EMD Shale Gas and Liquids Committee Annual Report, FY 2013

Neil S. Fishman, Chair

April 23, 2013

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INTRODUCTION

It is a pleasure to present this Mid-Year Report from the EMD Shale Gas and Liquids Committee. This report contains information about specific shales across the U.S., Canada, Europe, China, as well as SE Asia from which hydrocarbons are currently being produced or shales that are of interest for hydrocarbon exploitation. This report also includes a section on southeast Asia, in addition to an entire section on China, and an expanded section on Europe. 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 natural gas, however, has affected gas production in many of the plays in the U.S., which is clear from information provided in several of the sections below.

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), China, and other parts of Asia. 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 26 years old, having begun the modern phase of development in 1987. The total number of producing wells drilled in the play through end of September, 2012 is approximately 11,500 with about 9,649 still online. Total cumulative production of gas reached 3.114TCF by the end of September, 2012. Michigan Antrim production is reported by project rather than by individual well or lease. Projects may be only a few wells or more than 70 wells. There were 770 separate projects at the end of September, 2012. Cumulative production for first 9 months of 2012 was 81,137,676 MCFG. That was a 5.04% decline from the same period in 2011.

There were 30 operators with production at the end of September, 2012. There were 9,649 wells online at the end September, 2012. There were 111 new wells drilled in 2009, only 58 in 2010 and 13 drilled in 2012. That is a 48% decrease in wells drilled from 2009 to 2010, a continuing drop of 33% in 2011 and a 78% drop in 2012. 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 83.0% of the total Antrim gas in 2012. Two of the 30 operators produced no gas as all their projects were shut in due to low prices. As of September 2012, 20 less Antrim projects and 139 less wells were online compared to the same period in 2011.

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

CO2 is also an issue in the produced Antrim gas that is mostly of biogenic origin. Most wells begin with very low amounts of CO2 in the produced gas; however, the percentage of CO2 increases through time. Some projects that have a long production history may now exceed 30% CO2 in the produced gas. The play wide average was just over 12.5% 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:
Chevron Michigan LLC
Linn Operating, Inc.
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 and 2012 due to low gas prices. Production continues to decline as do the total number of active wells. Daily gas production per well declined by 5.04% in the first 9 months of 2012. However, daily water production per well decreased 2.6% in 2012 compared to the same period in 2011. The numbers of horizontal completions still represent less than 5% of total wells.

Issues – None

Legislation – None

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

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

In 2008, the United States Geological Survey (USGS) used a standardized assessment regime that concluded that the Bakken Petroleum System in the entire Williston Basin contains an undiscovered 3.65 BBbls of oil, 1.85 trillion cubic feet of natural gas, and 148 million barrels of natural gas liquids that are technically recoverable with current technologies (Pollastro and others, 2008). The North Dakota Department of Mineral Resources (Bohrer and others, 2008) estimates that, within the North Dakota portion of the Williston Basin, the Bakken Formation contains 2.3 BBbls of recoverable oil in place (OIP) and the underlying Three Forks Formation contains an additional 2.1 BBbls (Nordeng and Helms, 2010) . A re-assessment of the Bakken Petroleum System is currently underway by the USGS with an expected publication date September 2013, although an update is expected to be provided at the AAPG Annual Meeting in Pittsburgh.

Development of 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 600 horizontal wells have been drilled in the 450-square-mile field from which more than 94 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 when Michael Johnson noted that wireline logs of the Bakken Formation along the eastern limb of the Williston Basin in Mountrail County, North Dakota resembled those from Elm Coulee. Even though the

kerogen within the Bakken shales appeared immature and thus might not be generating oil, free oil in DSTs and some minor Bakken production encouraged Johnson to pursue a 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, EOG Resources drilled the #1-36 Parshall and #2-36 Parshall which resulted in wells with initial production rates in excess of 500 BOPD. Well stimulation of the early wells typically involved large single stage fracs using over 2 million pounds of proppant and over a million gallons of water. More recently single stage fracture stimulations have been replaced by multistage stimulations. These fracture the lateral with similar amounts of fluid and proppant but that is distributed over 10 to 40 or more separate stages. In a few instances, different laterals in the same well as well as laterals in adjacent wells are stimulated at the same time. Whiting Oil & Gas Corp. has installed a microseismic array in the Sanish Field in order to better visualize the real-time generation of induced fractures during stimulation process.

Subsequent horizontal drilling coupled with staged fracture stimulation has resulted in wells with IPs in excess of 2,000 BOPD. The Parshall field is currently averaging 779 MBbls of oil per month from 233 wells. Sanish Field, next to Parshall, is averaging 1.5 MMBbls of oil/month from 331 wells.

Over 354.5 million bbls of oil have been recovered from the 3,157 wells in the 240 middle Bakken producing fields put into service since 2004. The 882 horizontal wells drilled into the Three Forks Formation since 2006 have produced a total of 71.5 million bbls of oil. Currently there are 173 fields with Three Forks production. Sixty-eight wells have been completed in both the Bakken and Three Forks Formations. The majority of these wells were drilled in 2010.

The increase in information from recent drilling has resulted in the definition of a new member of the Bakken Formation called the Pronghorn. Additionally, to conform to adjoining states and provinces the original members have been formalized. New standard subsurface reference sections have also been designated. The formation now consists of four members, including: Upper; Middle; Lower; and Pronghorn.

As the play moves into the production phase, multiple wells are now drilled from single pads with a closed mud system to minimize the footprint. Also, there has been an increase in the number of acquisitions. The latest is the purchase of Denbury's Bakken holdings by Exxon-Mobil.

The North Dakota portion of the Williston Basin is extremely active with 186 rigs running. The top 10 producers in the play are:

1. EOG Resources (405 wells; up from 267)
2. Whiting Oil and Gas Corporation (360 wells; up from 161 wells)
3. Hess Corporation (473 wells; up from 172 wells)
4. Continental Resources, Inc. (480 wells; up from 210 wells)
5. Marathon Oil Company (280 wells; up from 177 wells)
6. Slawson Exploration Company, Inc. (139 wells; up from 73 wells)
7. Brigham Oil & Gas, L.P. (194 wells)
8. Burlington Resources Oil & Gas Company, LP. (165 wells; up from 92 wells)
9. XTO Energy Inc. (112 wells; up from 83 wells)
10. Petro-Hunt, LLC (188 wells)

Additional Information:

The Bakken Source System was the focus of this past year's Williston Basin Petroleum Conference. The materials presented are available at the following link:
http://ndoil.org/?id=279&page=2012+WBPC+Presentations

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

Recent Publications:

First 60 - 90 Day Average Bakken Horizontal Production by Well Available: North Dakota Geological Survey: Geological Investigations 149

LeFever, J.A., Nordeng, S.H., T. Nesheim, 2012, Core Workshop Booklet: North Dakota Geological Survey Geological Investigations 155

LeFever, J.A., and S.H. Nordeng, 2012, Preliminary Report on the Bakken Formation, North-Central ND: North Dakota Geological Survey Geological Investigations 156.

Robinson, J.W., LeFever, J.A., and S.B. Gaswirth, 2011, Bakken-Three Forks Petroleum System in the Williston Basin: Rocky Mountain Association of Geologists, Denver, CO. 546p.

S.H. Nordeng and L.D. Helms, 2010, Bakken Source System: Three Forks Formation Assessment: https://www.dmr.nd.gov/ndgs/bakken/bakkenthree.asp

Sonnenberg, S.A., and A. Pramudito, 2009, Petroleum geology of the giant Elm Coulee Field, AAPG Bulletin, vol. 93, p. 1127-1153.

Bohrer, M. and others, 2008, DMR Bakken Assessment: https://www.dmr.nd.gov/ndgs/bakken/bakkenthree.asp

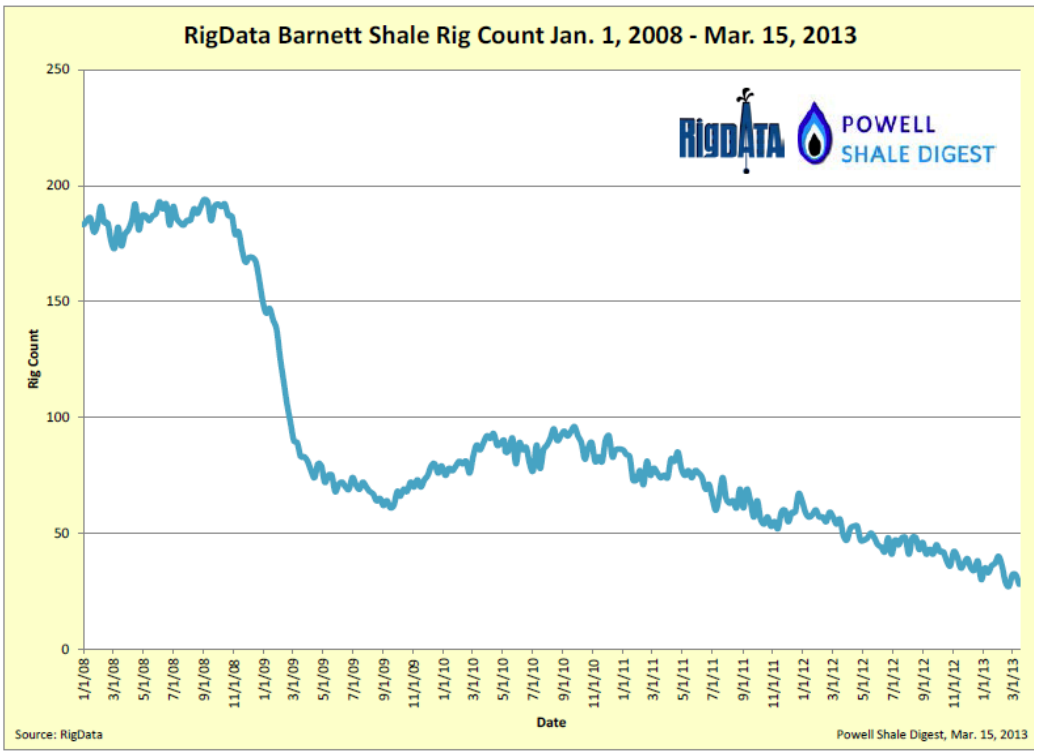
Pollastro, R. and others, 2008, Assessment of Undiscovered Oil Resources in the Devonian-Mississippian Bakken Formation, Williston Basin Province, Montana and North Dakota: USGS FS08-3021_508

Barnett Shale (Mississippian), Fort Worth Basin, U.S.

By Kent Bowker (Bowker Petroleum, LLC)

Through 2012, the Barnett Shale accounted for 31% of total gas production in Texas (http://www.rrc.state.tx.us/data/fielddata/barnettshale.pdf).

The rig count in the Barnett has slowly dropped in the past several years to 37 in 12 counties (as compared to 47 operating rigs in 18 counties at this time last year). Wise County has the most rigs at 11 (Wise County has more liquids-rich production than many other portions of the play, as noted in the Powell Shale Digest - www.shaledigest.com). Devon continues to be the most active operator in the play. As of January 1, 2013, there were 18,591 total wells producing from the Barnett, and total production stood at 13,121 BCF of gas and 45,016 MB of oil (includes condensate). The total well count includes 13,748 horizontal wells.



(used with permission of Gene Powell)

All time peak gas production from the Barnett was reached in May, 2011 at 5.87 BCF/D, with peak oil/condensate production reached in July, 2011 at 29,736 B/D. Average daily gas production in December 2012 was 5.24 BCF/D and daily oil production was 22,373 B/D. These production data appear to refute the contention that production from shale plays will decline quickly once drilling activity declines.

The Texas Bureau of Economic Geology (BEG), supported by funding from The Alfred P. Sloan Foundation, has recently completed an exhaustive study of the production from the Barnett (http://www.utexas.edu/news/2013/02/28/new-rigorous-assessment-of-shale-gas-reserves-forecasts-reliable-supply-from-barnett-shale-through-2030/). The study indicates that the Barnett will be a substantial contributor to the nation's gas stream through 2030 and that over 10,000 additional wells will be drilled in the play. The details of the techniques and methods used in the study are contained in five manuscripts that have been submitted to appropriate journals; for example, I am currently reviewing a paper submitted by the BEG team to the AAPG *Bulletin* concerning their method for assessing reservoir quality.

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 as 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. The wells that have been completed display a steady decline in production similar to those in other shale plays. As for shale oil wells, recently drilled wells have shown initial production rates of several hundreds to as much as 1000 BOPD. As of September, 2012, there were 2,093 oil wells, 817 gas wells, and 4,976 permitted wells in Eagle Ford (Railroad Commission of Texas). The trend occurs at an average depth of 11,000 feet, and it is over-pressured.

As with the Barnett and Haynesville Shales, the Eagle Ford is a viable target for hydrocarbon exploitation because of advances in the application of horizontal drilling and fracturing procedures. 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 and are fracing the wells with slick water or acid in at least 10 different 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/.

Continued activity and success in the Eagle Ford in Texas has generated renewed interest in the laterally equivalent Cenomanian-Turonian Tuscaloosa marine shale in eastern Louisiana and southern Mississippi. Initial exploration in the Tuscaloosa Marine Shale in the 1970's has been followed by minimal exploration and production in the 1980's, 1990's and early 2000's. In 2010 and 2011, several companies began significant leasing in eastern Louisiana and southern Mississippi. Over the last twenty-four months, those companies have begun exploratory and initial development drilling for the Tuscaloosa marine shale, based in part on the current higher price for oil, corresponding low price for natural gas, and the recent horizontal drilling success in the Eagle Ford in Texas, as well as a historical record of hydrocarbon generation and proven, but minimal, production from the unit. The trend averages about 12,000 to 15,000 ft and is overpressured. During 2011 and 2012, several companies have drilled successful horizontal wells; 15 oil wells have come on line in northeast Louisiana and southern Mississippi. 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. A summary of play history and a discussion of recent leasing and exploration trends can be found in the August 2011 issue of the AAPG Explorer:
http://www.aapg.org/explorer/2011/08aug/tuscaloosa0811.cfm.

