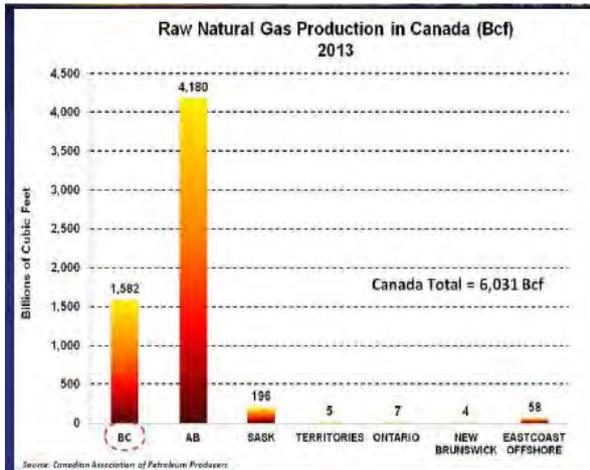
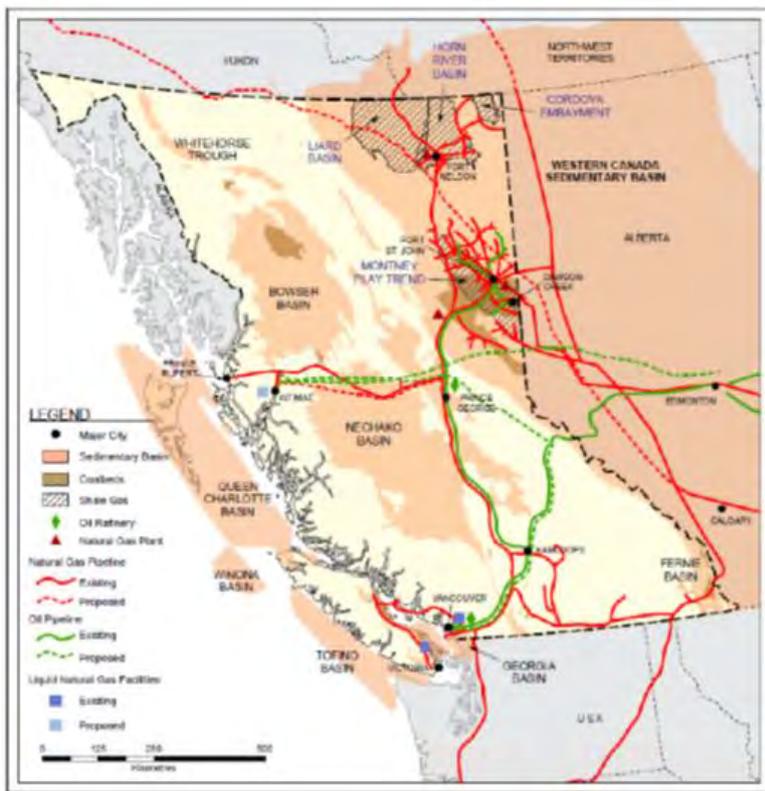
NORTHEAST BRITISH COLUMBIA

Northeast British Columbia contains Cretaceous to Devonian aged shale deposits that potentially could contain 2900 TCF of natural gas in place of which over 400 TCF is estimated to be marketable with about 70% being unconventional. The gas production keeps ramping upward with 1.58 TCF (4.4 BCF/D) raw natural gas production in 2013 or 26 % of the total Canadian gas production. Shale gas accounts for about 60% of these volumes. Advances in

horizontal drilling and completion techniques have largely contributed to these advances in all the play areas. Industry spending has increased substantially on exploration and development activities over the last 15 years with \$7.9 Billion spent in 2008 and \$5.2 Billion in 2012. Total oil and as revenue was \$1.12 Billion in fiscal 2013. This shale gas interest in all the areas has therefore dominated the sale of petroleum and natural gas (PNG) rights from the province in the last ten years (see chart below). The Montney play is garnering much interest because of its liquids component and now producing at more than 2.26 BCF/D.

<http://www2.gov.bc.ca/gov/DownloadAsset?assetId=D2628717CD3D41A5A17E5139F5FCAC53>

British Columbia has developed a Natural Gas and Liquefied Natural Gas Strategies considering the immensity of this resource.





Resource Potential in BC's Shale Gas Regions

Liard Basin – Devonian

- 9,340 square kilometres
- OGIP – large!
- 2 wells producing (March 2014)
- Daily production – 4.5 MMcf/d
- Cumulative production – 10.1 Bcf

Horn River Basin – Devonian

- 11,400 square kilometres
- OGIP – 448 Tcf, Marketable – 78 Tcf
- 200 wells producing (Feb. 2014)
- Daily production – 492 MMcf/d
- Cumulative production – 635 Bcf

Cordova Embayment – Devonian

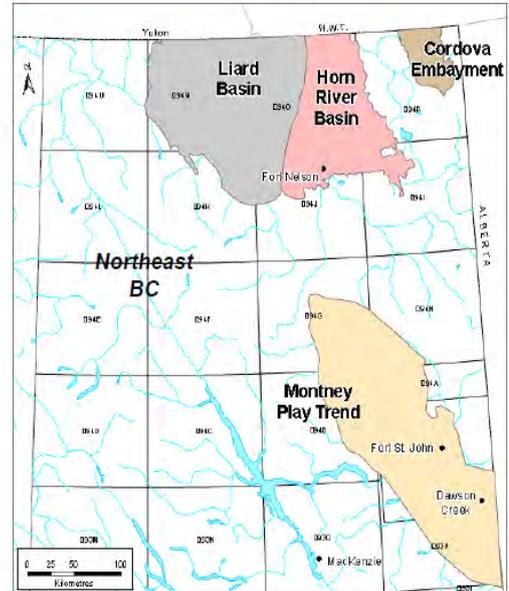
- 2,690 square kilometres
- OGIP – 200 Tcf, Marketable – 20 Tcf
- 19 wells producing (March 2014)
- Daily production – 30 MMcf/d
- Cumulative production – 25 Bcf

Montney – Triassic

- 29,850 square kilometres
- OGIP – 1,965 Tcf, Marketable – 271 Tcf
- 1,644 gas wells producing (March 2014)
- Daily production – 2.26 Bcf/d
- Cumulative production – 2.53 Tcf

Total GIP estimates of approx. 2,900 Tcf

Over 400 Tcf marketable

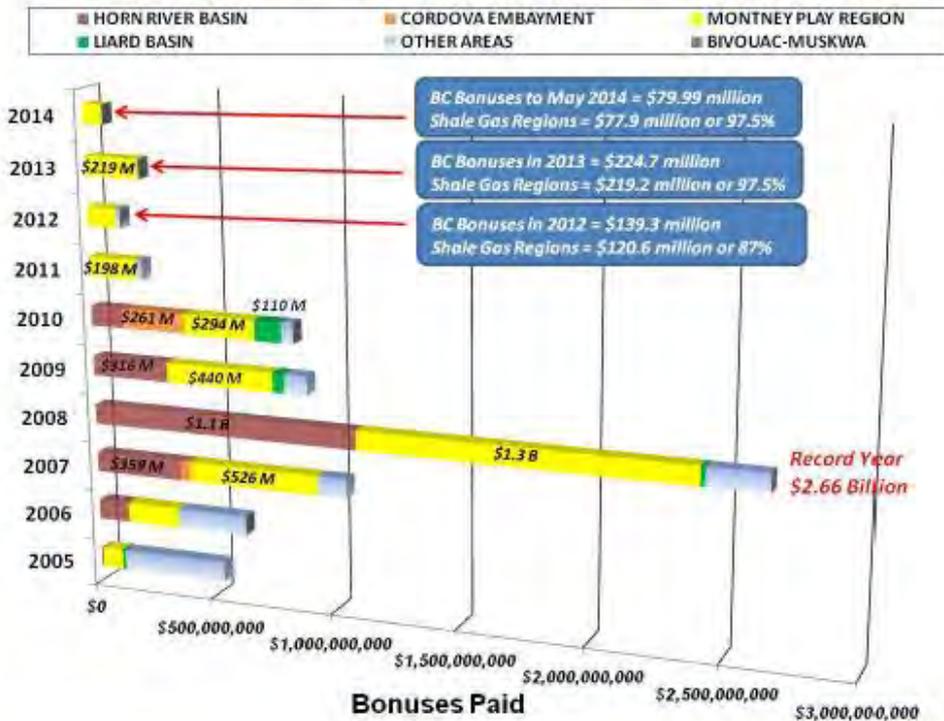


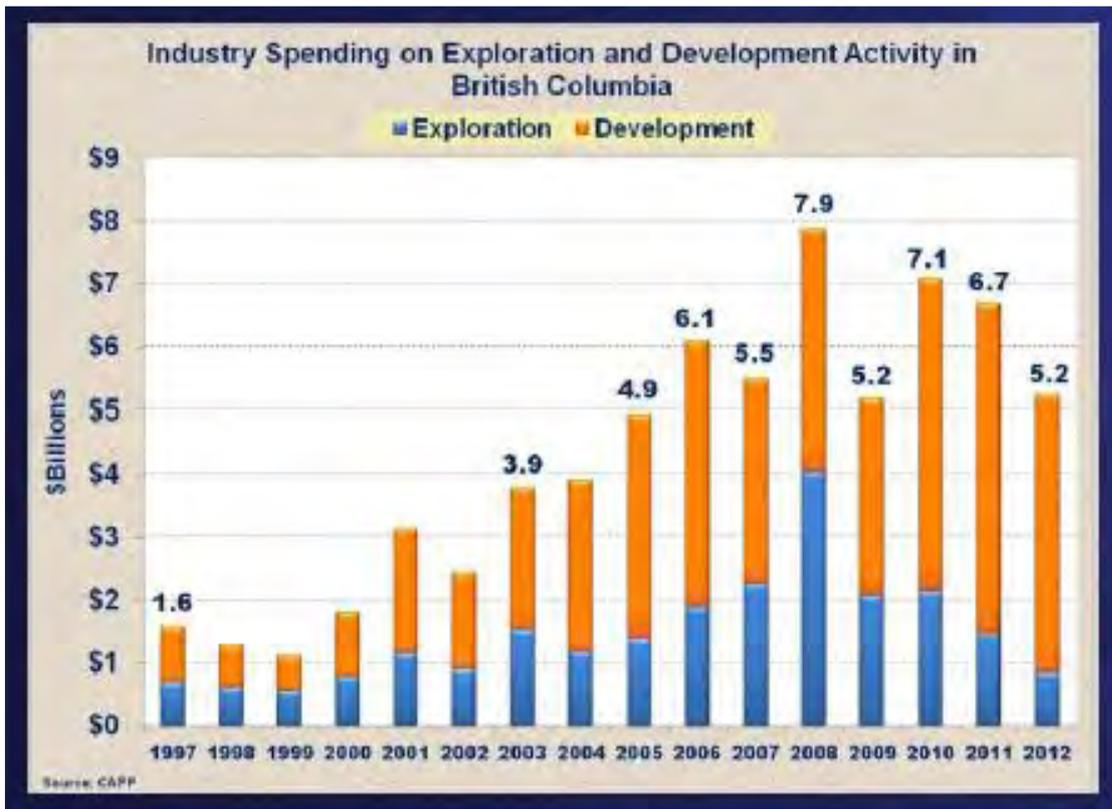
Shale Gas Play Areas in British Columbia

- Cordova Embayment
- Horn River Basin
- Liard Basin
- Montney Trend

BRITISH COLUMBIA
Ministry of Natural Gas Development
Update on Decisions of Cabinet
to the 2014 Executive of Council

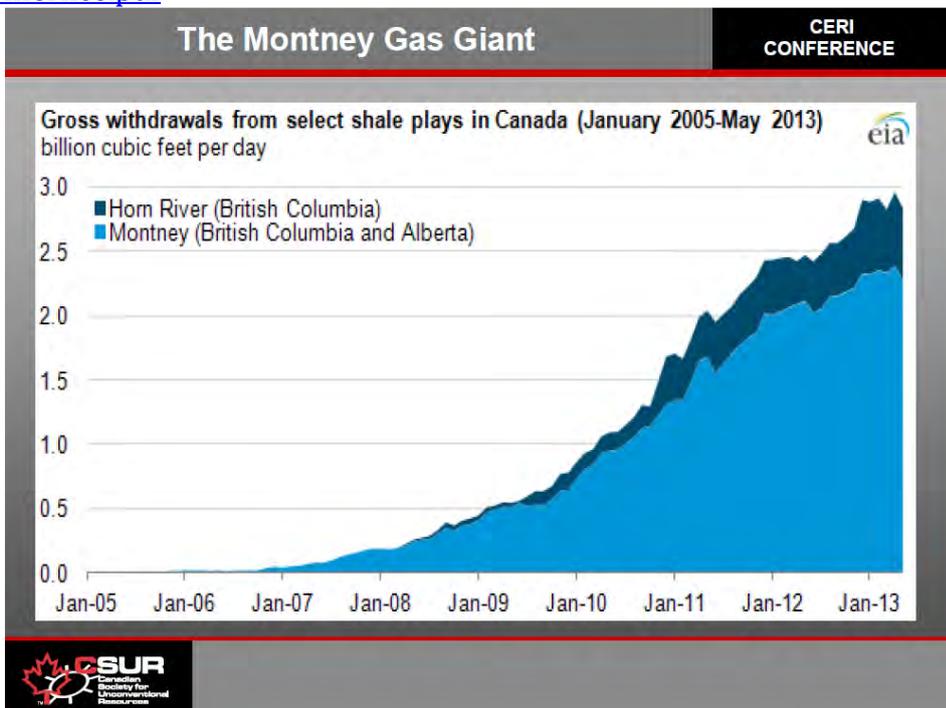
Bonuses Paid for PNG Rights in BC's Shale Gas Regions

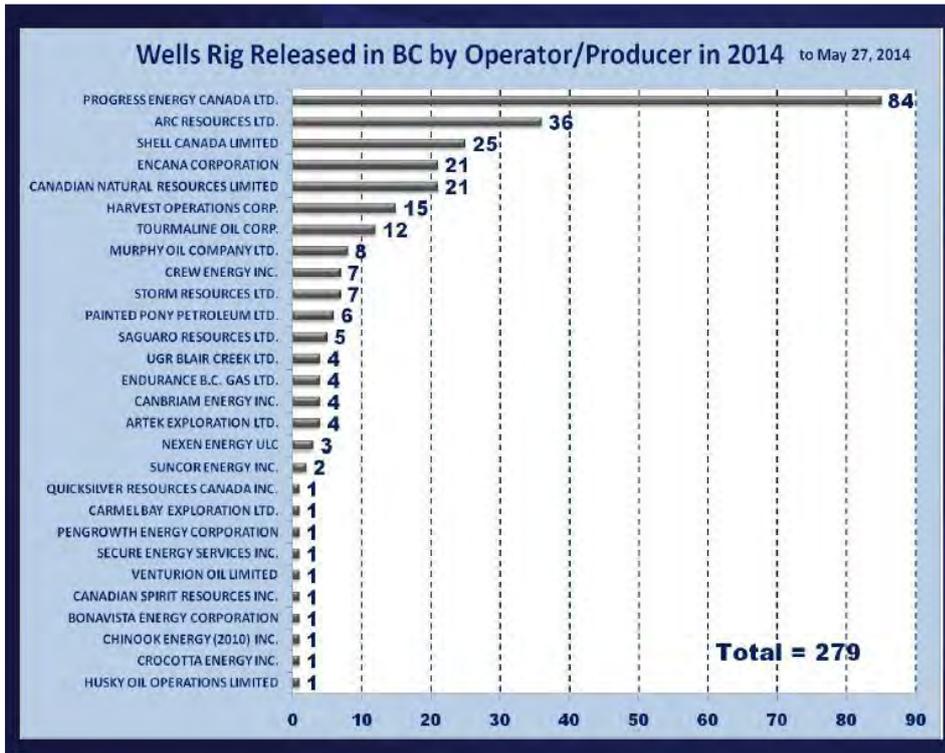




The gas production for the Horn River and Montney as presented by D. Allan.

http://www.csur.com/images/CSUG_presentations/Allan_presentation_CERI_2014_Natural_Gas_Conference.pdf



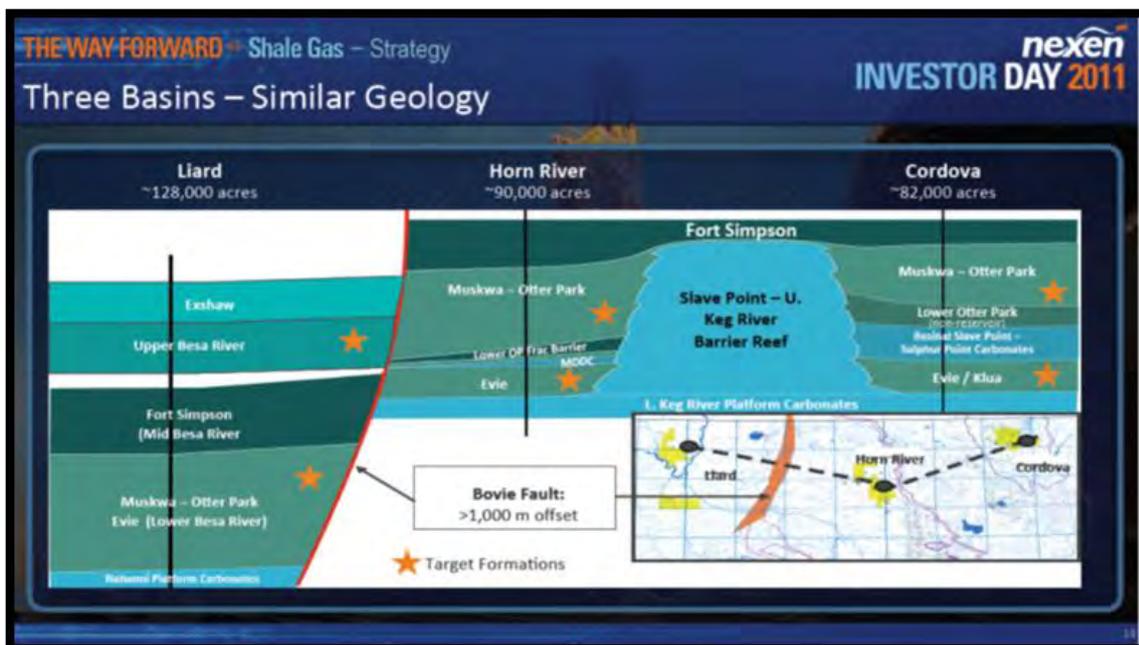


Upper and Middle Devonian, Evie (Klua), Otter Park and Muskwa members of the Horn River Formation Horn River Basin, Cordova Embayment and the Liard Basin

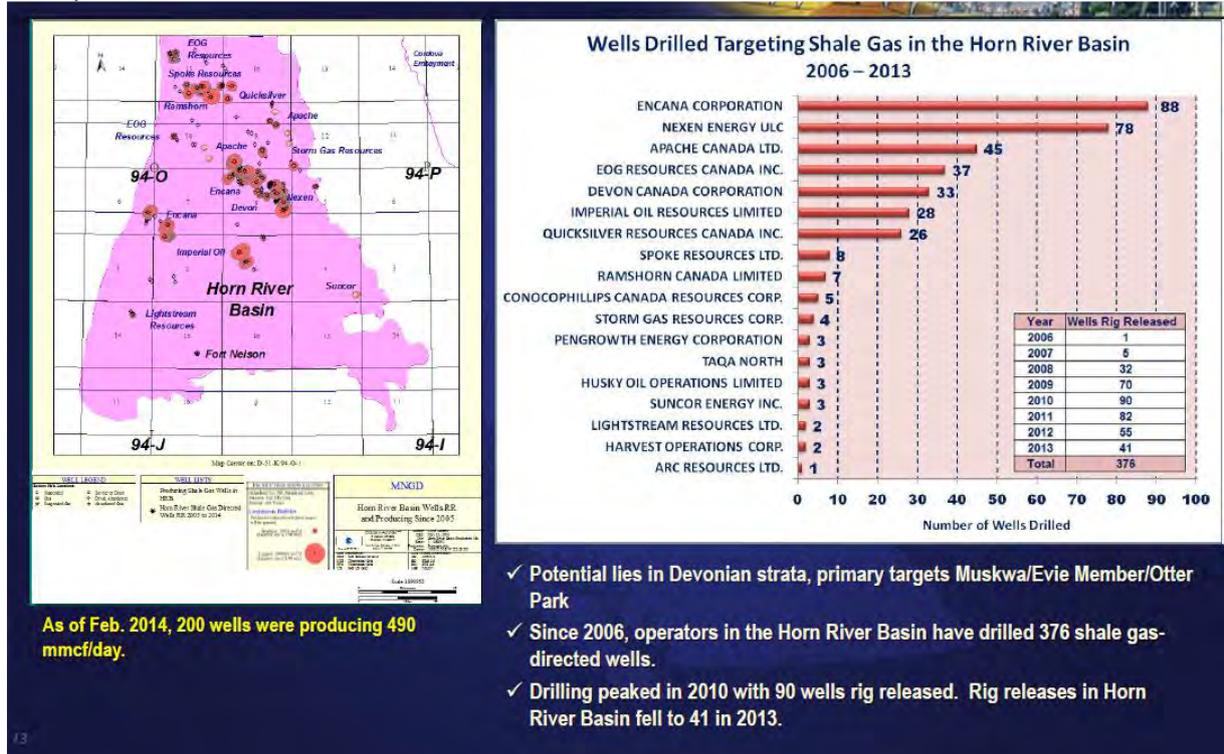
Of these very far north basins, the Horn River has the most activity. As of Dec. 2014 there were 200 wells producing 500 MMCF/D. increasing from roughly 80 MMCFD at the end of 2009 and a cumulative gas production of approximately 770 BCF. As a result of current economic conditions there has not been any significant new development drilling programs initiated in the past few years.

Horn River Basin Unconventional Shale Gas Play Atlas JUNE 2014 | BC Oil and Gas Commission

<http://www.bcogc.ca/node/11238/download>



The seven companies with the most drilling, as of end of 2013 were Encana, Nexen, Apache, EOG, Devon, Imperial Oil and Quicksilver. The potential lies within the Muskwa/Evie Member/Otter Park.



The Laird Basin, straddling the Yukon, North West Territory and British Columbia, containing has great potential with 3 million acres and 5 kilometres of section from the Cambrian to the Upper Cretaceous. It remains relatively unexplored with only a few recent shale-targeted wells but Houston-based independent Apache Corp. calls the Lower Besa River black shale “the best unconventional gas reservoir evaluated in North America with excellent vertical and lateral reservoir continuity.”

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

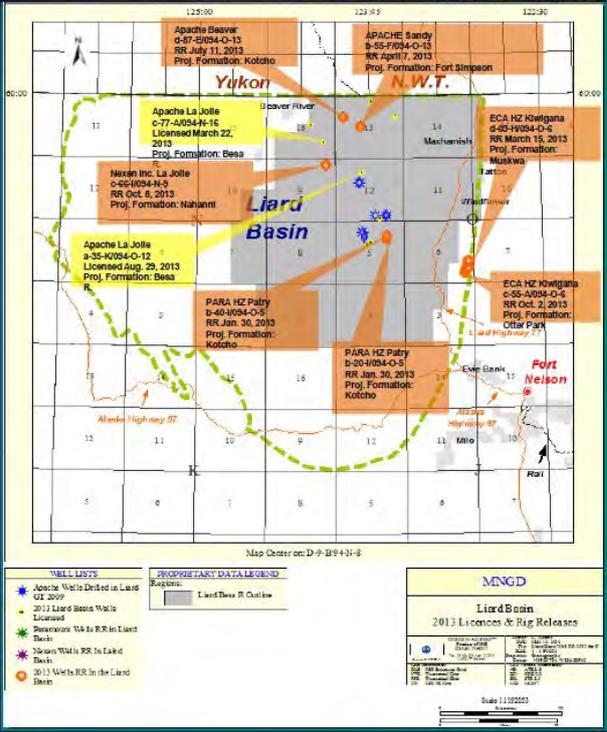


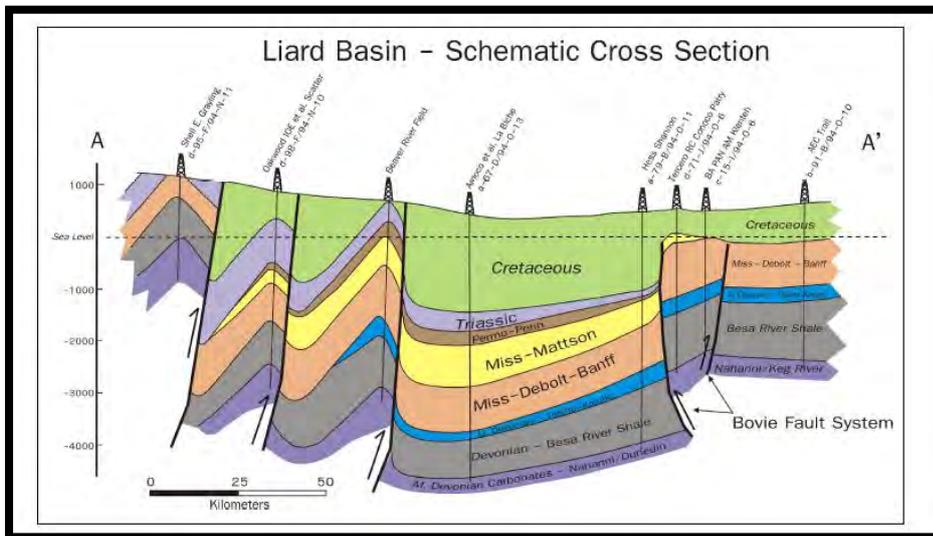
BRITISH COLUMBIA
Ministry of Natural Gas Development

Liard Basin



- ✓ Could contain a resource larger than that found within the Horn River Basin and Cordova Embayment
- ✓ Potential lies in Devonian strata, primary targets Muskwa/Evie Member/Otter Park
- ✓ Apache Canada Ltd. has been working in the east-central region of the Liard Basin in an area called Patry.
- ✓ Nexen Energy ULC plans to develop shale gas resources in the Liard Basin in a strategic partnership with a consortium led by INPEX CORPORATION of Japan
- ✓ Paramount Resources Ltd. holds over 51,000 net hectares in the Liard Basin that are prospective for shale gas in the Middle Devonian Besa River.



