EMD Shale Gas and Liquids Committee Annual Report, FY 2015

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May 10, 2015

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INTRODUCTION

It is a pleasure to present this 2015 Annual Report from the EMD Shale Gas and Liquids Committee. This report contains information about specific shales across the U.S., Canada, Europe, and China, from which hydrocarbons are currently being produced or shales that are of interest for hydrocarbon exploitation. The inclusion in this report of shales from which any hydrocarbon is produced reflects the expanded mission of the EMD Shale Gas and Liquids Committee to serve as a single point of access to technical information on shales regardless of the hydrocarbons produced from them (e.g., gas, oil, condensate). 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. The price of oil has affected production in many of the US plays, which is clear from information

provided in several of the sections below; however, some of the top 100 oil and gas fields in the US are in shales (see http://www.eia.gov/naturalgas/crudeoilreserves/top100/).

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), Canada (by province), Europe (by country), and China. Additional sections of the report include Valuable Links, Additional Sources of Information, and a Gas Shales and Shale Oil Calendar. The leaders of this committee are interested in your feedback. Please feel free to contact Neil Fishman (nfishman@hess.com) with your comments and suggestions.

Antrim Shale (Devonian), Michigan Basin, U.S.

By Dr. William B. Harrison, III (Western Michigan University)

The Michigan Basin Antrim Shale play is currently 27 years old, having begun the modern phase of development in 1987. The total number of producing wells drilled in the play through end ofOctober, 2013 is approximately 11,550 with about 9,672 still online. Total cumulative gas production reached 3.216TCF by the end of October, 2013. 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 768 separate projects at the end of October, 2013. Cumulative production for first 10 months of 2013 was 84,525,378 MCF, which was a 1.45% decline from the same period in 2012.

There were 30 operators with production at the end of October, 2013. There were 9,672 wells online at the end October, 2013. There were 111 new wells drilled in 2009, only 58 in 2010, 13 drilled in 2012 and 5 new wells drilled in 2013. That is a 48% decrease in wells drilled from 2009 to 2010, a continuing drop of 33% in 2011, a 78% drop in 2012 and 61% in 2013. Overall drilling activity in Michigan was down 2% in 2012 compared to 2011. Most of the production comes from a few operators. The top 10 operators produced 82.5% of the total Antrim gas in 2013.

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 October, 2013 was 28 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 1.60 MCF/BBL through October, 2013. 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.

CO_2 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 12.5% CO2 in 2012.

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

Top 10 Operators, Antrim Shale:

Linn Operating, Inc.
Chevron Michigan LLC
Terra Energy Ltd
Breitburn Operating Limited Partnership
Ward Lake Energy
Muskegon Development Co.
Trendwell Energy Corp
Jordan Development Co. LLC
Merit Energy Co.
Delta Oil Co. Inc.

Significant Trends – New drilling has almost ceased during 2011 through 2013 due to low gas prices. Production continues to decline as do the total number of active wells. Daily gas production per well declined by 1.45% in the first 10 months of 2013. However, daily water production per well decreased 5.67% in 2013 compared to the same period in 2012. The numbers of horizontal completions still represent less than 5% of total wells.

Bakken Formation (Upper Devonian-Lower Mississippian), Williston Basin, U.S.

By Julie LeFever and Stephan Nordeng (North Dakota Geological Survey)

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 879.5 million bbls of oil have been recovered from the 6021 wells in the 300 middle Bakken producing fields put into service since 2004. The 2093 horizontal wells drilled into the Three Forks Formation since 2006 have produced a total of 297 million bbls of oil. Currently there are 240 fields with Three Forks production. Seventy-nine 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. Eighty-four 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 (1186 wells)
2. Continental Resources, Inc. (1084 wells)
3. Hess Bakken Investments II, LLC (972 wells)
4. XTO Energy Inc. (581 wells)
5. Oasis Petroleum North America LLC (570 wells)
6. EOG Resources (560 wells)
7. Statoil Oil & Gas, LP (472 wells)
8. Marathon Oil Company (434 wells)
9. Burlington Resources Oil & Gas Company LP (406 wells)
10. SM Energy Company (294 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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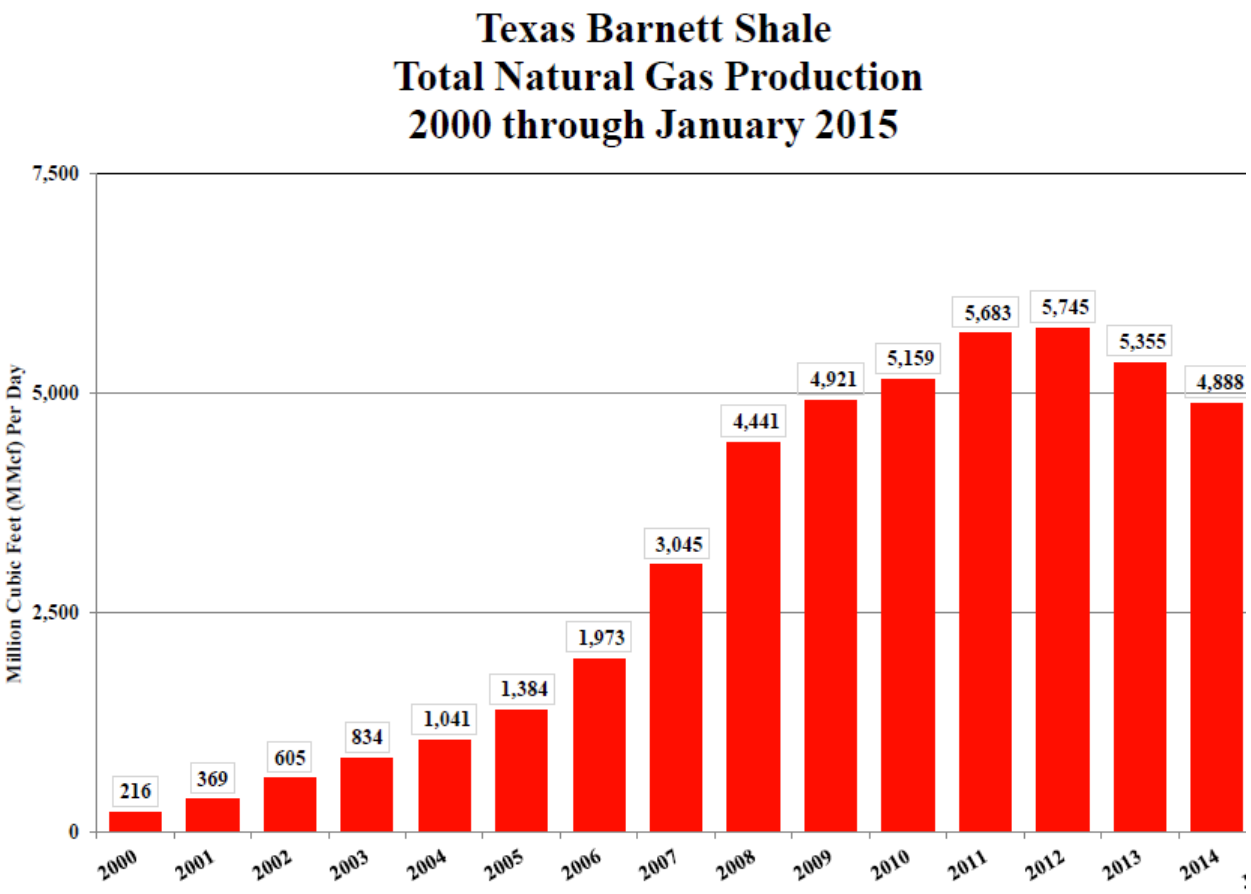
Barnett Shale (Mississippian), Fort Worth Basin, U.S.

By Kent Bowker (Bowker Petroleum, LLC)

Daily gas production from the Barnett Shale continues to decline and has now dropped below 5 BCF/day. But at a rate less than might have been expected given the massive decrease in drilling and completion activity over the past five years. The current daily gas production is right at 4.8 BCF while oil/condensate production is at 10,900 bbls.



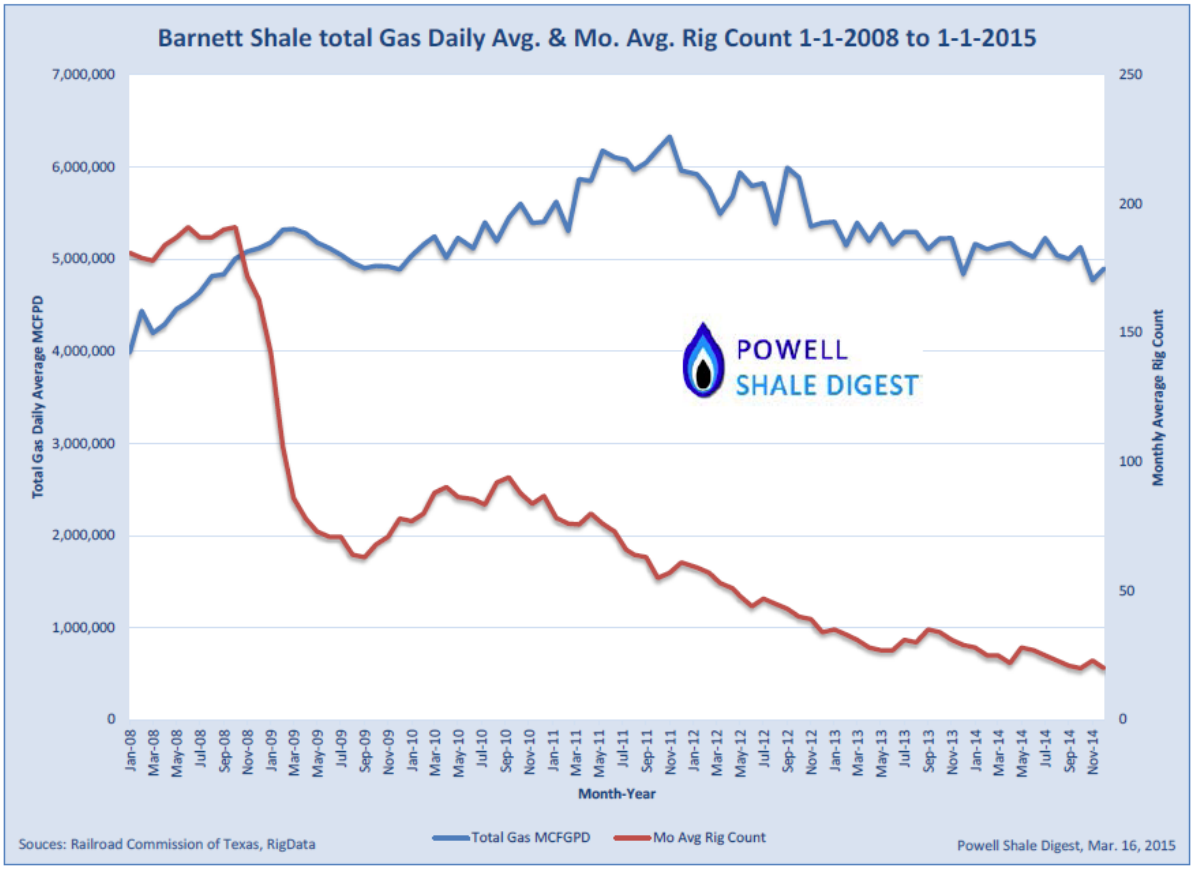
http://www.rrc.state.tx.us/media/22204/barnettshale_totalnaturalgas_day.pdf

There are sixteen named Barnett fields in the Fort Worth basin, and as of December 2014 they have produced a total of 16.8 trillion cubic feet and gas and 63 million barrels of oil/condendsate. Again as of December 2014, there were a total of 19,992 producing Barnett wells in the basin, with the vast majority of those in the Newark, East field. Tarrant County has had the most cummulative production (5.3 TCF) with Johnson (3.9 TCF), Wise (2.7 TCF) and Denton (2.6 TCF) following as major producing centers.

Chesapeake's Hog "A" #4H well in Johnson County is the largest well in terms of cummulative production in the play at 6.2 BCF (on line for 45 months).

Texas Barnett Shale Field (North Texas)		Averages							Field Totals	
Texas Railroad Commission Designation	No. Wells	Oil Peak Mo Daily Ave BOPD	Gas Peak Mo Daily Ave MCFGPD	Age Mo	Oil Nov 2014 Daily Ave BOPD	Gas Nov 2014 Daily Ave MCFGPD	Oil Total to Dec 1 2014 BO	Gas Total to Dec 1 2014 MCF	Oil Total to Dec 1 2014 BO	Gas Total to Dec 1 2014 MCF
ANTIOCH (BARNETT SHALE)	2	0	244	128	0	15	1	231,243	1	462,485
AVONDALE (BARNETT)	1	0	272	137			8	252,508	8	252,508
BELLEVUE (BARNETT SHALE)	5	20	65	51	1	8	3,231	30,100	16,156	150,499
BOWIE, NW. (BARNETT SHALE)	2	23	147	95	8	90	23,329	249,392	46,657	498,784
CLEBURNE (BARNETT SHALE)	30	0	803	68	0	32	0	360,685	0	10,820,549
CLEBURNE, W. (HANCOCK BARNETT)	2	0	65	26	0	0	0	19,885	0	39,770
DENTON CREEK (BARNETT)	3	20	156	7	0	0	1,359	15,781	4,078	47,343
DUBOIS (BARNETT)	1	0	114	150	0	0	34	87,917	34	87,917
JASON DVORIN (BARNETT SHALE)	1	0	483	42	0	0	0	247,134	0	247,134
LAMKIN-HAMILTON (BARNETT)	1	3	0	43	0	0	901	0	901	0
MULLINIKS (BARNETT SHALE)	2	0	196	56	0	0	0	28,686	0	57,372
NEWARK, EAST (BARNETT SHALE)	19,868	18	1,557	77	1	241	3,063	842,817	60,858,290	16,745,094,883
PREMONITION (BARNETT SHALE)	4	28	43	9	3	6	5,932	9,199	23,727	36,797
RECTOR (BARNETT SHALE)	7	0	130	54	0	1	3	60,878	19	426,144
SANFORD DVORIN (BARNETT SHALE)	2	0	330	46	0	0	0	79,706	0	159,411
ST. JO RIDGE (BARNETT SHALE)	61	85	256	89	1	23	27,299	181,666	1,665,223	11,081,645
	19,992	<TOTALS>							62,615,093	16,769,463,240

(used with permission of Gene Powell)



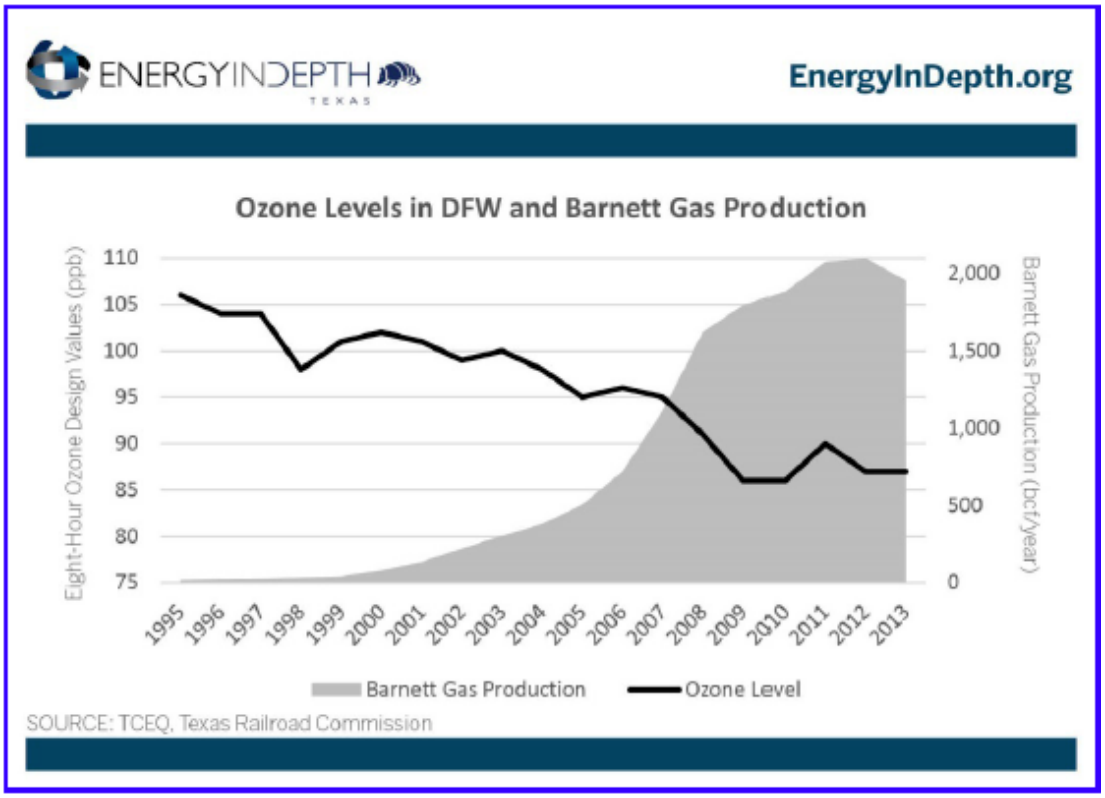
(used with permission of Gene Powell)

The graph above illustrates the precipitous decline in the number of drilling rigs in the Barnett through 2014 but with the daily production levels dropping at a much lower rate. As of early April, there is only one rig working in the Barnett play. The last time there was only one rig in the Barnett was during the crash of 1999. We will now be able to see what the natural production decline is for the play since virtually no new wells are being added to the inventory of producers.

Annual Average	Total Gas MCFGPD	Total Condensate / Oil BOPD	Mo. Ave. Drilling Rig Count	Mo. Ave. Gas Price $/MMBtu	Annual Average	Total Gas MCFGPD	Total Condensate / Oil BOPD	Mo. Ave. Drilling Rig Count	Mo. Ave. Gas Price $/MMBtu
2008	4,617,514	9,565	183	$8.90	2012	5,702,415	25,492	47	$2.82
2009	5,088,198	9,255	81	$4.16	2013	5,224,193	21,287	31	$3.73
2010	5,271,068	11,555	86	4.40	2014	5,064,177	24,528	24	$4.28
2011	5,958,680	33,002	69	$4.03	*Updated 3-16-2015*				

(Used with permission of Gene Powell)

Recently, the EPA has proposed to lower the National Ambient Air Quality Standard for ozone from 75 ppb to between 65 and 70 ppb. There have been several public hearings concerning this proposed change with personnel from many environmental groups testifying that increased oil and gas activities (they like to use the "fracking boom" for some reason) in the Dallas-Fort Worth Metroplex is the primary reason that area has not been in compliance with EPA regulations. These statements have been shown to be false on several occasions (see, for example http://www.tceq.texas.gov/assets/public/comm_exec/pubs/pd/020/2013/Outlook-Nov-2013-x.pdf). But only one graph should be necessary to counter the claim that oil and gas activities have been a substantial source of ozone in the Metroplex:



http://www.rrc.state.tx.us/barnettshale/NewarkEastField_1993-2013.pdf

Eagle Ford Group (Cretaceous), Gulf Coast Basin, U.S.

Russell 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 into the Karnes Trough, where it is variably a target for dry gas, wet gas/condensate, or oil (Fig. 1). 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 July 2014, there were more than 6,400 oil wells and more than 3,000 gas wells in the Eagle Ford (Texas Railroad Commission http://www.rrc.state.tx.us/eagleford/). The trend occurs at an average depth of 11,000 feet, and it is overpressured.

Similar to the Barnett Shale and Haynesville Formation, the Eagle Ford is a viable target for hydrocarbon exploitation because of advances in the application of horizontal drilling and hydraulic fracturing. Mineralogy 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 beds that are brittle and enhance the opportunity for induced fractures. Most operators are drilling horizontal well laterals of 3,500 to 5,000 feet (ft) 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 link at http://www.rrc.state.tx.us/eagleford/.

Activity and success in the Eagle Ford in Texas has generated renewed interest in the laterally equivalent Cenomanian-Turonian marine shale of the Tuscaloosa Formation 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 four years, those companies have begun exploration and initial development drilling for the Tuscaloosa marine shale. This activity is based in part on the historical record of hydrocarbon generation and proven, but minimal, production from the unit, the current high price for oil, corresponding low price for natural gas, and the recent success of horizontal drilling in the Eagle Ford in Texas. The Tuscaloosa marine shale trend averages about 12,000 to 15,000 ft in depth and is overpressured. Since 2010, several companies have drilled successful horizontal wells, with about 42 wells currently producing in eastern Louisiana and southern Mississippi (http://dnr.louisiana.gov/; http://www.sonris.com/). This production trend is comparable to the approximately 42 wells that were current in the Eagle Ford in early 2009 (Texas Railroad Commission http://www.rrc.state.tx.us/eagleford/). Reported IPs are encouraging, in the neighborhood of several hundred BOPD, but currently only minimal yearly production data is available to evaluate the play's future success.

References Cited

EIA, 2010, Eagle Ford Shale Play, Western Gulf Basin, South Texas, http://www.eia.gov/oil_gas/rpd/shaleusa9.pdf, accessed September 4, 2014.

Texas Railroad Commission, http://www.rrc.state.tx.us/eagleford/.; accessed August 10, 2014.

Louisiana Department of Natural Resources, SONRIS Database Access, (http://dnr.louisiana.gov/; http://www.sonris.com/), accessed August 14, 2014.

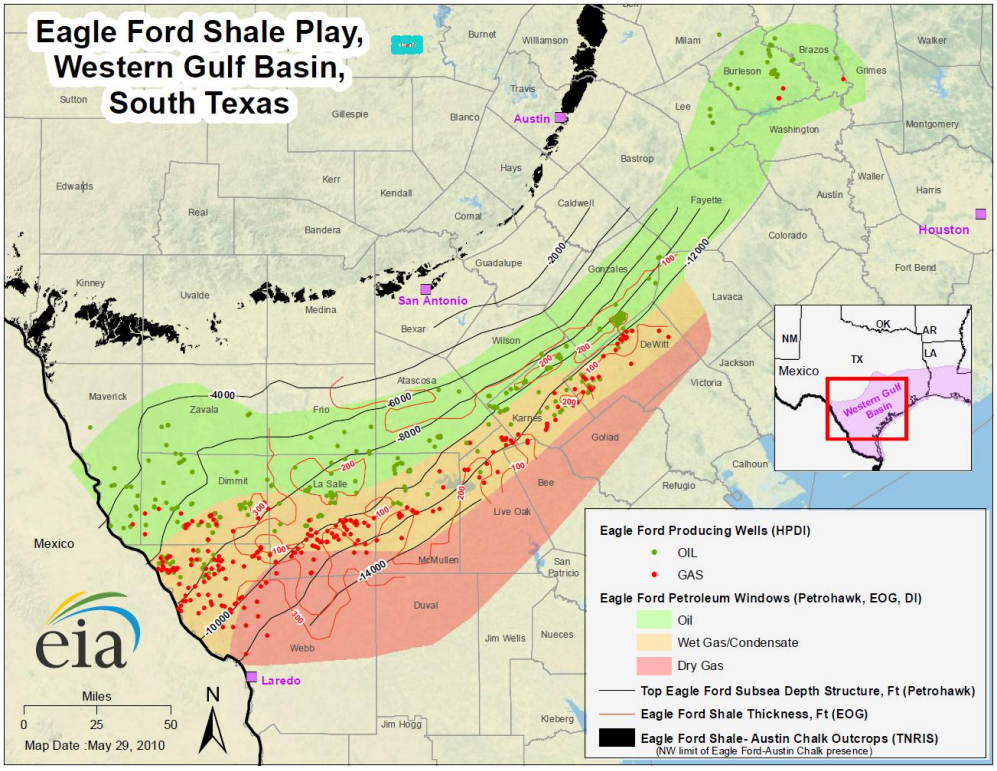


Figure 1. Map showing extent and hydrocarbon windows of the Eagle Ford Shale (from EIA, 2010).

Fayetteville Shale (Mississippian), Arkoma Basin, U.S.

By 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.

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 year-end 2014 has totaled 5,678,708,837 Mcf from 5,656 wells. Annual production of Fayetteville Shale for 2014 is 1,022,440,678 Mcf from 5,392 wells, which is a decrease from 2013 of 7,182,248 Mcf. 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/Fayprodinfo.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 7 rigs in March 2015. Of the three primary producers operating in the Fayetteville, XTO is operating 1 rig, SEECO (SWN) has 6, and BHP has 0. 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. Since 2013, Southwestern Energy has drilled its average well in just 6.5 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 by 14% from 4,532 feet in 2010 to 5,165 feet in 2013.

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 year-end 2014, there are a total of 5,656 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).

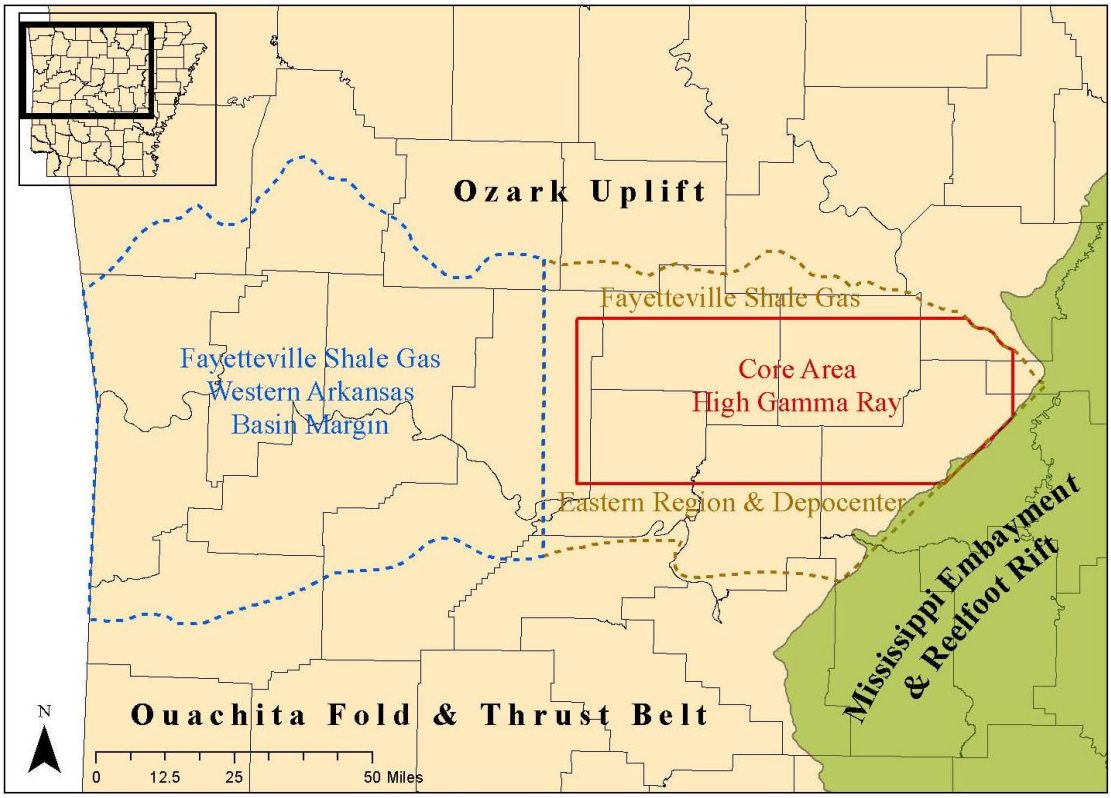


Figure 1. Primary area of the Fayetteville Shale exploration and development in Arkansas.

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) – accounted for over 99% of gross operated production from the field. The three companies hold close to 2 million net acres under lease in the play. Southwestern, with 906,000 net acres and more than three thousand producing wells, is by far the largest operator among the three companies, and accounts for about two-thirds of the field's total production volume. Exxon and BHP are approximately equal in terms of their acreage and gross operated production. During 2012, Southwestern contributed 724.8 Bcf in Fayetteville gas sales, good for 70.3% of the play's total sales that year. BHP sold 155.7 Bcf (15.1%) and XTO Energy sold 147.9 Bcf (14.3%). The remaining 0.3% of sales, or 2.4 Bcf, was spread out among nine companies.

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

1) SEECO Inc. (an exploration subsidiary of Southwestern Energy) (3,720 wells)

2) BHP Billiton Petroleum (965 wells)
3) XTO Energy, Inc. (a subsidiary of ExxonMobil) (840 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 and the AGS Fayetteville Shale well location maps can be viewed at http://www.geology.arkansas.gov/home/fayetteville_play.htm. AGS updates these maps and associated well database (in Excel® format) online every two weeks.

(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.

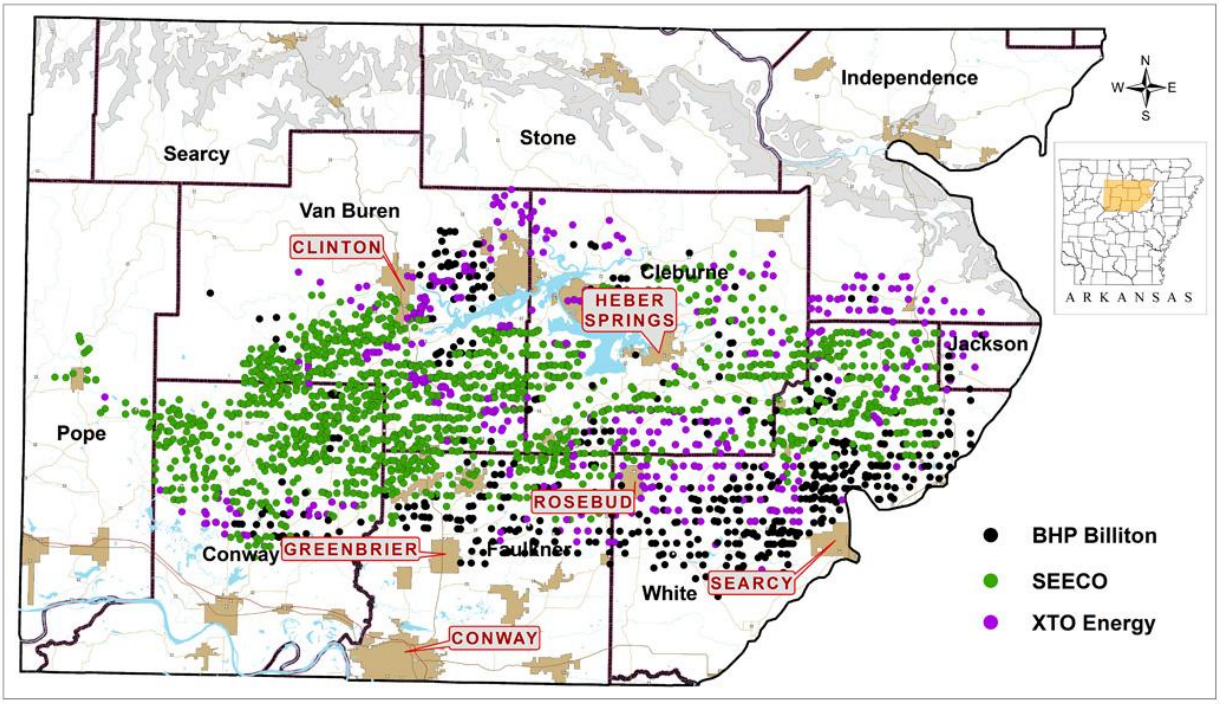


Figure 2. Location map of the Fayetteville Shale producing wells by top 3 operators as of March 2015.

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.

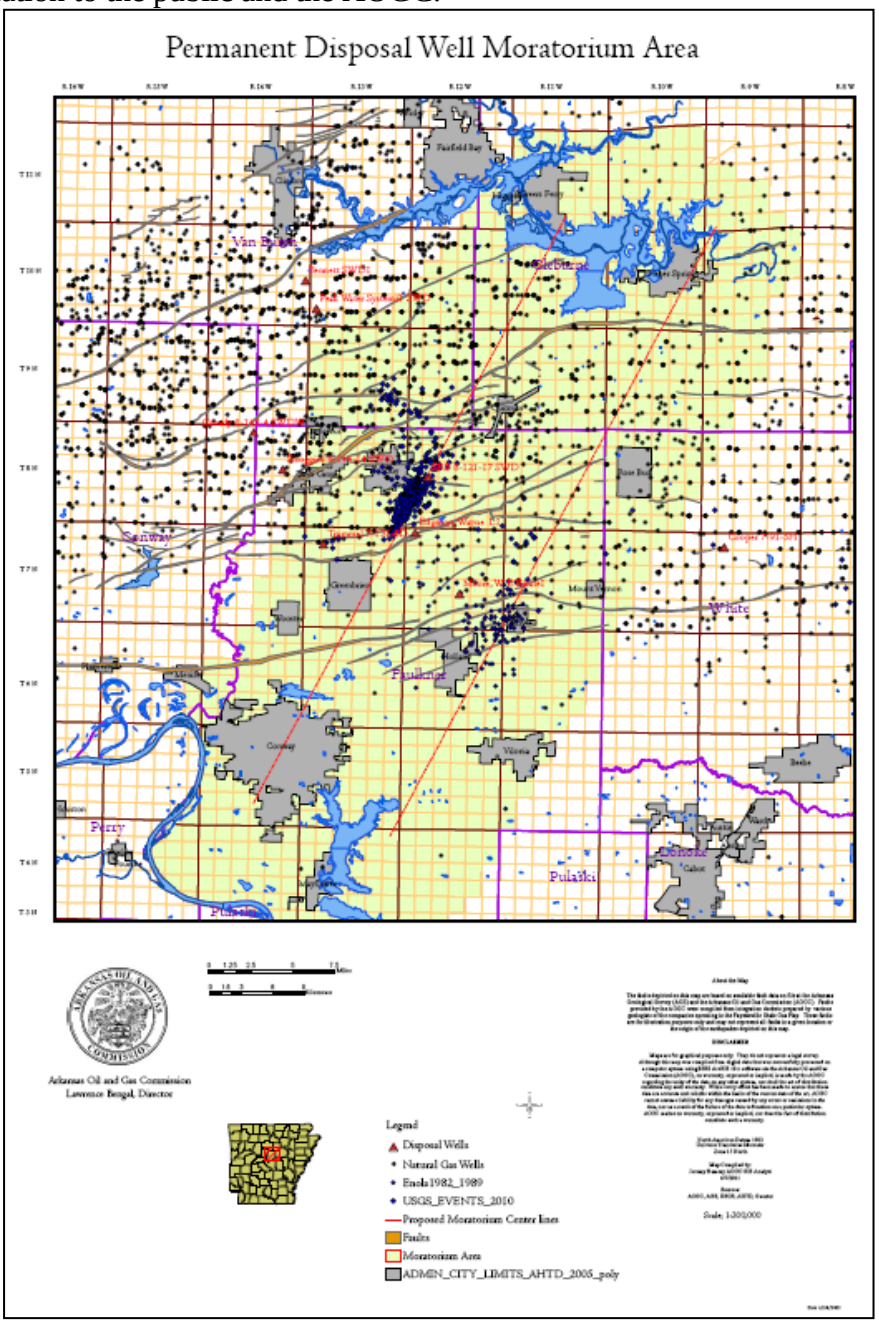


Figure 3. Permanent moratorium area for disposal wells in the Fayetteville Shale Play, Arkansas (from the AOGC website).

Concerns about the effect of Fayetteville gas exploration and production on public heath, 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.

Haynesville/Bossier Shale (Jurassic), Texas and Louisiana, U.S.

by Ursula Hammes (Bureau of Economic Geology, Austin, TX)

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 fewer wells in Texas over Louisiana and an overall decrease in rigs from last year (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/ ccessed April 21, 2015.

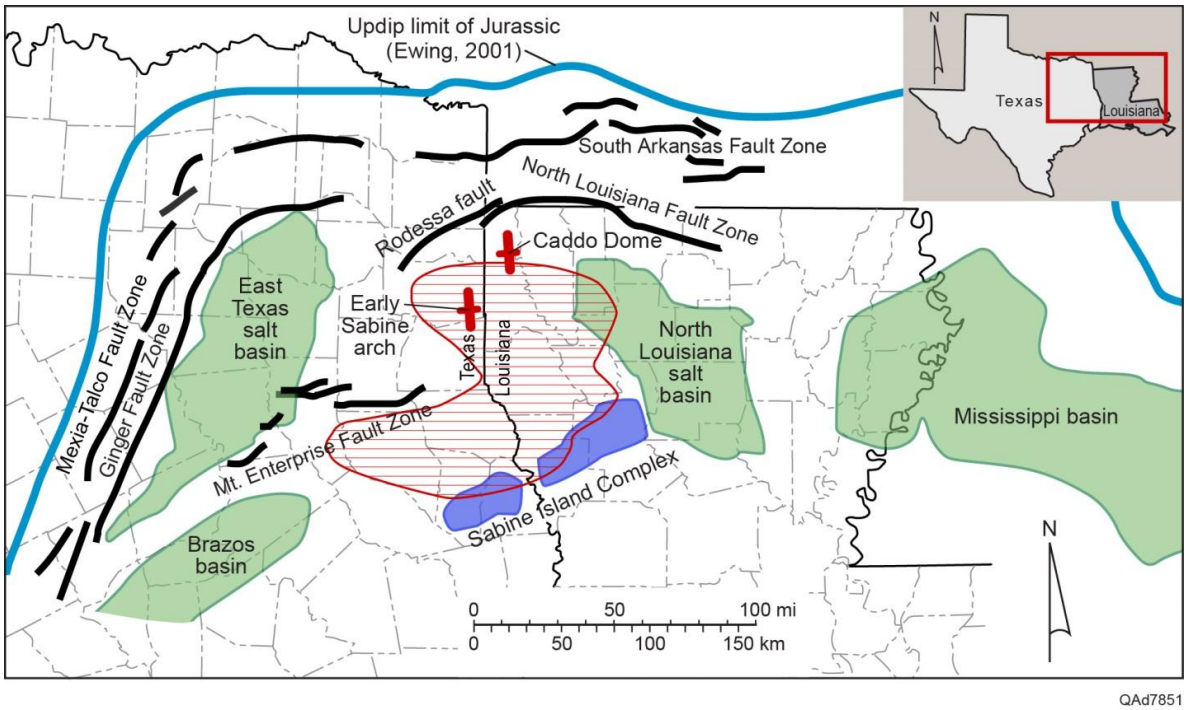


Figure 1: Location of Haynesville Basin and productive zone of Haynesville Shale (red stippled pattern; from Hammes et al., 2011).

April 17, 2015	All Haynesville/MBS Wells		
Operator	**LA**	**TX**	**Total**
Chesapeake	6	0	6
Exco Resources	0	4	4
Anadarko	1	2	3
XTO Energy	0	2	2
BHP Billiton	2	0	2
Comstock Oil & Gas	1	0	1
EP Energy	1	0	1
BP America	0	1	1
Vine Oil & Gas	1	0	1
J-W Operating	1	0	1
Total	**13**	**9**	**22**

Parish/County	17-Apr	10-Apr	3-Apr
DeSoto, LA	7	6	6
San Augustine, TX	4	4	4
Panola, TX	3	3	3
Bossier, LA	2	2	2
Caddo, LA	2	3	3
Red River, LA	2	2	1
Nacogdoches, TX	1	1	1
Natchitoches, LA	1	0	0
Total	22	21	20

Figure 2: Rig counts in Louisiana and Texas for April 2015 (www.haynesvilleplay.com; accessed April 23, 2015)

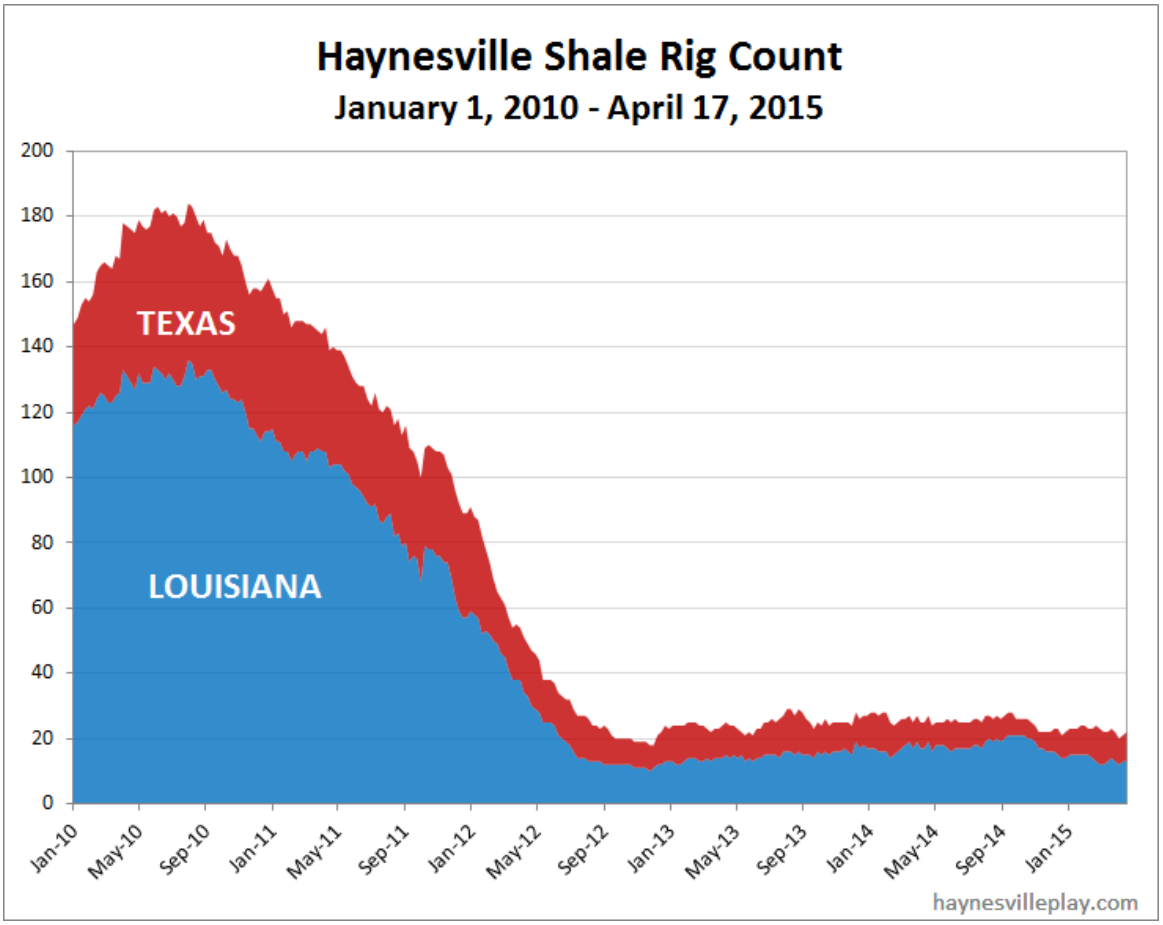


Figure 3: Louisiana and Texas Haynesville rig count through March 2015 (from www.haynesvilleplay.com).

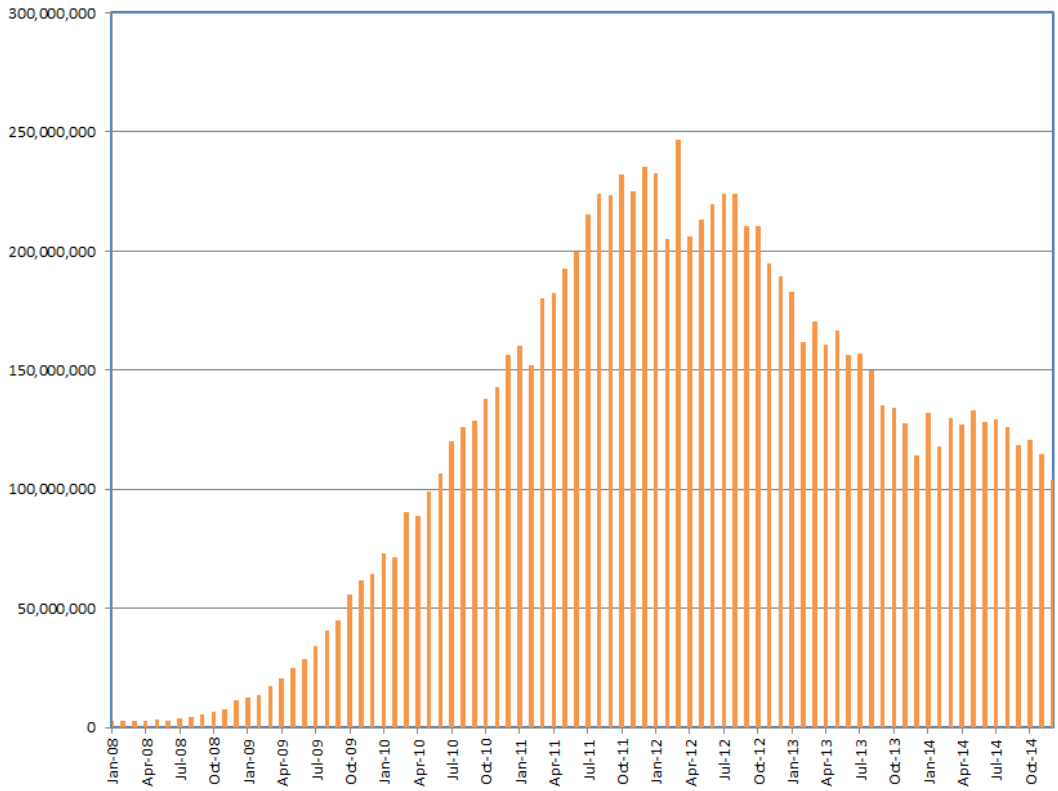


Figure 4: Monthly gas production (in MMcf) through end of 2014 of the Haynesville Shale (data from IHS Enerdeq).

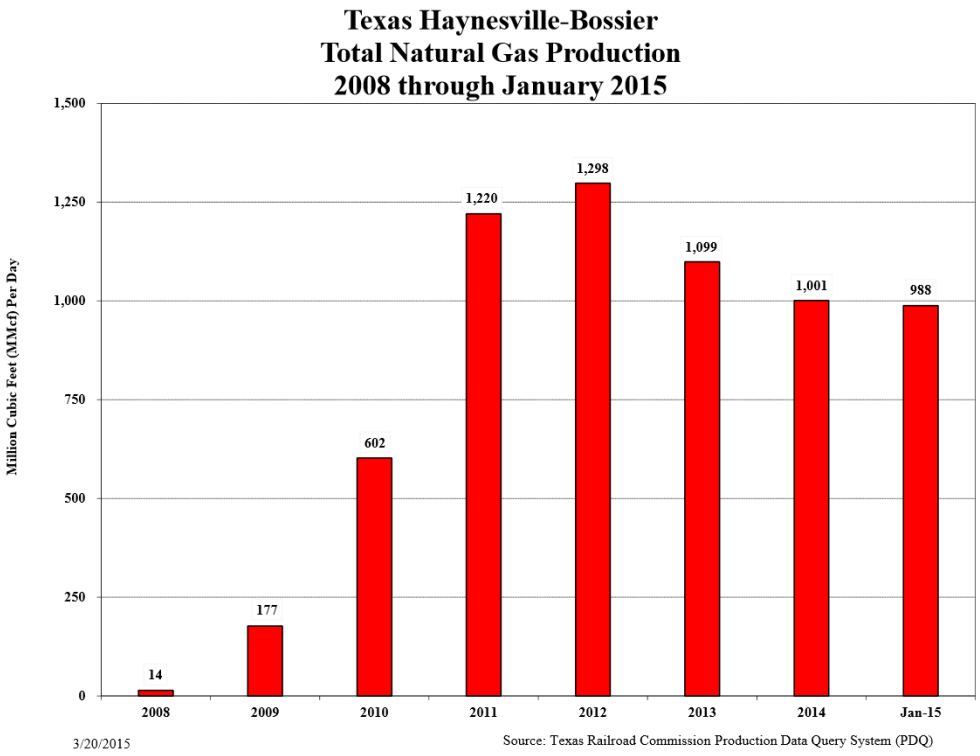


Figure 5: Yearly gas production chart (MMCF/day) through January 2015 for Haynesville Shale (from RRC TX).

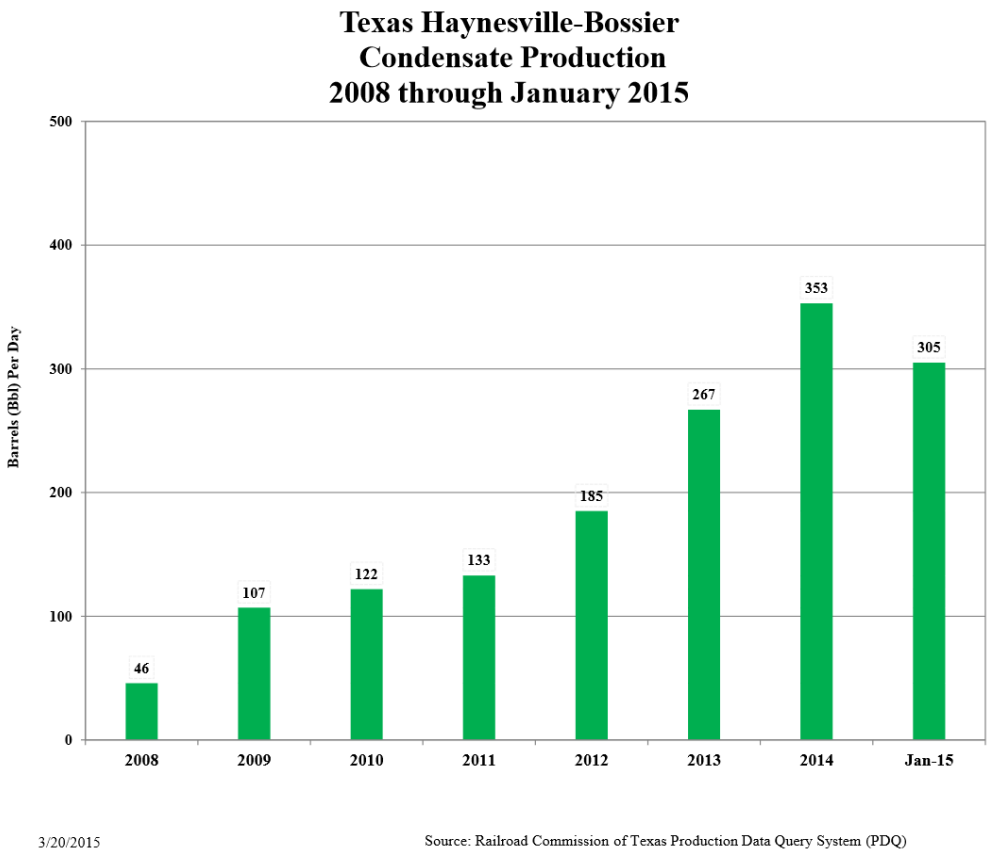


Figure 6: Texas Haynesville Shale condensate production (in barrels per day) through January 2015 shows significant liquids production.

References:

Hammes, U., H.S. Hamlin, and T.E. Ewing, 2011, Geologic analysis of the Upper Jurassic Haynesville Shale in east Texas and west Louisiana: AAPG Bull., v. 95, p. 1643-1666.

Hammes, U., and G. Frébourg, 2012, Haynesville and Bossier mudrocks: A facies and sequence stratigraphic investigation, East Texas and Louisiana, USA: Marine and Petroleum Geology (2011), doi: 10.1016/j.marpetgeo.2011.10.001.

Wang, F.P., and U. Hammes, 2010, Effects of petrophysical factors on Haynesville fluid flow and production: World Oil, D79-D82.

Wang, F.P., U. Hammes, and Q. Li, 2013, An overview of Haynesville Shale production, in, Hammes, U., and J. Gale, (2013): Geology of the Haynesville Gas Shale in East Texas and West Louisiana, USA: AAPG Memoir 105, p. 155-178.

Marcellus Shale (Devonian)—Appalachian Basin, U.S.

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

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 hydrocarbons, 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 February, 2014 (U.S. Energy Information Administration, 2014), which contained analyses of drilling data through January, 2014, and projected production through March, 2014, the number of rigs that completed wells in the Marcellus Shale decreased from over 140 per month on January 1, 2012, to about 100 per month, as of January 31, 2014. However, the daily gas production rate of new Marcellus Shale wells increased from less than 3 million cubic feet (Mcf) per day to over 6 Mcf per day for the same period. Including production

declines in legacy wells, the total production from the Marcellus Shale is about 14 billion cubic feet (bcf) of gas per day and almost 50,000 barrels (bbls) of oil per day, as of January 31, 2014, according to the EIA report (U.S. Energy Information Administration, 2014).

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 .

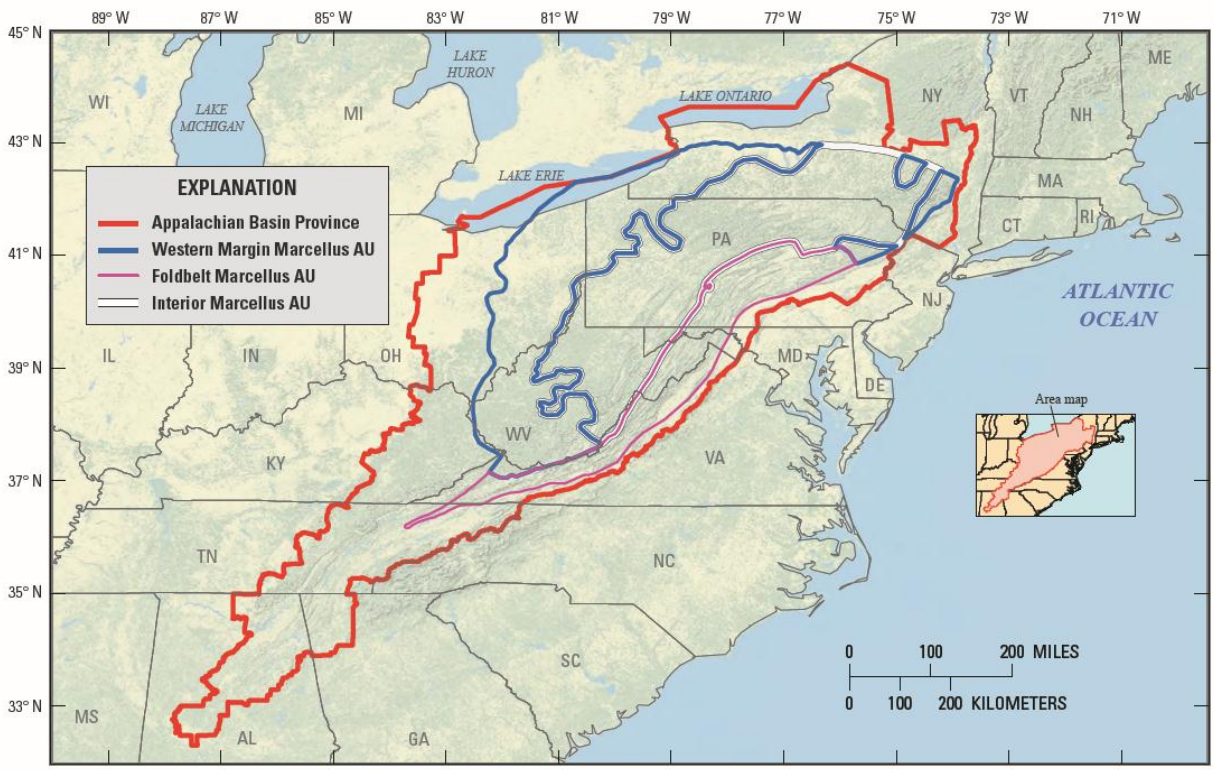


Figure 1. Map of the Appalachian Basin Province showing the three Marcellus Shale assessment units (Coleman and others, 2011).

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.

Maryland: According to the Maryland Geological Survey (MGS), there were no exploration wells drilled in Maryland between 1996 and 2014. In 2009, four companies submitted applications for permits to drill Marcellus Shale wells. None of these applications were approved, and all of the applications were withdrawn by the companies. 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 access at http://www.mde.state.md.us/programs/Land/RecyclingandOperationsprogram/SpecialProjects/Documents/Oil%20and%20gas%20reg%20proposal%20-%20MD%20Register%20notice%201-9-15.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), there were 27 vertical wells with Marcellus Shale listed as the producing formation in 2013, but only 14 reported production in 2013. Natural gas production from the Marcellus Shale in 2013 was 16.8 Mcf, down from the high of 64 Mcf reported for 2008. There was no reported oil production. According to the DEC, there were over 269 Mcf of gas produced from the Marcellus Shale between 2000 and 2013. 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. A search of the DEC wells database indicated that 50 wells have been drilled with the objective formation as "Marcellus," and 14 have "active" well status. All are vertical wells.

The New York DEC published a Preliminary Revised Draft Supplemental Generic Environmental Impact Statement (SGEIS) in July, 2011. Additional information was added and a Revised Draft SGEIS was released September 7, 2011. The public comment period ended January 11, 2012, after which DEC was required to refile the draft regulations covering high volume hydraulic fracturing. DEC held public hearings for the SGEIS and for the regulations in November, 2012. The public comment period closed on January 11, 2013. The DEC Commissioner announced that DEC will complete the SGEIS in early 2015, and that the Commissioner will issue a legally binding findings statement prohibiting High-Volume Hydraulic Fracturing.

Ohio: The Ohio Department of Natural Resources (DNR) reported that about 1.35 bcf of gas and over 21,500 bbls of oil were produced from the Marcellus Shale from 2007 through 2013. There were about 20 wells that reported production from the Marcellus Shale in 2013. The productive wells were in Athens, Belmont, Jefferson, Meigs, Monroe, Noble, and Washington counties. According to DNR, there were about 87.3 Mcf of gas and about 3,650 bbls of oil produced in 2013. This is the highest annual oil production since 2007, but the second lowest annual gas production since 2007. As of March 7, 2015, 44 Marcellus Shale horizontal well permits were issued, 29 horizontal wells have been drilled into the Marcellus Shale,

and 13 horizontal wells were producing from the Marcellus Shale. The horizontal Marcellus Shale wells reported as productive are in Belmont, Carroll, Jefferson and Monroe counties.

The maximum thickness of the Marcellus Shale in Ohio is about 75 feet, and the Marcellus Shale is over 30 feet thick in the productive area in easternmost Ohio (Erenpreiss and others, 2011). The depth of the base of the Marcellus Shale in the productive area in eastern Ohio is 3,000-6,000 feet. The Ohio Geological Survey published a map of the area of potential within the Marcellus Shale (http://geosurvey.ohiodnr.gov/portals/geosurvey/Energy/Utica/Utica_Marcellus_Ohio_8x11.pdf), which includes 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 are 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.

Tennessee: According to de Witt and others (1993), the Marcellus Shale is present in the subsurface in northeastern Tennessee. Therefore, the USGS determined that the Foldbelt Marcellus Assessment Unit extends 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 2014. It is likely 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=stelprd3799959.

West Virginia: Total production from wells completed in the Marcellus Shale from 1979 through 2013 was over 1.2 tcf of gas, over 5.9 million bbls of oil, and over 475,000 bbls of NGL, according to information from the West Virginia Geological and Economic Survey (WVGES). The first production reported from a horizontal well completed in the Marcellus Shale in West Virginia was in 2007. Between 2007 and 2013, about 1.1 tcf of gas were produced from horizontal wells completed in the Marcellus Shale, as well as about 5.7 million bbls of oil and 475,000 bbls of NGL. West Virginia is second to Pennsylvania in cumulative production of hydrocarbons from the Marcellus Shale. According to the production file available from the WVGES Marcellus Shale web page, there were 952 horizontal wells completed in the Marcellus Shale from which over 535 bcf, 4 million bbls of oil and 475,000 bbls of NGL were produced in 2013. The companies with the most gas production in 2013 from the Marcellus Shale were Chesapeake Appalachia, LLC, Antero Resources Corporation, EQT Production Company, and Stone Energy Corporation. The companies with the most oil production in 2013 from the Marcellus Shale were Chesapeake Appalachia LLC, Gastar Exploration USA, Inc., Stone Energy Corporation, and Triad Hunter LLC.

In 2013, the counties from which most of the liquids were produced were Brooke, Doddridge, Marshall, Ohio, Tyler and Wetzel. 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 of the base of the Marcellus Shale ranges from about 4200 feet in Brooke County to about 7000 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/46288.html
http://www.dec.ny.gov/energy/36159.html
http://www.dec.ny.gov/energy/205.html
http://www.dec.ny.gov/energy/1603.html
http://geosurvey.ohiodnr.gov/energy-resources/marcellus-utica-shales
http://oilandgas.ohiodnr.gov/
http://oilandgas.ohiodnr.gov/shale
http://www.dcnr.state.pa.us/cs/groups/public/documents/document/dcnr_006811.pdf
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
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Monterey Formation (Miocene), various California basins, U.S.

by Margaret A. Keller (U.S. Geological Survey, retired, originally submitted in 2013)

The Monterey Formation of central and southern California, USA, is widely known as a world-class petroleum source rock (one of the geologically youngest) and for sourcing much of the petroleum in California over the 100 plus years of development (e.g., see Behl, 1999; Isaacs, 2001; Isaacs and Rullkötter, 2001). Most of this production occurs in California's share of the EIA's top 100 oil and gas fields of the USA (http://www.eia.doe.gov/oil_gas/rpd/topfields.pdf), and is predominantly heavy oil in the coastal regions (e.g., Santa Maria and Santa Barbara-Ventura), and lighter oil in the interior basins (e.g., San Joaquin; see USGS Professional Paper 1713 at http://pubs.usgs.gov/pp/pp1713/). Conventional gas production occurs in both the onshore (http://www.eia.doe.gov/oil_gas/rpd/conventional_gas.pdf) and offshore regions (http://www.eia.doe.gov/oil_gas/rpd/offshore_gas.pdf) of California. However, California and the Monterey Formation are not highlighted on the most recent EIA map of shale gas plays for the lower 48 states (http://www.eia.doe.gov/oil_gas/rpd/shale_gas.pdf), and so far, no shale gas production has been reported. The Monterey Formation is primarily an oil play because much of the formation is either currently within the oil window or has not matured beyond that. Only a few places have the high maturity required to match the Barnett model [for shale gas] -- southern San Joaquin, western Ventura, and Los Angeles (P. Lillis, Pers. Comm. 8/12/10). Nevertheless, some characteristics of the gas production from siliceous shales of the Monterey Formation at Elk Hills (http://www.onepetro.org/mslib/servlet/onepetropreview?id=00035742&soc=SPE) fit some of the criteria for a shale gas play.

The Monterey Formation is notable for and primarily recognized by its fine-grained lithofacies that contain abundant biogenic silica from diatoms. These lithofacies - diatomite and diatomaceous shales or mudstones - and their diagenetic equivalents - chert, porcelanite, and siliceous shales or mudstones - and characteristic interbedding at millimeter scale, distinguish the Monterey Formation from other Tertiary rock systems in California which, for the most part, comprise predominantly terrigenous derived siliciclastic rocks - clay-rich and clay-dominated mudstones, sandstones, and coarser-grained lithofacies. In addition to being the source for most of the petroleum in reservoirs of interbedded coeval sandstones and adjacent

Tertiary strata, within the past 3 decades the Monterey Formation has become better known for self sourcing its less conventional, fine-grained reservoir lithofacies (oil and associated gas in fractured chert, diatomite, and siliceous shale reservoirs within the formation). Two different oil types (low and high sulfur Monterey sourced systems) originate from different type II kerogens - generally those forming within the more proximal parts of the Monterey depositional system being low in sulfur and those in more distal areas of the system being relatively higher in sulfur (Orr, 1986).