In depth discussions of the nuances of the Tuscaloosa marine shale can be found on a blog maintained by Kirk Barrel of Amelia Resources: http://www.tuscaloosatrend.blogspot.com/.

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

By Peng Li (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 2011 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). EIA also reports that the proved gas reserves of the Fayetteville Shale in 2010 is 12.526 TCF, 3.456 TCF of increase from the 2009 estimates. Estimated ultimate recovery (EUR) for a typical horizontal Fayetteville gas well increases from 1.8 BCF in 2008 to 3.2 BCF in 2011 (OGJ, 2012). Estimated cumulative production of gas from the Fayetteville Shale as of July 2012 has totaled 3,649,989,502 MCF. Annual production of Fayetteville Shale for 2012 is 1,027,711,866 MCF from 4,434 wells. The daily production has amounted to 2.9 Bcf in November 2012. Initial production rates of horizontal wells have recently averaged about 3,136 MCF/day. Notably, even in the face of the challenging gas price environment in 2011 and 2012, production from the Fayetteville continued to grow at a fast clip, increasing by over 21% since January 2011. 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 13 rigs in December 2012. The continued production growth, in spite of the sharply lower rig count, is explained by the truly remarkable gains in rig productivity and operating efficiencies as the transition towards the full development mode in many areas is beginning to bear fruit. In 2013, Southwestern Energy projects to drill 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 is expected to increase by over 10%.

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 two consecutive years, with 829 in 2011 and 675 in 2012. As of March 2013, there are a total of 4,587 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. Completed lateral length has increased 82% over the last four years while holding total well costs flat at about $ 2.8 million. Horizontal wells drilled from 2010 to 2012 averaged 5,600 feet in lateral length with some wells up to 8,000 feet. 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).

Since the play's inception, the Fayetteville Shale play has been dominated by a small number of large players. As of November 2012, three operators -- Southwestern, Exxon Mobil and BHP Billiton -- 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 925,000 net acres and just fewer than three thousand operated wells drilled as of 2012, 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.

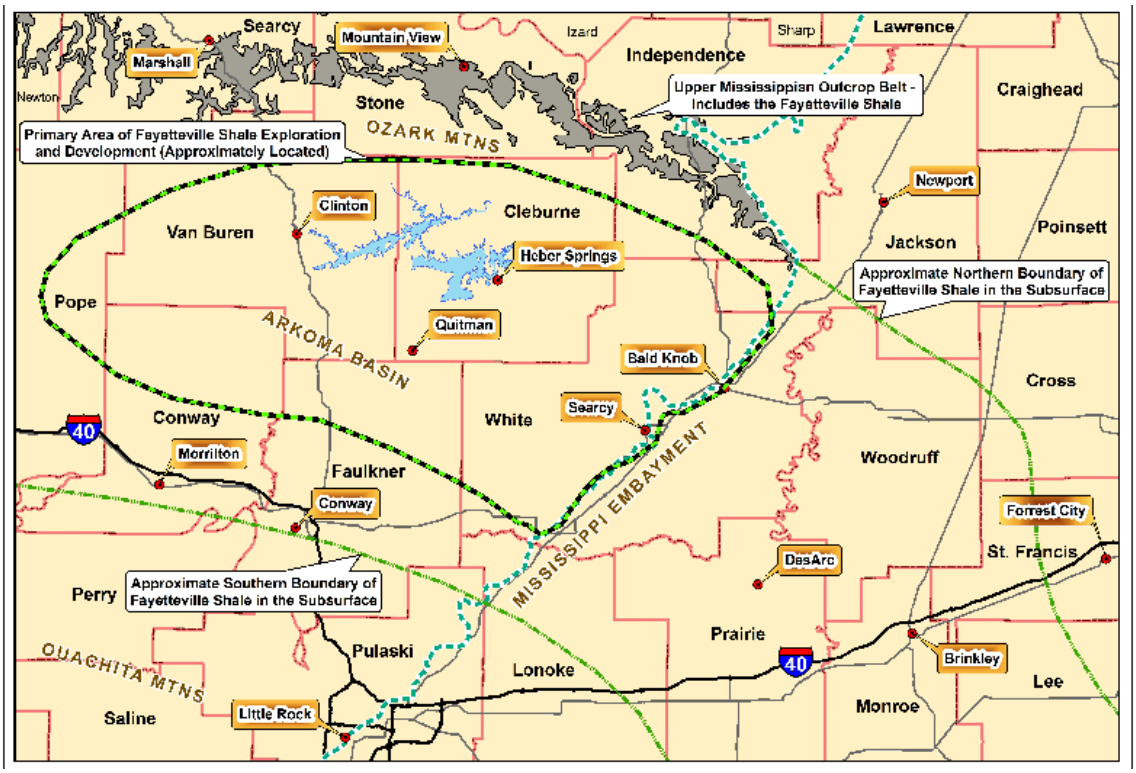


Figure 1. Primary area of the Fayetteville Shale exploration and development in Arkansas.

The top three operators of the Fayetteville gas shale play as of March 2013 based on numbers of producing wells are as follows (Figure 2):

1) SEECO Inc. (an exploration subsidiary of Southwestern Energy) (2,908 wells)
2) BHP Billiton Petroleum (911 wells)
3) XTO Energy, Inc. (a subsidiary of ExxonMobil) (758 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.

Disposal of wastewater through injection wells has gradually mounted a concern in the Fayetteville Shale play area given thousands of area earthquakes, most too small to be felt, detected beneath an area near the towns of Guy and Greenbrier, Central Arkansas, since last fall. A recently discovered fault, the Guy-Greenbrier Fault, near the disposal wells, is nearly 7.5 miles long, which could theoretically generate a quake of around 6.0 in magnitude. In January 2011 AOGC imposed a six-month moratorium on new injection wells in 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 the 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.

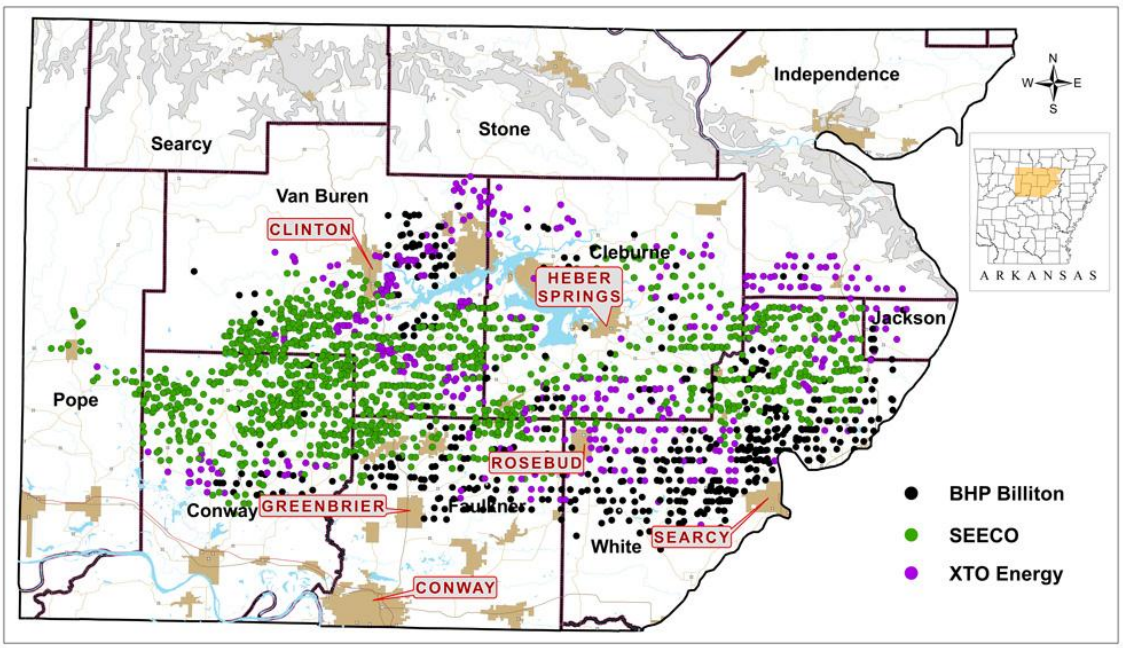


Figure 2. Location map of the Fayetteville Shale producing wells by top 3 operators as of March 2013.

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.

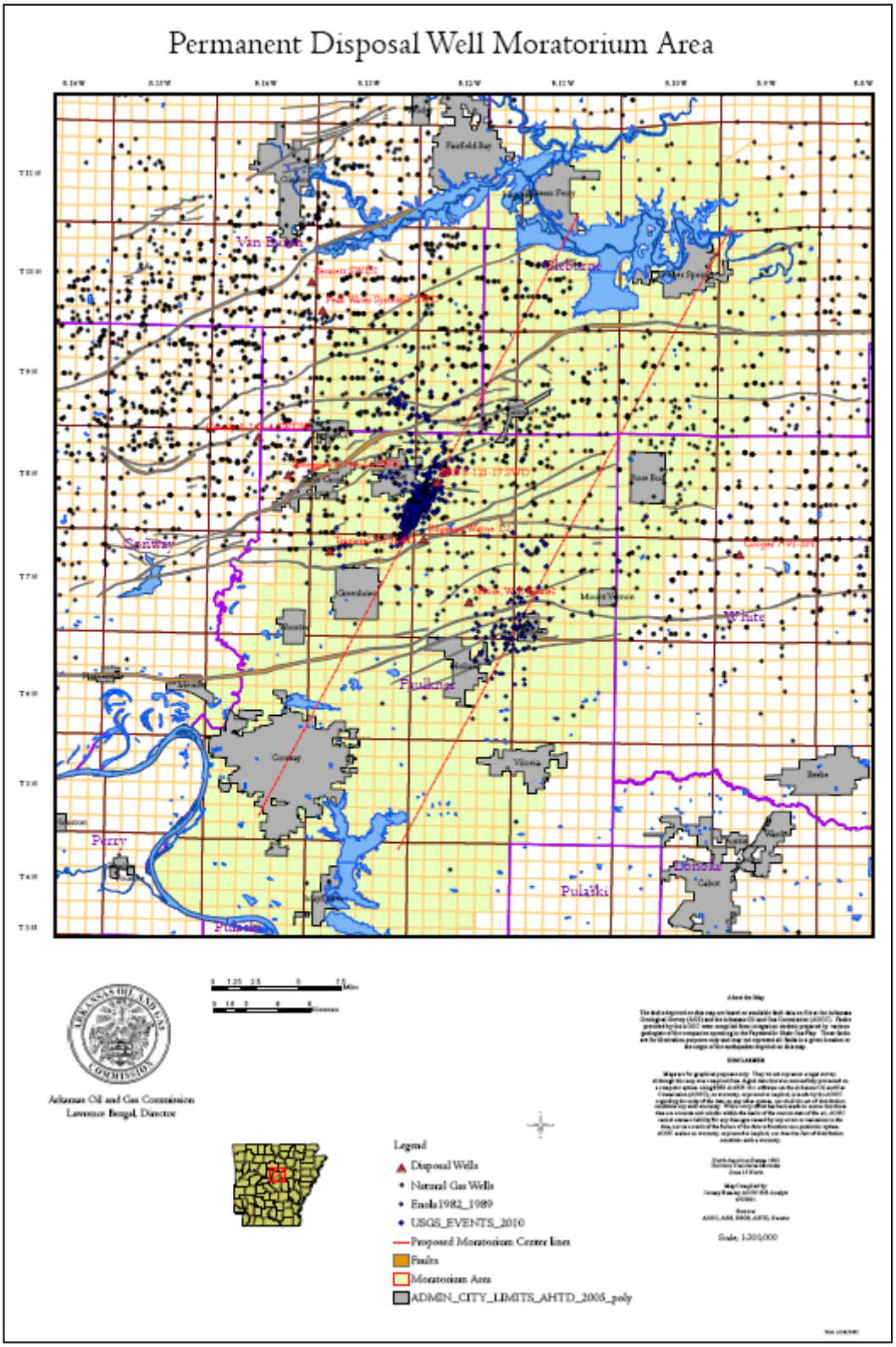


Figure 3. Moratorium area for the permanent disposal wells in the Fayetteville Shale Play, Arkansas (from the AOGC website).

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 along the boundary of eastern Texas and western Louisiana as well as a more liquid-rich area in southeast Arkansas.

Basement structures and salt movement influenced carbonate and siliciclastic sedimentation associated with the opening of the Gulf of Mexico. 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. 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 (Fig. 1). Reservoir depth ranges from 9,000 to 14,000 ft (3000–4700 m), and lateral drilling distances are 4000– 5000 ft (1300–1700 m). Optimal frac stages are 12-16 with an optimum number of 15 with multiple perforation clusters (Wang et al., in press).

Production has fallen slightly from its peak in 2011-2012 (Fig. 2) and drilling activity has been reduced from 186 rigs 2 years ago to approximately 19 rigs in October (Baker Hughes rig count). However, despite the decline in rig count, gas production has remained steady and production has even increased 2-3% since early Spring 2012 (Fig. 2). This has been attributed to more efficient completion and production techniques, such as increased frac stages and usage of cluster perforation (Wang et al., in press; McKeon, 2011). Substantial increase in liquids production results from the more liquid-rich play that has been emerging in Arkansas and parts of northern Louisiana. Accessing the liquid-rich part of the Haynesville Shale resulted in a 3-fold increase in liquids production (Fig. 3). Additional information on the Haynesville can be found at the Louisiana Oil and Gas association (http://www.loga.la/haynesville-shale-news/, accessed November 1, 2012.