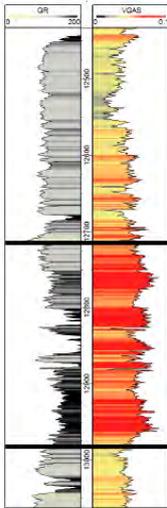


From Apache presentation Jun 2012.

http://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=6&cad=rja&uact=8&ved=0CEwQFjAF&url=http%3A%2F%2Ffiles.shareholder.com%2Fdownloads%2FAPA%2F2148221537x0x577564%2Fd3ace688-47ba-48e4-8179-83b15adb6881%2FApache_Investor-Day_20120614.pdf&ei=NJg4U53sA-66yAGXsoDACQ&usg=AFQjCNHNYyC2VdJ9Etmrv3Uxkf8KzrfBRw&bvm=bv.63808443,d.aWc

LIARD BASIN

BEST UNCONVENTIONAL GAS RESERVOIR IN NORTH AMERICA



Reservoir	Units	Liard	NE-PA Marcellus	Haynesville
Depth	(ft)	9500 - 15000	7000 - 11000	10000 - 13000
Thickness	(ft)	400 - 1000	150 - 400	100 - 300
Porosity	(%)	3 - 8	6 - 12	4 - 7
Water Saturation	(%)	15 - 20	15 - 45	20 - 40
OGIP / Sec	(BCF)	170 - 500	30 - 200	50 - 100
Thermal Maturity	(VRo)	>1.5	>1.6	>1.7
Pressure	(Psi/ft)	0.85 - 0.92	0.5 - .65	~0.85
GOR		Dry Gas	Dry Gas	Dry Gas
Quartz+Carb	(Vol %)	>90	65 - 90	60 - 70
TOC	(Wt. %)	3 - 6	2 - 10	2 - 4

- Lower Besa River First Black Shale
- Best gas-shale reservoir evaluated in North America
- Excellent vertical and lateral reservoir continuity

Gas Filled Porosity

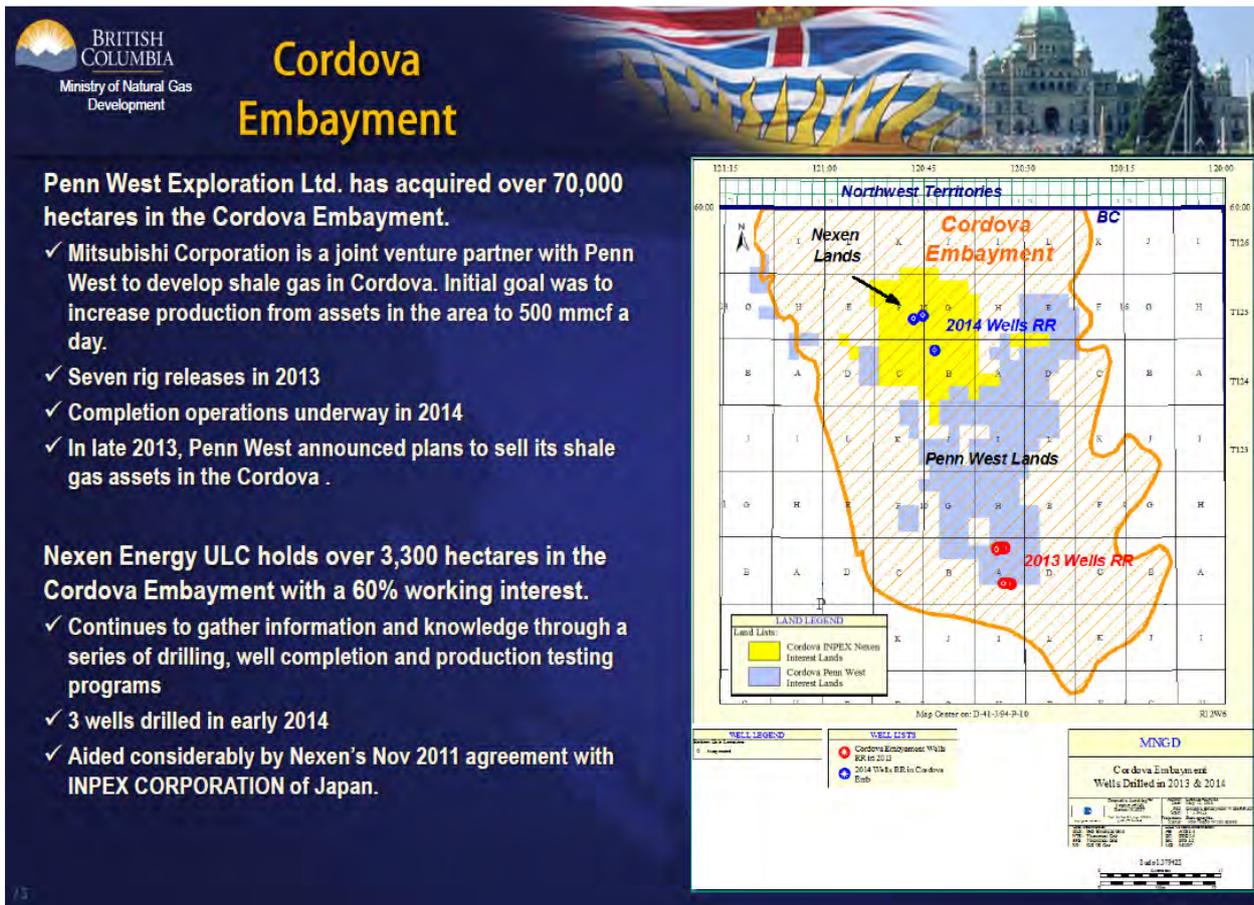
84

In 2012, Apache, with 430,000 acres, reported that one of their wells (Apache HZ Patry d-34-K/94-O-5) recorded a 30 day initial production rate of 21.3 MMCF/D on a six-stage fracturing operation (3.6 MMCF/D per hydraulic fracture). The well was drilled in 2010 to a vertical depth of 3843 m with a horizontal leg of 885 m and has an estimated ultimate recovery (EUR) of 17.9 BCF. It is considered to be one of the best shale gas resource tests in any of North America's unconventional reservoirs (Apache Canada Ltd., 2012).

Apache is targeting the Upper Devonian Lower Besa River Black Shale and estimates that its Liard Basin lands carry a net gas-in-place of 201 TCF, which could yield net sales gas of 48 TCF. The shale is 400-1,000 ft. thick lying at depths of 9,500-15,000 ft. Porosity range is 3-8% and water saturation is 15-20%. Total organic carbon values are 3-6 wt. %. Apache showed a development model that would involve recovery of 54 TCF of raw gas using 731 well locations on 61 pads with two drilling rigs per pad

The company's vertical C-86-F well went to 15,000 ft. and had a 30-day initial potential of 9.8 MMCFD, and the vertical D-28-B well went to 13,200 ft. and flowed 4.6 MMCFD. The two vertical wells had only a single frac apiece. Net pay thickness is 1,024 ft. at C-86-F and 708 ft. at D-28-B. In its development model, Apache envisions drilling horizontal wells with 7,050-8,040-ft laterals with 18 fracs per lateral. The company estimates 400 ft. spacing between fracs and 600 m between wells. Drilling time is 110-120 days/well. The company plans to drill tenure wells in this year's second half followed by more concept wells in 2013.

The Cordova Embayment area, an area of 936,000 acres where most blocks of land were purchased in 2007, is now being drilled. B.C. has an experimental scheme ownership where operations are kept confidential for three years of which Nexen, Penn West and Canadian Natural Resources Ltd. have participated.

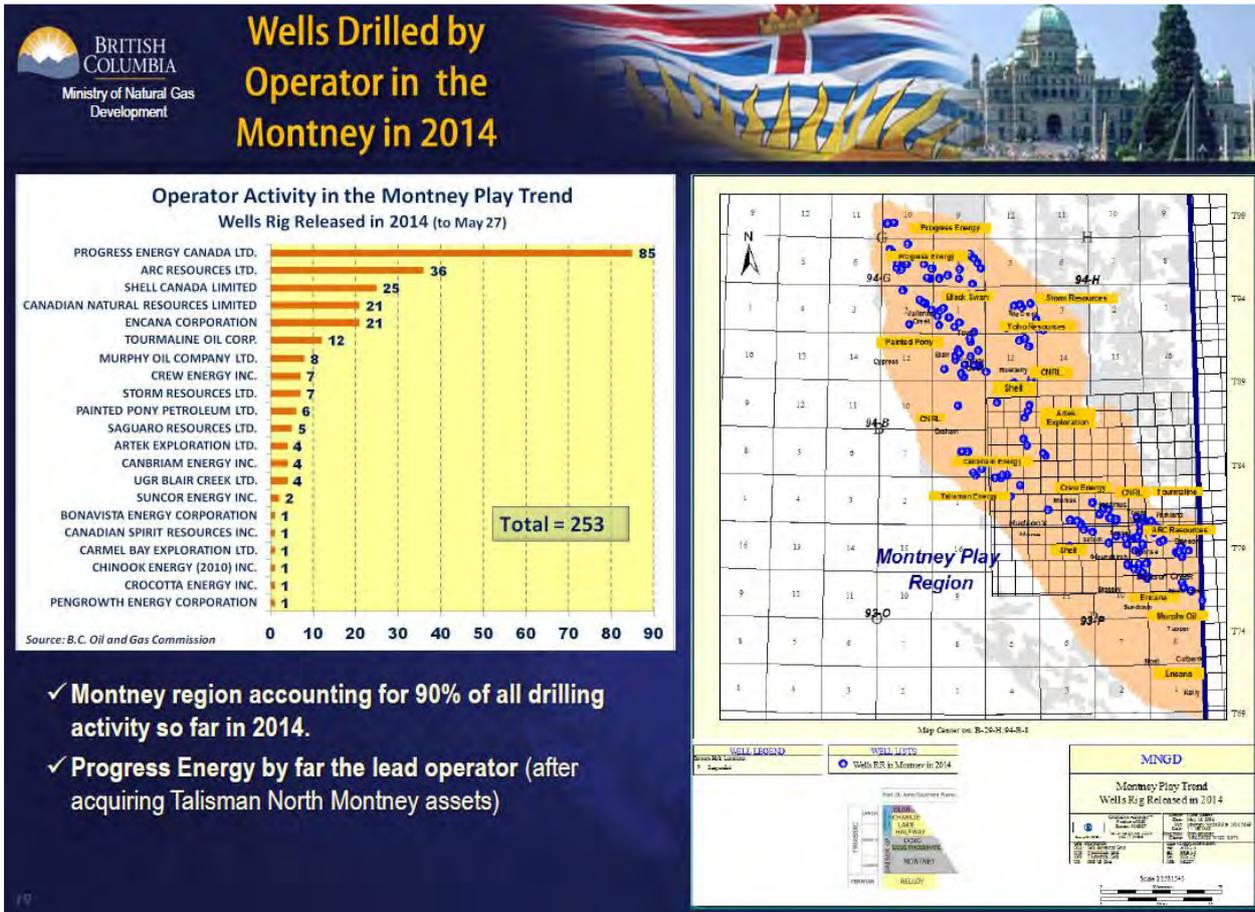


Triassic Doig and Montney Fort St. John/Dawson Creek Area

The Montney is a liquids-rich tight gas/shale gas play, with cumulative production as of Dec 2014 at 3.2 Trillion Cu FT and now producing at more than 2.8 BCFD. There are some projections that it double by 2020. This Montney Play Trend, of 6.6 million acres, is now one of the most active natural gas plays in North America. The primary zones are the Upper Middle and Lower Montney as well as the Doig and Doig Phosphate. The major facies include fine-grained shoreface, shelf siltstone to shale, fine-grained sandstone turbidites, and organic rich phosphatic shale. This play varies from the traditional distal shale facies along the Alberta/British Columbia border to a tight calcareous siltstone and sandstone in Central Alberta. The current trend for companies is to explore up dip towards the “oil window” in search of liquids-rich gas. The top six Montney players out of the more than twenty two, in order of rig utilization, are Progress Energy Ltd., ARC Resources, Shell Canada Ltd, Canadian Natural Resources, Encana Corp., and Tourmaline Oil Corp.

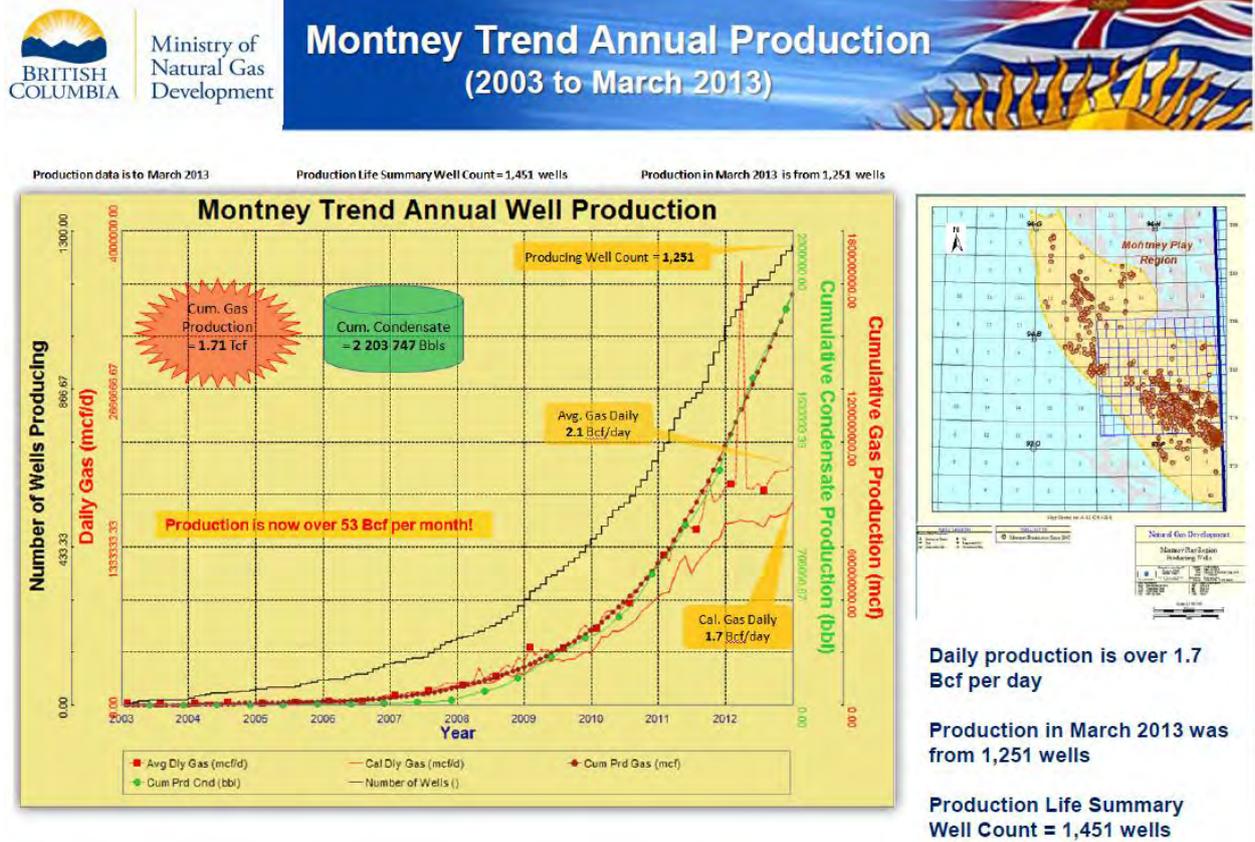
Montney Formation Play Atlas NEBC October 2012 | BC Oil and Gas Commission

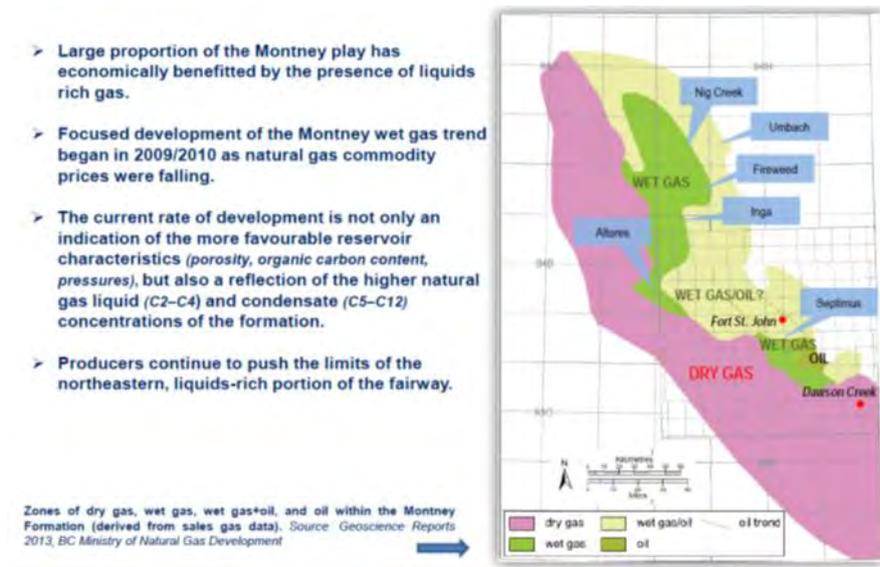
<http://www.bcogc.ca/node/8131/download>



- ✓ Montney region accounting for 90% of all drilling activity so far in 2014.
- ✓ Progress Energy by far the lead operator (after acquiring Talisman North Montney assets)

The graph below shows the well production in the Montney from the Adams, 2013 report.

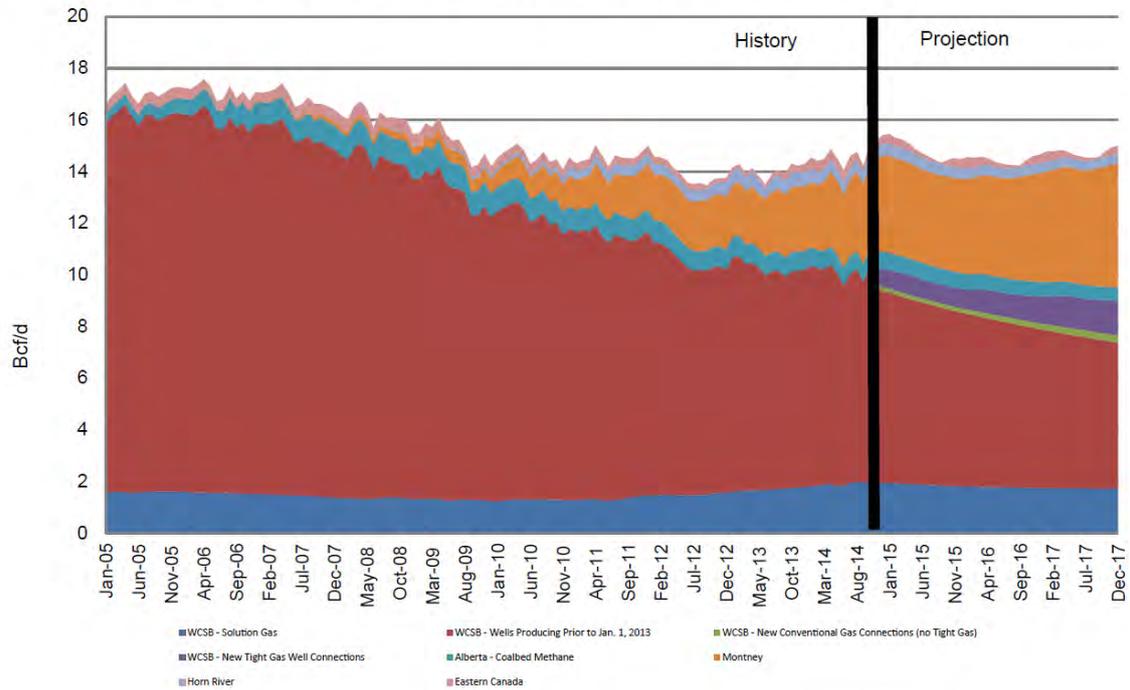




The graph below shows the gas deliverability 2004 to 2015. Note the increasing Montney contribution. <https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/ntrlgsdlvrblty20152017/ntrlgsdlvrblty20152017ppndc-eng.pdf>

FIGURE C.1

Outlook for Canadian Gas Deliverability – Mid-Range Price Case



The following table is from Adams, 2013.

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

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

The Ultimate Potential for Unconventional Petroleum from the Montney Formation of British Columbia and Alberta, November 2013 NEB

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

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

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

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

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

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

<https://www.neb-one.gc.ca/nrg/sttstc/nrllgs/rprt/ltmptntlmntnyfrmtn2013/ltmptntlmntnyfrmtn2013-eng.html>

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

Shale gas activity directed towards Cretaceous horizons is being assessed in several areas of the Fort St. John and Northern Foothills regions. The Blair Creek and Farrell Creek areas in the Northern Foothills region have seen a steady increase in the sale of petroleum and natural gas rights over the last four years. Lower Cretaceous sequences are the exploration focus in the Beg/Jedney areas and further south in the Blair Creek and Farrell Creek areas. Each of these areas has unique characteristics in terms of its shale gas potential. Companies currently operating in these areas are evaluating fracture stimulation programs and continue to optimize completion methods that could potentially increase well productivity. The Buckinghorse Formation is about 1000m thick in some places.

Infrastructure

Spectra Energy Corp. transportation system stretches from Fort Nelson, in northeast British Columbia and Gordondale at the British Columbia/Alberta border, to the southern-most point at the British Columbia/U.S. border at Huntington/Sumas. They have about 2,900 kilometres

(1,800 miles) of natural gas transmission pipeline which can transport 2.9 BCFD. TransCanada Corp keeps expanding their pipeline infrastructure to meet supply and demand. In April 2015 the National Energy Board issued its report recommending the federal government approve the TransCanada proposed North Montney Mainline Project which will add approximately 301 km of pipeline in to the existing system.

With all these gas resources, which are mostly unconventional, the Asian gas market is now being targeted by 19 (11 in 2013) joint venture export groups with the building of LNG terminals with their pipeline routes in Kitimat, Prince Rupert and Grassy Point BC, 643 kilometers north of Vancouver. These projects, details and partners are ever changing with the summary, as of June 2014, below, (10 out of the 19 with 16 BCF/D accounted for):

Kitimat LNG (Chevron, Apache) 1.4 BCF/D, Permits received (including Export License); awaiting investment decision, **BC LNG Export Co-operative**, 0.125 BCF/D, Permits received (including Export License), **LNG Canada** (Shell, KOGAS, Mitsubishi, PetroChina), 2.0 – 3.2 BCF/D, Feasibility stage; applied for some permits; Export License granted, **Pacific Northwest LNG** (Petronas, Japex, Indian Oil Corp., Pet. Brunei, SINOPEC) 2.6 BCF/D (at full build out), Applying for environmental permits, Export License granted, **Aurora LNG** (Nexen/Inpex), Conducting feasibility; Export License granted, **Prince Rupert LNG** (BG Group), 3.0 BCF/D, Advancing feasibility, Export License granted, applying for environmental permits, **Triton LNG** (AltaGas/Idemitsu Kosan) ,0.3 BCF/D, Conducting feasibility; Export License granted, **ExxonMobil/Imperial Oil** (WCC LNG Ltd.) 4.0 BCF/D, Granted Export License, **Woodfibre LNG**, 0.3 BCF/D, Granted Export License, **Woodside** (Grassy Point LNG), 1.8 BCF/D, Conducting feasibility

The BC government has summed up this project with 20 proposed LNG projects, 13 NEB export licences and 34 project partners. <https://engage.gov.bc.ca/Inginbc/lng-projects/>
[http://www.ceri.ca/images/stories/Examining the LNG LPG Puzzle June 21 2014 Final.pdf](http://www.ceri.ca/images/stories/Examining_the_LNG_LPG_Puzzle_June_21_2014_Final.pdf)



The following diagrams shows the proposed pipelines to the coast.