Resurgence in exploration for shale oil in the Monterey Formation is occurring again in California (Durham, 2010; Huggins, 2010). Durham's (2010) article quotes Marc Kammerling's estimate of ultimate recovery from fields identified as Monterey producers only as 2.5 billion barrels. Durham (2010) also reports that the Monterey is "estimated to contain more than 500 billion barrels of oil in place." As noted by Huggins (2010), "thousands of acres have been leased and top leased, millions of dollars have been invested in shooting seismic and drilling wells. New rigs are arriving on a regular basis, and land consultants are being brought in from out of state to deal with all the transactions and lease checks." In addition to providing a short history of the evolution of Monterey development/exploration concepts, Huggins (2010) also makes the important point that "the other big change is the realization that significant thicknesses of high total organic carbon-rich rocks, in the right structural configuration, with the right combination of porosity and permeability, can in themselves be productive."

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Niobrara Formation (Cretaceous), Rocky Mountain Region, U.S.

by Stephen Sonnenberg (Colorado School of Mines, previously submitted)

The Niobrara is a significant, self-sourced, resource play throughout the Rocky Mountain region. New technology of horizontal drilling and multi-stage, hydraulic-fracture stimulation is unlocking reserves that previously were not obtainable.

Known production comes from both fracture and matrix porosity systems (dual porosity). High matrix porosity is present in the shallow biogenic gas accumulations of eastern Colorado and Western Kansas. The shallow biogenic play is important for natural gas production at burial depths of less than 3500 feet. The deeper Niobrara thermogenic accumulations generally occur at burial depths greater than 7000 feet. Burial diagenesis (chemical and mechanical compaction and cementation) reduces porosities to values less than 10 percent in the deeper parts of the various basins where the Niobrara is prospective. Mature Niobrara source rocks are located in these areas of low porosity. Natural fractures are important contributors to production in the deeper areas.

The Niobrara Petroleum System contains all aspects of a large resource play (e.g., widespread mature source and reservoir rocks, self-sourced). The Niobrara was deposited in the Western Interior Cretaceous (WIC) Basin and is a widespread unit in the Rocky Mountain Region (Fig. 1). The WIC Basin was broken

into numerous smaller basins during the Laramide orogeny. The Niobrara contains reservoir rocks, rich source beds and abundant seals. The various productive lithologies all have low porosity and permeability. TOC values in shales locally range from 2% to 8% in the eastern WIC area and are reduced to 1-3% because of siliciclastic dilution in the western WIC area. Laramide structural events exert the primary control on fracturing within the Niobrara as well as thermal maturity. Neogene extension fracturing is also thought to be an important component for locating production "sweet spots." Understanding the thermal maturity of the source rocks will assist in predicting the distribution of hydrocarbon accumulations. Hydrocarbon generation may enhance the tectonic fractures and may also create new ones as a result of overpressuring associated with this process.

A summary of factors thought to be important for Niobrara production in the Rocky Mountain region are as follows: presence of favorable reservoir facies (brittle chalk) and a diagenetic history that enables open fracture systems to exist; presence of mature source rocks to enable a continuous oil column to exist in the trap; source rocks interbedded with respect to the reservoir limestone (chalk); a favorable tectonic history for fracture formation. Most fracture systems fall into two major categories: structure-related fractures and regional orthogonal fractures.

Resistivity mapping can be used to determine both the presence of a hydrocarbon accumulation and the maturity of source rocks for the Niobrara. The presence of oil in open fracture systems is thought to be the cause of the high resistivity anomalies in chalk beds. A relationship between increasing resistivity of source shales with increasing thermal maturity has also been demonstrated.

Knowledge of the distribution and occurrence of hydrocarbon source and reservoir rocks in the Niobrara interval will greatly aid future exploration.

REGIONAL SETTING

The Upper Cretaceous Niobrara (Coniacian-Campanian; ~ 82 to 89.5 million years ago) was deposited in a foreland basin setting in the Western Interior Cretaceous Seaway of North America during a time of a major marine transgression (Fig. 1). This major transgression probably represents the maximum sea-level highstand during the Cretaceous and may contain the best source rocks in the Cretaceous. The present-day basins in the Rocky Mountain region formed during the Late Cretaceous to Early Tertiary Laramide orogeny.

The Western Interior Cretaceous (WIC) Basin was an asymmetric foreland basin with the thickest strata being deposited along the western margin of the basin (Figs. 1, 2). The WIC Basin is a complex foreland basin that developed between mid to late Jurassic to Late Cretaceous time. The basin was bordered by mountainous areas to the west (zone of plutonism, volcanism, and thrusting that formed the Cordilleran thrust belt) and a broad stable cratonic zone to the east. The foreland basin subsided in response to thrust and synorogenic sediment loading and pulses of rapid subduction and shallow mantle flow.

During sea-level highstands, coccolith-rich and planktonic foraminifera-rich carbonate sediments (chalks) accumulated on the eastern half of the seaway. Chalky beds extend into Montana and southern Canada (where they are called the White Spec zones) and into the Gulf Coast region (Austin Chalk). Chalk-rich carbonate facies change westward into siliciclastic-rich beds.

STRATIGRAPHY AND DEPOSITIONAL SETTING

The Niobrara represents one of the two most widespread marine invasions and the last great carbonate producing episode of the Western Interior Cretaceous basin (the first widespread event is represented by the Greenhorn chalks). The dominant lithologies of the Niobrara Formation are limestones (chalks) and interbedded with marls and calcareous shales (Figs. 2, 3). The chalk-shale cycles are interpreted to represent changes from normal to brackish water salinities possibly related to regional paleo-climatic factors or sea level fluctuations. The chalk lithologies are thought to represent deposition in normal to near normal marine salinities having a well-mixed water column and well oxygenated bottom waters. The chalks reflect influx of
warm Gulfian currents into the WIC seaway during relatively high sea levels. The interbedded shale/marl cycles are interpreted to be caused by an increase in fresh water runoff caused by increased rainfall which may be related to climatic warming. The fresh water runoff creates a brackish water cap and salinity stratification. Vertical mixing of the water column is inhibited causing anoxic conditions in the bottom

waters. This enhances preservation of organic material and results in organic-rich source rocks. The decrease in water salinities is also suggested by oxygen isotopic values. The shalier intervals may reflect lower sea levels and greater influx of clastic material from the west. The chalks have previously been interpreted to represent higher sea levels during Niobrara time.

Three major facies are present in the Niobrara and equivalents across the Rocky Mountain region (Figs. 1 and 2). On the western side of the area, a sandstone facies is present which changes laterally to the east into a calcareous shale facies, and which, in turn, changes eastward into a limestone and chalk facies. These various lithologies interfinger and the facies changes are very gradational. The Niobrara name is used for chalk and shale units located on the eastern side of the Western Interior Seaway; whereas, the term Mancos is generally used for the equivalent shale, and siltstone units in the western part of the area. The equivalent shoreline and non-marine sandstone units further to the west are known by a variety of names. The limestone facies is composed of coccolith-rich fecal pellets probably derived from pelagic copepods, inoceramid and oyster shell fragments, planktonic foraminifer tests, micrite, clay, and quartz silt. The thick siltstone facies was derived from highlands to the west. The shales found in the Mancos/Niobrara are dark-gray to black and generally organic rich (>1% TOC). The shales are fair to excellent source rocks and also provide seals for the chalky and sandy reservoir facies. TOC content in the interval increases to the east (Fig. 1).

The chalks of the Niobrara are rich in organic matter and organic related material (e.g., pyrite). On the east side of the WIC basin, the Niobrara consists of four chalk beds and three shale intervals (Fig. 3). The basal chalk bed is known as the Fort Hays limestone member and the unit contains some of the purest chalk in the Western Interior. The Fort Hays is regionally extensive and ranges in thickness from 50 feet in southeast Colorado to 120 feet in New Mexico to less than 10 feet in southeast Wyoming. Carbonate content persists from the Denver Basin to southwest Colorado into the Laramie, North Park, South Park, and Sand Wash basins. The Fort Hays interval is difficult to distinguish from the remainder of the Niobrara north of the Laramie Basin.

The Fort Hays is overlain by the Smoky Hill member. The Smoky Hill consists of organic rich shales to chalky shale (marls) to massive chalk beds. The interval has been subdivided by various authors into several units. Figure 3 illustrates a six member subdivision.

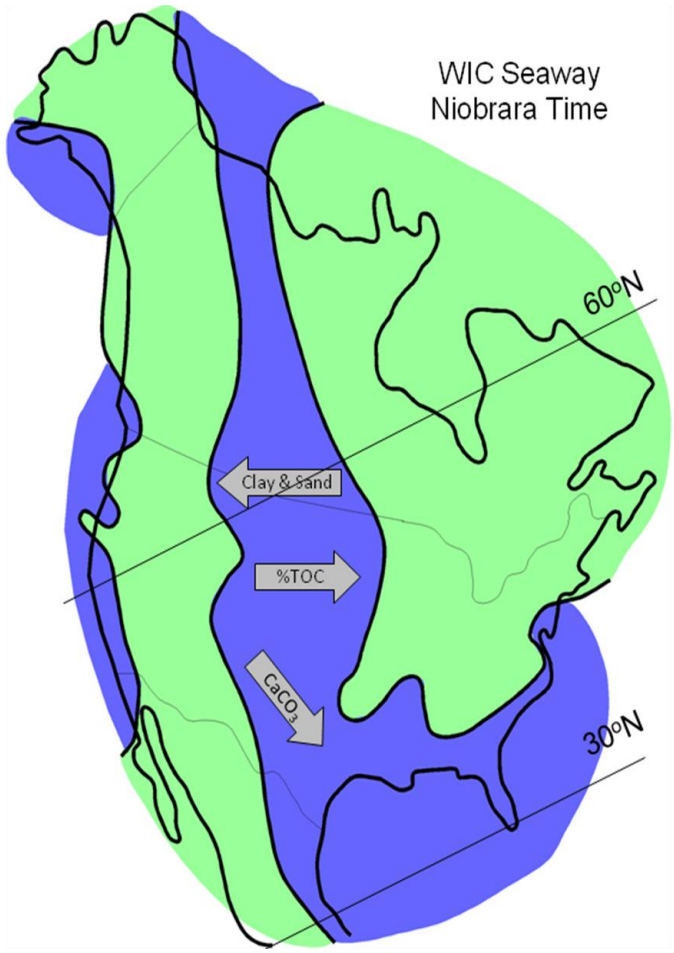

Figure 1. The Western Interior Cretaceous Basin during Niobrara time (modified from Longman et al., 1990). Source area for clastics is dominantly to the west, total organic carbon content in the Niobrara increases to the east, carbonate content generally increases on the eastern side of the Western Interior Cretaceous (WIC) seaway and to the southeast.

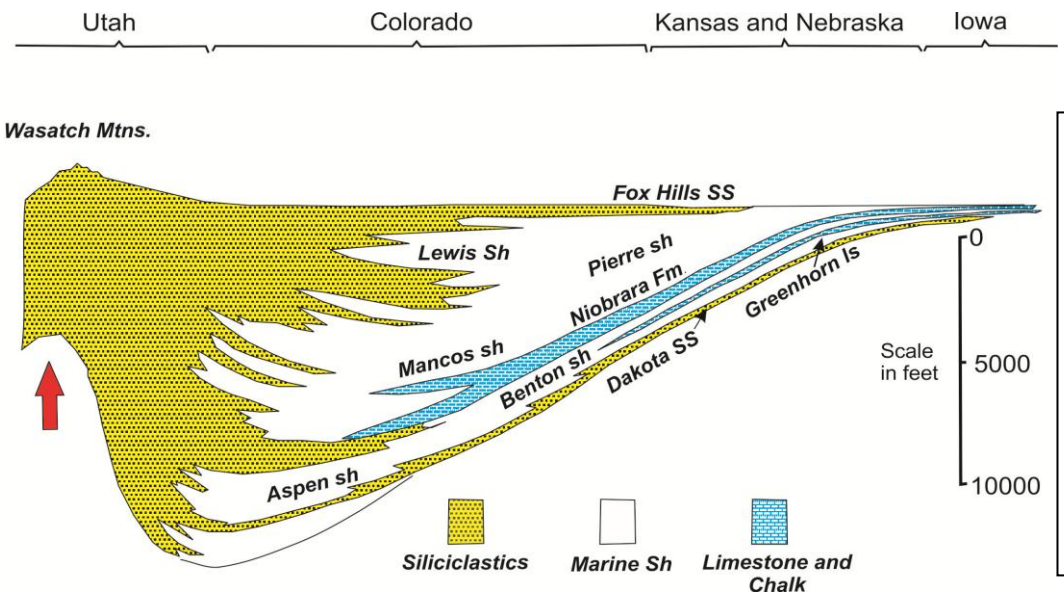

Figure 2. Generalized cross section across the Western Interior Cretaceous Basin. The Niobrara is Upper Cretaceous in age. Limestone and chalk beds are present over the eastern two thirds of the basin (modified from Kauffman, 1977).

The Niobrara ranges in thickness from 100 to 300 feet along the eastern side of the WIC basin to over 1500 feet on the west side of the WIC basin. Figure 4 illustrates an isopach map of the Niobrara across the northern Rockies region. Thinning occurs is a northeast trend across the map area. This thin trend was related to paleotectonic movement on the Transcontinental arch. Superimposed on the Transcontinental arch are northeast axes of thinning (Fig. 4). Thinning in the Niobrara is believed to result from differing rates of

sedimentation (i.e., convergence or divergence of section) and unconformities at the base, within, and at the top of the formation.

Niobrara deposition in the Western Interior Basin was strongly influenced by the interplay of warm north-flowing currents from the paleo-Gulf of Mexico and cooler southward-flowing currents from the Arctic region along with sea level fluctuations. Warm waters from the Gulf brought in rich carbonate flora of coccoliths and promoted carbonate production and deposition. Siliciclastic input from the west and cooler Arctic currents inhibited carbonate production and deposition.

Chalks and marls are abundant in the Denver Basin. The section changes to marl and is shalier west of the Front Range and north of the Hartville Uplift. Chalk intervals extend into the Laramie, Hanna, North Park, Sand Wash, and Piceance basins. The section in the Piceance consists of interbedded sandstone, siltstone, and shale. In the San Juan Basin, the Niobrara consists of a mixture of siliciclastic and marl lithologies.

The Niobrara is overlain by the Pierre Shale in the eastern part of the Western Interior Basin and its age equivalent Mancos shale in the western part. The Niobrara overlies the Carlile Formation across much of the Western Interior basin (and its members: Codell Sandstone, Sage Breaks Shale, etc.). The Sharon Springs member of the Pierre shale overlies the Niobrara in most of eastern Colorado. The Sharon Springs is an excellent source rock with TOC's ranging from 2 to 8 weight percent.

The type locality for the Niobrara Chalk is Knox County in northeastern Nebraska.

SOURCE ROCKS

Several workers have discussed the organic-rich nature of the Niobrara Formation and the increased thermal maturity and resistivity with increased burial depth. Vitrinite reflectance and resistivity of the organic-rich shale both increase with increasing thermal maturity. These values can be mapped to show areas of source rock maturity.

The Niobrara Formation has been analyzed using the Rock-Eval instrument by several workers (Fig. 5). Organic-rich beds in the formation have total organic carbon values which average 3.2%. A plot of hydrogen index versus oxygen index (modified van Krevelen diagram) illustrates the type and level of maturity of the source rocks for different depths across the Denver basin. The plot also illustrates that the kerogen present in the Niobrara is Type-II or oil-prone (sapropelic).

RESERVOIR ROCKS

The lithology of the Niobrara changes from east to west across the Western Interior Basin (Fig. 2). In the Denver Basin, the lithology consists of interbedded calcareous shale, shaley limestones, marls, and limestones (Fig. 3). Westward, the lithology becomes shalier and sandier (Fig. 1). The carbonates are still present in the western area but clastics begin to dominate.

Most Niobrara reservoir rocks have undergone mechanical and chemical compaction and are low porosity and permeability rocks. Burial depth is the single most important factor affecting porosity. Chalks have high original porosities (50% or greater). Initial dewatering and mechanical compaction is the first diagenetic phase. Grain and fossil breakage and re-orientation reduce porosity. Initial coccolith grain sizes are 0.2 to one micron. Chemical compaction is characterized by calcite dissolution along wispy dissolution seams, microstylolites, and stylolites. Grain-to-grain dissolution along microstylolites is common and the dissolved calcite is reprecipitated locally.

HYDROCARBON PRODUCTION

Niobrara production represents some of the oldest established production in the Rocky Mountain region. The oldest field in the region is the Florence-Cañon City field which was discovered in 1881 (Fig. 6). The field produces from the Pierre shale immediately above the Niobrara and is believed to be sourced from the Niobrara and Sharon Springs. The Boulder oil field (western Denver basin) was discovered in 1901 and is also productive from fractured Pierre shale but also sourced from the Niobrara. Fractured Mancos shale production was found in Rangely (northwest Colorado) in 1902. Niobrara production was established in Tow Creek (Sand Wash basin) in 1924. The Berthoud field of the western Denver basin is productive from several horizons including the Niobrara and discovered in 1927. Gas in the Niobrara was discovered in Beecher Island (eastern Colorado) in 1919 (commerciality was not established until 1972,

however). The Niobrara interval is productive in the Bowdoin field of Montana which was discovered in 1913. The reason for these early discoveries is that many of them are associated with surface structures which were the primary targets of early explorers.

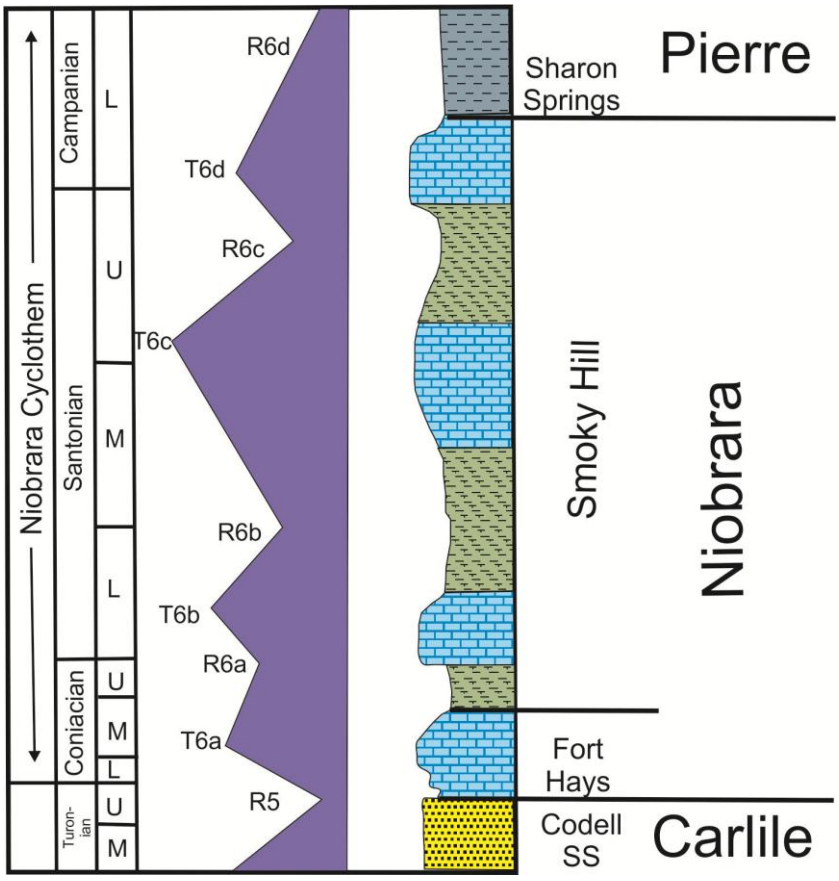

Figure 3. Generalized stratigraphic column for the Niobrara from the Denver Basin setting. The Niobrara ranges in age from Coniacian to lower Campanian. Several transgressive and regressive cycles are noted for the Niobrara interval. Four chalk –rich intervals were deposited during trangressive events , calcareous shales during regressive events (modified from Longman et al., 1998; Barlow and Kauffman, 1985).

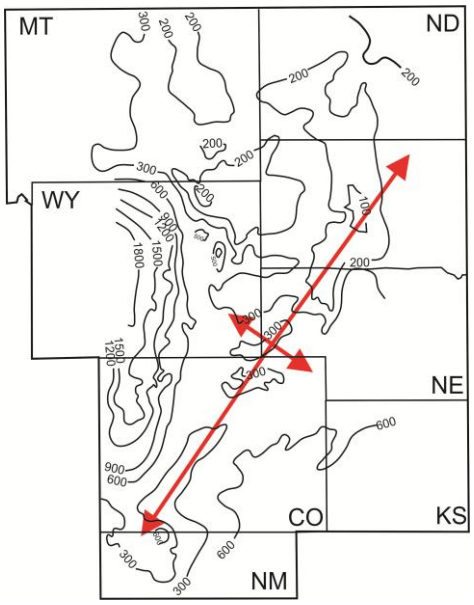

Figure 4. Isopach of the Niobrara across the northern Rockies (modified from Longman et al., 1998). The Niobrara ranges in thickness from less than 100 feet to over 1800 feet. Thinning occurs in a northeast trend across the area known as the Transcontinental Arch (Weimer, 1978).

Hydrocarbon production comes from all three major Niobrara lithofacies: 1) microporous and fractured coccolith- and planktonic foraminifer-rich limestone (eastern part of WIC basin); 2) fractured

marls and shales (mainly in the central part of the seaway); 3) fractured sandstone and siltstone rich facies, mainly in the western and southwestern parts of the seaway. Production occurs in the Laramide-aged Powder River, Denver, North Park, Greater Green River (including Sand Wash), Raton, San Juan, and Piceance basins and in north-central Montana. The widespread distribution of the production along with many wells with hydrocarbon shows across these basins suggests a large resource play may exist. The majority of recent drilling activity in the Niobrara has been in the Denver Basin, north of Wattenberg field and in southeast Wyoming around the Silo field.

Hydrocarbon production from chalk reservoirs occurs along the shallow eastern margin of the Denver basin. Many of the gas accumulations in this area occur in structural traps and reservoirs require hydraulic-fracture stimulation. The gas is biogenic or microbial in origin. Production in the shallow play comes from the upper chalk bench or Beecher Island member of the Niobrara and is mainly from microporosity within the chalks, but is enhanced by natural fracturing. Production from the shallow Niobrara from eastern Colorado is 600 BCFG. Beecher Island Field is one of the largest and first fields discovered in the shallow Niobrara. Commercial production dates back to 1972 (initial discovery in 1919!) and the cumulative for the field is 100 BCFG. Three-dimensional seismic data have been used effectively to improve development and exploration success ratios in fields.

Shallow gas production from the Niobrara also occurs in north central Montana. Bowdoin Dome has produced 62 BCFG and 19 MBO from the Niobrara. Additional Niobrara fields are located to the west the Alberta Basin extends into Montana. The largest field to date is the St. Joe Road field which was discovered in 2001 and has produced 18.2 BCFG.

Deeper in the Denver Basin, the Niobrara is oil productive in a number of fields. The porosity of the chalks in the deeper part of the basin has been dramatically reduced by compaction and burial diagenesis. Production is attributed to the presence of fractures in the chalky intervals. Some attempts have been made to establish production from some of the rich, shaley intervals within the Niobrara. The shale gas and fractured chalk potential of the deep Denver basin area is significant as shown by fields like Wattenberg and Silo. Silo Field was discovered in 1981 and has produced approximately 10.4 MMBO and 8.9 BCFG.

The Niobrara is productive on the Casper Arch of Wyoming at Salt Creek and Teapot fields. Total production has been 1.5 MMBO and 0.2 BCFG. In the deeper Powder River Basin production has been established in a number of accumulations including Fetter, Hilight, Brooks Draw and Flat Top. Hilight has produced 411 MBO and 0.8 BCFG to date.

The western portion of the region is productive in a variety of traps and lithologies (mainly siliciclastic) and there is significant potential for hydrocarbon production in many of the western basins. The basal part of the Niobrara equivalent in the west yields oil and gas in the San Juan basin from a sandstone and shale interval (Tocito and Gallup sandstones). Examples of producing fields from the Gallup are Bisti and Verde fields. Bisti Field has produced 41.8 MMBO and 79.2 BCFG. Verde Field has produced 8.1 MMBO and 2.5 BCFG. Examples of fields producing from the Tocito Sandstone are the Blanco South and Chipeta fields. These fields have produced 4.2 MMBO and 18.8 BCFG. Production is from interparticle porosity but is enhanced by fractures. The upper Niobrara equivalent (Smoky Hill member) is productive in the Sand Wash basin from fractured reservoirs (Fig. 6) and perforated intervals are commonly long. Field examples are Buck Peak and Tow Creek. Buck Peak has produced 4.8 MMBO and 8.5 BCFG. Tow Creek has produced 3 MMBO and 0.3 BCFG. Farther to the west where the Niobrara equivalents are dominantly shale, production is found in the Rangely and Douglas Creek Arch fields. Production form fractured Mancos shale at Rangely represents some of the oldest production in Colorado (1902). The Mancos at Rangely has produced around 11.9 MMBO and 0.2 BCFG. Neogene age extensional faulting is a key to production at Buck Peak and Rangely. The extensional fracture trend is N60W. The Douglas Creek arch production comes mainly from Cathedral Field. The field has produced 56.5 BCFG and 40.6 MBO from the Mancos (mainly the Mancos B zone).

Other production equivalent to the upper Niobrara zone comes from the Mancos interval in the San Juan basin. Examples of Mancos producing fields are: East and West Puerto Chiquito, Rio Puerco; Gavilan, Basin, and Boulder. These fields are interpreted to be fractured reservoirs and producing intervals are hundreds of feet thick. The Puerto Chiquito fields have produced 19.3 MMBO and 55.5 BCFG. Gavilan

Field has produced 7.8 MMBO and 111 BCFG. Boulder Field has produced 1.8 MMBO and 1.6 BCFG. Basin Field has produced 120 MBO and 4.1 BCFG. Rio Puerco Field has produced 1.3 MMBO and 1.4 TCFG.

The Mancos is gas productive in the deeper parts of the Uinta basin in several fields including Natural Buttes. Mancos is also productive in some silty and very fine-grained sandstone zones in the Cathedral field of the Douglas Creek Arch. New Mancos/Niobrara production has been established in several areas of the deeper Piceance Basin (e.g., Mamm Creek field).

EXPLORATION METHODS

Methods of exploration for fractured Niobrara reservoirs should incorporate many if not all of the following: seismic acquisition; aeromagnetics study; surface lineament analysis; subsurface mapping; isoresistivity mapping; logging technology; and technology to produce the reservoir. 2-D and 3-D seismic is extremely important to map structural anomalies. Three-dimensional three-component (compressional and shear wave data) methods have also proved to be effective in analyzing the fractured reservoir. Aeromagnetics is a tool that may identify basement shear zones areas of potential fractures having gradient changes such as narrow zones of steep gradients. Aeromagnetic data examined in the Silo field area illustrates possible northwest-trending shear zones. If basement fracture systems propagate all the way to the surface then a surface lineament analysis may also be effective. Northwest-trending surface lineament in the Silo area have been mapped by use of remote sensing techniques. Resistivity mapping is important to show areas of oil accumulation. When resistivity mapping is combined with subsurface mapping the most probable areas of fracturing can be predicted. Logging technologies available to identify fractured reservoirs are geophysical logs such as the FMS, FMI and CAST logs. Horizontal drilling and multi-stage hydraulic fracturing offer technologies to economically produce hydrocarbons from the reservoir.

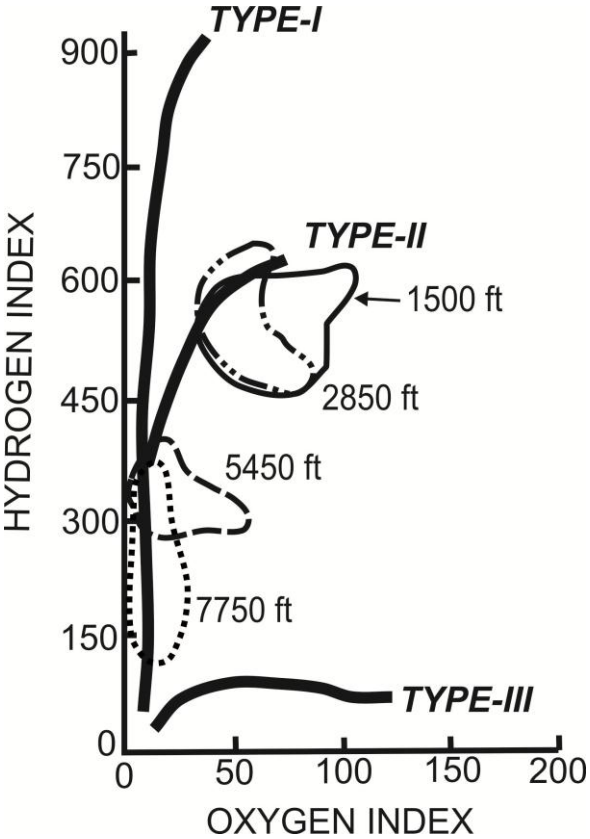

Figure 5. Niobrara Van Krevelen diagram. Niobrara source rocks are Type-II (oil prone) kerogens based on Rock Eval data. With increasing burial depth and thermal maturity the HI values decrease significantly. Data from Rice (1984); Barlow (1985); Pollastro (1985); after Sonnenberg and Weimer (1993).

An understanding of the regional stress field is important in most tight oil and gas plays. The direction of maximum horizontal stress (Shmax) is generally the direction of open fractures. Regional

horizontal stress maps have been published for North America. The present-day stress field reflects Neogene extensional tectonics and the epeirogenic uplift that has taken place in the western United States.

SUMMARY

Widespread source and reservoir rocks make the Niobrara Formation an attractive target for exploration across the Rocky Mountain region. The Niobrara contains mature source rocks interbedded with brittle limestones (chalks) in the deeper parts of many basins in the Rocky Mountain region. Thermogenic production occurs from the chalk intervals in the eastern part of the region and from siliciclastics and shales in the western and southwestern parts of the Rocky Mountain regions (Uinta and San Juan basins). Biogenic gas production occurs at shallow depths along the eastern Rocky Mountain region in Colorado, Kansas, and Nebraska. Generally production comes from depths less than 3500 feet. Shallow gas production also occurs in several areas of north-central Montana. The shallow gas production generally is structurally controlled.

The Niobrara reservoirs generally have low permeabilites so natural fracturing plays a role in economic production. The limestone (chalk) beds behave in a brittle manner, whereas, the adjacent calcareous shales often behave in a ductile manner. Fractures occur for a variety of reasons and several models can be used for exploration. Early created fractures are susceptible to extreme diagenesis and thus generally completely cemented. Late stage structural movement can help re-open old fractures or create new ones. Regional epeirogenic uplift of western North America and subsequent erosion (denudation) may play a role in Niobrara microfractures. The removal of overburden results in lowered effective stress in rocks that may also be overpressured. This mechanism may be important in all tight-reservoir plays in the Rocky Mountain Region.

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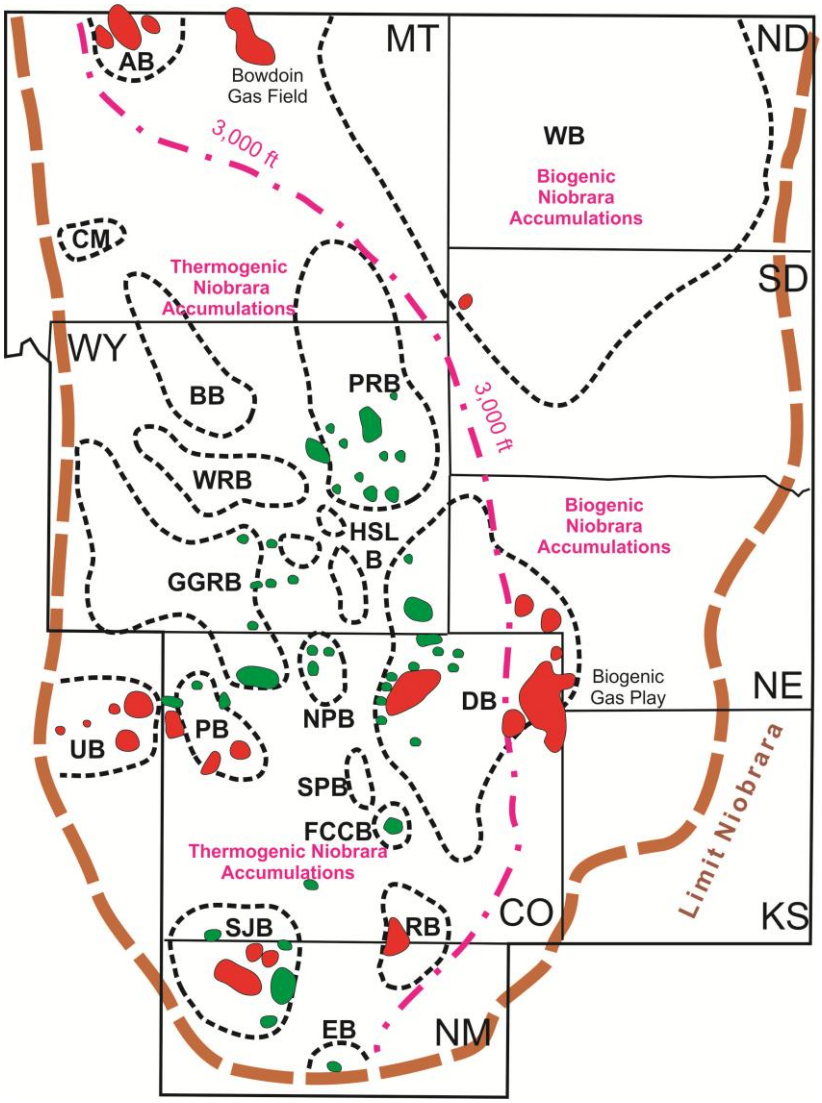

Figure 6. Niobrara producing areas across the north Rockies (Oil fields-green; gas fields-red)(modified from Longman et al., 1998). Basin abbreviations are as follows: AB-Alberta Basin; CM-Crazy Mountain; WB-Williston Basin; BB-Bighorn Basin; PRB-Powder River Basin; WRB-Wind River Basin; GGRB-Greater Green River Basin; NPB-North Park Basin; PB-Piceance Basin; UB- Uinta Basin; SPB-South Park Basin; FCCB-Florence-Canon City Basin; SJB-San Juan Basin; RB-Raton Basin; DB-Denver Basin; EB-Estancia Basin. Distribution of sapropelic oil-generation-prone Niobrara source rocks within brown dashed line (Meissner et al., 1984). Dot-dashed line equals 3,000 ft current burial depth; biogenic accumulations east of line; thermogenic accumulations west of line (from Lockridge and Scholle, 1978).

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Utah Shales, U.S.

By Thomas Chidsey and Michael D. Vanden Berg (Utah Geological Survey)

The dramatic crash of crude oil that occurred towards the end of 2014, coupled with continued low natural gas prices, has severely affected exploration and development of liquid hydrocarbon reserves in Utah. Following on the success of the recent shale gas boom and employing many of the same well completion techniques, numerous petroleum companies have, until recently, been exploring for liquid petroleum in shale formations in the state. In fact, many shales or low-permeable ("tight") carbonates targeted for natural gas include areas in which the zones are more prone to liquid production. Organic-rich shales in the Uinta and Paradox Basins have been the source for significant hydrocarbon generation, with companies traditionally targeting the interbedded sands or porous carbonate buildups for their conventional resource recovery. With the advances in horizontal drilling and hydraulic fracturing techniques, operators in these basins for the past several years explored the petroleum production potential of the shale and interbedded tight units themselves.

Uinta Basin

Overview

The Uinta Basin is the most prolific petroleum province in Utah. It is a major depositional and structural basin that subsided during the early Cenozoic along the southern flank of the Uinta Mountains. Lake deposits filled the basin between the eroding Sevier highlands to the west and the rising Laramide-age Uinta Mountains, Uncompahgre uplift, and San Rafael Swell to the north, east, and south, respectively. The southern Eocene lake, Lake Uinta, formed within Utah's Uinta Basin and Colorado's Piceance Creek Basin.

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

The Uinta Basin is asymmetrical, paralleling the east-west trending Uinta Mountains. The north flank dips 10-35º southward into the basin and is bounded by a large north-dipping, basement-involved thrust fault. The southern flank gently dips between 4-6º north-northwest.

Activity

Recent tight-oil drilling and exploration activities in the Uinta Basin are targeting relatively thin porous carbonate beds of the Uteland Butte Limestone Member of the lower Green River Formation (figures 1 and 2), particularly in an area referred to as the "Central Basin region" between Altamont-Bluebell field to the north and Monument Butte field to the south. The Uteland Butte has historically been a secondary oil objective of wells tapping shallower overlying Green River reservoirs and deeper fluvial-lacustrine Colton Formation sandstone units in the western Uinta Basin.

The Uteland Butte records the first major transgression of Eocene Lake Uinta after the deposition of the alluvial Colton Formation, and thus it is relatively widespread in the basin (figure 3). The Uteland Butte ranges in thickness from less than 60 ft to more than 200 ft and consists of limestone, dolomite, organic-rich calcareous mudstone, siltstone, and rare sandstone (figures 2, 4, and 5). The dolomite (figure 2), the horizontal drilling target, often has more than 20% porosity, but is so finely crystalline that the permeability is very low (single mD or less).

Several companies (Newfield, LINN, Bill Barrett Corporation, Crescent Point, QEP Resources, and Petroglyph) have had recent and continued success targeting the Uteland Butte with horizontal wells in both the central, normally pressured part of the basin near Greater Monument Butte field, and farther north in the overpressured zone in western Altamont field (figure 1). There are over 84 active horizontal wells producing from the Uteland Butte. Production from these wells averages 500 to 1500 barrels of oil equivalent (BOE) per day from horizontal legs up to 4000 ft in length. As of January 1, 2015, cumulative production from the Uteland Butte was 4.4 million barrels (bbls) of oil and 7.3 billion cubic feet of gas (BCFG) with 2.3 million bbls of water (Utah Division of Oil, Gas, and Mining, 2015a). There were also over 200 applications for permits to drill (APDs) for horizontal wells targeting the Uteland Butte and other potential Green River tight-oil zones (figure 1) (Utah Division of Oil, Gas, and Mining, 2015b) at the beginning of 2015. However, at the time of this report there were no rigs drilling horizontal wells in the Uinta Basin. Prior to the oil price collapse, Newfield had completed six super-extended lateral wells (horizontal lengths greater than 5000 ft) in

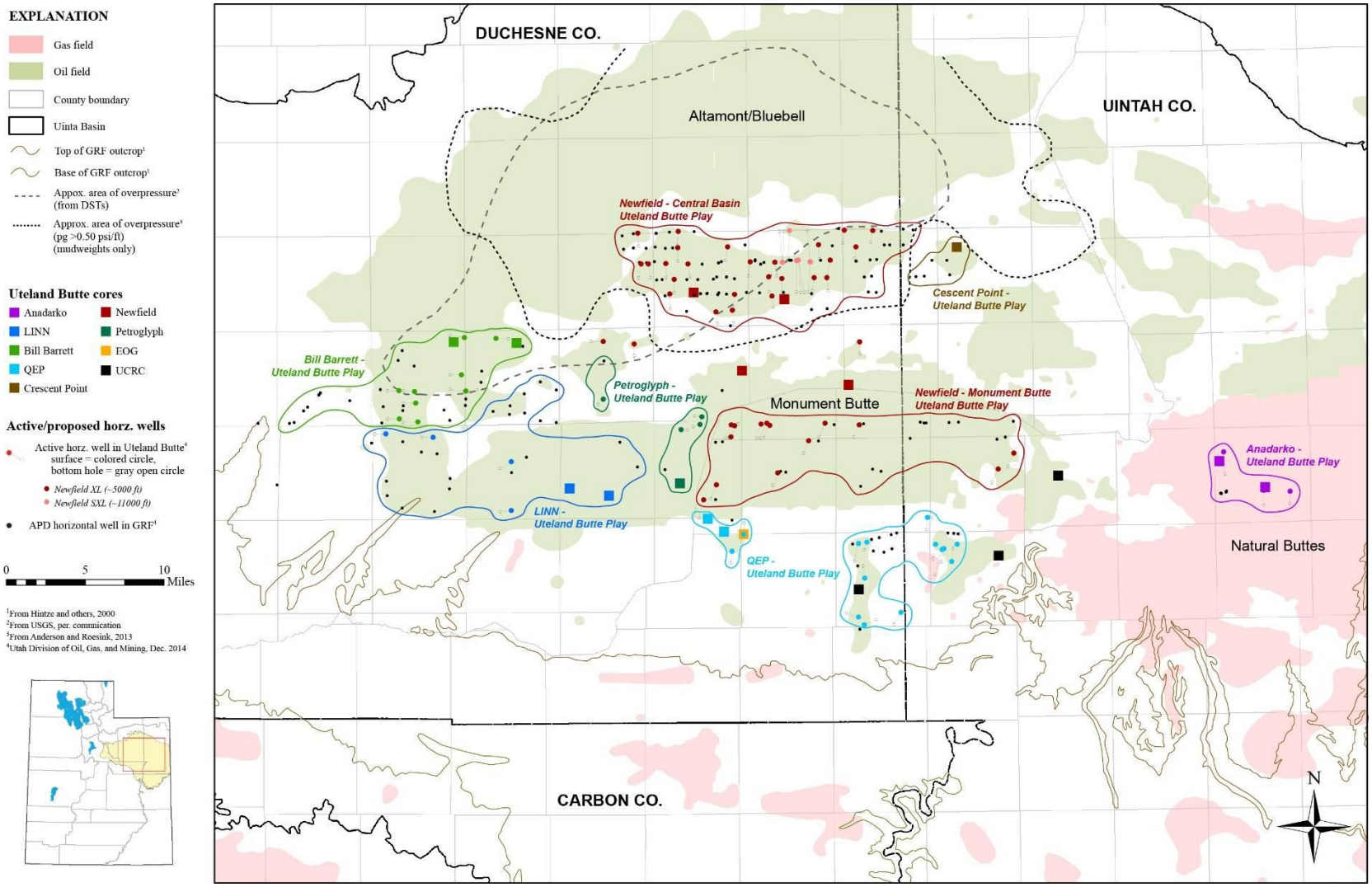

Figure 1. Map of the Uinta Basin, Utah, showing play areas for the Uteland Butte Limestone Member of the Tertiary Green River Formation, APD horizontal well locations, and active horizontal wells by operators.

Figure 2. Uteland Butte core from the Bill Barrett 14-1-46 well. The horizontal drilling target is the roughly 5-ft light brown dolomitic interval. Porosity in this interval ranges from 15-30% and permeability averages 0.06 mD. The dolomite is interbedded with organic-rich mudstones and limestones averaging between 1% and 3% TOC. Note the abundant shell fragments indicating deposition in a freshwater lacustrine environment.

the central basin Uteland Butte play area (figure 1) at rates of about 1800 barrels of oil per day (BOPD) (IHS Inc., 2014b).

Paradox Basin

Overview

The Paradox Basin is located mainly in southeastern Utah and southwestern Colorado with small portions in northeastern Arizona and the northwestern corner of New Mexico. The Paradox Basin is an elongate, northwest-southeast-trending, evaporitic basin that predominately developed during the Pennsylvanian, about 330 to 310 Ma. The basin was bounded on the northeast by the Uncompahgre Highlands as part of the Ancestral Rockies. As the highlands rose, an accompanying

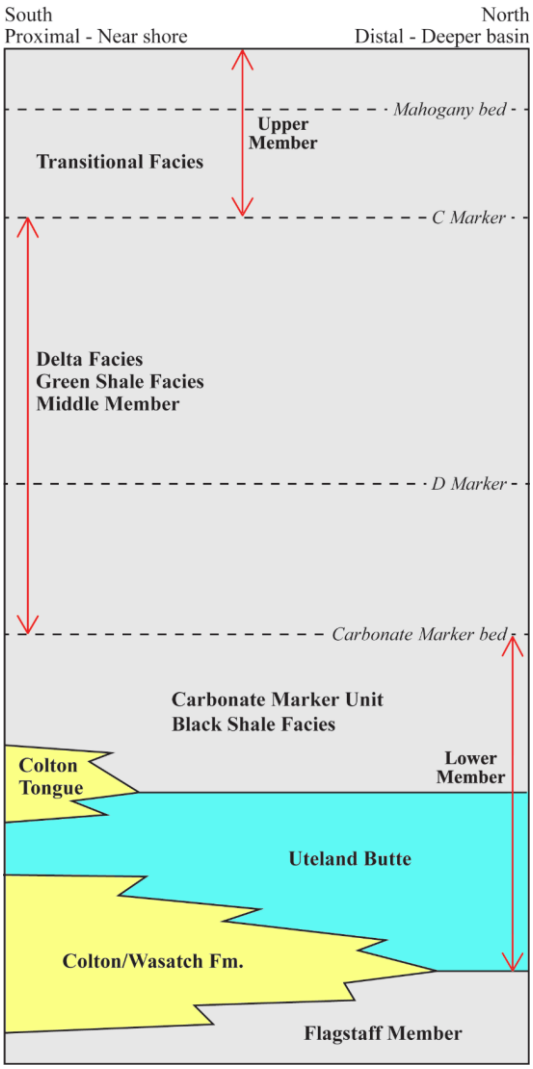

Figure 4. Outcrop of the Uteland Butte Member of the Green River Formation, Nine Mile Canyon, central Utah.

Figure 5. Fresh road cut exposure of Uteland Butte Member of the Green River Formation consisting of interbedded dolomite and mudstone/limestone, Nine Mile Canyon, central Utah.

depression, or foreland basin, formed to the southwest—the Paradox Basin. Rapid basin subsidence, particularly during the Pennsylvanian and continuing into the Permian, accommodated large volumes of evaporitic and marine sediments that intertongue with non-marine arkosic material shed from the highland area to the northeast. Deposition in the basin produced a thick cyclical sequence of carbonates, evaporites, and organic-rich shale of the 500- to 5000-ft-thick Pennsylvanian Paradox Formation (Hintze and Kowallis, 2009).

Rasmussen (2010) divided the middle part of the Paradox Formation in the evaporite basin into as many as 35 salt cycles, some of which onlap onto the basin shelf to the west and southwest (figure 6). Each cycle consists of a clastic interval/salt couplet. The clastic intervals are typically interbedded dolomite, dolomitic siltstone, anhydrite, and black, organic-rich shale—the sources of the petroleum in the basin. The clastic intervals typically range in thickness from 10 to 200 ft and are generally overlain by 200 to 400 ft of halite.

The Paradox Basin can generally be divided into three areas: the Paradox fold and fault belt in the north, the Blanding sub-basin in the south-southwest, and the Aneth platform in the southernmost part in Utah. The area now occupied by the Paradox fold and fault belt was the site of greatest Pennsylvanian/Permian subsidence and salt deposition. Folding in the Paradox fold and fault belt began as early as the Late Pennsylvanian as sediments were laid down thinly over, and thickly in areas between, rising salt. Spectacular salt-cored anticlines extend for miles in the northwesterly trending fold and fault belt. Reef-like buildups or mounds of carbonates consisting of algal bafflestone and oolitic/skeletal grainstone fabrics in the Desert Creek and Ismay zones of the Paradox Formation are the main hydrocarbon producers in the Blanding sub-basin and Aneth platform. Oil in these zones is sourced above, below, or within the organic-rich Gothic, Chimney Rock, Hovenweep, and Cane Creek shales (figure 6).

Activity

The Cane Creek shale zone of the Paradox Formation has been a target for tight-oil exploration on and off since the 1960s and produces oil from several small fields (figure 7). The play generated much interest in the early 1990s with the successful use of horizontal drilling. Currently, eight active fields produce from the Cane Creek in the Paradox Basin fold-and-fault belt, with cumulative oil production over 6.6 million bbls and 7 BCFG (Utah Division of Oil, Gas, and Mining,

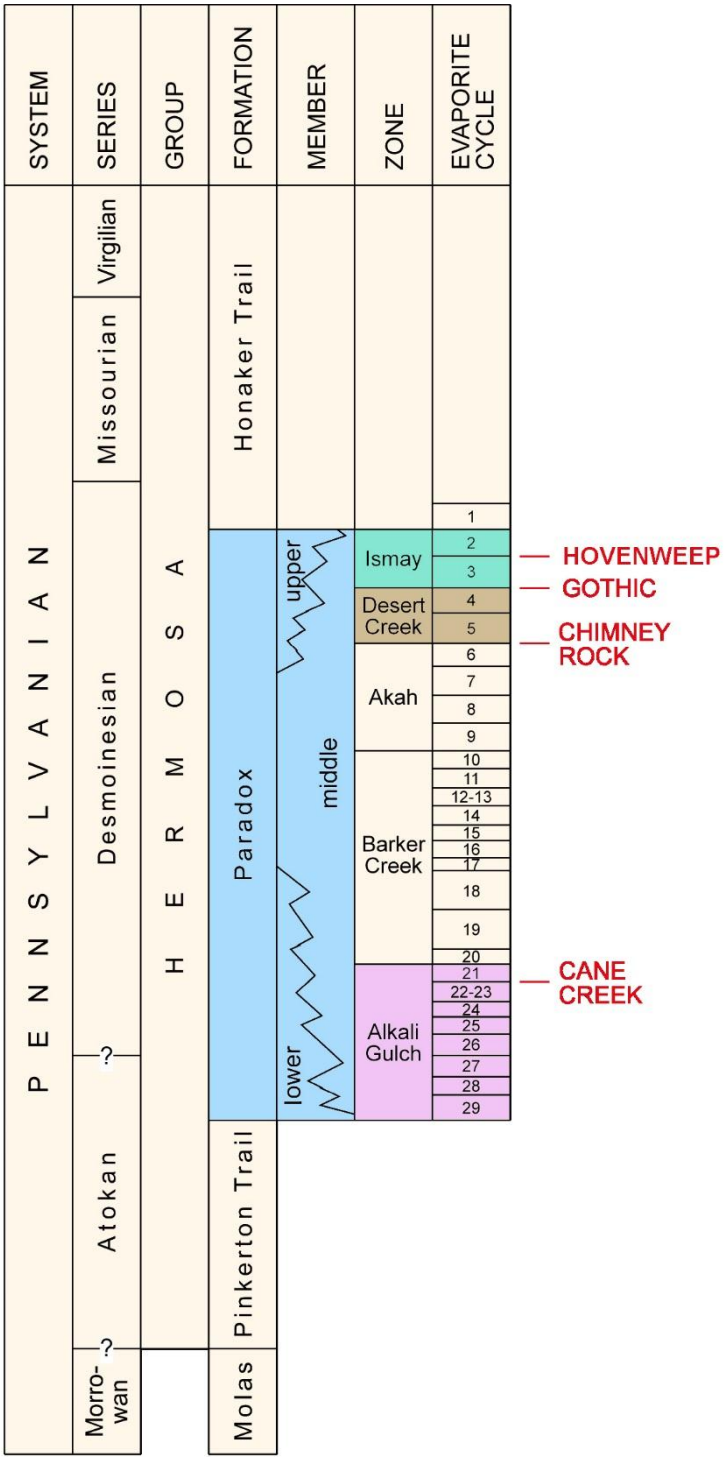

Figure 6. Pennsylvanian stratigraphic chart for the Paradox Basin, informal organic-rich shale units are highlighted. Modified from Hite (1960), Hite and Cater (1972), and Reid and Berghorn (1981).

2015a). Until the recent drop in oil prices, the Cane Creek and other Paradox zones have been targeted for exploration using horizontal drilling.

The Cane Creek shale zone records an early stage of a transgressive-regressive sequence (cycle 21) in the Paradox Formation and consists of organic-rich marine shale with interbedded dolomitic siltstone and anhydrite (figure 8). The unit is up to 160 ft thick and areally extensive within the Paradox Basin. It is divided into the A, B, and C zones, with the shale and silty carbonates of the B zone considered both the source rock and reservoir. The A and C zones are anhydrite rich and provide an upper and lower seal to the B zone. The unit is highly overpressured, with measurements

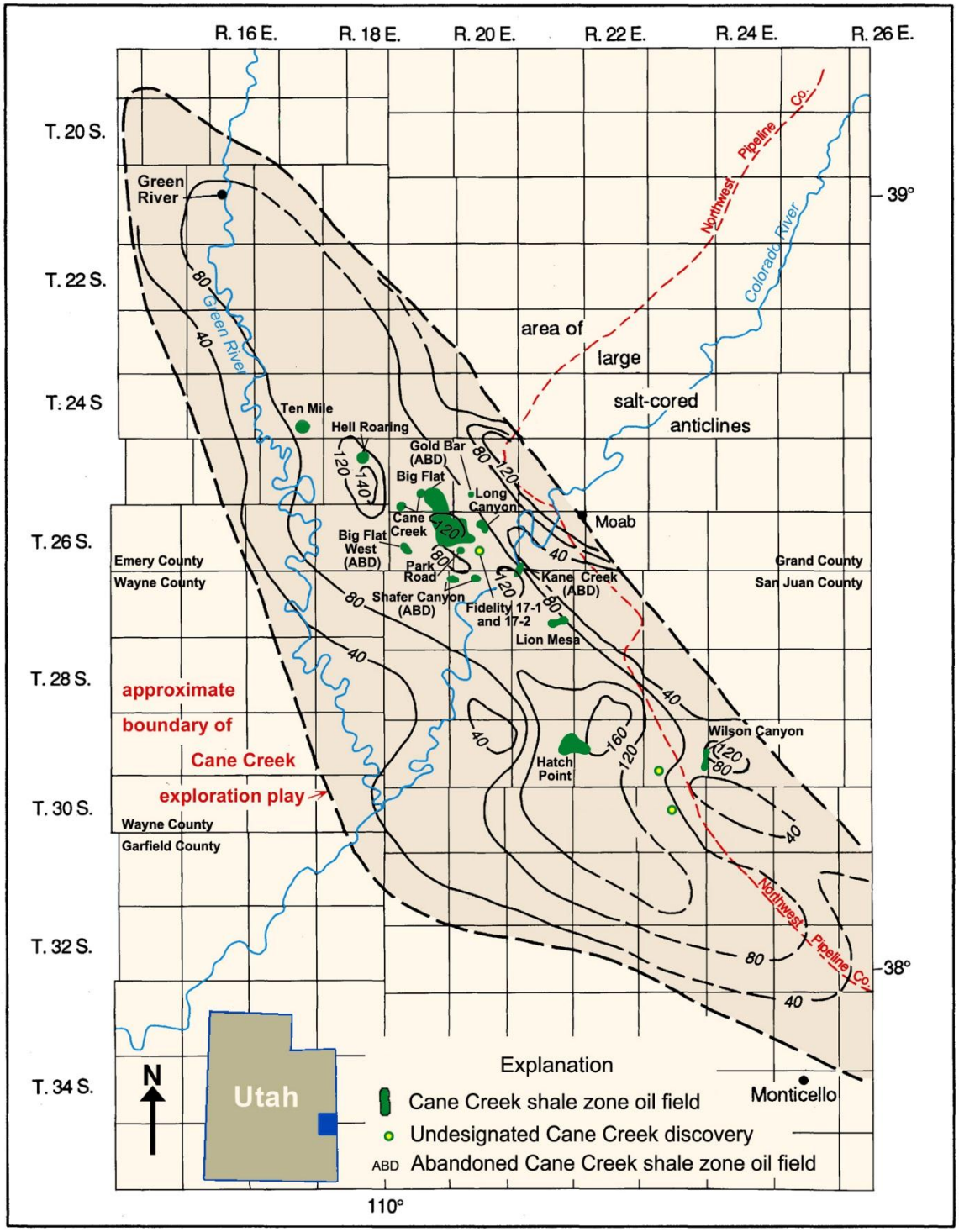

Figure 7. Thickness map and exploration play area of the Cane Creek shale zone of the Pennsylvanian Paradox Formation, northern Paradox Basin, Utah, showing Cane Creek fields. Contour interval = 40 ft. Dashed red line is natural gas pipeline.

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

As of the beginning of 2015, Fidelity Exploration & Production Company had 12 permitted horizontal wells targeting the Cane Creek shale including delineating Hatch Point field (IHS, 2015) (figure 7); the company holds 140,000 acres in leases. Fidelity announced a successful

Figure 8. Cane Creek shale zone core from the Union Pacific Resources Remington 21-1H well (section 21, T. 31 S., 23 E., SLBL&M, San Juan County, Utah) displays interbedded medium gray dolomite with organic-rich dark gray/black shale. Also present is mottled light gray to white anhydrite.

horizontal offset, the 17-2 Cane Creek Unit well, to the 2014 discovery (figure 7), the 17-1 Cane Creek Unit discovery (SWSE section 17, T. 26 S., R. 20 E., Salt Lake Basin Line & Meridian [SLBL&M], Grand County) just east of Park Road field; the new well having been drilled from the same pad. The 17-2 well was drilled in a south-southeast direction and averaged 394 BOPD and 63 MCFGPD (IHS, 2014c). Fidelity completed several additional wells in Big Flat field in 2014 including the 28-3 Cane Creek Unit (NESE section 28, T. 25 S., R. 19 E., SLBL&M, Grand County) for 600 BOPD, the 13-1 Cane Creek Unit (SENE section 13, T. 26 S., R. 19 E., SLBL&M, Grand County) for 255 BOPD, and the 26-3H Cane Creek Unit (NESW section 26, T. 25 S., R. 19 E., SLBL&M, Grand County) for 276 BOPD and 222 MCFGPD (IHS, 2014a, 2014c, 2015). The company estimates that with extended horizontal drilling, the estimated ultimate recovery could be as much as 1.7 million bbls of oil per well (IHS Inc., 2014c). However, lower than expected flow rates in recent wells indicate that the Cane Creek is "tighter" than originally thought and test fracture stimulations are planned in the future. Fidelity is also constructing a 24-mile, 12-inch diameter gas gathering system and processing facilities; gas has been flared for many years.

The U.S. Geological Survey (2012), Whidden and others (2014), and Anna and others (2014) re-assessed the undiscovered oil resource in the Cane Creek shale at 103 million barrels at a 95% confidence level and 198 million barrels at a 50% confidence level. In addition to the Cane Creek, several other organic-rich shale zones are present in the Paradox Formation, creating the potential for significant resource base additions. The Gothic, Chimney Rock, and Hovenweep shales (figure 6) in the Blanding sub-basin and Aneth platform are estimated to hold an undiscovered oil reserve of 126 million barrels at a 95% confidence level and 238 million barrels at a 50% confidence level (U.S. Geological Survey, 2012; Whidden and others, 2014; and Anna and others, 2014).

Blue Gate and Tununk Shale Members, Cretaceous Mancos Shale, Central Utah

Overview

In central Utah, potential shale gas reservoirs include the Blue Gate and Tununk Shale Members of the shallow marine Upper Cretaceous Mancos Shale. The Mancos was deposited in the Western Interior Seaway in the foredeep basin east of the Sevier orogenic belt, and the Mancos intertongues westward with coarser-grained clastic sediments shed from the belt. The Blue Gate contains an upper high-TOC interval with dense, non-fissile, dark gray claystone and scattered, light gray silt laminae and bivalve fragments. The Tununk consists of dark gray calcareous mudstone with interbeds of silt to very fine sand laminae containing silt-filled burrows. The Mancos has produced gas in the Uinta Basin of eastern Utah where it represents a secondary objective in wells targeting tight-gas sands in the Mesaverde and Wasatch sections above. However, the extent and resource potential of this frontier play in central Utah are unknown.

Activity

In late 2014, Whiting Oil & Gas Corporation drilled the Moroni 11M-1107 well (SWSW section 11, T. 15 S., R. 3 E., SLBL&M, Sanpete County) just northwest of the abandoned Cimarron Energy 1AXZ (SENW section 14, T. 15 S., R. 3 E., SLBL&M) that tested 163 bbls of oil and 588 MCFG from a horizontal leg in the Tununk Shale. The Whiting 15,656-ft well (measured depth) was also drilled horizontally in the Tununk and is capable of producing between 400 to 500 MCFG per day (Utah Division of Oil, Gas, and Mining Board Hearing Docket No. 2015-001, Cause No. 176-05). Whiting has permitted two additional horizontal wells in the same area targeting the Tununk or Blue Gate Shales.

Current Research

Liquid-Rich Shale Potential of Utah's Uinta and Paradox Basins: Reservoir Characterization and Development

The Utah Geological Survey (UGS), with funding from the National Energy Technology Laboratory, U.S. Department of Energy (DOE), is in the third year of a four-year project titled "Liquid-Rich Shale Potential of Utah's Uinta and Paradox Basins: Reservoir Characterization and Development." The overall goals of this study are to provide reservoir-specific geological and engineering analyses of the (1) emerging Green River Formation tight-oil plays (such as the Uteland Butte Limestone Member, Black Shale facies, deep Mahogany zone, and other deep Parachute Creek member high-organic units) in the Uinta Basin, and (2) the established, yet understudied Cane Creek shale (and possibly other shale units such as the Gothic and Chimney Rock shale zones) of the Paradox Formation in the Paradox Basin. To accomplish these goals, the project will:

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

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

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

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

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

Cretaceous Mancos Shale, Uinta Basin, Utah: Resource Potential and Best Practices for an Emerging Shale-Gas Play

The University of Utah and the UGS, with funding from the Research Partnership to Secure Energy for America (RPSEA) and the National Energy Technology Laboratory, DOE, is in the final year of a four-year project titled "Cretaceous Mancos Shale, Uinta Basin, Utah: Resource Potential and Best Practices for an Emerging Shale-Gas Play." The overall goals and/or benefits of this study are to (1) identify and map the major trends for target shale intervals and identify areas with the greatest gas potential, (2) characterize the geologic, geochemical, and petrophysical properties of those reservoirs, (3) reduce exploration costs and drilling risk, especially in environmentally sensitive areas, and (4) recommend the best practices to complete and stimulate Mancos gas shales to reduce development costs and maximize gas recovery. To accomplish these goals and benefits, the project will:

- Compile data from existing wells and publications.
- Conduct petrophysical, geochemical, and rock mechanical analysis of cores and cuttings from the UGS collection and samples provided by industry partners.
- Examine outcrops and collect samples.
- Evaluate logs of geochemical and petrophysical properties.
- Analyze seismic reflection attributes of 3-D data supplied by industry partners.
- Model discrete fracture networks.
- Develop regional maps and cross sections that show structure, thickness, thermal maturity, and depositional facies of key reservoirs.
- Design, describe, and recommend the best completion practices (drilling, fracturing, acidization, perforation, etc.) for the Mancos gas reservoirs based on parameters defined by the study.