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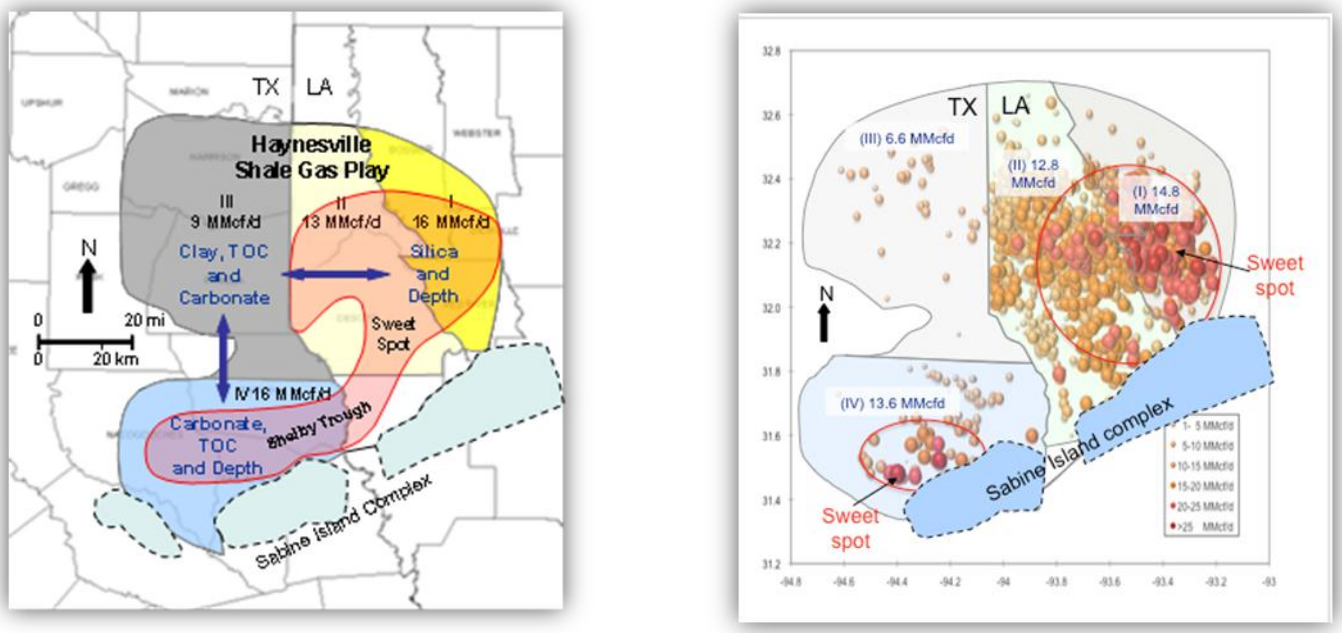

Figure 1: A. Initial potentials of four production areas and factors (mineralogy) affecting initial potential in the core area of the Haynesville play. B. Bubble map of initial potential for Haynesville wells. TX = Texas, LA = Louisiana. From Wang and Hammes (2010) and Wang et al. (in press).

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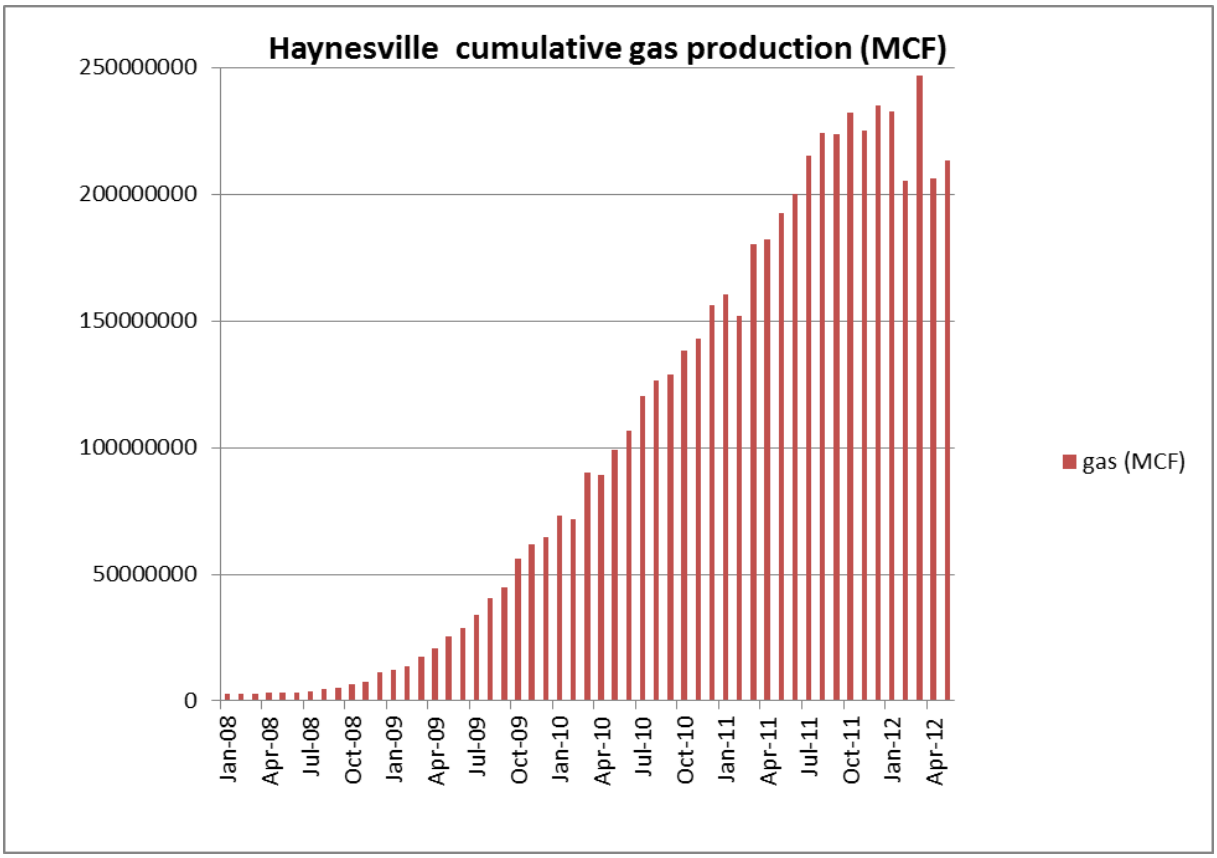

Figure 2: Cumulative production chart (MCF) for Haynesville Shale (data from IHS Enerdeq).

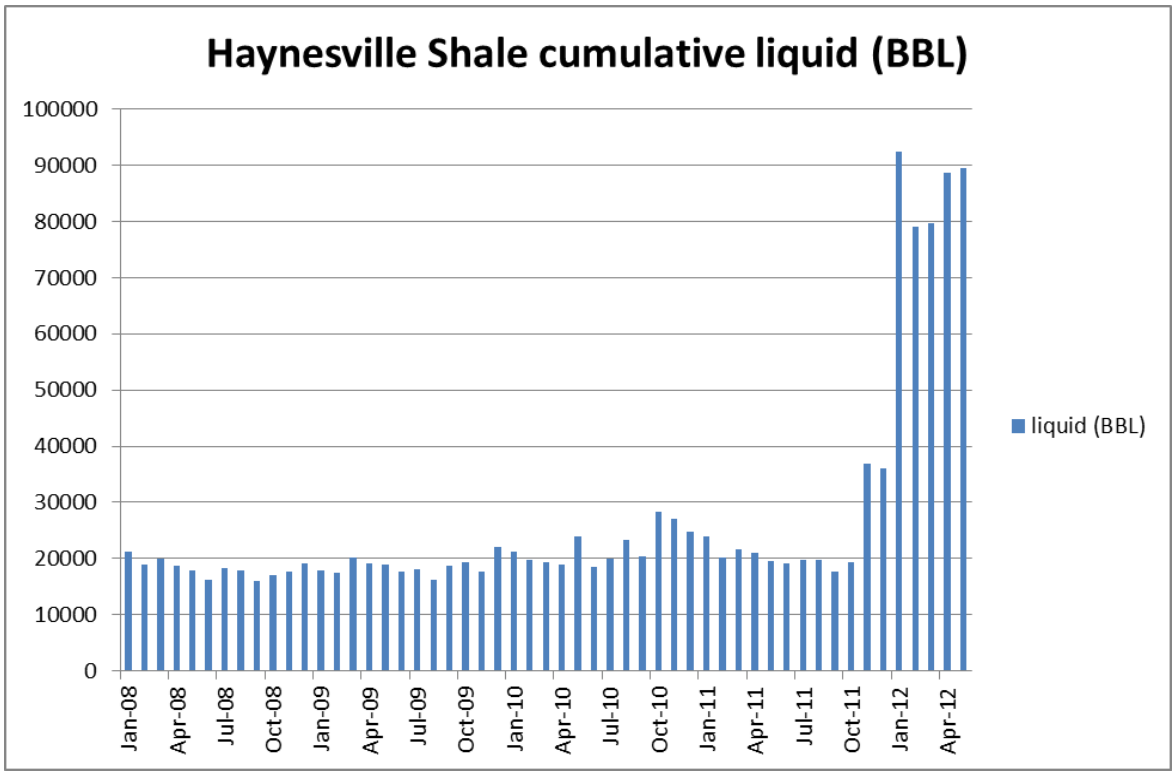

Figure 3: Cumulative liquids production for Haynesville Shale (data from IHS Enerdeq).

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Maquoketa and New Albany Shales, Illinois Basin

By Rachel Walker (Countrymark Energy Resources, LLC)

The Illinois Geological Survey released to the public data related to source rocks and potential source rocks of the Illinois Basin on January 14th, 2013. Strata include the New Albany and Maquoketa Shales with data including Rock-Eval, X-Ray Diffraction, various other geochemical and geomechanical data and photographs. As most of the analyses were performed by outside laboratories, the Illinois Geological Survey cannot attest to the validity or accuracy of the results, and the data is presented 'as-is'.

Maquoketa Shale

Indiana:
One horizontal Maquoketa well was permitted in March 2013 by Midwest Gas Storage in Clay County, Indiana. It is located within the Carbon Gas Storage Project and has yet to be drilled.
Illinois:
No wells have been permitted since last reported in October 2012.
Kentucky:
No new wells have been permitted since last reported in October 2012.

New Albany Shale

Indiana:
No new wells have been permitted since last reported in October 2012.
Illinois:
In October 2012, Core Minerals permitted a New Albany well in the Salem Field located in Marion County, Illinois. The well has yet to be drilled.
Kentucky:
No new wells have been permitted since last reported in October 2012.

Since late 2011, large blocks of acreage have been leased in a potential New Albany/Maquoketa shale liquids play, with most of the activity in the extreme southern and southwestern counties in Illinois - notably Gallatin, Saline, White and Wayne counties. This area is in the deeper part of the basin and is the most thermally mature. While leasing still appears to be occurring in relation to this potential play, no drilling activity has yet been reported.

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The Scout Check Report, LLC, Evansville, IN

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

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

The Marcellus Shale of the Appalachian Basin is the most areally 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 higher radioactivity responses, and thus higher gamma ray values on well logs, because the organic matter tends to concentrate uranium ions (Harper, 2008). Based on 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. In the majority of the currently productive area, the Marcellus has a vitrinite reflectance above 1.0 %Ro (Ryder and others, 2010; Milici and Swezey, 2006) and produces mostly natural gas. However, areas in southwest Pennsylvania, eastern Ohio, and northern West Virginia have reported condensate and oil production 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 permeability which allows for commercial production of hydrocarbons from this formation. The orientation of the horizontal sections of the wells and the design of the staged hydraulic fracture procedures 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). Issues with water supply for large volume fracturing, and disposal of produced formation water and used hydraulic fracturing water, called "flow-back" water, are being studied, and have been addressed with a variety of approaches including recycling and reuse.

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 barrels in continuous-type accumulations in the Marcellus Shale. The estimate of natural gas resources ranges from 43 to 144 TCF (95 percent to 5 percent probability, respectively), and the estimate of natural gas liquids resources ranges from 1.6 to 6.2 billion barrels (95 percent to 5 percent probability, respectively). This re-assessment of the undiscovered 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 0.01 billion barrels of natural gas liquids in the Marcellus Shale .

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

The increase in undiscovered, technically recoverable resources is due to new geologic information and engineering data. In late 2004, the Marcellus was recognized as a potential reservoir rock, instead of only a regional source rock. Technological improvements resulted in commercially viable gas production and 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 production from the Marcellus Shale was in 2005 by Range Resources in Washington County, PA, and the first horizontal wells in the Marcellus were drilled in 2006. Natural gas production was reported from wells that were completed in the Marcellus in West Virginia as early as 2005, too.

Maryland: There were no wells drilled in Maryland for the Marcellus Shale between 2004 and 2012. 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 no production from the Marcellus Shale in Maryland. Due to the estimated thermal maturity of the Marcellus Shale in Maryland (Repetski and others (2008)), it may be suggested that dry gas will be found if wells are drilled to 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. Recommendations for best practices for all aspects of natural gas exploration and production in the Marcellus Shale in Maryland are now required by August 1, 2013, and a final report with findings including environmental impacts and recommendations will be issued no later than August 1, 2014.