Other BC Information and Links

<http://www.capp.ca/publications-and-statistics/publications/266489>

http://www.csur.com/misc/Oilweek_Top_%20100_%20Breakfast_%20June%2012.pdf

<http://engage.gov.bc.ca/Inginbc/>

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

<http://www.empr.gov.bc.ca/OG/OILANDGAS/PETROLEUMGEOLOGY/SHALEGAS/Pages/default.aspx>

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

<http://www.bcogc.ca/publications/reports>

BC MEM/NEB Report, May 2011: Ultimate Potential for Unconventional Natural Gas in Northeastern British Columbia's Horn River Basin

http://www.em.gov.bc.ca/OG/Documents/HornRiverEMA_2.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 through the collection, interpretation and marketing of publically available.

Some of their major projects have been aquifer studies.

- The B.C. government announced in July 2015 an investment of \$5 million in Geoscience BC to support mineral, water and energy earth science in British Columbia

<http://www.geosciencebc.com/s/AboutUs.asp>

This link below summarizes news items concerning the Horn River area.

<http://hornrivernews.com/>

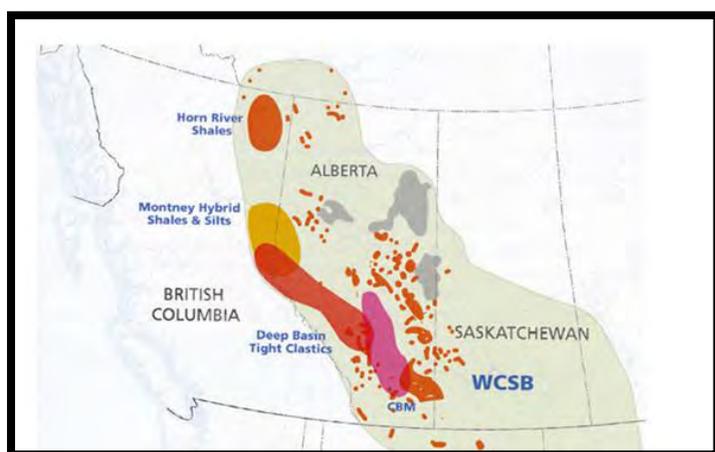
ALBERTA

Note that the recent oil price collapse has changed the dynamics of this industry dramatically especially for Alberta, creating a challenge in the updating for this report.

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

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

Estimates of shale resources within the Western Canada Sedimentary Basin (see map below) vary from 86 to 1000 TCF. This early estimate did not include liquid phase. While there is a huge potential in Alberta, commercial shale production is at early stages but additional new plays have suddenly begun to emerge.



In Oct 2011 the NEB published the “Tight Oil Developments in the Western Canada Sedimentary Basin” which included Plays highlighted are the Bakken/Exshaw Formation (Manitoba, Saskatchewan, Alberta, and British Columbia), Cardium Formation (Alberta), Viking Formation (Alberta and Saskatchewan), Lower Shaunavon Formation (Saskatchewan), Montney/Doig Formation (Alberta), Duvernay/Muskwa Formation (Alberta), Beaverhill Lake Group (Alberta) and Lower Amaranth Formation (Manitoba). The list did not include potential formations, such as the Second White Specks, Nordegg, and Pekisko and others, largely because these new developments are at very early stages. The NEB estimated that Canadian tight oil production, at March, 2011, to be over 160,000 BBL/D. It is too early to estimate with any degree of confidence what the ultimate impact of exploiting tight oil plays in western Canada might be; however, there are some indications. The Alberta Energy Resources Conservation Board’s latest Supply and Demand report estimates that Alberta’s tight oil plays will add an additional 170,000 BBL/D to conventional light oil production by 2014. In Saskatchewan, tight oil production in the first quarter of 2011 was 90,000 BBL/D, while Manitoba, reached 25,000 BBL/D. Companies have so far identified just over 500 million barrels of proved and probable reserves in their plays of interest and not all companies active in those plays have issued formation-specific reserves. This is enough oil to provide production of about 134,000 BBL/D

over a period of 10 years. As well, the technologies used to develop tight oil will continue to evolve, likely increasing the amount of recoverable oil from these plays.

Since 2007, the various governments have been collecting and still in the progress of collections data on the following formations: Colorado Group-First White Speckled Shale, Puskwaskau, Wapiabi, Colorado Shale, Muskiki, Second White Speckled Shale, Blackstone, Kaskapau, Fish Scales, Shaftesbury, Joli Fou, Wilrich Formation, Bantry Shale member, Fernie Formation, Fernie Shale, Pokerchip Shale, Nordegg, Rierdon, Montney, Lower Banff, Exshaw, Duvernay and Muskwa.

In October 2012 a very comprehensive study was published by Rokosh et al.: “Summary of Alberta's Shale- and Siltstone-Hosted Hydrocarbons”. This study concluded that the shale gas resources (hydrocarbon endowment) in Alberta alone are estimated to be 3,424 TCF of natural gas, 58.6 Billion Barrels of NGL’s, and 423.6 Billion Barrels of oil. They evaluated the geology, distribution, characteristics, and hydrocarbon potential of key shale and/or siltstone formations (units) in Alberta. Five units show immediate potential: the Duvernay Formation, the Muskwa Formation, the Montney Formation, the Nordegg Member, and the basal Banff and Exshaw formations (sometimes referred to as the Alberta Bakken by industry). The study also includes a preliminary assessment of the Colorado, Wilrich, Rierdon, and Bantry Shale units. These units were systematically mapped, sampled, and evaluated for their hydrocarbon potential. In total, 3385 samples were collected and evaluated for this summary report. The following table and 4 maps are from this report.

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

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

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

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

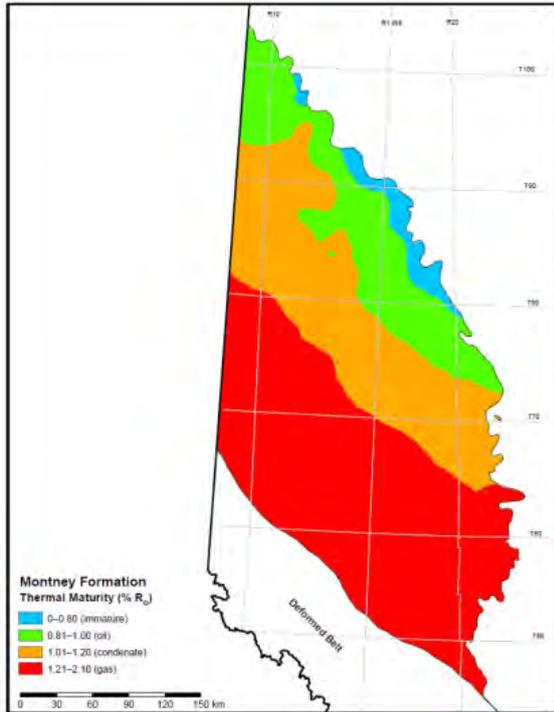


Figure 2.3.7. Thermal maturity map of the Montney Formation.

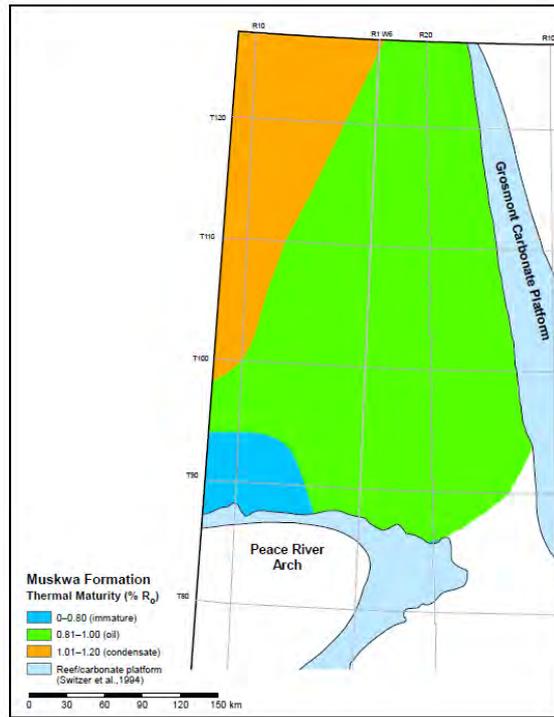


Figure 2.2.6. Thermal maturity map of the Muskwa Formation.

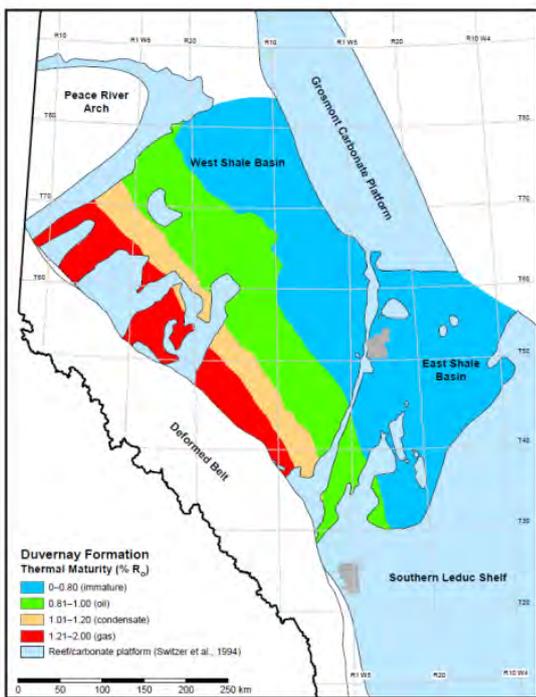


Figure 2.1.7. Thermal maturity map of the Duvernay Formation.

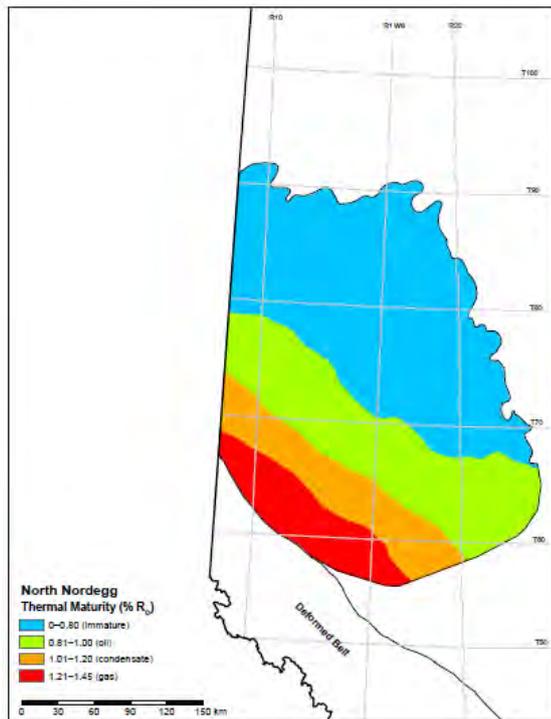


Figure 2.5.7. Thermal maturity map of the north Nordegg.

Thermal Maturity Maps of the Montney, Muskwa, Duvernay and Nordegg from Rokosh et al 2012.

Cretaceous Colorado Group Eastern Alberta

This play is potentially widespread but there has been limited shale gas activity and production within this interval mostly as a result of the gas price. The shale gas intervals are normally co-mingled so numbers are difficult to grasp for the shales. There have been small

companies producing gas from this zone but they are limited and some are selling their interests. Some companies are now focusing on the liquids potential of the Second White Specs.

Lower Jurassic Nordegg (Gordondale)

West Central Alberta

There a small number of companies playing the potential of the Nordegg Member which is a source rock composed of basinal shales, silts and carbonates.

Some companies involved or were involved are: Penn West, EOG, Apache, Surge, Nordegg, Lightstream, Altima, Long Run and others. See Meloche in references.

Triassic Montney Shale

Western Alberta

The Montney fairway extends in Alberta where this play is being picked up for both gas and liquids rich gas. Some of this Montney is classified as conventional because of facies change. Companies actively testing oil-prone Montney exploration acreage include ARC Resources Ltd. at Ante Creek and Tower, Athabasca Oil Sands at Kaybob, Celtic Exploration at Karr, CIOC at Karr and Simonette, Canadian Natural Resources Ltd. at Tower, Crew Energy Inc. at Tower, Harvest at Ante Creek, Imperial Oil at Berland, Long Run at Girouxville, RMP Energy Inc. at Grizzly and North Waskahigan, Seven Generations at Karr, and Triology Energy Corp. at Kaybob West.

In November 2013 the National Energy Board (NEB) in conjunction with their provincial agencies, an ultimate potential of the Montney was released (see below): "The Ultimate Potential for Unconventional Petroleum from the Montney Formation of British Columbia and Alberta" The following two figures are from this report.

<https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/lmtptntlmntnyfrmtn2013/lmtptntlmntnyfrmtn2013-eng.html>

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

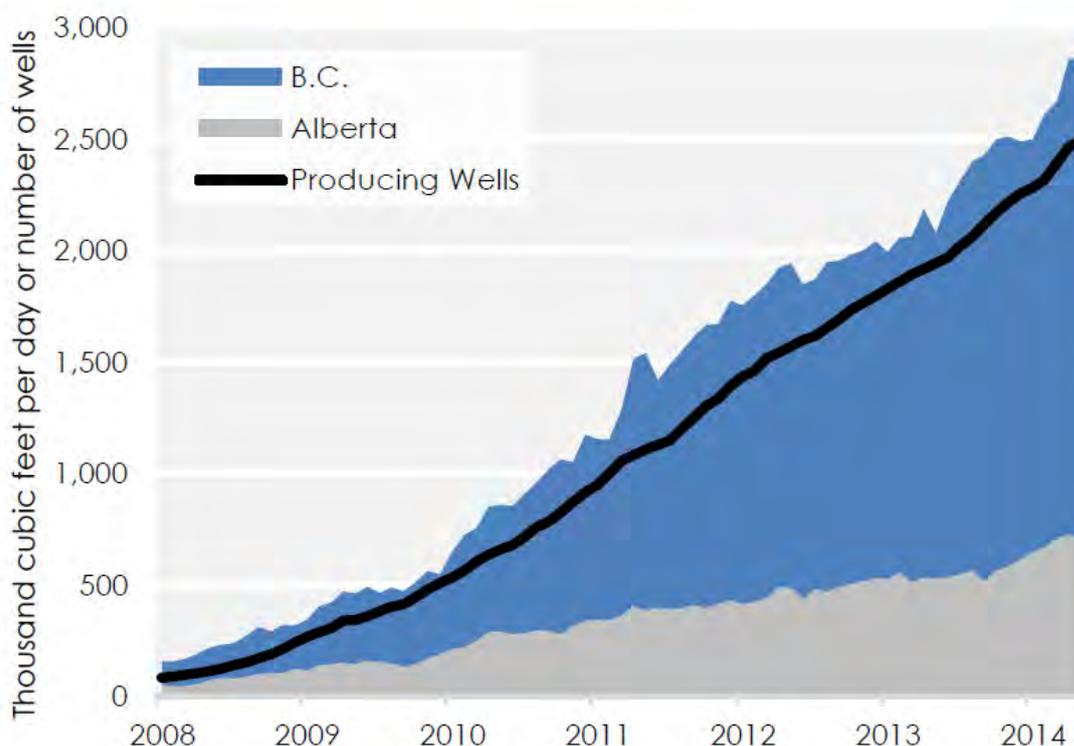
Hydrocarbon Type	In-Place			Marketable		
	Low	Expected	High	Low	Expected	High
Natural Gas – billion m ³ (trillion cubic feet)	90,559 (3,197)	121,080 (4,274)	153,103 (5,405)	8,952 (316)	12,719 (449)	18,257 (645)
NGLs – million m ³ (million barrels)	13,884 (87,360)	20,173 (126,931)	28,096 (176,783)	1,540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

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

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

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

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

Figure 10 Montney Natural Gas Production

<https://www.neb-one.gc.ca/nrg/ntgrtd/mrkt/dnmc/2014/2014nrgdnmc-eng.pdf>

<http://www.ogi.com/articles/print/volume-111/issue-4/general-interest/montney-duvernay-will-be-key-to-canada.html>

Devonian Duvernay/ Muskwa Shales - Western Alberta

The Duvernay is often compared to the prolific Eagle Ford of Texas because they are both shale plays that offer a full spectrum, from dry gas through liquids rich gas to oil. In terms of the potential size of the play area, the richness of the source rock and even some of the early production results, the Duvernay “is well on its way to being as big or bigger than the Eagle Ford,” Canadian Discovery has proclaimed.

This exciting new liquids play, Duvernay Shale is the stratigraphic equivalent to the Muskwa in N.E. B.C. The Duvernay has been credited as the source rock for most of the gigantic Devonian oil and gas pools of Alberta. This zone compares favorably to other North American shale plays with its position in the liquids window, organic content, porosity, thickness and over pressuring. The Duvernay is often compared to the prolific Eagle Ford of Texas because they are both shale plays that offer a full spectrum, from dry gas through liquids-rich gas to oil. According to the Energy Resources Conservation Board, the Duvernay holds an estimated 443 trillion cubic feet of gas, 11.3 billion barrels of natural gas liquids and 61.7 billion barrels of oil. It is estimated that \$4.2 was spent on this play as of June 2012. This BMO Capital markets research report, June 2012, have a wealth of data on this play. Encana believes that this play is 2 times the size of the Eagle Ford Play.

The Duvernay play is divided into the Western and Eastern Shale Basin with the West divided into three drilling districts, Kaybob, Edson and Pembina.

The companies involved in this deep and expensive play of 3100 to 3700 m are numerous, some of which are: Celtic now Exxon (paid C\$2.6 billion), Encana (Petro-China), ConocoPhillips, Husky, Athabasca, Chevron (\$1.5 Billion deal to Kuwait Foreign Petroleum Exploration Corp.), Trilogy, Shell, Talisman, Yoho, Taqa North amongst others.

Encana just announced that they have driven down their well costs significantly from \$30 MM in 2012 to about \$10.4 MM. They have improved the well performance significantly with some wells producing more than 2,000 BOE/d after 55 days. They have accumulated a large position holding 1/3 of the high-graded liquids fairway with a well inventory (gross) of 1,400. Encana's Duvernay comparison with other shales is shown below.

Duvernay – World Class Reservoir

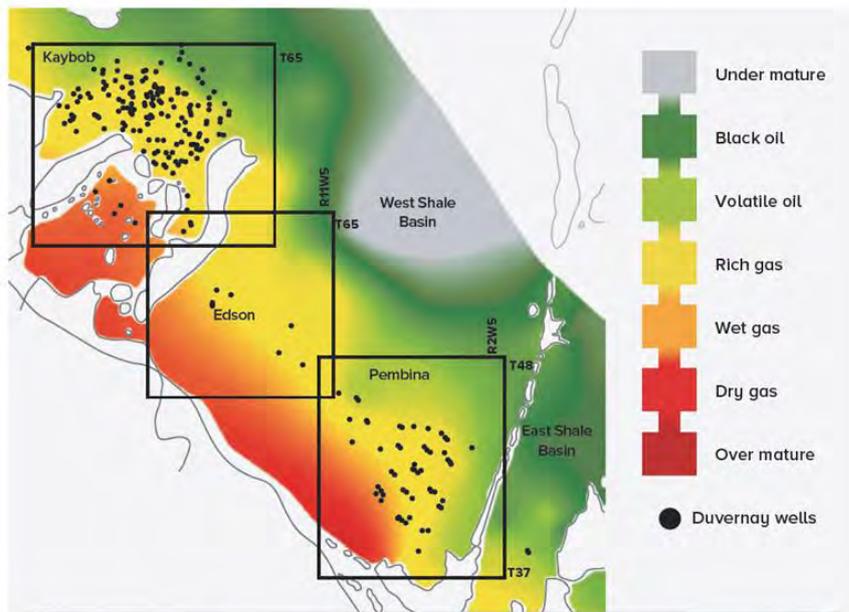
Encana controls one third of the top tier land in the condensate window*

Reservoir Attribute	Duvernay	Marcellus	Eagle Ford
TVD Depth (ft)	8,200 – 13,100	400 – 8,400	8,800 – 13,800
Gross Thickness (ft)	65 – 230	50 – 200	50 – 280
Porosity (%) / Permeability (nD)	3 – 8 / 10 – 400	10 / 20 – 55	10 – 11 / 50 – 1200
Reservoir Temperature (°F)	220 – 250	130 – 170	220 – 280
Gas Composition	Wet / Dry	Wet / Dry	Wet / Dry
Total Organic content (TOC %)	1 – 20	3.0 – 12.0	4.5
Maturation (Ro %)	0.6 – 2.9	1.4 – 3.0	0.6 – 2.2
Pressure Gradient (PSI/ft)	0.72 – 0.96	0.45 – 0.60	0.60 – 0.80
EUR (MMboe / well) (6:1)	0.7 – 1.6	0.3 – 1.0	0.5 – 1.3

*Encana estimate

Source: RBC Richardson Barr / RBC Rundle estimates, industry estimates, DOE April 2009 publication "Modern Shale Gas: A Primer"

From the ALBERTA OIL & GAS INDUSTRY QUARTERLY UPDATE Fall 2015
http://media.angi.s3.amazonaws.com/2015/ANGR_151001_Book_DE.pdf



Duvernay Fairway

Late Devonian and Early Mississippian Alberta Bakken – Exshaw Southern Alberta

The Alberta Bakken (Exshaw) was another emerging tight oil resource play starting in 2010 in SW Alberta to NW Montana consisting of three zones, Big Valley / Stettler Carbonates, Bakken/Exshaw dolomitic siltstones and Banff carbonates. This play has similar characteristics as the North Dakota Bakken in the Williston Basin but since it lies in the Alberta Basin it has been called the “Alberta Bakken”. This play gained momentum south of the border in Montana and moved into Alberta and there was a rush to get a position. In a report a few years ago the research firm Wood Mackenzie said the tight oil play that straddles the Alberta-Montana border could contain a recoverable 2.6 billion barrels of oil. Production of about 300 to 350 BOPD has been published. There are a number of companies initially in this play. Crescent Point, Shell, Penn-West, Murphy, Torc, Argosy, Primary, Nexen, LGX (Bowood/Legacy), Rosetta and Newfield are some of the companies involved or were involved. Over 30 horizontal wells have been drilled so far but with little publication of results. Press releases on this play are minimal and references to this play on their websites have disappeared so either the operators have not been as successful and/or the low oil price has slowed down activity.

Crescent Point Energy had a significant land base and drilled eight wells in the 4th quarter of 2012. Murphy drilled 6 to 9 wells with 3 producers, one being evaluated and one awaiting completion. They have announced tests of 415 to 800 BOPD. Granite Oil (Deethree Exploration) said it had two drilling rigs operating on the lands of 200,000 acres, where they have tested 600 to 950 BBL/D of 30 ° API oil. They have drilled 17 horizontal wells into this zone in 2012. Recently they are focusing on one area where they have started an EOR gas injection scheme creating higher recoveries and slowing declines. Torc has reported that two of their wells have yielded IP rates of 510 and 514 BOPD. LGX Oil + Gas Inc have recently announced success in the Banff and Big Valley Formations with rates up to 530 BOPD. See Zaitlin 2011 and 2012.

The links below provide some of the initial information when this play first came out.

<http://enfieldexploration.com/wp-content/uploads/2014/01/Alberta-ABPS-Bakken-Steady-As-She-Goes.pdf>

http://enfieldexploration.com/wp-content/uploads/2014/02/PIE_Industry_News_2011-03-10.pdf



Other Alberta Information and Links

Alberta Energy Shale Gas <http://www.energy.alberta.ca/NaturalGas/944.asp>

The Alberta Geological Survey (AGS) is active in publishing geological studies including a number of studies on shales.

AGS Shale Gas Section

<http://www.ags.gov.ab.ca/energy/shale-gas/shale-gas.html>

AGS Reports <http://www.ags.gov.ab.ca/publications/pubs.aspx?tkey=shale%20gas>

AGS Conference Papers and posters

<http://www.ags.gov.ab.ca/conferences/geology-poster-ppt.html>

Alberta Duvernay/Muskwa and Montney Formations Shale Analysis poster by the ERCB and Alberta Geological Survey.

http://www.ags.gov.ab.ca/conferences/shale_gas_cspg_2009_poster.pdf

The Alberta Geological Survey has this link with documents on the Colorado Play.

<http://www.ags.gov.ab.ca/publications/pubs.aspx?tkey=colorado%20group>

In 2012 the Alberta Geological Survey just published a new document. Rokosh et al, Summary of Alberta's Shale- and Siltstone-Hosted Hydrocarbon Resource Potential. See the references

Alberta quarterly reports are available through this link. <http://www.junewarren-nickles.com/alberta-oil-and-gas-update/>

The AER is the regulator for Alberta. <http://www.aer.ca/>

AER May 2014 report. <http://www.aer.ca/documents/sts/ST98/ST98-2014.pdf>

SASKATCHEWAN

Upper Cretaceous Colorado Group – biogenic gas

Central Saskatchewan

As in Alberta the Colorado Group shales have been produced in Saskatchewan at low volumes for a 100 years but the recent gas price decline has kept this play minimized. The Saskatchewan natural gas production has gone from 259 BCF in 2005 to about 100 BCF in 2013. This information below will just highlight some the history.