Successful development of shale-gas plays requires integration of accurate geologic characterization and reservoir-specific engineering practices. Existing gas production in Utah's Uinta Basin could be greatly enhanced by the addition of recoverable gas reserves in the Upper Cretaceous Mancos Shale. While the

Mancos is an emerging shale-gas play, both the geologic and engineering insights are still relatively immature compared to better-established shale-gas plays. The thickness of the Mancos (averaging 4000 ft in the Uinta Basin) and the variable lithology present drillers with a wide range of potential stimulation targets. Identifying and mapping favorable reservoir units within the Mancos will allow development of completion strategies based on appropriate geologic models. At least four members of the Mancos have shale-gas potential: in descending order, they are the Prairie Canyon (Mancos B), Lower Blue Gate Shale, Juana Lopez, and Tununk Shale. Organic matter in the shales has a large fraction of terrigenous material derived from the shorelines of the Sevier belt. Thicknesses of organic-rich zones within individual highstand system tracts exceed 12 ft. Vitrinite 1 values from a limited number of samples at the top of the Mancos range from 0.65% at the Uinta Basin margins to >1.5% in the central basin. As some wells in the central basin produce from depths greater than 13,000 ft, Mancos exploration can entail considerable financial risk. This project hopes to reduce that financial risk, particularly for independent operators, by providing the industry with an integrated compilation of geologic and engineering data relevant for Mancos exploration and production.

All final project maps, data reports, and results will be publicly available and presented to the petroleum industry (both small and large operators) through a technology transfer plan that includes exhibits and presentations at national and regional conferences, meetings with industry partners, workshops, website postings, and UGS publications. This project began activities in November 2010 and will conclude in the fall of 2015. For more information about this ongoing project, including available posters and talks (in pdf), refer to the UGS's project website: http://geology.utah.gov/resources/energy/oil-gas/shale-gas/cret-shale-gas/.

Recent Presentations

"Geologic Evaluation of the Cane Creek Shale, Pennsylvanian Paradox Formation, Paradox Basin, Southeastern Utah," by April 9, 2014 AAPG Annual Convention, Houston, Texas.

"Differentiating Green River Formation Oils Sourced from Freshwater and Saline Lacustrine Facies in the Uinta Basin, Utah," by Justin Birdwell, Ronald C. Johnson, Paul G. Lillis, Michael Brownfield, July 20-22, 2014 AAPG Rocky Mountain Section Meeting, Denver, Colorado.

"Comparative Geochemical and Spectral Gamma-Ray Study of the Lower Mancos Shale, Southwestern Piceance Basin, Southern Douglas Creek Arch, and Southeastern Uinta Basin, Colorado and Utah," by Rex Cole, William C. Hood, Richard Bingley, Anna Dunn, James Rice, Richard Root, Thomas Spain, and Aaron Tofsrud, July 20-22, 2014 AAPG Rocky Mountain Section Meeting, Denver, Colorado.

"Wide-Azimuthal 3-D Seismic Data Integrated with Geologic Information from Open-Hole Logs Unlocks the Secrets of a Naturally Fractured Trap in the Western Uinta Basin, Utah," by Jeffrey Ehrenzeller, Walter Korenkiewicz, and Julie Pyle, July 20-22, 2014 AAPG Rocky Mountain Section Meeting, Denver, Colorado.

"Calibration of Petrophysical Log Response in the North and Eastern Uinta Basin to Allow Extension of Outcrop Belts into the Subsurface Using Well Data," by James D. Hogan, J. Frederick Sarg, Kati Tanavsuu-Milkeviciene, July 20-22, 2014 AAPG Rocky Mountain Section Meeting, Denver, Colorado.

"Play Analysis of the Cane Creek Shale, Pennsylvanian Paradox Formation, Paradox Basin, Southeast Utah," by Craig D. Morgan, Stephanie M. Carney, Peter Nielsen, Michael D. Vanden Berg and Rebekah E. Wood, July 20-22, 2014 AAPG Rocky Mountain Section Meeting, Denver, Colorado.

"Correlation of Niobrara-Equivalent Strata in the Eastern Uinta Basin, Utah," by Robert Ressetar, Andrew McCauley, Lauren Birgenheier, and Jeffrey Quick, July 20-22, 2014 AAPG Rocky Mountain Section Meeting, Denver, Colorado.

"Geological Characterization of the Uteland Butte Member of the Eocene Green River Formation: An Emerging Unconventional Carbonate Tight-Oil Play in the Uinta Basin, Utah," by Michael D. Vanden Berg, Rebekah E. Wood, Stephanie M. Carney, and Craig D. Morgan, July 20-22, 2014 AAPG Rocky Mountain Section Meeting, Denver, Colorado.

"Microbial Mat Textures in Lithofacies of the Paradox Formation, Paradox Basin, Utah," by Katherine J. Whidden, Russell F. Dubiel, Jennifer D. Eoff, Sarah J. Hawkins, Kristen R. Marra, Ofori N. Pearson, Janet K. Pitman, July 20-22, 2014 AAPG Rocky Mountain Section Meeting, Denver, Colorado.

"Utah's Emerging Tight Oil Plays: Uteland Butte, Basal Green River Formation, Uinta Basin, and Cane Creek Shale, Paradox Basin," by Michael D. Vanden Berg, September 10, 2014, RPSEA Onshore Production Conference – Unconventional Hydrocarbon Reservoirs and Produced Water Management, Salt Lake City, Utah.

"Well Completion Strategies and Geomechanics of the Uteland Butte and Cane Creek Tight Oil Plays," by John McLennan, September 10, 2014, RPSEA Onshore Production Conference – Unconventional Hydrocarbon Reservoirs and Produced Water Management, Salt Lake City, Utah.

"Hydrocarbon Potential of Utah's Mancos Shale," by Lauren Birgenheier, September 10, 2014, RPSEA Onshore Production Conference – Unconventional Hydrocarbon Reservoirs and Produced Water Management, Salt Lake City, Utah.

"Paleozoic Shale-Gas Plays in Utah," by Thomas C. Chidsey, Jr., September 10, 2014, RPSEA Onshore Production Conference – Unconventional Hydrocarbon Reservoirs and Produced Water Management, Salt Lake City, Utah.

"Advancing a Web-Based Tool for Unconventional Natural Gas Development with Focus on Flowback and Produced Water Characterization, Treatment, and Beneficial Use," by Mengista Geza, September 10, 2014, RPSEA Onshore Production Conference – Unconventional Hydrocarbon Reservoirs and Produced Water Management, Salt Lake City, Utah.

"Development of GIS-Based Tool for Optimized Fluid Management in Shale-Gas Operations," by Ken Carlson, September 10, 2014, RPSEA Onshore Production Conference – Unconventional Hydrocarbon Reservoirs and Produced Water Management, Salt Lake City, Utah.

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Utica Shale (Ordovician), Appalachian Basin, U.S.

By Rich Nyahay

OVERVIEW:

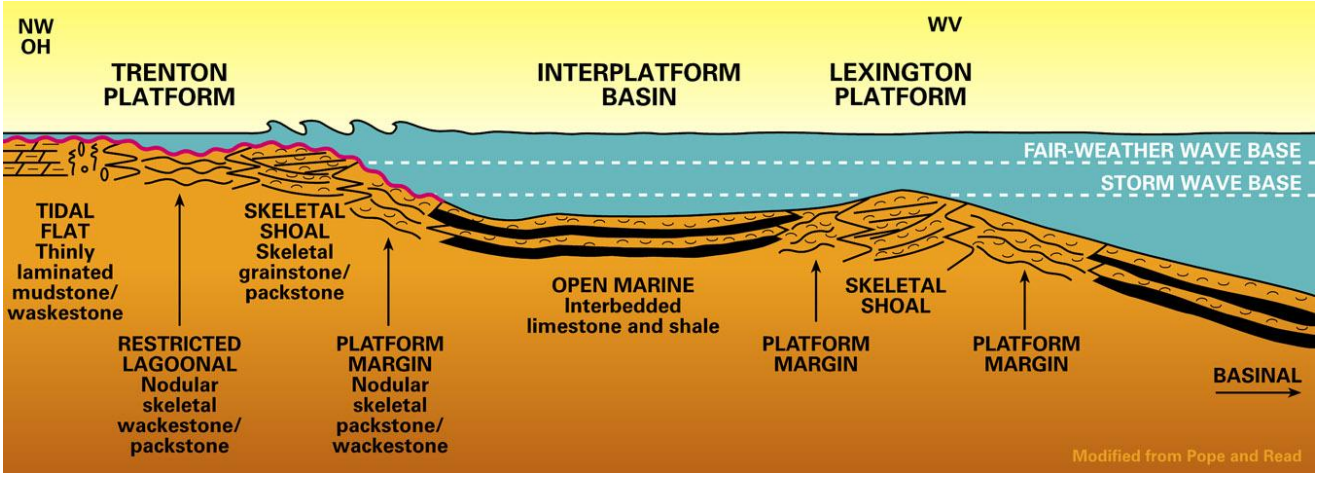
The Ordovician Utica (Indian Castle), Dolgeville, and Flat Creek are the formations of interest. These shales and interbeded limestones range in TOC from 1- 5% in the dry gas window. They cover an area from Mohawk Valley south to the New York State boundary line with Pennsylvania and extend west to the 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 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).

GEOLOGY:

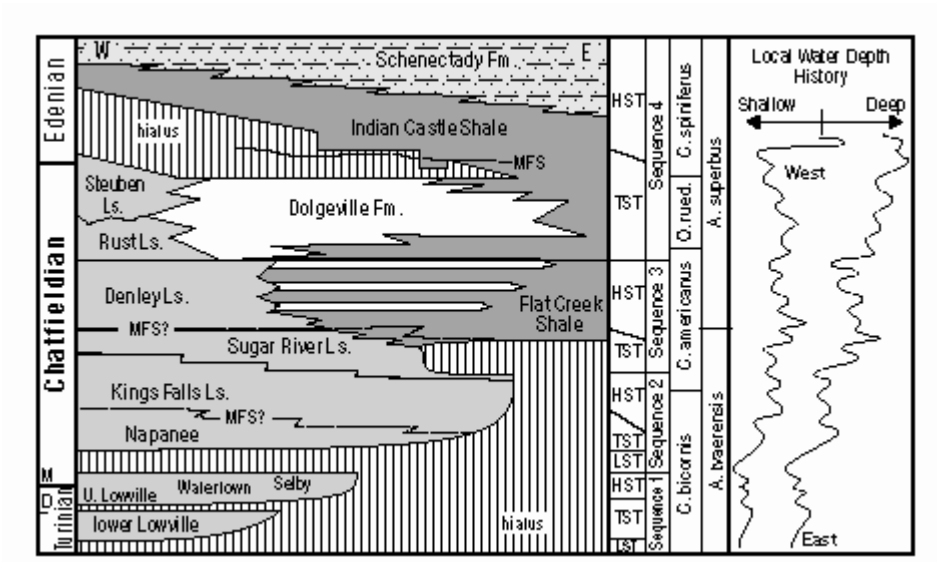
The Late Ordovician Utica shale was deposited in a foreland basin setting adjacent to and on top of, the Trenton and Lexington carbonate platforms. Initial deposition of the Trenton and Lexington platform began on a relatively flat Black River passive margin. Early tectonic activity from the Taconic 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).



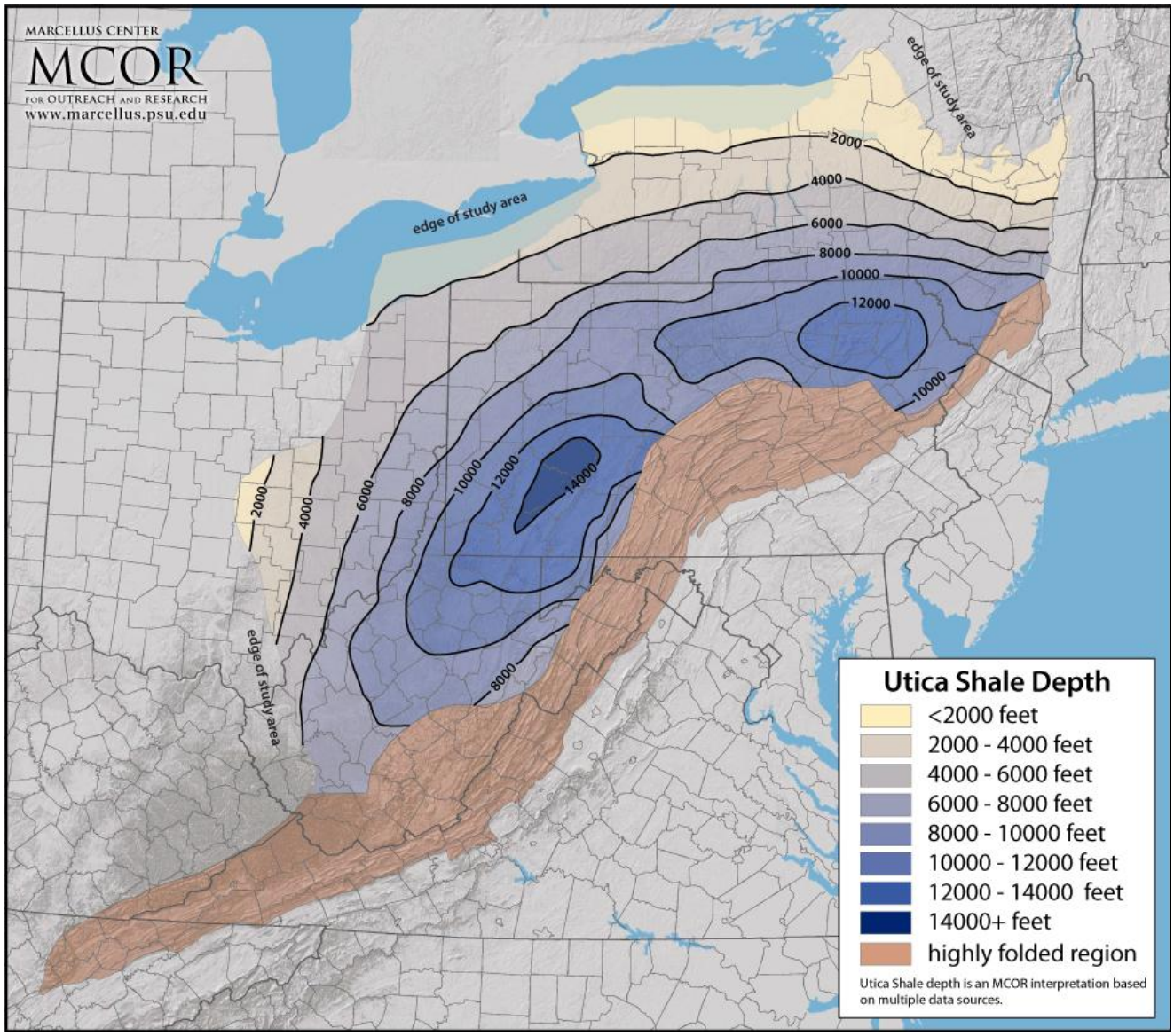
(Riley and Baranowski, 2011)

The Trenton/Lexington limestone through the Utica Shale comprise the trangressive systems tract (TST) of a large second-order sequence, superimposed with four, smaller scale third-order composite sequences. Third order sequences are regional correlative, aggradational, and lack lowstand deposits. Sequences are separated by type 3 sequence boundaries that amalgamate with trangressive surfaces and separate underlying highstand system tracts(HST's) from overlying TST's(McClain, 2012).

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.



(Joy et al. 2000)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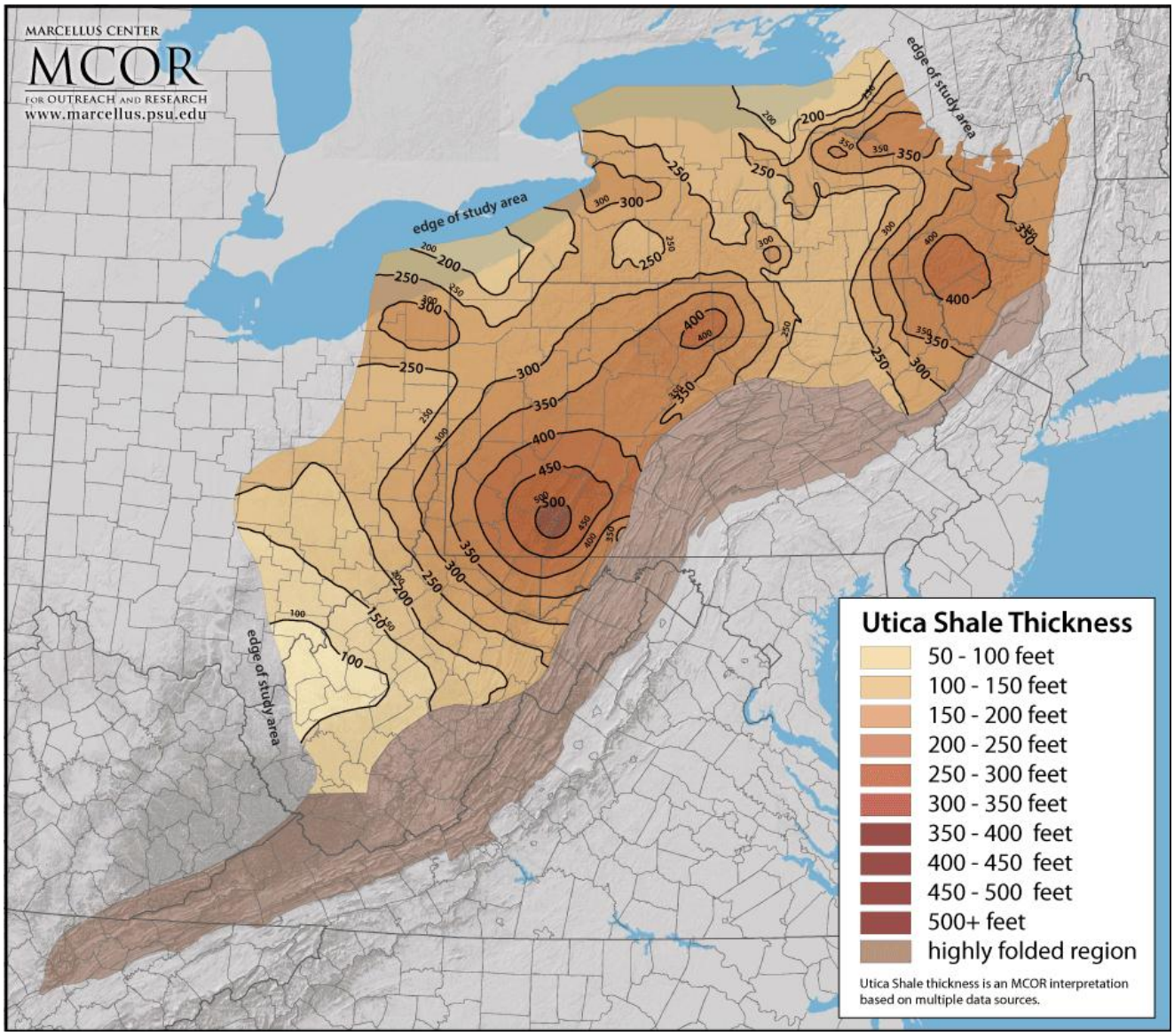
edge of study area
edge of study area
edge of study area
2000
4000
6000
8000
10000
12000
14000
Utica Shale Depth
<2000 feet
2000 - 4000 feet
4000 - 6000 feet
6000 - 8000 feet
8000 - 10000 feet
10000 - 12000 feet
12000 - 14000 feet
14000+ feet
highly folded region
Utica Shale depth is an MCOR interpretation based on multiple data sources.

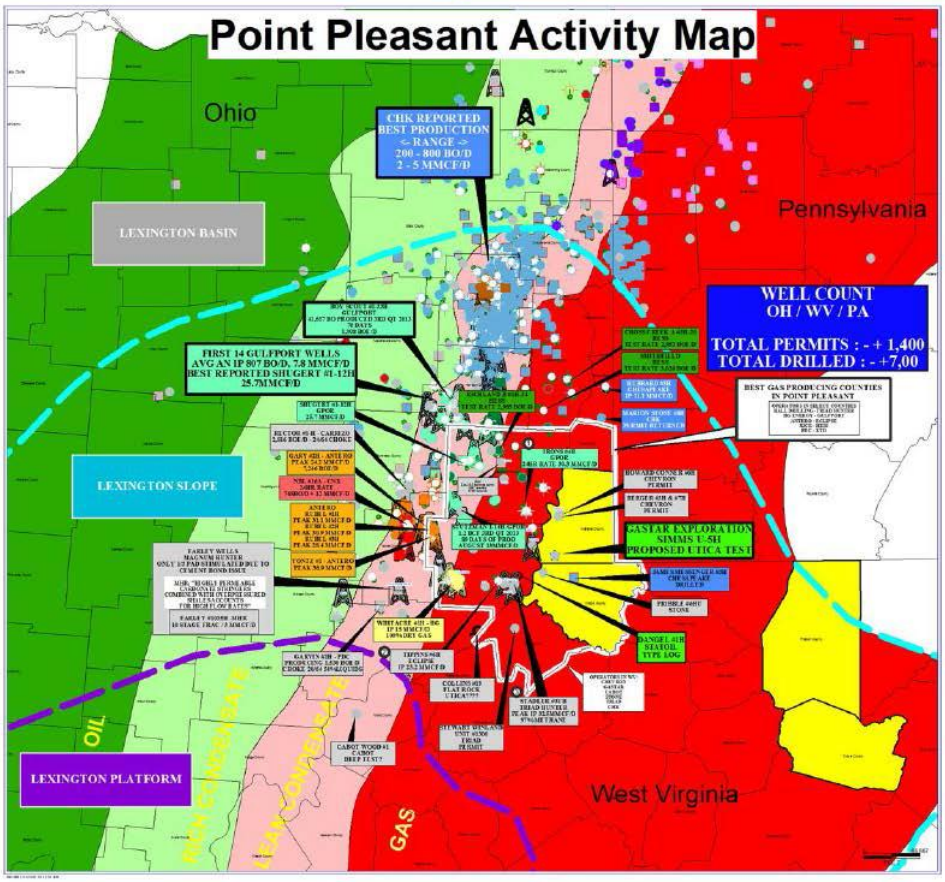


Well Activity: The table below lists some of the major companies and their net acreage in the Utica in 2014.

Company	Ticker	Net Acres	EV ($MM)	Acres/EV
Chesapeake Energy	CHK	1,000,000	34,063	29
Chevron	CVX	600,000	233,468	3
Anadarko Petroleum	APC	267,000	57,360	5
Devon Energy	DVN	195,000	30,153	6
Range Resources	RRC	190,000	15,451	12
Hess Corporation	HES	185,000	33,068	6
EV Energy	EVEP	177,000	2,746	64
Gulfport Energy	GPOR	147,350	4,996	29
Halcon Resources	HK	142,000	4,953	29
Antero Resources	AR	104,000	17,013	6
Magnum Hunter	**MHR**	**99,000**	**2,690**	**37**
BP	BP	84,000	164,525	1
Consol Energy	CNX	80,000	11,590	7
ExxonMobil	XOM	75,000	427,308	0
PDC Energy	PDCE	48,000	2,496	19
Carrizo Oil & Gas	CRZO	21,700	2,922	7
Rex Energy	REXX	21,000	1,369	15
EQT Resources	EQT	13,600	15,469	1

(Magnum Hunter Resources, 2014)

Point Pleasant Activity Map



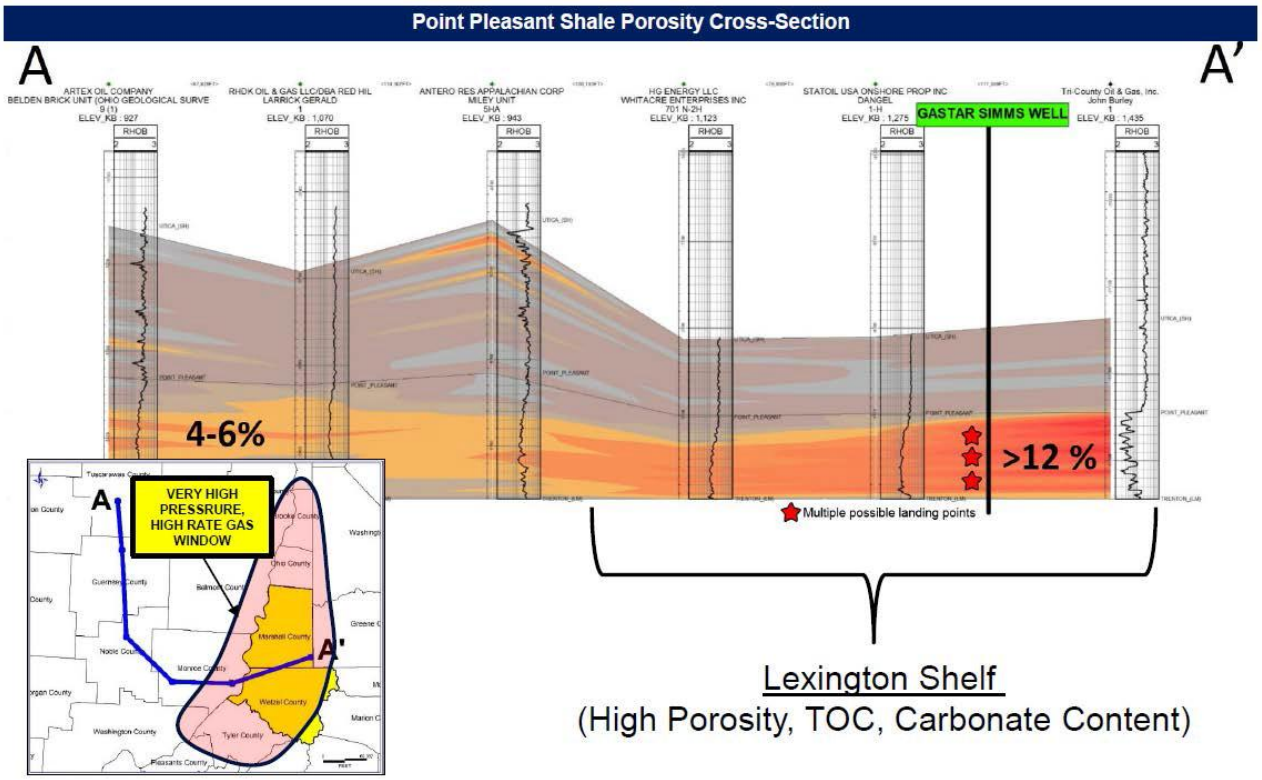
(Gastar Exploration Inc, 2014)

With the current regulatory moratorium in place in New York, activity has been focused in eastern Ohio, western Pennsylvania and western West Virginia. Ohio current drilling activity as of April, 2015 lists 1872 Utica permits, 1442 wells drilled and 504 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. From the table and cross-section 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 closely it shows the density logs decreasing as wells trend to the east in the Point Pleasant. 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.

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

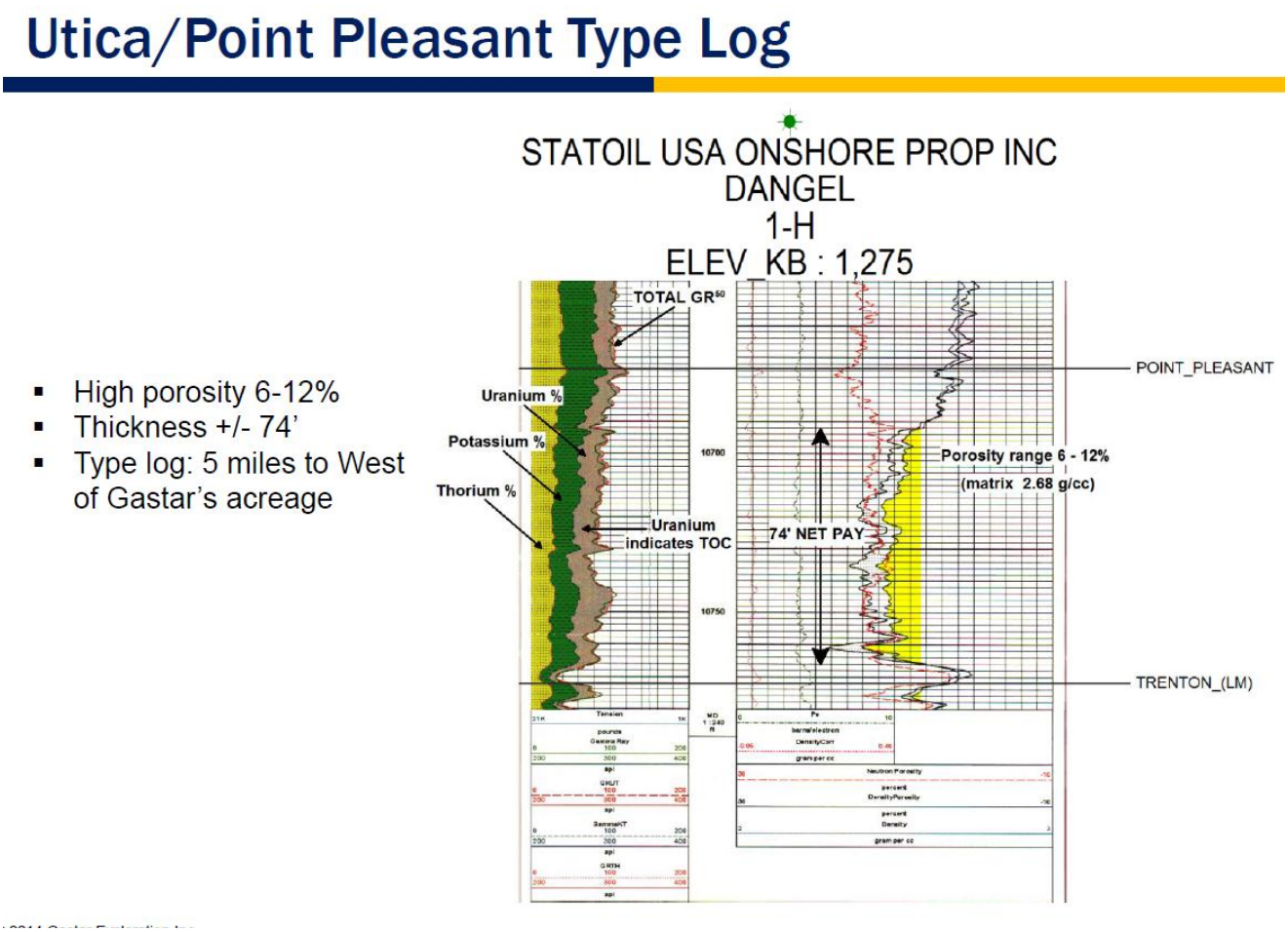
Well	Operator	State	County	IP (Mmcf/d)	Lateral Length (Ft)	IP/1000' LL
Claysville Sportsman's Club 11H	**Range Resources**	**PA**	**Washington**	**59.0**	**5420**	**10.9**
Stewart Winland Unit 1300U	Magnum Hunter	WV	Tyler	46.5	5289	8.8
Bigfoot 9H	Rice	OH	Belmont	41.7	6957	6.0
Stadler Unit A 3UH	Magnum 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)



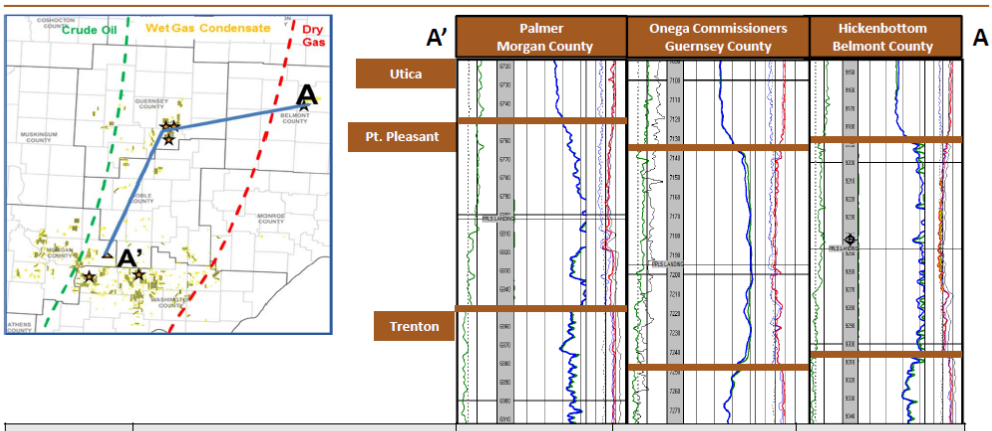
(Gastar Exploration Inc., 2014)

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



(Gastar Exploration Inc, 2014)

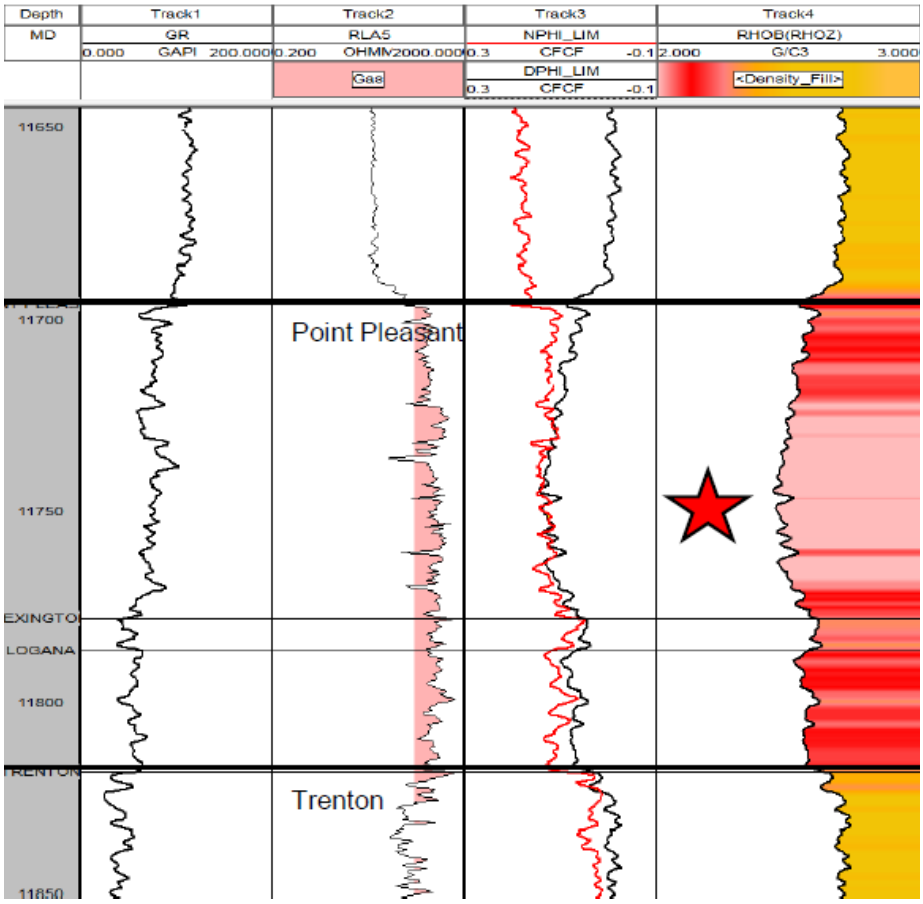
All logs in the highlighted southeastern Ohio, PA and West Virginia area all show increasing resistivity and decreasing density which correlates to higher TOC values and increasing porosity.



Average Rock Properties PDC Acreage			
Resistivity (ohm-m)	800 – 2,000	1,000 – 2,000+	1,000 – 2,000+
Porosity (%)	6 - 11%	6 - 12%	6 - 13%
Thickness of Pt. Pleasant (ft)	100'	112'	117'
Total Organic Content (TOC)	Max 4.4	Max 4.8 (est.)	Max 4.5
Formation Depth (ft)	6,750' – 6,850'	7,135 – 7,247	9,188' – 9,305'
BTU of gas stream	1,261	1,254	1,040

(PDC Energy, 2014)

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



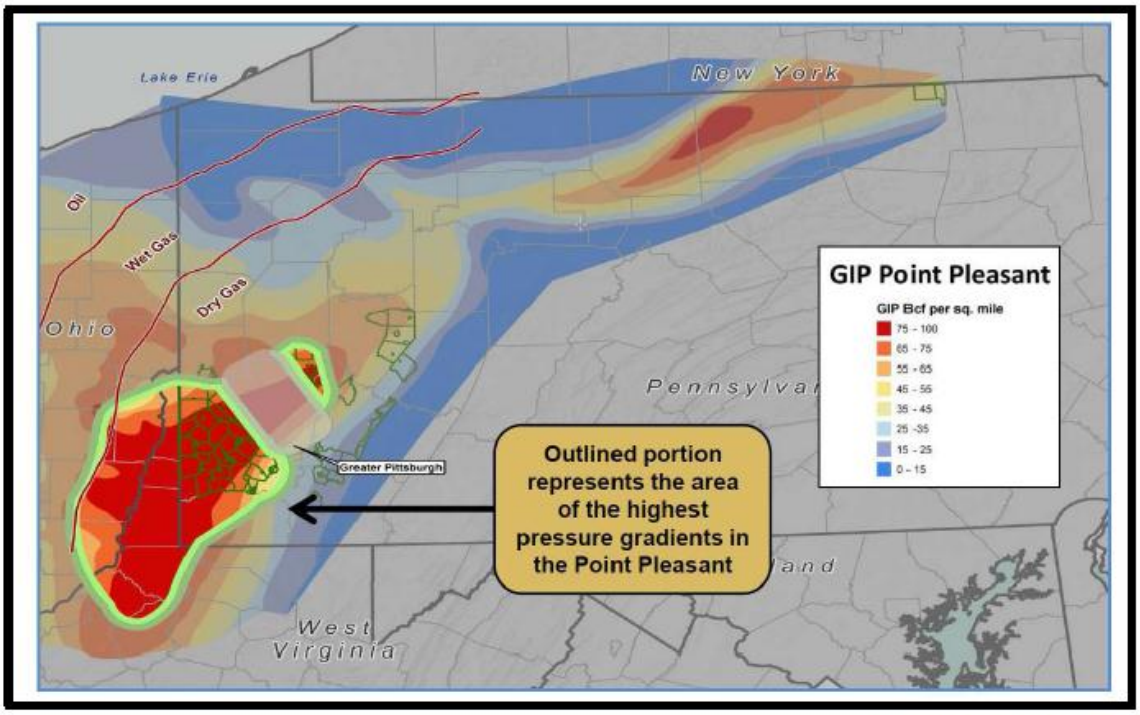
(Range Resources, 2015)

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

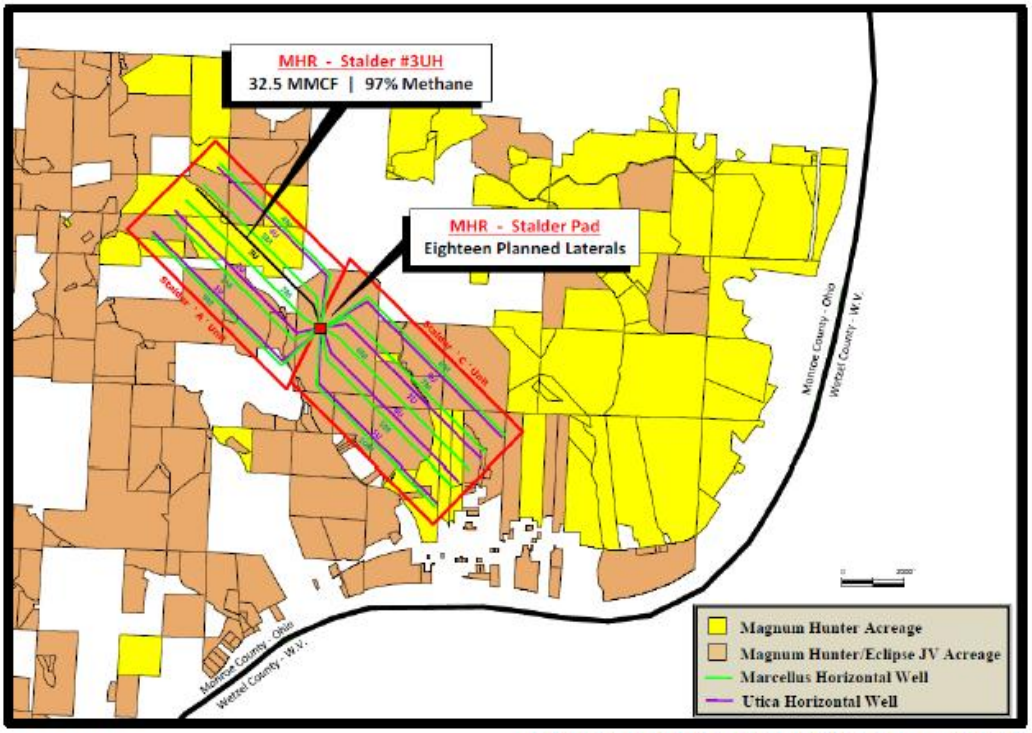
(Range Resources, 2015)

With high gas in place values, Range Resources is also reporting highest pressure gradients



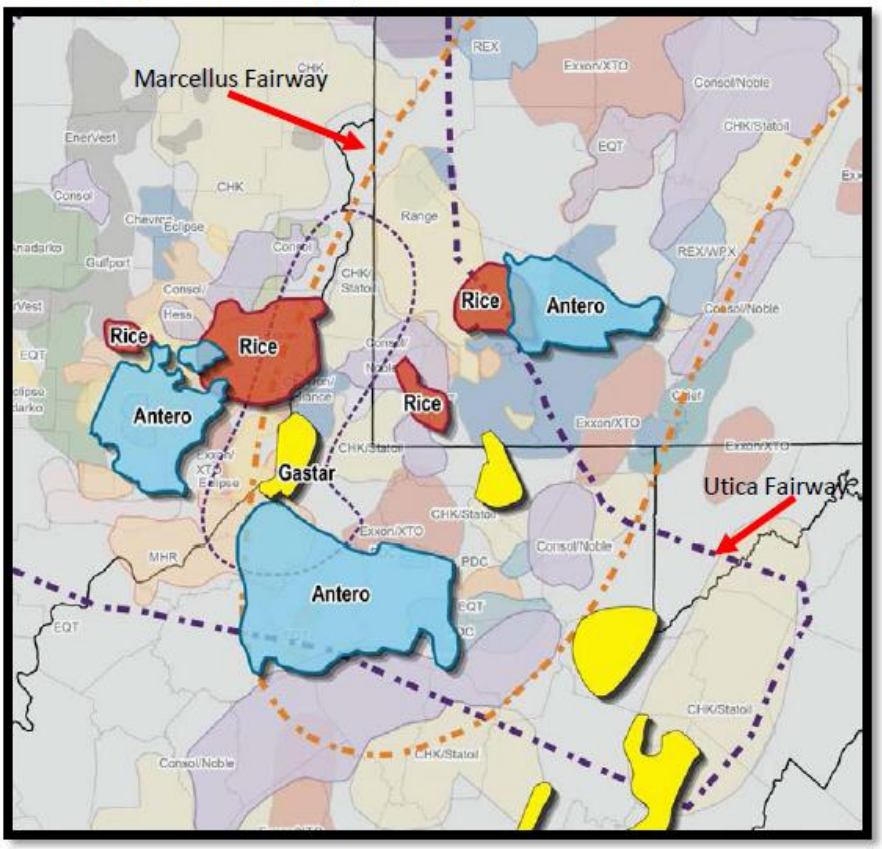
(Range Resources, 2015)

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.



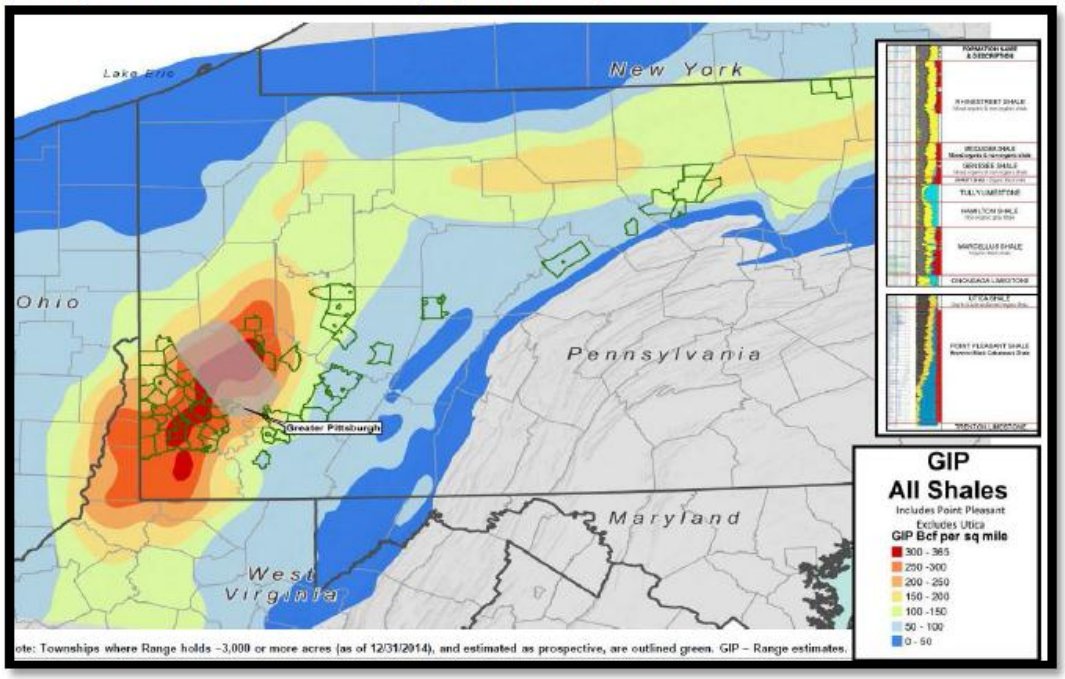
(Magnum Hunter Resources Inc., 2014)

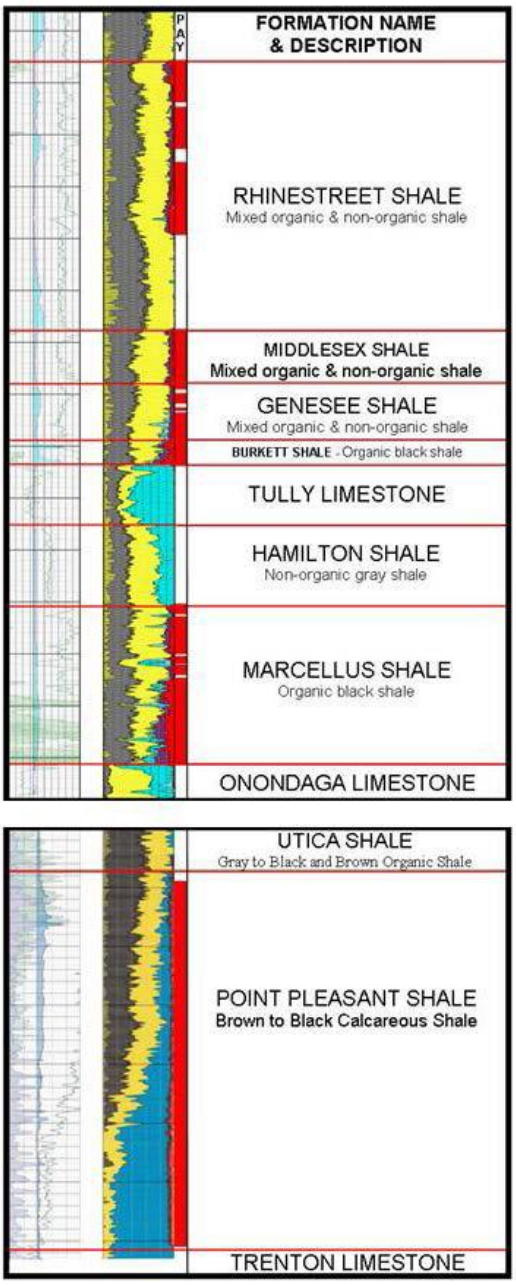
Companies with acreage in stackable play area.



(Gastar Exploration Inc., 2014)

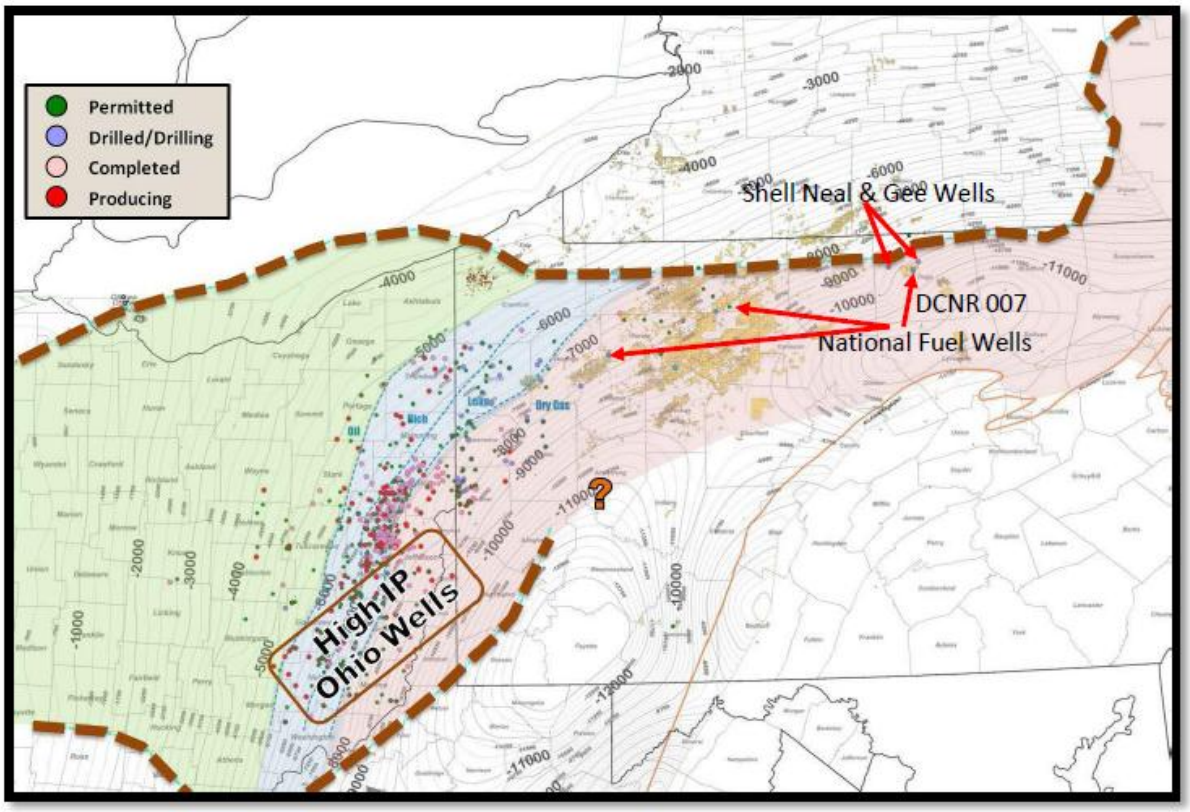
Gas in place estimates for stackable plays from Range Resources.





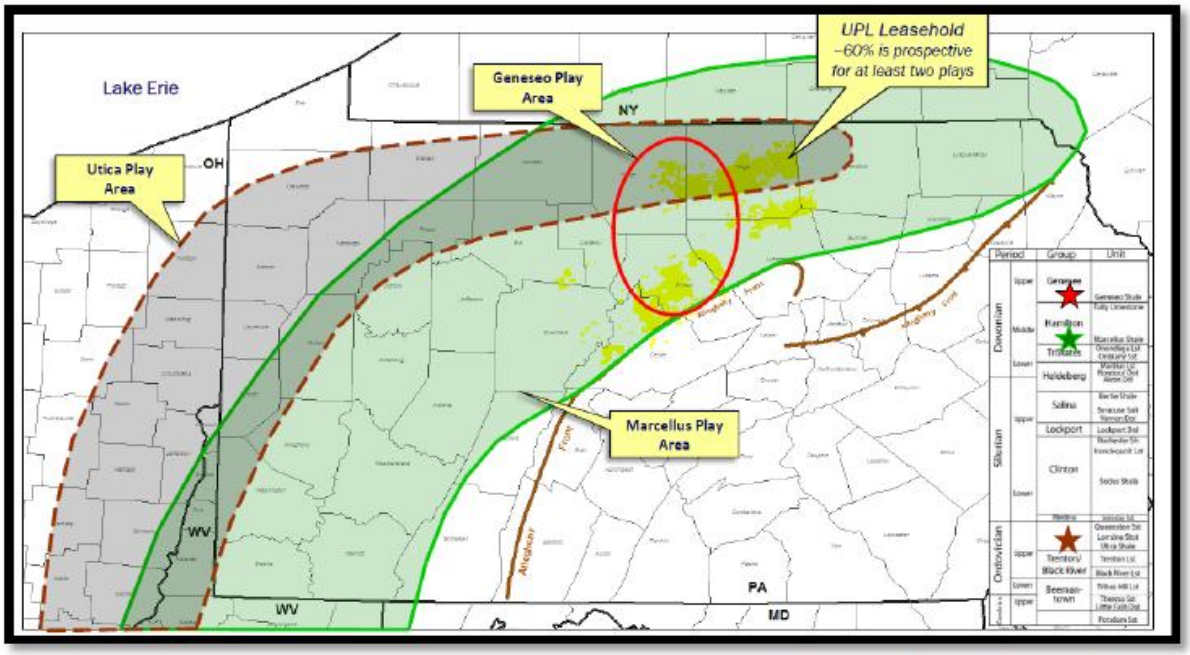
Stratigraphic Section and Log responses formations targeted.

Tioga County, PA has three new Utica tests that extends the dry gas area further to the east, notice in the figure below the thermal maturity lines are cut off and extending some of the oil and gas liquids into PA and the dry gas window into New York. The most recent well from National Fuel DCNR 007 well generated 22.7 million cubic feet per day with a 30 stage 4640 feet lateral.



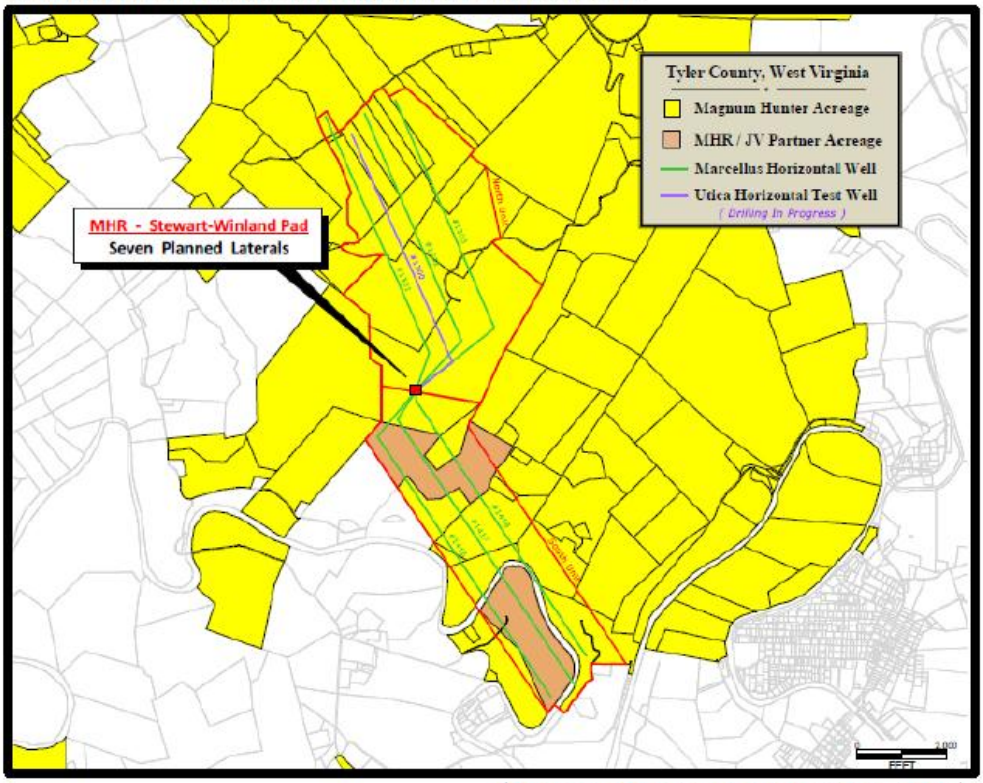
(National Fuel, 2014)

The figure below indicates where the Genesee play area might be located.



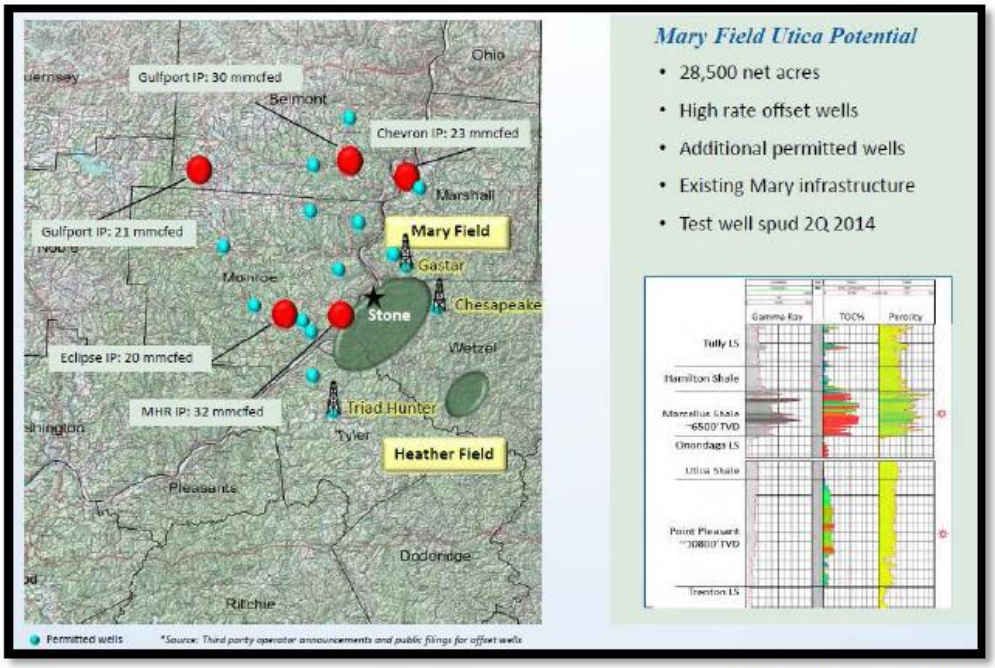
(Ultra Petroleum Corp., 2014)

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

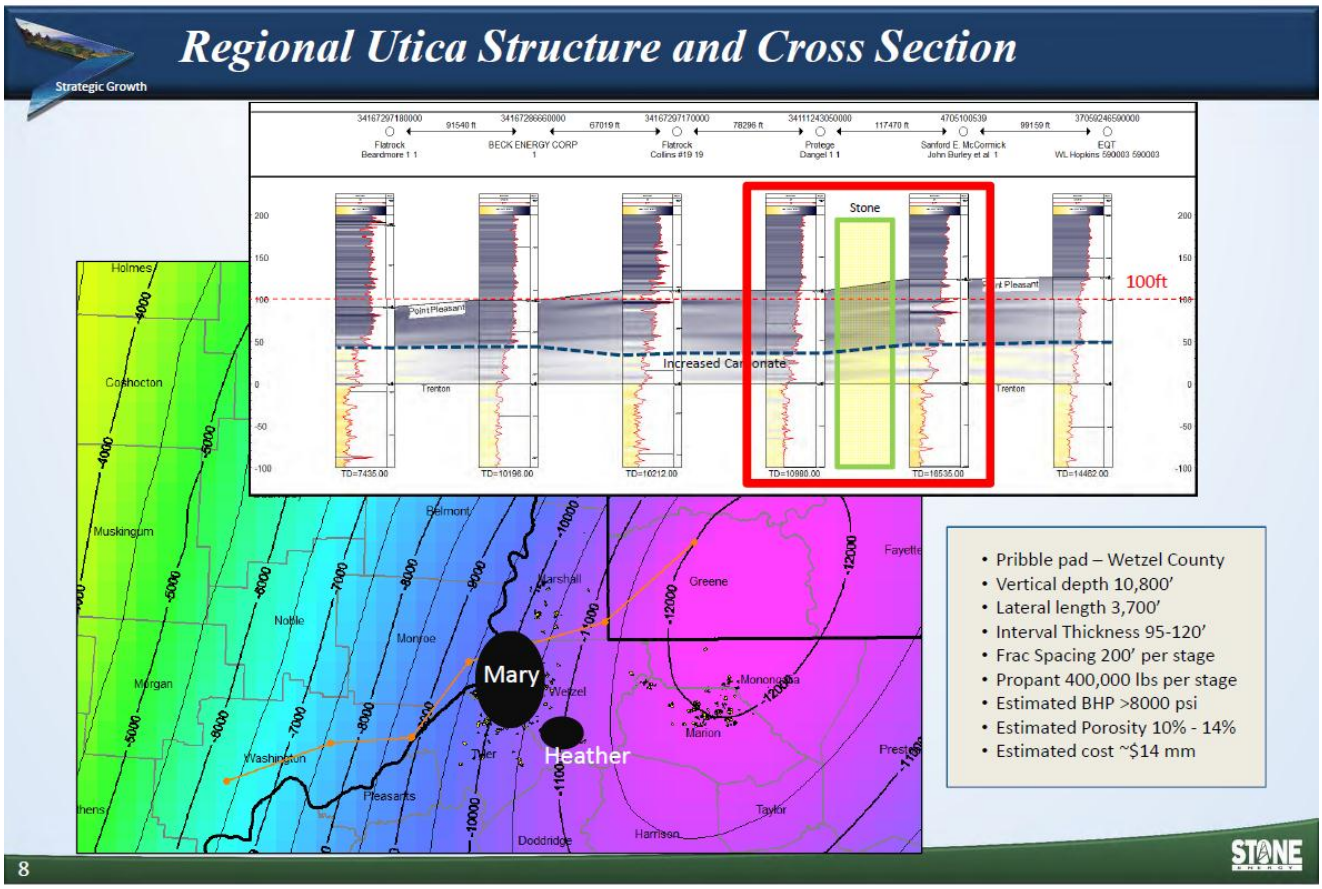


(Magnum Hunter Resources Inc., 2014)

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)

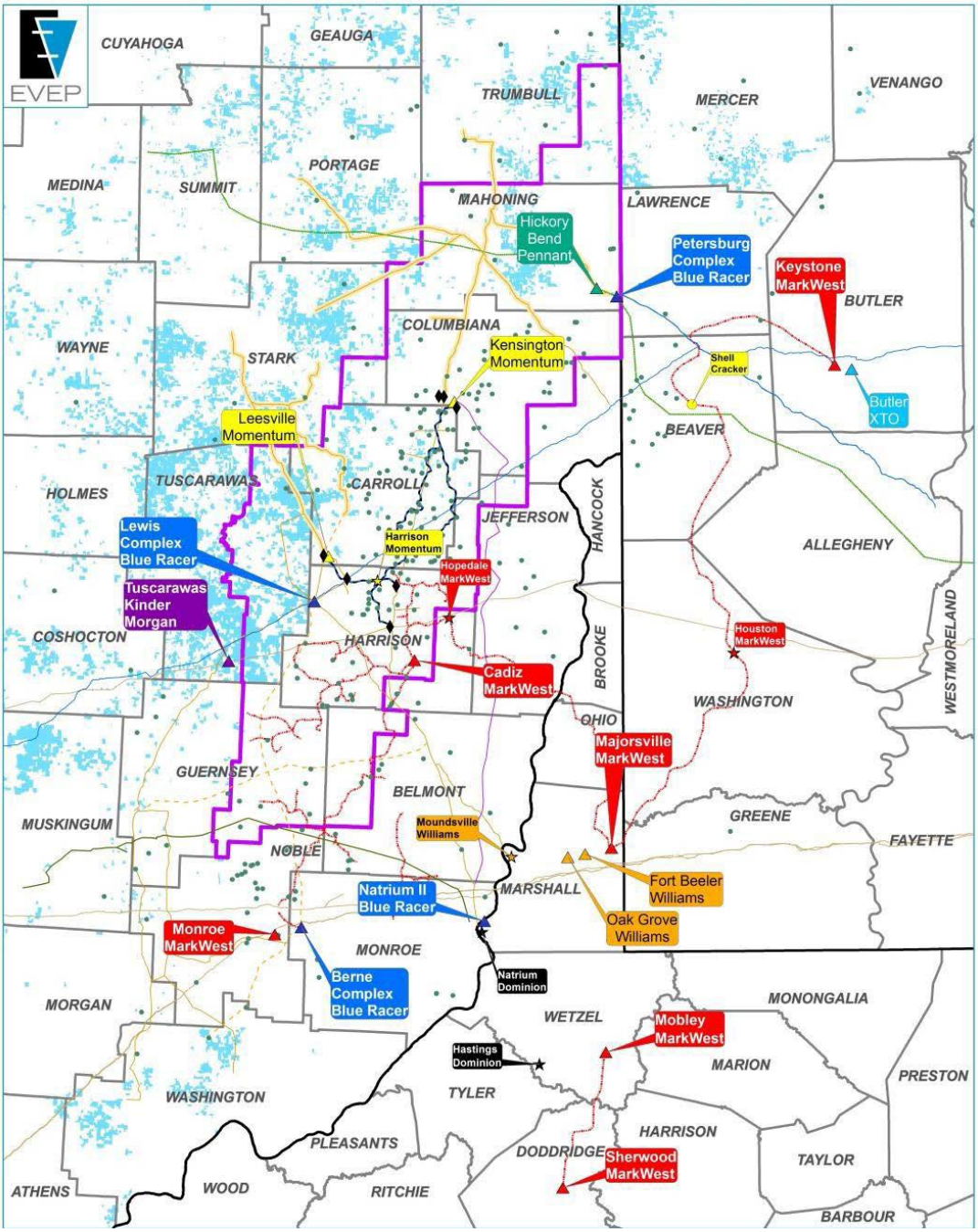


(Stone Energy, 2014)

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 and 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.