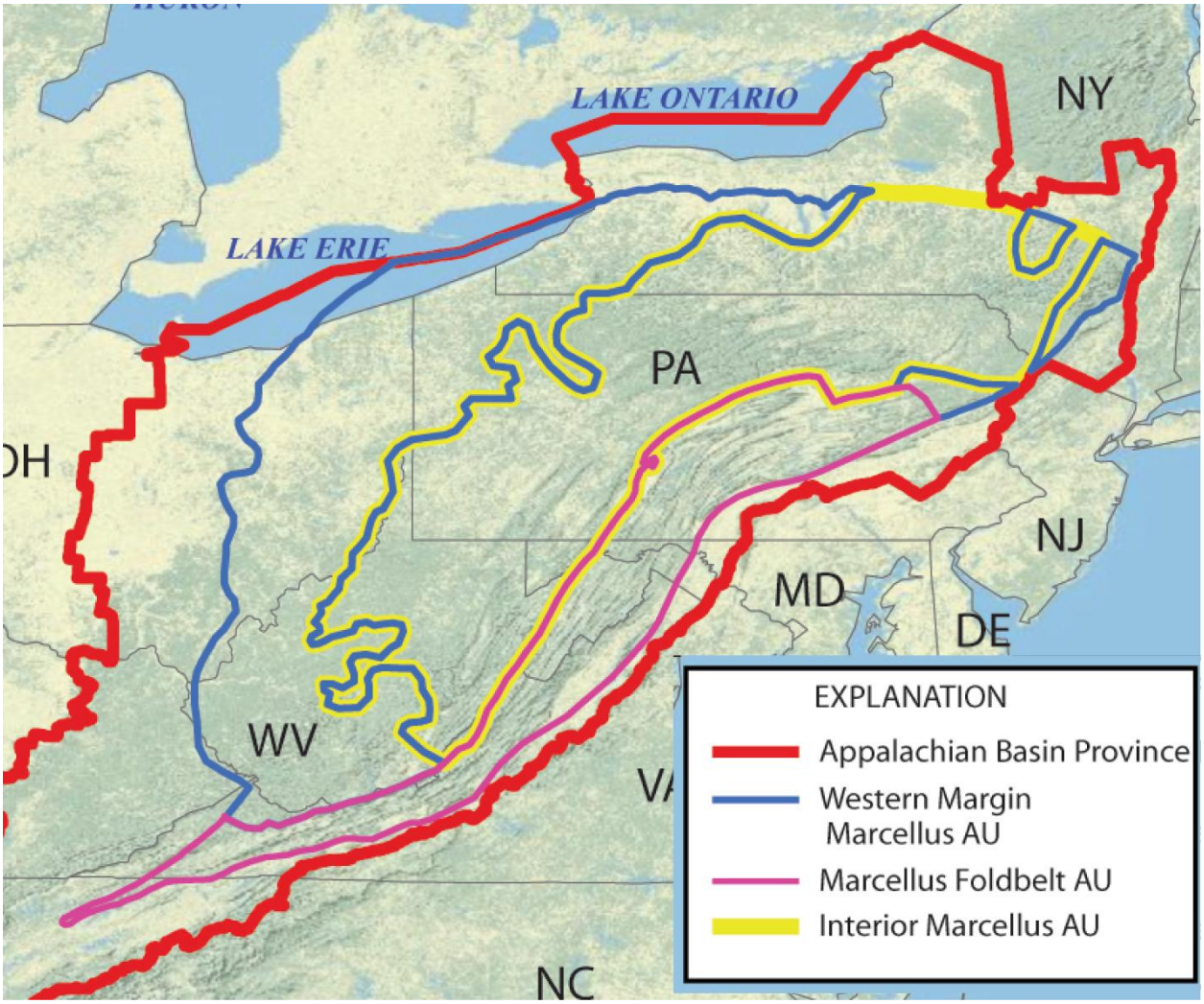

Figure 1. 2011 Marcellus Shale Assessment Units (modified from Coleman and others, 2011).

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 (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 Department of Environmental Conservation (DEC), as of July, 2012, there were 28 wells with Marcellus Shale listed as the productive formation, but only 14 reported production in 2011. Natural gas production from the Marcellus in 2011 was 25.6 mmcf, down from reported production of 34 mmcf in 2010, and down from the high of 64 mmcf reported for 2008. There was no reported oil production. According to the New York DEC, there were almost 230 mmcf produced from the Marcellus between 2000 and 2011. The DEC also reported that between 1967 and 1999, there may have been as much as 543 mmcf produced from the Marcellus. Production data for 2012 was not available at the time of this report.

A search of the NY DEC wells database returned 184 well permit applications where the "objective formation" was Marcellus. 134 of these wells have been drilled, and almost half are horizontal wells. None of the horizontal wells were productive as of July, 2012.

The NY 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. DEC was required to refile the draft regulations covering high volume hydraulic fracturing. DEC held public hearings during the comment period for the SGEIS and for the regulations in November, 2012. The public comment period closed on January 11, 2013. While the process of reviewing the SGEIS is ongoing, any company that applies for a drilling permit for horizontal drilling in the Marcellus Shale will be required to undertake an individual, site-specific environmental review.

Ohio: The Ohio Department of Natural Resources (ODNR) reported that almost 1.08 BCF of gas and over 17,000 barrels of oil were produced from the Marcellus Shale from 2007 through 2011. In April, 2013, there were 28 wells producing from the Marcellus Shale in Monroe, Noble, Washington, Belmont, Jefferson, and Carroll counties. As of March, 2013, 20 permits for horizontal wells in the Marcellus had been issued, 10 horizontal wells were drilled, and 5 were producing from the Marcellus. The productive horizontal Marcellus Shale wells are in Belmont, Carroll, Jefferson and Monroe counties. Production data for 2012 was not available at the time of this report.

The maximum thickness of the Marcellus Shale in Ohio is 70 feet, and averages about 50 feet in the prospective area in easternmost Ohio. However, the Marcellus is oil-productive in Ohio, making it an attractive target at current commodity prices.

A non-profit, multi-stakeholder organization reviewed Ohio's state regulatory program as to its effectiveness in regulating hydraulic fracturing. The results were published in a report titled "Ohio Hydraulic Fracturing State Review" in January, 2011. While there were recommendations for improvements, the Executive Summary of this report states that the Ohio program is well-managed, professional, and meeting its program objectives.

In October, 2011, the ODNR Division of Oil and Gas Resources Management was created as a separate division to regulate oil and gas drilling and production operations, disposal of brine and other wastes produced from the drilling, and underground injection operations that were formerly regulated by the Division of Mineral Resources Management.

Pennsylvania: The deepest depth to the base of the Marcellus Shale is in east-central Pennsylvania, and the deepest wells to test the Marcellus have been drilled to 8,500 feet in Clinton County. The areas of greatest activity are in southwestern and northeastern PA. The production of oil and condensate from fields in southwest Pennsylvania make this area particularly attractive with current commodity prices.

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), as of March 2012, over 11,700 permits to drill to the Marcellus Shale had been issued, and over 9,600 of those were for horizontal wells. By March, 2012, 1456 completion reports were received for Marcellus wells. The counties with the most drilling and production activity are Greene, Washington, Fayette, Lycoming, Tioga, Bradford, and Susquehanna.

The format, and therefore content, of the production reports published by DEP changed each of the last 4 years. This caused the data reported here to exhibit changing trends and may have contained errors.

According to PA*IRIS/WIS, the Pennsylvania database of oil and gas records, and DEP, by the end of 2012, 2,252 wells reportedly produced from the Marcellus Shale. About 84% of these productive wells are horizontal wells. In 2012, there were 1,266 bcf of gas, about 450,300 bbl of condensate, and almost 61,000 bbl of oil produced from the Marcellus Shale in Pennsylvania. According to PA*IRIS/WIS and DEP, in 2011, 843 bcf of gas, about 350,000 bbl of condensate, and almost 359,000 bbl of oil were produced from the Marcellus Shale in Pennsylvania. There was an expected increase in the volume of gas and condensate produced between 2011 and 2012, but there was a decrease in the volume of oil produced, according to DEP.

In 2012, Chesapeake Appalachia LLC was the largest producer of natural gas from the Marcellus Shale, having reported over 346 bcf in the 12-month reporting period. Chesapeake was followed by Cabot Oil & Gas Corporation, Talisman Energy USA Inc., Anadarko E&P Onshore LLC, and Range Resources Appalachia LLC, each with production of over 100 bcf of natural gas in the latest 12-month reporting period. The companies that produced the most condensate were Range Resources and Atlas Resources. The companies that produced the most oil in 2012 were Chesapeake Appalachia and Atlas Resources.

Virginia: There were no wells drilled exclusively for the Marcellus Shale in Virginia between 2004 and 2012. There may be gas production from the Marcellus Shale commingled with other zones in vertical wells in Virginia, but the quantity is unknown.

"Geology of the Devonian Marcellus Shale-- Valley and Ridge Province, Virginia and West Virginia—a field trip guidebook for the American Association of Petroleum Geologists Eastern Section Meeting, September 28-29, 2011" was published in 2012 and is available from the U.S.Geological Survey website. The character and structural elements of the Marcellus Shale, and the results of geochemical and mineralogical analyses of samples collected at six stops are included in this report.

The George Washington National Forest (GWNF) Plan was last revised in 1993. In an effort to update its land management plan, The U.S. National Forest Service (NFS) issued the Draft Environmental Impact Statement (DEIS) and Draft Revised Land and Resource Management Plan for the GWNF in April, 2011. Several options were proposed by the NFS, but the NFS' preferred alternative forest plan included the restriction that, on lands administratively available for gas and oil leasing within the GWNF, no horizontal drilling will be allowed. The public comment period for the Draft Forest Plan and Draft Environmental Impact Statement ended on October 17, 2011. The NFS continues to proceed through the review and update process, and it is expected that the Final Forest Plan and Final Environmental Impact Statement will be completed by the spring of 2013.

West Virginia: As of September, 2012, about 1830 wells were completed in the Marcellus Shale, according to the West Virginia Geological and Economic Survey (WVGES). According to the WVGES, production of approximately 158 BCF and 476,000 barrels of oil can be attributed to wells with Marcellus Shale reported as at least one of the pay zones through 2011, although Avary and Schmid (2012) estimate that 192 BCF was produced from the Marcellus Shale in West Virginia in 2011. Total production from wells completed in the Marcellus from 2005 through 2011 was over 293 BCF of gas and almost 806,000 barrels of oil, according to information from WVGES. West Virginia is second to Pennsylvania in production of hydrocarbon liquids from the Marcellus Shale.

Based on the volume of gas production from the Marcellus Shale through 2011, the major producers included Chesapeake Appalachia LLC, Antero Resources Appalachian Corp., EQT Production Company, XTO Energy, Inc., and AB Resources PA. The companies with the most oil production from the Marcellus Shale were Chesapeake Appalachia LLC, AB Resources PA, EQT Production Co., and Stone Oil & Gas.

According to the West Virginia Department of Environmental Protection (DEP), 974 active gas wells denote the target formation as Marcellus Shale. No wells that targeted the Marcellus Shale are classified as oil wells. Production data for 2012 was not available at the time of this report.

Production from a "deviated," or horizontal, well in West Virginia was first reported in 2007. Well records through 2011 indicate that 390 wells completed in the Marcellus are deviated, while over 660 wells list the Marcellus Shale as the only pay zone. Most of the completed Marcellus wells that are reported as "deviated" are located in Brooke, Ohio, Marshall, Wetzel, Monongalia, Marion, Preston, Taylor, Harrison, Doddridge, and Upshur counties. In these counties, the thickness of the zone of the Marcellus Shale with high gamma-ray measurements is 25 to 100 feet. In the first three months of 2013, 143 permits were granted for horizontal wells that will not target coalbed methane, and will disturb three acres or more of surface, or will utilize more than 210,000 gallons of water in any 30-day period.

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

http://www.eia.gov/oil_gas/rpd/shale_gas.pdf
http://www.eia.gov/energy_in_brief/about_shale_gas.cfm
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/geo/pub/MarcellusShaleGeologyPPT.pdf
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http://www.mgs.md.gov/geo/pub/MarcellusShaleGeology.pdf
http://www.mde.state.md.us/programs/Land/mining/marcellus/Pages/index.aspx
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://www.ohiodnr.com/mineral/oil/tabid/10371/Default.aspx
http://www.ohiodnr.com/portals/11/publications/pdf/oilgas11.pdf
http://www.ohiodnr.com/oil/shale/tabid/23174/Default.aspx
http://www.dnr.state.oh.us/tabid/23014/Default.aspx
http://www.dnr.state.oh.us/Portals/11/oil/pdf/stronger_review11.pdf
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
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https://www.paoilandgasreporting.state.pa.us/publicreports/Modules/DataExports/DataExports.aspx
http://www.dmme.virginia.gov/DGO/pdf/NaturalGasFAQs.pdf#Chemicals
http://www.fs.fed.us/r8/gwj/
http://www.fs.usda.gov/detail/gwj/landmanagement/?cid=fsbdev3_000397
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Monterey Formation (Miocene), various California basins, U.S.

by Margaret A. Keller (U.S. Geological Survey)

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)

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.