The past exploration focus has been primarily on two types of biogenic shale gas potential within the Upper Cretaceous. The first type is a hybrid shale gas play along the Saskatchewan–Alberta border, where thin laminae of sand and silt lie within the shales of the Upper Colorado Group. Other intervals within the Colorado Group that were once lumped and dismissed as ‘non-productive shale’ are also now being re-evaluated. The second type of play currently being evaluated is the Colorado shale gas play in the eastern half of the province. These highly organic

shales have been the focus of exploration in the past, prior to World War II, when gas seeps were reported near the towns of Kamsack and Hudson Bay. Several wells near Kamsack produced from the early 1930s to late 1940s with total gas production of 168 MMCF. From 2001 to September 2008, 59 new wells, licensed for gas, were drilled in the Hudson Bay and Kamsack areas.

Between 2004 and 2008 more than 50 test wells were drilled for shale gas in all areas in the province, including Watrous, Moose Jaw, Strasbourg, Foam Lake, Smeaton, Shell Lake and Big River but no commercial discoveries have been announced.

http://www2.canada.com/reginaleaderpost/news/business_agriculture/story.html?id=c41a6b5b-b892-40cc-8cb4-902156681111&k=18412

PanTerra Resource Corp. have drilled and cased thirty-six wells within their more than one million acres of land. They feel they have 3 TCF of recoverable gas. They had been coring, logging and fracture stimulating but no rates have been announced to date. Because of the low gas prices they have put this project on hold.

There has also been some activity in the Pasquia Hills in central east Saskatchewan. Pasquia Hills has a huge potential for Oil Shale in this area but there have been about 23 wells drilled by various operators with gas shows and some limited gas tests. There have been a number of smaller operators every few years announce plans but nothing seems to materialize or the company cannot be found on the internet.

Questerre announced a Pasquia Hills program. They acquired 100% interest in 39,000 high-graded net acres overlying an established oil shale deposit in one of Canada's largest oil shale deposits. They have partnered up with a USA firm uses the EcoShale In-situ capsule process which is an innovative approach that moves the machines to the rocks instead of moving the rocks to the machines to extract the oil. Drilled 16 wells in 2012 and analysis of core indicates recoveries between 10-20 gallons/ton with select intervals of up to 16-20 gallons/ton within a 20-35 m section. Further work suspended with low oil prices.

Upper Devonian- Lower Mississippian Bakken

Saskatchewan is also reaping the benefits of the boom in horizontal and fracturing techniques drilling, especially in the Bakken. Production has risen from about 1-2,000 BOPD in 2005 to about 63,000 BOPD at the end of 2014 with a cumulative production of 26 MM M3 or 164 MM BBL. The Bakken production comes from the tight siltstone and sandstone beds with in the shales (Kreis, L.K. and Costa, A. 2005) so it is not really a shale oil play. The Bakken wells tend to highly productive at 200 BOPD producing a light sweet crude oil with 41 ° API gravity.

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.

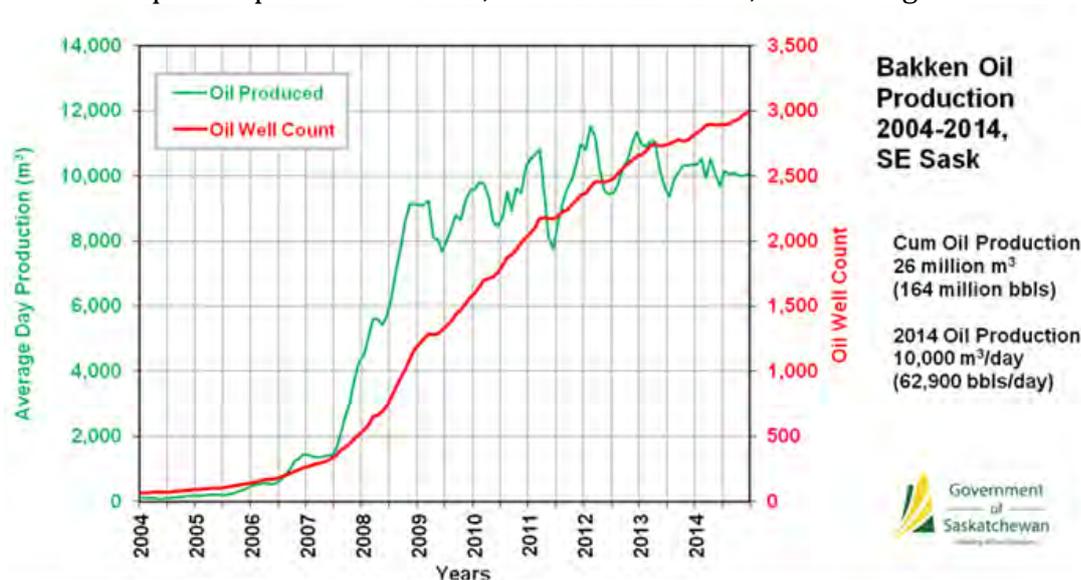
<https://www.neb-one.gc.ca/nrg/sttstc/crdlndptrlmprdct/rprt/2015bkkn/index-eng.html>

Located in the southeast corner of the province, the unconventional, marketable resources of the Bakken are expected to be 223 million m3 (1,401 million barrels) of marketable oil and 81.2 billion m3 (2.9 trillion cubic feet (TCF)) of marketable natural gas.

There are many operators in this play. One of the two bigger players are Crescent Point with 914 wells drilled in 2014. Their Q4/14 production >63,000 boe/d ~4.6 billion barrels of original oil in place with a recovery factor of 3.5%. Their 25-stage cemented liner completion technique

has improved overall returns, recovery factors and water consumption. PetroBakken now Lightstream is the other Bakken producer with Bakken

2015 2nd quarter production of 11,720 BOEPD and >1,050 drilling locations.



Saskatchewan Government energy and resources is the regulator.

<http://www.er.gov.sk.ca/Default.aspx?DN=4c585c56-193a-485a-91fd-7c49f0104a60>

MANITOBA

Cretaceous Colorado Group

There is the potential of shale gas in Manitoba, but no activity or production. There have been a number of publications on the shallow shale potential by Nicholas and Bamburak.

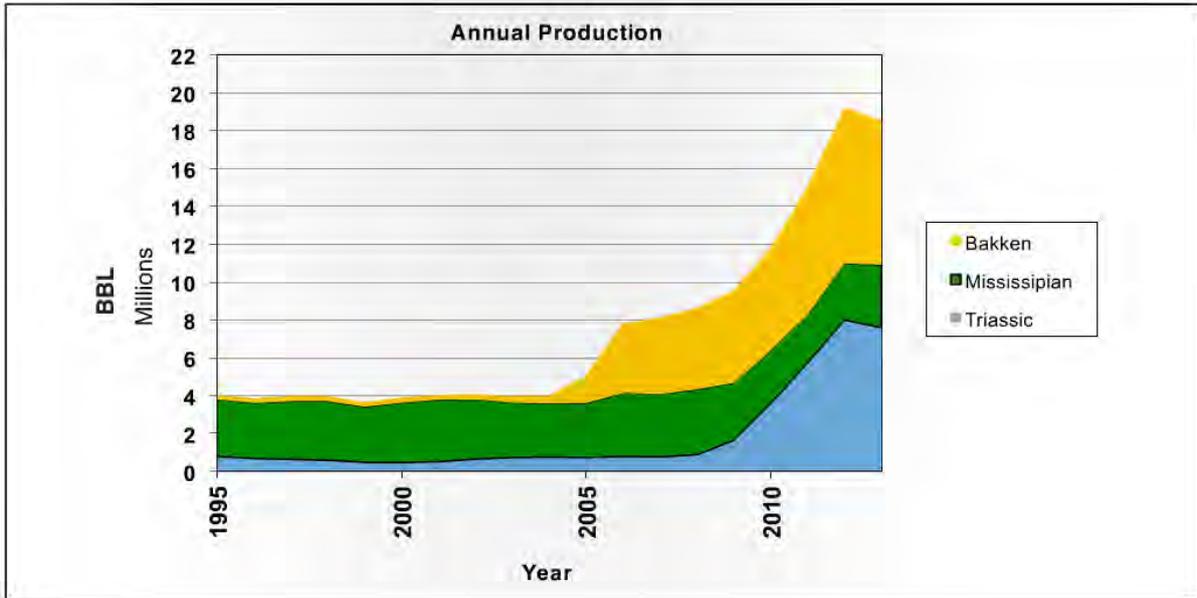
http://www.wbpc.ca/assets/File/Presentation/11_Nicolas_Manitoba.pdf and http://www.wbpc.ca/assets/File/2011%20Presentations/Tuesday/Nicolas%20WBPC%202011_Shale%20gas%20to%20Three%20Forks.pdf

http://www.wbpc.ca/assets/File/2011%20Presentations/Tuesday/Nicolas%20WBPC%202011_Shale%20gas%20to%20Three%20Forks.pdf

Upper Devonian-Lower Mississippian Bakken

The production of oil from the co-mingled Bakken/Torquay, which began in the mid-1980's, continues, with about 640,740 BBL per month or 21,385 BBL/D. Cumulative historical production is 42,364,754 BBL from about 1831 producing wells. The Bakken produces more water than oil so water disposal is a continuing issue. The following graph shows production from the Bakken, Mississippian and Triassic (Lower Amaranth).

The Bakken variability in the Williston Basin is summarized per province/state below.



Basin Variability

Saskatchewan:

- Thick formations

Avg. Torquay: ~87 m
 Avg. M.Bakken: ~46 m
 Depth to Torquay:
 300 – 2400 m

North Dakota:

- Thick formations

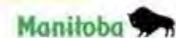
Avg. Torquay: ~90 m
 Avg. M.Bakken: ~46 m
 Depth to Torquay:
 700 – 3900 m



Manitoba:

- Thin formations

Max. Torquay thickness: 45 m
 (65 m in anomalous area)
 Avg. M.Bakken: 6 m
 (13 m in anomalous area)
 Depth to Torquay:
 360 – 1290 m



The Manitoba oil and gas is the regulatory agency.

<http://www.gov.mb.ca/stem/petroleum/index.html>

Manitoba Mineral Resources

<http://www.manitoba.ca/iem/mrd/index.html>

Manitoba Geological Survey

<http://www.manitoba.ca/iem/mrd/geo/index.html>

ONTARIO

Upper Devonian Kettle Point Shale (Antrim Shale Equivalent)

Middle Devonian Marcellus Shale

Upper Ordovician Blue Mountain and Collingwood Shale (Utica Equivalent)

As of Aug. 2015 shale gas or shale oil are not being extracted anywhere in Ontario, and there have been no requests to explore for shale gas or shale oil even though some companies suggest future evaluation. These shales are mostly considered secondary targets but only one well has been drilled to test these zones to date.

The Ministry of Northern Development and Mines – Ontario Geological Survey has been conducting a field study of bedrock in southern Ontario to assess the bedrock's potential to host gas and to characterize the gases. The purpose of the study is to better understand the natural connection between Ontario's shale rock formations and possible implications for groundwater quality in Southern Ontario. <http://www.nrcan.gc.ca/energy/sources/shale-tight-resources/17709#a3>

The only drilling activity is by the Ontario Geological Survey. They drilled two stratigraphic tests last year to assess the shale gas potential of the Kettle Point Formation. They have just released a request for proposals to drill two more stratigraphic test wells to test the Collingwood-Blue Mountain. No results have been published yet.

In the spring of 2010, 2 boreholes were drilled through the Kettle Point Formation. Core samples were collected to evaluate gas concentration and other key parameters. Similar work was performed in 2011 near Mount Forest in the County of Wellington to assess the shale gas potential of the Ordovician shale succession. Furthermore, in the summer of 2012, additional rock samples were collected from previously drilled wells from southern Ontario and were analyzed for mineralogy and Rock-Eval® 6 pyrolysis parameters. These analyses may assist in refining stratigraphic correlations across provincial and international borders. This project is referenced in Béland Otis 2012.

A new company was recently formed, Ontario Oil and Gas, with their total objective to acquire 60,000 acres of shale lands over the next three years. OSO currently controls 2,500 net acres and anticipates growing this quickly over the coming months.

The Ministry of Natural Resources of Ontario is the regulator.

http://www.ogsrlibrary.com/government_ontario_petroleum.html

http://www.ogsrlibrary.com/downloads/Ontario_Shale_Gas_OPI_2009_Nov11.pdf

http://www.wnloilandgas.com/media/uploads/Carter_Presentation.pdf

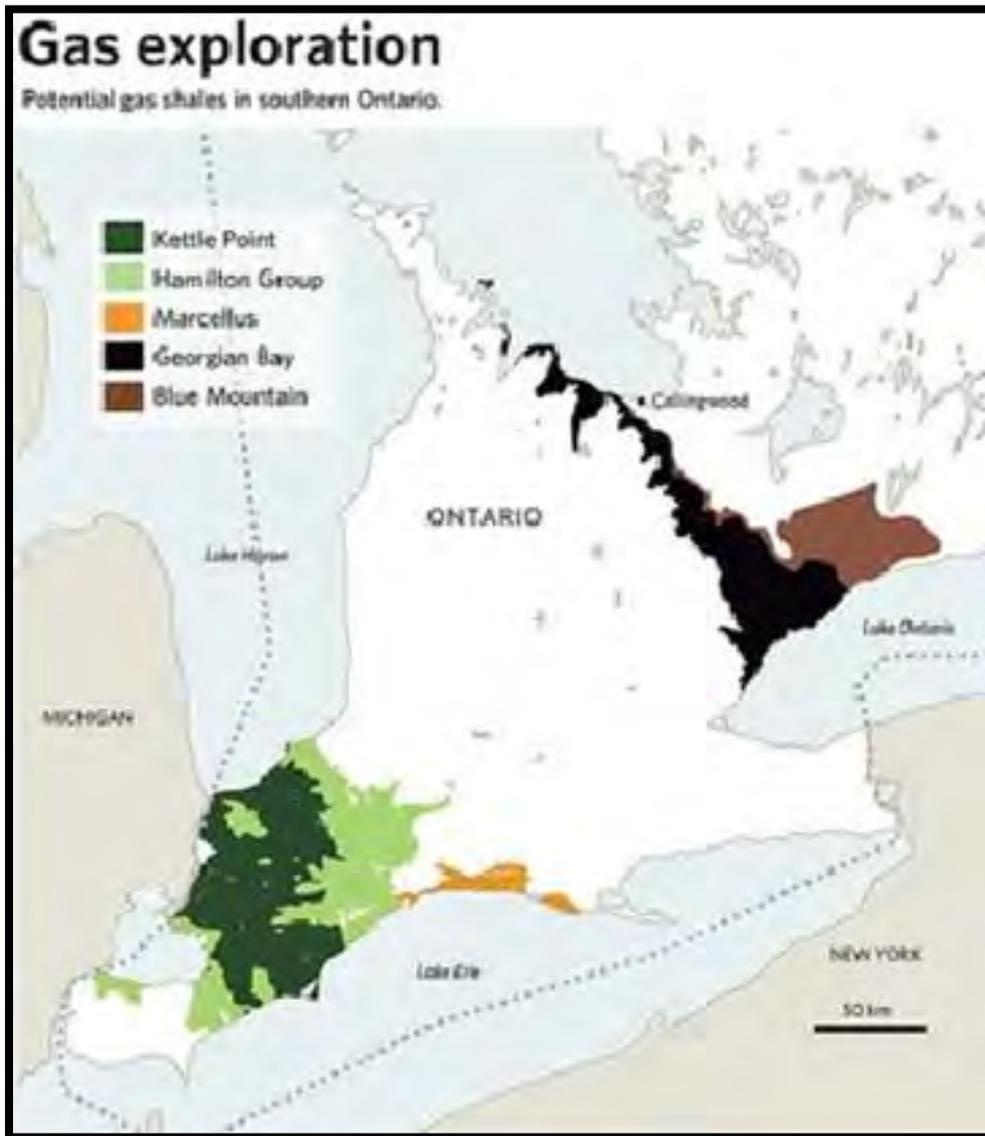
<http://www.ogsrlibrary.com/>

Ontario Geological Survey

<http://www.mndm.gov.on.ca/en/mines-and-minerals/geoscience/non-renewable-energy>

<http://www.geologyontario.mndmf.gov.on.ca/mndmfiles/pub/data/imaging/OFR5716/OFR5716.pdf>

<http://www.geologyontario.mndmf.gov.on.ca/mndmfiles/pub/data/imaging/OFR5817/OFR5817.pdf>



QUEBEC – ST. LAWRENCE LOWLANDS

Ordovician Lorraine and Utica Shale

The other potential bright light in Canadian shale exploration in 2008 was in Québec, within a 300 km by 100 km fairway between Montreal and Québec. The Upper Ordovician Utica and Lorraine shales are the targets.

Update on Hydraulic Fracturing

After six years of debate on the merits and risks of fracking, Québec’s advisory office of environmental hearings published a report in Dec 2014 that found shale gas development in the Montreal-to- Québec 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.”

The other shale play, which will probably require fracking in Québec, on Anticosti Island, is being actively explored in partnership with a Government of Québec affiliate Ressources Québec.(see below)

The Government has announced they will introduce new hydrocarbon legislation as early as spring of 2016.

The Play History

Industry has drilled or evaluated 23 wells and spent \$200 million. Assuming a green light after the environment review finishes industry is saying that it would take 3 to 4 years before the production stage is reached. CERI published Potential Economic Impacts of Developing Quebec's Shale Gas in March 2013.

[http://www.ceri.ca/images/stories/2013-03-08 CERI Study 132 - Quebec Shale.pdf](http://www.ceri.ca/images/stories/2013-03-08_CERI_Study_132_-_Quebec_Shale.pdf)

Both Forest Oil Corporation and their partners and Talisman and their partners have drilled to evaluate both the Lorraine (up to 6,500 feet thick) and the Utica (300 to 1,000 ft. thick). Talisman with their partners and a 771,000 acre land position has drilled six vertical wells with tested rates at from 300 to 900 MCFD. In 2009 and 2010 they drilled or will be drilling five horizontals which were currently being evaluated. Talisman has since suspended its shale gas exploration in Québec. <http://www.theglobeandmail.com/globe-investor/talisman-suspends-shale-gas-exploration-in-quebec/article4753334/>

Forest, after drilling two vertical wells with production rates up to 1 MMCFD and three horizontals, is waiting for the rock work and the analysis before proceeding further. The horizontals rates range from 100 to 800 MCFD with 4 stage fracs. These are ten year leases. Forest estimated 4.1 TCF resource potential at 20% recovery. These black shales of 1 to 3% TOC are 500 ft. thick within the gas window. Cambrian, Gastem, Junex, Questerre, Molopo, Intragaz, Petrolympic and Altai are among the other interest holders in this play.

Questerre Energy Corporation reported on the test results from the St. Edouard No. 1A horizontal well. The horizontal well was successfully completed with 8 stage fracture stimulations. Clean-up and flow back commenced January 29, 2010. During the test, the well flowed natural gas at an average rate of over 6 MMCFD.

<http://www.questerre.com>

See Rivard et al 2013 for a comprehensive review of this play.

Upper Ordovician Macasty Shale

In addition, the Upper Ordovician Macasty Shale (Utica Equivalent) drilled by Corridor and Petrolia on Anticosti Island in the Gulf of St. Lawrence has seen some interest, largely as a secondary target, with results from recent coring identifying shale oil potential. 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 have announced a new program where coring, water wells, and data collection are expected to be completed by the end of 2012, with the final analytical results due in 2013. These results were just announced in Jan 2013. Junex has a position in Anticosti Island as well.

<http://www.corridor.ca>

<http://petrolia-inc.com/en>

Utica Emerges in Québec Shale Play Extends to Canada by Susan Eaton

<http://www.aapg.org/explorer/2010/01jan/shale0110.cfm>

Quebec announced Feb. 13 2014 that it would move ahead with oil exploration on Anticosti with the province pledging \$115-million to finance drilling for two separate joint ventures.

Anticosti Hydrocarbons L.P. is a limited partnership was created to develop oil and gas on Anticosti Island. The partners are Ressources Québec, Pétrolia Inc., Saint-Aubin E&P (Québec) Inc., and Corridor Resources Inc. Their primary objective is to demonstrate the commercial viability of oil and gas resources on Anticosti Island and to produce them.

To achieve this, Corridor Resources Inc. and Pétrolia Inc. pooled their Anticosti Island exploration licenses and transferred them to the limited partnership. On March 31, 2014, the four partners signed a partnership agreement on these 38 licenses, which cover a total area of 6,195 km². For their part, Ressources Québec and Saint-Aubin E&P agreed to finance an exploration program of up to \$100 million. In 2011, Sproule Associates Limited established a best estimate of 33.9 billion barrels of oil equivalent (P50) in undiscovered resources for the licenses held.

The primary aim of the March 31, 2014 agreement between the four partners is to conduct up to \$100 million in exploration work in two phases. To finance the work, Ressources Québec will invest up to \$56.7 million and Saint-Aubin E&P up to \$43.3 million. Pétrolia Anticosti, a subsidiary of Pétrolia, has been appointed contract operator and Saint-Aubin E&P assistant technical operator.

For the first phase, they had planned to drill 15 to 18 core holes in 2014 and 2015, followed by 3 fracking test wells in 2016. This initial phase is budgeted at between \$55 and \$60 million. The stratigraphic survey campaign will allow them to complete our knowledge of the characteristics of the Macasty formation and determine the best locations for the oil drilling planned for 2016. Five wells were drilled and core last year. The drill locations are shown on this map.



<http://hydrocarbures-anticosti.com/en>

Other Québec Information and Links

The *Association pétrolière et gazière du Québec* (Quebec Oil and Gas Association)

APGQ/QOGA Energy Inc. with annual Québec Shale Conferences.

<http://www.apgq-qoga.com/en/>

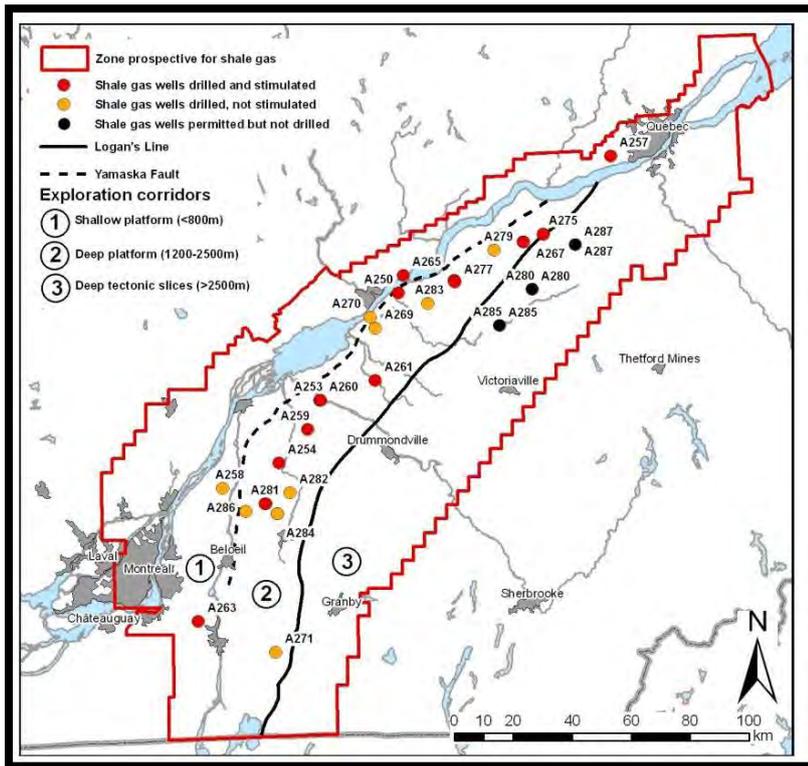
<http://www.apgq-qoga.com/en/conference-2015-2/>

7th Annual conference Le Centre Sheraton Montréal on November 8 and 9, 2015. Nov 8-9 2015

Ministère des Ressources naturelles et de la Faune de Québec is the regulator.

<http://www.mrnf.gouv.qc.ca/english/energy/oil-gas/oil-gas-potential.jsp>

St. Lawrence Lowlands, Québec: Shale Gas Area (Séjourné et al 2013)



NEW BRUNSWICK Lower Mississippian Fredrick Brook Shale Moncton Basin

Update on Hydraulic Fracturing

The New Brunswick government, Dec 2014, is introducing a moratorium on hydraulic fracturing that says won't be lifted until five conditions are met. Those conditions include a process to consult with First Nations, a plan for waste water disposal and credible information about the impacts fracking has on health, water and the environment. This was voted on in March 2015 to prohibit fracking committing to study the controversial method of extracting oil and gas for one year before reconsidering the ban in 2016.