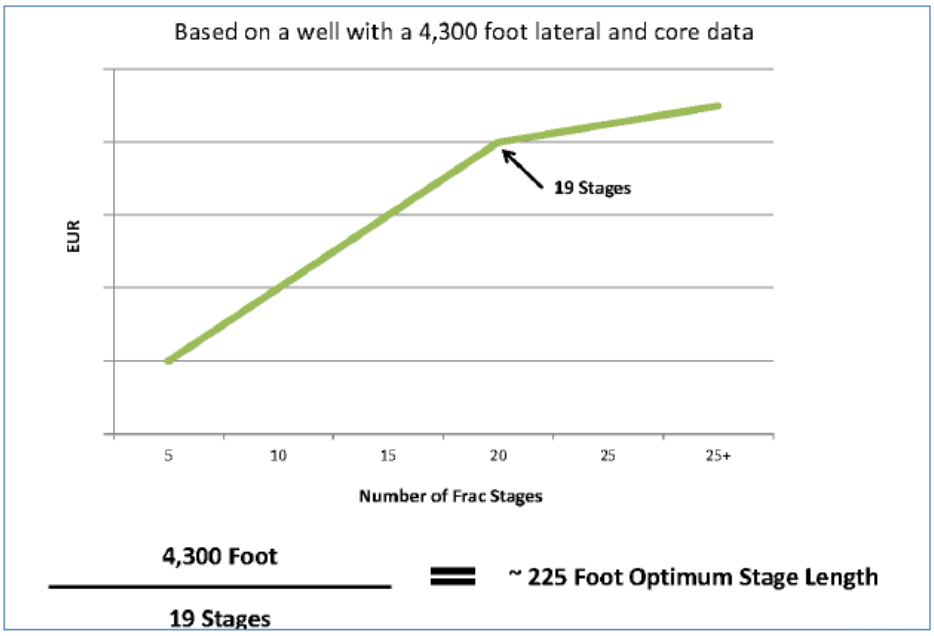
(ODNR, 2015)

Average well cost range from 8 to 14 million dollars per well.

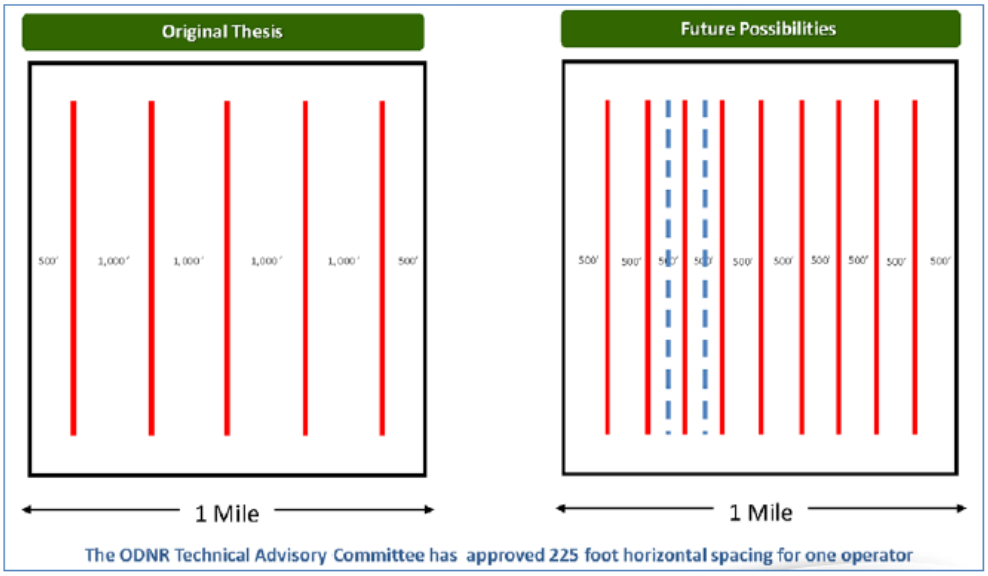
Completion Techniques:

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).

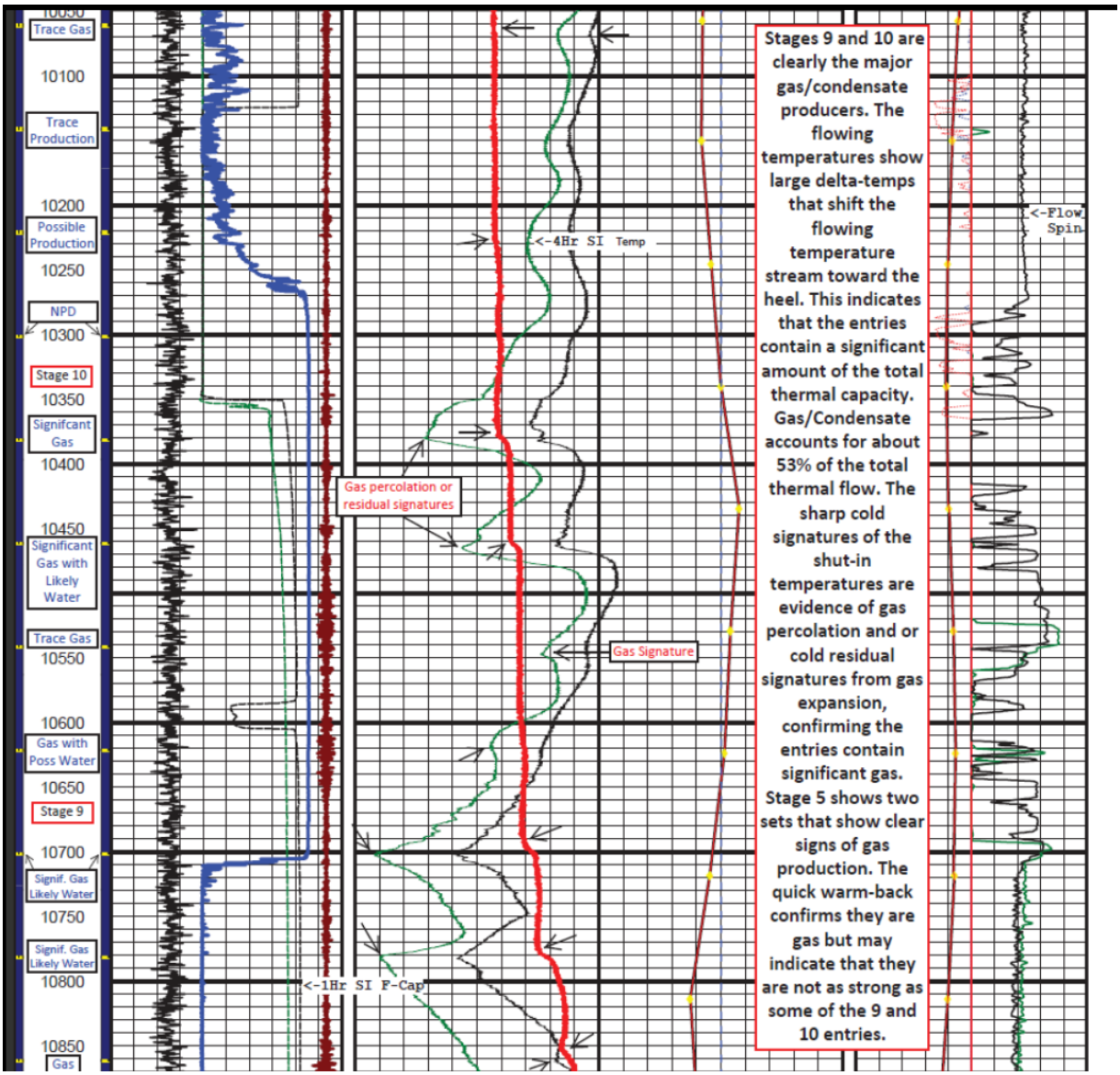
Gulfport Energy found a 225 foot optimum stage length and is now thinking about 250 ft between laterals.33



Optimum Stage Length *(Gulfport Energy Inc DUG East 11-14-2012)*



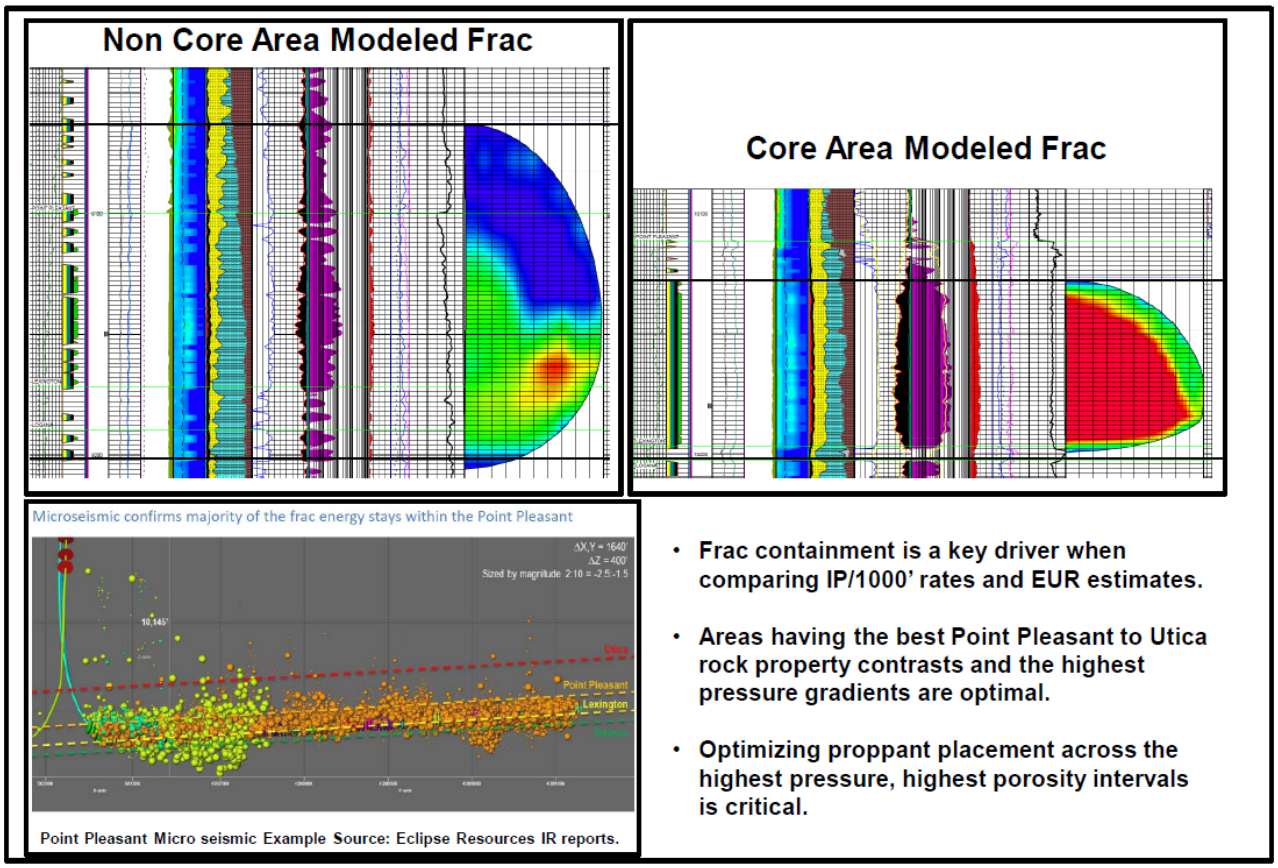
Lateral spacing consideration of Gulfport Energy Inc (Gulfport Energy Inc DUG East 11-14-2012)



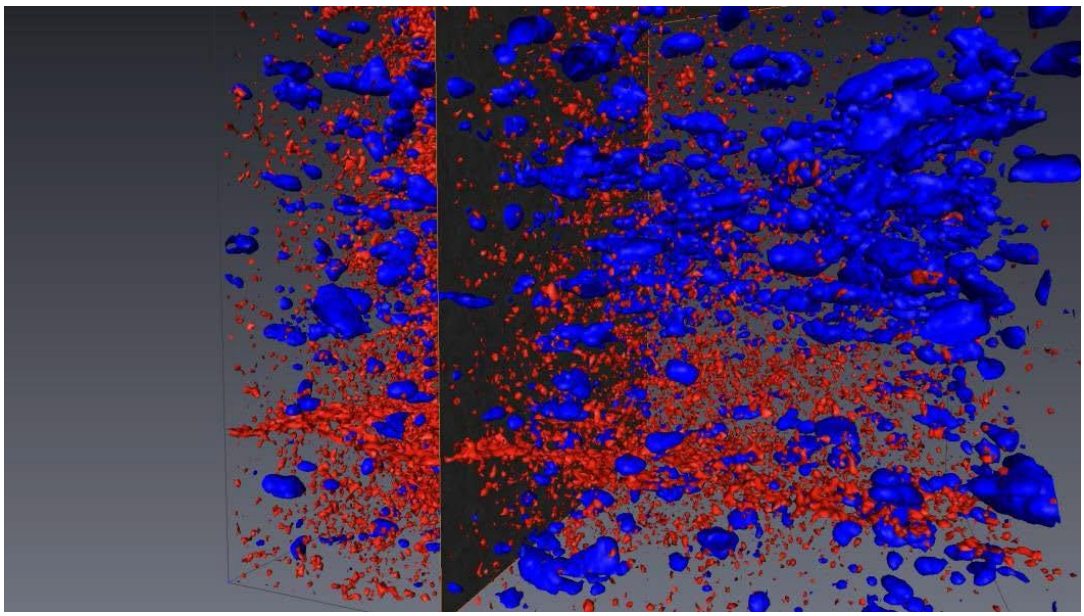
Production Log from a Gulfport Energy well (Gulfport Energy Inc DUG East 11-14-2012)

The basic completion concept is to drill with long laterals, have short stages, and shut in the well for a determined resting period.

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 an 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.

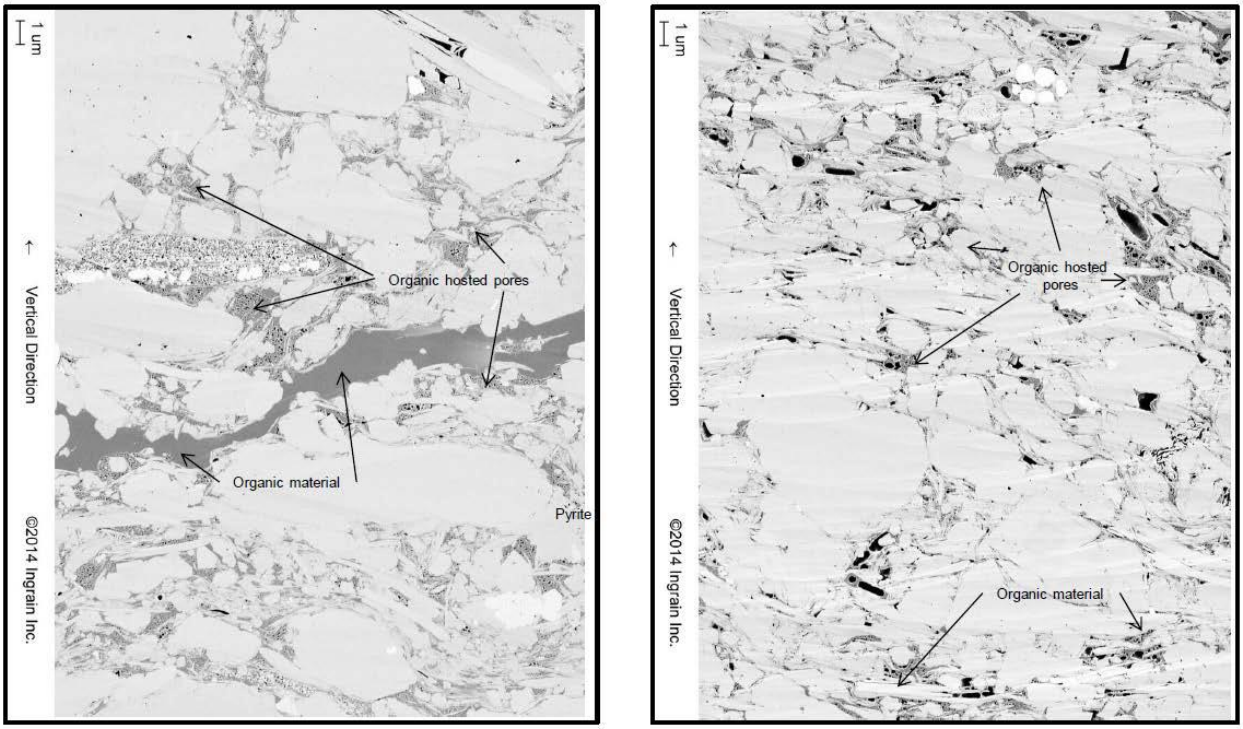


A conclusion from a paper by Swift, et al 2014 which looked at nano to microscale pore characterization of the Utica Shale found that mudstones with abundant clasts and clay reduces anisotropy more at the nanometer scale of clay folia than at the microscale of clasts themselves. Swift, et al 2014, conclude 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.



(Swift, et al, 2014)

Claysville 11H Point Pleasant Pore Systems

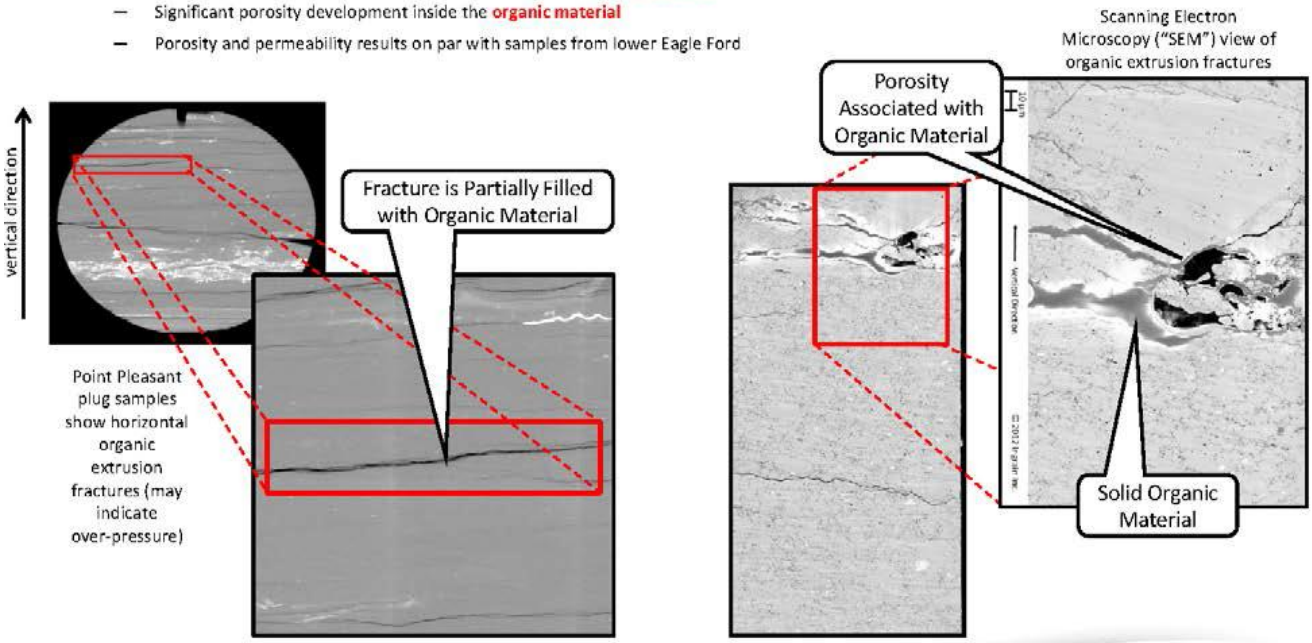


FIB SEM examples from lateral target interval. Note TOC content and well developed pore network.

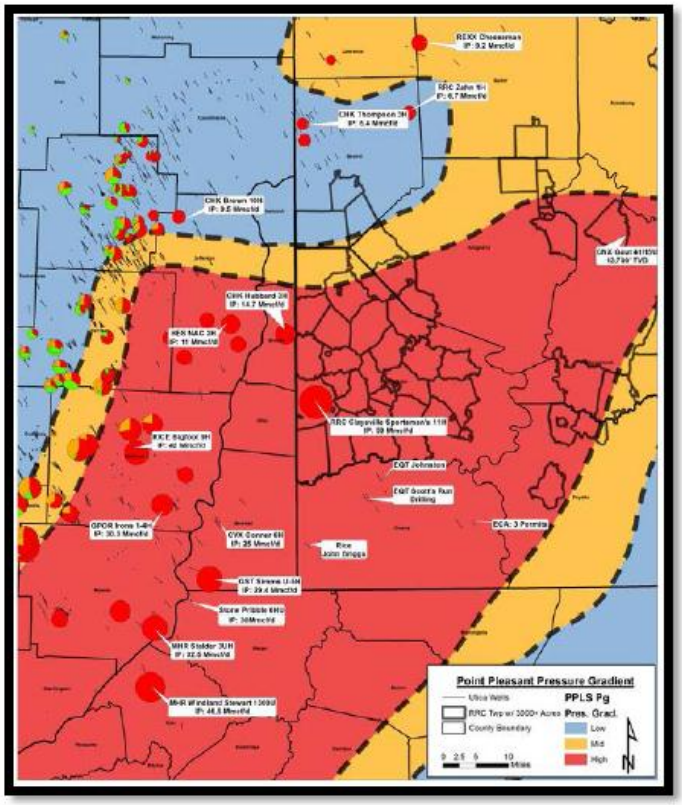
(Range Resources, 2015)

Comparison of SEM images from the high IP and Pressure gradient area and the Point Pleasant outside that area.

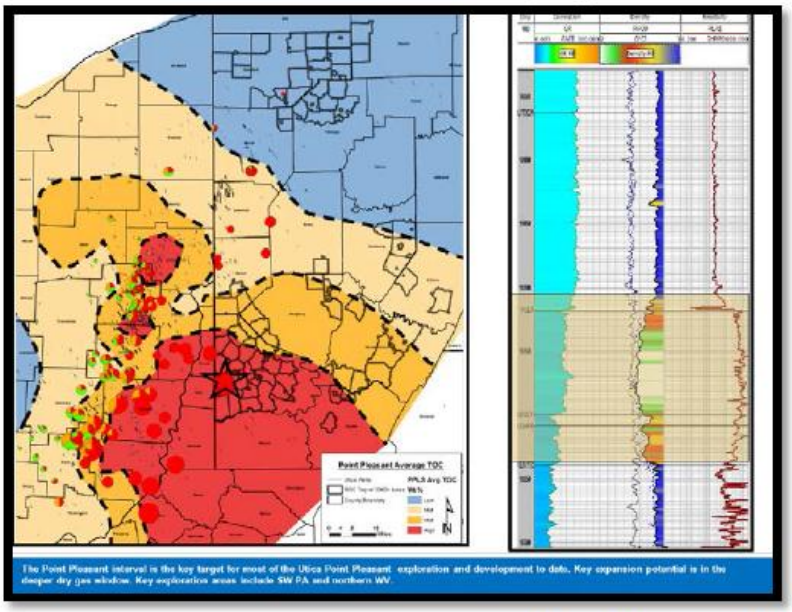
- **Analysis of Ion-milled Scanned Electron Microscopy ("SEM") images of the Point Pleasant formation indicate:**
  - Horizontal organic extrusion fractures may be indication of **overpressure**
  - Significant porosity development inside the **organic material**
  - Porosity and permeability results on par with samples from lower Eagle Ford



Ion Milled SEM Images of the Point –Pleasant Formation (Gulfport Energy Inc DUG East 11-14-2012)

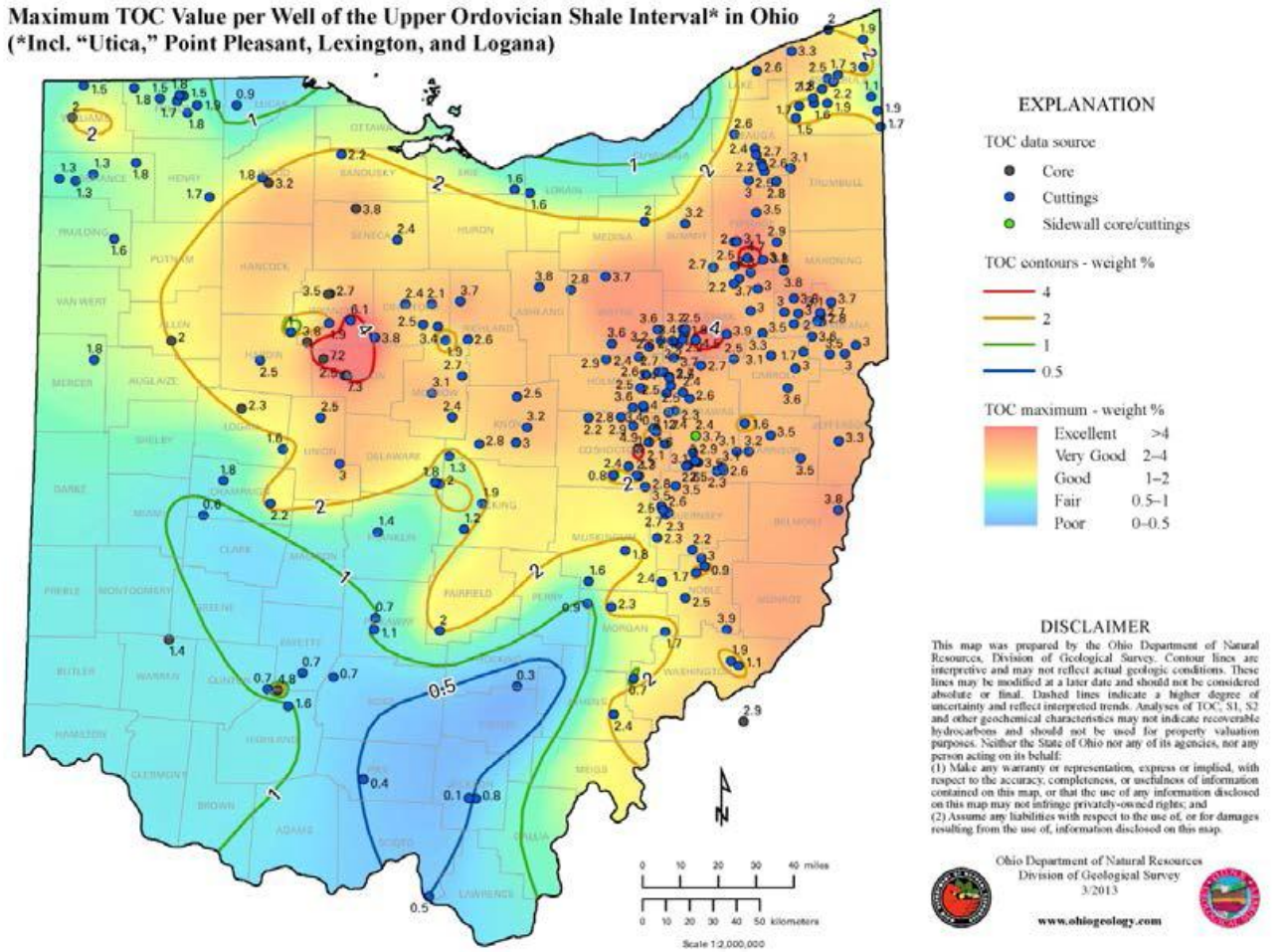


(Range Resources, 2015)



(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.



(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..

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 3miles (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 are 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).

SITES:

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://www.dec.ny.gov/energy/205.html This is the website to find out information on wells being permitted, well spacing and all state regulations regarding oil and gas well drilling. This also the website to download the 1000 page draft Supplemental Generic Environmental Impact.

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), Anadarko, Arkoma, and Ardmore Basins, U.S.

by Brian Cardott (Oklahoma Geological Survey).

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 3,799 well completions from 1939 to March 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 (118), Excello Shale/Pennsylvanian shale (2), Goddard Shale (lower Springer shale)(23), Sylvan Shale or Sylvan Shale/Woodford Shale (18), and Woodford Shale (3,599). Shale wells commingled with non-shale lithologies are not included. Exceptions include 20 Sycamore Limestone/ Woodford Shale, 10 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. Figure 1 illustrates 3,727 Oklahoma shale gas and tight oil well completions (2004–2014) on a geologic provinces map of Oklahoma.

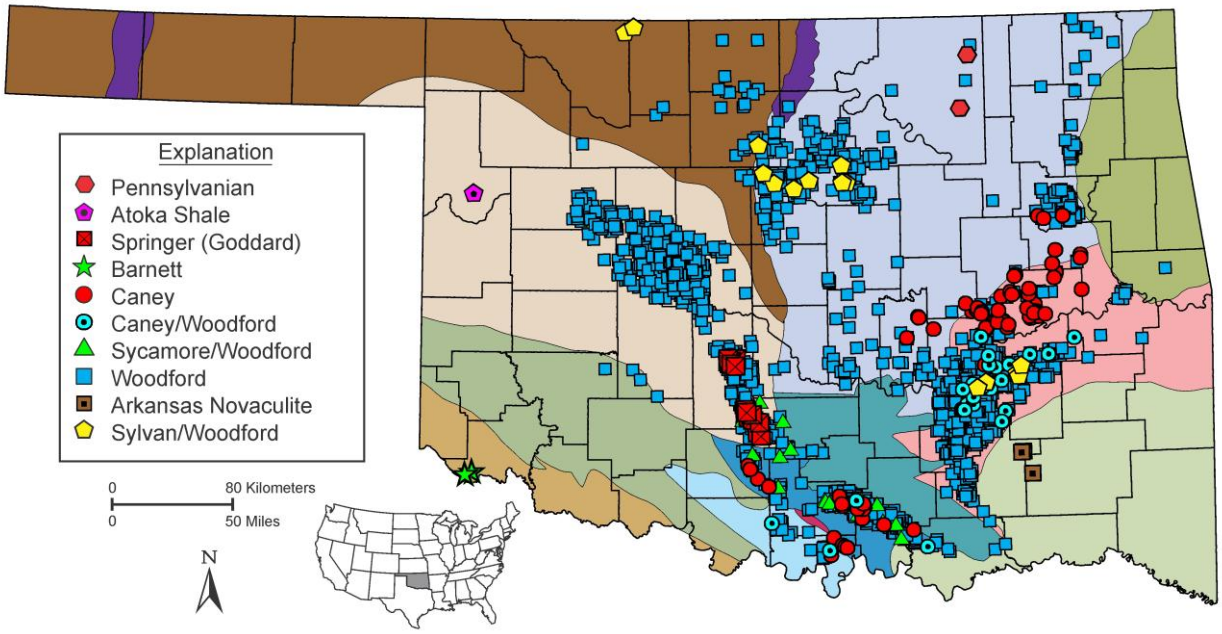


Figure 1. Map showing Oklahoma shale gas and tight oil well completions (2004–2014) on a geologic provinces map of Oklahoma.

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" for "South Central Oklahoma Oil Province" play in the Anadarko Basin and western Arkoma Basin) and oil (northern Ardmore Basin, "Cana", "SCOOP", and north-central Oklahoma) areas. Of the 3,562 Woodford-only well completions from 2004–2014, 3,190 wells are horizontal wells and 372 wells are vertical wells. 780 Woodford Shale wells are classified as oil wells based on a gas-to-oil ratio of less than 17,000: 1. Total vertical depths range from 388 ft (Mayes Co.) to 17,355 ft (Stephens Co.). Initial potential gas rates range from a trace to 16 million cubic feet per day. Initial potential oil/condensate rates range from a trace to 1,411 barrels per day. Reported oil gravities range from 21 to 67 API degrees.

The annual peak of 539 Woodford Shale well completions occurred in 2014, even with a lag in well completion reporting (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. Figure 4, showing Woodford Shale wells from 2011–2014, illustrates the expansion of the Woodford Shale condensate play in the Anadarko Basin which began in Canadian County ("Cana") in 2007 and South Central Oklahoma Oil Province ("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.

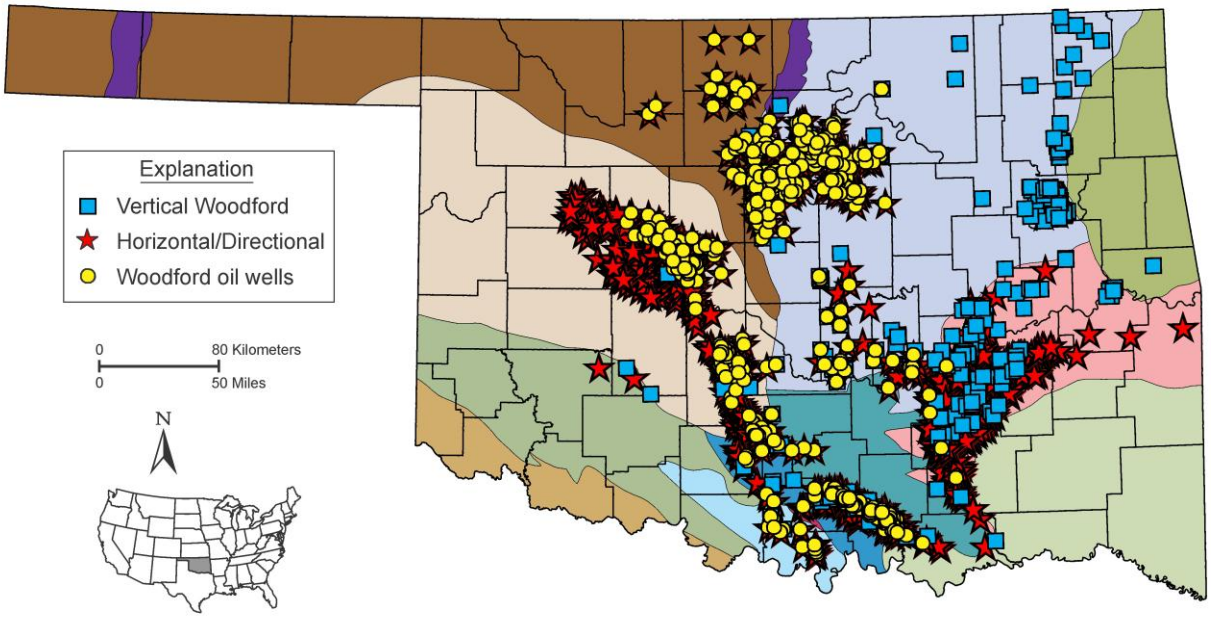


Figure 2. Map showing 3,511 Woodford Shale-only gas and oil well completions (2004–2014) on a geologic provinces map of Oklahoma.

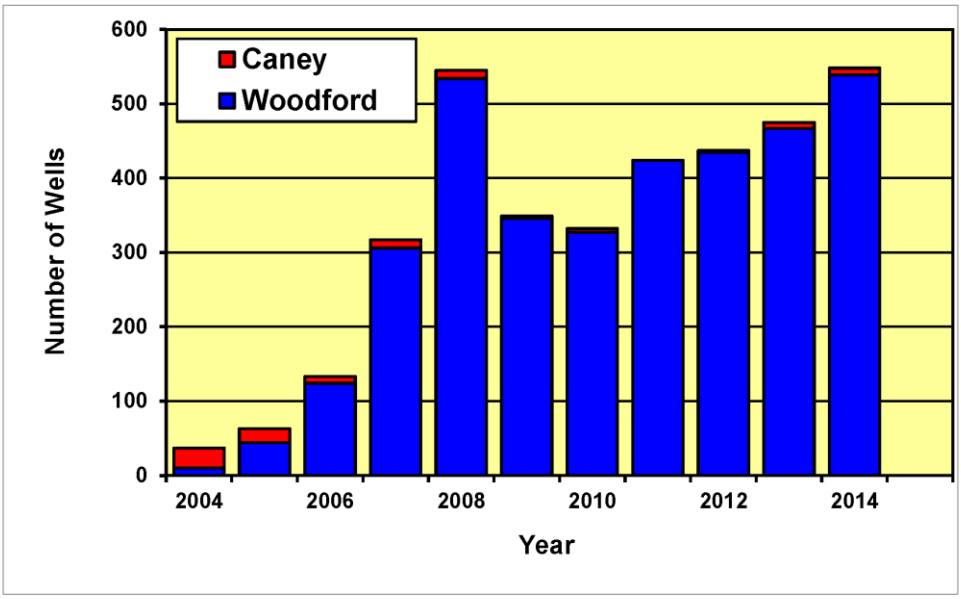


Figure 3. Histogram showing numbers of Woodford Shale and Caney Shale well completions, 2004–2014.

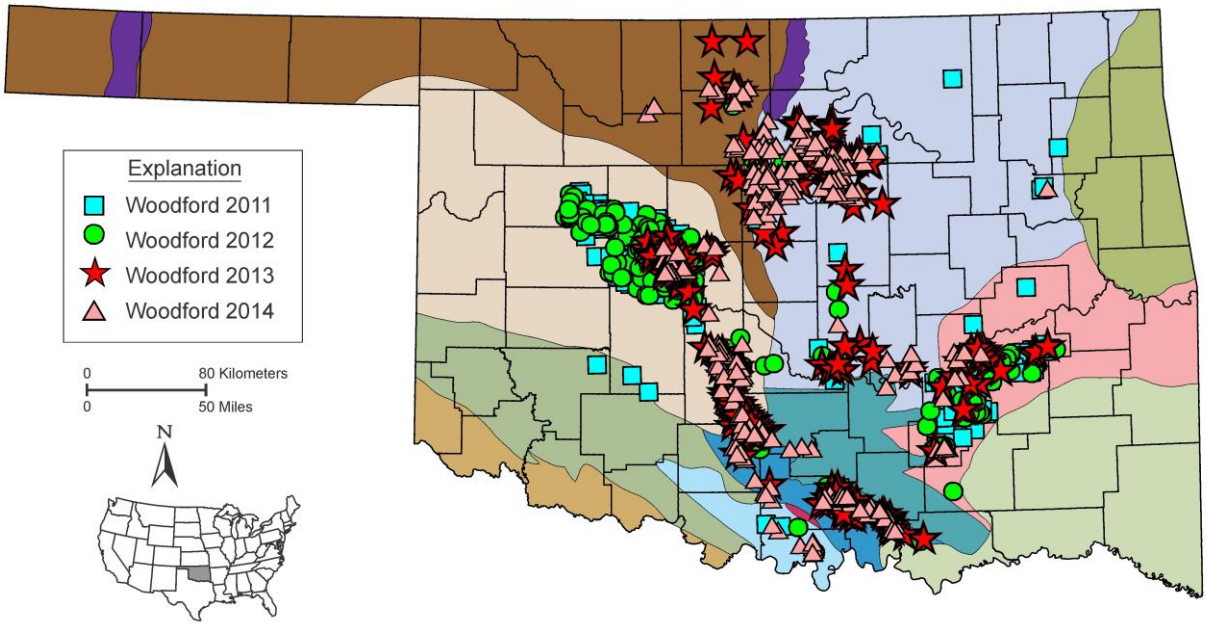


Figure 4. Map showing Woodford Shale-only gas and oil well completions (2011-2014) on a geologic provinces map of Oklahoma.

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).

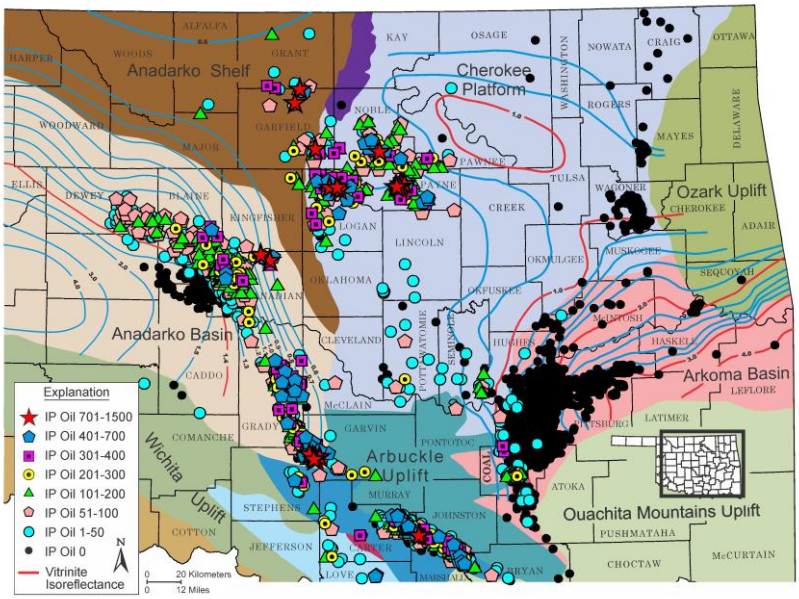


Figure 5. Map showing initial potential liquid hydrocarbon production of Woodford Shale-only gas and oil well completions (2004-2014) in the Arkoma Basin and Cherokee Platform of eastern and north-central Oklahoma.

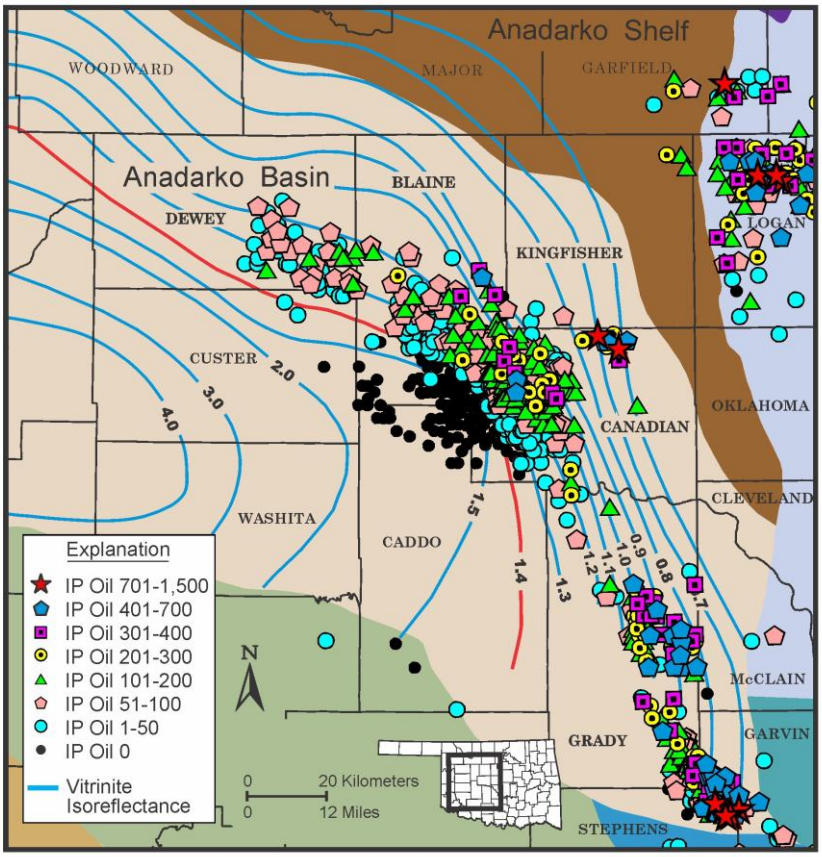


Figure 6. Map showing initial potential liquid hydrocarbon production of Woodford Shale-only gas and oil well completions (2004-2014) in the Anadarko Basin of western Oklahoma.

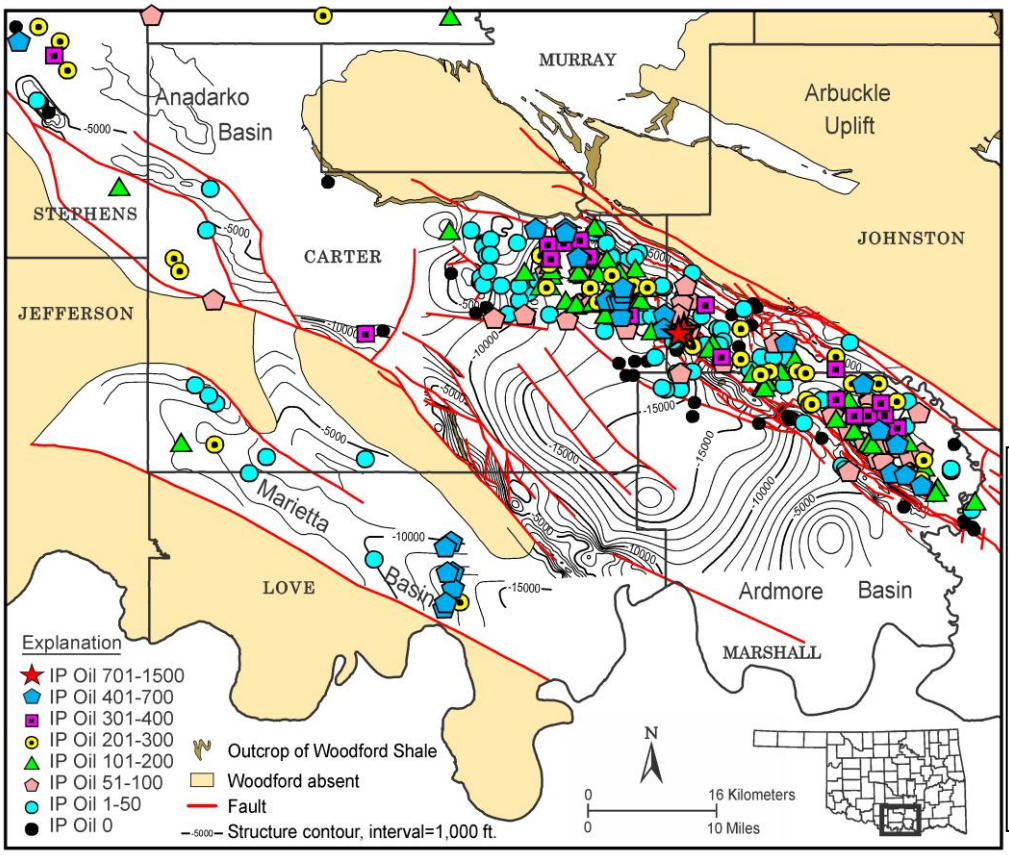


Figure 7. Map showing initial potential liquid hydrocarbon production of Woodford Shale-only gas and oil well completions (2004-2014) in the Ardmore and Marietta basins of southern Oklahoma.

Of 36 operators active in Oklahoma shales during 2014, the top nine operators (for number of wells drilled during 2014) are:

(1) Devon Energy Production Co. LP (195)
(2) XTO Energy (94)
(3) Continental Resources (64)
(4) Newfield Exploration Mid-Continent Inc. (35)
(5) American Energy – Woodford (28)
(6) Cimarex Energy (26)
(7) Pablo Energy II LLC (17)
(8) Jones Energy LLC (16)
(9) Silver Creek Oil & Gas (10)

Canadian Shales

By Jock McCracken (Egret Consulting)

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 kilometres (540,000 sq. mi) of Western Canada including southwestern Manitoba, southern Saskatchewan, Alberta, northeastern British Columbia, southeast corner of the Yukon and the southwest corner of the Northwest Territories. It consists of a massive wedge of sedimentary rock extending from the Rocky Mountains in the west to the Canadian Shield in the east. This wedge is about 6 kilometres (3.7 mi) thick under the Rocky Mountains, but thins to zero at its eastern margins. The WCSB 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.

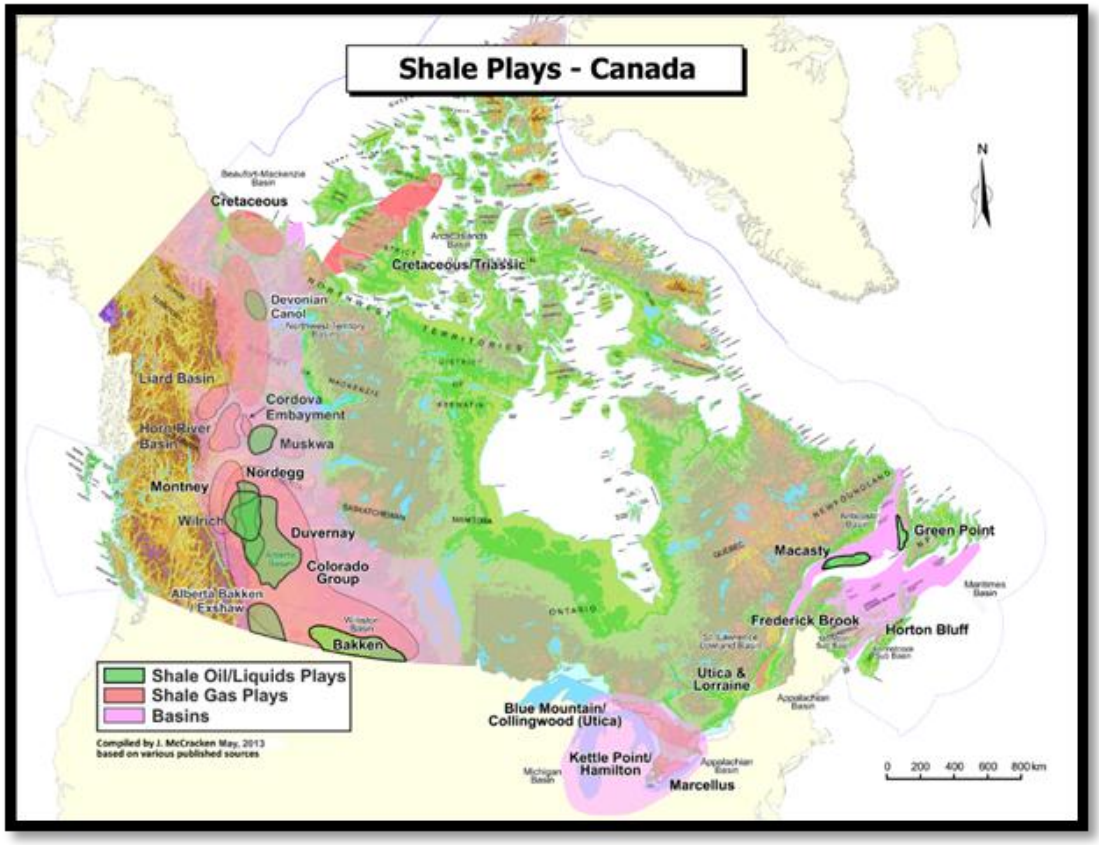
The first announcement of new discoveries in shale occurred in Canada at the beginning of 2008, seven years ago. Now, about 25% of Canada's natural gas is coming from unconventional which would include tight sands. The state of development for the shale plays range from speculative to exploratory to 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 prices operators have been focusing exploration and production into the liquids-rich hydrocarbons. 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 shales that have been disappointments for technical and regulatory reasons. Significant shale gas wells have been drilled and tested in the St. Lawrence Lowlands of Québec but a government freeze on fracking because of environmental concerns will slow or stop any future exploration and production. The positive announcements 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/

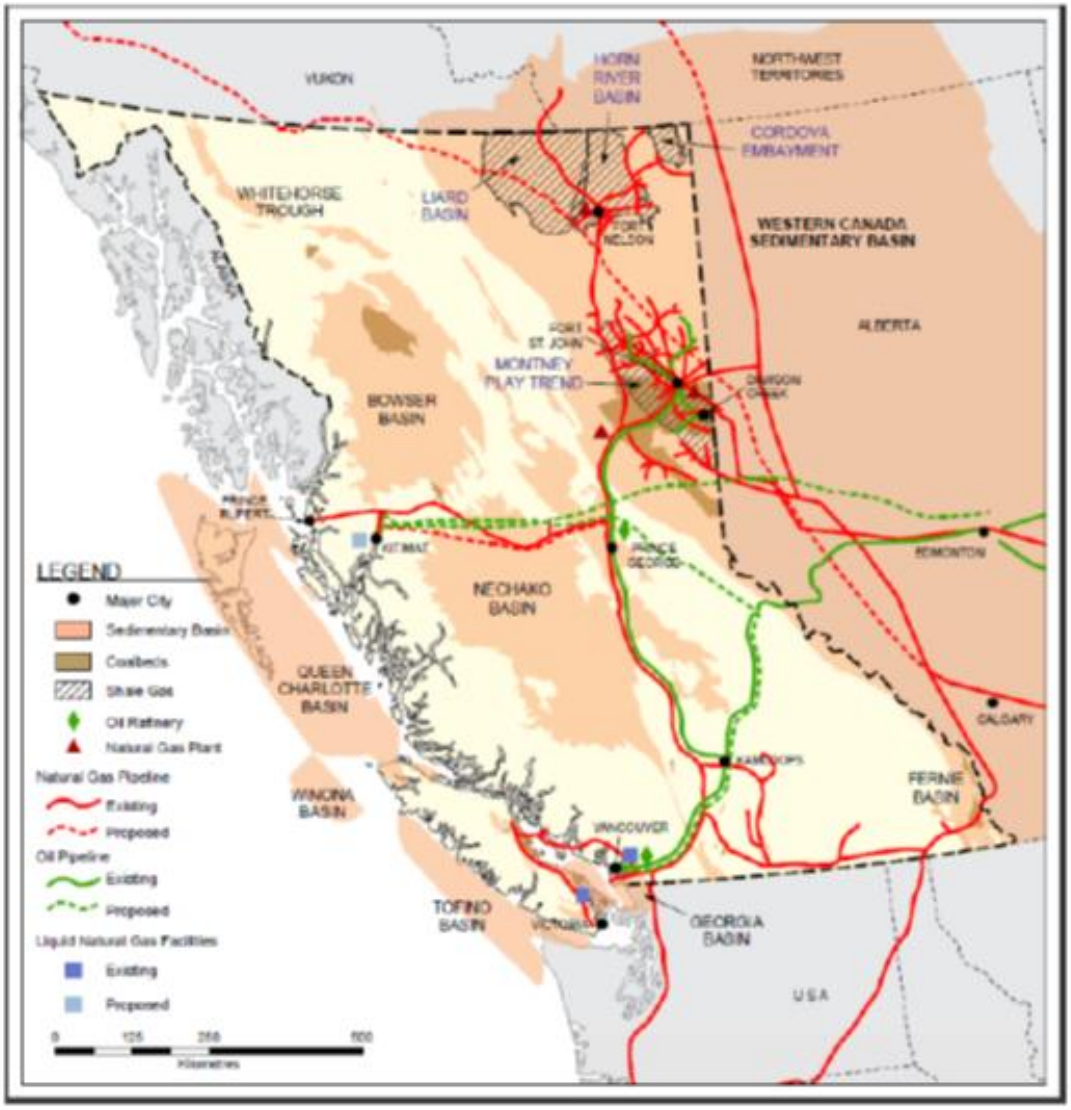
Quebec, Nova Scotia, New Brunswick and the Yukon effectively have put hydraulic fracking under partial or full moratorium with Newfoundland and North West Territory under review. Alberta recently updated their regulations. It is hopeful, at the end of this discussion, hydraulic fracturing will be managed such that it will minimize potential risks and allow the public to have a balanced and realistic sense of the costs and benefits.

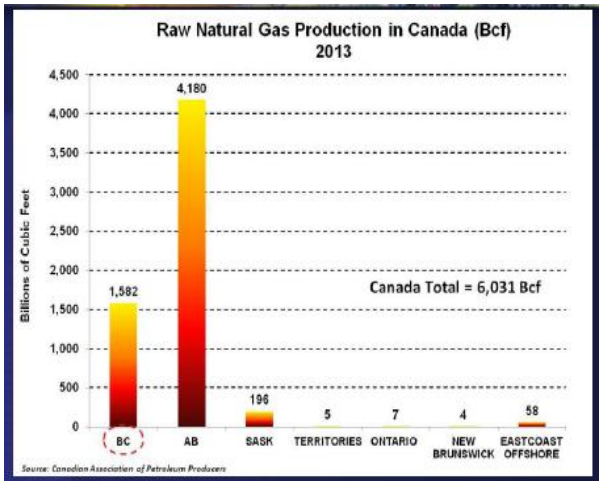


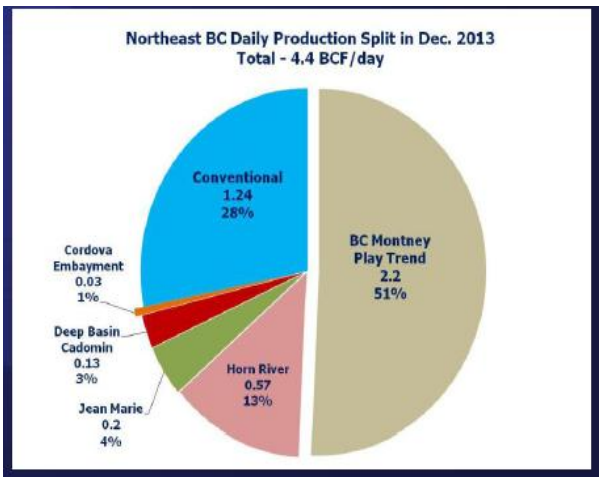
NORTHEAST BRITISH COLUMBIA

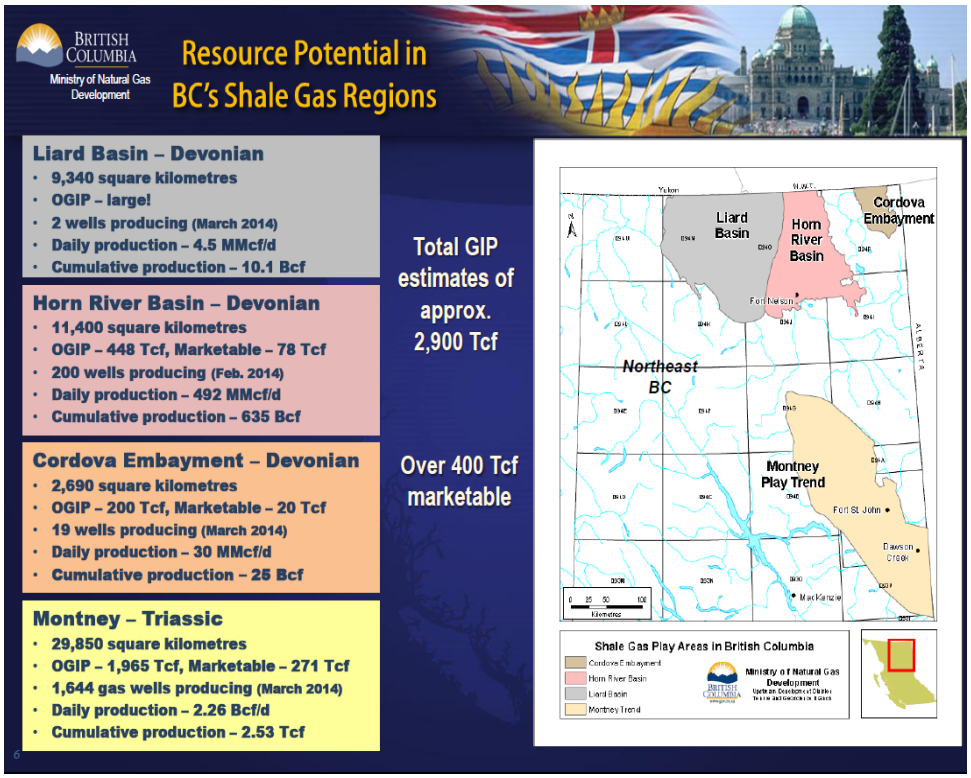
Northeast British Columbia contains Cretaceous to Devonian aged shale deposits that potentially could contain 2900 TCF of natural gas in place of which over 400 TCF is estimated to be marketable with about 70% being unconventional. The gas production keeps ramping upward with 1.58 TCF (4.4 BCF/D) raw 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

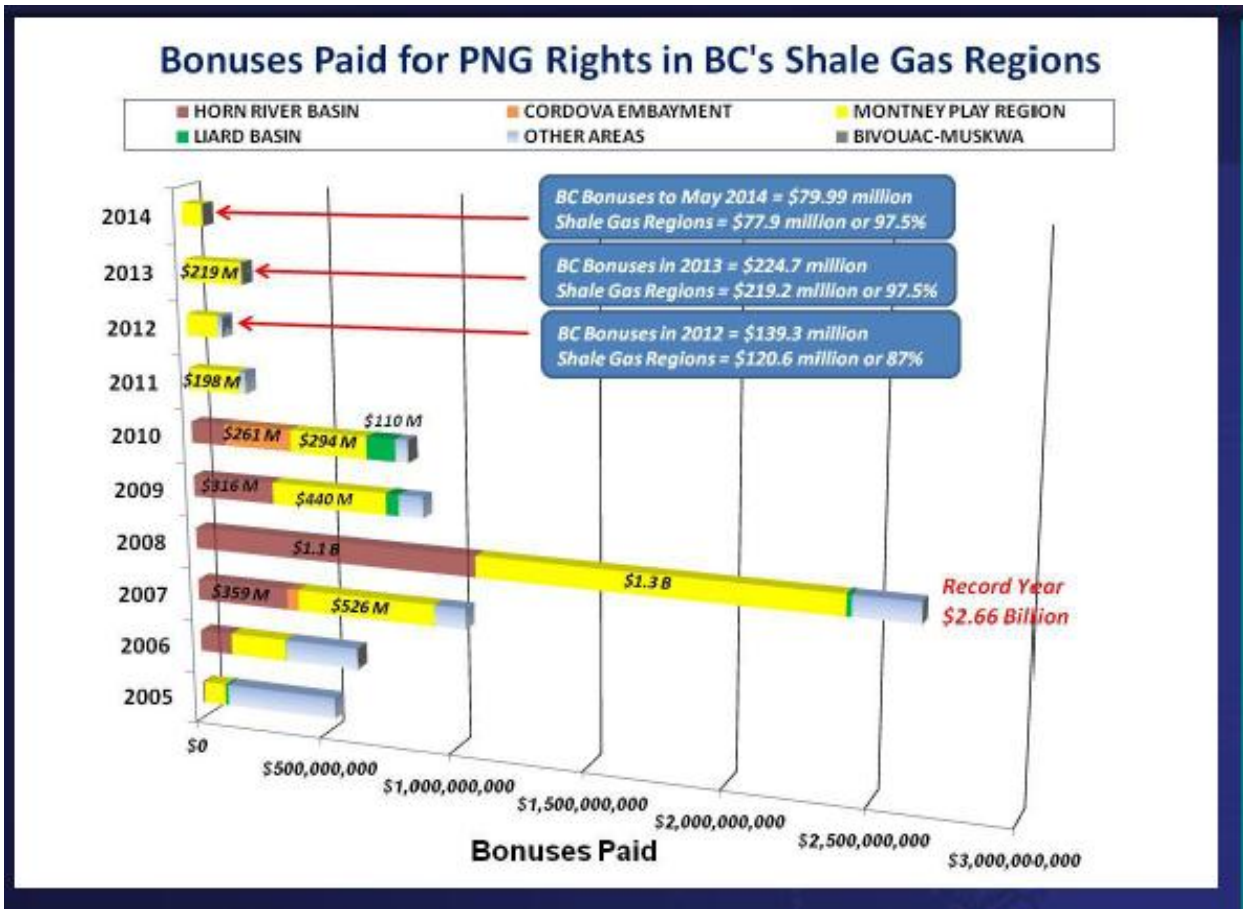
British Columbia has developed a Natural Gas and Liquefied Natural Gas Strategies considering the immensity of this resource.