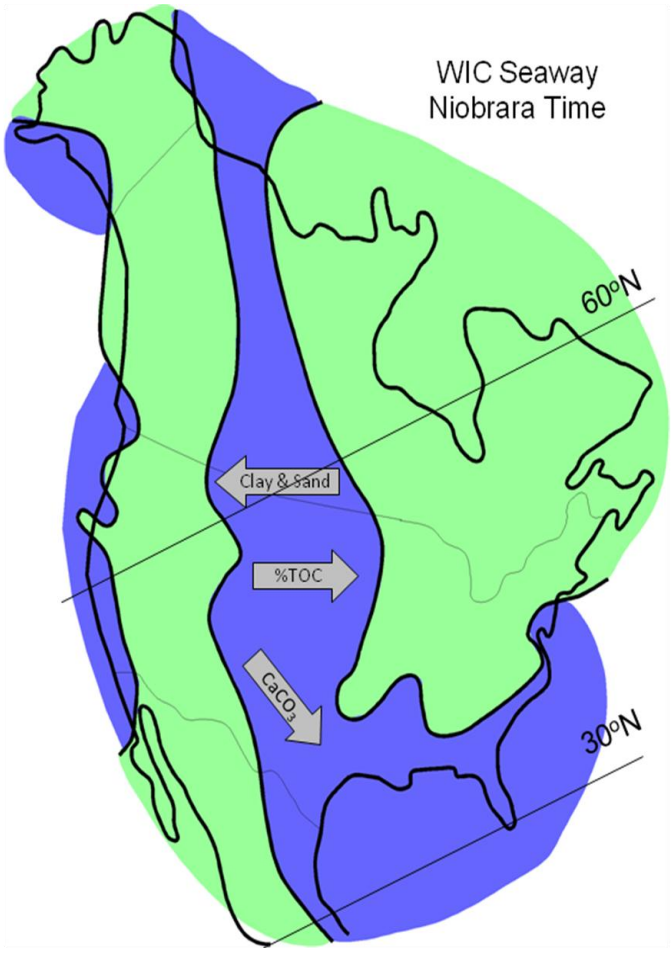

Figure 1. The Western Interior Cretaceous Basin during Niobrara time (modified from Longman et al., 1990). Source area for clastics is dominantly to the west, total organic carbon content in the Niobrara increases to the east, carbonate content generally increases on the eastern side of the Western Interior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

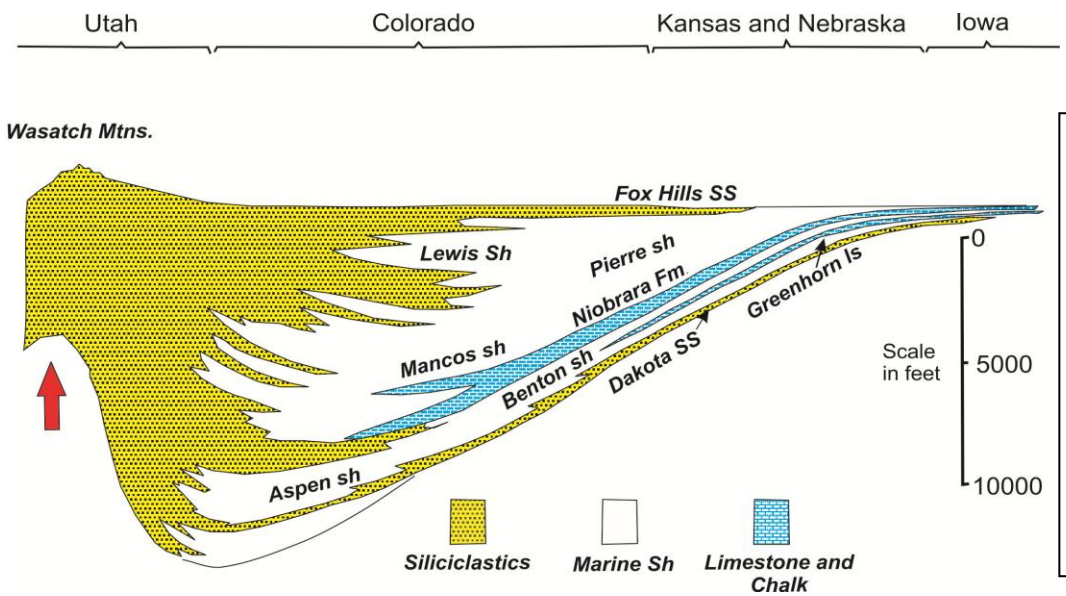

Figure 2. Generalized cross section across the Western Interior Cretaceous Basin. The Niobrara is Upper Cretaceous in age. Limestone and chalk beds are present over the eastern two thirds of the basin (modified from Kauffman, 1977).

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.

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).

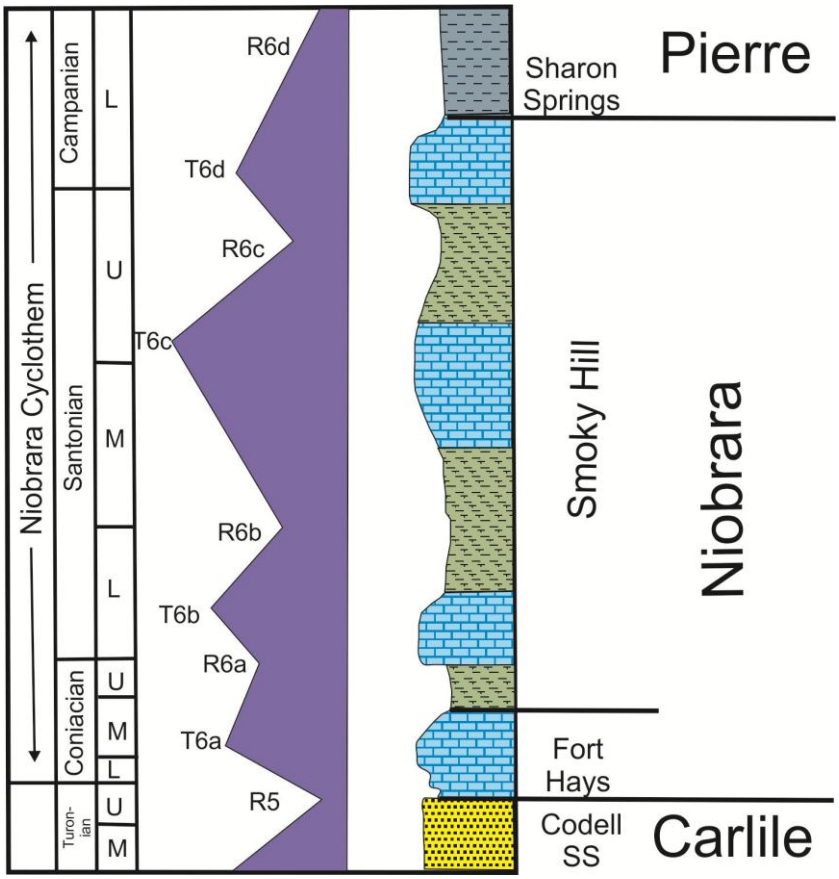

Figure 3. Generalized stratigraphic column for the Niobrara from the Denver Basin setting. The Niobrara ranges in age from Coniacian to lower Campanian. Several transgressive and regressive cycles are noted for the Niobrara interval. Four chalk –rich intervals were deposited during trangressive events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

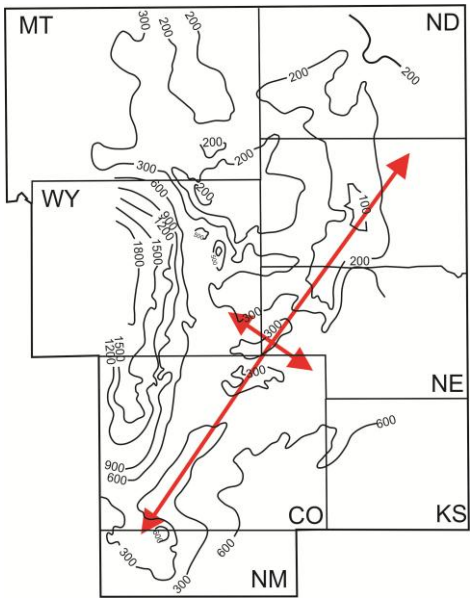

Figure 4. Isopach of the Niobrara across the northern Rockies (modified from Longman et al., 1998). The Niobrara ranges in thickness from less than 100 feet to over 1800 feet. Thinning occurs in a northeast trend across the area known as the Transcontinental Arch (Weimer, 1978).

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.

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).

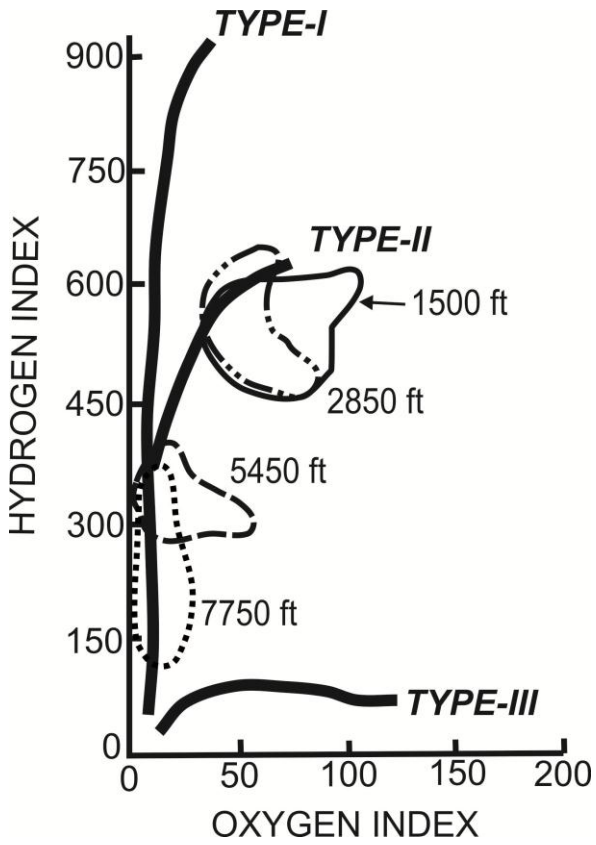

Figure 5. Niobrara Van Krevelen diagram. Niobrara source rocks are Type-II (oil prone) kerogens based on Rock Eval data. With increasing burial depth and thermal maturity the HI values decrease significantly. Data from Rice (1984); Barlow (1985); Pollastro (1985); after Sonnenberg and Weimer (1993).

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.

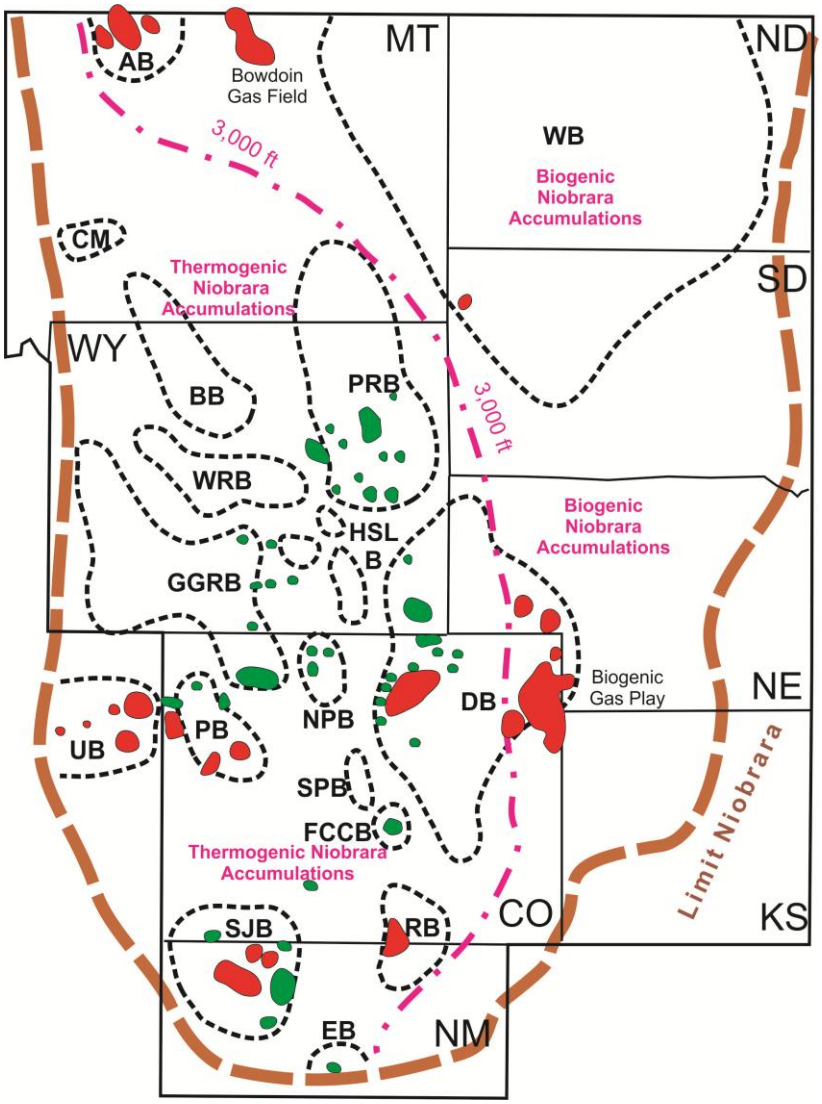

Figure 6. Niobrara producing areas across the north Rockies (Oil fields-green; gas fields-red)(modified from Longman et al., 1998). Basin abbreviations are as follows: AB-Alberta Basin; CM-Crazy Mountain; WB-Williston Basin; BB-Bighorn Basin; PRB-Powder River Basin; WRB-Wind River Basin; GGRB-Greater 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).

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.

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.

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.

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Utah Shales, U.S.

By Thomas Chidsey (Utah Geological Survey) and Steven Schmel (GeoX Consulting, Inc.)

Central Utah Mississippian/Pennsylvanian Shale Gas Play

Overview: Paleozoic shale in the Colorado Plateau and eastern Basin and Range Provinces have long been known for their potential as source rocks for hydrocarbons that have migrated into other formations but have not been considered as in-situ gas reservoirs. These include the Mississippian/Pennsylvanian Manning Canyon Shale and Doughnut Formation of central Utah. The Manning Canyon/Doughnut is mainly claystone with interbeds of limestone, sandstone, siltstone, and mudstone, and has a maximum thickness of 2,000 ft. TOC varies from 1% to greater than 8% with type III (?) kerogen. In north-central Utah, the Manning Canyon was deeply buried by sediments in the Pennsylvanian-Permian-aged Oquirrh Basin and is therefore likely very thermally mature. Shale beds within these formations are widespread, thick, buried deep enough to generate dry gas (or oil in some areas of the Paradox Basin), and sufficiently rich in organic material and fractures to hold significant recoverable gas reserves.