The Play History

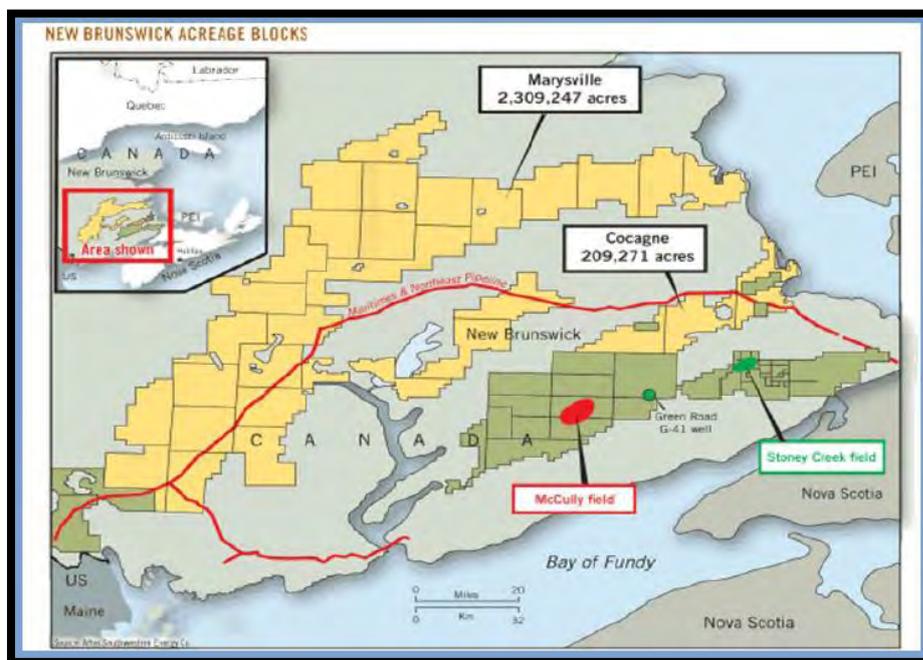
The Lower Mississippian Fredrick Brook Shale in the Moncton Basin had been the focus of thermogenic gas exploration in this province. The Green Road G-41 well was drilled by Corridor Resources in November, 2009 and tested in two zones in the Fredrick Brook, after fracking with propane. The lower black shale interval of the formation flowed at a rate of 0.43 MMCFD, whereas the upper silty/sandy shale zone of the formation tested at initial peak rates of 11.7 MMCFD with a final rate of 3.0 MMCFD. Corridor also announced the farmout of 116,018 acres this shale-potential land to Apache. Apache drilled their second well into this play and proceeded to run five slickwater stimulations per well with no gas recovery. Apache has left the project. Ten wells have been drilled into this play with seven completed and 6 testing gas. The rates have not been consistent. Another appraisal well has been recently spudded. Their plans were to try to develop this thick play of greater than 500 m vertically. During 2011 Corridor completed the drilling of the vertical Will DeMille 0-59 shale gas appraisal well to a total depth of 3188 meters measured depth. Strong gas shows were encountered within Hiram Brook sandstones and the Upper Frederick Brook shale. Based upon initial analysis of well log information, the well intersected at least eight intervals with significantly elevated gas shows that are considered frac candidates. Corridor plans to evaluate these intervals with logs and

sidewall cores in order to select the intervals for future fracture stimulation. The Will DeMille O-59 well is located north of Elgin, New Brunswick.

Contact Exploration and PetroWorth Resources were also re-evaluating their shale gas potential in the Fredrick Brook.

On March 16, 2010, Southwestern Energy Company bid \$47 million for 2.5 million acres in two areas for both conventional and unconventional resources of the Mississippian Horton Group. The company has completed airborne magnetic and gravity acquisition and is in the second phase of surface geochemical sampling and the acquisition phase of approximately 250 miles of 2-D data. Interpretation of the data is underway. \$10.7 million was invested in 2010 with \$14.2 million investment planned for 2011 and then \$14.2 million in 2012 with possible well(s). They finished their seismic program in Dec 2013. Four wells are proposed for drilling and the necessary documents have been filed.

<https://www.swnb.ca/>



Other New Brunswick Information and Links

"Frederick Brook Shale spurs Canadian exploration," by Susan Eaton *AAPG Explorer*, August 2010, p.6-10.

<http://www.aapg.org/explorer/2010/08aug/fredrick0810.cfm>

New Brunswick Natural Resources, Minerals and Petroleum is the regulator for this province.

<http://www.gnb.ca/0078/minerals/index-e.aspx>

http://www.gnb.ca/0078/minerals/GSB_Hydrocarbon_Basin_Analysis-e.aspx#Objective
Shale Gas Website

http://www2.gnb.ca/content/gnb/en/corporate/promo/natural_gas_from_shale.html

Update on New Brunswick by Steven Hinds

http://www.wnloilandgas.com/media/uploads/Hinds_Nfld2011.pdf

NOVA SCOTIA

Upper Devonian/Lower Mississippian Horton Bluff Kennetcook Basin - Update on Fracking

The Government has had a long history of reviewing the hydraulic fracturing starting in the spring of 2011 when an internal committee of officials from the Departments of Energy and Environment examined the environmental issues associated with hydraulic fracturing in shale gas formations. Recommendations were made for additional reviews.

The Nova Scotia Department of Energy commissioned the Verschuren Centre for Sustainability in Energy and the Environment at Cape Breton University on August 28, 2013 to conduct an independent review and public engagement process to explore the social, economic, environmental, and health implications of hydraulic fracturing practices and their associated wastewater streams. Dr. David Wheeler, President and Vice-Chancellor of Cape Breton University convened and chaired the 10 person Expert Panel on Hydraulic Fracturing and made the recommendations in a report dated 28th August 2014. The major conclusion of the Wheeler panel is that Nova Scotians are not yet ready for high volume hydraulic fracturing as part of onshore shale development. Therefore Nova Scotia moved ahead with legislation (Nov 2014) but the proposed law also includes an exemption that would allow fracking for testing and research purposes.

The Play History

The Upper Devonian-Lower Mississippian Horton Bluff Shale in the Kennetcook Basin has been the primary target for thermogenic shale gas exploration in the province by Triangle (Elmworth) Petroleum since May 2007. A 2D and 3D seismic program was initiated and a total of 5 vertical exploration wells have been drilled since May 2007. Various fracture treatments have been performed although none have successfully produced gas so far. On April 16, 2009, Triangle executed a 10-year production lease on its Windsor Block in Nova Scotia which covers 474,625 gross acres (270,000 net acres) with a potential of 20 TCF recoverable. They have agreed to drill at least 7 more wells in this block before 2014. In 2009 they conducted a 30 km 2D seismic program to try to pinpoint areas with structure for future shale targets. Currently there has been no work this year as they are looking for partners.

This abstract is from "The Horton Bluff Formation Gas Shale Opportunity, Nova Scotia, Canada, Adam MacDonald, 2012 AAPG Search and Discovery
<http://www.searchanddiscovery.com/abstracts/html/2011/annual/abstracts/MacDonald.html?q=%2BtitleStrip%3Acanada+%2ByearSort%3A%5B2011+TO+2012%5D>

The Horton Bluff Formation gas shale's are within the Carboniferous lacustrine Horton Group of the Maritimes Basin. Gas in place (GIP) estimates are 69 TCF and leading indicators of a prospective shale gas play such as TOC at >5.5 % , Maturity (Ro) of 1.6, thickness of >500 meters and estimates of 100 Bcf per section across an area of > 2 million acres, have generated an increased interest in the Horton Bluff Formation within this frontier basin. Comparison of this shale play characteristics to many others (mineralogy, gas filled porosity, pressure gradient, adsorbed gas) across North America ranks the Horton Bluff shale as among some of the most prospective.

The Nova Scotia Department of Energy (NSDOE), worked closely with industry, has undertaken the task of trying to understand the resource potential. GIP or "size of the prize" is determined by the shale's gas generating potential, the mineralogy which may dictate the fracking techniques and lead into the engineering solutions that need to be achieved through the drilling and piloting phase to reach commercial producibility.

The energy trader who co-founded Galveston LNG Inc. and later sold the Kitimat LNG scheme to Apache Canada and EOG Resources for roughly \$300 million is back with a new plan to export natural gas from Canada's east coast. Alfred Sorensen said today that his new company, Pieridae Energy Canada, plans to build an export terminal at Goldboro, Nova Scotia. It is contemplated that the gas source come from the Marcellus, New Brunswick? and offshore Nova Scotia. It has been issued long-term licenses (Aug 2015) by the National Energy Board of Canada to import natural gas from the USA and to export liquefied natural gas (LNG) from Canada.

<http://pieridaeenergy.com/>

<http://www.albertaoilmagazine.com/2012/10/pieridae-energy-proposes-east-coast-lng-facility/>

The Goldboro LNG Facility is to include a gas liquefaction plant and facilities for the storage and export of LNG, including a marine jetty for off-loading, and upon completion, is expected to ship approximately five million metric tons of LNG per year and have on-site storage capacity of 420,000 cubic metres of LNG. The Goldboro LNG Facility is to be located adjacent to the Maritimes & Northeast Pipeline, a 1,400-kilometre transmission pipeline system built to transport natural gas between Nova Scotia, Atlantic Canada and the North eastern United States.

The Nova Scotia Department of Energy is the regulator for the province.

<http://www.gov.ns.ca/energy/oil-gas/onshore/>

NEWFOUNDLAND

Ordovician Green Point Shale - Western Newfoundland

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. Further drilling of the shale oil potential in this formation was undertaken by re-entry of the previous well bore, sidetracking and testing. These plans were unsuccessful and discontinued because of severe formation damage. Some of acreage has been relinquished but there are still two licences left with about approximately 150,000 acres of land. This is an offshore block enclosed, for the most part, by land with onshore to offshore drilling sites. The target package is a tectonically thickened and naturally fractured, interbedded black shales, siltstones and carbonates in excess of 2000 metres thick.

These projects are delayed since the government announced a study of the future of fracking.

<http://www.releases.gov.nl.ca/releases/2013/nr/1104n06.htm>

<http://www.nr.gov.nl.ca/nr/energy/index.html#3>

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.

<http://nlhfrp.ca/>

The Newfoundland Department of Natural Resources is the regulator for the onshore portion of the province.

<http://www.nr.gov.nl.ca/mines&en/oil/>

<http://www.nr.gov.nl.ca/nr/energy/petroleum/onshore/onshore.html>

This is the latest publication by the DNR on the Shale Oil Potential of the Anticosti Basin.

<http://www.internationalpavilion.com/NAPE%202012%20Presentations/I%202.48-3.00%20Wednesday%20Newfoundland%20and%20Labrador.pdf>

The Canada-Newfoundland Labrador Offshore Board is the regulator for the offshore portion.

<http://www.cnlopb.nl.ca/>

TERRITORIES - NORTHWEST TERRITORIES

The Northwest Territories (NWT) has vast undeveloped oil and gas reserves. It is estimated that the NWT could hold as much as 37 percent of Canada's marketable light crude oil resources and 35 percent of its marketable natural gas resources.

The Department of Industry, Tourism and Investment (ITI) is responsible for the administration of onshore oil and gas interests in the Northwest Territories, including the Inuvialuit Settlement Region. Interests issued in the offshore are the responsibility of Aboriginal Affairs and Northern Development Canada. This study was commissioned jointly by the National Energy Board and NWT Geological Survey.

<https://www.neb-one.gc.ca/nrg/sttstc/crdlnpdtrlmprdct/rprt/2015shlnt/index-eng.html>

The National Energy Board (NEB) had regulatory responsibilities for oil and gas exploration and production activities, including the drilling, completion, hydraulic fracturing and formation flow testing of, and production from onshore unconventional reservoirs under the Canada Oil and Gas Operations Act (COGOA) and its regulations. who is responsible for these lands. They completed the following guidelines. Filing Requirements for Onshore Drilling Operations Involving Hydraulic Fracturing September 2013.

<https://www.neb-one.gc.ca/bts/ctr/gnthr/flrqnsdrllprtn/flrqnsdrllprtn-eng.pdf>

The GNWT is currently in the process of developing an NWT Oil and Gas Strategy. Part of that Strategy is considering improvements to the regulatory regime to ensure that any future development employing hydraulic fracturing will be done safely to assure protection of our environment and the health and safety of our people.

<http://www.iti.gov.nt.ca/news/discussions-hydraulic-fracturing-regulations-continue-18th-legislative-assembly>

2014–2015 Call for Bids in the Central Mackenzie Valley Date of Launch: January 30, 2015 and closing date: June 2, 2015 – no bids were received. This area is far to the north west of the Canol Shale area around Norman Wells.

<http://www.iti.gov.nt.ca/infopage/central-mackenzie-valley-call-bids-2014-2015>

Devonian Canol Shale

Recent News

With the recent decline in oil prices, most companies have put their exploration plans for the Northwest Territories (NWT) on hold.

The National Energy Board of Canada completed a study of volume of oil-in-place for the Bluefish Shale and the Canol Shale of the Northwest Territories' Mackenzie Plain has been evaluated for the first time by the National Energy Board and the Northwest Territories Geological Survey. The thick and geographically extensive Canol Shale is expected to contain 145

billion barrels of oil-in-place. The much thinner Bluefish Shale is expected to contain 46 billion barrels of oil-in-place.

The amount of marketable (i.e., recoverable) oil was not estimated because well-test results are not yet publicly available and there is still uncertainty about whether these shales are capable of production. However, if only one percent of the in-place resource could be recovered from the Canol Shale, it would represent a marketable resource of 1.45 billion barrels. Based on the limited geological data available, the analysis assumes that both shales are saturated with oil throughout the study area.

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

Historical Background

The Northwest Territory Geoscience Office commissioned Dr. Brad Hayes of Petrel Robertson Consulting Ltd. of Calgary to undertake a regional-scale study of the unconventional shale gas and shale oil potential of the southern and central Northwest Territories. His report assembles available outcrop and subsurface data to systematically assess shale gas and oil potential and is available as NWT Open File 2011-08 (See below). The work follows on an earlier unconventional natural gas scoping study for the NWT also authored by Dr. Hayes (NWT Open File 2010-03) (See references below).

Canada's Northern Oil & Gas Directorate held lease sales in 2011 and 2012 where industry has committed \$628 million in work commitments on 13 exploration licenses in the central Mackenzie region. It is speculated the Canol Shale play was the main target.

The Canol shale formation could be as big as the prolific Bakken light oil play. Initial estimates peg the Canol play at two to three billion barrels of recoverable crude in a region which has seen drilling activity for almost a century but has yet to reap substantial economic benefit because of its remote and challenging terrain. The plan is for companies such as Imperial Oil, Shell Canada and MGM Energy (one well), ConocoPhillips (two wells), Husky Energy (two wells) and International Frontier to continue activity to prove up the resource and eventually produce crude for southern market.

<http://m.theglobeandmail.com/globe-investor/husky-prepares-an-arctic-expedition/article4179898/?service=mobile>

In the 2012/2013 winter drilling season ConocoPhillips drilled two horizontal-fracture-stimulated wells on EL-470, the wells were the first horizontal-fracture-stimulated wells that evaluated the Canol Shale, both wells are on confidential status.

MGM (Now Paramount) in partnership with Shell, who farmed in, were the first to announce the results of drilling and hydraulic fracturing this new play. Their vertical well into the Canol shale resulting in the recovery of approximately 140 barrel of fluid consisting of frack fluid, crude oil and natural gas. Their discovery was awarded a large Significant Discovery Area this summer.

According to MGM, the Canol/Hare Indian shale is 30-170 metres thick at a depth of 1,000-2,500 metres. In addition, the Bluefish Shale is 15-25 metres thick at a depth of 1,000-2,700 metres. Both are highly brittle, which is a key attribute for successful fracturing. There independent reserve estimate on four exploration licenses are about 11 Billion Barrels oil in place, mean. Drilling is restricted to the months of January to March.

Husky Energy has withdrawn its application to horizontally drill and frack up to four wells in the Sahtu region of the N.W.T. ConocoPhillips drilled and fracked their two horizontal wells in the Canol shale. They were successful and are applying for a Significant Discovery License (SDL). No results of the publication of this report. ConocoPhillips says it doesn't plan to do any more exploration work on its parcel in the N.W.T.'s Canol shale oil play for the foreseeable future.

<http://www.cbc.ca/news/canada/north/conocophillips-seeks-declaration-of-significant-n-w-t-discovery-1.2998597>

The nearby Norman Wells oil field discovered in the 1920s, has been in decline for a decade and the Enbridge Pipeline to Alberta is running at 33% capacity at 40,000 barrels of oil per day. See Hadlari and Issler and Pyle and Gal in References.

<http://www.ihs.com/products/oil-gas-information/source-newsletter/international/jan2012/canadian-alaskan-exploration.aspx>

Geoscience Office

<http://www.nwtgeoscience.ca/petroleum/>

http://www.nwtgeoscience.ca/petroleum/unconventional_gas.html

YUKON

The Yukon Geological Survey has conducting studies to determine the potential of shale gas in the territory. Shale gas has not been explored for or produced in Yukon; however, future oil and gas projects will most likely consider shale gas reservoirs as potential targets. Shale is likely found in all of Yukon's oil and gas basins. Whether or not the shale formations contain natural gas in sufficient quantity to produce has yet to be determined. The Yukon Geological Survey conducted a scoping study to identify the presence of shale gas and other unconventional oil and gas resources in the Yukon. The results of this study were published in 2012.

http://ygsftp.gov.yk.ca/publications/miscellaneous/Reports/YGS_MR-7.pdf

Northern Cross Yukon acquired 15 exploration permits in Northern Yukon. There will be 4 wells drilled in the far north for conventional targets as well as consideration of the shale potential in the Devonian.

In the south, in the Laird Basin, which extends into BC, EFLO Energy and partners are planning to exploit the Devonian/Mississippian shales near the Kotaneelee conventional field. This resource has the potential of 500 to 100 BCF of conventional gas and 7.2 to 13 TCF of shale gas. A sales gas pipeline exists to Ft. Nelson.

The Yukon government has established a committee to review hydraulic fracturing before it is permitted.

<http://www.legassembly.gov.yk.ca/rbhf.html>

The report was completed in Jan 2015 with comments that a clear majority of First Nation governments and Yukoners who participated in the Committee's activities indicated their opposition to hydraulic fracturing but they came up with a list of 19 recommendations.

The latest news suggests that the territorial government plans to pave the way for fracking in the Liard basin in southeast Yukon, saying it will focus on the area "for further research and possible shale development."

<http://www.emr.gov.yk.ca/oilandgas/hydraulic-fracturing.html>

Yukon Energy, Mines and Resources

<http://www.geology.gov.yk.ca/>

<http://www.emr.gov.yk.ca/oilandgas/>

NUNAVUT

There are 12 Basins with potential and discovered hydrocarbons through to the Paleozoic. Nothing is being worked on but shale plays would exist within the many source rock intervals. It is too isolated to be commercial at present.

Canada-Nunavut Geoscience Office <http://cngo.ca/>

Additional Information

National Energy Board of Canada

<http://www.neb-one.gc.ca/clf-nsi/rcmmn/hm-eng.html>

Geological Survey of Canada

<http://www.nrcan.gc.ca/earth-sciences/science/geology/gsc/17100>

Canadian Association of Oil Producers

<http://www.capp.ca/Pages/default.aspx>

Societies, Conferences and Courses

Canadian Society for Unconventional Gas (CSUR)

<http://www.csur.com/>

Annual Unconventional Resources Conference-Joint with SPE and CSUR

2015 Oct 20 - 22 at the BMO Center Stampede Park in Calgary, AB.

2016 conference not announced yet

Note that they have technical luncheons for members.

<http://www.csur.com/csur-technical-luncheon-series-presentations>

<http://www.csur.com/events/technical-conference>

CSUR now has Canadian Play maps at this location.

<http://www.csur.com/canadian-discovery-play-maps>

Canadian Society of Petroleum Geologists (CSPG)

Note the CSPG has technical luncheons throughout the year.

<http://www.cspg.org/>

GeoConvention 2016: Optimizing Resources: Calgary TELUS Convention Centre March 7-11,

<http://www.geoconvention.com/>

Gussow Conference: Fine-Grained Rocks: Resources to Reserves Banff Centre, Banff, Alberta.

Oct 13-15

CSPG Courses

http://www.cspg.org/CSPG/IMIS20/Events/Technical_Luncheons/Upcoming_Luncheons/CSPGIMIS20/Technical/Luncheons/Tech_Luncheons.aspx?hkey=9fcfbf39-6bd4-47ca-ad92-3360d2a6bd34

AAPG - ACE BMO Centre Stampede Park, Calgary, 9-22 June 2016

<http://ace.aapg.org/2016/>

Other Meetings

The Canadian Institute (CI) has had unconventional forums in the past but non noted in 2016 http://www.canadianinstitute.com/energy_resources

2015 International LNG in B.C. Conference: October 14-16, 2015 | Vancouver Convention Centre | Vancouver, British Columbia

<http://engage.gov.bc.ca/lnginbc/lng-conference/>

10th Unconventional Gas Technical Forum April 4-5, 2016, Victoria Conference Centre, Victoria, British Columbia

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

2016 Williston Basin Petroleum Conference will take place May 24-26, 2016 in Bismarck, North Dakota at the Bismarck Event

<http://www.wbpcnd.com/?AspxAutoDetectCookieSupport=1>

Feb 24-26, 2014 at the TELUS Convention Centre in Calgary, Alberta, Canada

<http://www.dugcanada.com/>

Do not see any upcoming conferences in Canada this year announced so far.

Exploration, Mining and Petroleum New Brunswick 2015, Fredericton Convention Centre, November 1 to 3. 2015 – no announcements for 2016 yet

http://www2.gnb.ca/content/gnb/en/departments/energy/conference/Conf_home.html

Energy West Symposium 22-24 Sept 2015, Corner Brook, West Newfoundland. No announcements of the 2016 date yet.

<http://www.wnloilandgas.com/energy-west-symposium/programme/>

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CHINA SHALE GAS AND SHALE OIL

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The shales spanning from Pre-Cambrian Sinian to Quaternary are widely 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 potential and Mesozoic to Cenozoic organic-rich shales with maturity in oil window have shale oil potential (Figs.1, 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 2011, the US Energy Information Administration (EIA) assessed that China could have 1275 trillion cubic feet (TCF) technically recoverable shale gas. 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. Recently, EIA reduced China recoverable shale gas reserve to 1115 TCF in June 2013 and gave a number of 32 Billion Barrel recoverable shale oil for China. Either number indicates China’s shale resource is comparable with US’s updated 665 TCF recoverable shale gas and 58 billion barrels of shale oil resource. China has been emulating the successful U.S. production experiences and models in order to power its economy and reduce greenhouse gas emissions.