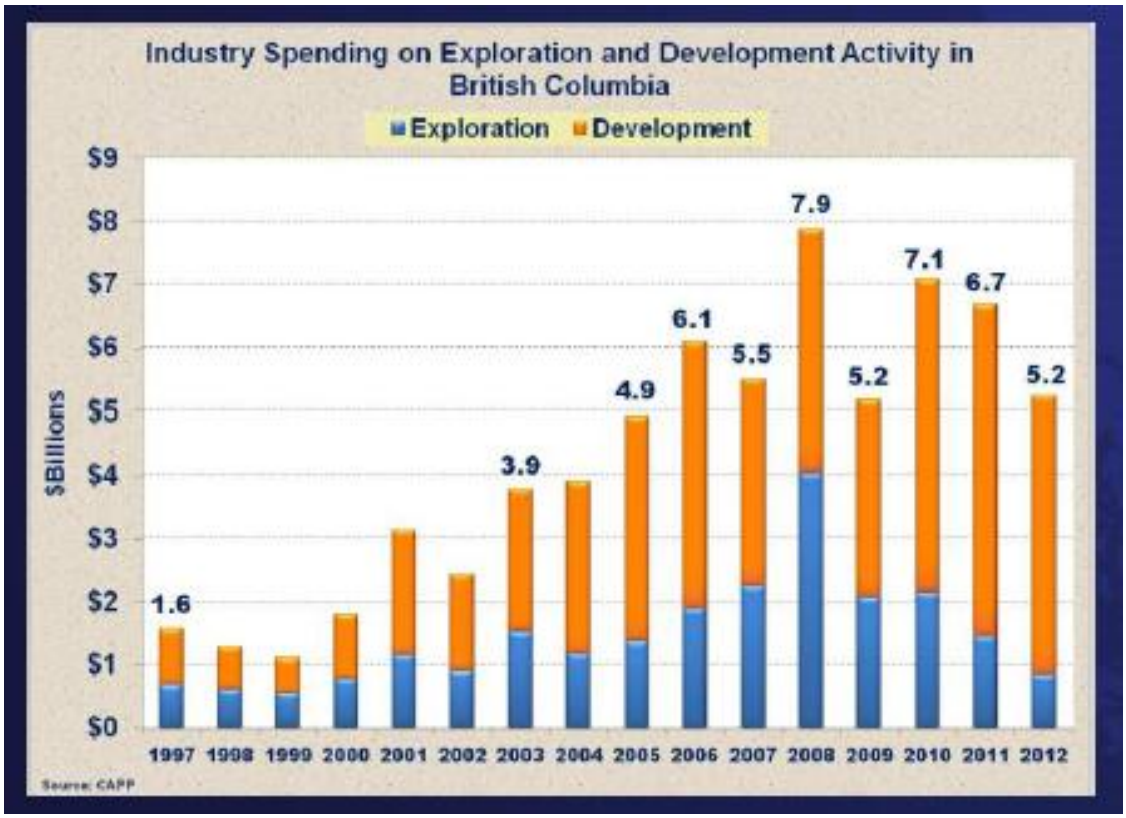

YUKON
NORTHWEST TERRITORIES
HORN RIVER BASIN
CORDOVA EMBAYMENT
WHITEHORSE TROUGH
LIARD BASIN
FORT NELSON
WESTERN CANADA SEDIMENTARY BASIN
ALBERTA
FORT ST JOHN
MONTNEY PLAY TREND
DAWSON CREEK
BOWSER BASIN
PRINCE RUPERT
KITIMAT
PRINCE GEORGE
EDMONTON
NECHAKO BASIN
QUEEN CHARLOTTE BASIN
CALGARY
KAMLOOPS
WINONA BASIN
FERNIE BASIN
VANCOUVER
TOFINO BASIN
VICTORIA
GEORGIA BASIN
USA
LEGEND
Major City
Sedimentary Basin
Coalbeds
Shale Gas
Oil Refinery
Natural Gas Plant
Natural Gas Pipeline
Existing
Proposed
Oil Pipeline
Existing
Proposed
Liquid Natural Gas Facilities
Existing
Proposed
0
125
250
500
Kilometres


Raw Natural Gas Production in Canada (Bcf)
2013
Billions of Cubic Feet
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
1,582
4,180
196
5
7
4
58
Canada Total = 6,031 Bcf
BC
AB
SASK
TERRITORIES
ONTARIO
NEW BRUNSWICK
EASTCOAST OFFSHORE
Source: Canadian Association of Petroleum Producers

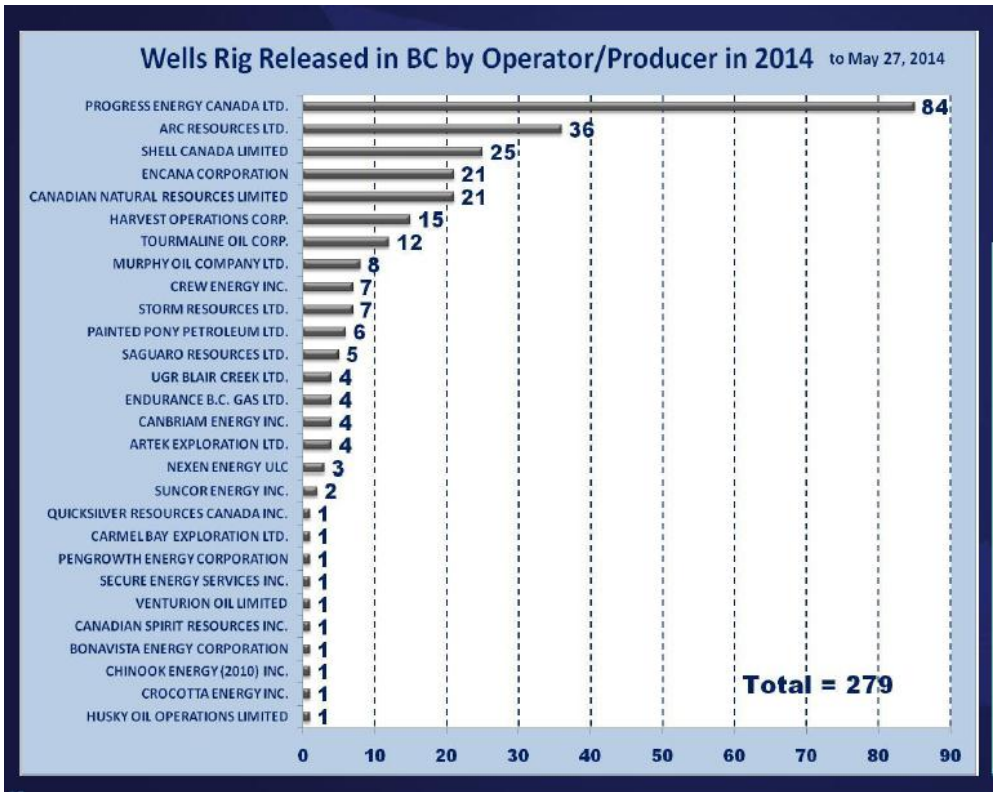

Northeast BC Daily Production Split in Dec. 2013
Total - 4.4 BCF/day
Conventional
1.24
28%
BC Montney Play Trend
2.2
51%
Cordova Embayment
0.03
1%
Deep Basin Cadomin
0.13
3%
Jean Marie
0.2
4%
Horn River
0.57
13%


British Columbia
Ministry of Natural Gas Development
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
Liard Basin
Horn River Basin
Cordova Embayment
Northeast BC
Montney Play Trend
Fort Nelson
Fort St John
Dawson Creek
Mackenzie
Shale Gas Play Areas in British Columbia
Cordova Embayment
Horn River Basin
Liard Basin
Montney Trend
Ministry of Natural Gas Development


Bonuses Paid for PNG Rights in BC's Shale Gas Regions
HORN RIVER BASIN
CORDOVA EMBAYMENT
MONTNEY PLAY REGION
LIARD BASIN
OTHER AREAS
BIVOUAC-MUSKWA
BC Bonuses to May 2014 = $79.99 million
Shale Gas Regions = $77.9 million or 97.5%
BC Bonuses in 2013 = $224.7 million
Shale Gas Regions = $219.2 million or 97.5%
BC Bonuses in 2012 = $139.3 million
Shale Gas Regions = $120.6 million or 87%
2014
2013
2012
2011
2010
2009
2008
2007
2006
2005
$219 M
$198 M
$261 M
$294 M
$110 M
$316 M
$440 M
$1.1 B
$1.3 B
$359 M
$526 M
Record Year
$2.66 Billion
$0
$500,000,000
$1,000,000,000
$1,500,000,000
$2,000,000,000
$2,500,000,000
$3,000,000,000
Bonuses Paid

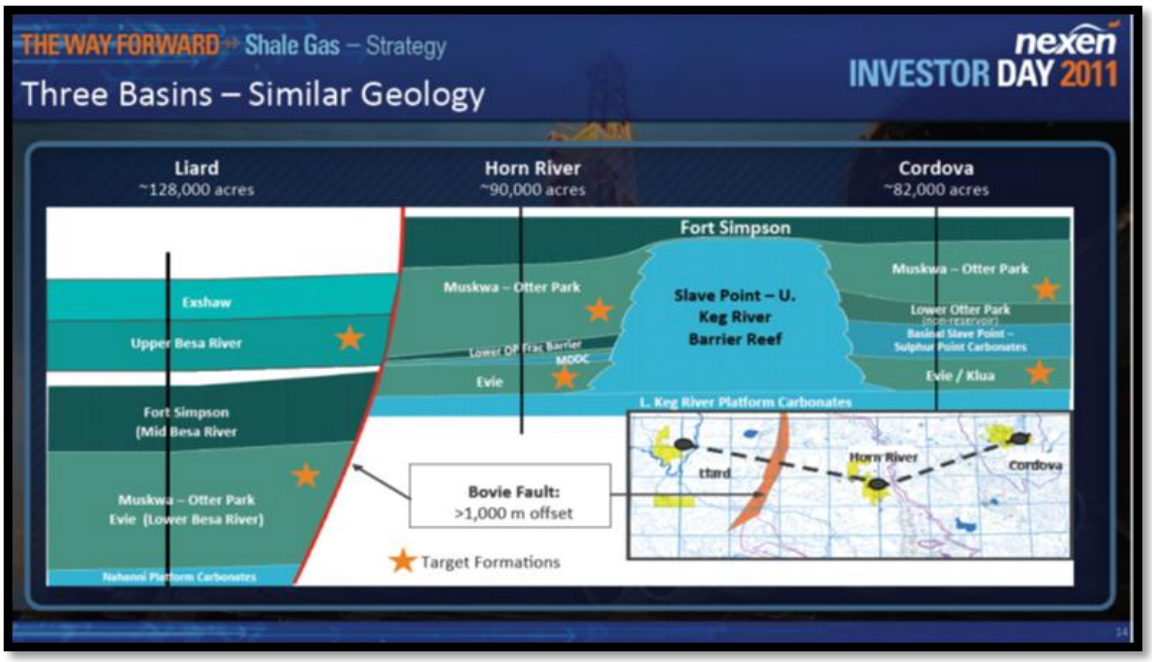


The gas production for the Horn River and Montney as presented by D. Allan. http://www.csur.com/resources/csur-presentations

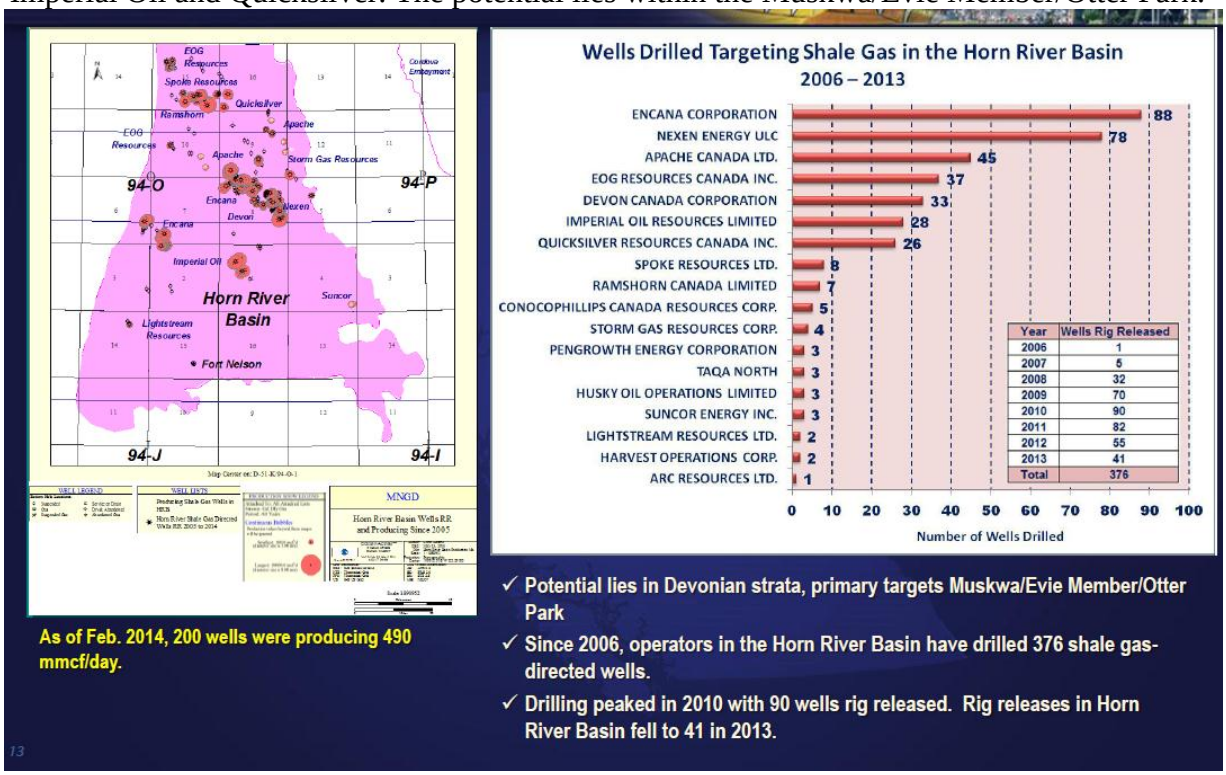


Upper and Middle Devonian, Evie (Klua), Otter Park and Muskwa members of the Horn River Formation Horn River Basin, Cordova Embayment and the Liard Basin

Of these very far north basins, the Horn River has the most activity. As of Feb. 2013 there were 200 wells producing 490 MMCF/D. increasing from roughly 80 MMCFD at the end of 2009 and a cumulative gas production of approximately 635 BCF.



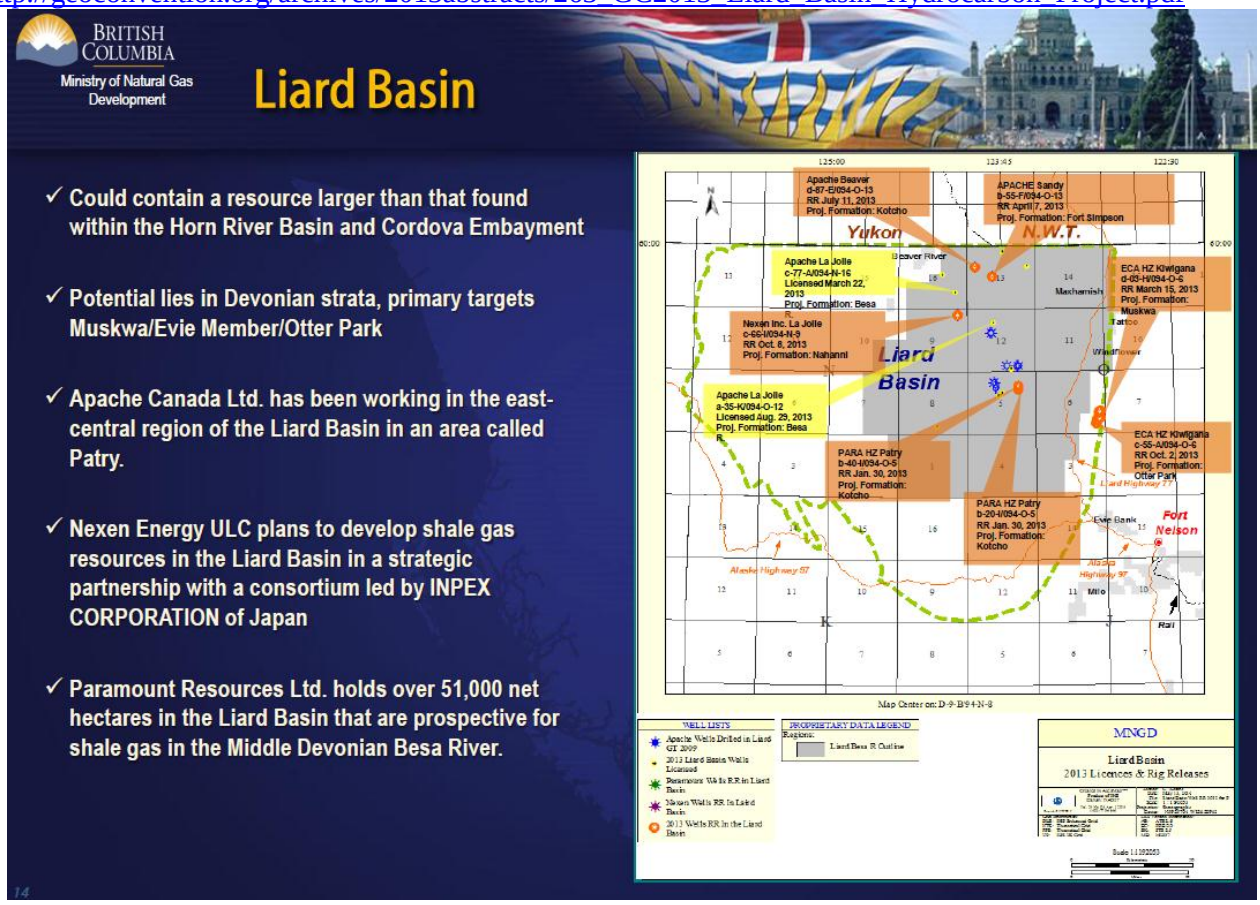
The seven companies with the most drilling, as of end of 2013 were Encana, Nexen, Apache, EOG, Devon, Imperial Oil and Quicksilver. The potential lies within the Muskwa/Evie Member/Otter Park.

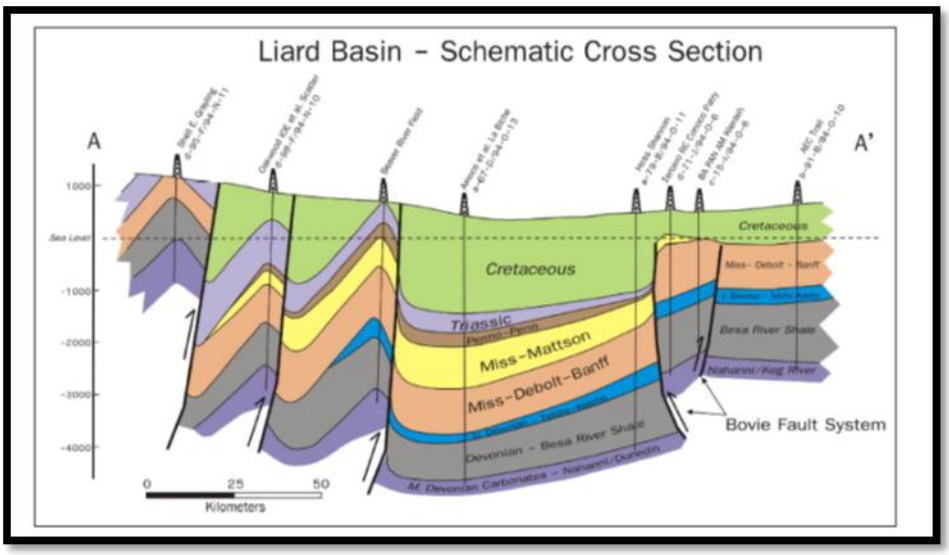


The Laird Basin, straddling the Yukon, North West Territory and British Columbia, containing has great potential with 3 million acres and 5 kilometres of section from the Cambrian to the Upper Cretaceous. It remains relatively unexplored with only a few recent shale-targeted wells but Houston-based independent 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

http://geoconvention.org/archives/2013abstracts/263_GC2013_Liard_Basin_Hydrocarbon_Project.pdf



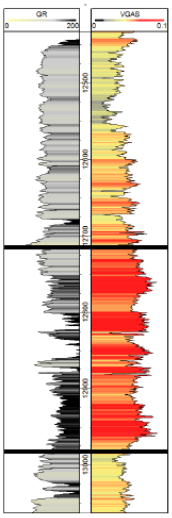


From Apache presentation Jun 2012.

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 Apache

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

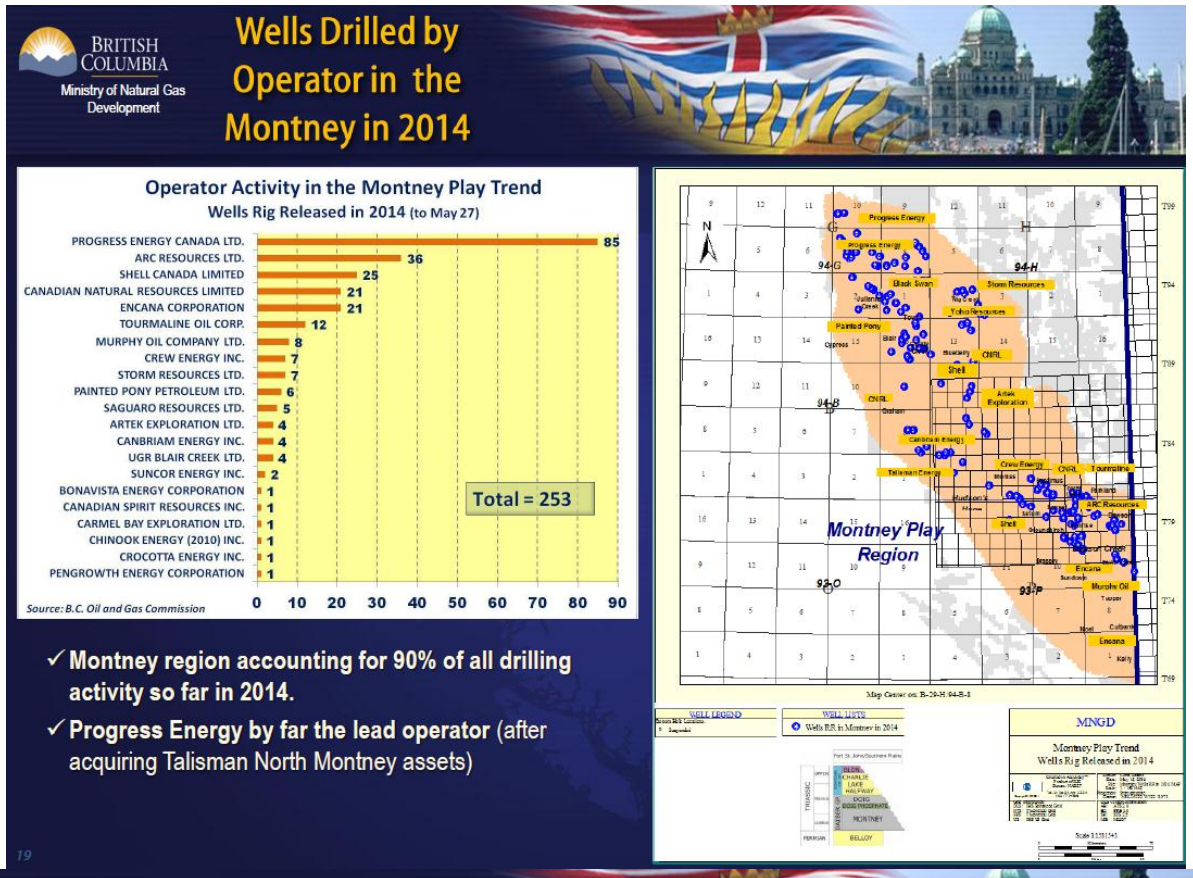
The company's vertical C-86-F well went to 15,000 ft. and had a 30-day initial potential of 9.8 MMCFD, and the vertical D-28-B well went to 13,200 ft. and flowed 4.6 MMCFD. The two vertical wells had only a single frac apiece. Net pay thickness is 1,024 ft. at C-86-F and 708 ft. at D-28-B. In its development 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.

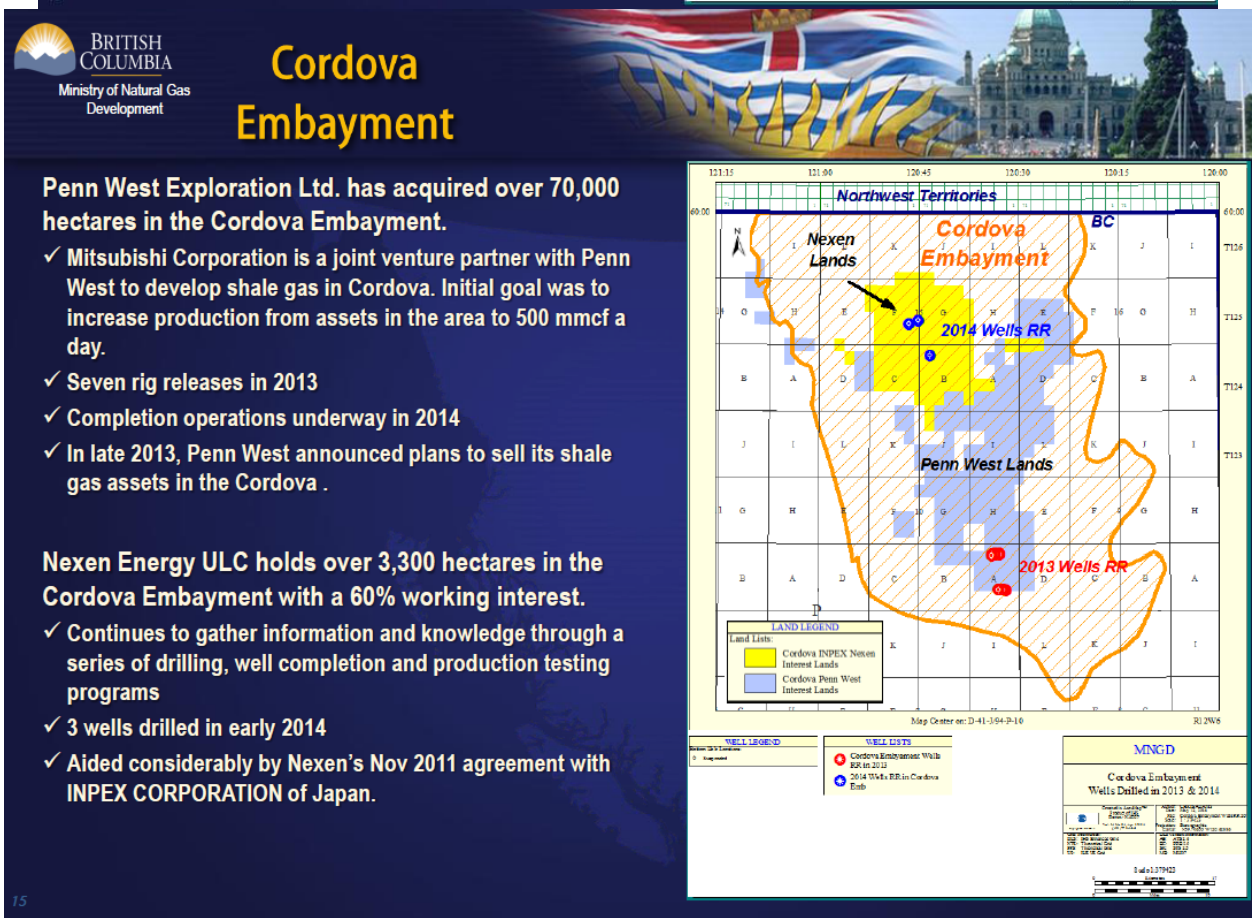
The Cordova Embayment area, an area of 936,000 acres where most blocks of land were purchased in 2007, is now being drilled. B.C. has an experimental scheme ownership where operations are kept confidential for three years of which Nexen, Penn West and Canadian Natural Resources Ltd. have participated.

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

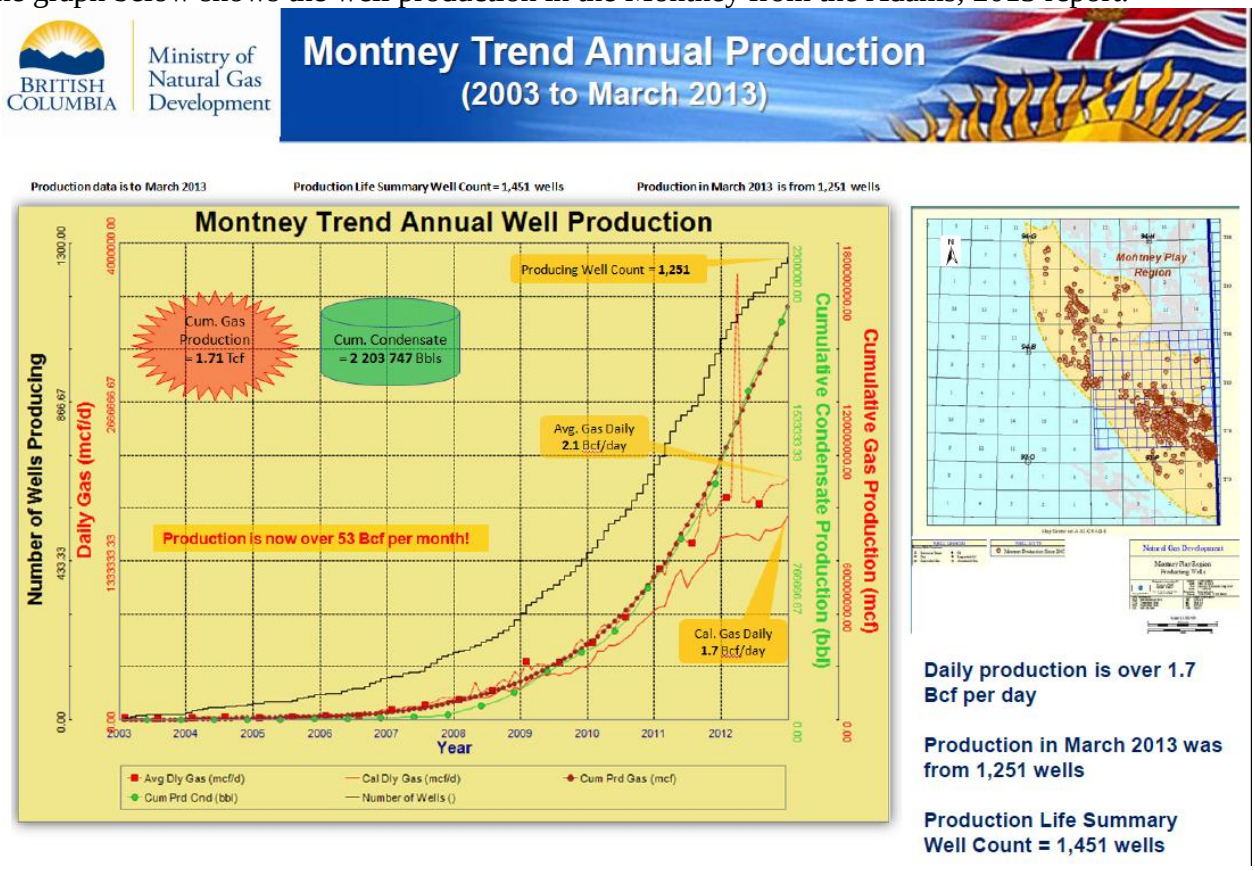
The Montney is a liquids-rich tight gas/shale gas play, now producing at more than 2.3 BCFD as of June 2014. This Montney Play Trend, of 6.6 million acres, is now one of the most active natural gas plays in North America. The primary zones are the Upper Middle and Lower Montney as well as the Doig and 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.

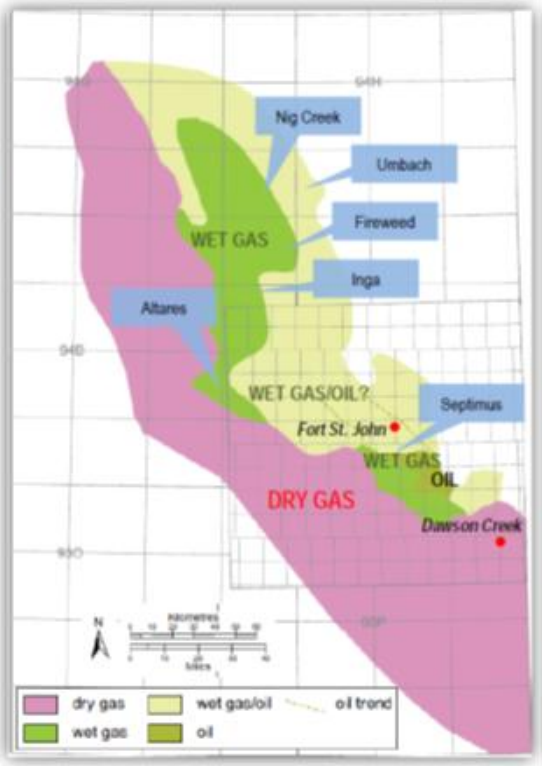




The graph below shows the well production in the Montney from the Adams, 2013 report.

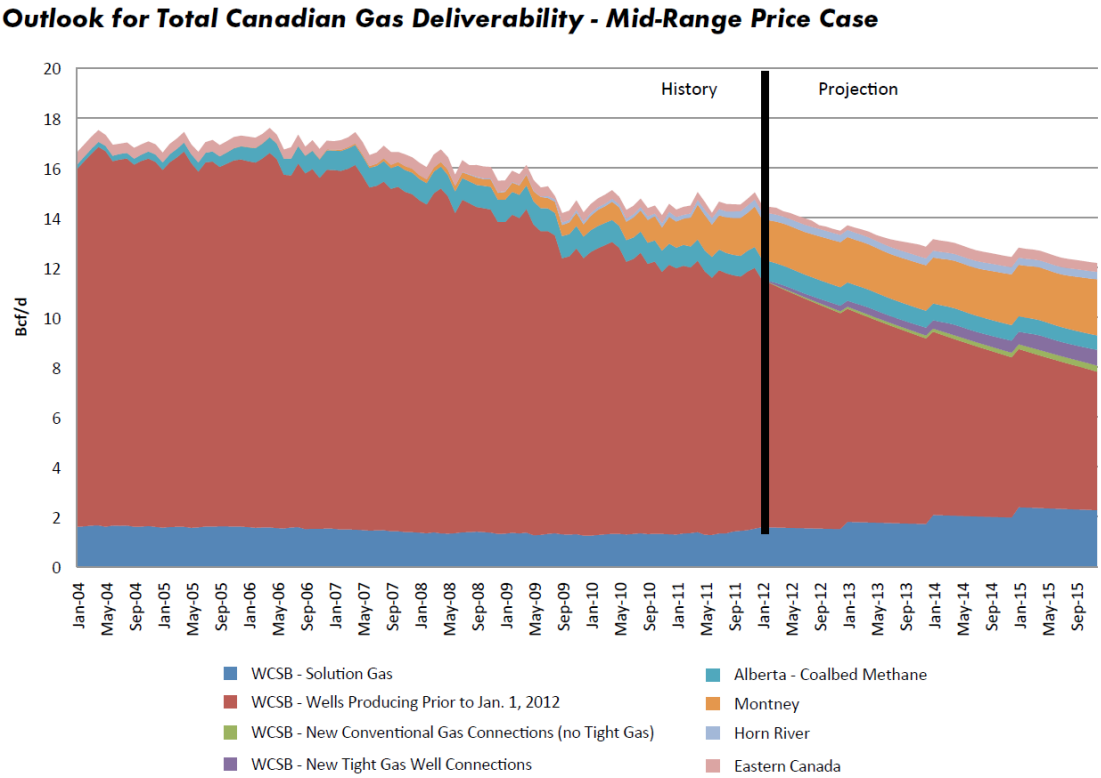


- Large proportion of the Montney play has economically benefitted by the presence of liquids rich gas.
- Focused development of the Montney wet gas trend began in 2009/2010 as natural gas commodity prices were falling.
- The current rate of development is not only an indication of the more favourable reservoir characteristics *(porosity, organic carbon content, pressures)*, but also a reflection of the higher natural gas liquid *(C2–C4)* and condensate *(C5–C12)* concentrations of the formation.
- Producers continue to push the limits of the northeastern, liquids-rich portion of the fairway.



Zones of dry gas, wet gas, wet gas+oil, and oil within the Montney Formation (derived from sales gas data). *Source: Geoscience Reports 2013, BC Ministry of Natural Gas Development*

The graph below shows the gas deliverability 2004 to 2015. Note the increasing Montney contribution. http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/ntrlgsdlvrblty20132015/ntrlgsdlvrblty20132015ppndc-eng.pdf



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

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.

NEB

http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/lsnd/pprtntsndchllngs20152006/pprtntsndchllngs20152006-eng.pdf

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.

Painted Pony Petroleum has 82,465 net acres of Buckinghorse potential with recompletion and testing of 3 wells and 2 more wells drilled. No production numbers announced yet as they experiment with drilling and completion techniques. They have announced that 2 existing wells will be fracked in 2013. Canadian Spirit is another player in the area, mostly with experimental schemes, on the Gething. No production volumes reported yet. Unconventional Gas Resources is experimenting with the Buckinghorse shale.

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 2,800 kilometres (1,700 miles) of natural gas transmission pipeline which can transport 2.9 BCFD. TransCanada Corp keeps expanding their pipeline infrastructure to meet supply and demand.

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

http://www.ceri.ca/images/stories/Examining_the_LNG_LPG_Puzzle_June_21_2014_Final.pdf

http://bit.ly/1pyT8DD

http://www.capp.ca/getdoc.aspx?DocId=233813&DT=PDF

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

http://engage.gov.bc.ca/lnginbc/

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://www.offshore-oil-and-gas.gov.bc.ca/OG/oilandgas/petroleumgeology/UnconventionalGas/Documents/C%20Adams.pdf

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

http://www.aapg.org/explorer/2010/10oct/regsec1010.cfm

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 though the collection, interpretation and marketing of publically available. Some of their major projects have been aquifer studies. http://www.geosciencebc.com/s/AboutUs.asp

This link below summarizes news items concerning the Horn River area. http://hornrivernews.com/

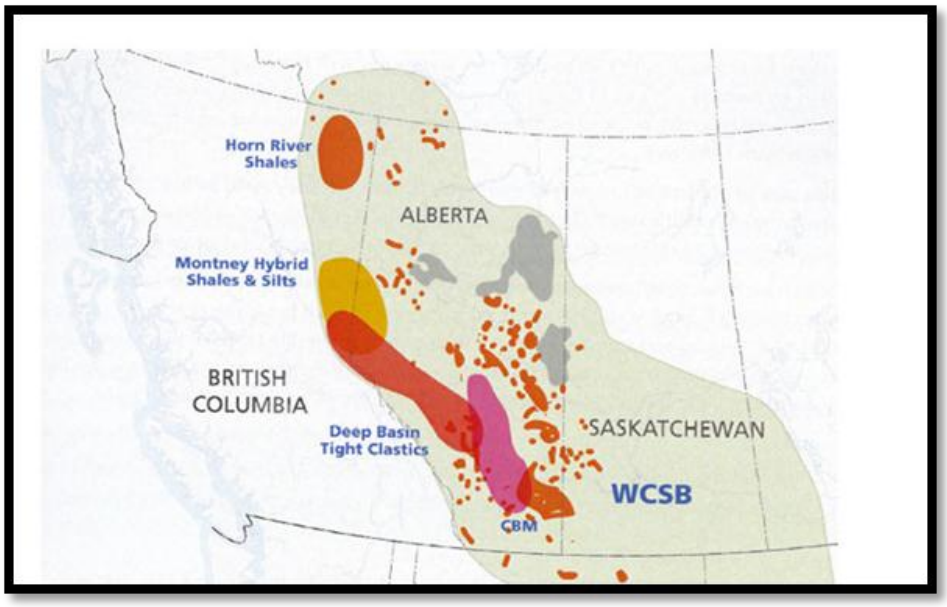
ALBERTA

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 but I have tried to remain current as possible.

The shales and tight rocks of the Western Canada Sedimentary Basin have been under investigation for the last number of years. The Alberta portion of this basin, Alberta Basin, has been studied thoroughly by Alberta Energy 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.

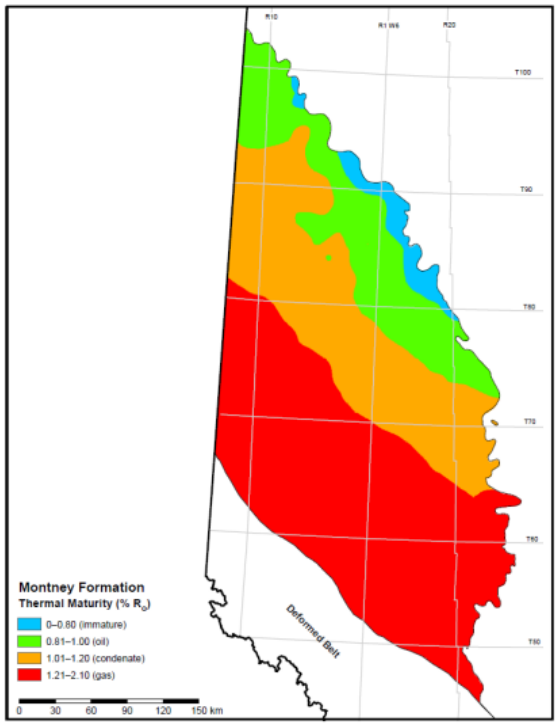


Figure 2.3.7. Thermal maturity map of the Montney Formation.

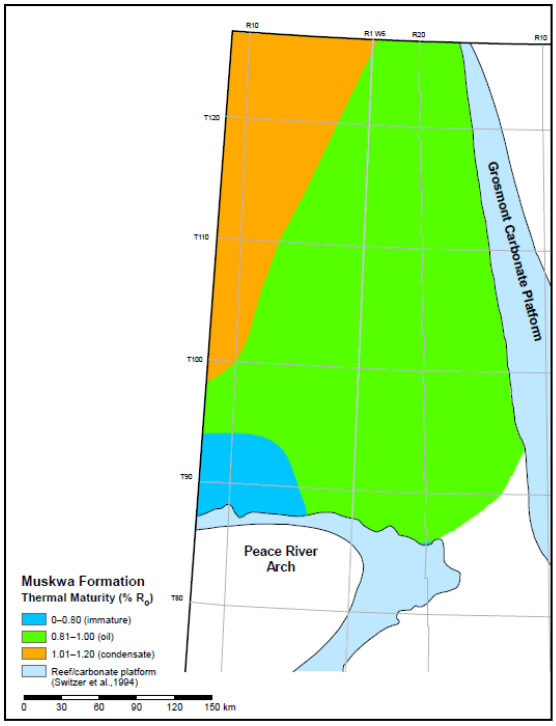


Figure 2.2.6. Thermal maturity map of the Muskwa Formation.

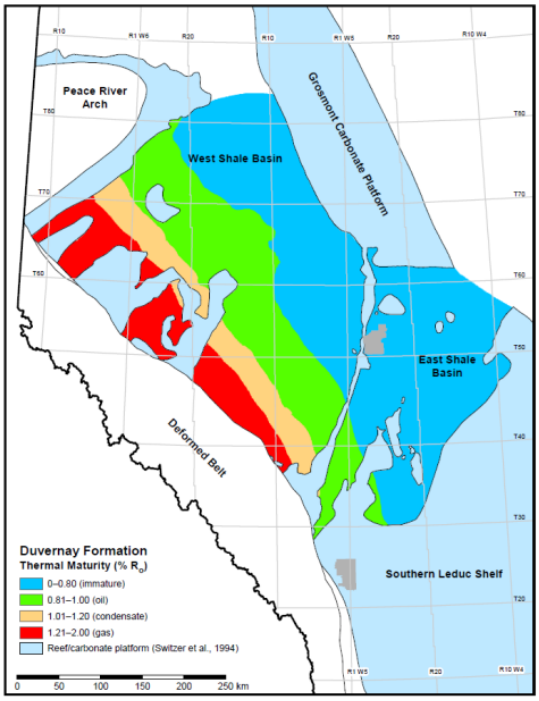


Figure 2.1.7. Thermal maturity map of the Duvernay Formation.

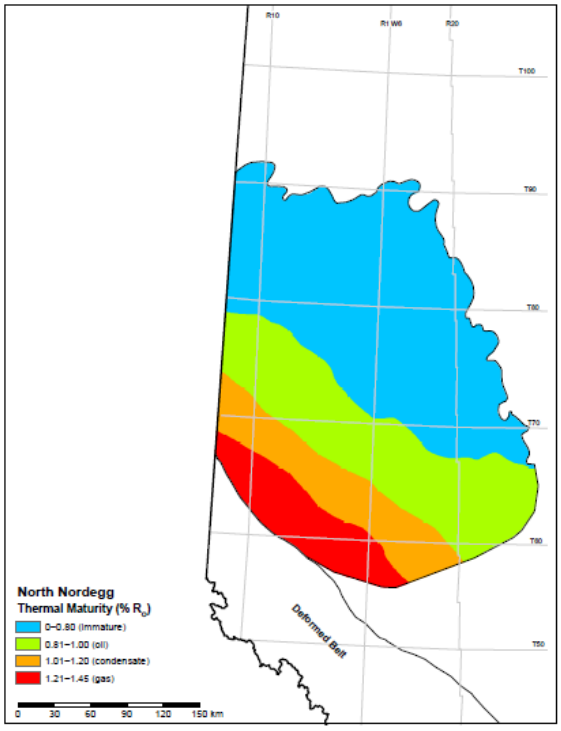


Figure 2.5.7. Thermal maturity map of the north Nordegg.

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

In November 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"

http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/ltmtptntlmntnyfrmtn2013/ltmtptntlmntnyfrmtn2013-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	90,559	**121,080**	153,103	8,952	**12,719**	18,257
(trillion cubic feet)	(3,197)	**(4,274)**	(5,405)	(316)	**(449)**	(645)
NGLs – million m^3	13,884	**20,173**	28,096	1,540	**2,308**	3,344
(million barrels)	(87,360)	**(126,931)**	(176,783)	(9,689)	**(14,521)**	(21,040)
Oil – million m^3	12,865	**22,484**	36,113	72	**179**	386
(million barrels)	(80,949)	**(141,469)**	(227,221)	(452)	**(1,125)**	(2,430)

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

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

Anglo Canadian Oil Corp. now Tallgrass Energy Corp. has been playing the potential of the Nordegg Member which is a source rock composed of basinal shales, silts and carbonates. They drilled a horizontal well to test this play producing limited liquids. Athabasca Oil Sands second Kaybob Nordegg horizontal well, at 04-11-63-20w5, offsetting its first Nordegg horizontal well. After a 16-stage slickwater frac and 4 days of clean-up, the 04-11 well made 335 b/d of 41° gravity oil and 500 MCFD of gas at 910 psig flowing pressure.

There are others in this play but information is tight: Penn West, EOG, Apache, Surge, Nordegg, Petro-Bakken, 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.

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

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

Hydrocarbon Type	In-Place			Marketable		
	Low	**Expected**	High	Low	**Expected**	High
Natural Gas – billion m^3	90,559	**121,080**	153,103	8,952	**12,719**	18,257
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(million barrels)	(87,360)	**(126,931)**	(176,783)	(9,689)	**(14,521)**	(21,040)
Oil – million m^3	12,865	**22,484**	36,113	72	**179**	386
(million barrels)	(80,949)	**(141,469)**	(227,221)	(452)	**(1,125)**	(2,430)

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[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.

NEB

http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/lsnd/pprtntsndchllngs20152006/pprtntsndchllngs20152006-eng.pdf

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

Devonian Duvernay/ Muskwa Shales

Western Alberta

The 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 has been spent on this play as of Jun 2012. This BMO Capital markets research report, June 2012, has a wealth of data on this play. Encana believes that this play is 2 times the size of the Eagle Ford Play.

https://bmo.can.idrsite.com/Login%20Page%20Document%20Library/ADLibrary/Presentations/BMO%20Duvernay%20DUG%20June%202012.pdf

http://www.junewarren-nickles.com/alberta-oil-and-gas-update/

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.

Athabasca has 200,000 high graded acres with approximately 1,100 locations and have reported IP30 rates of 600 – 1,400 BOE and EUR of 360- 1,000 MBOE.

Encana has accumulated a 343,000 acre position in this play and a well inventory (gross) of 1,400 – 1,450. Their EUR/well is 1,000 – 1,200 MBOE and some of the initial production are about 1,000 BOP/D. They recently announced a joint working interest with PetroChina. Encana's Duvernay comparison is shown below.

Duvernay – World Class Reservoir

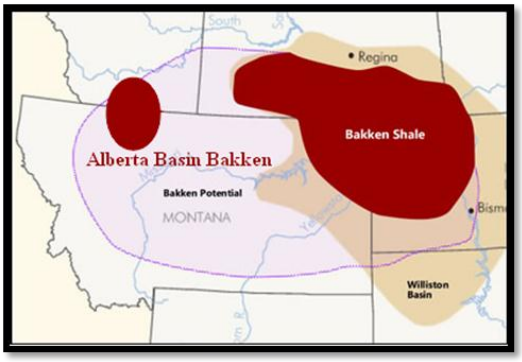
Encana controls one third of the top tier land in the condensate window*

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"

Late Devonian and Early Mississippian Alberta Bakken – Exshaw Southern Alberta

The Alberta Bakken (Exshaw) is another emerging tight oil resource play 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 has recently emerged into Alberta and there is 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 in this play. Over 30 horizontal wells have been drilled so far but with little publication of results. Crescent Point, Shell, Penn-West, Murphy, Torc, Argosy, Primary, Nexen, Bowood/Legacy, Rosetta and Newfield are some of the companies involved. Crescent Point Energy has a significant land base and drilled eight wells in the 4th quarter of 2012. Murphy is drilling 6 to 9 wells with 5 drilled to date: 3 producers, one being evaluated and one awaiting completion. They have announced tests of 415 to 800 BOPD. 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 ^{o} API oil. They have drilled 17 horizontal wells into this zone in 2012. Torc has reported that two of their wells have yielded IP rates of 510 and 514 BOPD. See Zaitlin 2011 and 2012.



The Alberta Energy Resources Conservation Board (ERCB) just recently published a document to clarify the definition of shale for shale gas development and to identify the geological strata from which any gas production will be considered to be shale gas.

http://www.ercb.ca/docs/documents/bulletins/Bulletin-2009-23.pdf

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

The ERCB is the regulator for Alberta. http://www.ercb.ca/portal/server.pt

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

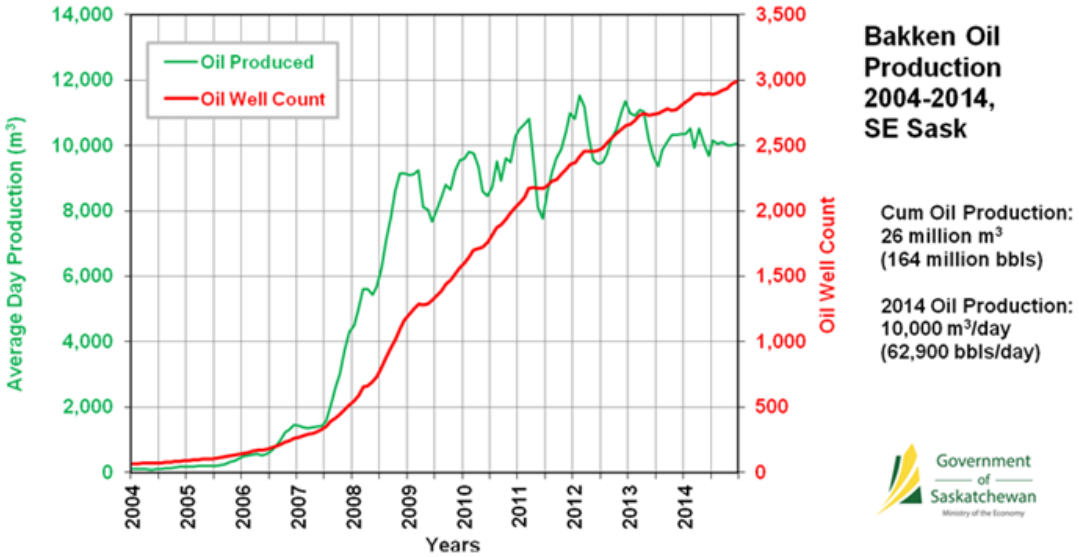
PanTerra Resource Corp. have drilled and cased thirty-six wells within their more than one million acres of land. They feel they have 3 TCF of recoverable gas. They had been coring, logging and fracture stimulating but no rates have been announced to date. Because of the low gas prices they have put 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 48,000 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.

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 ^{o} API gravity. 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 one big Bakken producer with 20,742 BOEPD and >1,200 drilling locations. Their strategy is to sell their Bakken business unit within the next 12-24 months.



Saskatchewan Government energy and resources is the regulator.
http://www.er.gov.sk.ca/Default.aspx?DN=4c585c56-193a-485a-91fd-7c49f0104a60

MANITOBA

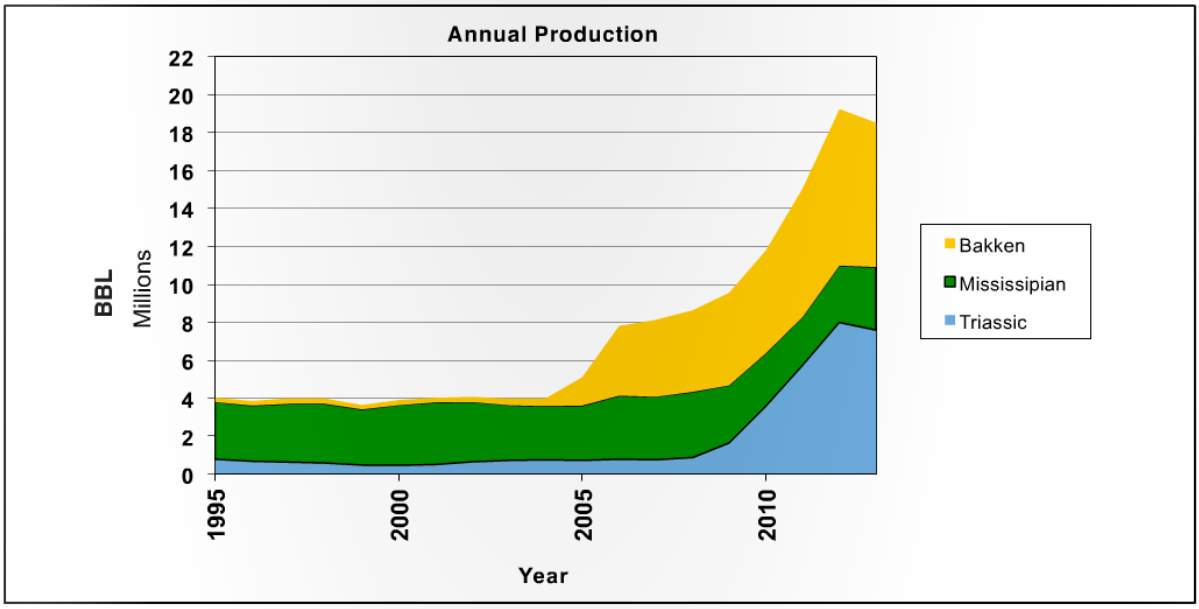
Cretaceous Colorado Group

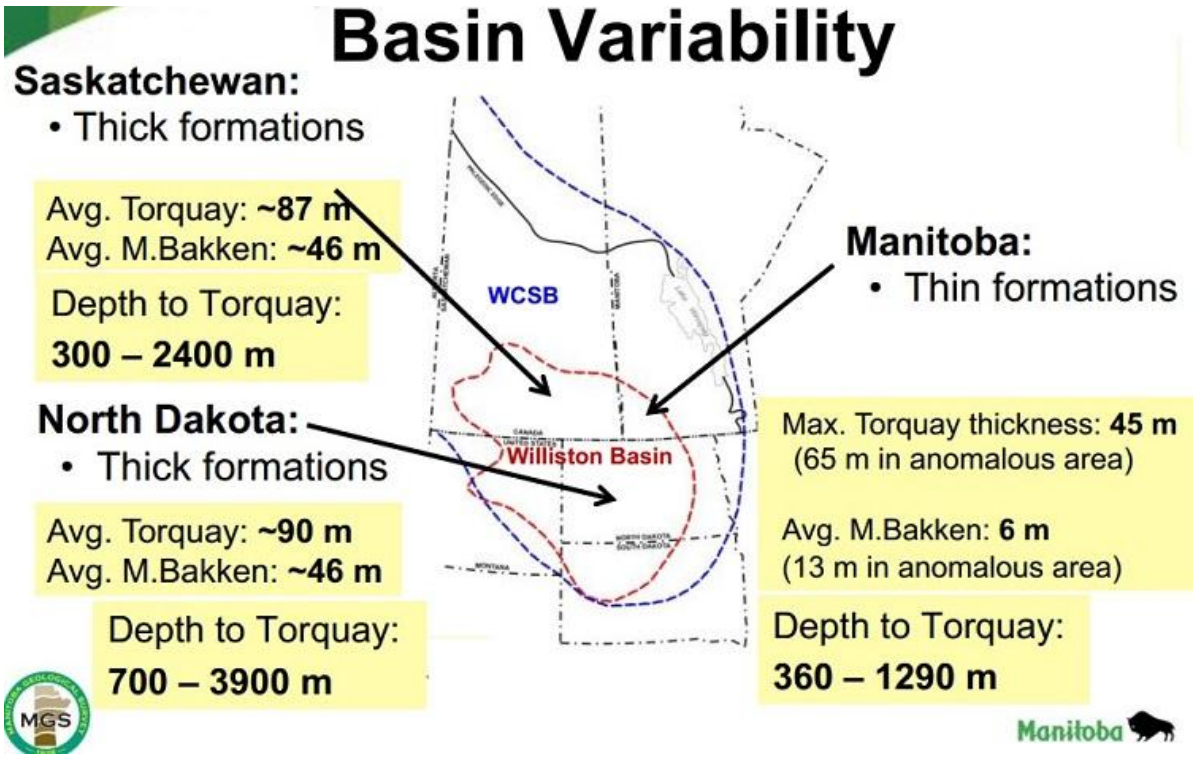
There is the potential of shale gas in Manitoba, but no activity or production. There have been a number of publications on the shallow shale potential by Nicholas and Bamburak.
http://www.wbpc.ca/assets/File/Presentation/11_Nicolas_Manitoba.pdf and Nicholas 2011
http://www.wbpc.ca/assets/File/2011%20Presentations/Tuesday/Nicolas%20WBPC%202011_Shale%20gas%20to%20Three%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.





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

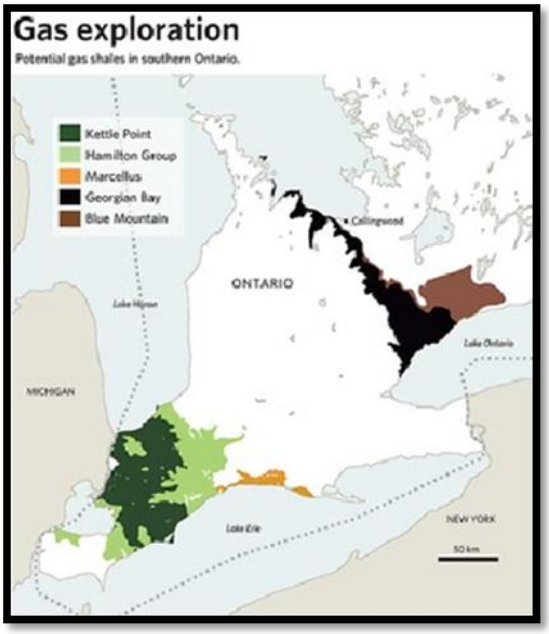
Upper Devonian Kettle Point Shale (Antrim Shale Equivalent)
Middle Devonian Marcellus Shale
Upper Ordovician Blue Mountain and Collingwood Shale (Utica Equivalent)

Exploitation of these shales has been very quiet with only a few operators discussing the evaluation of these shale targets. These shales are mostly considered secondary targets but only one well has been drilled to test these zones to date. 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 Quebec, within a 300 km by 100 km fairway between Montreal and Quebec. 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, Quebec's advisory office of environmental hearings published a report in Dec 2014 that found shale gas development in the Montreal-to-Quebec City region wouldn't be worthwhile. The Bureau d'audiences publiques sur l'environnement (BAPE) warned of a "magnitude of potential impacts associated with shale gas industry in an area as populous and sensitive as the St. Lawrence Lowlands."