Activity: In the northern San Rafael Swell, Bill Barrett Corporation and its partner ConocoPhillips acquired leasehold acreage in a 58,000-acre area named "Hook prospect." In 2008, Barrett (50% working interest with ConocoPhillips) drilled the State 15-32-15-12 well (section 32, T. 15 S., R. 12 E., Salt Lake Base Line and Meridian [SLB&M], Carbon County, to a total depth 8,550 ft in the Hook prospect targeting the Doughnut Formation. The Doughnut consisted of 589 ft of shale over a total formation thickness of 816 ft, 422 ft of which was cored for gas content and reservoir analysis. The well analysis indicated good gas shows and high gas contents from core samples but it was completed as a dry hole. In October 2009, the company completed a horizontal well with a 3,700-ft horizontal lateral offsetting the vertical well in the same section. The State 16H-32-15-12 well had a subcommercial IPF of 275 MCFGPD and 235 BW on an 18/64-inch choke through a hydraulically fractured gross interval from 8,252 to 10,436 ft. This horizontal production well is shut-in, but the vertical test well is merely "suspended." Barrett presented plans to the Utah Division of Oil, Gas, and Mining (DOGM) to drill two more wells in section 32 (a request was made to permit one of the wells) with longer horizontal lengths and using improved completion techniques based on the information acquired from their first horizontal well. In addition, Barrett received DOGM approval to stake two additional Doughnut wells 3 miles east in section 35, T. 15 S., R. 12 E., SLB&M, Carbon County, within its Hook prospect area. The company had also planned to conduct a 3-D seismic program in the area covering 142 square miles. However, all these exploration plans were dropped due to falling gas prices and other issues; no drilling or seismic surveys in the area are projected by Barrett in the near future.

West of the Hook area, Shell Western Exploration & Production, Inc. drilled and cored the Doughnut Formation in the 5-12 Carbon Canal well (section 12, T. 16 S., R. 10 E., SLB&M, Emery County. The Doughnut was 975 ft thick, of 531 ft of which was cored for gas content and reservoir analysis. The well was completed in 2008 as a gas discovery with an IPF of 468 MCFGPD and 1750 BW. The natural gas produced has an energy value of 1052 Btu/Mcf. Production is from three hydraulically fractured Doughnut intervals. Flow was gauged through chokes ranging from 16/64-inch to 64/64-inch. Flowing casing pressure ranged up to 5,200 psi. The well is currently shut-in. Shell intended to drill two additional 9,400-foot wells to test potential Paleozoic shale-gas reservoirs, 3.5 miles southwest and 6 miles west-northwest in Emery and Carbon Counties, respectively. However, like the area in the east, these drilling activities were dropped when gas prices fell.

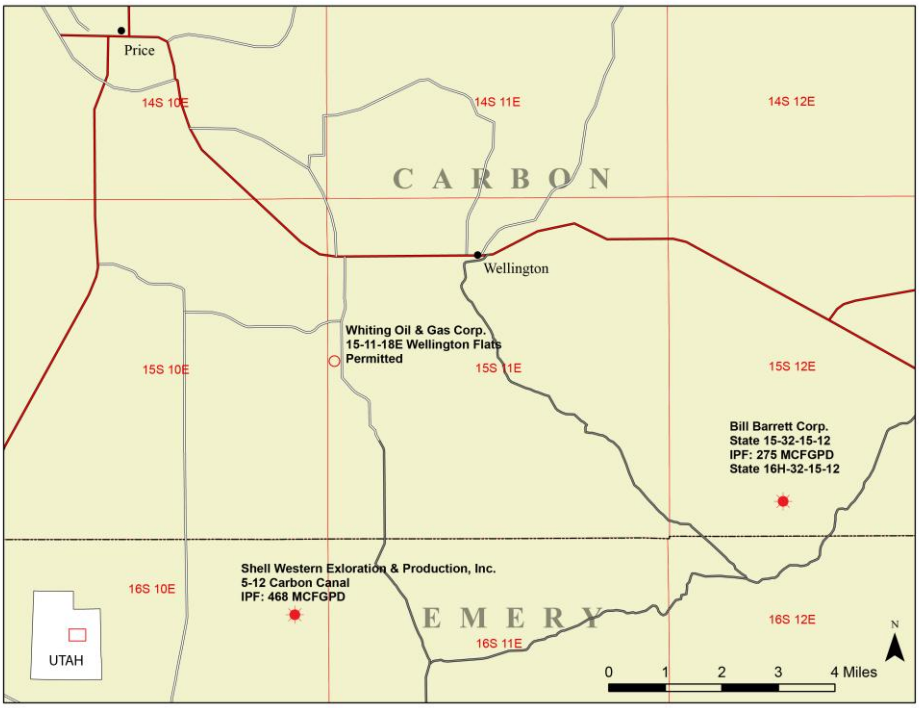
After a three-year hiatus, Denver independent Whiting Oil & Gas Corporation was granted a permit in September 2012, to drill an 8,890-ft vertical wildcat in the northern San Rafael Swell. The

15-11-18E Wellington Flats (section 18, T. 15 S., R. 11 E, SLBL&M, Carbon County) is projected to test the Mississippian section, northeast and northwest of the Shell and Barrett wells, respectively.

New Research: Under the direction of the Utah Geological Survey (UGS) and with project funding provided by Research Partnership to Secure Energy for America (RPSEA), research has been completed on well cuttings, cores, and outcrops to define specific Manning Canyon play areas. For example, at the north end of the San Rafael Swell, the UGS study defines a 600-mi^2 potential shale gas play area. Average depth to the top of the formation is 7,470 ft. In the play area the formation is up to 1,200 ft thick, of which approximately two-thirds is dark gray carbonaceous shale and argillaceous limestone. Associated intercalated lithologies include limestone and varicolored fine-grained sandstone and siltstone. Strata appear to alternate between marginal marine and non-marine. Integrated analysis of well cuttings, limited core, and well logs permit identification of the stratigraphic relationships between potential gas pay and non-pay intervals. In central Utah the formation was deposited in a shallow structural depression on the craton margin between the incipient Uncompaghre uplift to the northeast and the Emery arch to the south. The Manning Canyon/ Doughnut may have been deposited in a shallow restricted marine, brackish, and freshwater setting not unlike the modern Everglades and Florida Bay. Programmed pyrolysis (RockEval™) and vitrinite reflectance (Ro) analyses of the organic-rich shale indicate that it is uniformly in the "dry gas" generative window. Measured Ro values from many wells range 1.3% to 1.9%.

Many factors point to the substantial gas resource and development potential of the Manning Canyon Shale: net organic-rich shale-limestone thicknesses on the order of 500 ft and greater, "dry gas" thermal maturities, observed gas during drilling, numerous intercalated brittle lithologies for supporting fracture stimulation of the reservoir, reasonable operating depths, a relatively large area for the gas play, and proximity to a gas transmission pipeline.

For information about this project including available posters (in pdf), deliverables, etc., refer to the UGS's project Webpage http://geology.utah.gov/emp/shalegas/paleo_shalegas/index.htm. The UGS plans to publish the study in early 2013. Note: this study also includes a detailed evaluation of potential shale-gas plays in the Pennsylvanian Paradox Formation [Chimney Rock, Gothic, and Hovenweep shales] in the Paradox Basin, southeastern Utah, and a summary of recommended best drilling and completion practices for Utah's Paleozoic shale-gas reservoirs.



Location of recently drilled or planned wells targeting the Mississippian/Pennsylvanian Doughnut Formation (Manning Canyon Shale) in the northern San Rafael Swell, central Utah.

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

By Rich Nyahay

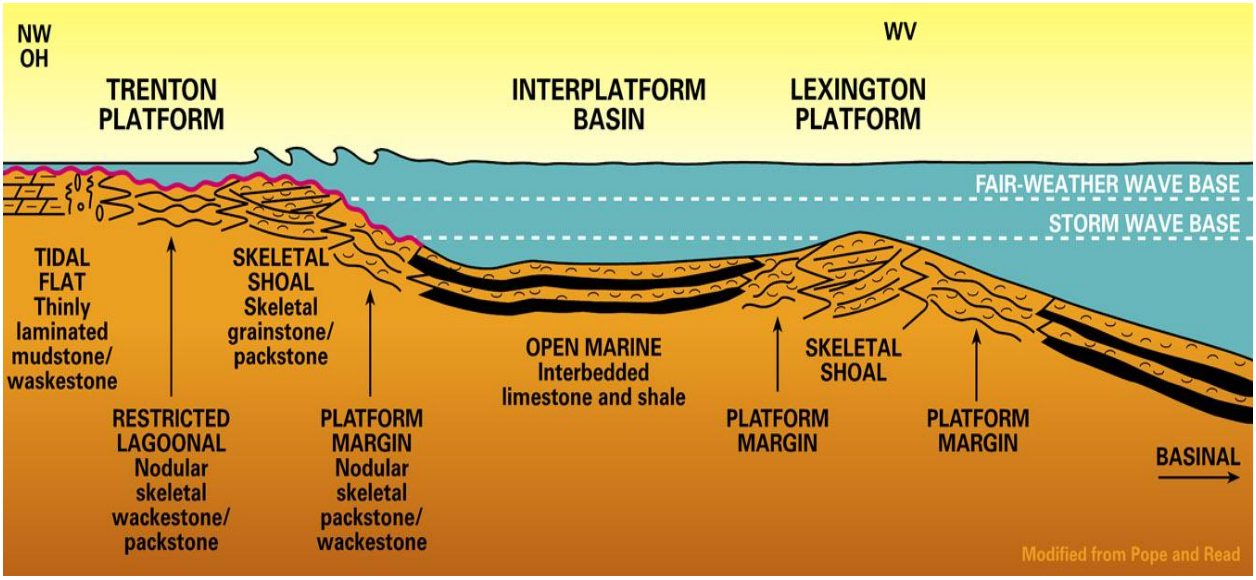
The Ordovician Utica (Indian Castle), Dolgeville, and Flat Creek are the formations of interest. These shales and interbeded limestones range in TOC from 1- 5% in the dry gas window. They cover an area from Mohawk Valley south to the New York State boundary line with Pennsylvania and extend west to the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

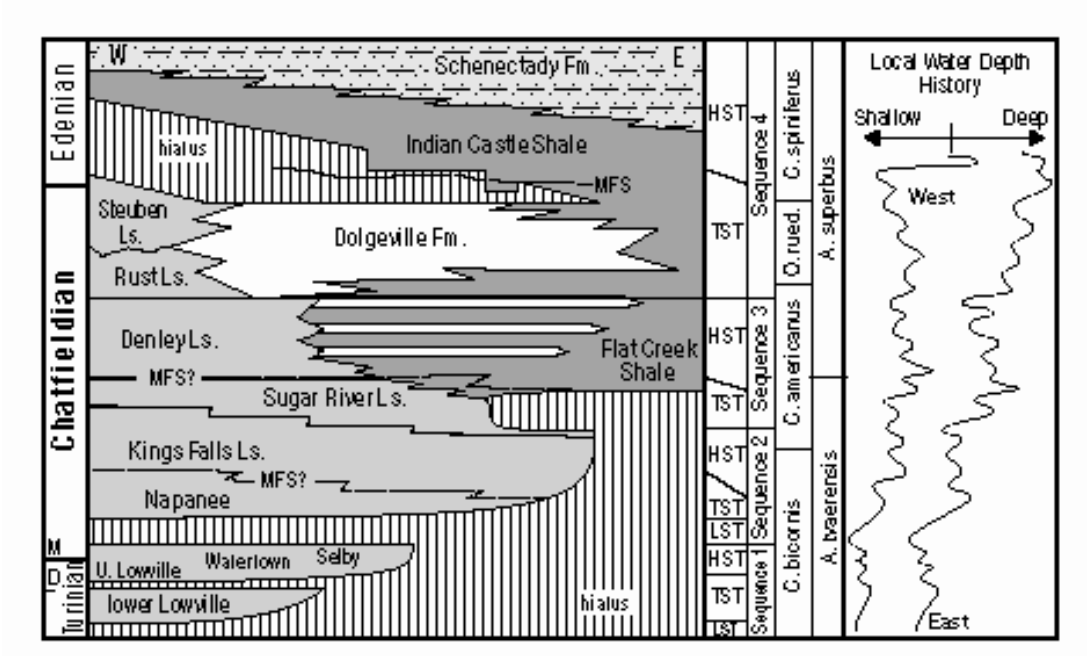
GEOLOGY:

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 & 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).



(Joy et al. 2000)

CURRENT:

With the current regulatory moratorium in place in New York, activity has been focused in eastern Ohio, western Pennsylvania and northern Michigan. The current drilling activity as of April 1st, 2013 lists 596 Utica permits, 29 rigs in operation, 292 wells drilled and 81 producing wells(Dick, 2013). Expectations have been dampened by larger companies selling large acreage parcels, pipeline infrastructure not in place, and construction of gas processing units. Also a threat of a state severance tax has overshadowed the potential production.

Gulfport Energy, who have discovered many of the bigger wells, plans to drill 50 wells in 2013. Consol Energy plans to drill 11 horizontal wells in Noble County. The Consol Energy MAH 2A in Mahoning County drilled a lateral of 2785 ft which produced a 24 hour test of 1.4 Mmcf natural gas and 240 barrels of oil after a 60 day shut in period. Magnum Hunter Resources plans to drill 4 more wells in Washington County. This seems to be reflective of the new TOC map the ODNR released in March(see geochemistry). BP plans to drill 10 wells in Trumball County by April 2013.