Geologic time scale (Ma)			Tectonic movements	Depositional environment	Major organic rich shale source rocks	Distribution basins of typical organic rich shales	
Age	Era	Period and age					
-100	Cenozoic	Neogene (N) to Quaternary	20 Ma Himalayan ² orogeny	Lacustrine		Qaidam	
		Paleogene (E)	40 Ma Himalayan ¹ orogeny			Bohai Bay, Jianhan, Nanxiang, Qaidam, Subei and Baise basins	
	Mesozoic	Cretaceous (K)	100 Ma Yanshanian orogeny			Songliao, Jiuquan and Erlan basins	
		Jurassic (J)	210 Ma Indosinian orogeny			Turpan-Hami, Junnggar, Tarim, Sichuan and Qaidam basins	
		Triassic (T)				Ordos and Sichuan basins	
		Paleozoic (Pz)				Permian (P)	Hercynian-Indosinian (HI)
	Carboniferous (C)					Yangtze Platform, Tarim Platform and North China including Ordos basin	
	-400	Paleozoic (Pz)	Devonian (D)			400 Ma Qilian orogeny Late Ca	Central Guangxi in Upper Yangtze Platform
			Silurian (S)			Caledonian orogeny (Ca)	Yangtze Platform
			Ordovician (O)				Yangtze Platform including Sichuan Basin and Tarim basin
-500			Cambrian (E)	510 Ma Salairian orogeny (St)	Yangtze Platform including Sichuan Basin and Tarim basin		
					Upper and Middle Yangtze Platform		
-600	Pre-Cambrian	Sinian (Z)					

Figure 1: Geologic history and organic rich shale deposits in China

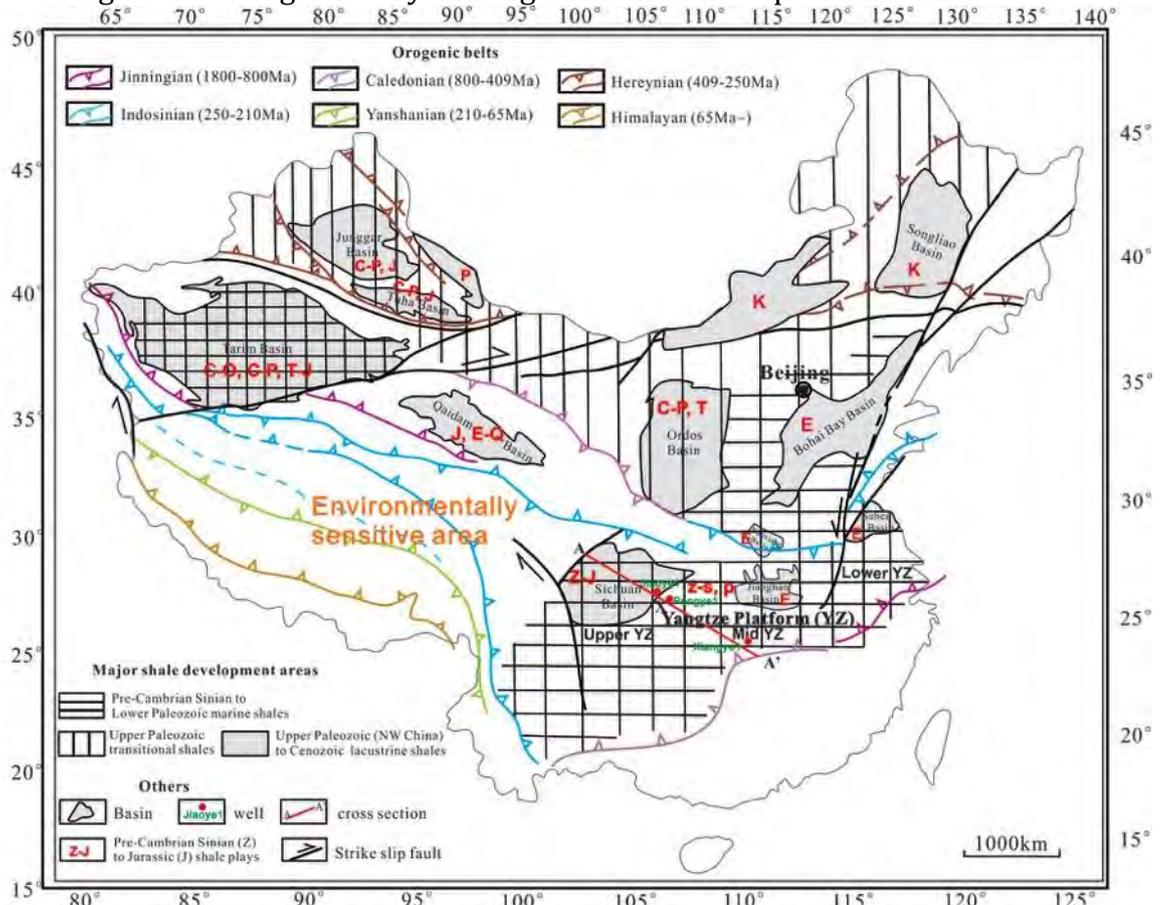


Figure 2: The distribution of organic-rich shales in China. Z=Pre-Cambrian Sinian;

E=Cambrian; O=Ordovician; S=Silurian; C=Carboniferous; P=Permian; T=Triassic; J=Jurassic;

K=Cretaceous; E=Paleogene. Q=Quaternary

US producing shales were deposited in marine depositional settings, however, hydrocarbon-bearing shales in China were formed in more diverse paleo-environments. The Pre-Cambrian to Lower Paleozoic shales distributed all over China were deposited in marine setting. The Upper Paleozoic (Carboniferous to Permian) shales mainly in North China and NW China were deposited in transitional (coastal swamp associated with coal) setting. The Meso-Cenozoic sporadically distributed shales were deposited in lacustrine setting (Fig.2). The typical marine shale, transitional shale and lacustrine shale are represented by Lower Paleozoic Sichuan Basin, Carboniferous to Permian Ordos Basin and Cenozoic Bohai Bay Basin, respectively (Fig.2). Table 1 summarizes the depositional settings and distribution in time and space for the potential gas and oil shales in China.

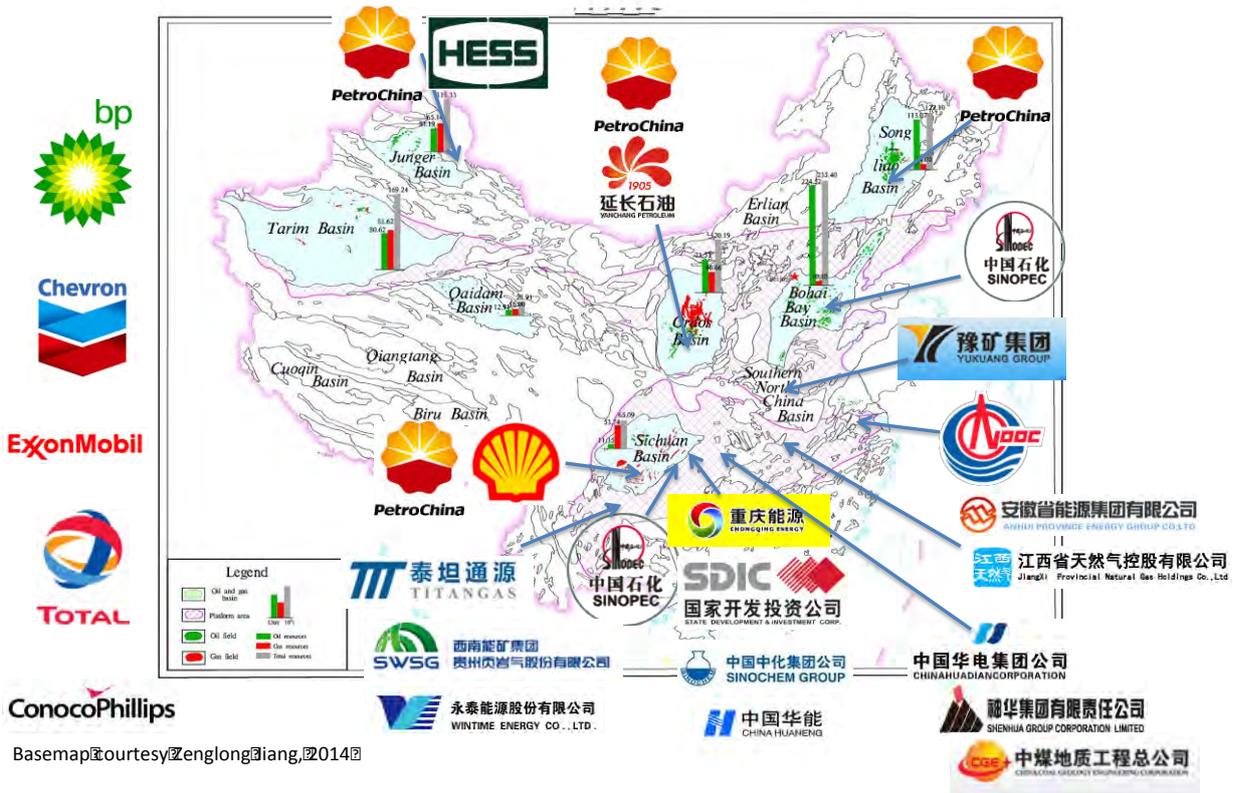


Figure 3 :the shale exploration activities in China

Table 1: Depositional setting and distribution in time and space of potential China shales

Depositional setting	Age and Formation		Distribution area
Lacustrine	Cenozoic	Neogene	Qaidam Basin
		Paleogene	Bohai Bay Basin, Qaidam Basin
	Mesozoic	Cretaceous	Songliao Basin
		Jurassic	Turpan-Hami, Junggar, Tarim, Qaidam, Sichuan Basin
		Triassic	Ordos Basin, Sichuan Basin
	Paleozoic	Late Permian	Junggar, Turpan-Hami
Transitional (coastal setting associated with coal)	Paleozoic	Late Permian (Longtan Fm)	Yangtze Platform including Sichuan in Upper Yangtze
		Early Permian (Taiyuan, Shanxi Fm)	North China
		Late Carboniferous (Benxi Fm)	North China
Marine	Paleozoic	Early Silurian (Longmaxi Fm)	Yangtze Platform including Sichuan in Upper Yangtze
		Late Ordovician (Wufeng Fm)	Yangtze Platform including Sichuan in

			Upper Yangtze, Tarim Basin
		Early Cambrian (e.g. Qiongzhusi Fm)	Yangtze Platform, Tarim Basin
	Pre-Cambrian	Sinian (e.g. Doushantuo Fm)	Upper and Middle Yangtze Platform

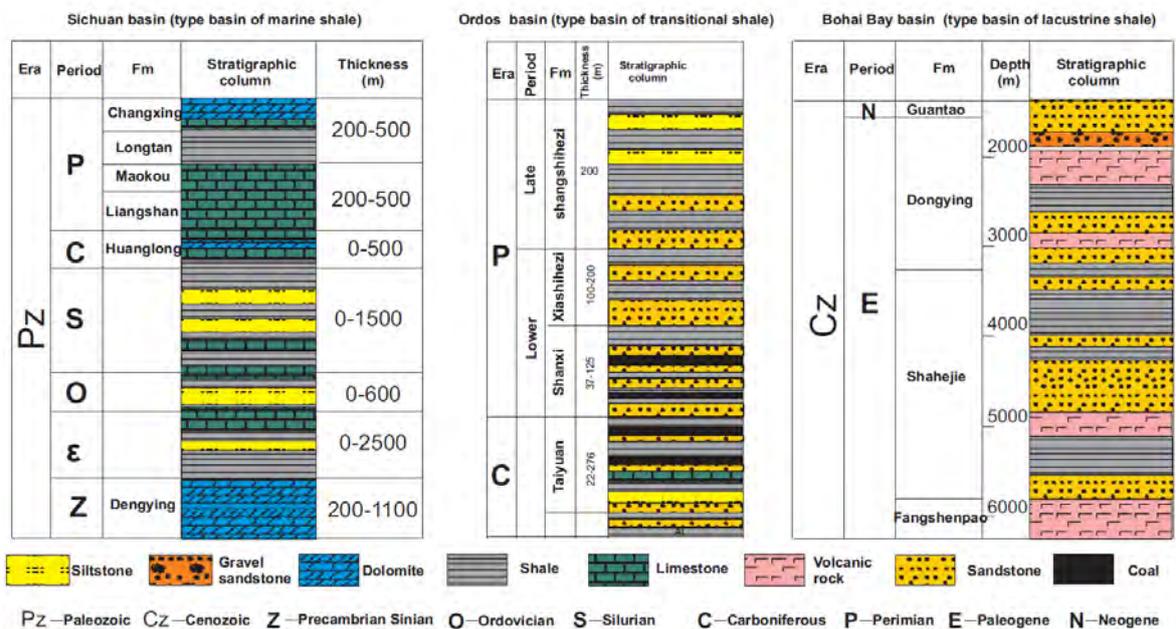


Figure 4: Three kinds of potential shales (marine, lacustrine and transitional/coastal setting) and their type basins

China has investigated shale gas and shale oil for nearly 6 years. So far, 2D seismic data covering 9000 km² and 3D seismic data covering 800 km² were acquired, and 400 shale-gas wells (including shallow parameter wells behind outcrop) targeting marine, lacustrine and transitional (coastal swamp setting associated with coal) shales were drilled by PetroChina, Sinopec, CNOOC, Yanchang Petroleum, and other state or private companies who recently acquired shale leases, as well as Ministry of Land and Resources and foreign partners of Chinese state oil companies. The exploration activities have been mainly focused in Sichuan Basin, Yangtze Platform outside Sichuan Basin, Ordos Basin, Bohai Bay Basin and Nanxiang Basin (Fig.3). Recently, the Junggar basin has also become target basin for shale oil associated with tight dolomite oil play. One recent breakthrough is that China and Argentina becomes only two countries outside of North America that has reported commercially viable production of shale gas and tight/shale oil, although the volumes contribute less than 1% of the total natural gas production in China. The successful development evidence in Sichuan Basin especially shale gas production from Silurian Longmaxi marine shale in Fuling area recently makes the China's 2015 output target of 6.5 bcm possible, which was thought impossible before. Recently, China has nearly tripled the size of proven reserves to 380.6 bcm in its Fuling area according to Sinopec

and Ministry of Land and Resources. By the end of August 2015, a total of 142 wells at the Jiaoshiha block had tested high-yield industrial gas flows and an additional 253 wells will be drilled according to Sinopec's development plan. A well in Fuling shale gas field in E Chongqing was reported to produce 547,000 cubic meters/day. As examined and approved by China's Ministry of Land and Resources recently, CNPC has added 207.87 km² of new shale gas bearing areas in the well blocks of Wei-202, Ning-201 and YS108 in the Sichuan basin. The areas have been added with proven original gas in place of 163.53 Bcm and technically recoverable reserves of 40.88 Bcm. All three well blocks are located in the national shale gas demonstration zone in the Sichuan basin. By August, 2015, 47 wells have been put into production in the newly proved areas, producing 3.62 MMcmgd. The rate from well Yang201-H2 in Luzhu, Sichuan was reported to produce at 430,000 cubic meters per day. Both Sinopec and CNPC's shale gas discoveries will encourage Beijing government and draw interests of international oil companies. For the tight oil, PetroChina's Changqing Oilfield recently discovered the country's largest tight oil field-Xinanbei field with 100 million tonnes proven geological reserves. For lacustrine shales, PetroChina and Sinopec recently speeded up lacustrine shale oil exploration in Junggar and Sichuan Basin, e.g. Sinopec drilled Shiping 2-1H horizontal wells targeting Jurassic lacustrine shale and got 33.79 tons condensate production after 5 stage-fracs in 864 m lateral.

Geological investigation and exploration show that most potential shales in China had and still have high organic content and marine shales have high maturity for gas generation and lacustrine (lake) shales have low maturity for oil generation. Characteristics of high organic matter content, high maturity, high brittle minerals (Fig.5) and high intra-organic nano-porosity (Fig.6) make China marine shales similar to US shales and potentially producible. The drilled shale-gas wells targeting marine shale in Sichuan Basin show the similar favorable shale properties e.g. high TOC, high brittleness, etc. as US producing marine shales (Fig.7). Generally, China lacustrine shales have high clay content than marine shales (Fig.5), this is why many experts think it is much more difficult to frac the lacustrine shale. Since lacustrine basins contribute 90% oil production in China and they are expected to pay a more significant role in shale oil production, we need new technologies to develop the gas or oil trapped in lacustrine shales. Recently, the tight dolomite oil production from Permian source rock interval in Junggar Basin in NW China (Fig.8) and tight sand oil from Ordos Basin (Fig.9) in North China showed the potentials of lacustrine tight oil potential similar to Bakken shale oil which is mainly produced from middle Bakken dolomite equivalent tight reservoirs. But the oil production from lacustrine shale is still in early stage. In the future, the shale gas, shale oil, tight sand and tight carbonate reservoirs within the organic rich shale might consist of hybrid reservoirs (e.g. shale oil and tight sand oil in Triassic source rock interval in Ordos Basin, Fig.9).

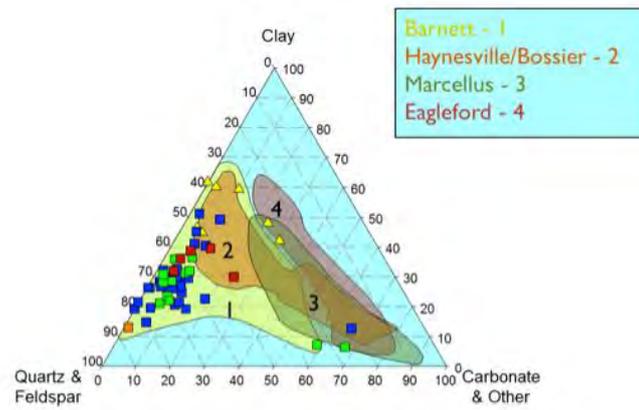


Figure 5: Ternary diagram for mineralogy of marine shale (square legend) and lacustrine shale (triangle legend) in China and its comparison with mineralogy of typical US shales.

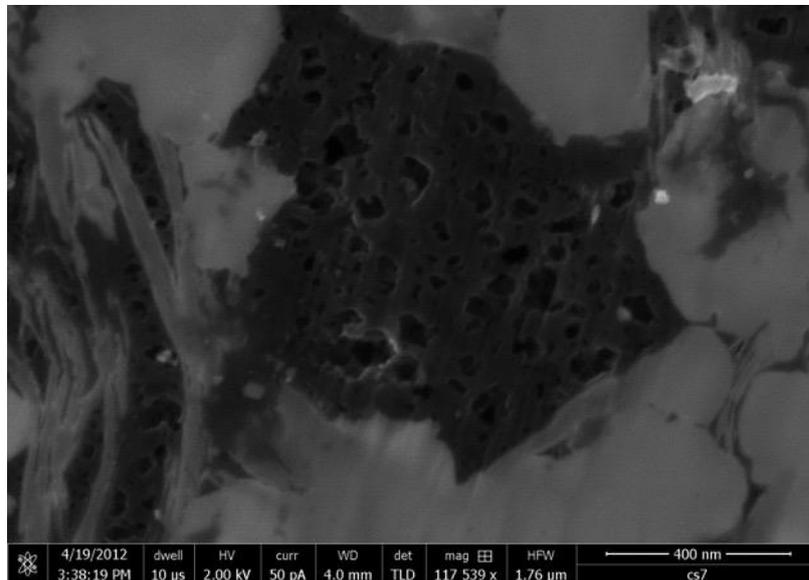
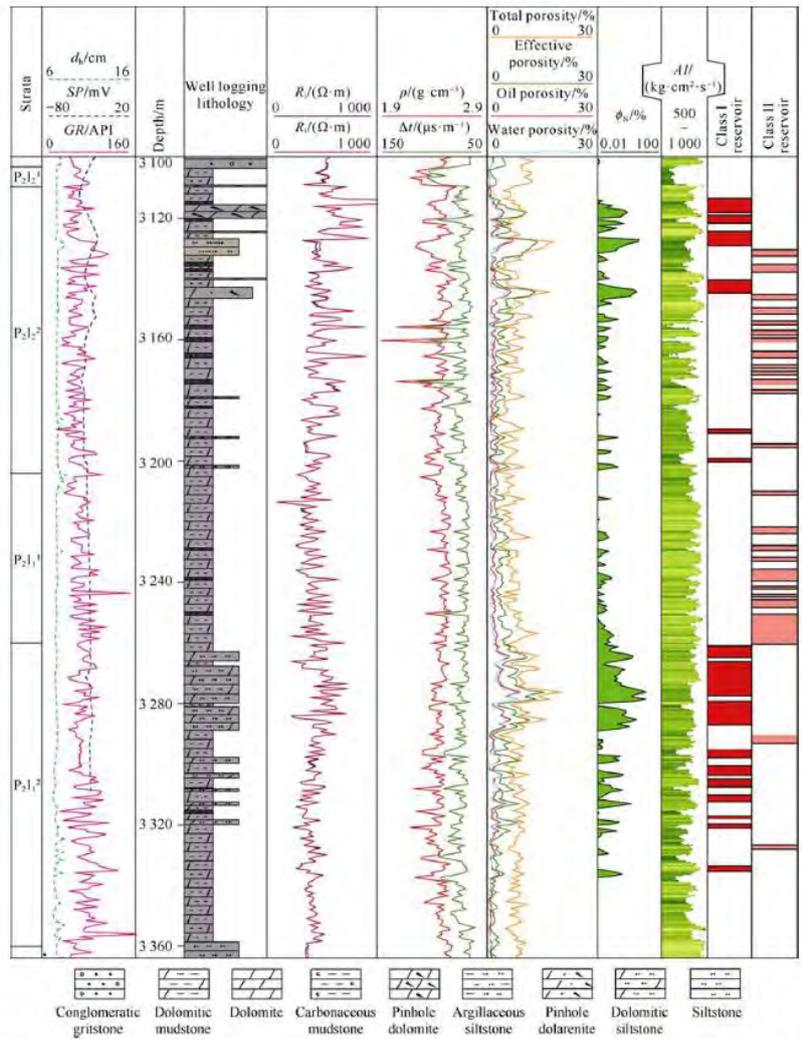


Figure 6: SEM of ion polished sample showing intra-organic nano-pores of a marine shale Sichuan Basin, China



Comprehensive well logging evaluation chart of the Lucaogou Formation reservoir in the Jimsar Sag. d_h —hole diameter; SP —spontaneous potential; GR —gamma ray; R_t —resistivity of intrusion zone; R_f —formation resistivity; ρ —density; Δt —interval transit time; ϕ_n —neutron porosity; AI —acoustic impedance.

Figure 8: Tight dolomite oil from Permian source rock interval with shale oil show, Junggar Basin, NW China (L. Kuang, 2012)

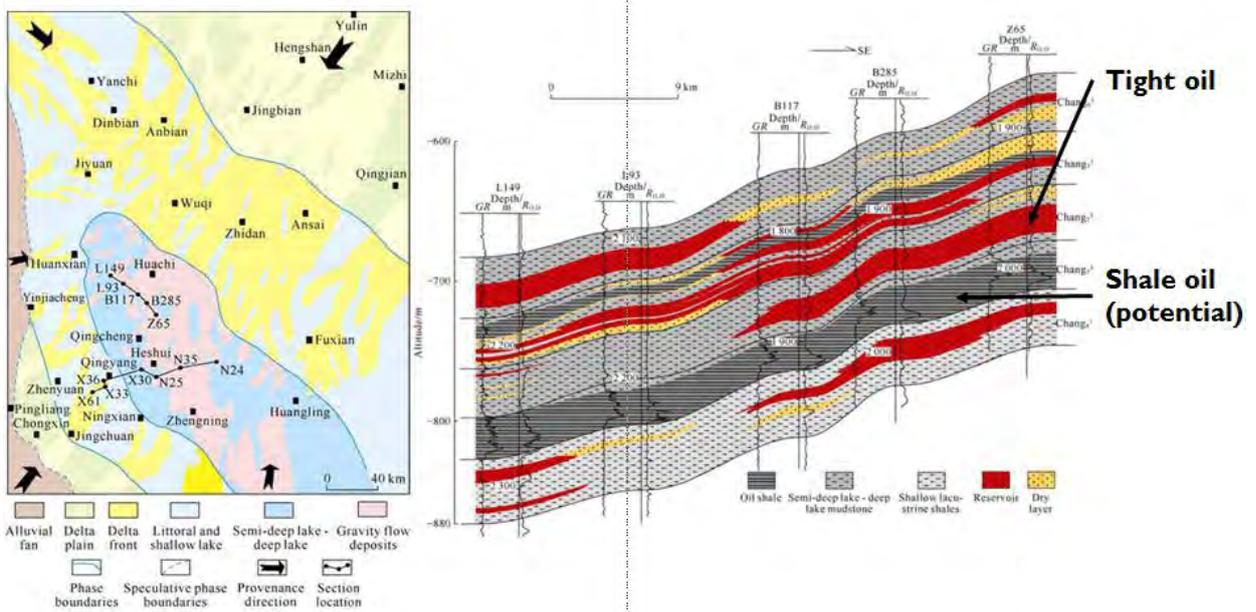


Figure 9: Tight oil and potential shale oil of Triassic Yanchang Fm in Ordos Basin (modified from YAO Jingli, 2013).

What made shale gas/oil work is hydraulic fracturing or fracing, but every shale in the world is different, the shale depositional settings and geologic history made each shale with unique mechanical property. Shale gas and shale oil are produced from marine shales, fine-grained chinks and dolomite interbedded in source rock intervals in US basins. These basins have relatively simpler tectonic settings than China. Even promising marine shales in China are similar to brittle Barnett shale in US regarding mineralogy, a more complex tectonic setting, much more complex diagenetic history and harsh ground conditions make shale gas extracting in China more challenging than that in US. In some areas in China, the shale resources are either located in the subsurface below the rugged mountain or desert, also, the historical multi-stages of strong tectonic compression, extension in China cause shales in China to have different stress fields than those in US, e.g. the maximum principal stress is horizontal in some areas e.g. basins in front of collision zone of Tibet Plateau and the maximum principal stress is vertical in US (Fig. 9). Therefore, fracing methodology as applied in the US may not work very well in China. We need to investigate more about the geology, geomechanics and hydraulic fracturing design for unique China shales.