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

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

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 Quebec.
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. Canbrian, 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/assets/files/PDF/101121_QEC_Presentation-Update.pdf

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/investors/documents/March2011TechnicalPresentationonAnticostiIsland.pdf
http://www.corridor.ca/documents/Martel_Anticosti_NAPE_2012.pdf
http://www.corridor.ca/media/2011-press-releases/20110713.html
http://www.petroliagaz.com/imports/pdf/en/18168.Petrolia.FinalReport.pdf
Utica Emerges in Quebec Shale Play Extends to Canada by Susan Eaton
http://www.aapg.org/explorer/2010/01jan/shale0110.cfm

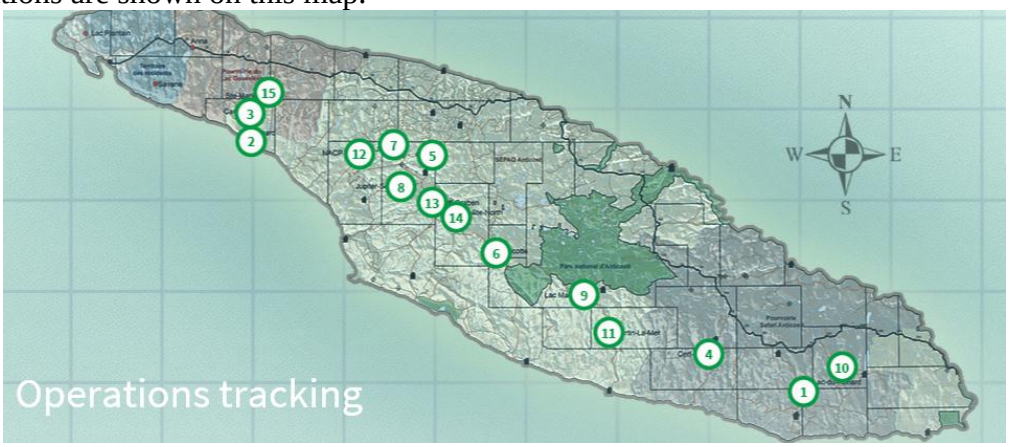
Quebec announced Feb. 13 2014 that it would move ahead with oil exploration on Anticosti with the province pledging $115-million to finance drilling for two separate joint ventures.

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

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

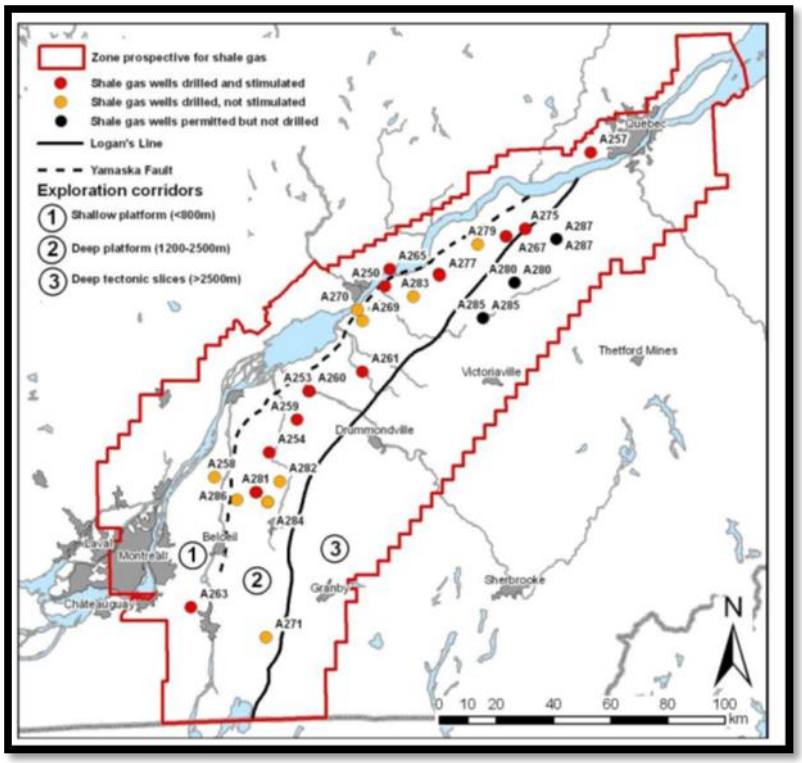
APGQ/QOGA Energy Inc. with annual Quebec Shale Conferences.

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

Ministère des Resources 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, Quebec: 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**.**

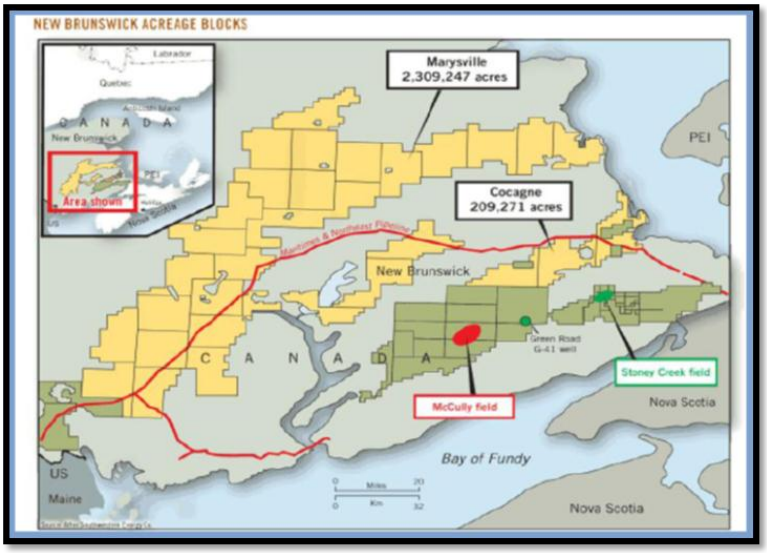
The Play History

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 O-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 2011and then $14.2 million in 2012 with possible well(s).They finished their seismic program in Dec 2013.

https://www.swnnb.ca/



"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 is 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 is moving ahead with legislation that would ban high-volume hydraulic fracturing for onshore oil and gas, 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 producabilty.

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.

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. Pieridae Energy (Canada) Ltd. ("Pieridae") is pleased to announce that the Province of Nova Scotia, has issued environmental assessment (EA) approval, with conditions, for company's proposed Goldboro LNG project in March of 2014.

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/J%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/

NORTHWEST TERRITORIES

Devonian Canol Shale

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, ConocoPhillips and Husky Energy 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

MGM (Now Paramount) in partnership with Shell, who farmed in, were the first to announce the results of drilling and hydraulic fracking 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. 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 drilled two vertical exploratory wells into the oil mature Devonian- aged Canol and Hare Indian/ Bluefish Shales south of the community of Norman Wells in the Central Mackenzie Valley. 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). 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.680news.com/2015/04/14/minister-says-yukon-must-pull-its-weight-as-government-paves-way-for-fracking/

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/

Other Important Canadian Websites

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
2015 Oct 20 - 22 at the BMO Center Stampede Park in Calgary, AB.
http://www.spe.org/events/urc/2015/
Note that they have technical luncheons for members.
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 2015: New Horizons: Calgary TELUS Convention Centre, May 4 - 9
http://www.geoconvention.com/
CSPG Courses
http://www.cspg.org/CSPG/IMIS20/Technical/Short_Courses_Field_Seminars/CSPGIMIS20/Technical/ConEd/Short_Courses_Field_Seminars.aspx?hkey=266465fc-f8ff-42eb-a4df-0ab6a3d2615f

Other Meetings

CI Energy Group's 10th Annual Shale Oil & Gas Symposium, January 28-29, 2014 in Calgary
http://www.shalegassymposium.com/
2015 no conferences announced

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/
9th BC Unconventional Gas Technical Forum June 08 - June 09, 2015 Victoria Conference Centre, Victoria B.C.
https://ugtf.ener.gov.bc.ca/Register.aspx?CourseID=11
2015 Williston Basin Conference, April 28 - 30, 2015 | Evraz Place, Regina, Saskatchewan, Canada
http://www.wbpc.ca/

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 http://www2.gnb.ca/content/gnb/en/departments/energy/conference/Conf_home.html
9th International Symposium of West Newfoundland Oil and Gas 10-11 Sept 2014, Corner Brook area of West Newfoundland. No announcements of the 2015 date yet.
http://www.wnloilandgas.com/international-symposium/

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Shale Gas/Shale Oil in Europe

By Ken Chew

Summary of the year April 2014 – March 2015

The issues that surround shale liquids and gas development in Europe can be significantly different from those encountered to date in North America and it is likely that a different socio-economic model will be required if development is to proceed. Population density is high, as are levels of local authority planning controls and environmental controls. Public awareness of environmental issues is also high. Mineral rights are generally vested in the state, resulting in little benefit to landowners and the community from hydrocarbon production. Large-scale development will therefore only take place where communities and the public can see that risks are at a minimum and that some benefits will filter down to the community. As a consequence, Europe remains relatively unexplored for shale gas and, especially, shale liquids. In total some 125 exploration and appraisal wells with a shale gas exploration component have been drilled, including horizontal legs from vertical wells. 30 of these wells were 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 March 2014 has been limited to Poland, where 8 shale gas exploration wells were spudded, Romania, where a first shale gas well was drilled, England where 2 wells with a shale gas exploration element were drilled, and Sweden, where 6 shallow wells were drilled, 3 of which were put on a 3-month extended well test. One shale liquids test was drilled in Poland and a well in southern England also had a shale liquids component.

Opposition to hydraulic fracturing and shale oil and gas exploration at grassroots level in general remains strong and major protests have taken place in the United Kingdom and Romania. 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 and Wales). Proposed new environmental legislation led OMV to abandon its plans for shale gas exploration in Austria.

At European and some national political levels, one can detect a desire to permit and even encourage exploration. While Germany effectively introduced a moratorium on hydraulic fracturing in November 2013, the Spanish government has moved to explicitly legalise hydraulic fracturing and the European Commission clarified its position in January 2014 without issuing binding legislation.

Political institutions and major companies have noted the impact of shale gas and shale oil production on the U.S. economy and fear that European consumers are suffering from unduly high gas prices and that European companies are becoming uncompetitive compared with their North American rivals and even considering relocating businesses to North America. Politicians, especially in Eastern Europe, are expressing a desire for more energy independence and recent political upheavals in Ukraine have added to those concerns. In addition, technical experts such as the French Académie des Sciences and German Federal Institute for Geosciences and Natural Resources have challenged the views and reports of environmental authorities.

The geology, however, has not proved entirely favourable. Interest in the exploration potential of Poland has decreased significantly over the past year. Of 121 shale gas and shale liquid concessions awarded to date, 73 have now been relinquished, 48 of them in the past 12 months. Chevron, ExxonMobil, Marathon, Talisman, Eni and Total have all withdrawn from Poland leaving ConocoPhillips as the only significant international player. Of the 48 remaining concessions, 25 are now operated by three Polish companies - Polish state company PGNiG (11), PKN Orlen (8) and LOTOS Petrobaltic (7 offshore). In addition to Poland, Chevron has now exited shale exploration in Bulgaria, Lithuania, Romania and Ukraine in a refocus of its global exploration portfolio.

The best combination of geology and effective regulatory regime appears to be in the United Kingdom, where the UK government has shown considerable support for the emerging shale gas industry. The perceived prospectivity of the UK is indicated by company acquisition and farm-ins to acreage with shale gas potential by IGas, INEOS and Egdon Resources within the past twelve months.

Shale gas in Europe

Europe is particularly well-suited to gas resource play exploitation on account of its large market, established pipeline infrastructure, increasing demand and current dependence on gas imports. Relatively high natural gas prices add to the attraction. Shale gas exploration in Europe is in its infancy. The first exploratory well was spudded in Scotland in 2005 and since then shale-specific exploratory drilling has been limited to seven countries, with most wells being drilled from 2010 onwards. As a consequence, little is known about Europe's ultimate potential.

Resources.

Rogner's 1996 estimate of the in-place shale gas resource of Europe (including Turkey) was 550 Tcf. More recent studies indicate significantly larger in-place resources. In its assessment of the world's shale gas resource, the U.S. Energy Information Administration (EIA) estimated the European shale gas in-place resource for 9 countries at 2,314 Tcf with a combined technically recoverable resource of 563 Tcf (U.S. EIA, 2011). A revised and extended report published in June 2013 (U.S. EIA, 2013) increased the study to 12 countries and included additional areas within countries such as Poland. The gas in place estimate increased to 2,408 Tcf but the recoverable estimate decreased to 472 Tcf (Table 1).

	EIA 2011		EIA 2013	
	Gas Initially In Place	Technically-Recoverable	Gas Initially In Place	Technically-Recoverable
Bulgaria			66	17
Denmark	92	23	159	32
France	720	180	727	137
Germany	33	8	80	17
Lithuania	17	4	4	0
Netherlands	66	17	151	26
Norway	333	83	0	0
Poland	792	187	763	148
Romania			233	51
Spain			42	8
Sweden	164	41	49	10
United Kingdom	97	20	134	26
TOTAL	2,314	563	2,408	472

Table 1. Shale Gas Initially In Place and Technically Recoverable from selected European Countries rounded to nearest Trillion Cubic Feet (EIA, 2011, 2013)

The EIA study estimates a gross shale rock volume based on maps of areal distribution and cross sections indicating lateral extent, unit thickness and depth of burial. Free gas and adsorbed gas in place are then estimated using available organic content and maturity data. Technically recoverable gas is then calculated by applying one of three recovery factors (Favourable – 25%; Average – 20%; Less Favourable – 15%) based on clay content, geological complexity, reservoir pressure and gas-filled porosity. Clearly, these estimates must be treated with caution. Much of the detailed information required to make accurate assessments is simply not available in many areas and so the assessments are still relatively speculative as the following individual country reports frequently indicate.

Austria.

OMV has suggested a potential recoverable shale gas resource of 15 Tcf in the Vienna Basin, Austria, from an in-place resource of 200-300 Tcf.

Denmark

The U.S. Geological Survey (2013) has estimated mean technically recoverable resources of Denmark's Alum Shale to be 6.935 Tcf, of which 0 to 4.848 Tcf (mean: 2.509 Tcf) occur onshore and 0 to 8.492 Tcf (mean: 4.426 Tcf) lie offshore. The much larger EIA recoverable shale gas estimates (2011: 23 Tcf; 2013: 32 Tcf) are for the onshore area only.

Germany.

In Germany the Federal Institute for Geosciences and Natural Resources (BGR) has estimated recoverable shale gas to be in the range 24 – 80 Tcf from an in-place resource of 240 – 800 Tcf.

Netherlands.

TNO's "best estimate" for "producible gas in place" in "high potential" areas of the Netherlands is 198 Tcf from an estimated in-place resource of 3,950 Tcf. This is substantially greater than either of the EIA estimates (Table 1 above).

Poland.

Four estimates of Polish Shale Gas resources have been made public through end-2013 (Table 2). The variance between the estimates is in large part a result of differences in methodology, which are outlined below.

Poland Shale Gas		Gas Initially In Place (Tcf)	Technically-Recoverable (Tcf)			Recovery
Study	Basin	Risked / Mean	P95 / Min	Risked / Mean	P5 / Max	Percent
EIA 2011	Baltic	514		129		25.1%
EIA 2011	Lublin	222		44		19.8%
EIA 2011	Podlasie	56		14		25.0%
EIA 2011	**Polish Foredeep Total**	792		187		23.6%
Polish Geological Institute March 2012	**Polish Foredeep Total**		1.22 - 2.71	12.2 - 27.1	30.5 - 67.8	
U.S. Geological Survey July 2012	**Polish Foredeep Total**		0	1.345	4.086	
EIA 2013	Baltic	532.1		105.2		19.8%
EIA 2013	Lublin	45.8		9.2		20.1%
EIA 2013	Podlasie	53.6		10.1		18.8%
EIA 2013	**Polish Foredeep Total**	631.5		124.5		19.7%
EIA 2013	Fore Sudetic	106.7		21.3		20.0%
EIA 2013	**Poland Total**	738.2		145.8		19.8%

Table 2. Estimates of Polish In-place and Technically Recoverable Shale Gas Resources

Polish Geological Institute – National Research Institute (PGI).

The study was based on archive data from 39 wells drilled between 1950 and 1990. Cut-offs of 15m shale thickness (minimum), 2% TOC (minimum) and thermal maturity (Ro) in the range 1.1 – 3.5% were chosen. In the absence of key data such as porosity, permeability, mineral composition, reservoir pressure and initial production (IP), Estimated Ultimate Recovery (EUR) and average well drainage area were based on U.S. analogues. The range of estimates therefore reflects the combination of two uncertainties: EUR per well, for which the range uses the results of the most poorly performing, the main cluster, and best performing of U.S. basins; potentially productive area conforming to the cut-off criteria, for which the greatest uncertainty lies in estimating TOC, which was largely unrecorded and which therefore relied on extrapolation from Gamma Ray and other well logs. A revised PGI estimate, based on testing of at least one significant horizontal leg, was planned for 2014 but it has also been suggested that a new summary report will await the drilling of 100 exploratory wells, which is still some way off.

U.S. Geological Survey (USGS).

The study was based on archive data from 56 wells drilled before 1990. The methodology was broadly similar to that of the PGI study (as the USGS was involved in training PGI staff). There were, however, significant differences in some of the criteria adopted, as follows:

- The PGI study includes offshore whereas the USGS study is limited to onshore. Whereas this, and the estimation of other cut-off criteria, resulted in a potentially productive area in the range 18,540 – 41,140 km^2 in the PGI study, the modal value in the USGS study was 4,850 km^2 with a maximum value of 20,250 km^2.
- Based on U.S. analogues, the PGI study estimated EUR per well in the most likely case as 0.4 Bcf/well whereas the USGS estimates it as 0.2 Bcf/well.
- The USGS also applies an average success factor to drilled wells which, in the most likely case, it estimates at 50%.

The combination of these differences accounts for the variance between the PGI and USGS estimates.

U.S. Energy Information Administration (EIA).

The EIA reports (U.S. EIA, 2011; U.S. EIA, 2013) were prepared on behalf of the EIA by Advanced Resources International (ARI). Their methodology is fundamentally different from those of the PGI and USGS. As global studies, the reports rely on geological information and reservoir properties assembled from the technical literature and data from publically available company reports and presentations. Depths and thicknesses, for example, are typically assembled from regional cross sections. In addition, the

methodology is based on making an estimation of gas initially in place and applying a recovery factor to this. The reports use one of three recovery factors: 15%; 20%; 25%. In the case of Poland they have generally selected a 20% recovery factor which is said to be applicable to plays with a medium clay content, moderate geologic complexity and average reservoir pressure and properties. In the case of Poland, this may be a rather optimistic outlook given that the only North American Lower Paleozoic analogue, the Utica Shale, is considered to have superior gas shale character to the Polish Foredeep shales but has recovery factors varying between 10 and 20%.

The 2011 study was limited to onshore but still considered the potentially productive area to be 53,115 km^2, greater than the maximum combined onshore and offshore area estimated by the PGI. All gas shale characteristics were based on those of the Lower Silurian. In the 2013 study, the potentially productive area of the onshore Polish Foredeep was reduced to 36,080 km^2, which is nevertheless some 3,000 km^2 greater than the maximum potentially productive onshore area estimated by the PGI. The 2013 report assessed the combined Lower Silurian, Ordovician and Upper Cambrian intervals.

Sweden.

The initial (2011) EIA report provided an estimated technically recoverable resource of 41 Tcf for Sweden's Alum Shale, which Shell's three wells found to have a very limited content of natural gas which it was not possible to produce. In the 2013 report, the estimate of technically recoverable resources for the Alum Shale was reduced to 9.8 Tcf.

United Kingdom.

Based on analogy with comparable shale plays in the U.S., in 2010 the British Geological Survey (BGS) tentatively estimated recoverable reserves (England only) at approximately 5.3 Tcf.
In June 2013, the BGS and Department of Energy and Climate Change (DECC) produced an estimate for gas in place in the Bowland Shale in the Craven Basin across Central England (Andrews, 2013). Total gas in place is estimated to fall within the range 822 Tcf (P90) to 2,281 Tcf (P10) with the most probable estimate (P50) being 1,329 Tcf. Compared with the EIA analyses, the BGS study is very much "bottom-up", based on geological parameters, volumetrics and gas contents. A similar study released in May 2014 for the Weald Basin in southeast England (Andrews, 2014) estimated the in-place shale liquids resource to be in the range 2.20 to 8.57 billion barrels with a central estimate of 4.4 billion barrels. No gas resource estimate was made due to lack of geological maturity required to generate significant gas. The Midland Valley of Scotland, where Europe's first certification of recoverable shale gas resources took place, was considered in the initial (2011) EIA report to be non-prospective. The BGS and Department of Energy and Climate Change (DECC) estimates of shale-hosted hydrocarbons in place for this area were released in June 2014 as follows: P90: 49.4 Tcf / 3.2 billion bbl; P50: 80.3 Tcf / 6.0 billion bbl; P10: 134.6 Tcf / 11.2 billion bbl (Monaghan, 2014).

A 2014 study by the British Geological Survey commissioned by the Welsh Government (British Geological Survey, 2014) did not make any new resource estimates for Wales as it was considered that there is insufficient publically-available data available on the geology, engineering or associated costs of production to make reliable estimates at this stage.

General

Given the potential size of the in-place resource it is not surprising that investigations have been proposed in at least seventeen countries. Company interest has ranged from super-majors, such as ExxonMobil and Shell, through majors (Chevron; ConocoPhillips; Eni; Total) and major independents (e.g. Marathon Oil; Talisman) to small niche players (e.g. Cuadrilla Resources) and coal seam gas explorers who may have some shale gas potential on their acreage (e.g. IGas Energy). Several of the North American companies have subsequently withdrawn from Europe (Chevron; ExxonMobil; Marathon; Talisman).

A number of companies have published resource estimates for their own acreage and these are reported in the shale gas plays section for individual plays by country (2.1 below).

Major shale gas plays in Europe

Organic-rich "bituminous" shales which form the self-contained source-reservoir petroleum systems that can be exploited for natural gas and hydrocarbon liquids occur at many stratigraphic levels. Global oceanic anoxic events (OAEs), which favour the preservation of organic matter, took place in the Late Ordovician and into the Silurian, in the Early Jurassic (Toarcian), and in the Late Cretaceous (Cenomanian-Turonian). In Europe, additional anoxic events occurred on a regional scale in the Late Cambrian, Visean (Middle Mississippian) to Namurian (Early Pennsylvanian), and Late Jurassic (Kimmeridgian-Tithonian). All of these units are under investigation in Europe, though the younger units tend to be more prospective for shale liquids than shale gas. There are three potentially major regional shale gas plays in Europe plus a number of others with more restricted distribution.

Lower Paleozoic

The oldest is a Lower Paleozoic play that occurs in northwest Europe running from eastern Denmark through southern Sweden to north and east Poland. The organic-rich shales with shale gas potential lie on the south western margin of the Baltica paleocontinent and tend to thicken towards the bounding Trans-European Suture Zone. This play was first tested in Sweden in 2009 and has since been the focus of exploratory drilling in Poland. In Denmark and Sweden the principal target is the kerogenous Alum Shale of Middle Cambrian to Early Ordovician (Tremadoc) age.

Denmark.

Natural gas was first found onshore Denmark in Nordjylland (North Jutland) in 1873 in association with water wells. The first successful well was drilled in 1905, finding gas at intervals down to 600'. Commercial gas production took place from the late 1930s to the early 1950s in the Frederikshavn area. The source, however, is probably shallow biogenic gas. Today, licences have been awarded over the Fennoscandian Border Zone and Norwegian-Danish Basin onshore Denmark.

Total S.A. / Nordsøfonden. Total S.A. has been 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 is expected to commence drilling in May 2015. In August / September 2013, Total and Nordsøfonden undertook an airborne gravity and magnetic survey over the area of their Nordsjælland (North Zealand) licence.

Sweden.

Fennoscandian Border Zone

Shell. On 28th November 2009 Shell spudded the first well in a three-well test programme in Sweden's Colonussänkan permit. The permit overlies the Colonus Shale Trough, Fennoscandian Border Zone (also known as the Sorgenfrei-Tornquist Zone), southern Sweden. Lövestad A3-1, Oderup C4-1 and Hedeberga B2-1 ranged in depth from 2,448' to 3,134'. The wells encountered Alum Shale (Alunskiffer) ranging in thickness from 225' to 345'. Total Organic Carbon (TOC) ranged from 3 – 16%, averaging 7%. Porosity averaged 6.5% and permeability was approximately 40 nanodarcies. Water saturation, however, was high (80%) and gas analysis (94% methane) indicated that gas content was approximately 30 scf/ton and that the Alum Shale is undersaturated. Vitrinite reflectance measurements from 1.7% to over 2% indicate

that the shale is post mature with little capacity for further gas generation. In May 2011, therefore, Shell announced that its investigations had been completed, that the rock samples from the three wells found only very limited gas traces which are not producible, and that the licences would not be renewed when they expired at end-May 2011 (Svenska Shell 2011).

Östergötland Lower Paleozoic Basin

The Östergötland Lower Paleozoic Basin is an E-W faulted synclinal outlier within which the Alum Shale occurs at shallow depth and is thermally immature but the 45'-80' thick shale has high TOC contents of up to 20%. It has been considered by some to be analogous to the biogenic-sourced shale gas of the Antrim Shale in the Michigan Basin. In both basins, methanogenesis may be a consequence of dilution of saline formation brines by meltwater from overlying Pleistocene glaciers. Although the Alum Shale is thermally immature in Östergötland, bitumen is present in limestone concretions and thin sandstones. The origin of these oils is thought to be either long-distance migration or more local heating during the intrusion of Permo-Carboniferous sills. Gas analysis indicates a mixture of thermogenic gas and secondary biogenic gas resulting from the breakdown of these pre-existing hydrocarbons. Gas flows are known from water wells and seeps in the area and flows of up to 40,000 cf/d have been reported from wells. Local farmers use the gas as a heating source and the Linköping commune has a mining (processing) concession, valid until 2033. Four companies own a total of 27 licences in the Östergötland Lower Paleozoic Basin.

Aura Energy. In October 2011, Aura Energy, an Australian uranium exploration company that is investigating the uranium potential of Sweden's Alum Shale, commenced a 5-hole drilling programme at its Motala shale gas project in the Östergötland Lower Paleozoic Basin, south-central Sweden, on the east shore of Lake Vättern near the town of Linköping. The 5 shallow wells were completed during Q4 2011 and gas samples were sent for analysis.

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% CH_4) was tested by a 3-month extended well test. 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 is now planned for 2015 and a Letter of Intent has been signed with a gas provider for the sale of any future gas production. 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.

Siljan Ring Depression

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), Fjäcka Shale (Upper Ordovician) and a Llandovery (Lower Silurian) shale (Kallholn Formation?), plus fractured basement. AB Igrene plans to drill and production test the Vattumyren-3 well in the Mora area in summer 2015.

[*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.]

Poland.

Further to the southeast, in Poland, the most widespread Lower Paleozoic target has been Lower Silurian-age graptolitic shale, with the Upper Cambrian to Lower Ordovician and Upper Ordovician being secondary targets. The Silurian in particular thickens towards the southwest in the area of the Gdansk Depression (Baltic Depression) and the Danish-Polish Marginal Trough which defines the southwest margin of the Baltic Depression. In parts of the Trough, such as the Warsaw Trough and Lublin Trough, more than 10,000' of Silurian section may be present. Burial depths to base Silurian range from 3,000' in the east and on the East European Platform Margin to 15,000 in the west, being deepest in the Warsaw Trough. Depths in the Lublin Trough are variable because of the presence of a number of separate fault blocks, but maximum depth to base Silurian is about 10,000'. To date, this play has been the most sought after in Europe. 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 Wisent Oil & Gas, were considered to be more prospective for shale liquids than for shale gas. Thirteen (13) concessions have subsequently been relinquished. Another 40 concessions have been awarded in the Danish-Polish Marginal Trough and 14 on the East European Platform Margin, northeast of the Marginal Trough. 39 of these awards (25 – 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.

Baltic Depression.

Fifteen (15) 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, seven companies remain active, principally ConocoPhillips, PGNiG and San Leon.

3Legs Resources / ConocoPhillips. The first tests of the Polish Lower Paleozoic commenced in the Gdansk Depression. Between June and October 2010, Lane Energy (a subsidiary of 3Legs Resources) drilled two vertical wells, Łebień LE-1 on its western Lębork concession and Legowo LE-1 (tested with a DFIT) on the eastern Cedry Wielkie concession. In January 2011 Netherland, Sewell & Associates estimated gross gas in place in the Silurian / Ordovician section of Lane's six licences at 170 Tcf. Following a decision to prioritise Lane's three western Baltic Basin concessions, Legowo LE-1 was plugged and abandoned.

A 3,300' horizontal leg drilled within the Upper Ordovician Sasino Formation in a second Łebień well (LE-2H) in May 2011 was the first horizontal shale gas well drilled in Poland. After a 13-stage slickwater frac the well flowed an unstabilised 2.2 MMscf/d on 8th September 2011 using coiled tubing and N_2 lift. It was recompleted with a tubing string on 17th September and flowed from 380 up to 520 Mscf/d on N_2 lift, plus frac fluid. 15% of the total frac fluid had been recovered by the end of the test. A second flow test in early November 2012 using a 3 ½" string flowed at rates of up to 780 Mscf/d, averaging 550 Mscf/d. A third phase of testing commenced on 8th July 2013 using a 2 3/8" tubing string. Downhole pressure gauges were installed and pressurized samples collected. Flowing commenced on 21st July at an initial rate of 470 Mscf/d and had declined to 230 Mscf/d by 11th September, by which time 44% of the frac fluid had been recovered. The productive intervals in all three wells were in the Lower Silurian and Upper Ordovician.

In July 2011 Lane spudded Warblino LE-1H, in a third concession (Damnica). A vertical pilot was drilled to 10,570'. This was followed by a horizontal leg of 4,088' within the top 16' of a presumed new Cambrian prospective interval which was then redrilled with a 1,650' horizontal leg (12,610' MD) because

of hole stability issues. Subsequent analysis has revealed that the horizontal leg was actually drilled within the Lower Ordovician Sluchowo Formation instead of the intended Cambrian Alum Shale (also known as the Piasnica Formation). A 7-stage gel frac test was suspended after 5 days during which flow declined from 60-90 Mscf/d to 18 Mscf/d. On retest in summer 2012 the well produced at a rate of 90 Mscf/d after 20 days of flow. Log analysis confirms that the Alum Shale (Piasnica Formation) is prospective in this area re-entering the well to drill and test a lateral within the Cambrian section is under consideration.

Lane's initial seismic and drilling programme on its six Gdansk Depression concessions was funded by ConocoPhillips (see *4.3 Ownership Transactions: Farm-ins*) after which ConocoPhillips opted to retain an interest (and operatorship) in only the three western concessions. The companies spudded the Strzeszewo LE-1 vertical well on the Lębork concession on 4th October 2012 and drilled to a TD of 10,040'. A DFIT was carried out in the Cambrian interval in January 2013 followed by a single stage hydraulic frac in May. Clean-up using nitrogen lift commenced on 4th August. The well was shut in on 7th September 2013 after recovering 22.5% of the frac fluid and flowing gas intermittently. A second DFIT, single-stage hydraulic frac and flow test took place in the primary target, the Upper Ordovician Sasino Formation, in December 2013, flowing gas at modest rates and recovering 63% of frac fluid.

Lublewo LEP-1 was spudded in the Lębork concession in December and drilled to a TD of 9,593'. The rig then spudded Slawoszyno LEP-1 in February 2014 on the Kawia concession, drilling to a TD of 9,250'. The wells confirmed the thickness and prospectivity of the Upper Ordovician Sasino Formation and Upper Cambrian Piasnica Formation. Based on these results and recently acquired 2D seismic, in March 2014 the rig was then mobilised to drill a 4,960' horizontal sidetrack (LEP-1ST1H) in the Sasino formation in Lublewo LEP-1. A stimulation programme (cross-linked gel) of 25 frac stages commenced on 15th July 2014 across a 4,820' interval using 7.7 million lbs of white sand proppant. The well flowed gas and light oil. Nitrogen lift commenced on 20th August. Over the period 8th August to 17th September flow averaged 396 Mscfg/d and 157 b/d of light oil. On 17th September 2014, the well was producing 512 Mscf/d and 115 b/d, at which point some 26% of frac fluid had been recovered.

BNK Petroleum – Saponis Investments. The drilling contractor, NAFTA Pila, which drilled the first two Lane wells spudded Wytowno S-1 (Slawno concession) in December 2010 on behalf of Saponis (BNK; RAG; Sorgenia: LNG Energy). The US$ 6 million well reached TD at 11,745' in mid-February 2011. The well encountered gas shows in a shallower 130' Lower Silurian section and over a deeper 300' Lower Silurian hot shale section. The well appears to have been drilled on a localised paleo-topographic high which accounts for the absence of a Cambro-Ordovician section. The strongest shows were recorded in the deeper Lower Silurian interval (124 scf/ton), while the shallower interval averaged 77 scf/ton. Wytowno S-1 was followed by a 11,780' well, Lebork S-1, on the Slupsk concession which encountered gas shows over a 935' interval from Lower Silurian to Cambrian Alum Shale. The Lower Silurian averaged 40 scf/ton while the 155' Cambro-Ordovician interval averaged 268 scf/ton. Total Organic Carbon (TOC) is also significantly higher in the Cambro-Ordovician interval.

In July 2011 Saponis spudded a third well, Starogard S-1 which had reached a TD of 11,560' by early September. The well encountered a similar Lower Silurian to Cambrian section to that of Lebork S-1 with a gross thickness of some 820'. Gas contents (Lower Silurian: 38 scf/ton; Ordovician: 17 scf/ton) were lower than in the first two wells. Completion of the first two wells commenced in mid-September 2011 with fracking of the Cambrian interval in Lebork S-1 commencing on 30th September. The fracturing of the Cambrian and Ordovician intervals did not permit an effective test to take place as insufficient proppant was injected as a result of higher than expected overpressures. The gas that did flow and was flared contained methane, ethane and propane. The shale character in the three Saponis wells is indicated in Table 3 below.

Location	Play	Age	Thickness Range (ft)	SiO_2 %	Carbonate %	Clay %	Porosity %	Total Organic Carbon %
Saponis Concessions, Baltic Depression	Graptolitic Shale	Lower Silurian	300 - 485	28 - 30	8 - 27	44 - 50	1 - 9.6 (avg 3.8)	0.1 - 4.2
	Graptolitic Shale	Ordovician	75 - 90	32 - 54	8 - 18	33 - 43	1.4 - 6.9 (avg 4.2)	0.05 - 6
	Alum Shale	Upper Cambrian	45	25	30	39	4.1 - 5.2 (avg 4.6)	5.0 - 9.2 (avg 7.2)

Table 3. Shale Character in Saponis Wells, Baltic Depression

In April 2012, gas in place in the Saponis concessions was estimated to lie within the range 45.4 to 66.8 Tcf with a best estimate of 55.5 Tcf. Prospective recoverable resources were estimated in the range 4.5 to 13.2 Tcf with a best estimate of 8.0 Tcf. In December 2013, BNK Petroleum and Esrey Energy (formerly LNG Energy) acquired the Saponis interests of RAG and Sorgenia. It was also announced that Saponis will relinquish the Starogard and Slawno concessions, retaining the Slupsk concession on which Lebork-S1 was drilled. In March 2015, BNK announced that it will acquire Esrey Energy's 42.96% interest in the Slupsk concession for no consideration and seek a joint interest partner.

BNK Petroleum – Indiana Investments. BNK announced that it would commence the drilling of three wells on its wholly-owned blocks to the south of the Saponis Slawno and Slupsk concessions in February 2012 and on 28th February spudded Miszewo T-1 in the Trzebielino concession. The well drilled to a TD of ~ 17,700' but only muted gas shows were recorded. The well appears to have been drilled on the downthrown side of a major fault and to have encountered a different depositional environment from wells further to the northeast.

Gapowo B-1 was then spudded in May 2012 in the Bytow concession. It lies on the upthrown side of the fault and was drilled to a TD of some 14,000'. The well encountered a 400' Lower Silurian interval and 155' Ordovician interval, both overpressured. Core data suggest that prospective shale is 130' to 250' in thickness and has higher porosity (3.9 – 6.1%; 5.1% avg.), permeability and TOC (1.1 – 4.2%; 2.5% avg.) than any of the other BNK-operated wells in the Baltic Depression. The average gas readings from these fractured overpressured shales were over 20 times greater than those encountered in Lebork S-1. Gas in place for the most prospective Lower Silurian / Ordovician interval is estimated at up to 86 Bcf / section with total gas in place for the well estimated at up to 135 Bcf. Permission to drill and fracture stimulate a horizontal leg was obtained and a 5,900' horizontal section was drilled and cased in January / February 2014 in well B-1A. In Q2 2014 20 fracs were stimulated over the entire length of the horizontal leg, of which only 8 were considered to be contributing to the flow. Flow rates spiked at over 1 million cf/d and averaged between 200 and 400 Mcf/d. In March 2015 BNK announced that it will relinquish its interest in the Indiana Bytow and Trzebielino concessions to focus on the Slupsk concession held by Saponis.

San Leon. San Leon / Talisman commenced a two vertical well Gdansk Depression drilling programme with the spudding of the Lewino-1G2 well in the Gdansk-W concession in late September 2011. Strong gas shows were encountered over an interval in excess of 3,300' ranging from Middle Silurian to Upper Cambrian. After reaching a TD of 11,810' the rig moved to the Rogity-1 location on the Braniewo concession. This well drilled to 9,147', encountering shows of rich gas over a 1,600' interval from Lower Silurian to Middle Cambrian. Oil shows were also recorded in Lower Silurian shale, Ordovician limestone and shale and Middle Cambrian sandstone.

Following Talisman's announcement of its withdrawal from its Polish Operations, on 8th May 2013 San Leon reported that it had assumed 100% ownership of the Gdansk West and Braniewo concessions through its acquisition of the shares of Talisman Energy Polska. San Leon has announced a proposed pilot development programme for the Gdansk West concession. The concession appears to fall within the gas/condensate window and the pilot area of 183 km^2 (70 square miles) is estimated to contain 1.3 Tcf and

40 million bbl of condensate recoverable. The entire Gdansk West concession has an estimated 12 – 18 Tcf shale gas in place.

On 2nd July 2013, United Oilfield Services (UOS) performed a hydraulic fracture through the 5 ½" liner of Lewino-1G2, pumping over 11,000 barrels of fluid and 95 tons of sand at 120 barrels / minute with a maximum pressure of 12,200psi. The frac was conducted between 11,632' and 11,647' in the Upper Ordovician (Caradoc) Sasino Formation. 25% of frac fluid was recovered along with a small but consistent flow of burnable gas. UOS performed 2 further fracs in Q4 2013. The first was a refrac of the initial interval but using ceramic proppant. The second frac was conducted in a higher part of the Sasino Formation using a slickwater design and flowed gas throughout the duration of the clean-up period (one week). In January 2014, after 6 weeks flow, the well was producing 45-60 Mscf/d (cond / gas: 20bbl / MMscf). Flow is believed to have been from the upper fractured interval only (frac 3) with total Upper Ordovician potential for 200-400 Mscf/d. A 5,000' horizontal well is now planned from the same well pad.

PGNiG (Polskie Górnictwo Naftowe i Gazownictwo – state-controlled). A promising gas flow was also reported by PGNiG from a single-stage frac test of the Lower Silurian over the interval 9,495-9537' on its Lubocino-1 well on the Wejherowo concession, completed in March 2011. Gas quality was good with heavier hydrocarbons reported, no H_2S and low N_2. Average flow was 10 Mscf/d. A second test was subsequently conducted at 9,200'. A horizontal well (Lubocino-2H) was spudded in August 2012. After 6-stage hydraulic fracturing in the Upper Ordovician (Caradoc) Sasino Formation, testing was conducted in Q2 2013. The company drilled Lubocino-3H between August and December 2013. PGNiG has also drilled a vertical well, Opalino-2, in the Wejherowo concession. The well, which was spudded in September 2012, with target depth of 10,000', was reported to be production testing in July 2013. Gas flows were reported from tight Middle Cambrian sandstone from 9,785-10,000'. Wells Opalino-3 and 4 were drilled between November 2013 and March 2014 and at one stage PGNiG has indicated that it might start production from the Opalino area in 2015. In conjunction with a consortium of Polish companies (KGHM; PGE; Tauron Polska Energia; Enea), PGNiG also drilled Kochanowo-1 on the Wejherowo concession between May and June 2013. The Tepcz-1 well was drilled to a depth of 11,100' on the concession in April-June 2014. 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 the period July – September 2013 Borcz-1 was drilled to TD at 12,335' on the Kartuzy-Szemud concession. A second well, Milowo-1, followed in May-July 2014.

Eni. Eni completed an initial 3 vertical well programme on its Malbork (Kamionka-1) and Elblag (Bagart-1; Stare Miasto-1) concessions. A horizontal leg was drilled on one of the wells and frac testing commenced in the second half of 2012. Eni has withdrawn from Polish shale gas exploration and did not renew two of its three licences when they expired in December 2013 and January 2014. The third licence was subsequently relinquished.

Danish-Polish Marginal Trough & East European Platform Margin.

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, four companies remain active, principally PGNiG and Orlen.

ExxonMobil. The first wells in the Podlasie Depression of the East European Platform Margin (Siennica-1) and Lublin Trough of the Danish-Polish Marginal Trough (Krupe-1), were drilled by ExxonMobil in Q4-2010 and Q1-2011. The wells were fracced in September / October 2011 but the wells failed to flow commercial volumes of gas. In June 2012 it was reported in the Polish press that ExxonMobil will discontinue its Polish shale gas exploration operations. The company had the option to relinquish or transfer its six concessions. Total SA, partner in two of them, announced in October 2012 that it will become operator of one of the concessions (Chelm) and drill a further well, while relinquishing the other.

Ultimately, Total relinquished both. Of the other four concessions, two were relinquished and two transferred to PKN Orlen.

PKN Orlen. On 24th October 2011 PKN Orlen commenced its drilling programme in the Lublin Trough of the Danish-Polish Marginal Trough spudding its first well, Syczn-OU1 in the Wierzbica concession. Based on the results of this vertical well Syczn-OU2K was spudded in September 2012, with a planned horizontal leg of some 3,600'. A 12-stage fracture operation and four-week production test was completed in June2013 but did not yield commercial flow rates. Two other wells were completed in the Wierzbica concession in April (Stręczyn-OU1) and September 2013 (Dobryniów-OU1). Between September and October 2014 a horizontal leg (OU1-K) was drilled from the Stręczyn well. In mid-December 2011, PKN Orlen spudded Berejow-OU1 in the Lubartów concession, followed later that month by the Berejow-OU2K horizontal well. Both wells have now been completed and the horizontal well was frac tested in November / December 2013 using 19,000 cubic metres (5 million U.S. gallons) of water & 160 tons sand. Seven frac stages were conducted over a horizontal length of 2,300' at a depth of 8,200'. Between May and July 2013, Uscimów-OU1 was also drilled in the Lubartów concession. In July 2012, Orlen spudded Goździk-OU1 in the Garwolin concession, drilling to a TD of 13,830'.

Location	Play	Age	Thickness (ft)	SiO_2 %	Carbonate %	Clay %	Effective Porosity %	Total Organic Carbon %
PKN Orlen, Lublin Trough	Lublin Shale	Lower Silurian	200	16 - 33	10 - 30	40 - 56	4.7 max	0.8 - 3.5

Table 4. Silurian Shale Character in Lublin Trough Wells

On the East European Platform Margin PKN Orlen drilled the Stoczek-OU1 vertical well to a depth of 10,300' on the Wodynie-Lukow concession between November 2013 and January 2014. This was immediately followed by the Stoczek-OU1K horizontal well with a measured depth of 14,130', drilled at a depth of 9,500' in the Silurian. The planned length of the horizontal leg was 3,600'. The horizontal well was fracture tested in Q3 2014. Orlen's first well on the Wolomin concession, Pęclin-OU1, was drilled between December 2014 and March 2015 to a TD of 12,505', taking 775' of core.

Chevron. Chevron also commenced its Lublin Trough programme in Q4-2011 with a well in the Grabowiec concession at Lesniowice, spudded on 31st October 2011. A second well at Andrzejow on the Frampol concession was spudded in March 2012. A third well was spudded on the Zwierzyniec concession in December 2012. Krasnik-1 was then drilled on the Krasnik concession between May and August 2013. The company had by then drilled a Lower Silurian test on each of its four Lublin Trough concessions. Zwierzyniec was apparently the most promising as the first well was fracced and a second well was planned. Further development work on the Grabowiec concession, where Chevron conducted a DFIT in Grabowiec-6, was delayed by protests by local villagers at Żurawlów and Chevron is now relinquishing its Polish concessions.

Marathon / Nexen / Mitsui. In Q4-2011 and Q1-2012 Marathon drilled Cycow-1 (Orzechow concession) and Domanice-1 (Siedlce concession) on the East European Platform Margin. The latter well was plugged and abandoned. Drilling activity then moved to the Danish-Polish Marginal Trough where Lutocin-1 (Rypin concession) and Prabuty-1 (Kwidzyn concession) were drilled in the Pommeranian Trough, followed by Lubawskie-1 (Brodnica concession), spudded in September 2012. The final well in the initial 6-well programme, SOK-Grębków-1 in the Sokolow Podlaski concession in the Podlasie Depression, East European Platform Margin, was plugged and abandoned in January 2013. Diagnostic fracture injection tests (DFITs) were conducted in the four non-abandoned wells. Three wells were hydraulically fractured using hybrid slickwater/gel fracs, with one well flowing gas for a week. Marathon announced its intention to dispose of its Polish assets as part of its global portfolio management and relinquished 7 of its 11 concessions in October / November 2013. The remaining 4 concessions have since been relinquished also.

San Leon. San Leon / Talisman spudded Szymkowo-1, the final well in their 3-well drilling program, on the Szczawno concession, Danish-Polish Marginal Trough (Pomeranian Trough), in early March 2012. The well drilled to a depth of 14,930' and recorded wet gas shows over some 2,000' of Lower Paleozoic shale. The strongest shows were encountered in the Lower Silurian and Ordovician over a combined thickness of some 350'. San Leon reported that a 1,650' horizontal leg was drilled in this well. Following Talisman's withdrawal from Poland, San Leon is operator and now owns 50% of the concession, the other 50% being held by Greenpark Energy.

PGNIG. PGNiG spudded the Lubycza Królewska-1 well on the Tomaszów Lubelski concession, Lublin Trough on 26th March 2012. The well was completed in August 2012 and may be frac tested. A second well, Majdan Sopocki-1, was drilled on the concession in Q4 2014. Also in the Lublin Trough, Kościaszyn-1 (Wiszniow-Tarnoszy concession) and Wojcieszków-1 (Kock-Tarkawica concession) were drilled between September 2013 and January 2014. A second (horizontal) well is planned at the Wojcieszków-1 location.

Dart Energy. Dart Energy published a "best estimate" of 9.485 Tcf shale gas in place in its Milejow concession, where a seismic programme was carried out in Q3-2011. Dart considered its Polish assets to be non-core and relinquished the concession in October 2013.

Poland General. An interesting feature revealed by sampling and gas shows from the three Lane Energy, three Saponis and two San Leon / Talisman well locations in the Gdansk Depression is that thermal maturity appears to decrease in an east to northeast direction leading to an increase in the content of NGLs. The Starogard well produced hydrocarbons up to pentane and Rogity-1 produced C1 – nC8 while the western wells in general produced only methane, ethane and propane. This does suggest that there is the potential for significant liquids production from some concessions. Rogity-1 also discovered a 30' oil column in tight Middle Cambrian sandstone, confirming the decrease in thermal maturity towards the northeast of the Gdansk Depression. Exploration results to date have shown that the earliest deposition of organic-rich shales is diachronous from northwest to southeast. Only to the northwest of Gdansk (Łeba High) are the Upper Cambrian Alum Shale (Piasnica Formation) and Lower Ordovician Sluchowo Formation organic rich. Organic-rich shales also occur in the Łeba High region from Middle Ordovician (Llandeilian) through to Lower Silurian (Llandovery). Elsewhere, organic-rich Upper Ordovician shale occurs only to the southeast of the Łeba High in the central part of the Gdansk Depression. Organic-rich Silurian shale occurs throughout the region though once again this is diachronous, with only the Llandovery tending to be organic rich in the northwest while further to the south and east in the eastern part of the Gdansk Depression, the Podlasie Depression and the Lublin Trough, both the Llandovery and Wenlock contain organic-rich shales.

Lithuania.

The Cambrian to Lower Silurian succession is also thought to have potential in south-west Lithuania. The Lithuanian Geological Survey has estimated in-place shale gas resources at up to 20 Tcf, with 10-15% recoverable.

Chevron. Chevron planned 2D and 3D seismic and multiple wells primarily for shale gas / oil exploration (see *4.3 Farm-ins: Lithuania*) on the Rietavas onshore licence. On 25th June 2012 the Lithuanian Geological Survey opened two areas to tender for exploration with a submission deadline of 31st October 2012. In January 2013 it was announced that Chevron was the only applicant. Award of the application was delayed until Parliament amended laws to strengthen environmental regulations and on 16th September Chevron was announced winner of the tender but on 8th October Chevron announced that it was withdrawing from the tender. It is understood that this was because changes in the legal and financial environment covering hydrocarbon exploration had been and would continue to be made since the date Chevron was granted the award. On 29th October 2013, the Environment Ministry announced that a repeat tender would be offered; possibly in Q1 2014 if all legal and tax changes had been determined by that time. Terms would be eased, especially in the area of experience which was extremely stringent in the initial tender. Modified hydrocarbons legislation was eventually passed by Parliament in December 2014, to take effect on 1st January 2015. In April 2015 the Energy and Environment ministers announced that in view of

the prevailing oil market conditions it was not a suitable time to launch a tender and that such a launch should only be undertaken in future if companies expressed interest. In July 2014, Chevron sold its 50% interest in LL Investicijos, holder of the Rietavas licence, to Tan Oil, another shareholder in the company, thereby withdrawing completely from Lithuanian E&P.

***Romania*.**

Chevron. Chevron acquired a concession (Block EV-2 Barlad) on the platform margin in northeast Romania where the Silurian foredeep shales that are prospective in Poland and Ukraine are also believed to occur at depths between 10,000 and 13,000'. Chevron committed to 400 km of 2D seismic and 3 wells. Prior to the introduction of a shale gas drilling moratorium, the first well in the multi-well drilling programme had been planned for late 2012.

Following the expiry of the moratorium, Chevron moved ahead with seismic exploration and the permitting required for drilling. The company sought permits for three wells: Popeni-1 in Gagesti, Silistea-1 in Pungesti, and Paltinis-1 in Bacesti. Having obtained all the required permits, in early October 2013 Chevron commenced preparatory work at the drill site near the village of Silistea in Vaslui County but halted operations after five days of protests by villagers. On 19th October 1,700 locals and environmental activists held protests. The government, while accepting the right to peaceful protest, warned against violence. President Traian Basescu appeared on TV to stress that failure to source indigenous gas resources plays into the hands of Russia's Gazprom while Prime Minister Victor Ponta stated that the government's desire and political decision is to have energy independence for Romania by exploiting all of the resources that the country has. Chevron commenced drilling its first well on the Barlad concession, Silistea-Pungesti-1, in early May 2014. On 8th July it was reported that drilling had been completed and that the results were being studied. The well is believed to have been drilled to about 10,000'. In February 2015 Chevron announced that it intends to pursue relinquishment of its interest in its 4 Romanian concessions in 2015. A second Lower Paleozoic play occurs on the composite Saxothuringian-Barrandian-Moldanubian terranes (Bohemia) that probably detached from Gondwana at around the time of the Ordovician-Silurian boundary.

***Czech Republic*.**

Hutton Energy. BasGas (now Hutton Energy) applied for acreage in the Prague and Intra-Sudetic basins of the composite Bohemian terranes. The Silurian pelagic shale is reported to be the target in both basins. The Trutnov application in the Intra-Sudetic Basin was approved on 21st December 2011 but the Trutnov award was cancelled in April 2012 and sent back to the Ministry of Environment regional department to be decided again. In September 2012 the Minister of Environment announced a moratorium on shale gas exploration in the Czech Republic until 30th June 2014.

***Spain*.**

Silurian black shale has also been identified as a potential play in Spain's Ebro Basin (by San Leon) and in central Spain.

Carboniferous

The second major play is a Carboniferous basinal marine shale play that extends eastwards from western Ireland and includes the East Irish Sea / Cheshire Basin in northwest England, the Anglo-Dutch Basin, the Northwest German Basin, the Fore-Sudetic Monocline (Northeast German-Polish Basin) in southwest Poland, and the Culm Basin in eastern Czech Republic. The age of the most prospective shales appears to young westwards from the Visean (Middle Mississippian) Kulm facies of Poland, the Czech Republic and northeast Germany to the Namurian (Upper Mississippian to Lower Pennsylvanian) of northwest Germany, the Epen Formation of the Netherlands, the Bowland Shale in northwest England, the Black Metals Marine Band of the Midland Valley Scotland, and the Clare Shale in western Ireland. Visean (Middle Mississippian) shale may also be prospective in Scotland and northwest Ireland.

Tests of the Namurian Black Metals Marine Band in the Midland Valley of Scotland by three wells drilled in 2005 and 2007 were the earliest investigations of shale gas potential in Europe. The Carboniferous play has since been drilled in England, Wales and Poland.

***Czech Republic*.**

Cuadrilla Resources. Cuadrilla Resources has received preliminary notification of the award of the Mezerici licence in which the target is considered to be deep marine sediments present in the Lower Carboniferous of the Culm Basin, where the Variscan foreland basin reaches its most easterly extent on the eastern flank of the Bohemian Massif. TOC ranges from 1.2 – 2.4%.

***Germany*.**

The nature of German E&P reporting is such that it can be difficult to establish the activity taking place on long-held licences. It is assumed that ExxonMobil, both directly and indirectly through the BEB ExxonMobil / Shell joint venture, will be examining the potential of Visean (Middle Mississippian) shale in eastern Germany and Namurian (Upper Mississippian to Lower Pennsylvanian) shale in the west. Of BNK Petroleum's 8 relinquished concessions, Adler, Falke, and Falke South in North Rhine – Westphalia's Munsterland Basin appeared to have primarily Carboniferous potential. Wintershall's Rhineland and Ruhr concessions and Dart Energy's Saxon I West and Saxon II concessions also appear to be primarily targeting Carboniferous shale gas. Dart (now IGas Energy) reported combined shale gas in-place estimates for the two concessions in the range 0.25 – 2.95 Tcf with a best estimate of 0.97 Tcf.

***Ireland (Republic of Ireland & Northern Ireland)*.**

Enegi Oil. In February 2011 Enegi Oil was awarded Licensing Option ON11/1 to evaluate the shale gas potential of the Namurian (Upper Mississippian – Lower Pennsylvanian) Clare Shale in western Ireland. The Clare Shale is known to have high TOC (3-8%) but also high levels of thermal maturity. The main issues are whether it is over-mature for gas and gas leakage during Late Carboniferous uplift. In September 2012 Enegi stated that vitrinite reflectance analysis indicates that the shale is of lower maturity than recorded in the literature and that it had engaged Fugro to undertake further testing of the prospectivity. The report submitted to the Irish Petroleum Affairs Division (PAD) in November 2012 indicated that within the area of seismic coverage and assuming a porosity of 7%, gas in place is estimated at 3.62 Tcf. The in-place estimate for the entire option area is 13.05 Tcf and for the high-grade area it is 1.23 Tcf. Having completed the work programme, Enegi Oil announced on 21st February 2013 that it had applied to the PAD for an Exploration Licence. The final award decision is subject to further research being conducted by the Environmental Protection Agency. These additional environmental studies were still underway at 31st March 2015.

Tamboran Resources. In the Northwest Ireland Carboniferous Basin (Lough Allen Basin), which straddles the border between the Irish Republic and Northern Ireland, Tamboran Resources and the Lough Allen Natural Gas Co. have taken out licences on both sides of the border to evaluate the potential of the Visean (Middle Mississippian) Bundoran and Benbulben shales, both of which yielded strong gas shows in wells drilled in the mid-1980s. TOCs are lower than in Clare (<2%).

***Netherlands*.**

Cuadrilla Resources. Cuadrilla Resources has been awarded a licence (Noord Brabant) on the margin of the London-Brabant High and West Netherlands Sub-basin of the Anglo-Dutch Basin. It is assumed that the Namurian (Upper Mississippian to Lower Pennsylvanian) Geverik Member of the Epen Formation shale is one of the targets in this location. Two wells, at Boxtel and Haaren, are planned. It is also possible that one of these wells may be targeting shale oil in the Lower Jurassic Aalburg and Posidonia formations in the Roer Valley Graben while another also targets tight gas in the Triassic. Cuadrilla's other Netherlands licence (Noordoostpolder) in the Northwest German Basin is a Namurian gas shale play.

Drilling of the first well (Boxtel) is unlikely to take place before 2016 as a result of permitting delays and the need to await the outcome of studies commissioned by the Dutch Ministry of Economic Affairs, Innovation and Agriculture on the risks associated with unconventional gas drilling and production. The first study, which was delivered on 27th August 2013, concluded that risks remained very small and is being followed by a 12-18 month study to identify preferred locations for shale gas exploration.

Poland.

A total of 23 concessions thought to have shale gas potential have been awarded in the Fore-Sudetic Monocline in southwest Poland but 18 have subsequently been relinquished. Orlen, PGNiG, PPI Chorobok and San Leon are the only remaining licence holders. Although all 5 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. On behalf of the Polish state company, PGNiG, Halliburton frac tested Upper Carboniferous shale in Markowola-1 in the Lublin Trough in July 2010 but the flow rates are said to have been lower than expected.

San Leon. The next test of the Carboniferous, Siciny-2, was spudded on 10th November 2011 by San Leon in the Gora concession, Fore-Sudetic Monocline. This well was located close to Siciny 1G-1, drilled in the 1970s, which had encountered a 3,266' Carboniferous section and was still in Carboniferous at TD. Siciny-2 was drilled to a depth of 11,550', encountering some 3,300' of Carboniferous. Continuous gas shows were encountered across three prospective shale intervals and two tight sandstone intervals encountered below 9,400'. The three highly-fractured shale intervals in Siciny-2 lie between 6,775' and 8,560' with a gross thickness of 1,400'. TOC values range from 1.2 - 3.25% and vitrinite maturity between 1.2 and 1.5%. Porosities are in the range 1.4 – 8.5% and average permeability is between 80 – 100 nD. Silica content is about 45%. Further prospective shale intervals are expected beneath the deeper of the two tight sandstones in which drilling terminated. Shale gas in place is estimated at up to 70 Bcf/ section. San Leon's estimate 61 Tcf of net risked recoverable tight gas and shale gas across its 13 concessions in the Fore-Sudetic Monocline.

In March 2013 San Leon signed a Memorandum of Understanding with Halliburton to jointly explore and develop the Carboniferous and deeper in three of these concessions (Wschowa; Gora; Rawicz). Halliburton perform 3 DFITs on the tight gas sand in Siciny-2 between May and August 2013. In June 2014 Palomar Natural Resources farmed into a number of San Leon's Fore-Sudetic Monocline concessions, taking a 65% interest and operatorship. Following the farm-in a number of licences were relinquished, including the Gora licence on which the Siciny-2 well is located.

United Kingdom.

England.

In central England Visean-Lower Namurian (Middle to Upper Mississippian) organic-rich deep-water marine shales of the Craven Group were deposited in a complex set of tectonically active grabens and half-grabens ("troughs") which developed as a result of N-S tension during the onset of subduction in the Variscan Foreland Belt to the south. Laterally, on horsts and tilt-block highs, the shales grade into shelf limestones and deltaic sandstones but in the depocentres hemipelagic marine shales and interbedded mass flow deposits may be as much as 16,000' thick. Rifting ceased in the late Visean but subsidence continued in the Namurian. A number of phases of Late Carboniferous uplift associated with the Variscan orogeny brought about basin inversion, and a complex set of hydrocarbon maturity conditions.

The primary target has been informally named the Bowland-Hodder unit by the British Geological Survey, and comprises the Bowland Shale, Hodder Mudstone, Edale Shales, Holywell Shales and other local unit names. The unit has been subdivided into a thick lower syn-rift unit (Lower Bowland Shale; Hodder Mudstone) and thinner upper post-rift basin infill unit (Upper Bowland Shale). The lower unit is known to reach thicknesses of up to 11,500' in depocentres and may be thicker. The upper unit transgressed across the highs and platforms but is considerably thicker and more organic rich within the basins. It is typically about 500' thick but reaches up to 2,900'. Depths to the top of the Bowland-Hodder unit range from zero to 16,000'. Depth to gas maturity (Ro > 1.1%) is estimated at about 9,500' but will be less where there has been subsequent basin inversion and uplift. TOC ranges from 0.2 – 8% but normally falls within the range 1-3%. For reasons of sample availability, most of these values come from the upper unit. Present-day kerogen is dominated by mixed type II-III and type III but may have been modified by maturation. The most prospective areas are considered to be the Bowland Basin, Edale Gulf, Gainsborough Trough and Cleveland Basin.

Cuadrilla Resources. Cuadrilla Resources, through its Bowland Resources subsidiary, has interests in the onshore portion (Bowland Basin) of the East Irish Sea Basin in PEDL 165 in Lancashire, northwest England. Spudded on 16th August 2010, the company's Preese Hall-1 well targeted a Visean-Namurian (Middle to Upper Mississippian) interval with the Bowland Shale the primary target. Drilled to a depth of 9,098', the vertical well encountered over 4,000' of shale between 4,400' and 9,004'. The shales contained both vertical and horizontal fractures and produced "substantial gas flows". The well encountered three prospective shale formations with a net thickness of 2,411': Sabden Shale of Arnsbergian (Late Mississippian) age (approximately 170'); Bowland Shale of Brigantian (Middle to Late Mississippian) age (1,685'); Hodder Mudstone of Visean (Middle Mississippian) age (554'). The well was due to have a 12 frac-stage completion over an interval from 5,260' to 9,000' but after 5 fracs, fracking was suspended due to two small earthquakes in the vicinity of the well (2.3 and 1.5 Richter Local Magnitude). The company commissioned a study to determine the relationship, if any, between the fluid injection and seismicity (see *5. Above-ground issues: United Kingdom*). The first three fracs (perforated intervals from 8,420' – 8,949' in the Hodder Mudstone) were tested on comingled flow and produced satisfactory amounts of gas and frac flow-back water. Fracs 4 and 5 (7,810' – 8,259' in the base of the Lower Bowland Shale) were being flowed in mid August 2011. In December 2013, Cuadrilla announced that no further exploration work will take place on the Preese Hall site. Between January and August 2011 the rig drilled a second well 3 km NE of Preese Hall-1 at Grange Hill-1, where top Lower Bowland Shale was forecast at ~ 6,500', slightly shallower than in Preese Hall-1. Preliminary core analyses suggest similar gas contents to Preese Hall-1 but over a thicker series of possible pay zones, as indicated by the final TD of 10,775' compared with the forecast TD of 9,500'. In July 2013, Cuadrilla announced that it intended to apply for planning permission to hydraulically fracture and test the well but subsequently announced that it does not intend to frac the well at this time but rather to use it as an observation well for seismic monitoring of two new sites. Becconsall-1, 15 km south of Preese Hall-1, spudded on 16th August 2011 and represented a substantial step-out from the locations of the first two wells.. Top Lower Bowland Shale was forecast at ~ 8,000', significantly deeper than in the previous two wells. On 13th October a vertical sidetrack, 1Z, was spudded and the well was completed on 21st December 2011. No results have been announced other than the TD of 10,500'. Cuadrilla plans a DFIT on this well.