Mercer County of Pennsylvania has been gaining interest with well permits by Halcon Resources(7), Hilcorp Energy(5), Shell Western E&P Inc. – a division of Royal Dutch Shell(3), and Cheveron –Appalchia(3).Shell Western E&P Inc. – a division of Royal Dutch Shell also permitted a well in Lawrence County, PA. Devon drilled and plugged three wells on the western part of the play and put its acreage up for sale after disappointing results. Production data due out on March 31, 2013 from the ODNR has still not been released yet. Production data has been limited and falling rates from initial test peaks rates have people casting dispersions on early Utica potential in Ohio.

WELLS:

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.

The basic completion concept is to drill with long laterals, have short stages, and shut in the well for a determined resting period. Drilling time have decreased and operating costs have been cut in half, average well now cost 6.2 -6.5 million dollars. (Downing, April 17, 2013). The Utica is still in its infancy, everyone is still trying to get the oil and liquids from the Formation. With all the wells scheduled to be drilled in 2013, looking at more geological and petrophysical data that will be generated from each well will further define the future of Utica Play in the Appalachian Basin.

Well Name	County	Completion Date	Length of Lateral (feet)	Frac Stages	Peak IP Test (Boe/d) (1)	Production Mix			
						Oil	Gas	NGLs	Shrink Factor (1)
Wagner 1-28H	Harrison	5/28/12	8,143	28	4,650	9%	50%	40%	18%
Boy Scout 1-33H	Harrison	6/13/2012	7,974	22	3,456	45%	26%	29%	25%
Groh 1-12H	Guernsey	7/7/2012	5,414	16	1,935	61%	20%	19%	18%
Shugert 1-1H	Belmont	7/27/2012	5,758	16	4,911	3%	56%	41%	17%
Ryser 1-25H	Harrison	8/11/2012	8,291	23	2,914	51%	27%	22%	21%
BK Stephens 1-14H (2)	Harrison	9/19/2012	5,276	19	3,007	41%	34%	25%	11%

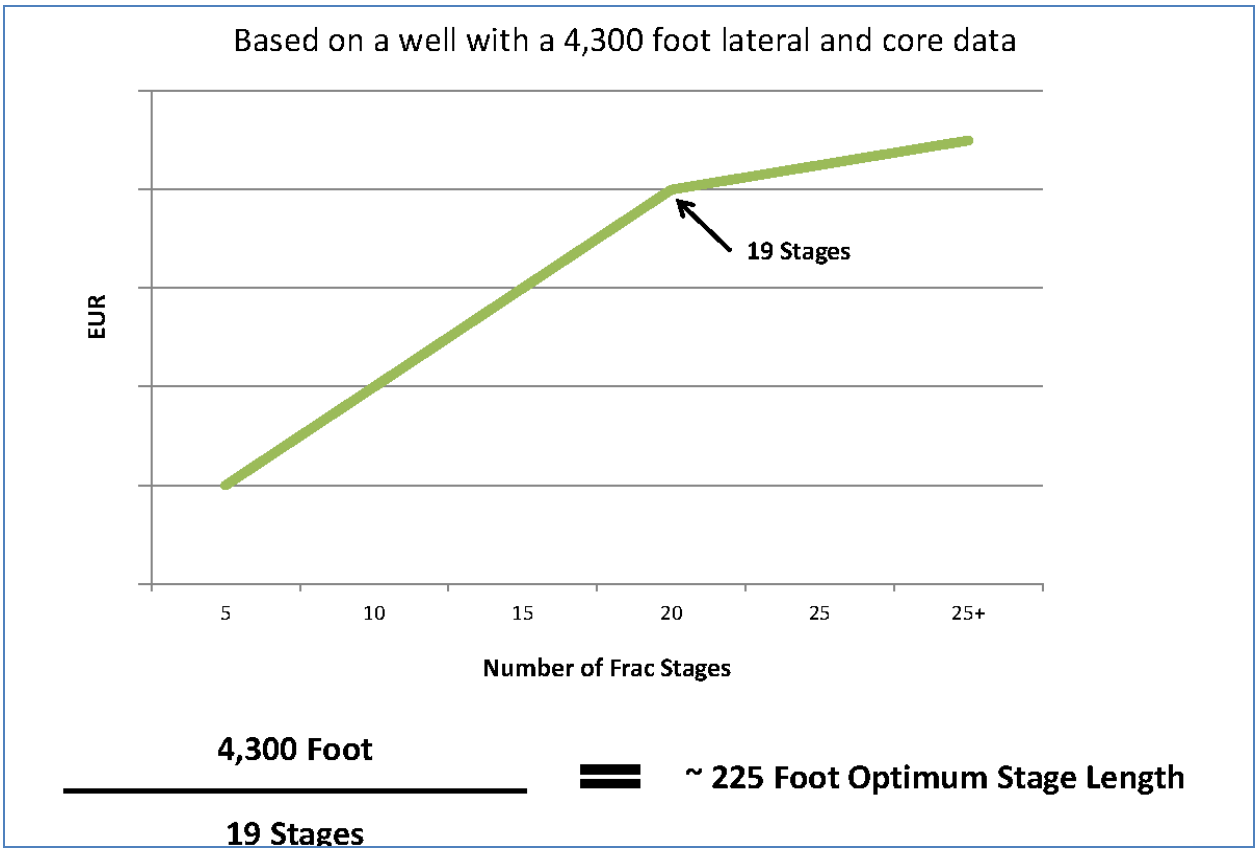
- First six wells averaged a peak rate of 1,006 barrels of condensate per day, 8.17 MMCF of natural gas per day and 1,111 barrels of NGLs, or 3,479 BOEPD (1)
  - Production mix of included approximately 29% condensate, 39% natural gas, and 32% natural gas liquids

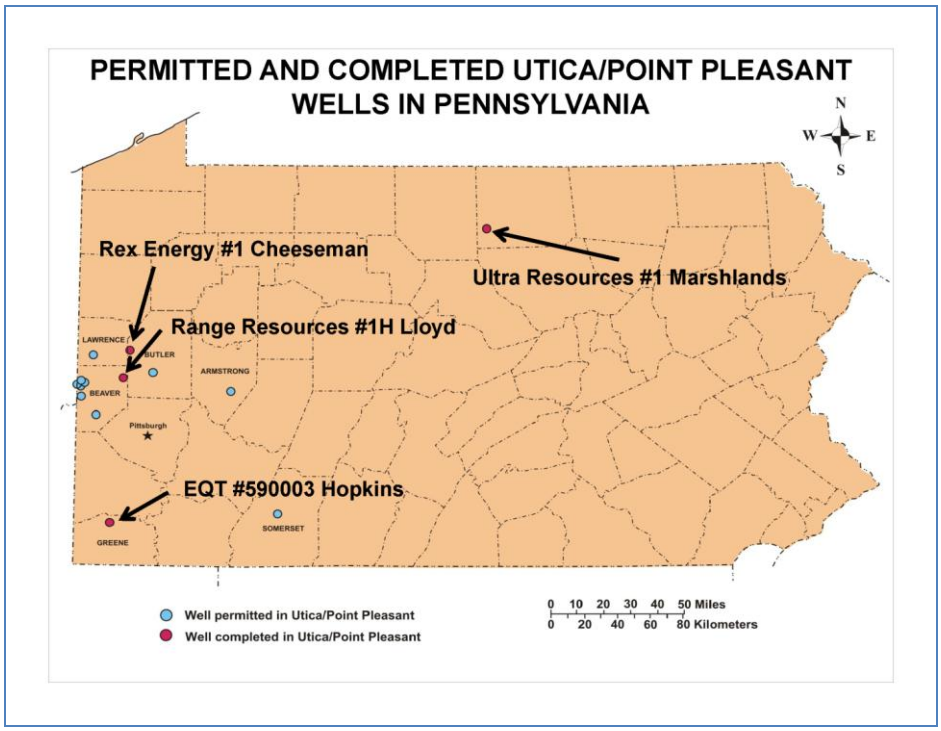
Early results for Gulfport's Energy Corporation wells (Gulfport Energy Inc DUG East 11-14-2012)

GEOCHEMISTRY:

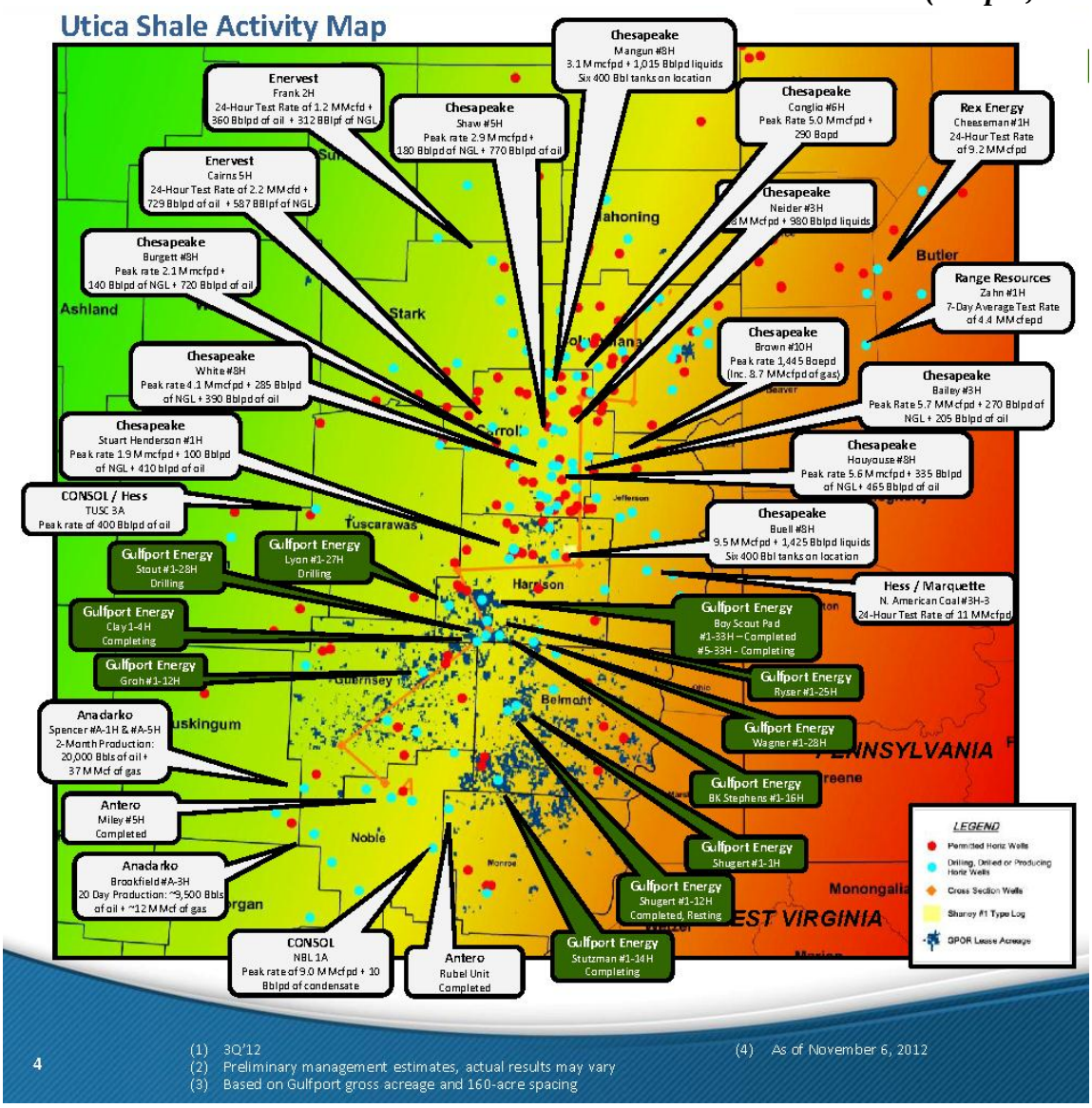
In May of 2012, a TOC (Total Organic Content) map generated by the Ohio Geological Survey caused a fall out between the State Geologist and critics from southeastern counties of Ohio. The main criticism of the map was the limited amount data points in the southeastern part of the state which may have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

New SEM images from Gulfport Energy well show porosity and permeability is associated with organic matter and organic horizontal fractures might indicate overpressure.