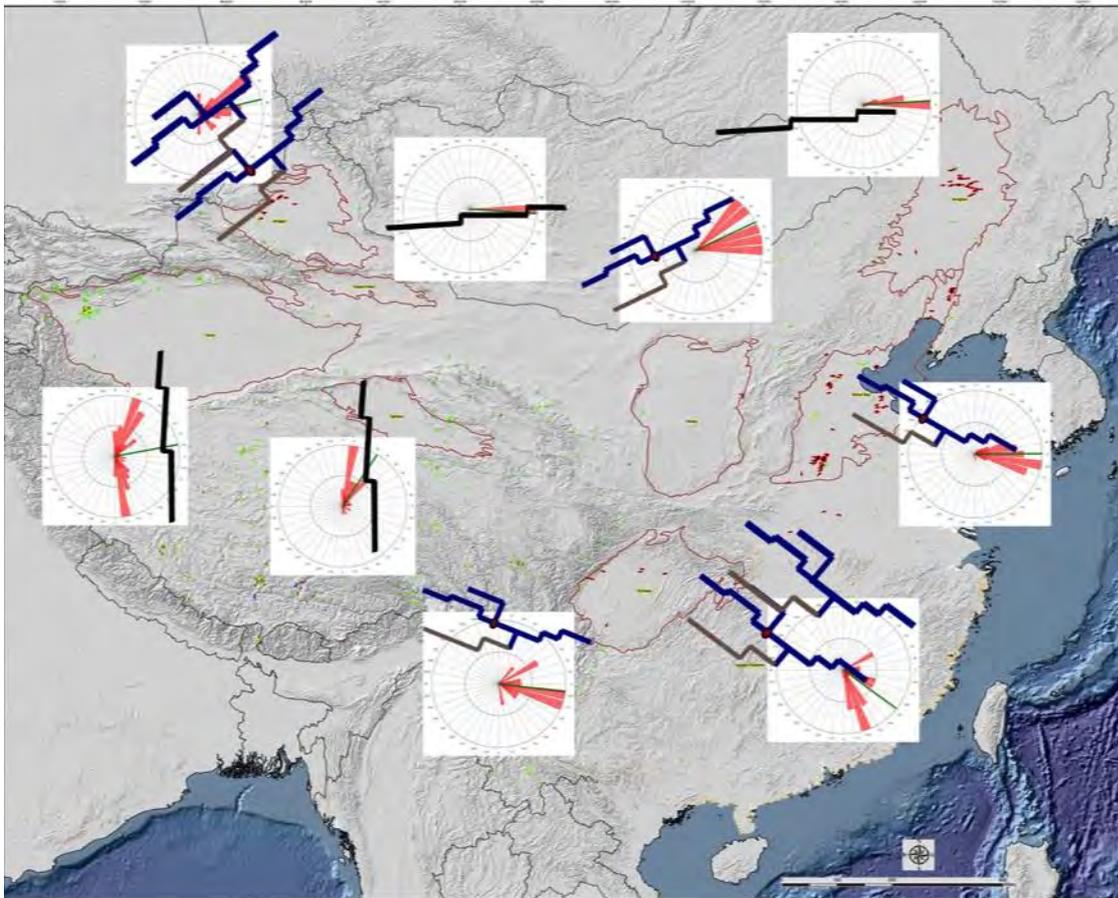


Figure 9: Hypothesized, possible geometries of hydraulic fractures based on stress azimuth fluctuations in major basins in China.

Because of technical challenges in mudrock exploitation of China basins, China has been collaborating with international oil firms and service companies to achieve an ambitious shale gas production plan. Chinese state-owned oil, coal and power energy companies and privately-owned junior companies with non-energy experience have tied up with foreign oil companies such as Shell, ExxonMobil, Chevron, ConocoPhillips, Eni, BP, Total, Statoil, Schlumberger, etc. to gain hydraulic fracturing technology in shales. Even though the recent 2nd round bidding blocks located at the margin or outside conventional oil and gas producing basins disappointed many companies. With the speeding and recent good exploration result of Paleozoic marine shale gas exploration and Meso-Cenozoic lacustrine shale oil exploration and very exciting test result in Sichuan Basin, Shell's production-sharing contract with CNPC (parent company of PetroChina) got approved by Chinese government and Hess signed PSC with CNPC in Langma shale oil block in NW China recently, which are inspiring for many companies. Shell will spend \$1 billion developing China's shale resources in Fushun-Yongchuan block covering 3,500 sq km in Sichuan Basin. But the recent evaluation shows mixed results in Shell-CNPC's joint blocks. Due to complex geology in China, recent downturn of oil price and budget cut of many companies. Some companies are pulling out of China. ConocoPhillips has ended talks with PetroChina on shale-gas development in China after two-year study on the Neijiang-Dazu block in Sichuan Basin.

PetroChina plans to drill 113 horizontal shale gas development wells in the next 2 years in Sichuan Basin. Sinopec has planned to drill more in SE Chongqing/E Sichuan Basin and NE Sichuan Basin due to recently commercial shale gas from both marine and lacustrine shales in Sichuan Basin. Based on these, the coming third shale gas bid round will be better than the first two.

The complex geologic setting and different geomechanics regime in China basins did challenge many international companies with successful US shale experiences to frack shales in China. The trial-and-error in the in pilot shale gas areas in Changning-Weiyuan in Sichuan, Fuling in Chongqing, Yanchang block in Ordos has helped companies improve fracing of shales in China. With limited participation from established global service companies such as Baker Hughes and Schlumberger, Sinopec's Jianghan oilfield has improved in key areas of fracturing and logging. At one well in Sichuan Basin, Sinopec-Jianghan did 22-stage fracturing at a depth of 1,500 meters and the test result showed commercial flow of shale gas. So far, the horizontal drilling and hydraulic fracturing of shales have been reported to generate large stimulated reservoir volume (SRV) (Fig.10). As Chinese companies gain experience and knowledge of producing from shale, the cost of shale gas drilling has declined. The cost of drilling a horizontal well in shale formations in the Sichuan Basin was reduced to \$11million per well in 2015 from \$15 million per well in 2013 (Fig. 11).

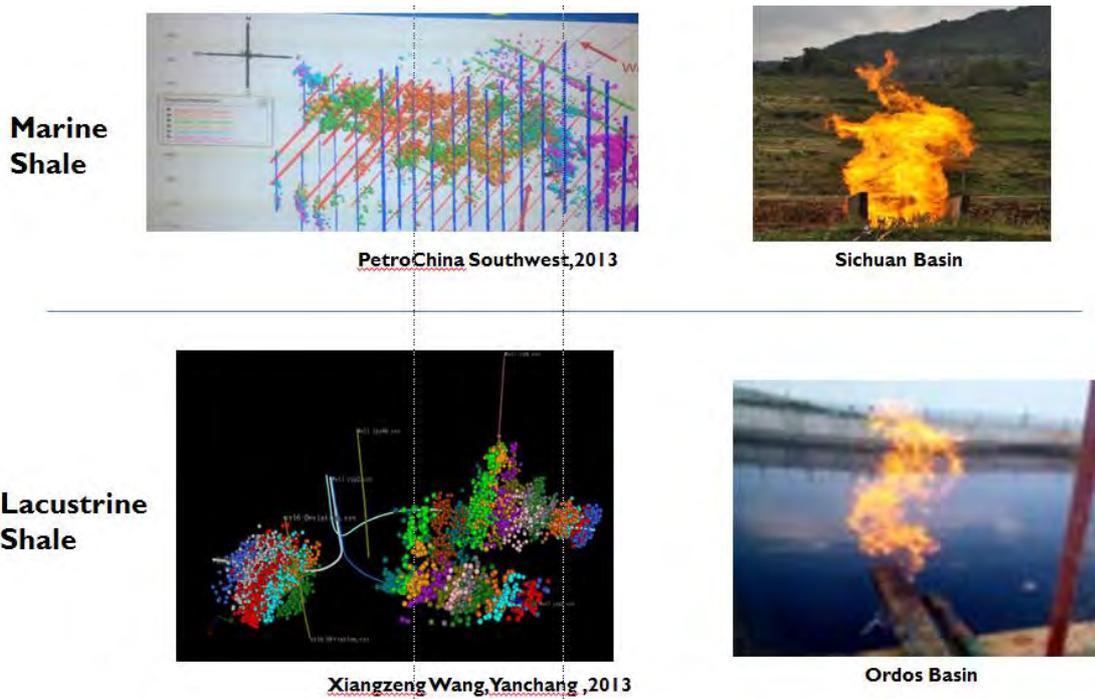


Figure 10: Horizontal drilling and hydraulic fracturing for both marine and lacustrine shales in China

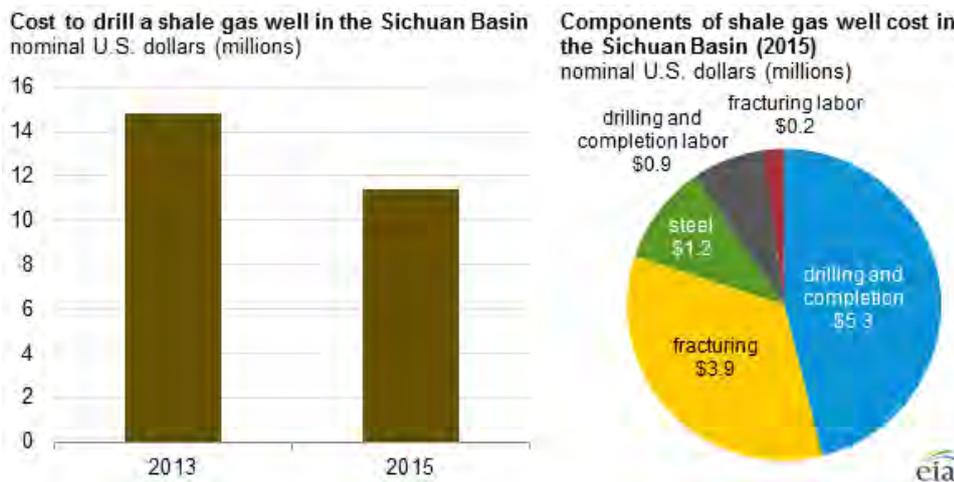


Figure 11: Cost of shale gas well in Sichuan Basin in China (EIA, 2015)

At the same time, The China National Energy Administration (“NEA”) issued the Shale Gas Industry Policy (“Policy”) in late October, 2013. The Policy recommends certain reforms to encourage more companies besides oil companies to get access to shale gas exploration and development in China. Also, the new policy gives subsidies and tax incentives to shale gas production companies. In 2012, to encourage the exploration of shale gas, the Chinese government established a four-year, \$1.80 per million British thermal units subsidies program for any Chinese company reaching commercial production of shale gas. In mid-2015, these subsidies were extended to 2020, but at a lower rate. After two disappointing shale licensing rounds (in 2011 and 2012), China is working to identify prospective and investor-friendly blocks and adopt better policies to attract potential investors.

In summary, China has important shale gas and shale oil potential, even though the geological setting and geomechanical characteristics are more complex than US producing shales for hydraulic fracturing. Technology advancement, decreases in the cost to drill shale gas

wells, continued investment into domestic production and policy support for incentives and reforms from Chinese government are important improvements for exploiting lacustrine shale gas in Ordos Basin, shale oil in Nanxiang Basin in central China, tight/shale oil in Santanhu and Junngar Basin in Northwest China, and recent commercial shale gas from marine shales in Sichuan Basin. China has commercially produced 4 billion cubic meters in first three quarters of 2015 from pilot areas and the China vast shale resources are expected to be produced on a larger scale. For China, developing its shale gas reserves would have the triple effect of: lower energy costs, replacing coal with gas for power generation, which would reduce air pollution, and thirdly – producing more gas to meet energy needs and curbing the country’s dependence on foreign energy. China continues to push to develop its unconventional resources despite slumping commodity prices have caused some companies to lay down rigs and forgo completions in the U.S. and other countries.

SHALE GAS AND SHALE LIQUIDS PLAYS IN EUROPE

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Introduction

Europe remains relatively unexplored for shale gas and, especially, shale liquids. In total some 127 exploration and appraisal wells with a shale gas exploration component have been drilled, including horizontal legs from vertical wells. 32 of these wells are shallow gas tests drilled in Sweden, largely using mineral exploration equipment. Some 8 wells have been drilled to target shale liquids.

Significant shale gas exploration activity since April 2015 has been limited to Poland, where one horizontal shale gas appraisal well was spudded, Denmark where one well was drilled, and Sweden where a first production test well is under way at the site of the Siljan Ring impact crater.

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 and Netherlands, plus certain administrative regions in Spain, Switzerland and the UK (Scotland; Wales; Northern Ireland). Proposed new environmental legislation led OMV to abandon its plans for shale gas exploration in Austria.

The geology, however, has not proved entirely favourable either. Interest in the exploration potential of Poland has decreased significantly over the 18 months. Of 121 shale gas and shale liquid concessions awarded to date, 88 have now been relinquished, 62 of them in the past 18 months. Chevron, ConocoPhillips, ExxonMobil, Marathon, Talisman, Eni and Total have all withdrawn from Poland. Of the 33 remaining concessions, 18 are now operated by three Polish companies - PKN Orlen (7), LOTOS Petrobaltic (7 offshore) and Polish state company PGNiG (4). The other significant concession holder is ShaleTech Energy, a 100% subsidiary of Luxembourg-registered Stena Investment, the international holding company of Swedish company Stena AB. ShaleTech holds 3 concessions with shale gas potential and 4 with shale liquids potential. Two other international companies, BNK Petroleum and San Leon, are seeking partners to drill, frac and test existing discoveries on their Gdansk Depression acreage.

The best combination of geology and effective regulatory regime appears to be in the United Kingdom, where the UK Conservative government elected in May 2015 has shown considerable support for the emerging shale gas industry. The perceived prospectivity of the UK is also indicated by company acquisitions and farm-ins to acreage with shale gas potential since May 2013 by Centrica, Total, GDF Suez, IGas, INEOS and Egdon Resources.

A review of all European activity prior to April 2015 can be found [here](#) at:

[https://www.academia.edu/12126359/Shale Gas and Shale Liquids Plays in Europe April 2015](https://www.academia.edu/12126359/Shale_Gas_and_Shale_Liquids_Plays_in_Europe_April_2015)

Country Updates

Denmark.

Total S.A. / Nordsøfonden. Total S.A. was awarded two licences. In March 2012 Total applied for a third area relinquished by Schuepbach Energy in November 2011 but by September 2012 this application appears to have lapsed. Total and the Danish North Sea Fund (Nordsøfonden) commenced evaluation of the Alum Shale in the North Jutland area (Fennoscandian Border Zone) during 2012.

Prior to the planned drilling of Vendsyssel-1 in Nordjylland (North Jutland), a well work program, including environmental studies, was submitted to Frederikshavn Municipality in October 2012. Despite reviews by the Danish Energy Agency, Environmental Protection Agency, Nature Agency and the Administration of Frederikshavn Municipality which raised no comments, Frederikshavn City Council decided on 27th February 2013 to request a full Environmental Impact Assessment (EIA). While disagreeing with the City Council's decision Total and Nordsøfonden decided not to contest it as this would just lead to further delays. On 26th February 2014 the Frederikshavn City Council agreed the EIA reports for publication and it entered an 8-week public consultation period. The City Council gave final approval on 25th June and site preparation commenced in July 2014. Vendsyssel-1 commenced drilling on 4th May 2015, drilling to a TD of 11,684'. Although gas shows were encountered, the target Alum Shale was not present in economic thickness and the well was abandoned.

In August / September 2013, Total and Nordsøfonden undertook an airborne gravity and magnetic survey over the area of their Nordsjælland (North Zealand) licence. In May 2015 Total announced that, following geological studies which indicated that the Alum Shale in the Nordsjælland licence was thinner than expected, the partners would relinquish that licence, effective 1st July 2015.

Germany.

On 1st April 2015 the German cabinet approved draft legislation which would effectively ban hydraulic fracturing of shales for five years. An expert panel will reassess technological developments in mid-2018 potentially allowing commercial fracturing from 2019. Hydraulic fracturing is likely to remain banned at depths shallower than 3,000 metres (~ 9,850'). It will also be permanently banned in nature reserves and natural parks. The legislation was not placed before parliament, however, as the governing coalition could not find common ground on final details. The resultant lack of a reliable and proportionate legislative framework drew

criticism from industry sources and gas industry employee groups. Domestic natural gas production, which uses hydraulic fracturing in tight sandstone reservoirs, has declined by almost one-third since 2011.

Poland.

Some 39 concessions have been awarded in the Baltic Depression, of which 10, largely operated by LOTOS Petrobaltic, were offshore in the Baltic Sea and 29 lay onshore in the Gdansk Depression. Six of the most easterly concessions, such as the four held by ShaleTech Energy, are considered to be more prospective for shale liquids than for shale gas. Eighteen (18) concessions have subsequently been relinquished. Sixteen (16) different companies have been active in the onshore Gdansk Depression at some time including ConocoPhillips, Eni, Talisman and the Polish state company, PGNiG, plus a number of small niche players, frequently active through consortia. At present, five companies remain active, principally LOTOS Petrobaltic, ShaleTech Energy and PGNiG.

Another 40 concessions have been awarded in the Danish-Polish Marginal Trough and 16 on the East European Platform Margin, northeast of the Marginal Trough. 48 of these awards (34 – Marginal Trough; 14 - Platform Margin) have since been relinquished but 2 relinquishments by ExxonMobil on the East European Platform Margin were taken up by Orlen Upstream. Sixteen (16) different companies have been active in the Platform Margin and Marginal Trough, the most prominent participants having been Chevron, ExxonMobil, Marathon, Total, Polish state company PGNiG, and PKN Orlen, another Polish company. At present, three companies remain active, principally Orlen.

A total of 23 concessions thought to have shale gas potential have been awarded in the Fore-Sudetic Monocline in southwest Poland but 19 have subsequently been relinquished. Orlen, PPI Chorobok and San Leon are the only remaining licence holders. Although all 4 remaining Fore-Sudetic Monocline concessions are considered to have some shale gas prospectivity, some are also being investigated for their tight gas and conventional oil and gas prospects.

PGNiG (Polskie Górnictwo Naftowe i Gazownictwo – state-controlled).

Between March and May 2013 the company drilled its first well on the Stara Kiszewa concession, Wysin-1, to a depth of 13,255', some 20 miles southeast of Gdansk. A second well, Bedomin-1, was drilled in June-August 2014. In June 2015 a follow-up horizontal well, Wysin-2H, was spudded with a planned TVD of 12,975' and measured depth including horizontal leg of 17,880'.

By 1st October 2015 a total of 84 shale gas and 4 shale liquids concessions had been relinquished, 34 in the Danish-Polish Marginal Trough, 14 on the East European Platform Margin, 22 on the Fore-Sudetic Monocline and 18 in the Baltic Depression. All significant international players (Chevron; ConocoPhillips; Eni; ExxonMobil; Marathon; Talisman; Total) have now exited Poland.

Relinquishments to 1st October 2015 by company / company consortium are shown in Table below:

Polish Shale Gas and Shale Liquids Concession Relinquishments at 1st October 2015					
Company / Group	Baltic Depression	Danish-Polish Marginal Trough	East European Platform Margin	Fore-Sudetic Monocline	Relinquished Total
Shale Gas Concessions					
3Legs Resources	3			3	6
BNK Petroleum - Indiana Investments	3				3
BNK Petroleum - Saponis Investments	2				2
Canadian International Oil Corp				2	2
Chevron Corp		4			4
Quadrilla Resources Ltd		1			1
Dart Energy Ltd		1			1
DPV Service		5			5
Eni SpA	3				3
EurEnergy Resources (Baltic Energy Resources)	1				1
ExxonMobil Corp			4		4
ExxonMobil Corp / Total SA		1	1		2
LOTOS Petrobaltic	1				1
LOTOS Petrobaltic - Baltic Gas (CalEnergy Resources)	1				1
Mac Oil	1				1
Marathon		1			1
Marathon / Nexen / Mitsui		6	4		10
Orlen Upstream		1	1		2
PETROLINVEST SA - ECO Energy		1	2	1	4
PETROLINVEST S.A. - Silurian		1	1	3	5
PGNiG		10		1	11
San Leon - Aurelian O&G				2	2
San Leon - Czersk	1			2	3
San Leon - Helland Energy		1			1
San Leon - Gora Energy				1	1
San Leon - Liesa Energy				1	1
San Leon - Vabush Energy				1	1
San Leon - Joyce Investments (Esrey Energy 50%)	1				1
San Leon - Maryani Investments (Esrey Energy 50%)			1		1
San Leon - Strzelecki Energia (Hutton Energy 25%)		1		2	3
Total Relinquished Shale Gas Concessions	17	34	14	19	84
Shale Liquids Concessions					
Company / Group	Baltic Depression			Mogilno-Łódź Trough	Relinquished Total
Shale Liquids Concessions					
Hutton Energy				3	3
PGNiG	1				1
Total Relinquished Shale Liquids Concessions	1			3	4

Sweden.

Gripen Oil & Gas. In April 2012, Gripen Gas (now Gripen Oil & Gas), the largest licence holder with 14 permits, announced that it had tested biogenic gas from the Alum Shale at a depth of around 300' in 4 shallow wells drilled in the Ekeby permit in Östergötland. The best well, GH-2, flowed 97.5% methane and in Q3 2012 was appraised by 2 successful step-out wells and a further well drilled adjacent to GH-2 which cored the entire Alum Shale section. A further 3 appraisal wells were drilled in June 2013. All three wells flowed gas to surface from a 3" hole. OPC Ltd. has assigned a 2C contingent resource estimate of 51.0 bcf raw gas to the Östergötland onshore licences. Gripen Oil & Gas has identified three 36-hole development areas on the Ekeby permit.

In Q4 2015 Development Area One (2C resource: 1.70 bcf of 100% CH₄) was tested by a 3-month extended well test (EWT). The three appraisal wells used in the Ekeby permit test formed part of a six-well drilling programme undertaken in May – August 2014, which also included one exploration well on the Orlunda permit and two exploration wells on the Eneby permit. Depths ranged from 125' to 365' and Alum Shale reservoir thickness ranged from 55' to 95'. All six wells flowed gas. The extended well test, at depths between 230' and 330', averaged 2.6 Mscf/d over the 3-month period. A pilot gas production scheme was planned for 2015 and a Letter of Intent has been signed with a gas provider for the sale of any future gas production, but in the light of low commodity prices, capital expenditure has been reduced and the results of the EWT continue to be studied.

Gripen Oil & Gas has also been granted the Sandön licence, in Lake Vättern, where the Alum Shale is thought to be deepest and thickest. Water depths range from 30' – 100'. Drilling has already taken place in the lake for mining exploration purposes.

Gripen Oil & Gas also has six (6) concessions in the Baltic Depression on the island of Öland.

AB Igrene. Further north, AB Igrene has 18 concessions with Lower Paleozoic shale potential in the Siljan Ring, where Lower Paleozoic rocks have been preserved around the margin of a depression formed by a major Late Devonian meteor impact. The concessions have been renewed until June 15th 2015. To date five percussion holes have been drilled followed by five core holes of about 1,600' each, three of them in the Mora area on the west of the ring, which is now the focus of exploration, with the last two core holes having been drilled there in Q2 2013. Produced gas is dry, exceeding 90% methane with the remainder dominantly nitrogen. Gas occurs at depths below 1,180' in Mora-001 and below 1,000' in Solberga-1. Identified units with shale gas potential include the Tøyen Formation (Lower Ordovician), Fjäckå Shale (Upper Ordovician) and a Llandovery (Lower Silurian) shale (Kallholn Formation?), plus fractured basement.

AB Igrene commenced drilling the Vattumyren-3 well in the Mora area in July 2015. The well has a planned TD of 2,300' and a production test is scheduled for early 2016.

[*Note:* In the late 1980s, the Gravberg-1 well was drilled through a fractured granite within the impact crater to a TD of 22,000' to test Thomas Gold's theory of the abiogenic origin of petroleum.]

United Kingdom.

Cuadrilla Resources applied to Lancashire county council in May 2014 to drill and frac a number of wells on two sites (Preston New Road and Roseacre Wood). The county council repeatedly delayed proceedings and finally rejected the bids in June 2015. (See below)

Subsequently, on 13 August 2015, the UK government announced new measures for shale gas planning applications to be fast-tracked through a new, dedicated planning process which could deny councils the right to decide fracking applications unless they approve them quickly.

As part of the new measures, appeals against any refusals of planning permission for exploring and developing shale gas must be treated as a priority for urgent resolution. Councils that repeatedly fail to determine oil and gas applications within the 16 week statutory timeframe (unless applicants agree to a longer period) will be identified and, where applications are made to underperforming local planning authorities, the Communities Secretary of State will consider whether he/she should determine the application instead of the relevant council.

England

On 18th August 2015, the Oil & Gas Authority (OGA) – the UK’s oil and gas regulator – announced that 27 onshore blocks from the 14th Onshore Oil and Gas Licensing Round will be formally offered to companies.

A second group of 132 additional blocks has been subjected to detailed assessment under the Conservation of Habitats and Species Regulations 2010, the findings of which are now out for consultation. Subject to the outcome of that consultation, the OGA will announce offers for the second group of licence blocks later in 2015. The licences for all offered blocks will then be granted after the terms and conditions have been finalised.

Successful applicants in the first 27 blocks awarded include Cuadrilla Resources, Egdon Resources, GDF Suez, Hutton Energy, IGas, INEOS and Total. The acreage awarded includes prospective shale gas acreage in the Rossendale Basin, Humber Basin, Gainsborough Trough, Widmerpool Gulf and other parts of the East Midlands Shelf.

Scotland

On 28th January 2015 the Scottish Government Energy Minister announced a moratorium on the granting of planning consents for all unconventional oil and gas developments, including fracking. This moratorium will continue until technical work on planning, environmental regulation and assessing the impact on public health, and a full public consultation on unconventional oil and gas extraction, have been completed.

The UK government was already committed to Scotland having devolved powers for licensing of oil and gas as part of its efforts to give the Scottish government more decision-making powers. On 26th February 2015 the UK government therefore announced that it has agreed in principle not to award licences in Scotland for unconventional oil and gas exploration in the current 14th Onshore Licensing Round, though consultation with companies who have already applied will be undertaken before making a final decision.

On 8th October 2015, the Scottish Government extended the moratorium to cover underground coal gasification (UCG).

Cuadrilla Resources. On 4th February 2014, Cuadrilla announced that the company 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.