On 6th October 2012, drilling commenced on a fourth well (Anna's Road-1), some 5 km southwest of the Preese Hall-1 location. Top Bowland Shale was estimated at 9,000' and TD at 11,500'. On 16th November, however, it was reported that the well had been abandoned at 2,000' because of a stuck packer. Plans to respud the well in January 2013 were subsequently altered to allow the company to modify its planning application to include the vertical well, a 3,000' horizontal leg, hydraulic fracturing and flow testing. Cuadrilla subsequently decided to abandon the Anna's Road well and restore the site to its previous condition. On 4th February 2014, Cuadrilla announced that the company intends 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 will also be 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) and 16th June 2014 (Roseacre Wood). The Environment Agency granted the necessary environmental permits for shale gas exploration on 16th January (Preston New) and 6th February 2015 (Roseacre Wood). The company still requires planning permission from Lancashire County Council before operations can 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.

Because of the substantial thickness of the Bowland Shale in PEDL 165, shale character shows significant variation. The shale is thought to have undergone an early period of oil generation prior to Variscan (Late Carboniferous) uplift. The subsequent deposition of the Manchester Marl and anhydrite (Upper Permian) formed a regional seal. Peak maturity occurred during the Jurassic – Cretaceous and was

followed by Alpine uplift. Total Organic Carbon (TOC) ranges from 1 – 6%, averaging 2 – 4%. Thermal maturity ranges from wet gas (C1 – C5) at the top of the shale to dry gas, with Ro range of 0.8 – 2.0% and Btu in the range 990 – 1,450. Porosity can range from 1 – 6% but gas-filled porosity is typically 4-5%. Silica / carbonate content is high with less than 50% clay, though the younger Sabden Shale, which is generally within the oil window, has higher clay content.

Based on gas desorption and geochemical studies undertaken at the Preese Hall well and a net shale thickness of 2,411' in that well, original gas in place at the Preese Hall location was estimated at 538.6 Bcf / square mile. On 22nd September 2011, Cuadrilla Resources announced a preliminary gas in place estimate of 200 Tcf for its 1,130 km^2 (436 square miles) PEDL 165 licence in Lancashire. The uncertified estimate was based on the two wells drilled at that time by Cuadrilla plus historical data from three wells drilled between 1987 and 1990 by British Gas. At the ShaleUK 2014 conference on 4th March 2014, Cuadrilla announced an increase in gas in place to 330 Tcf with potential for 100 Tcf recoverable.

IGas Energy. On 4th November 2011, IGas Energy spudded a joint coal seam gas / shale gas exploration well in the Carboniferous Rossendale Basin (beneath the Permo-Triassic Cheshire Basin) on PEDL 190 south of the River Mersey opposite Liverpool. The Ince Marshes-1 well was completed on 21st January 2012 having encountered about 1,000' of Bowland Shale in which gas indications were observed throughout. The well was still in shale at TD with total thickness estimates at ~ 1,650'. TOC generally fell in the range 1.2 – 3.7%, averaging 2.73%. Previous independent analysis suggested 4.6 Tcf gas in place in this area but on the basis of the well results IGas said that its potential in-place resource could be doubled to 9.2 Tcf. On 3rd June 2013, IGas reported that its in-house estimate of shale gas initially in place in its northwest England licences was 15.1 to 172.3 Tcf with a most likely in-place resource of 102 Tcf. In June 2012 IGas announced the beginning of a formal process to find a farm-in partner for its Cheshire shale gas prospect. On 15th January 2013, IGas announced a successful share placing, part of which is intended to fund a two-well shale gas appraisal programme intended to "augment value ahead of any farm-out". ExxonMobil was one of the companies rumoured to have been in discussions with IGas. On 10th January2014 IGas spudded a second Rossendale Basin joint coal seam gas / shale gas exploration well at Irlam, west of Manchester. Irlam-1 reached TD at 7,004' having penetrated 15 coal seams (net 77') and the Upper and Middle "Sabden" shales (Samlesbury Formation) and Bowland Shale. The section from Upper Sabden Shale to base Bowland Shale was continuously cored (384' of core) in sidetrack 1Z, spudded 3rd March 2014. The well was drilled on the eastern flank of the Rossendale Basin, hence the thin shale section. All three shale units were within the gas window.

Formation	TOC (%)	Porosity (%)	Permeability (µD)
Upper Sabden Shale	avg 1.6; max 2.1	3.3 - 5.3	0.03
Middle Sabden Shale	avg 2.4; max 5.7	0.9 - 4.5	0.02
Bowland Shale	avg 1.8' max 2.4	1.1 - 2.9	0.03
Source: IGas			

Table 5. Core analysis results from Irlam-1Z

Mineralogically, the Bowland Shale most closely resembled the Fayetteville Shale (USA). Following the drilling of the Irlam-1/1Z well and the acquisition of Dart Energy, on 4th November 2014 IGas increased its in-house estimate of shale gas initially in place in its northern England and Scottish licences to 50 Tcf (34 net) to 352 Tcf (263 net) with a most likely in-place resource of 192 Tcf (147 net). In November / December 2014 IGas drilled Ellesmere Port-1 in a more central location within the Rossendale Basin. Total "Sabden" and Bowland shale thickness was estimated at approximately 1,400' with significant gas indications being observed across the shale section.

Dart Energy (acquired by IGas on 16th October 2014). Dart Energy had 11 licences in the Cheshire and Stafford basins. Netherlands Sewell & Associates (NSAI) made a best estimate of 30.5 Tcf original gas in place over six of these licences. The Bowland Shale may also be prospective east of the Pennine High in the East Midlands, Humber and Cleveland basins, where it is a known source rock for oil and gas. Since 2010 a complex set of acquisitions, farm-ins and ownership exchanges has taken place on licences PEDL 139 and 140 in the Gainsborough Trough, East Midlands Basin, reflecting the potential of this acreage. Of the original licencees, only Egdon Resources remains, with eCorp International, IGas, Dart Energy and, most recently, French major Total all acquiring interests. Total (40%) is the largest interest holder and IGas is the operator. Total will fund a work programme including the drilling of a vertical exploration well. Total has also taken an option to farm into the adjacent PEDL 209 operated by Egdon. Dart Energy bought into the Gainsborough Trough acreage through its acquisition of Greenpark Energy's unconventional gas assets (see *4.2 Licence Acquisitions: United Kingdom*). Dart's (now IGas) NSAI best estimate of Original Gas in Place for 7 of its 13 licences east of the Pennines was 32.4 Tcf net to Dart (47.6 Tcf gross). The above estimates of net gas in place predate the GDF SUEZ farm in. A number of wells which have been drilled in Yorkshire to explore for conventional Permian and Carboniferous carbonate and sandstone reservoirs have also drilled through and sampled the Bowland Shale.

Rathlin Energy (UK). Between April and September 2013, Rathlin Energy (UK), a wholly owned subsidiary of Canada's Connaught Oil & Gas, drilled Crawberry Hill-1 and West Newton-1 in PEDL 183 in the Humber Basin, north of Hull, East Riding of Yorkshire. The wells were conventional exploration wells designed also to appraise the Bowland Shale. Planning permission for testing the two wells has been applied for. The applications are for flow tests of the Permian carbonate and Carboniferous (Lower Namurian) sandstone plus mini fall-off tests (DFITs) in the Upper Visean / Lower Namurian (presumed Bowland Shale) at 8,783' in Crawberry Hill-1 and 10,023' in West Newton-1.

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. Planning permission has also been obtained to investigate Carboniferous shale potential in southern England.

Coastal Oil & Gas. On PEDL 252 on the southern margin of the Wales – Brabant High near Woodnesborough in Kent (north of the Kent Coalfield), Coastal Oil & Gas (a wholly owned subsidiary of UK Onshore Gas Ltd.) has received planning permission for a well to take core samples of some 8 Westphalian (Middle Pennsylvanian) coal seams and the Lower Limestone Shales of the Tournasian (Lower Mississippian) Avon Group. It is not known when this well will be drilled.

Wales.

IGas Energy. IGas Energy has identified 1.14 Tcf of 2P contingent resources of gas in place in the Bowland Shale equivalent on its acreage in North Wales.

Coastal Oil & Gas. In South Wales Coastal Oil & Gas applied for permission to drill the Llandow gas shale exploration well to a depth of 2,130' to log and core the Namurian Millstone Grit Shale Group, the Dinantian Upper Limestone Series and Lower Limestone Series, and possible gas shale in the Ordovician, in addition to Devonian tight gas. Despite this well being drilled on the same basis as previous coal seam gas exploration wells drilled in the area by Coastal in 2007/8, the company was obliged to withdraw the application in the face of local opposition to the drilling. When resubmitted the application was rejected by Vale of Glamorgan Council but has since been approved on appeal (see *5. Above-ground issues: United Kingdom*). Although the principal shale gas target in the Llandow well appears to have been the Lower

Limestone Shales of the Courceyan (Lower Mississippian) Avon Group, Coastal's partner, Eden Energy has identified the Namurian as the principal target over its acreage. The most prospective unit is presumed to be the Pendleian (basal Namurian or Upper Mississippian) Aberkenfig Formation. Eden has reported a gross unrisked P90 estimate of 34.2 Tcf shale-gas-in-place in the Namurian of its seven South Wales licences (17.1 Tcf net to Eden).

U.K. Methane. In August / September 2011, U.K. Methane (another wholly-owned subsidiary of UK Onshore Gas Ltd.) spudded St Johns-1 and Banwen-1, targeting Namurian shale. The target depths are believed to be relatively shallow, about 2,000' in the case of St Johns-1.

Scotland.

The basal Namurian (Upper Mississippian) Black Metals Marine Band in licence PEDL 133 in the Midland Valley of Scotland was cored by Composite Energy in Airth-6 (2005) and Longannet-1 and Bandeath-1 (2007). These were the earliest shale gas investigations in Europe. The Black Metals Member (Limestone Coal Formation) of the Kincardine Basin occurs at depths of 1,000' to 4,000'. The Black Metals was 120' thick in Airth-6 and the core analysis results are assumed to have been promising, as BG Group subsequently farmed into the licence. In June 2011, Australia's Dart Energy (formerly Composite Energy) announced the results of an independent assessment by NSAI of shale resources in PEDL 133, in the Midland Valley of Scotland. This indicated an estimated gas-in-place of 0.8 Tcf in the Black Metals Member, and a potential resource of 0.1 Tcf. The deeper Visean (Middle Mississippian) shales of the Lawmuir and Lower Limestone formations were estimated to contain 3.6 Tcf gas in place with a gross resource of 0.5 Tcf. Dart Energy owned 100% of the Namurian prospect but BG retained a 51% interest in the Visean prospect until sold to INEOS in August 2014. Shale gas exploration of PEDL 133 was still at an early stage while Dart focused on the start-up of coal seam gas production from the licence but in October 2014 Dart was acquired by IGas and in March 2015 IGas announced its intention to sell its remaining interest in PEDL 133 to INEOS, the joint licence holder. INEOS (80%) will also explore for shale gas in the adjacent PEDL 162.

Liassic (Lower Jurassic)

The third major regional play comprises Lower Jurassic bituminous shales that are being targeted in the Weald Basin (southern England), Paris Basin, the Netherlands, northern Germany and Switzerland's Molasse Basin. In continental Europe, the principal target is the Lower Toarcian Posidonia Shale. In eastern Germany and Poland the Lower Toarcian grades into a terrestrial facies and loses its source potential. In southern England the principal bituminous shales (Blue Lias; Black Ven Marls; Green Ammonite Beds) are older and occur in the Lower Lias. These bituminous shales are clearly oil-prone. The principal limitation regarding their shale gas potential therefore lies in finding locations in which they have been sufficiently deeply buried to have entered the gas window. Locations where this may have occurred include the flexural foreland basin of the Swiss Molasse and the Mesozoic depocentres of the Lower Saxony Sub-basin (Northwest German Basin) and the offshore Broad Fourteens Basin and Central Graben of the Netherlands. A number of companies are thought to be investigating Lower Jurassic shale gas potential. These include Cuadrilla Resources in *England*'s Weald Basin and Schuepbach Energy in *Switzerland*'s Molasse Basin. Whether the Liassic shales will be within the gas window in the Weald Basin remains to be seen though it is possible that they may have generated biogenic gas at shallow depths. To date, the only known exploratory tests of the Lower Jurassic shale gas play have taken place in Germany where ExxonMobil drilled wells between 2008 and 2011.

France.

Schuepbach Energy was awarded two permits in the Languedoc-Provence Basin where Total was awarded the Montélimar permit. The Lower Jurassic (Toarcian) Schistes Carton is considered to have potential in the area covered by all three permits. Both the Schuepbach and Total permits have since been cancelled (see *5. Above-ground issues: France*) and Schuepbach is reported to have asked the French

government for 1 billion Euros by way of compensation. A number of other companies have also applied for permits in Languedoc-Provence, many of them overlapping.

Germany.

ExxonMobil. The ExxonMobil / Shell co-venture (BEB) commenced shale gas exploratory drilling in 2008 in the Lower Saxony Basin, drilling Damme-2/2A in the Munsterland concession and Oppenwehe-1 in Minden. Schlahe-1 was drilled in 2009 in the Scholen concession. Posidonia Shale is known to have been at least one of the targets for these wells. ExxonMobil is believed to have spudded Lünne-1 (Bramschen concession, Emsland) around 17th January 2011 and reached the Posidonia Shale at about 4,720'. In March 2011, the Lünne-1A horizontal sidetrack was drilled in the Posidonia Shale to a total length of 760'. (The well was planned to have a 1,600' horizontal leg.) A frac test is planned but has not yet been applied for. The thickness of the Posidonia Shale ranged from 80' (Lünne-1) to 115' (Oppenwehe-1; Schlahe-1). ExxonMobil has also announced plans to drill and frac test a 3,300' horizontal leg (Z14b) at a depth of 3,380' within the Posidonia Shale from well Z14 in the Bahrenborstel Upper Permian Zechstein carbonate sour gas field. The Bahrenborstel Z14b sidetrack is one of a number of future horizontal shale gas exploratory wells planned by ExxonMobil in Lower Saxony, also including: Leese-Ost-1 and Ortland 26. No dates for drilling any of these wells are available at this time

Other plays with shale gas potential

Austria.

OMV. OMV has investigated the potential of the Upper Jurassic Mikulov Formation in the Deep Vienna Basin. The company estimates that the formation contains 200 – 300 Tcf of gas in place of which 15 Tcf may be recoverable. The target occurs at depths greater than 14,700' and a temperature of 160° C. Two initial wells had been planned near Herrnbaumgarten and Poysdorf in the Mistelbach District of Lower Austria at a combined cost of EUR 130 million. But subsequent proposed changes to Austrian environmental legislation mean that the project is no longer economically viable.

Bulgaria.

The Lower to Middle Jurassic of the Moesian Platform, especially the basal Stefanetz Member of the Middle Jurassic Etropole Formation, is a target in northern Bulgaria, where Direct Petroleum (TransAtlantic Petroleum) has a licence and Chevron successfully applied for a licence which was subsequently revoked. Chevron has indicated that the Silurian was also a target in its Novi Pazar licence.

Transatlantic Petroleum / LNG Energy. Direct Petroleum / LNG Energy spudded the 10,500' Goljamo Peshtene R-11 well in the A-Lovech exploration licence in late September 2011. The well (TD 10,465') encountered 375' of net pay in the Etropole Formation with numerous gas shows in the C1 – C3 range. TransAtlantic has estimated the gross unrisked prospective undiscovered recoverable resource at 11 Tcf (best estimate). Operations in Bulgaria are constrained by the decision of the Bulgarian Parliament in January 2012 to ban hydraulic fracturing. Permission from the Bulgarian Government has not yet been received to resume completion and testing operations on the Peshtene R-11 well.

Croatia.

Hungary's MOL and its part-owned subsidiary INA have indicated that the Miocene of the Mura and Drava sub-basins (Pannonian Basin) of eastern Croatia has shale gas potential.

Czech Republic.

Potential shale gas plays include the Mikulov Marl (Upper Jurassic - Oxfordian) in the Czech portion of the Deep Vienna Basin (SE Czech Republic). The oil window is at depths of 13-19,000' and the gas window even deeper. The Menilite Formation (Oligocene) of the Carpathian Flysch Belt which may generate gas below 16,000'. The autochthonous Paleogene of the SE Bohemian Massif has favourable TOC and gas-prone kerogen, but a gas window starting at 19,000'.

France.

Permo-Carboniferous basins in the Languedoc such as the Stephanian-Autunian (Upper Pennsylvanian – Lower Permian) Lodève Basin may have some potential in bituminous Autunian (Lower Permian) shale. Schuepbach Energy was awarded two permits in the Languedoc-Provence Basin, one of which also incorporated part of the Lodève Basin. The Schuepbach permits have since been cancelled (see *5. Above-ground issues: France*) and Schuepbach is reported to have asked the French government for 1 billion Euros by way of compensation.

Realm (San Leon) identified Stephanian-Autunian potential in the Bresse-Valence Basin, where it submitted an application. Elixir Petroleum is exploring for shale gas (and tight gas) in the Permo-Carboniferous of the Moselle concession in the eastern Paris Basin, where in the past at least two wells have produced gas to the surface from the target interval (probably Carboniferous). In the main Paris Basin many conflicting applications have been filed. While the main focus of these is probably Liassic shale oil, a number are presumably also targeting shale gas potential in underlying Permo-Carboniferous half-grabens.

Germany.

The Upper Devonian Kellwasser shale has been touted as having potential in northern Germany, as have Wealden paper shales of Berriasian age in the Lower Saxony Sub-basin.

ExxonMobil. The ExxonMobil / Shell co-venture (BEB) commenced shale gas exploratory drilling in 2008 in the Lower Saxony Basin, drilling Damme-2 and 3 in the Munsterland concession and Oppenwehe-1 in Minden. Schlahe-1 was drilled in 2009 and Niedernwöhren-1 was spudded in the Schaumburg permit in October 2009. ExxonMobil is believed to have spudded Lünne-1 (Bramschen concession, Emsland) around 17th January 2011. The Wealden is known to have been at least one of the targets in all of these wells and Damme-3 and Niedernwöhren-1 targeted the Wealden exclusively. Damme-3 is known to have been frac tested (3 fracs). Wealden thickness ranges from 800' (Schlahe-1) to 2,300' in the Damme wells. Realm Energy (San Leon) also sees the Wealden as a potential target on its Aschen concession.

3Legs Resources. In the Bodensee Trough, north of the Swiss-German border, Parkyn Energy, another 3Legs Resources subsidiary, took out two licences in 2009 in which the principal prospect appears to be lacustrine shale of Permian age. The company acquired two-year extensions to these licences in December 2013 and then transferred its interest to Rose Petroleum in order to maximise its focus on its Baltic Basin concessions in Poland. In November 2014 Rose Petroleum decided to exit the two licences in view of the uncertain regulatory environment for unconventional hydrocarbon exploration in Germany.

Hungary.

The shale gas exploration situation in Hungary is unclear.

Falcon Oil & Gas. In September / October 2009, Falcon Oil & Gas / ExxonMobil / MOL tested an Upper Miocene basin-centred gas prospect in the Makó Trough (Pannonian Basin) with only limited success, after which ExxonMobil and MOL exited the project. But Falcon has suggested that its acreage holds a "potential fractured oil and gas play". Previously, in 2007, Falcon had tested a naturally fractured marl-rich section of the Upper Miocene Endröd Formation in Szekkutas-1. After fracture treatment at about 11,100' the well flowed at an unstabilised rate of 1.577 million scf/d plus 50 to 100 ppm H_2S. RPS Energy (January 2013) estimated the 2C gas resources of the Lower Endröd at 1.11 Tcf but with the qualification that there is a less than or equal to 25% chance that the contingent resources will be converted to reserves.

MOL / INA. MOL and its part-owned subsidiary INA have indicated that the Miocene of the Mura and Drava sub-basins (Pannonian Basin) of eastern Croatia has shale gas potential and it can be assumed that this extends into western Hungary.

Delcuadra. In September 2009, Austria's RAG (Rohöl-Aufsuchungs Aktiengesellschaft) acquired Toreador Hungary Ltd. Toreador had just drilled the Balotaszallas-E-1 (Ba-E-1) well in the Kiskunhalas Trough of the Pannonian Basin. Ba-E-1 encountered an over-pressured 1,840' gross gas-bearing interval in an interbedded Karpatian (Lower Miocene) sequence of siltstone, shale and sandstone below 10,000'. The two lowest zones were fractured and are believed to have produced gas-condensate. At that time, the tested lithology was reported as tight sandstone (Shaoul et al., 2011). In July 2011, the Delcuadra Kft consortium (Delta Hydrocarbons 53%; RAG 25%; Cuadrilla 22%) recompleted an additional 3 zones of the Lower Miocene reservoir in Ba-E-1. At the Global Shale Gas Plays Forum in September 2011, RAG reported this as a shale gas frac and has subsequently confirmed that the completions were carried out in "a thick heterolithic sequence of shales and (very) fine clastics". Testing produced a gas flow rate of 1 million cf/d plus small amounts of condensate. Both are being sold and a long term production test commenced in August 2011 and full gas-condensate production was due to commence before end-2011. Cuadrilla had the option to earn a further interest by drilling and completing a second well in the Ba-IX Mining Block. This well, Ba-E-2, was planned for the second half of 2012.

***Italy*.**

Independent Resources. A shale gas / coal seam gas combination play is being investigated by Independent Resources in the Ribolla Basin, Tuscany. Upper Miocene (Messinian) gas shale straddles a coal seam of up to 20' thickness over a distance of tens of kilometers along the basin axis. The play was discovered in the course of evaluating the results of the Fiume Bruna-1 & 2 coal seam gas exploration wells drilled in 2009-2010. Farm-out discussions with companies which have experience of analogous plays were undertaken but have not produced a suitable partner, in part, the company believes, due to the public opposition in Europe to unconventional gas exploration and exploitation. In-place and recoverable 2C contingent resources are estimated at 300 Bcf and 160 Bcf, respectively. New seismic is scheduled for late 2013 and any early development will probably be based on coal seam gas to avoid concerns about hydraulic fracturing.

***Netherlands*.**

The Upper Jurassic Kimmeridge Clay is sufficiently deeply buried in the Central Graben in the northern Netherlands offshore to have reached the gas window. In view of the high well cost and drilling density likely to be required, it seems unlikely that offshore shale gas development will be economic in the foreseeable future unless an existing platform and wells happen to be fortuitously located in an optimal location for shale gas development.

***Romania*.**

Chevron and Sterling Resources / TransAtlantic Petroleum acquired a number of licences in the Moesian Platform of the East European margin in the south of the country, along the Bulgarian border. The targets were believed to be shale of Silurian to Lower Devonian age (Tandarei Formation) and Middle Jurassic age (Bals Formation). Sterling Resources / Transatlantic Petroleum reprocessed existing 2D seismic to identify a drillable location and evaluate re-entering a legacy well on a Silurian prospect in Sud Craiova Block EIII-7. All of these licences have now been dropped.

Romgaz. State-controlled Romgaz says it has made an unconventional discovery, which includes shale gas, in the Transylvanian Basin. It has been encountering the gas in drilling since the mid 1990s.

***Spain*.**

Applications that are presumed to be for shale gas exploration have been submitted in the Basque-Cantabrian Basin (BNK; Realm Energy (San Leon)), Pyrenean Foothills (Cuadrilla Resources), Ebro Basin (Realm Energy (San Leon)) and the Campo de Gibraltar (Schuepbach Energy / Vancast). The focus of interest appears to be the Basque-Cantabrian Basin and the area of the Pyrenean Foothills immediately to the

east. Trofagas Hidrocarburos (BNK) has been awarded three concessions in the basin, Realm (now San Leon, operating as Frontera Energy Corp.) has two awards plus two pending awards, Leni Oil & Gas has interests in four and while SHESA (owned by the Basque Energy Board, the regional government of the Basque Country) has interests in a substantial number of permits it seems to be focussing on the Enara permit. There does, however, appear to be a divergence of opinion regarding the most prospective targets. BNK, Leni and San Leon believe that the Jurassic is most prospective (especially the Lias) while SHESA is targeting Albian – Cenomanian shales. San Leon sees the Middle Albian – Lower Cenomanian Valmaseda Formation and Carboniferous shale as objectives in its Geminis licence on the Basque Country coast.

SHESA. SHESA and its partners, HEYCO Energy and True Oil, plan to drill two vertical wells, Enara 1 and 2, to evaluate the Albian – Cenomanian Valmaseda Formation where it estimates there are 200 Tcf in place.

BNK Petroleum. BNK has submitted five Environmental Impact Assessments on its Sedano and Urraca concessions as part of the exploratory drilling permitting process and planned to drill in 2014, pending permitting.

San Leon. In the Ebro Basin, San Leon's six pending awards are primarily targeting organic-rich Paleozoic shales (Ordovician; Silurian; Carboniferous) but Eocene shale is also a target.

Switzerland.

Schuepbach. In addition to the Lower Jurassic Posidonia Shale, Schuepbach has also targeted the Aalenian (Middle Jurassic) Opalinuston in the Molasse Basin. It is understood, however, that the cantonal authorities in Fribourg would not renew the Fribourg licence when it expired at end-2011, over environmental concerns. Schuepbach still hopes to explore for shale gas in Canton Vaud, to the south of Fribourg.

United Kingdom.

The Upper Jurassic Kimmeridge Clay has been proposed as a possible target in the Weald Basin, *England*, but there is considerable doubt that it will be mature for significant gas generation in this basin, although biogenic shale gas may be a possibility. Cuadrilla's interest in the Kimmeridge Clay is for shale oil rather than shale gas. If there is shale gas potential in the basin it seems more likely that it will come from older shales (Rhaetic or older). For example, Esso's 1963 Bolney 1 well is reported to have found a marine Middle Devonian interval within the gas window.

Some general gas resource play issues

Most plays are "statistical" in nature. Every coal unit and shale unit is "different" and also generally displays inhomogeneity. Statistical distributions can be obtained for parameters such as estimated ultimate recovery (EUR) and peak production from analagous wells. With a large enough sample size (number of wells) the geology of the play and the best drilling and completion strategies can be understood sufficiently well to make performance of a play and its recoverable resources predictable. European exploration is still some considerable way from achieving these levels of understanding. To convert recoverable resources into reserves requires good technology: smart wells; fracture and stimulation; real-time micro-seismic mapping.

Shale liquids in Europe

The principal shale liquids (tight oil) target in Europe is the Liassic (Lower Jurassic) which is considered by many to be an analogue to the Bakken Formation of the Williston Basin. It is being investigated in France, Germany, The Netherlands and Portugal. The Upper Jurassic is understood to be a target in the south of the United Kingdom and central Poland, while a liquids-rich area has also been identified in the Polish Lower Paleozoic play.

France.

There are four Liassic (Lower Jurassic) targets in the Paris Basin: Schistes Carton (Toarcian); Banc de Roc (Pliensbachian); Amaltheus Shale (Pliensbachian); Sinemurian-Hettangian Shale. The Liassic section is similar to the Bakken Formation in that the bituminous shales also contain a middle calcareous member (Banc de Roc). TOC ranges from 1 – 12%, averaging 6%, and thickness ranges from 30' to 230'.

Hess. Toreador Resources (now ZaZa Energy Corp.) investigated the fractured shale oil potential of the Liassic interval. Shows had previously been detected in 11 conventional exploration wells drilled from the 1950s onwards and 6 wells have produced oil on test. On 10th May 2010 Toreador signed an investment agreement with Hess Corp. whereby each partner would hold a 50% interest in Paris Basin unconventional oil exploration and production. In July 2012 ZaZa Energy transferred its remaining 50% interest to Hess (see *4.3 Ownership Transactions: Farm-ins*). Toreador / Hess had planned to drill six wells in 2011, at least two of them horizontal, but as a result of the French government study into the economic, social and environmental impact of shale gas and shale oil drilling and the introduction of the resultant legislation, the programme was suspended. Hess had scheduled a three (3) vertical well drilling program for 2013 but it is unclear whether this will test the Liassic play.

San Leon. Realm Energy (now wholly-owned by San Leon), although focused on shale gas, has shale oil potential on the nine permits for which it has applied in the Paris Basin. San Leon estimates the potential of these licences at greater than 100 million boe. Realm had in the past indicated that the Toarcian Schistes Carton may also have shale oil potential within the area of its Blyes permit application in the Bresse-Valence Basin.

Vermilion Energy. In spring and autumn 2010 Vermilion Energy fracture tested two vertical wells in the Toarcian Schistes Carton, producing 32 - 38° oil from both wells. In February 2011 these wells were believed to be producing about 63 bbl/d. Vermilion had planned to drill another two vertical wells in 2011 to evaluate all four zones and to drill a horizontal well in 2012 based on 2011 results but it is understood that Vermillion has now suspended all Paris Basin shale oil evaluation activity. On 22nd September 2011, Vermillion withdrew three permit applications in the Paris Basin, possibly as a consequence on the ban on hydraulic fracturing introduced on 13th July 2011 (see *5. Above-Ground Issues: France*).

Germany.

Outcrop work by BNK Petroleum identified samples of the Toarcian-age Posidonia Shale with thermal maturities ranging from below the oil window to within the gas window. It therefore seems probable that over some of BNK's former acreage the Posidonia Shale will fall within the oil window and have potential for tight shale oil. BNK has relinquished its eight German concessions.

Hungary.

Falcon Oil & Gas has indicated that the Upper Miocene Endröd Formation in the Makó Trough (Pannonian Basin) has shale oil potential. In 2007, Magyarcsanad-1 flowed 48° API oil and gas from natural fractures in argillaceous marl and siltstone of the Upper Endröd at 13,320'. The initial rate of 387 bo/d and 655 Mscf/d declined to 63 bo/d and 137 Mscf/d after 23 days. The well produced a total of 850 barrels of oil and 2 million cf gas intermittently between November 2009 and July 2012. RPS Energy (January 2013) estimated the 2C oil resources of the Upper Endröd at 76.71 million barrels but with the qualification that there is a less than or equal to 25% chance that the contingent resources will be converted to reserves.

Lithuania.

Minijos Nafta. In Mid-May 2012 local oil producer Minijos Nafta spudded a Cambrian sandstone oil exploration well, Skomantai-1, on its Gargzdai concession which was also intended to test the Ordovician and Silurian shales for unconventional hydrocarbons. Core samples were sent abroad for analysis of natural fractures, induced fracturing potential, porosity, permeability, source rock quality & maturity. In this location the Lower Paleozoic probably has shale liquids potential.

Netherlands.

Cuadrilla Resources, in partnership with Dutch state company EBN, is targeting multiple unconventional hydrocarbon prospects on its Noord Brabant concession. The first well to be drilled (Boxtel-1) will evaluate the shale oil potential of the Posidonia Shale (Lower Toarcian) in the Roer Valley Graben at a depth of about 11,500'.

Poland.

Wisent Oil & Gas. Wisent Oil & Gas has four of the most easterly concessions in the Gdansk Depression, along the border with the Russian enclave of Kaliningrad, where Lukoil has been producing conventional oil for some time. As is noted above, these concessions appear to be situated in a more liquids-prone part of the basin (see *2.1.1 Lower Paleozoic: Poland*). In addition to tight shale oil, Wisent expects there to be conventional prospects in Cambrian and Ordovician carbonates. Wisent drilled its first well, Rodele-1, on the Kętrzyn concession between February and March 2013 to a depth of 5,075'. The Silurian shale was found at the depth and thickness expected. The well was fracced in September 2013. Wisent spudded Babiak-1 on the Lidzbark Warmiński concession in March. The well drilled to a true measured depth of 9,160', including a 1,865' horizontal leg. The well was fracced in July 2013. Between March and April 2014 Wisent drilled Mingajny-1 on the Lidzbark Warminski concession.

San Leon. Following Talisman's announcement of its withdrawal from its Polish Operations, on 8th May 2013 San Leon reported that it had assumed 100% ownership of the Gdansk West and Braniewo S concessions through its acquisition of the shares of Talisman Energy Polska. On 3rd July San Leon then announced an agreement whereby Wisent Oil & Gas could earn a 45% interest in the Braniewo S concession by conducting a three-stage fracture on the Rogity-1 well followed by drilling and testing a multi-stage horizontal well on the concession. The first Rogity-1 frac was completed in tight oil-bearing Middle Cambrian quartzitic sandstone on 4th August 2013. The fluid produced from the 9,055-9,070 interval indicated that the sandstone is in the vicinity of the oil-water contact in this location. The second (8,860-8,925' in Ordovician shale and marl) and third (8,630-8,710' in Lower Silurian Llandovery shale) frac stages were then tested comingled with the first, oil (39°) flowing to surface. Geochemical analysis indicated that oil different from Cambrian oil was recovered and that mobile oil had therefore been recovered from the shales. Wisent is scheduled to drill a vertical well, Rogity-2, either on the crest of the Rogity Cambrian structure or to the south of Rogity-1, where the Silurian shale is forecast to have higher TOC. Wisent will also undertake 3D seismic or additional drilling to compensate for the horizontal multi-fracced well originally envisaged.

Hutton Energy. In 2011, Hutton Energy's Polish subsidiary Strzelecki Energia acquired three concessions in the Mogilno-Łódź Trough of the Northeast German-Polish Basin in central Poland. In addition to conventional traps in Jurassic and Triassic sandstone, the company considered that the concessions have unconventional oil and gas potential in Jurassic shale, most probably of Middle Jurassic (Dogger) and Late Jurassic (Kimmeridgian) age. In February 2013, Hutton engaged Challenge Energy to find a partner to progress exploration activity on the three concessions. The prospectus indicated an upside of 100 million barrels of Jurassic shale oil potential. Hutton has since relinquished these concessions without drilling.

Portugal.

On 1st March 2012, Porto Energy Corp., holder of five licences on and offshore the Lusitanian Basin, announced that it had entered into a definitive joint venture agreement with Sorgenia International of the Netherlands and Austria's Rohöl-Aufsuchungs Aktiengesellschaft (RAG) to evaluate the unconventional resource potential of the Lower Jurassic (Liassic) basal Brenha Formation within Porto's concessions. The organic-rich Lias is the source of oil seeps along the coast and has historically been surface mined for bitumen. In September 2012 the company announced that it has received approval from the Portuguese oil and gas authority for its development and production plan for the Company's concessions onshore Portugal. The plan covers a period of five years during which Porto will execute a work programme focused on

commercialising the Lias resource play in one or more areas within its concessions. In October 2012 Porto announced the conclusion of a 23-well stratigraphic drilling programme (Phase 1) to evaluate the unconventional resource potential of the Lower Jurassic (Lias) stratigraphic interval. The preliminary results demonstrated thicknesses and presence of organic-rich intervals consistent with pre-drill estimates and cores taken within the Lias interval showed higher than expected Total Organic Carbon. The farm-in partners had until December 31, 2012 to elect to proceed to Phase 2 activities as contemplated under the joint venture but on 5th April 2013 Porto announced that the partners had elected not to do so. Porto therefore expects to commence a farm-out process for its unconventional onshore Lias acreage. On 26th May 2014 Porto announced that it was winding down its operations in Portugal as it had been unable to attract investors.

United Kingdom.

The Bowland Shale is an oil source rock in the East Midlands area of England and can be expected to lie within the oil mature zone at a number of locations. In the younger Namurian (Upper Mississippian – Lower Pennsylvanian) Millstone Grit Group in Lancashire, basinal shales such as the 2,000' "Sabden Shale" (Samlesbury Fm) and the 230' "Caton Shale" (Silsden Fm) are believed to lie within the oil window in some locations. In southern England, the Upper Jurassic Kimmeridge Clay (thickness > 1,600'; TOC > 20%) and Lower Oxford Clay (thickness 300' maximum TOC 12%) and Blue Lias, Black Ven Marls and Green Ammonite Beds of the Lower Jurassic Lower Lias (thickness > 1,600'; maximum TOC 12%) have shale liquids potential.

Cuadrilla Resources. Cuadrilla Resources is investigating the shale oil potential of the Upper Jurassic Kimmeridge Clay in its Bolney project on PEDL 244 in the Weald Basin, southern England, where Esso found gas shows at shallow depth in Bolney-1 (1963). In April 2010 Cuadrilla received planning permission to drill the Lower Stumble test of the Kimmeridge Clay using the well pad of Balcombe-1, drilled by Conoco in 1986 on the Bolney (Lower Stumble) anticline. Top Kimmeridge Clay is estimated to occur at a depth of around 1,830' at this location and to lie within the relatively small sweet spot where the Kimmeridge Clay has reached oil maturity. Cuadrilla spudded Balcombe-2 on 2nd August 2013, drilling to a TD of 2,700' on 5th September, despite interruptions caused by protesters. The 1,700' Balcombe-2Z horizontal leg was then drilled within the Mid-Kimmeridge "I" Micrite at 2,500' and the well completed on 22nd September 2013. The well encountered hydrocarbons and has been suspended while Cuadrilla applies for planning permission for testing. The planning application excludes hydraulic fracturing and is being treated as a conventional well producing from natural fractures. In May 2011, AJ Lucas reported that Cuadrilla had fracced the Cowden 2 gas discovery well in the Weald Basin. The well was drilled by Independent Energy in August 1999 on a separate licence, EXL 189. The results were said to be inconclusive. It is not known if this was a test of the well's shale oil or shale gas potential since an oil discovery, Lingfield-1, was also made within the EXL 189 licence area in 1999. AJ Lucas indicated that a further well would be drilled later but it is unclear whether this refers to the Lower Stumble shale oil test on PEDL 244 or a well on EXL 189.

Horse Hill Developments. Horse Hill Developments, as operator, drilled Horse Hill-1 between September and November 2014 on PEDL 137 in the Weald Basin to a TD of 8,770' in Paleozoic rocks. A conventional oil discovery (still to be tested) was made in the Portland Sandstone (Upper Jurassic). The well also identified potential recoverable liquids within a 653' aggregate net pay in naturally fractured argillaceous limestone and mudstone of the Kimmeridge Clay and mudstones of the Oxford and Lower Lias intervals. The Kimmeridge section contains 511' net pay with average TOC of 2.8% and calculated oil-in-place of 115 million bbl / square mile. The hydrocarbon occurrence appears to be analagous to Cuadrilla's Balcombe-2 discovery and, according to one of the participants, the liquids could be developed by conventional horizontal drilling and completion techniques without recourse to hydraulic fracturing.

Celtique Energie. Celtique applied to the South Downs National Park Authority to drill Fernhurst-1 on PEDL 231 and to West Sussex County Council to drill Wisborough Green -1 on PEDL 234. Both Weald

Basin wells were envisaged as tests of a conventional Kimmeridge Limestone and a Great Oolite stratigraphic trap play but also to log and core the Kimmeridge Clay and Middle and Lower Lias to establish their shale liquids potential. Both planning authorities refused planning permission and on 11th March 2015 Celtique Energie announced that it would not appeal the Fernhurst decision, as shale exploratory drilling in protected areas is now banned in protected areas under the Infrastructure Act 2015, and withdrew its appeal against the Wisborough Green decision as the process could not be concluded before the expiry of the licence in June 2016.

Ownership transactions

There have been a substantial number of business deals in Europe as late entrants tried to gain a foothold in promising acreage and smaller companies sought additional financing. Full company M&A activity has also occurred though most transactions have taken the form of licence purchases or farm-ins. Some of the more significant transactions are listed in the following sections.

Company mergers, acquisitions and restructuring

On 28th February 2011, Dart Energy Ltd. of Australia announced that it would acquire with immediate effect the 90% of the shares in the UK's Composite Energy Ltd. that it did not already own. Although primarily a coal seam gas explorer, Composite Energy had acreage with shale gas potential in both Scotland and Poland. On takeover, Composite Energy became Dart Europe Ltd.

On 10th August 2011, Toreador Resources Corp. announced a merger with ZaZa Energy LLC of Houston, TX, combining ZaZa's Eagle Ford and Eagle Ford/Woodbine ("Eaglebine") interests with Toreador's Paris Basin interests. The new company will be called ZaZa Energy Corp.

On 26th August 2011, the UK's San Leon Energy plc and Canadian company Realm Energy International Corp. announced an agreement whereby San Leon would acquire all of the shares of Realm, resulting in Realm becoming an indirect subsidiary of San Leon. The acquisition was completed on 10th November 2011. On completion of the deal, San Leon acquired 3 licences in Poland, 1 in Germany and 2 in Spain. In addition Realm had 10 outstanding licence applications in France and 8 applications in Spain. With the exception of 9 applications in the Paris Basin focused on shale oil, the primary target of the Realm licences and applications was shale gas.

On 16th January 2012, Dart Energy announced the formation of Dart Energy International Shale. This wholly-owned subsidiary will manage and develop the company's growing portfolio of shale gas interests. With the exception of one asset in China, these are held in Europe.

On 24th January 2013, San Leon Energy plc completed the acquisition of Aurelian Oil & Gas plc. Aurelian owned unconventional gas assets and acreage with unconventional gas potential in Poland plus other largely conventional assets in several European countries.

On 2nd April 2013, Dart Energy announced the cancellation of the planned IPO of Dart Energy International (Dart Energy's non-Australian operations).

On 17th September 2013, Eden Energy announced that it had entered into a conditional agreement to sell all of its U.K. coal seam methane and shale gas portfolio to Shale Energy plc. The assets comprise Eden's 50% interest in 17 licences in England and South Wales and a 100% interest in one licence in South Wales. Seven licences in South Wales have an estimated P90 shale-gas-in-place of 17.1 Tcf net to Eden (6.35 Tcf recoverable). On condition that Shale Energy raised the capital to make the acquisition by November 2013, Eden Energy would hold a 29.9% direct interest in Shale Energy. Although Shale Energy failed to complete by the deadline, Eden has continued to extend the conditional agreement with Shale Energy Plc for the sale of its entire UK coal seam methane and shale gas portfolio for £11.5million (approximatelyA$19.3million), and at the date of this report, that contract, conditional upon Shale Energy raising £7 million, remains in existence .

On 25th March 2014, Eden Energy announced the termination of the conditional agreement with Shale Energy and that it had entered into a conditional Heads of Terms to transfer its wholly-owned UK subsidiary (Adamo Energy (UK) Ltd.) to UK Onshore Gas Ltd (parent company of Adamo UK's joint venture partners). On 14th January 2015 Eden announced that discussions between the parties were still

under way but that there was no certainty that the agreement would proceed. On 12th March 2015 Eden commented that "increasingly difficult market conditions for gas exploration in the UK, due to strong public opposition and changing political views, creates significant uncertainty in relation to this possible sale." The number of licences involved has reduced to 13 as 4 PEDLs have been surrendered due to both environmental and social reasons. Eden's P50 net resources in the 13 licences are estimated at - Shale Gas: 24.9 Tcf GIIP; 9.2 Tcf Prospective Recoverable; Coal Seam Gas: 3.2 Tcf GIIP; 1.4 Tcf Prospective Recoverable.

On 13th November 2013, Poland's PKN Orlen completed the acquisition of Canadian company TriOil Resources Ltd., a move designed to buy in experience in horizontal drilling and hydraulic fracturing.

On 9th May 2014, UK's IGas announced that it intended to acquire Australian company Dart Energy Limited via an Australian Scheme of Arrangement on a share exchange basis. Dart held interests in 24 UK licences with shale gas / coal seam gas potential plus non-core coal seam gas assets in a number of countries including Australia, Germany, India and Indonesia. The transaction was completed on 16th October 2014.

Licence acquisitions

Germany.

On the 23rd December 2011, in the course of acquiring BG's UK coal seam gas interests, Dart Energy obtained an exclusive option to acquire for no additional consideration a 100% interest in two licence areas held by BG in Germany (Saxon I West and Saxon II), which are prospective for both CBM and shale gas. Dart exercised the option in May 2012.

Poland.

On 15th November 2010, the UK's San Leon Energy plc announced that it had agreed to acquire Mazovia Energy Resources (a EurEnergy Resources Corp. subsidiary), holder of three concessions in the Fore Sudetic Monocline, southwest Poland. The concessions are thought to have Carboniferous shale gas potential.

On 10th December 2010, Eni S.p.A. announced that it had agreed to acquire Minsk Energy Resources (a EurEnergy Resources Corp. subsidiary), holder of three concessions in the Baltic Depression.

On 21st January 2013 PKN Orlen announced that it has been assigned two concessions on the East European Platform Margin, previously held by ExxonMobil.

United Kingdom.

On 28th December 2011, Dart Energy announced that it had agreed to acquire all of the unconventional gas assets of Greenpark Energy Ltd., comprising 22 onshore licences in the UK. Seven of these licences are considered to have shale gas potential.

On 18th August 2014, new player INEOS Upstream announced that it had acquired BG Group's 51% interest in the lower (shale gas) portion of PEDL 133. PEDL 133 underlies INEOS's Grangemouth refining and petrochemical complex. On 13th October 2014, INEOS announced that it had acquired an 80% interest and operatorship of PEDL 162 (adjacent to PEDL 133) from Reach Coal Seam Gas.

Farm-ins and interest transfers

Bulgaria.

On 29th August 2011, LNG Energy Ltd. announced that it had entered into an agreement with TransAtlantic Petroleum Ltd. to earn a 50% interest in the A-Lovech exploration licence in northwest Bulgaria. LNG Energy was to provide up to US$ 7.5 million to drill, core and test a 10,500' Middle Jurassic shale gas exploration well. Closure of the deal was announced on 22nd September 2011.

France.

On 10th May 2010, Toreador Resources Corp. (now ZaZa Energy Corp.) and Hess Corp. announced an agreement, whereby Hess would make a $15 million upfront payment and invest up to $120 million in a

two-phase work programme on Toreador's awarded and pending shale oil exploration permits in the Paris Basin. Phase 1 was to consist of an evaluation of the acreage and drilling of six wells. Depending on the results of Phase 1, Phase 2 was expected to consist of appraisal and development activities. Following Phase 2, provided contractual obligations had been met, Hess would hold a 50% share of Toreador's working interest in the covered permits. On 26th July 2012, ZaZa Energy announced that it had transferred its remaining 50% interest to Hess Corp., retaining a 5% overriding royalty interest. On 26th September 2013, however, the Minister for Ecology, sustainable Development and Energy refused to authorise the transfer to Hess Corp. on the grounds that (a) Hess's French subsidiary did not have the technical capacities required by the Mining Code and (b) the licences could be exploited only by the use of hydraulic fracturing.

On 15th July 2011, Realm Energy International Corp. (now San Leon) announced that it had entered into a farm out agreement with ConocoPhillips covering its nine exploration licence applications in the Paris Basin. The agreement provided Realm with a limited carry on exploration expenditure conditional on actual acreage acquired and required activity commitments. Realm was designated operator for the initial exploration phase with ConocoPhillips having an operatorship option thereafter. The nine licences are considered to be primarily prospective for tight oil. It is assumed that this agreement lapsed with the acquisition of Realm by San Leon.

Germany

Following renewal of its two licences in the Bodensee Trough, north of the Swiss-German border on 20th December 2013, Parkyn Energy, a 3Legs Resources subsidiary, transferred its interests to Rose Petroleum in exchange for a 2% royalty and contribution of €400,000 towards past costs. Rose Petroleum subsequently relinquished the licences in view of the uncertain regulatory environment for unconventional hydrocarbon exploration in Germany.

Lithuania.

In October 2012 it was reported that Chevron had taken a 50% interest in LL Investicijos, holder of the Rietavas oil field licence, with an option to acquire the other 50%. Tethys Oil announced that Chevron had also acquired a further 6% stake in the Rietavas field from Tethys with an option to acquire a further 8.5% within three years. It was understood that Chevron's primary interest in the licence was in shale exploration, probably for shale liquids, but Chevron has since relinquished its Lithuanian assets.

Poland.

In August 2009, ConocoPhillips reached an agreement to farm into 3Legs Resources' six Baltic Depression concessions. ConocoPhillips is funding the initial exploration and evaluation programme but 3Legs Resources remains the operator. ConocoPhillips had until 20th March 2012 to determine whether to exercise an option to take a 70% interest in the concessions. If exercised, operatorship would transfer to ConocoPhillips. On 20th March 2012, 3Legs Resources announced that ConocoPhillips would exercise its option in respect of the three western concessions. Completion of the option exercise took place on 14th September 2012, whereupon operatorship of the three western concessions passed to ConocoPhillips. It was also announced that the two companies were considering options for the three eastern Baltic Depression concessions which are situated in a more liquids-prone part of the basin (see *2.1.1 Lower Paleozoic: Poland*). In order to develop an appropriate strategy for the three eastern concessions, they were divested into a separate Polish legal entity, Lane Energy Exploration Poland, a wholly-owned subsidiary of 3Legs Resources. ConocoPhillips opted not to acquire a 70% interest in the three eastern concessions.

On 17th September 2014, believing the results of the Lublewo LEP-1ST1H well test to be sub-commercial, 3LegsResources exercised its one-time option to cease participation in activity on its three western Baltic Basin concessions and commenced the transfer of its equity interest to ConocoPhillips. On 30th November, 3Legs Resources concluded the sale of its entire interest in the three eastern Baltic Basin concessions by selling its Polish subsidiary, Lane Energy Exploration Poland, to a subsidiary of Stena AB (the "Stena Group").

On 1st March 2010, Irish company San Leon Energy Ltd. disclosed that it had entered an agreement with Talisman Energy Inc. whereby Talisman would acquire a 60% interest in San Leon's three Baltic Depression concessions in exchange for covering 60% of the cost of a seismic programme and drilling one well on each of the three concessions with an option to follow up with a further three wells. If the second three wells are not drilled, Talisman's interest will reduce to 30%. On 6th March 2013, Talisman announced that it was evaluating its options in Poland and on 8th May San Leon reported that it had reacquired 100% ownership of Talisman's Polish interests. On 3rd July San Leon then announced an agreement whereby Wisent Oil & Gas could earn a 45% interest in the Braniewo concession by conducting a three-stage fracture on the Rogity-1 well followed by drilling and testing a multi-stage horizontal well on the concession.

On 26th April 2011, Marathon Oil Corp. announced that Nexen Inc. will take a 40% interest in 10 of Marathon's 11 concessions in the Lower Paleozoic play, eastern Poland. On June 9th 2011, Mitsui & Co. Ltd. reported that it had agreed to acquire a 9% interest in the 10 concessions, reducing Marathon's interest to 51%. Marathon remained operator. The one concession excluded from the farm-outs was Plonsk SE in the Danish-Polish Marginal Trough.

On 13th May 2011, Total SA announced an agreement with ExxonMobil to farm in to two concessions in the Lublin Trough, Danish-Polish Marginal Trough. Total acquired a 49% interest while ExxonMobil retained a 51% interest and operatorship. The farm-in was approved in July 2011.

On 14th August 2011, Hutton Energy plc (formerly BasGas Pty Ltd.) announced that through its Polish subsidiary Strzelecki Energia it intended to take a 49% interest in four ExxonMobil concessions in the Podlasie Depression of the East European Platform margin. ExxonMobil would retain 51% and operatorship. Although the deal was approved subsequently by the Polish Office of Competition and Consumer Protection, the deal was never closed.

On 6th June 2012 San Leon announced that it had taken a 75% interest in three concessions owned by Hutton Energy plc through its Polish subsidiary Strzelecki Energia, one in the Danish-polish Marginal Trough and two with Carboniferous prospectivity in the Fore-Sudetic Monocline. In both cases the farm-in concessions are adjacent to concessions in which San Leon already has an interest. Total SA became 100% owner and operator of the Chelm concession on the East European Platform Margin. ExxonMobil previously held 51% of the concession and was operator.

United Kingdom.

On 13th June 2013 it was announced that Centrica plc had acquired a 25% interest in the Bowland exploration licence PEDL 165 from operator Cuadrilla Resources (56.25%) and AJ Lucas (18.75%). Centrica acquired the interest for GBP 40 million and will pay a further GBP 60 million in exploration and appraisal costs. If Centrica elects to continue into the development phase, it will then pay a further GBP 60 million.

On 22nd October 2013 Dart Energy announced that GDF SUEZ will farm into 13 of its U.K. licences in Central England and North Wales. GDF SUEZ will acquire a 25% interest with Dart retaining 75% and operatorship. The funding will support an unconventional exploration and appraisal programme of up to 4 shale gas wells and 10 coal seam gas wells. The farm-in was completed on 28th November 2013.

On 13th January 2014 it was announced that French major Total SA would take a 40% interest in PEDLs 139 and 140 in the Gainsborough Trough in Lincolnshire. Total will pay $1.6 million in back costs to the other partners, Dart Energy (17.5%), Egdon Resources (14.5%), eCorp Oil & Gas (13.5%) and IGas (14.5%) and fund a fully carried work programme of up to $46.5 million. The programme includes the acquisition of 3D seismic, drilling and resting a vertical exploration well and, conditional on its success, a second horizontal well. The farm-in was completed on 4th February 2014, at which time IGas became operator.

On 30th January 2014 Egdon Resources announced that Total SA has signed an opt-in agreement for PEDL 209, adjacent to PEDLS 139 and 140 (above) in the Gainsborough Trough. Total has the option to farm-in until 31st December 2015 and on doing so will earn a 50% interest by paying 100% of an exploration programme up to £13.47 million. Three conventional prospects on the acreage are excluded from the deal.

On 10th June 2014, Egdon acquired the shale gas interests of Alkane Energy in 10 licences in the Gainsborough Trough and Craven Basin. The licences are split on a horizontal basis with Alkane, a coal seam gas player, retaining the upper portion including the Westphalian Coal Measures and Egdon acquiring the lower Visean – Namurian shale gas prospective interval.

On 4th December 2014 Egdon exercised its option to farm in to Onshore Production Licences PL 161 (block SE/60b) and PL 162 (blocks SE/70a & SE/80b) held by Scottish Power Generation in Lincolnshire and South Yorkshire. The agreement defines an Exploration Area, which excludes the Hatfield Moor gas storage operation, with both conventional and unconventional prospectivity.

On 10th March 2015 IGas announced that it has signed a Farm out and Purchase Agreement with INEOS, a global manufacturer of petrochemicals, speciality chemicals and oil products including operatorship of Scotland's Grangemouth oil refinery.

INEOS has agreed to farm into a 50% interest in IGas' licences in the Bowland basin: PEDLs 147, 184, 189, 190; and a 60% interest in IGas' licences: PEDL 145, 193 and EXL 273, (the "Bowland Licences"), in the North West of England. In the East Midlands, INEOS has the option to acquire 20% in PEDL 012 and 200. INEOS will assume operatorship of licences PEDL 145, PEDL 193 and EXL 273. IGas will retain operatorship of all other Bowland Licences. INEOS has committed to agree to fund IGas' share of a forward work programme on the Bowland Licences subject to a gross expenditure cap of £138 million.

INEOS will also acquire IGas' entire working interest in the acreage held under PEDL 133 in the Midland Basin in Scotland and assume operatorship. INEOS has agreed to pay IGas an upfront cash consideration of £30 million payable on completion of the transaction. Completion is expected to take place not later than 30 June 2015. Excluding Weald Basin licence areas and coal seam gas, IGas currently has estimated Gas Initially In Place of 147 TCF (most likely case.) On completion, IGas will transfer 222,000 net acres and 67 TCF (most likely case and excluding coal seam gas) of GIIP to INEOS (based on IGas estimates and including PEDL 012 and PEDL 200). Completion is expected no later than 30th June 2015.

Relinquishments

Germany.

BNK Petroleum. BNK Petroleum has relinquished its eight German concessions.

Poland.

By 1st March 2015 a total of 69 shale gas and 4 shale liquids concessions had been relinquished, 25 in the Danish-Polish Marginal Trough, 14 on the East European Platform Margin, 18 on the Fore-Sudetic Monocline and 12 in the Baltic Depression. In the year to 1st March 2015 45 shale gas and 3 shale liquids were relinquished. With the exception of ConocoPhillips, all major companies (ExxonMobil; Chevron; Marathon; Total; Eni) have now exited Poland or indicated their intention to do so.

Relinquishments to 1st April 2015 by company / company consortium are shown in Table 6. Note that Chevron still holds 2 unrelinquished concessions which it intends to surrender.

Above-ground issues

Other than general fiscal, legal and environmental regulation of hydrocarbon exploration and exploitation, there are a number of issues that specifically face most gas and liquid resource play developments. Per-well reserves and productivity can be low and benefit from an established gas compression and distribution infrastructure. To convert resources into reserves also requires large numbers of wells. Some North American resource plays employ 10-acre spacing as opposed to the 640-acre spacing typical of conventional wells. This could pose a problem in densely populated areas of Europe but horizontal wells drilled from a single pad can be used to reduce the well footprint. In British Columbia's

Horn River Basin, Apache Corp.'s well design concept should recover gas from two different stratigraphic intervals over an area of 7 km^2 from a single 28-well pad.

Other environmental issues such as water availability and water disposal capacity may also impact on ultimate recovery. Almost inevitably, the concerns that have been raised in the U.S. about potential contamination of groundwater supplies from chemicals used in hydraulic fracturing of shale gas reservoirs are being echoed in Europe. In addition, the potential of fracking to induce local seismicity has also been raised. A major public misconception appears to be that the word "unconventional" implies new, untested, and therefore risky, drilling and completion technology.

Public disquiet has manifested itself in a number of countries, most notably Bulgaria, France, Germany, Romania and the United Kingdom. The issues have now entered the political realm, creating a further condition of uncertainty. While vested commercial interests (e.g. the coal, nuclear and renewable energy industries; importers of conventional gas; natural gas storage operators) are almost certainly a factor, populism in advance of elections is undoubtedly playing a part and environmental groups are using the controversy to advance their own agendas. Until there is public recognition that the drilling and fracturing technology that is in use has been applied for decades in hundreds of thousands of wells and that all that is "unconventional" is the mode of subsurface occurrence of the natural gas, there are likely to be deferrals and delays in the evaluation of shale gas potential in a number of countries. It remains a problem of perception. "People overestimate the dangers of what is new and underestimate those of what they're used to" (Rudolf Huber, CEO of NeXtLNG Ltd.). The commissioning on 8th November 2011 of the first of two 1,224 km (760-mile) Nord Stream gas pipelines across the Baltic Sea from Portovaya Bay in Russia to Lubmin in Germany, effectively created a divergence of interests between the western European countries served by Nord Stream (e.g. Germany; Denmark; U.K.; The Netherlands; Belgium; France; Czech Republic) and those countries still dependent on Russian gas from the overland route transiting through Ukraine (e.g. Poland; Bulgaria; Romania). Gazprom's announcement that it is considering further Nord Stream pipelines and its downbeat remarks about European shale gas exploitation suggest that it sees shale gas development in Europe as a threat to its position as largest gas supplier to the continent and is keen to divert governments away from shale gas and back towards Russia as a guaranteed supplier.

Polish Shale Gas and Shale Liquids Concession Relinquishments at 1st April 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**
BNK Petroleum - Indiana Investments	3					**3**
BNK Petroleum - Saponis Investments	2					**2**
Canadian International Oil Corp				2		**2**
Chevron Corp		2				**2**
Cuadrilla 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**
PETROLINVEST SA - ECO Energy		1	2	1		**4**
PETROLINVEST S.A. - Silurian		1	1	3		**5**
PGNiG		4				**4**
San Leon - Aurelian O&G				2		**2**
San Leon - Czersk				2		**2**
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	**13**	**25**	**14**	**18**		**70**
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**

Table 6. Shale Gas and Shale Liquids Concession Relinquishments in Poland

International Energy Agency.

Conscious of the impact that negative publicity has on realizing the potential of unconventional gas, on 29th May 2012 the Paris-based International Energy Agency released a World Energy Outlook special report on "Golden Rules" that are needed to support a potential "Golden Age of Gas". The report provides insights into the environmental challenges linked to unconventional gas production and how best to deal with them.

European Union (EU).

On 4th February 2011, the European Council announced a number of priority actions in its Conclusions on Energy (PCE 026/11). Priority 7 stated "In order to further enhance its security of supply, Europe's potential for sustainable extraction and use of conventional and unconventional (shale gas and oil shale) fossil fuel resources should be assessed." In September 2011, the EU Energy Commissioner, Guenther Oettinger of Germany, said that he hopes to put forward proposals in spring 2012 to standardise

regulations on hydraulic fracturing. This followed a report published in July for the European Parliament by six German authors entitled *Impacts of shale gas and shale oil extraction on the environment and on human health*. Herr Oettinger's announcement produced a strong reaction from the Polish Treasury Minister who stated that exploration for unconventional hydrocarbon resources is already adequately regulated and that the possibility of European Union wide regulation is not provided for in the Lisbon Treaty (Treaty on the Functioning of the European Union or TFEU). (Both the Lisbon Treaty and the Energy Treaty Charter recognise state sovereignty in the use of a county's energy resources.) On 22nd September 2011, Herr Oettinger's spokeswoman, Marlene Holzner, said that the commission is studying whether the current European Union environmental laws would apply to shale gas production, but isn't planning to propose any new legislation. On 13th October 2011 EU Climate Action Commissioner, Connie Hedegaard, said that she was not inclined towards a moratorium on shale gas drilling based on the information that she had heard so far. The European Commission (EC) selected a Brussels law firm, Philippe & Partners, to analyse how the relevant applicable European legal framework, including environmental law, is applied to the licensing, authorisation and operation of shale gas exploration and exploitation, using a sample of four Member States: France; Germany; Poland; Sweden. The 104-page report was published on 8th November 2011. On 27th January 2012 Energy Commissioner Oettinger stated that "the legal study confirms that there is no immediate need for changing our EU legislation." On 7 September 2012 the European Commission published three new studies on unconventional fossil fuels, in particular shale gas. The studies look at the potential effects of these fuels on energy markets, the potential climate impact of shale gas production, and the potential risks shale gas developments and associated hydraulic fracturing may present to human health and the environment.

Unconventional Gas: Potential Energy Market Impacts in the European Union. The study on energy market impacts shows that unconventional gas developments in the US have led to greater Liquefied Natural Gas supplies becoming available at global level, indirectly influencing EU gas prices.

Climate impact of potential shale gas production in the EU. The study on climate impacts shows that shale gas produced in the EU causes more GHG emissions than conventional natural gas produced in the EU, but – if well managed – less than imported gas from outside the EU, be it via pipeline or by LNG due to the impacts on emissions from long-distance gas transport.

Support to the identification of potential risks for the environment and human health arising from hydrocarbons operations involving hydraulic fracturing in Europe. The study on environmental impacts shows that extracting shale gas generally imposes a larger environmental footprint than conventional gas development. Risks of surface and ground water contamination, water resource depletion, air and noise emissions, land take, disturbance to biodiversity and impacts related to traffic are deemed to be high in the case of cumulative projects.