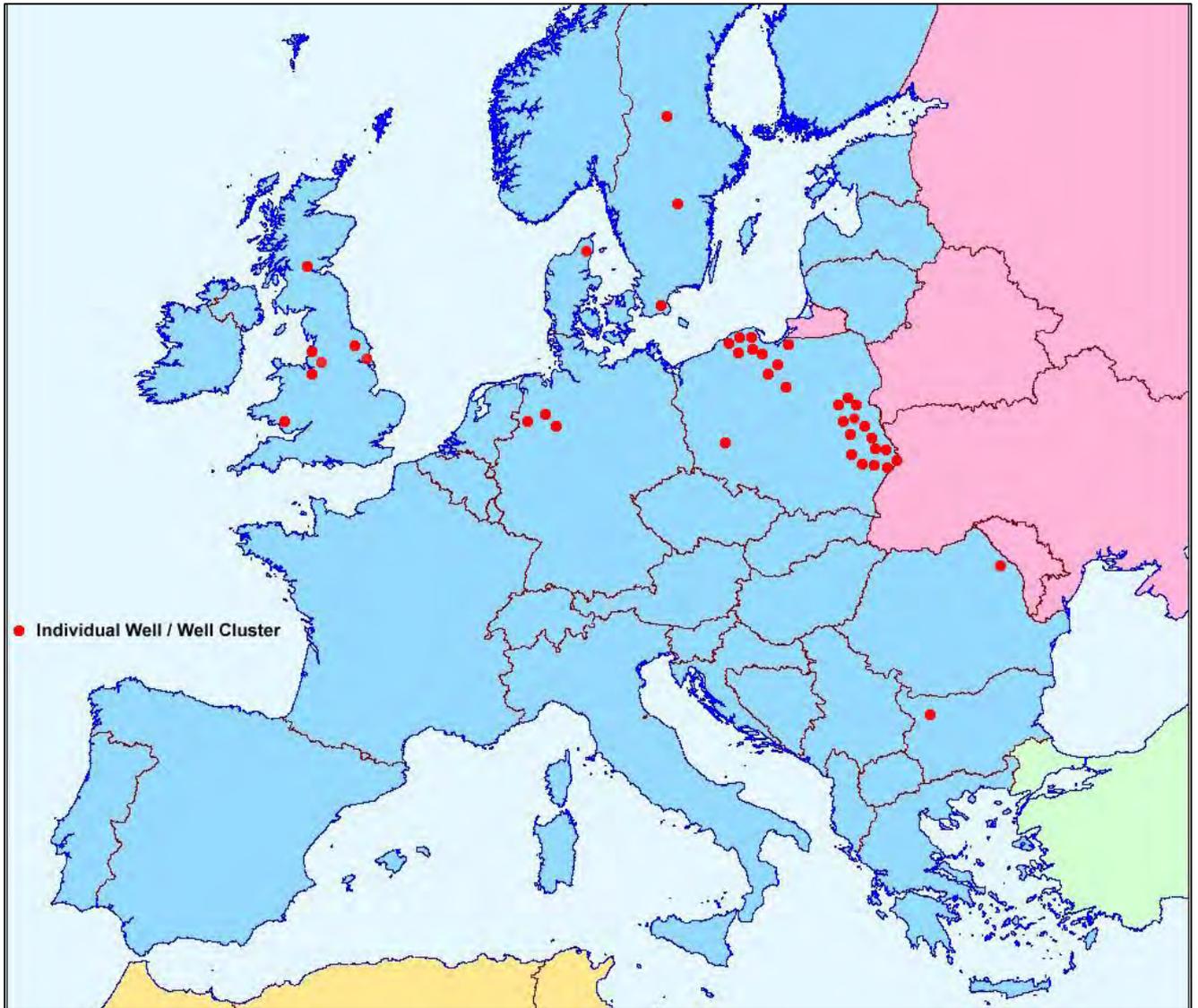
Planning applications were submitted on 29th May (Preston New Road) and 16th June 2014 (Roseacre Wood). The Environment Agency granted the necessary environmental permits for shale gas exploration on 16th January (Preston New Road) and 6th February 2015 (Roseacre Wood). The company still required planning 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 February 2015 the Council rejected an application to use the Grange Hill site for pressure testing and seismic monitoring. The site is now in limbo as permission to plug the well and restore the site was also refused.

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 is appealing the decisions.

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 has now entered the public consultation process.

Appendix 1.

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



Appendix 2.
Shale gas exploration and appraisal wells drilled in Europe:

Geological Province	Sub-Province	Concession	Well Name	No	Operator	Spud	Compl	TD ft	Horiz	Frac	Target Fm	Result - Content
Bulgaria												
Moesian Platform		A-Lovech	Gojamo Peshtene	R-11	LNG Energy	27-Sep-11	End Nov-11 @TD	10,466			Etropole	numerous show s C1 - C3
Moesian Platform		A-Lovech	Deventci	R-2	TransAtlantic Petroleum	27-Oct-11					Etropole	
Denmark												
Fennoscandian Border Zone		1/10 Nordjylland	Vendsyssel	1	Total	04-May-15	17-Aug-15	11,694			Alum Shale	gas show s
Germany												
Northw est German Basin	Low er Saxony Basin	Münsterland	Damme	2	ExxonMobil	2008	2008	10,950			Wealden, Posidonia	
Northw est German Basin	Low er Saxony Basin	Münsterland	Damme	2A	ExxonMobil	2008	2008	10,935			Posidonia Shale	
Northw est German Basin	Low er Saxony Basin	Münsterland	Damme	3	ExxonMobil	2008	2008	5,280		3	Wealden	
Northw est German Basin	Low er Saxony Basin	Minden	Oppenw ehe	1	ExxonMobil	Jun-08	2008	8,730			Wealden, Posidonia	
Northw est German Basin	Low er Saxony Basin	Schaumberg	Niederw öhren	1	ExxonMobil	2009	2009	3,394			Wealden	
Northw est German Basin	Low er Saxony Basin	Scholen-Barenburg II	Schlahe	1	ExxonMobil	2009	2009	4,870			Wealden, Posidonia	
Northw est German Basin	Low er Saxony Basin	Bramschen	Lünne	1	ExxonMobil	17-Jan-11	Mar-11	5,170			Wealden, Posidonia	
Northw est German Basin	Low er Saxony Basin	Bramschen	Lünne	1A	ExxonMobil	Mar-11	2011	5,503	Y		Posidonia Shale	
Poland												
Baltic Depression	Gdansk Depression	Trzebielino	Miszew o	T-1	Indiana Investments (BNK)	28-Feb-12	Sep-12	17,700			Low Paleozoic	Muted gas show s
Baltic Depression	Gdansk Depression	Bytow	Gapow o	B-1	Indiana Investments (BNK)	Mid-late May 12	Jul-12	14,100			Low Paleozoic	Major gas show s
Baltic Depression	Gdansk Depression	Bytow	Gapow o	B-1A	Indiana Investments (BNK)	Mid-Jan-14	23-Feb-14		Y	20 (8 effective)	Low Paleozoic	High gas show s
Baltic Depression	Gdansk Depression	Slaw no	Wytyw no	S1	Saponis Investments	Dec-10	14-Feb-11	11,750			Low Paleozoic	significant gas show s: C1 - C3
Baltic Depression	Gdansk Depression	Slupsk	Lebork	S1	Saponis Investments	11-Mar-11	25-Apr-11	11,780		Y	Low Paleozoic	significant gas show s: C1 - C3
Baltic Depression	Gdansk Depression	Starogard	Starogard	S1	Saponis Investments	16-Jul-11	Sep-11	11,560			Low Paleozoic	significant gas show s: C1 - C5
Baltic Depression	Gdansk Depression	Lębork	Łebień	LE-1	Lane Energy (3Legs)	Mid Jun-10	28-Jul @ TD	10,120		1; DFIT	Low Paleozoic	gas
Baltic Depression	Gdansk Depression	Lębork	Łebień	LE-2H	Lane Energy (3Legs)	10-May-11	Jun-11		Y	13	Low Paleozoic	gas show s
Baltic Depression	Gdansk Depression	Lębork	Strzeszew o	LE-1	Lane Energy (3Legs)	04-Oct-12	Early Dec-12	10,040		DFIT; 2 frac	Low Paleozoic	
Baltic Depression	Gdansk Depression	Lębork	Lublew o	LEP-1	Lane Energy (3Legs)	13-Dec-13	20-Jan-14	9,593			Low Paleozoic	
Baltic Depression	Gdansk Depression	Lębork	Lublew o	LEP-1ST1H	Lane Energy (3Legs)	02-Apr-14	28-Apr-14	14,688	Y	25 frac	Sasino Fm	
Baltic Depression	Gdansk Depression	Kaw ia	Slaw oszyno	LEP-1	Lane Energy (3Legs)	15-Feb-14	17-Mar-14	9,250			Low Paleozoic	
Baltic Depression	Gdansk Depression	Cedry Wielkie	Łęgow o	LE-1	Lane Energy (3Legs)	27-Aug-10	Q4-2010	11,270		2 DFITs	Low Paleozoic	gas show s
Baltic Depression	Gdansk Depression	Damnica	Warblino	LE-1H	Lane Energy (3Legs)	17-Jul-11	Sep-11	10,570	Y	7	Low Paleozoic	gas show s
Baltic Depression	Gdansk Depression	Gdansk-W	Lew ino	1G-2	Talisman Energy Polska	26-Sep-11	17-Nov-11	11,800		3	Low Paleozoic	C1+ small C2-C5
Baltic Depression	Gdansk Depression	Elblag	Bagart	1	Eni Polska	01-Dec-11	Mar-12				Low Paleozoic	
Baltic Depression	Gdansk Depression	Elblag	Stare Miasto	1	Eni Polska	Apr-12	Sep-12			Y	Low Paleozoic	
Baltic Depression	Gdansk Depression	Malbork	Kamionka	1	Eni Polska	May-12	Aug-12				Low Paleozoic	
Baltic Depression	Gdansk Depression	Wejherow o	Lubocino	1	PGNIG	Dec-10	Mar-11	10,010		2	Low Paleozoic	promising gas flow . No H2S and low N2. Heavier hydrocarbons
Baltic Depression	Gdansk Depression	Wejherow o	Lubocino	2H	PGNIG	Aug-12	Nov-12	13,060	Y	DFIT; 6 frac	Low Paleozoic	
Baltic Depression	Gdansk Depression	Wejherow o	Lubocino	3H	PGNIG	Aug-13	Dec-13	11,720	Y		Low Paleozoic	
Baltic Depression	Gdansk Depression	Wejherow o	Opalino	2	PGNIG	Sep-12	Dec-12	10,000			Low Paleozoic	flow ed gas
Baltic Depression	Gdansk Depression	Wejherow o	Opalino	3	PGNIG	Nov-13	Jan-14	10,070			Low Paleozoic	
Baltic Depression	Gdansk Depression	Wejherow o	Opalino	4	PGNIG	Jan-14	Apr-14	10,170			Low Paleozoic	
Baltic Depression	Gdansk Depression	Wejherow o	Tepecz	1	PGNIG	Apr-14	Jun-14					
Baltic Depression	Gdansk Depression	Stara Kiszew a	Wysin	1	PGNIG	Mar-13	May-13	13,255			Low Paleozoic	
Baltic Depression	Gdansk Depression	Stara Kiszew a	Wysin	2H	PGNIG	Mid Jun-15			Y		Low Paleozoic	
Baltic Depression	Gdansk Depression	Stara Kiszew a	Będomin	1	PGNIG	Jun-14	Aug-14				Low Paleozoic	
Baltic Depression	Gdansk Depression	Wejherow o	Kochanow o	1	PGNIG	May-13	Jun-13	10,750			Low Paleozoic	
Baltic Depression	Gdansk Depression	Kartuzy-Szemud	Borc	1	PGNIG	Jul-13	Sep-13	12,335			Low Paleozoic	
Baltic Depression	Gdansk Depression	Kartuzy-Szemud	Milow o	1	PGNIG	May-14	Jul-14				Low Paleozoic	

Appendix 2 (continued).
Shale gas exploration and appraisal wells drilled in Europe

Geological Province	Sub-Province	Concession	Well Name	No	Operator	Spud	Compl	TD ft	Horiz	Frac	Target Fm	Result - Content
Poland (continued)												
Danish-Polish Marginal Trough	Lublin Trough	Grabow iec	Grabow iec	G6	Chevron Polska	31-Oct-11	Feb-12			DFIT	Low Paleozoic	
Danish-Polish Marginal Trough	Lublin Trough	Frampol	Frampol	1	Chevron Polska	Mar-12	Apr-12				Low Paleozoic	
Danish-Polish Marginal Trough	Lublin Trough	Zwierzyniec	Zwierzyniec	1	Chevron Polska	Dec-12	Mar-13			DFIT; frac	Low Paleozoic	
Danish-Polish Marginal Trough	Lublin Trough	Krasnik	Krasnik	1	Chevron Polska	May-13	Aug-13				Low Paleozoic	
Danish-Polish Marginal Trough	Lublin Trough	Chelm	Krupe	1	ExxonMobil E&P Poland	03-Dec-10	Jan-11	12,490		Y	Low Paleozoic	
Danish-Polish Marginal Trough	Lublin Trough	Pionki-Kazimierz	Markow ola	1	PGNIG	Apr-10	Jun-10			1	Upp Carb	
Danish-Polish Marginal Trough	Lublin Trough	Tomaszów Lubelski	Lubycza Królów ska	1	PGNIG	26-Mar-12	Aug-12	11,495			Low Paleozoic	
Danish-Polish Marginal Trough	Lublin Trough	Tomaszów Lubelski	Majdan Sopocki	1	PGNIG	21-Oct-14	Dec-14					
Danish-Polish Marginal Trough	Lublin Trough	Wiszniow - Tarnoszyn	Kościaszyn	1	PGNIG	Oct-13	Jan-14	12,560			Low Paleozoic	
Danish-Polish Marginal Trough	Lublin Trough	Kock-Tarkaw ica	Wojcieszków	1	PGNIG	Sep-13	Dec-13	10,150			Low Paleozoic	
Danish-Polish Marginal Trough	Lublin Trough	Wierzbica	Syczyn	OU1	Orlen Upstream	24-Oct-11	Dec-11	9,445			Low Paleozoic	
Danish-Polish Marginal Trough	Lublin Trough	Wierzbica	Syczyn	OU2K	Orlen Upstream	24-Sep-12	Early Nov-12	13,450	Y	12	Low Paleozoic	
Danish-Polish Marginal Trough	Lublin Trough	Wierzbica	Stręczyn	OU1	Orlen Upstream	22-Feb-13	Apr-13	11,480			Low Paleozoic	
Danish-Polish Marginal Trough	Lublin Trough	Wierzbica	Stręczyn	OU1-K	Orlen Upstream	Sep-14	Oct-14		Y			
Danish-Polish Marginal Trough	Lublin Trough	Wierzbica	Dobryniów	OU1	Orlen Upstream	26-Jun-13	Sep-13				Low Paleozoic	
Danish-Polish Marginal Trough	Lublin Trough	Lubartów	Berejow	OU1	Orlen Upstream	Mid Dec-11	Jan-12	8,573			Low Paleozoic	
Danish-Polish Marginal Trough	Lublin Trough	Lubartów	Berejow	OU2K	Orlen Upstream	12-Dec-12	Feb-13	12,565	Y	7	Low Paleozoic	
Danish-Polish Marginal Trough	Lublin Trough	Lubartów	Uscimów	OU1	Orlen Upstream	May-13	04-Jul-13				Low Paleozoic	
Danish-Polish Marginal Trough	Lublin Trough	Garw olin	Goździk	OU1	Orlen Upstream	16-Jul-12	Oct-12	13,830			Low Paleozoic	
Danish-Polish Marginal Trough	Pomeranian Trough	Rypin	RYP-Lutocin	1	Marathon Oil Poland	Early Apr-12	Jul-12			Y	Low Paleozoic	
Danish-Polish Marginal Trough	Pomeranian Trough	Kwidzyn	KWI-Prabuty	1	Marathon Oil Poland	18-Jul-12	Sep-12			DFIT; frac	Low Paleozoic	
Danish-Polish Marginal Trough	Pomeranian Trough	Brodnica	BRO-NM Lubaw skie	1	Marathon Oil Poland	Sep-12	Dec-12			DFIT	Low Paleozoic	
Danish-Polish Marginal Trough	Pomeranian Trough	Szczaw no	Szymkow o	1	Talisman Energy Polska	07-Mar-12	Jun-12	14,930	Y		Low Paleozoic	C1 - C3
East European Platform Margin	Podlasie Depression	Minsk Mazow iecki	Siennica	1	ExxonMobil E&P Poland	20-Feb-11	Apr-11			Y	Low Paleozoic	
East European Platform Margin	Podlasie Depression	Siedlce	SIE-Domanice	1	Marathon Oil Poland	Jan-12	Mar-12				Low Paleozoic	
East European Platform Margin	Podlasie Depression	Sokolow Podlaski	SOK - Grębków	1	Marathon Oil Poland	Dec-12	Jan-13				Low Paleozoic	
East European Platform Margin	Podlasie Depression	Wodynie-Lukow	Stoczek	OU1	Orlen Upstream	18-Nov-13	Jan-14	10,300			Low Paleozoic	
East European Platform Margin	Podlasie Depression	Wodynie-Lukow	Stoczek	OU1K	Orlen Upstream	Jan-14	Mid Mar-14	14,130	Y	Y	Silurian	
East European Platform Margin	Podlasie Depression	Wolomin	Pęclicin	OU1	Orlen Upstream	Dec-14	Mid Mar-15	12,505				
East European Platform Margin	Volhyno-Podolian Monocline	Orzechow	ORZ-Cycow	1	Marathon Oil Poland	Dec-11	Jan-12			DFIT; frac	Low Paleozoic	
Fore-Sudetic Monocline		Gora	Siciny	2	Gora Energy (San Leon)	10-Nov-11	Mid Feb-12	11,550		DFIT	Low Carb	C1 - C3
Fore-Sudetic Monocline		Raw icz	Raw icz	12 SL-1								
Romania												
South Carpathian Basin		EV-2 Barlad	Silistea-Pungesti	1	Chevron Romania E&P	Early May-14	Early July-14	9,850				

Appendix 2 (continued). Shale gas exploration and appraisal wells drilled in Europe

Geological Province	Sub-Province	Concession	Well Name	No	Operator	Spud	Compl	TD ft	Horiz	Frac	Target Fm	Result - Content
Sweden												
Östergötland Low er Paleozoic		Motala area	5 wells		Aura Energy	Early Oct-11	Q4-2011				Alum Shale	
Östergötland Low er Paleozoic		Ekeby	Brunneby	BY-1	Gripen Energy	Mar-12	Mar-12	282			Alum Shale	w eak flow of flammable gas
Östergötland Low er Paleozoic		Ekeby	Bobergs Häradallmänings	BH-1	Gripen Energy	Mar-12	Mar-12	328			Alum Shale	w eak flow of flammable gas
Östergötland Low er Paleozoic		Ekeby	Rocklunda	RL-1	Gripen Energy	Mar-12	Mar-12	282			Alum Shale	w eak flow of flammable gas
Östergötland Low er Paleozoic		Ekeby	Ekebyborna	GH-2	Gripen Energy	Mar-12	Mar-12	328			Alum Shale	21 Mscfd in 2-hour flow - 97.5% CH4
Östergötland Low er Paleozoic		Ekeby	Ekebyborna	GH-1A	Gripen Energy	Sep-12	Sep-12	300			Alum Shale	strong gas flow
Östergötland Low er Paleozoic		Ekeby	Ekebyborna	GH-2A	Gripen Energy	Sep-12	Sep-12	340			Alum Shale	gas flow
Östergötland Low er Paleozoic		Ekeby	Ekebyborna	GH-3	Gripen Energy	Sep-12	Sep-12	305			Alum Shale	intermittent gas flow
Östergötland Low er Paleozoic		Ekeby	Fossala	FA-2	Gripen Energy	22-Jun-13	28-Jun-13	352			Alum Shale	
Östergötland Low er Paleozoic		Ekeby	Kullen KN-1	GH-5	Gripen Energy	18-Jun-13	24-Jun-13	366			Alum Shale	3.1 Mscfd after 30 minutes
Östergötland Low er Paleozoic		Ekeby	Uddenä	UD-1	Gripen Energy	10-Jun-13	14-Jun-13	355			Alum Shale	no details
Östergötland Low er Paleozoic		Ekeby	3 appraisal wells		Gripen Energy	May to Aug 15	May to Aug 15				Alum Shale	Flow ed gas
Östergötland Low er Paleozoic		Orlunda	1 exploration well		Gripen Energy	May to Aug 15	May to Aug 15				Alum Shale	Flow ed gas
Östergötland Low er Paleozoic		Eneby	2 exploration wells		Gripen Energy	May to Aug 15	May to Aug 15				Alum Shale	Flow ed gas
Siljan Ring Depression			5 percussion holes		AB Igrene	2009	2009				Low Paleozoic	
Siljan Ring Depression			Mora	001	AB Igrene	2010	2010	~1,650			Low Paleozoic	
Siljan Ring Depression			Solberga	1	AB Igrene	2011	2011	~1,650			Low Paleozoic	
Siljan Ring Depression			Stumsnäs	1	AB Igrene	2011	2011	~1,650			Low Paleozoic	
Siljan Ring Depression			Mora	002	AB Igrene	Q2-2013	Q2-2013	1,670			Low Paleozoic	
Siljan Ring Depression			Mora	003	AB Igrene	Q2-2013	Q2-2013	1,450			Low Paleozoic	
Siljan Ring Depression			Vattumyren	3	AB Igrene	20-Jul-15					Low Paleozoic	
Fennoscandian Border Zone	Colonus Shale Trough	Colonussänkan	Lövestad	A3-1	Shell	28-Nov-09		3,134			Alum Shale	
Fennoscandian Border Zone	Colonus Shale Trough	Colonussänkan	Oderup	C4-1	Shell			3,010			Alum Shale	
Fennoscandian Border Zone	Colonus Shale Trough	Colonussänkan	Hedeberga	B2-1	Shell			2,448			Alum Shale	
United Kingdom												
Anglo-Dutch Basin	Cleveland Basin	PL 080	Kirby Misperton	8	Viking UK Gas	06-Jun-13	04-Oct-13	~10,000			Bow land Shale	
Anglo-Dutch Basin	Humber Basin	PEDL 183	Craw berry Hill	1	Rathlin Energy (UK)	15-Apr-13	12-Aug-13	~9,000			DFIT	Bow land Shale
Anglo-Dutch Basin	Humber Basin	PEDL 183	West New ton	1	Rathlin Energy (UK)	27-Jun-13	06-Sep-13	~10,420			DFIT	Bow land Shale
Cheshire Basin	Rossendale Basin	PEDL 190	Ince Marshes	1	IGas	04-Nov-11	21-Jan-12	5,174			Bow land Shale	gas indications
Cheshire Basin	Rossendale Basin	PEDL 184	Ellesmere Port	1	IGas	15-Nov-14	22-Dec-14				Sabden & Bow land shales	Significant gas indications
Cheshire Basin	Rossendale Basin	PEDL 193	Irlam	1	IGas	10-Jan-14	03-Mar-14	7,004			Sabden & Bow land shales	
Cheshire Basin	Rossendale Basin	PEDL 193	Irlam	1Z	IGas	03-Mar-14	31-Mar-14				Sabden & Bow land shales	
East Irish Sea Basin	West Bow land Basin	PEDL 165	Preese Hall	1	Cuadrilla	16-Aug-10	08-Dec-10	9,098		5	Bow land Shale	substantial gas flow s
East Irish Sea Basin	West Bow land Basin	PEDL 165	Grange Hill	1	Cuadrilla	15-Jan-11	15-Apr-11				Bow land Shale	
East Irish Sea Basin	West Bow land Basin	PEDL 165	Grange Hill	1Z	Cuadrilla	15-Apr-11	Early Aug-11	10,775			Bow land Shale	
East Irish Sea Basin	West Bow land Basin	PEDL 165	Beaconsall	1	Cuadrilla	23-Aug-11	13-Oct-11				Bow land Shale	
East Irish Sea Basin	West Bow land Basin	PEDL 165	Beaconsall	1Z	Cuadrilla	13-Oct-11	21-Dec-11	10,500			Bow land Shale	
East Irish Sea Basin	West Bow land Basin	PEDL 165	Anna's Road	1	Cuadrilla	06-Oct-12	21-Nov-13	2,000			Bow land Shale	Junked & Abandoned
Midland Valley of Scotland	Kincardine Basin	PEDL 133	Airth	6	Composite Energy	15-Oct-05	05-Dec-05	3,524			Black Metals Marine Band	
Midland Valley of Scotland	Kincardine Basin	PEDL 133	Longannet	1	Composite Energy	16-Feb-07	29-Apr-07				Black Metals Marine Band	
Midland Valley of Scotland	Kincardine Basin	PEDL 133	Bandeath	1	Composite Energy	15-May-07	18-Jun-07				Black Metals Marine Band	
South Wales Carboniferous		PEDL 148	Banw en	1	UK Methane	07-Sep-11	16-Sep-11				Aberkenfig?	
South Wales Carboniferous		PEDL 149	St Johns	1	UK Methane	26-Aug-11	23-Mar-12				Aberkenfig?	