In launching the EU's green paper on energy and climate aims for 2030, Energy Commissioner Günther Oettinger took a favourable position on shale gas, quoting the gas prices in the U.S. compared with European prices. Anne Glover, chief scientific adviser, gave a scientific green light to shale while noting that there are risks involved with all energy production, including wind and coal. But she also noted that in terms of extraction and production there are non-scientific issues to be debated. Connie Hedegaard, Climate Commissioner, was less positive, stating that different geological conditions and environmental rules mean that shale gas exploitation in Europe will bear little comparison with the U.S. Separately from the European Commission, the German chairman of the European Parliament's committee on the Environment, Public Health and Food Safety indicated in July 2011 that he wants a new "energy quality directive" that would introduce stringent regulations to cover fuels with what are deemed to be adverse environmental impacts – tar sands oil and shale gas among them. As might be expected, given the variety of political positions represented, the European Parliament's opinions are more diverse than those of the Commission and in some cases contradictory. These were expressed in two resolutions adopted by committee in mid-September 2012.

The emergence of exploration for shale oil and shale gas in some EU countries should be backed up with "robust regulatory regimes" according to separate non-binding resolutions by the Energy Committee

(on industrial aspects) and the Environment Committee (on health and environment ones). Member states should be "cautious" pending further analysis of whether EU level regulation is adequate, according to environment MEPs. Each EU country has the right to decide for itself on whether to exploit shale gas, said the Energy Committee. Member states should have robust rules on all shale gas activities, including hydraulic fracturing of rock ("fracking"). MEPs also advised the EU to learn from US experiences, with a view to using environmentally-friendly industrial processes and "best available technologies". The European Commission previously concluded that EU rules adequately cover licensing and early exploration and production of shale gas but "a thorough analysis" of EU regulation on unconventional fossil fuels is needed, given the possible expansion of their exploitation, noted Environment MEPs. In April 2013, the chair of Parliament's science and technology options assessment panel said that Europe is in the "denial phase" on shale gas.

On 22nd January 2014 the European Commission adopted and published a non-binding Recommendation and Communication for its Shale Gas Enabling Framework (thereby avoiding legislative proposals). Member states are invited implement it within six months (thereby bypassing the European Parliament elections in May 2014) and the EC will review the Recommendation 18 months after publication.

The Recommendation invites Member States to ensure that:

- There is an integrated approach to the granting of permits;
- Risk assessments are undertaken on potential drilling sites;
- Baseline studies and subsequent monitoring are undertaken on drilling sites;
- Operators apply best practice;
- Use of chemicals in frac fluid is minimised and fluid content used is made publicly available on a per well basis;
- An EIA is carried out where required under EU Directive 2011/92/EU (i.e. when gas production exceeds 17.5 MMscf/d).

Background comment. Individual EU member states have the right to determine exploitation of energy resources and their energy mix (TFEU Article 194). Member states are also free to set more stringent environmental protection measures than required by EU legislation (TFEU Article 193). Most aspects of hydrocarbon exploration and production are covered by existing EU legislation: Hydrocarbon Directive; Water Framework Directive; Groundwater Directive; Environmental Impact Assessment; Registration, Evaluation, Authorisation and Restriction of Chemical substances (REACH); Natura 2000 (protected areas); and other regulations covering waste, noise etc.

Austria.

OMV's plans to drill one or two shale gas exploratory wells in the wine quarter of Lower Austria ran into substantial opposition. Despite seeking community support, the company's plans were resisted not only by environmental and community groups but also by politicians, including the Environment Minister and Governor of Lower Austria. On 2nd March 2012 OMV announced that it would suspend drilling plans pending the completion of a comprehensive environmental and social study by the Federal Environmental Agency and TÜV Austria Group, a technical and environmental safety consultancy. In July 2012 the Minister for Environmental and Agricultural Affairs announced plans to reform the environmental impact assessment act to incorporate shale gas exploration. The cost of producing a detailed environmental inspection and assessment for any proposed well effectively makes shale gas drilling uneconomic and OMV currently has no further plans for shale gas exploration in Austria.

Bulgaria.

The shale gas debate featured in the October 2011 presidential elections with the two principal opposition candidates both indicating that they opposed shale gas development. The election was won, however, by the candidate of the ruling party (Citizens for European Development of Bulgaria). Environmental organisations and opposition parties wished to impose a temporary moratorium on shale gas exploration and called for a referendum on allowing such activities. Although the Ministry of Economy,

Energy and Tourism indicated that it planned a thorough assessment of the risks involved in shale gas development it appeared to be broadly supportive of shale gas exploration. On 19th October 2011, a delegation representing a number of ministries and regional governors visited Poland to learn from the Polish experience. In the face of massive public protests, on 18th January 2012 parliament placed an indefinite ban on the use of hydraulic fracturing. The previous day, prior to final execution of the licence agreement, the government announced the withdrawal of the Novi Pazar permit for shale gas exploration awarded to Chevron in June 2011. Chevron continues in discussions with the government to provide assurances that hydrocarbons can be produced safely from shale. The Minister for Economy and Energy has said that he believes powerful financial interests were behind the mass protests. The pro-Russian Centre Left party played a leading role in opposing shale gas research. (Gazprom provides 98% of Bulgaria's gas.) Since the moratorium was imposed a Movement for Energy Independence has been established and has called for cancellation of the moratorium. But informed opinion suggests that at present the government does not believe that it is politically worthwhile to confront public opinion.

***Czech Republic*.**

The Náchod District assembly and some 50 local administrations submitted formal objections to the Ministry of Environment's award of the Trutnov permit to Basgas Energia Czech, a subsidiary of Hutton Energy. In April 2012 the Trutnov award was cancelled and sent back to the Ministry of Environment regional department to be decided again. In September 2012 the Minister of Environment sent a draft moratorium proposal on shale gas exploration in the Czech Republic until 30th June 2014 to an inter-ministry conference. While the moratorium appears never to have been formally approved the various ministries appear to have followed its provisions.

Prime Minister Petr Necas said that suitable legislation that will define the framework for prospecting and exploitation is required, and only after such legislation has been adopted could further steps be discussed. But there appears to have been no subsequent attempt to update the regulatory process, environmental legislation or energy policy and, as a result, the de facto moratorium remains in place.

France.

In February 2011, shale gas and shale oil drilling in France was suspended by the authorities pending a progress report on the environmental consequences of shale exploitation. The ultimate outcome of this process was the passing of a law on 13th July 2011 (Law 2011-835) that prohibited the exploration for, and production of, liquid or gaseous hydrocarbons by hydraulic fracturing. Permit holders had two months in which to advise the administrative authorities of the techniques that they use or intend to use in their exploration activities. Failure to respond or an intention to use hydraulic fracturing would result in withdrawal of the permit. A national commission would also be established to evaluate the environmental risks associated with hydraulic fracturing and to set out the conditions under which scientific research under public control can take place. The government is to report annually to parliament on the evolution of exploration and production technology in France, Europe and internationally and also on the results of the scientific research undertaken.

In September 2011, major French E&P company Total S.A. announced as part of its report to the authorities that it would continue the evaluation of its Montélimar exploration licence but that the work programme does not envisage the use of hydraulic fracturing. Other companies were expected to adopt a similar approach. On 3rd October 2011 the ministers of Ecology, Sustainable Development, Transport & Housing and Industry, Energy & the Digital Economy announced in a joint press release that the three permits issued specifically for exploration for shale gas would be cancelled. These are the Total S.A. Montélimar exploration and the Schuepbach Villeneuve-de-Berg and Nant licences. Total expressed surprise as it had undertaken not to use hydraulic fracturing and was awaiting the government's notification to understand the legal basis for the cancellation. The official confirmation of the repeal of the three licences was gazetted on 13th October 2011. On 26th November the CEO of Total S.A. announced that the company would appeal against the revocation of the Montélimar licence and on 12th December the company filed an appeal in the Paris Administrative Court in order to clarify the situation, on the grounds that the company

had complied with the Act of July 13th 2011. In October 2012 Christophe de Margerie, Total CEO, stated that the Group was no longer willing to spearhead the shale gas quest in France and that it is up to politicians and government officials to decide on the future of shale gas exploration in the country.

The French Union of Petroleum Industries declared that the cancellation decisions will send a negative signal to international investors and are prejudicial to an economy which imports 99% of its oil and 98% of its gas consumption. The CEO of French company GDF Suez said that while it was appropriate that the government evaluate technology and processes, closing the door forever to shale gas development would be "a major mistake". On 11th October 2011 the National Assembly rejected a bill submitted by the parliamentary opposition which set out to prohibit exploration for, and exploitation of, unconventional hydrocarbons irrespective of the techniques used. The proposed bill was deemed to contain several flaws and to be incompatible with the law of 13th July 2011.

On 21st March 2012, a new decree established a National Commission to evaluate shale oil and gas exploration techniques and operations. The commission would be consulted on: conditions for implementation of hydraulic fracturing research projects; managing risk and environmental protection during experimentation on new techniques to exploit shale oil and gas; the government's annual report to parliament set out in the Act of July 13th 2011 (above). At end September 2012, the members of the commission had not yet been appointed.

Since the presidential election in May 2012 and the formation of a new government, official statements have sent a variety of messages, some of them contradictory. Most recently, on September 14th, President Hollande stated that, as far as the exploration and exploitation of non-conventional hydrocarbons is concerned, hydraulic fracturing will be banned throughout his five-year term in office and instructed the Environment Minister to reject seven applications for permits to explore for shale gas, citing potential impacts on health and the environment. (It should be noted that he did not order the rejection of a number of pending applications for permits with shale oil potential.). The president's forceful statement seems to have taken industry representatives and even some government sources by surprise, as there are major concerns in France regarding the long-term impact of such a ban on the economy and energy security. At a parliamentary hearing in April 2013, senators, company representatives, scientists and energy policy analysts broadly supported a resumption of exploration for shale oil and gas so that at the very least France's resource potential could be evaluated.

On 11th October 2013, ruling on a challenge submitted by Schuepbach Energy, the French Constitutional Court ruled that the ban on hydraulic fracturing introduced in Law 2011-835 is not disproportionate and that the law conforms to the Constitution. Only Arnaud Montebourg, Minister of Industrial Renewal, has supported development of shale gas, subject to the proviso that the industry finds alternative ways of bringing gas to surface by methods that do not risk the pollution and other dangers for which hydraulic fracturing has been blamed. There is, however, a groundswell of support for lifting the ban from industry. A consequence of the ban on hydraulic fracturing has been an accumulation of unprocessed applications for exploration permits. On 31st January 2014 a total of 110 permit applications were awaiting decision.

Background comment. In 2007, 78% of all French electricity production came from nuclear power. Two new European pressurised water reactors (EPRs) are due to be commissioned by 2017, so it can be assumed that the nuclear industry will not be supporting shale gas development!

Germany.

Fracking was first used in conventional wells in 1955 (Schleswig-Holstein) and 1977 (Lower Saxony). Between 1977 and 2010 some 140 frac operations were conducted in Germany. The first fracking of unconventional gas wells (tight gas) occurred in the mid-1990s in the Söhlingen Field, Lower Saxony, and fracking was conducted in at least three other tight gas fields in Lower Saxony in the period 2005-2010. Despite a 55-year history of fracking, there was no public interest in the application of the technology in Germany until 2010.

Unlike France, where governance is highly centralised, the German Länder (constituent states of the Federal Republic of Germany) have a high degree of autonomy. The political strength of the Grüne (Green environmental party) is at an all-time high both federally and at state level, and environmental groups have exerted considerable pressure on politicians in areas where shale gas development is proposed. In March 2011 the state Environment minister of North Rhine-Westphalia, a member of the Grüne, introduced a moratorium on shale gas exploration. To date, however, most shale gas exploration has taken place in Lower Saxony, which has not introduced such a moratorium.

The Minister for Environmental Protection in the federal government announced on 29th July 2011 that an expert survey on the environmental impact of shale gas production would be ordered and that changes to the geological and mining laws are likely. On 4th August 2011 the Federal Environment Agency published an opinion entitled *Einschätzung der Schiefergasförderung in Deutschland* (Assessment of shale gas production in Germany). The report is generally negative towards shale gas and appears to selectively quote, for example, sources such as the Tyndall Centre for Climate Change at the University of Manchester and Robert Howarth at Cornell University that are generally considered to exaggerate the impact of natural gas as a source of greenhouse gas emissions. If the planning and legislative requirements proposed in the report are implemented, they will probably have the effect of making shale gas production uneconomic in Germany.

In September 2012 the German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU) produced a report entitled "Environmental impacts of fracking in the exploration and production of natural gas from unconventional deposits". Although the report does not recommend a ban on hydraulic fracturing, some of the proposed conditions are sufficiently prescriptive to cast doubt on the viability of much unconventional E&P activity. In the same month, following a risk study published by the Environment and Economic ministries of the state of North Rhine – Westphalia the state authorities banned hydraulic fracturing operations until more evidence on the risks involved is available. In December 2012, the German parliament voted to put forward a bill permitting hydraulic fracturing to resume, subject to strict controls (e.g. limited to areas where water resources will not be impacted; mandatory EIA; mandatory information on fluid treatment and flowback). In January 2013, the Federal Institute for Geosciences and Natural Resources (BGR) responded to the September 2012 Environment Ministry (BMU) report, criticising it for its lack of geosciences expertise, its inconsistency and subjectivity and failure to use the available broad knowledge base of existing technology.

Though current legislation permits requests for hydraulic fracturing to be filed under existing water rights and mining law, none of the public authorities would grant such a request, so there was effectively a moratorium on hydraulic fracturing until the new bill was introduced. The government failed to introduce the bill prior to the September 2013 federal elections. During the subsequent coalition-building process, in November 2013, it was announced that the partners in government had agreed to place a moratorium on hydraulic fracturing until environmental and health concerns are resolved. In February 2014, spokespersons for the German gas industry pointedly indicated that the decline in German gas production can be attributed to the political reluctance to permit hydraulic fracturing, despite it having been used in German tight sandstone reservoirs for over 50 years (see above). 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 upper house of parliament will discuss the draft and deliver an opinion on 8th May 2015 after which it will pass to the lower house where it will face opposition from the Green Party.

Background comment. The German unconventional hydrocarbons industry is not well developed and domestic companies lack the necessary technology. These companies are focused on the production, importation and storage of conventional gas. Germany also has a substantial renewable energy industry. All of these interests would be threatened by large volumes of low-cost indigenous natural gas. It is therefore in the interests of German industry not only to make shale gas production as unprofitable as possible in

Germany but to use its influence to restrict large-scale gas production elsewhere in Europe (see the direction of the German strategy in the *European Union* above).

Ireland (Republic of Ireland).

The principal prospect in Ireland lies in the Northwest Ireland Carboniferous Basin (Lough Allen Basin), which straddles the border between the Irish Republic and Northern Ireland but most of the opposition has come from the Republic side. At a company information meeting in early September 2011, the operator, Tamboran Resources, offered to conduct fracking without chemical additives but this did nothing to soften the opponents of the scheme. The government subsequently asked the Environmental Protection Agency (EPA) to conduct a study on the effects of fracking. The 26-page report prepared by the University of Aberdeen, entitled *Hydraulic Fracturing or 'Fracking': A Short Summary of Current Knowledge and Potential Environmental Impacts*, will be used as the groundwork for a more comprehensive study by the EPA. The major environmental trust, An Taisce, has called for fast track regulation to clarify the currently uncertain regulatory position regarding onshore drilling. In April 2013, Energy Minister Pat Rabitte reaffirmed that no decision on permitting hydraulic fracturing will be taken until the EPA's study is concluded at the end of 2014.

Background comment. As confirmed by the Minister of State at the Department of Communications, Energy and Natural Resources on 21st March 2012, conventional fracking has already been applied by Dowell Schlumberger in the case of three Irish onshore wells: Dowra-1 Re-entry (1981), Dowra 2 (2002) and Thur Mountain 1 (2002).

Netherlands.

Although the provincial authorities in Noord Brabant were opposed to Cuadrilla Resources' plans to drill two wells, in early 2011 the Dutch Minister for Economic Affairs, Agriculture and Innovation granted a licence for drilling to proceed. (The Dutch state, through its wholly-owned company EBN, has a 40% interest in the licence.) On June 29th 2011, however, the ministry indicated that shale gas exploration in the Netherlands would not move ahead until the results of the UK's inquiry into hydraulic fracturing had been assessed. "If it appears that there are unacceptable risks, no drilling for shale gas will occur," the Minister, Maxime Verhagen, said in a letter to parliament. "Concerns regarding shale gas are understandable and I take them very seriously." In October 2011, Cuadrilla encountered another setback when a court ruled that Boxtel town council was wrong to grant a temporary exemption from zoning for its Boxtel-1 well since that was based on activities concluding within five years and, if commercial production had been established, it was likely that operations would exceed this time span. Cuadrilla must now return to Boxtel council to resolve the situation and their spokesman expected a few months' delay to a well that was due to spud early in 2012. The most recent company estimate is that this well will not now spud until 2013.

The Dutch Ministry of Economic Affairs, Innovation and Agriculture commissioned an independent study of all possible risks and consequences of shale gas exploitation, including methane emissions from drilling, the presence of heavy metals in drilling mud, and the risk of induced seismicity. The study was delivered on 27th August 2013 and concluded that while total risks were slightly greater than the risks associated with conventional exploration due to the large number of wells involved, they remained very small. The government will now undertake a study to identify all likely shale gas exploration sites on Dutch soil to determine where locations with the highest likelihood of success and least environmental risk occur. This study is likely to take 12 – 18 months and in the meantime no shale gas exploration applications will be processed and where permits have already been granted, companies will not proceed until the study is complete. Some 60 out of 400 local authorities had declared their opposition to shale gas production. In December 2014 the Dutch Parliament passed a motion forbidding shale gas exploitation for the life of this parliament (normally end 2016). Exploration, however, may be permitted once the study of impacts and risks of, and necessity for, shale gas development has been completed. This is now foreseen by end 2015.

Poland.

Unlike most other countries the major political debate in Poland has been about maximising the benefit of shale gas exploitation to the state. In advance of the October 2011 parliamentary election, the opposition Law and Justice Party prepared draft legislation covering Polish shale gas. In the election, however, the ruling Civic Platform–Polish People's Party coalition won sufficient seats to continue in government. Draft regulations regarding a hydrocarbon extraction tax on conventional and unconventional hydrocarbon production were published on 16th October 2012 but will not come into effect until 2015. The implied tax burden is 40% of gross profits. More contentious, however, has been the licensing regime and the process of granting shale gas concessions, with six persons, three Ministry of Environment officials and three company employees, detained and released on bail on suspicion of offering or receiving bribes for the allocation of licences. *The Economist* has noted that the existing rules were designed for a system in which a small number of state-controlled companies were operating, and not for the current exploration environment. With most of the prospective shale gas acreage now under licence, however, any changes will be taking place after the horse has bolted. It was expected that new regulations on shale gas extraction would be announced in November / December 2012 and implemented from 2013. It is thought that a simplification of environmental requirements and general reduction in red tape would form a part of the new regulatory environment. Companies would no longer require to hold a licence before conducting non-drilling energy exploration operations, but energy companies looking to enter the Polish shale market will have to be pre-approved by the Polish government to buy existing licences. A state-owned National Energy Minerals Operator (NOKE) will also be created. NOKE will participate in shale gas projects, where it is intended that it strengthens administrative oversight of licence obligations, and have right of first refusal on secondary trade in exploration licences. NOKE will pay its net profit to the Polish Treasury and to municipal governments, thereby involving local communities in successful shale gas development. NOKE's profits will also go to a planned Hydrocarbon Generations Fund, a form of sovereign wealth fund.

In mid-February 2013 the new hydrocarbon regulations were published in draft form for a one-month public consultation period. They involve a changed Geology and Mining Law and amendments to eight other bills. Some environmental requirements will be loosened. The final draft of the regulations was submitted to the Prime Minister's office in mid-June. Parliament was expected to approve the bill before the end of 2013, after which it will require the signature of the President. In order to accelerate shale gas development, in March 2014 the Polish government offered six-year tax breaks to shale gas projects, avoiding the introduction of special taxes. According to Prime Minister Donald Tusk, the proposal would go through Parliament's approval as early as early April. It has also been reported that the government will drop plans to create the proposed National Energy Minerals Operator (NOKE), in a move to cut red tape and reduce regulatory hurdles.

***Romania*.**

The protests in Bulgaria (above) have been echoed in Romania. Bulgarian activists demonstrated outside the Romanian embassy in Sofia (capital of Bulgaria) and have been in contact with like-minded groups in Romania. The Barlad municipality, where Chevron planned to drill later in 2012, opposed shale gas exploration and in March 2012 some members of the parliamentary opposition filed a legislative initiative which, if passed, would ban hydraulic fracturing. The parliamentary opposition came to power in April 2012 and in May introduced a moratorium on shale gas exploration, due to run until December 2012. In June, the March proposal to ban shale gas exploration and exploitation by hydraulic fracturing and cancellation of licences in which fracking would be used, was overwhelmingly rejected by the Romanian Senate. Comments by the Environment Minister in August 2012, that shale gas exploitation by hydraulic fracturing will not be approved unless the results of EU studies on its environmental and health implications indicate that it is acceptable, suggested that the moratorium was likely to be extended but when it expired at end-December 2012 it was not renewed.

***Spain*.**

In October 2012 the Government of Cantabria in northern Spain published a draft law which, if implemented, would prohibit the use of hydraulic fracturing as long as the doubts and uncertainties

surrounding the use of the technique that exist today persist. The Cantabrian regional parliament passed the proposals into law on 8th April 2013. It should be noted that the bulk of the exploration permits in the Basque-Cantabrian basin, especially those in which shale gas exploration is proposed, lie in other regions: Basque Country (where the Autonomous Government is an active participant); Castilla y Leon; La Rioja; Navarra. On 30th October 2013 it is reported that the Spanish Government explicitly legalised hydraulic fracturing by amending a 1998 hydrocarbon exploration law to include hydraulic fracturing under permitted exploration techniques. EIAs will not be required before conducting fracturing operations. A law streamlining environmental requirement for industrial projects, which could accelerate shale gas exploration approvals, was published on 5th December 2013. In January 2014 the Spanish government then announced that it was taking Cantabria's ban on hydraulic fracturing to the Constitutional Court, arguing that it violates national law on hydrocarbon exploitation.

***Sweden*.**

In the September 2010 parliamentary election campaign the opposition centre-left alliance comprising the Social Democrats, the Left Party and the Green Party pledged to oppose large-scale fossil fuel production in Sweden, including Shell's planned exploitation of shale gas in southern Sweden. In the event, the ruling centre-right Alliance coalition was re-elected.

***Switzerland*.**

In Switzerland, the cantons have a substantial degree of independence and E&P is solely a cantonal responsibility. The Swiss Federation could have an indirect influence on shale gas through its responsibility for environmental legislation but there is no legislation specifically targeted at shale gas at the present time. The federal government's environmental focus is currently on carbon capture and storage (CCS). In April 2011 the cantonal authorities in Fribourg suspended all shale gas prospecting activities and refused the renewal of Schuepbach's exploration licence, due to expire at end-2011. The explanation given was that the environmental impact and pollution risk accompanying drilling had not yet been clearly identified and that the canton preferred to focus on renewable energies. In the canton of Jura, the Green party has questioned the authorities on their policies regarding shale gas. In Neuchatel the Grand Council has decided that in the event of a discovery, in principle an exploitation concession will be awarded to Celtique Energie and that shale gas is not specifically excluded from this decision. The Celtique Energie web site, however, suggests that their only unconventional prospects (shale oil and shale gas) are in the Weald Basin in southern England.

***United Kingdom*.**

On 24th November 2010, the House of Commons Energy and Climate Change Committee launched an evidence-based enquiry into the prospects for shale gas in the UK, the risks and hazards associated with shale gas, and the potential carbon footprint of large-scale shale gas extraction. The committee visited Fort Worth and Austin, Texas, Washington, DC, and two Cuadrilla Resources drilling sites near Blackpool, Lancashire. The voluminous report (223 pages in two volumes) which was published on 23rd May 2011 produced a number of conclusions and 26 recommendations. In its summary, however, the committee stated that "on balance, we feel that there should not be a moratorium on the use of hydraulic fracturing in the exploitation of the UK's hydrocarbon resources, including unconventional resources such as shale gas" (House of Commons Energy and Climate Change Committee, 2011). Nevertheless, a number of issues have arisen in different parts of the United Kingdom and some examples are given below.

As was indicated above (*2.1.2 Shale gas in Europe: Carboniferous*), fracking operations at Cuadrilla Resources' Preese Hall drilling site were halted after two small earthquakes (2.3 and 1.5 Richter Local Magnitude) were reported on 1st April and 27th May 2011. The British Geological Survey (BGS) subsequently determined that the earthquakes at depths of 12,000' and 6,500' were within a few thousand feet of the drilling site and that the correlation between the earthquakes and their proximity to, and the timing of, hydraulic fracturing operations pointed to the earthquakes being the result of the fracking process.

On 2nd November 2011, Cuadrilla Resources (well operator) presented a geomechanical report (de Payter & Baisch, 2011) on the causes of the seismicity and future mitigation procedures to the Department of Energy and Climate Change (DECC). The report concluded that the repeated seismicity resulted from direct injection of fluid into the same critically-stressed fault zone and that this could be avoided in future by rapid flowback after treatment and reduction in treatment volume, accompanied by real-time seismic monitoring to initiate appropriate action when seismic magnitude exceeds pre-defined thresholds.

The DECC sought input from the BGS and other expert sources before taking any decision on the resumption of fracking operations. A BGS spokesman did, however, indicate that earthquakes of the magnitude reported in Lancashire have been occurring for hundreds of years as a result of coal mining and generally go unnoticed. The independent report prepared for DECC agreed "that a suitable traffic light system linked to real-time monitoring of seismic activity is an essential mitigation strategy" allowing adjustments to be made to the injection volume and rate during the fracturing procedure, thereby preventing noticeable seismic activity (Green et al., 2012). On 5th December 2012, in a move widely read as encouraging shale gas exploitation, the government announced the creation of a new Office of Unconventional Gas and Oil, with the intention of focusing regulatory effort to meet the needs of future production. On 13th December it was announced that hydraulic fracturing can resume, subject to controls to mitigate the risk of seismic activity.

In the March 2013 Budget, the UK Chancellor of the Exchequer stated that tax arrangement for companies involved in shale gas exploration would be "generous". Planning clarity should be available by summer 2013 and proposals would be developed to ensure that local communities benefit from shale gas projects in their area.

Under the terms of the UK Infrastructure Act 2015, which received final approval on 12th February 2015, a number of conditions were imposed on hydraulic fracturing in England and Wales. These include the following prohibitions on hydraulic fracturing activity which cannot be conducted:

- unless an environmental impact assessment has been carried out;
- unless monitoring has been undertaken on the site over the previous 12 month period
- unless site-by-site measurement, monitoring and public disclosure of existing and future fugitive emissions is carried out;
- in land which is located within the boundary of a Groundwater Source Protection Zone;
- within or under protected areas (National Parks; Areas of Outstanding Natural Beauty; Sites of Special Scientific Interest);
- at depths of less than 1,000 metres.

A comprehensive but concise summary of the UK legislative position and the issues involved can be found in a House of Commons Library Note of 5th February 2015 (White et al.).

Northern Ireland

On December 6th 2011, the Northern Ireland Assembly passed a motion calling for a moratorium on hydraulic fracking. But no legislation exists to compel a Northern Irish Minister to act upon a moratorium and as the Minister for Enterprise, Trade and Investment has pointed out, no application had been submitted. She will, however, be in a difficult position if one is submitted. It should be noted that hydraulic fracturing has already been used in Fermanagh in 2001, in three tight gas wells. On 21st July 2014 Tamboran Resources confirmed its intention to drill a 2,500' sampling borehole near Belcoo, County Fermanagh on its licence PL2/10: Lough Allen Basin – North. Such an exploratory well was a requirement if the licence was not to lapse on 30th September. In August Northern Ireland Environment Minister Mark Durkan rejected the application to drill, requiring a full planning application with environmental statement before approval could be given. On 30th September Enterprise Minister Arlene Foster cancelled the licence because the well had not been drilled. In October Tamboran announced that it would seek a judicial review against both decisions and in November 2014 Tamboran announced that it would also sue both departments for estimated losses. The case is due to be heard in 2015.

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.

Wales

On 21st October 2011, the Vale of Glamorgan Council (south Wales) rejected a planning application submitted by Coastal Oil & Gas to drill Llandow-1, a shallow (2,600') conventional and shale gas exploratory well situated on an industrial estate. Despite Environment Agency Wales indicating that it had "no objection to the application as submitted", the Welsh Government declining to get involved as the issues were "not of more than local importance" and the application itself stating "This application does **not** include fracking", the local environmental group "The Vale says No" supported by the local member of the UK Parliament put sufficient pressure on the councillors to ensure that all 17 members of the planning committee opposed the application. Although in debate the councillors spoke of their concerns about pollution if fracking followed a positive exploration outcome, this does not represent a valid reason for rejection. The official reason given was therefore that "the applicant has submitted insufficient information to satisfy the Local Planning Authority that the quantity and quality of groundwater supplies in the vicinity of the site, would be protected". The council leader indicated subsequently that better guidelines were required from the Welsh Assembly (regional government) for test drilling and fracking. On 7th July 2012 an appeal against the decision to reject the planning application was upheld by the Welsh Planning Inspectorate who concluded that the main issue was the potential effect on the quantity and quality of groundwater supplies. The inspector concluded that the proposal would not harm groundwater supplies and Llandow-1 can now be drilled. Following the Scottish Government moratorium on unconventional oil and gas exploration, on 4th February 2015 the Welsh Assembly voted to ban hydraulic fracturing in Wales until 2021 in order to evaluate its impact on the environment and public health.

United Kingdom - General. A more general concern on the part of United Kingdom environmentalists is that development of an extensive low-cost shale gas industry threatens the development of renewable energy within the country, by rendering the latter uneconomic. There is also the argument on the one side that gas provides the most sustainable bridge to a low-carbon future while others see that ready availability of gas will simply result in increasing use of fossil fuel-based energy. As there are divisions even within the British government on these issues we can expect that, in the UK at least, this debate is set to run for some time!

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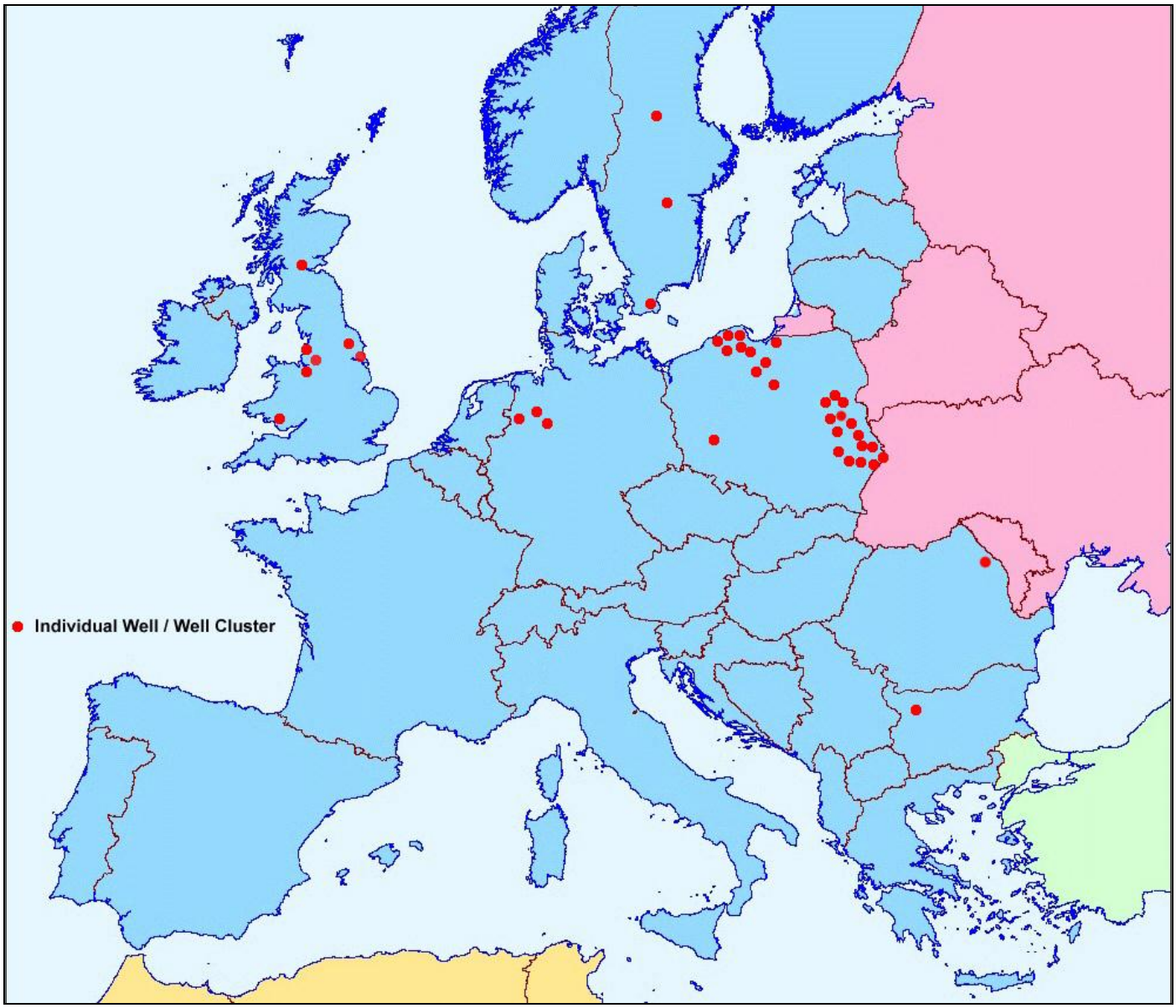
Appendix 1.

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	Fracs	Target Fm	Result - Content
Bulgaria												
Moesian Platform		A-Lovech	Goljamo 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	Planned May-15					Alum Shale	
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	Niedernw 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	Wytow 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 fracs	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 fracs	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 H_2S and low N2. Heavier hydrocarbons
Baltic Depression	Gdansk Depression	Wejherow o	Lubocino	2H	PGNiG	Aug-12	Nov-12	13,060	Y	DFIT; 6 fracs	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	Tepcz	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	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	Borcz	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	Fracs	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	Zw ierzyniec	Zw ierzyniec	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 Królew 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	Kw idzyn	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	Pęclin	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	Fracs	Target Fm	Result - Content
Sweden												
Östergötland Low er Paleozoic		Motala area	5 w ells		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 w ells		Gripen Energy	May to Aug 15	May to Aug 15				Alum Shale	Flow ed gas
Östergötland Low er Paleozoic		Orlunda	1 exploration w ell		Gripen Energy	May to Aug 15	May to Aug 15				Alum Shale	Flow ed gas
Östergötland Low er Paleozoic		Eneby	2 exploration w ells		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	
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	Becconsall	1	Cuadrilla	23-Aug-11	13-Oct-11				Bow land Shale	
East Irish Sea Basin	West Bow land Basin	PEDL 165	Becconsall	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?	

Appendix 3.
Selected companies with potential interest in shale gas exploration in Europe, by country.

Country	Companies
Austria	OMV
Bulgaria	Transatlantic Petroleum / Esrey Energy
Croatia	INA-MOL
Czech Republic	Applications: Cuadrilla Resources
Denmark	Total / Danish North Sea Fund (Nordsøfonden)
France	No valid permits as a result of moratorium on hydraulic fracturing: at 28 Feb 2014, there were 110 outstanding permit applications (many overlapping) from multiple companies.
Germany	ExxonMobil / Shell (BEB); IGas Energy; Wintershall
Ireland	Enegi Oil; Tamboran Resources
Italy	Independent Resources plc
Netherlands	Cuadrilla Resources / EBN
Poland	BNK Petroleum; Chevron Corp.; ConocoPhillips; Cuadrilla Resources; Greenpark Energy ; LOTOS Petrobaltic; PGNiG; PKN Orlen; PPI Chrobok; San Leon; Stena AB; Wisent Oil & Gas
Spain	BNK Petroleum; Hunosa; Leni Gas & Oil; Repsol; San Leon; Schuepbach Energy; Sociedad de Hidrocarburos de Euskadi (SHESA); Vancast Exploración
Sweden	Aura Energy; AB Igrene; Gripen Oil & Gas AB; Tekniska Verken i Linköping AB
Switzerland	Schuepbach Energy
United Kingdom	Centrica; Connaught Oil & Gas; Cuadrilla Resources; eCORP; Eden Energy; Egdon Resources; GDF Suez; Hutton Energy; IGas Energy; INEOS; Tamboran Resources; Third Energy; Total; UK Onshore Gas (Coastal Oil & Gas; UK Methane)
Certain of the companies listed have indicated their intention to exit shale gas exploration in the country indicated but retained their interest at the time of compilation of the table.	

China Shale Gas and Shale Oil

By Shu Jiang (University of Utah, Energy & Geoscience Institute, Salt Lake City, Utah 84108 USA)

The shales spanning from Pre-Cambrain Sinian (a period right before Cambrian) to Quaternary are wildely distributed in China. The Pre-Cambrian to Upper Paleozoic organic rich shales with maturity in gas window and shallow Quaternary shales have shale gas potentials and Mesozoic to Cenozoic organic rich shales with maturity in oil window have shale gas potentials (Fig.1). 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 (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. One recent breakthrough is that China is the only country outside of North America that has reported

commercially viable production of shale gas based on the latest commercial quantity shale gas production reported from Sichuan Basin by Sinopec and PetroChina, although the volumes contribute less than 1% of the total natural gas production in China. In comparison, the shale gas as a share of total natural gas production in 2012 was 39% in the United States and 15% in Canada (EIA, Oct 2013). The successful development evidence in Sichuan Basin especially in Fuling area recently makes the China's 2015 output target of 6.5 bcm possible, which was thought impossible before last month. This will encourage Beijing government and draw interests of international oil companies.

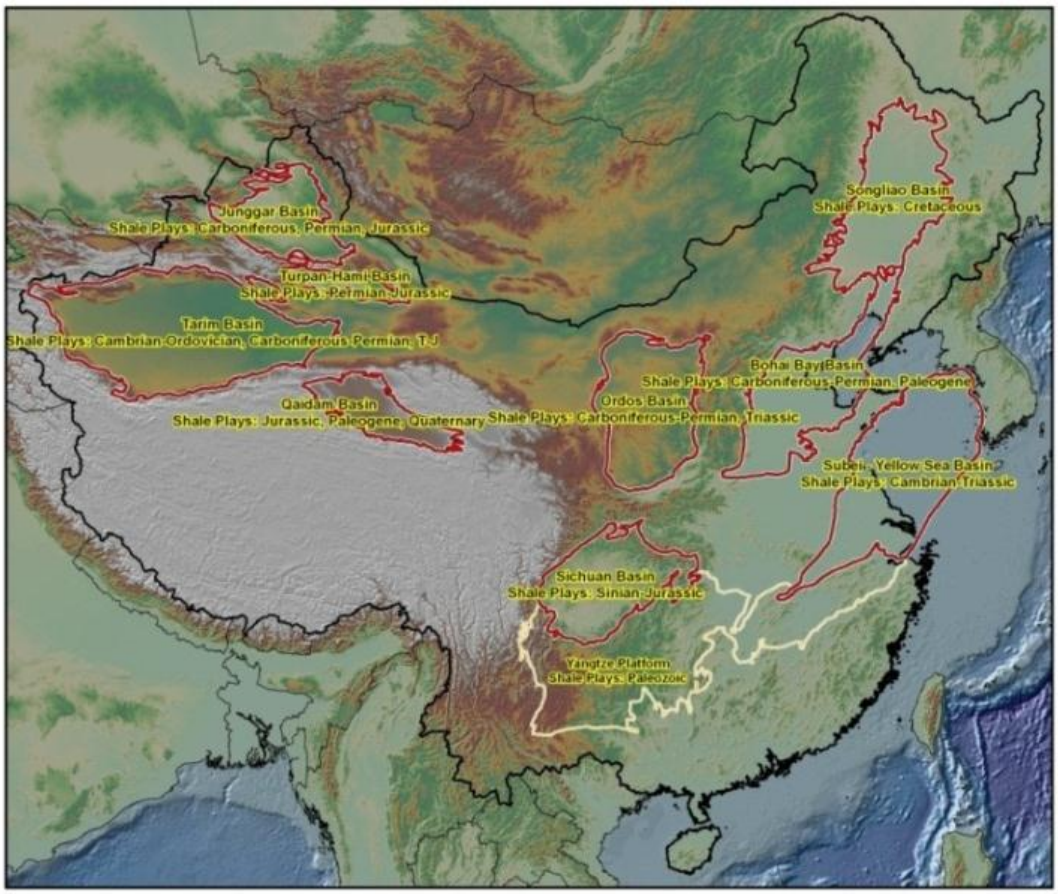


Fig. 1 The distribution of potential major China shale gas and shale oil plays.

For US producing shales, they were deposited marine depositional setting. But for hydrocarbon related shales in China were formed in 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 can be represented by Lower Paleozoic Sichuan Basin, Carboniferous to Permian Ordos Basin and Cenozoic Bohai Bay Basin respectively (Fig.3). The Table 1 summarizes the depositional settings and distribution in time and space for the potential gas and oil shales 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

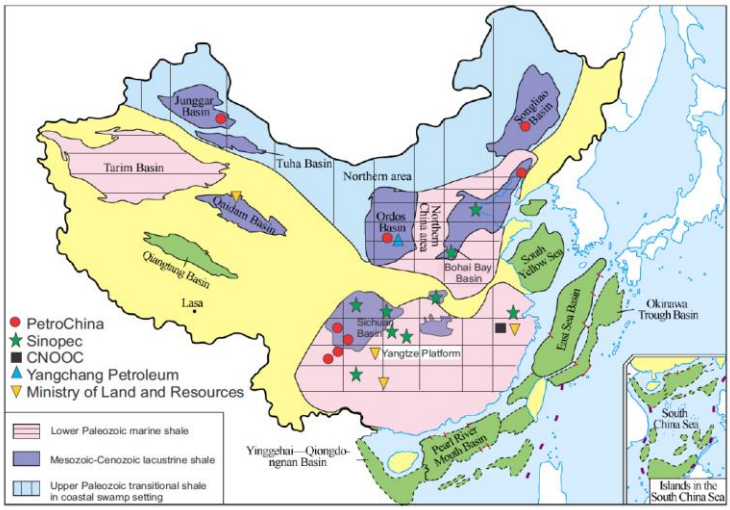


Fig. 2 the shale exploration activities in China

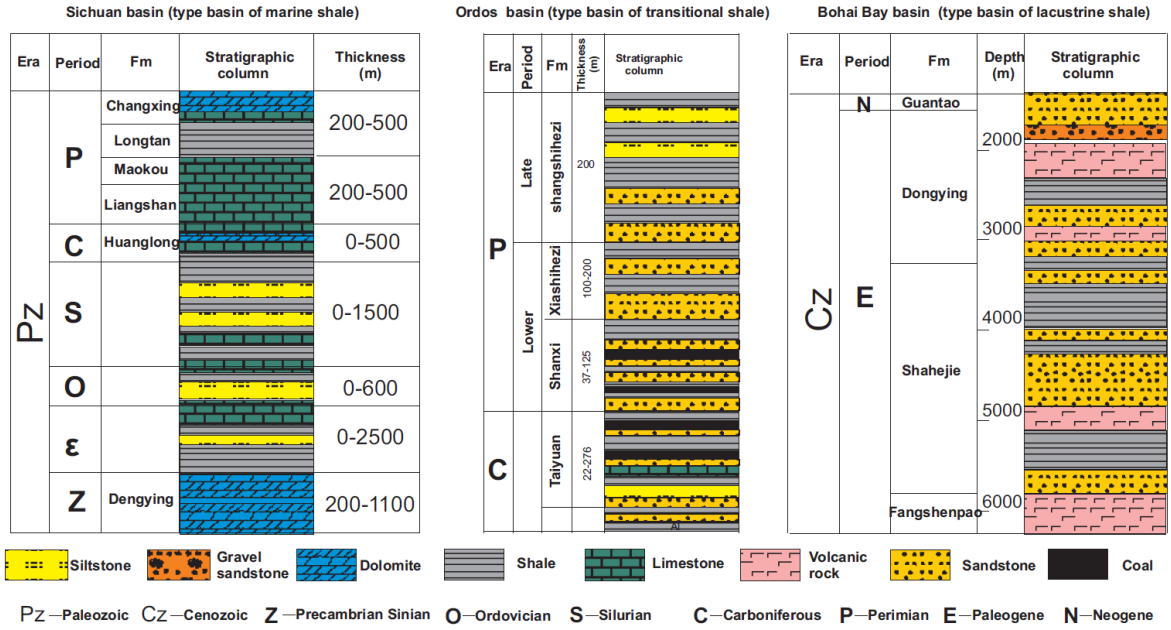


Fig.3 Three kinds of potential shales (marine, lacustrine and transitional/coastal setting) and their type basins

China has investigated shale gas and shale oil for nearly 6 years. So far, 2013, 2D seismic data covering 9000 km^2 and 3D seismic data covering 800 km^2 were acquired, and 150 shale gas wells (including shallow parameter wells behind outcrop) targeting marine, lacustrine and transitional (coastal swamp setting associated with coal) shales were drilled so far by the PetroChina, Sinopec, CNOOC, Yanchang Petroleum, other state or private companies who recently got shale blocks, 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.2). Recently, the Junggar basin has also become target basin for shale oil associated with tight dolomite oil play. So far, almost half of drilled shale wells have good shale gas and shale oil show. Among 30 hirizontal wells, several wells were reported very successful based on test results rate of over 100,000 cubic meters daily production. The rate from well Yang201-H2 in Luzhu, Sichuan was reported to produce at 430,000 cubic meters per day and recently a well in Fuling area in E Chongqiong was reported to produce 547,000 cubic meters/day. Sinope drilled 30 shale gas wells in Fuling pilot area and 6 wells were reported to have high rate commercial production with arerage 180,000 cubic meters/well. Sinopec claimed the 2015 output target in Fuling area will be doubled based on recently encouraging results. 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 stages fracing 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.4) and high intra-organic nano-porosity (Fig.5) make China marine shales same 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.6). Generally, China lacustrine shales have high clay content than marine shales (Fig.4), 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.7) and tight sand oil from Ordos Basin (Fig.8) 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 and shale oil and tight sand and tight carbonate reservoirs within the organic rich shale could consist of hybrid reservoirs (e.g. shale oil and tight sand oil in Triassic source rock interval in Ordos Basin, Fig.8).

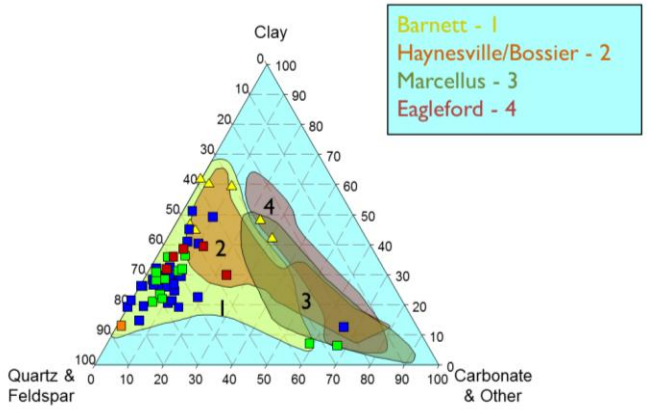


Fig.4 Ternary diagram for mineralogy of marine shale (square legend) and lacustrine shale (triangle legend) in China and its comparison with mineralogy of typical US shales.

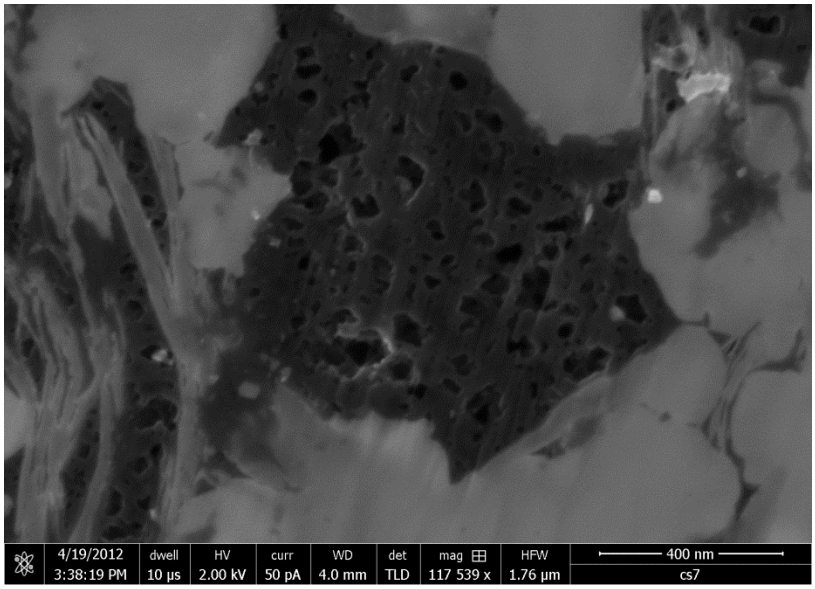


Fig.5 SEM of ion polished sample showing intra-organic nano-pores of a marine shale Sichuan Basin, China

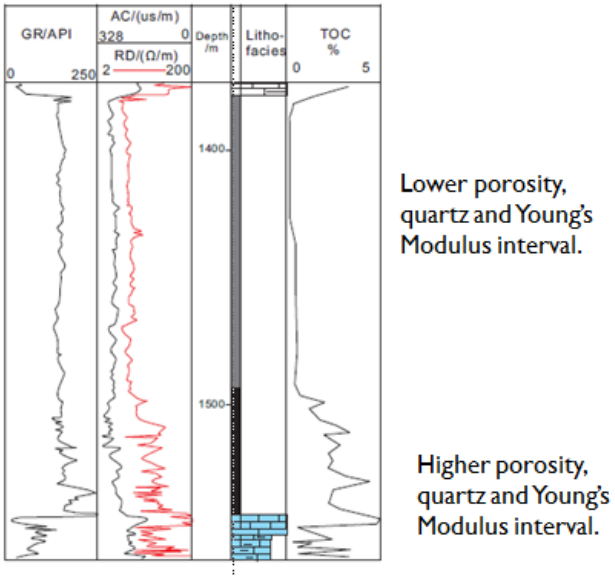
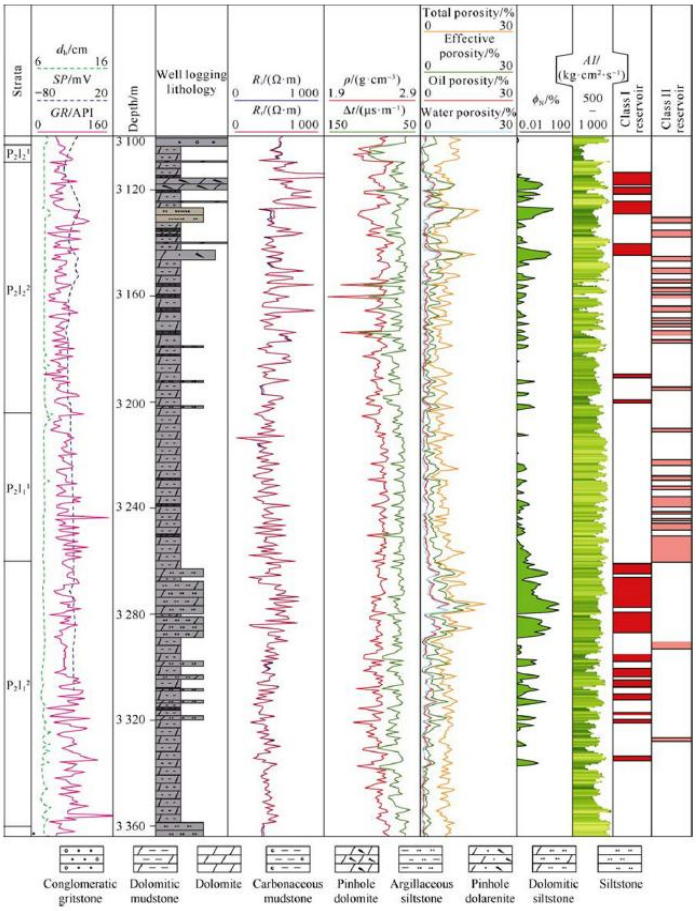


Fig. 6 Typical shale gas well in Sichuan Basin for marine shale gas



Comprehensive well logging evaluation chart of the Lucaogou Formation reservoir in the Jimsar Sag. d_h—hole diameter; ontaneous potential; GR—gamma ray; R_i—resistivity of intrusion zone; R_t—formation resistivity; ρ—density; Δt—interval tran- ϕ_N—neutron porosity; AI—acoustic impedance.

Fig.7 Tight dolomite oil from Permian source rock interval with shale oil show, Junggar Basin, NW China (L. Kuang, 2012)

What made shale gas or shale 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 chalks and dolomite interbeded in source rock intervals in US basins. These basins have relatively simple tectonic settings than China. Even promising marine shales in China are similar to brittle Barnett shale in US regarding mineralogy, the 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 have different stress fields than those in US, e.g. the maximum principal stress is horizontal in some areas in China and the maximum principal stress is vertical in US, this is why the fracing experiences in US may not work very well in China. We need investigate more about the geology, geomechanics and hydraulic fracturing design for unique China shales.

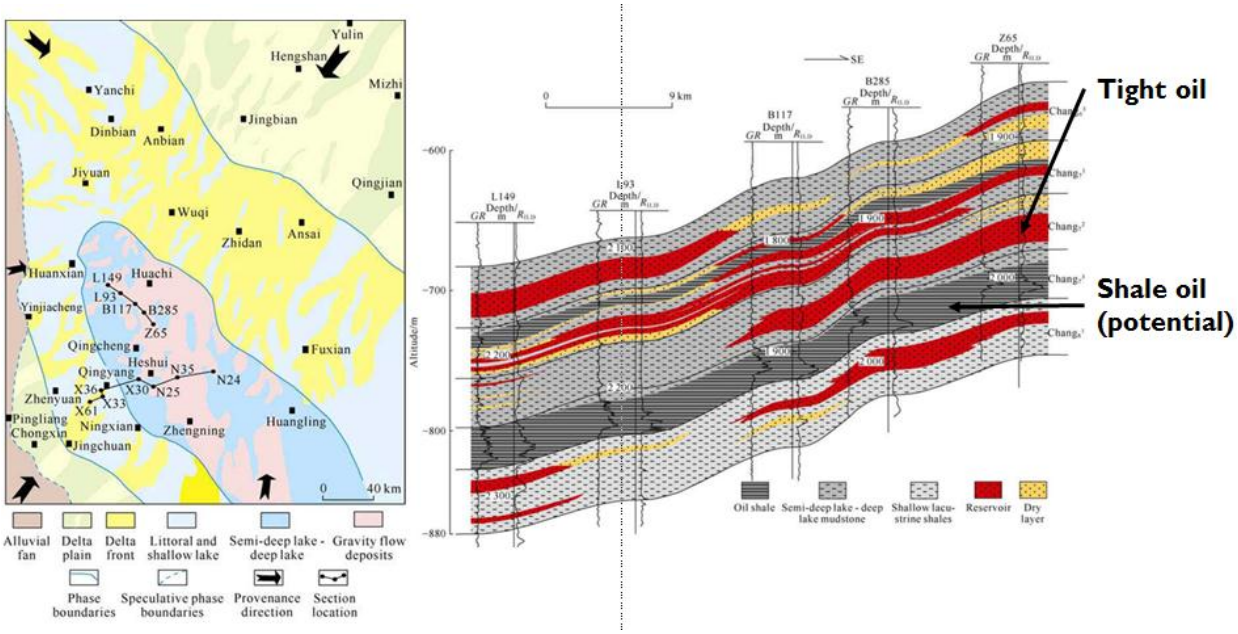


Fig. 8 Tight oil and potential shale oil of Triassic Yanchang Fm in Ordos Basin (modified from YAO Jingli, 2013

Since shale gas exploration and production is technically challenging and China basins have complex tectonic activities and different properties for shales, China has been collaborating with international oil firms and service companies to achieve the 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. 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 companes know better and better to frack 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.9)

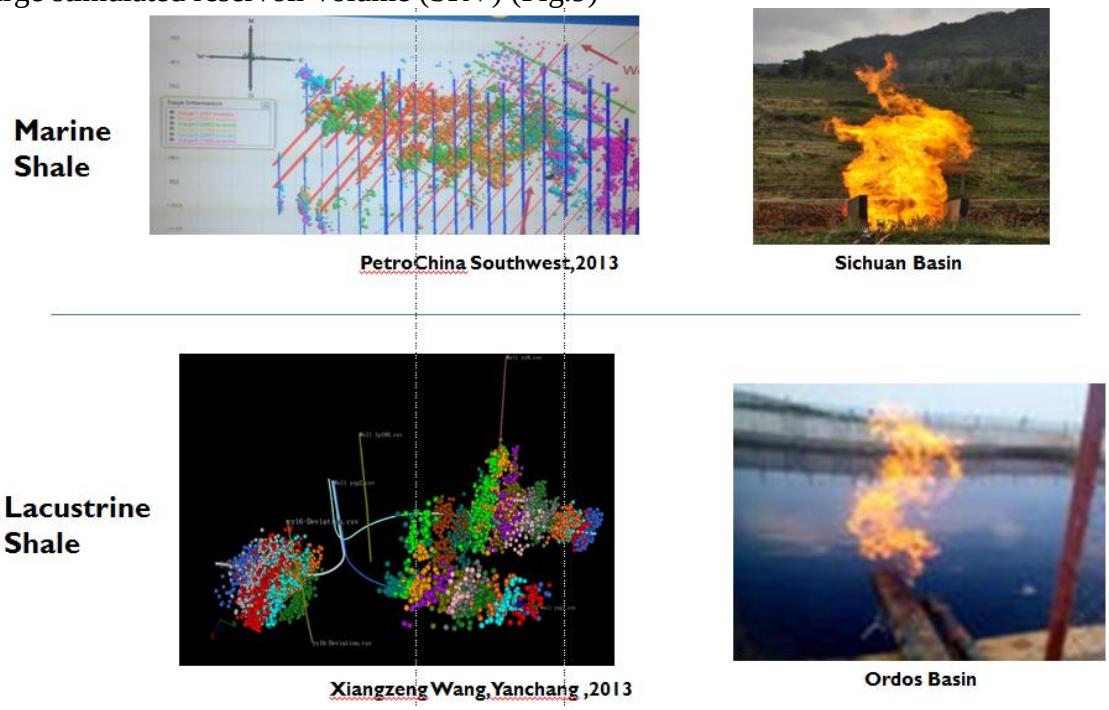


Fig. 9 Horizontal drilling and hydraulic fracturing for both marine and lacustrine shales in China

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 summary, China has huge potential for both shale gas and shale oil potential, even though the geological setting and geomechanics regime are more complex than US producing shales for hydraulic fracturing, with the learning curve for the lacustrine shale gas in Ordos Basin and shale oil in Nanxiang Basin in central China and tight/shale oil in Santanhu and Junngar Basin in Northwest China, and recent commercial shale gas flow from marine in Sichuan Basin by PetroChina and Sinopec, technology

advancement and policy support for incentives and reforms from Chinese government, China has commercially produced 200 million cubic meters in 2013 from pilot areas and the China vast shale resources are expected to be produced on a large scale.

Valuable links

Maps

- Active Shale Gas Plays, lower 48 http://www.eia.gov/oil_gas/rpd/shale_gas.pdf
- Various shale gas plays (Barnett, Fayetteville, Haynesville-Bossier, Marcellus, Woodford) and shale oil (Bakken). http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm

Assessments

- Assessments of undiscovered oil and gas resources, onshore US http://energy.cr.usgs.gov/oilgas/noga/
- Assessments of undiscovered oil and gas resources, World http://certmapper.cr.usgs.gov/rooms/we/index.jsp
- Assessment of Australian energy resources https://www.ga.gov.au/image_cache/GA17412.pdf (courtesy of Gesocience Australia)

Consortia

- Core Lab "Reservoir characterization and production properties of gas shales" (http://www.corelab.com/rm/irs/studies/GasShales_Global.aspx);
- "Haynesville and Bossier Shale Evaluation" (http://www.corelab.com/rm/irs/studies/Haynesville-Bossier.aspx);
- "Eagle Ford Shale Study" (http://www.corelab.com/rm/irs/studies/EagleFord.aspx);
- "Montney Shale Regional Study" (http://www.corelab.com/rm/irs/studies/MontneyShale.aspx);
- "Global Gas Shales Study" (http://www.corelab.com/rm/irs/studies/GasShales_Global.aspx)
- Colorado School of Mines FAST (Fracturing, Acidizing, Stimulation Technology) Consortium Project 9: stimulation of "shale" reservoirs (http://www.mines.edu/fast/).
- Humble Geochemical Services (http://www.humble-inc.com/) http://www.humble-inc.com/PlayTypes/ShaleGas/tabid/102/Default.aspx
- GeoMark Research
  - Appalachian Basin Shale Gas Study (2005) (http://www.geomarkresearch.com/studies_northamerica.cfm)
- Baseline Resolution (http://brilabs.com/)
  - Geochemistry Studies (http://brilabs.com/contents/basin_studies2.htm)
- GASH (Gas Shales in Europe)

- (http://www.gfz-potsdam.de/portal/-;jsessionid=7BA522526C3C6B6F7C57E0E6A3579326?$part=binary-content&id=2022464&status=300&language=en)
- GeoEn (Germany) http://www.geoen.de/index.php/shale-gas.html
- CSIRO Shale Research Centre (http://www.csiro.au/science/shaleResearchCentre.html)
- PTTC Unconventional Tech Center http://www.pttc.org/tech_centers/unconventional_resources.htm)

Additional Sources of Information

- **References** (see gas shale bibliography on Gas Shale Committee web site) (http://emd.aapg.org/members_only/gas_shales/gasshalereferences.pdf)
- **Trade Journals** (articles included in bibliography above)
    - Powell Barnett Shale Newsletter (http://www.barnettshalenews.com/)
    - American Oil and Gas Reporter (http://www.aogr.com/)
    - Oil and Gas Investor (http://www.oilandgasinvestor.com/)
    - Oil and Gas Journal (http://www.ogj.com/index.html)
    - Hart's E & P (http://www.epmag.com/)
    - AAPG Explorer (http://www.aapg.org/explorer/)
- **Subscription Services**
    - Hart Unconventional Natural Gas Report (http://www.ugcenter.com/)
    - IHS Energy (http://energy.ihs.com/)
    - Warlick International Report (http://warlickenergy.com/)
- **Hydraulic Fracturing**
    - http://www.strongerinc.org/

Gas Shales and Shale Oil Calendar

June 24-26, 2015: Lodgepole-Bakken-Three Forks Petroleum System Field Seminar, Montana. AAPG. www.aapg.org/career/training/in-person/field-seminars/details/articleid/13422/

July 20-22, 2015: Unconventional Resources Technology Conference, San Antonio, TX. SPE, AAPG, SEG. http://urtec.org/2015

September 6-8, 2015: China Shale Gas 2015, Wuhan, China. Institute of Rock and Soil Mechanics. http://www.csg2015.org