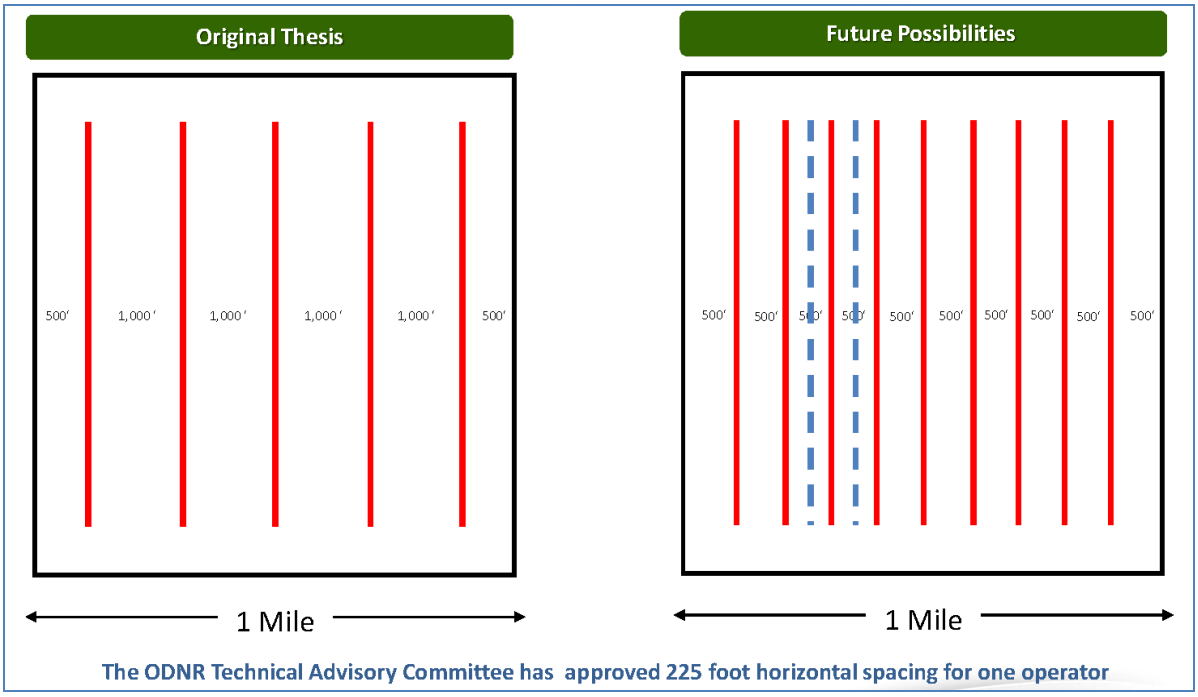




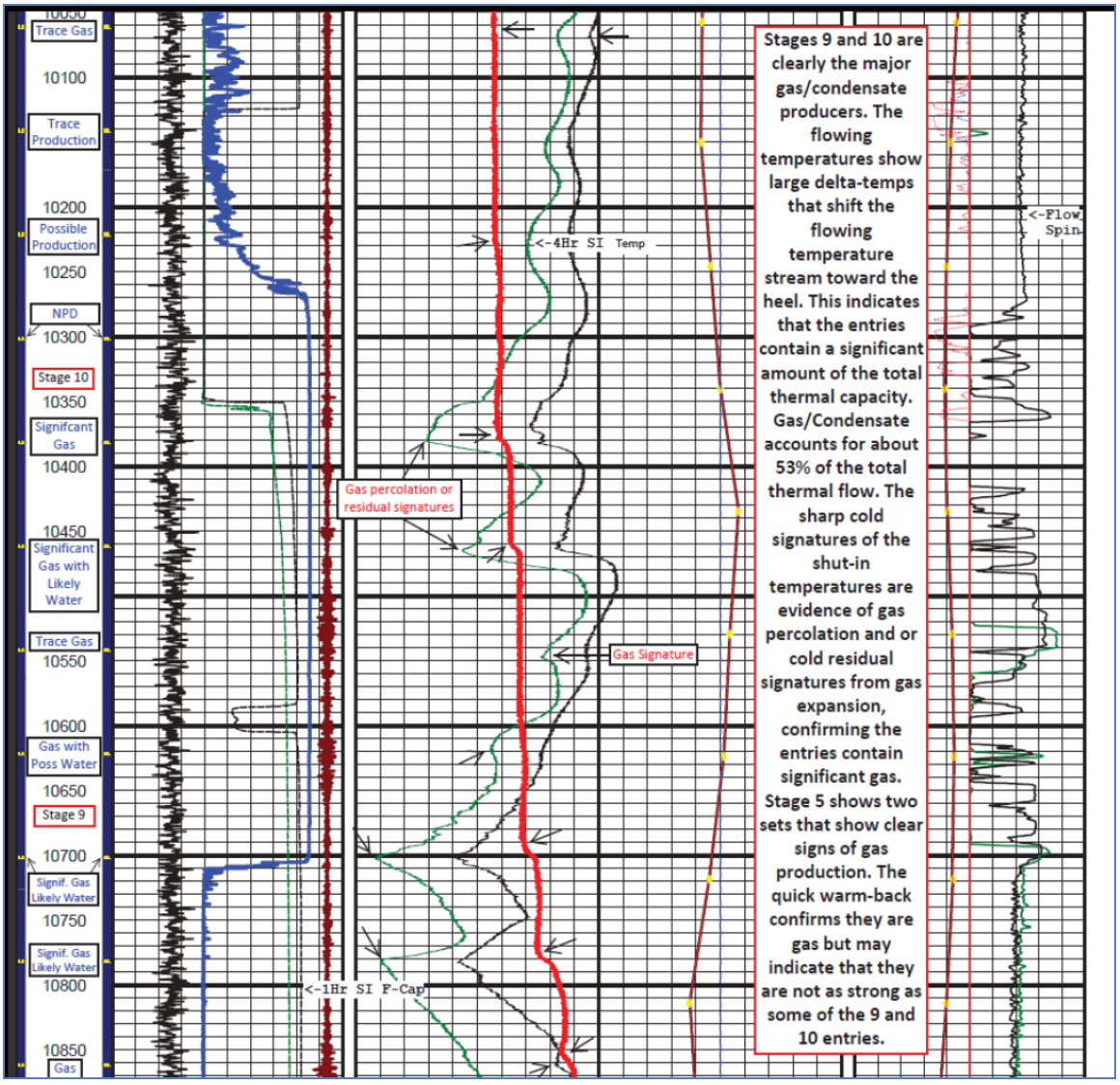
(Harper,2013)



Well Activity in Ohio list of wells and test information (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)

ISSUES: Dumping of 20,000 gallons of drilling wastewater into a tributary of the Mahoning River at the D&L energy property on Salt Springs Road in Youngstown Ohio. D& L Energy was the company that operated the injection well that caused the seismic activity a year ago (Morgan, 2013).

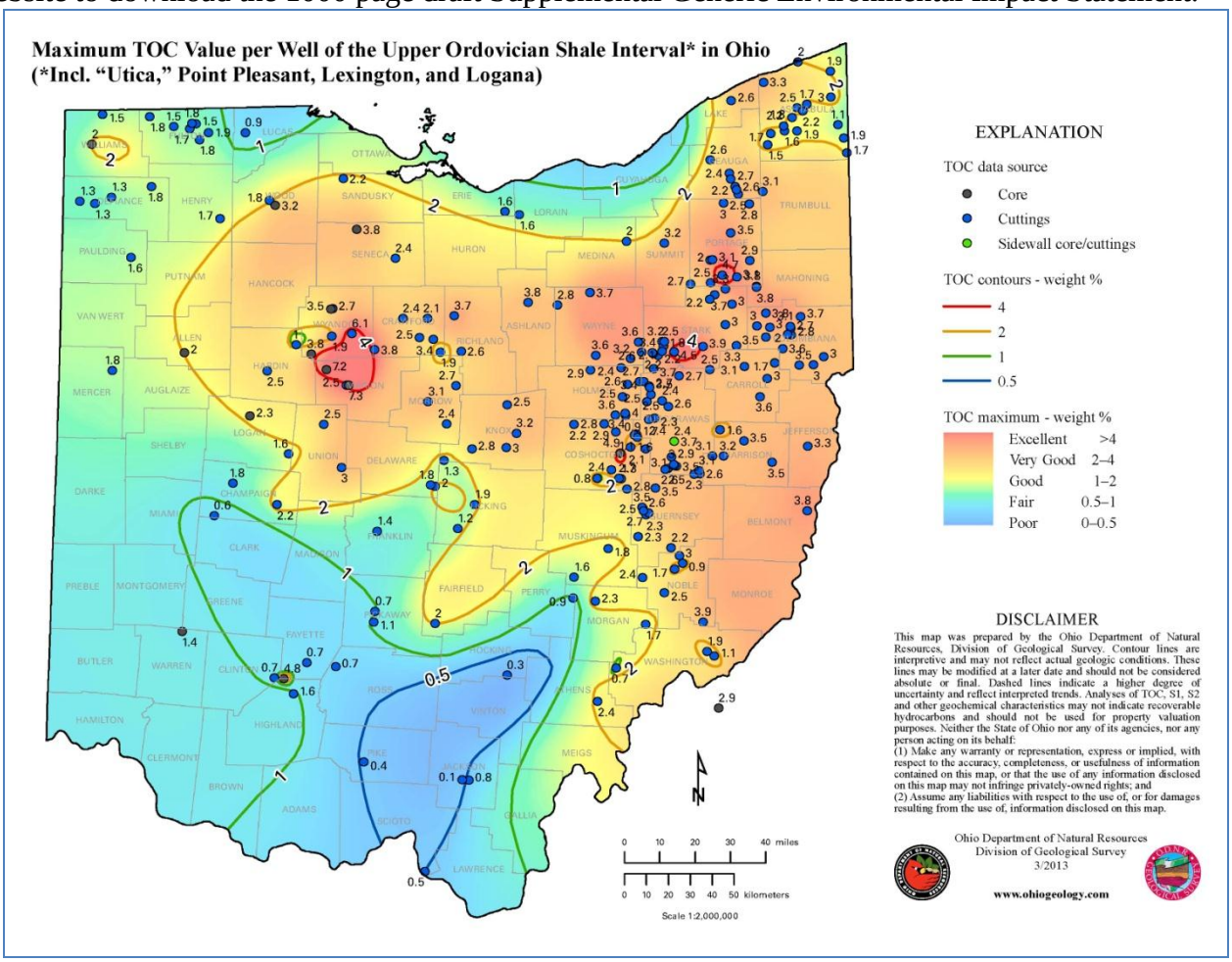
Ohio contains operating 190 Class II injections wells, in 2012, 14 millions barrels of frack fluid was pumped, and this is an increase of 1.4 percent from 2011(Boone, 2013). Most of the drilling waste fluid so far is coming from the Marcellus production in Pennsylvania. This is raising concern of injection capacity of Ohio wells because of the upcoming Utica potential in eastern Ohio.

WEB SITES:

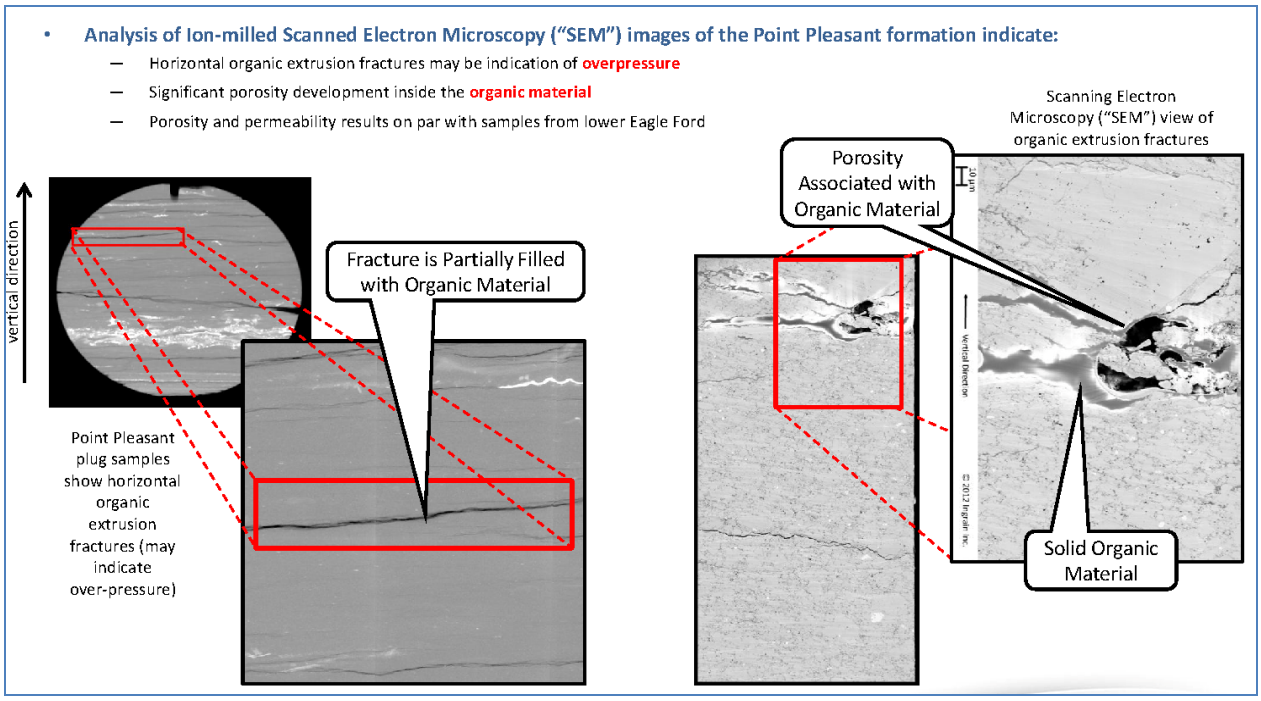
http://www.OhioGeology.com This website will lead you downloadable oil and gas data in Ohio as well as information on type logs, cores & instructions on how to download digital & raster geophysical logs.

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 Statement.



(ODNR, March 2013)



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

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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 oil well completions. The database of 2,748 well completions from 1939 to April 2013 contains the following shale formations and number of completions: Arkansas Novaculite (3), Atoka Group shale (1), Barnett Shale (2), Caney Shale or Caney Shale/Woodford Shale (100), Excello Shale/Pennsylvanian (2), Sylvan Shale or Sylvan Shale/Woodford Shale (10), and Woodford Shale (2,601). Shale wells commingled with non-shale lithologies are not included. Exceptions include 18 Sycamore Limestone/ Woodford Shale completions, 8 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. Shale oil wells have been added since 2004. Figure 1 illustrates 2,620 Oklahoma shale gas and oil well completions (1939–2012) 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 and "SCOOP") areas. Of the 2,601 Woodford-only well completions from 2004–April 2013, 235 wells are classified as oil wells and 2,204 wells are horizontal wells. Vertical depths range from 388 ft (Mayes Co.) to 16,259 ft (Caddo Co.). Initial potential gas rates range from a trace to 12 million cubic feet per day. Initial potential oil/condensate rates range from a trace to 965 barrels per day.

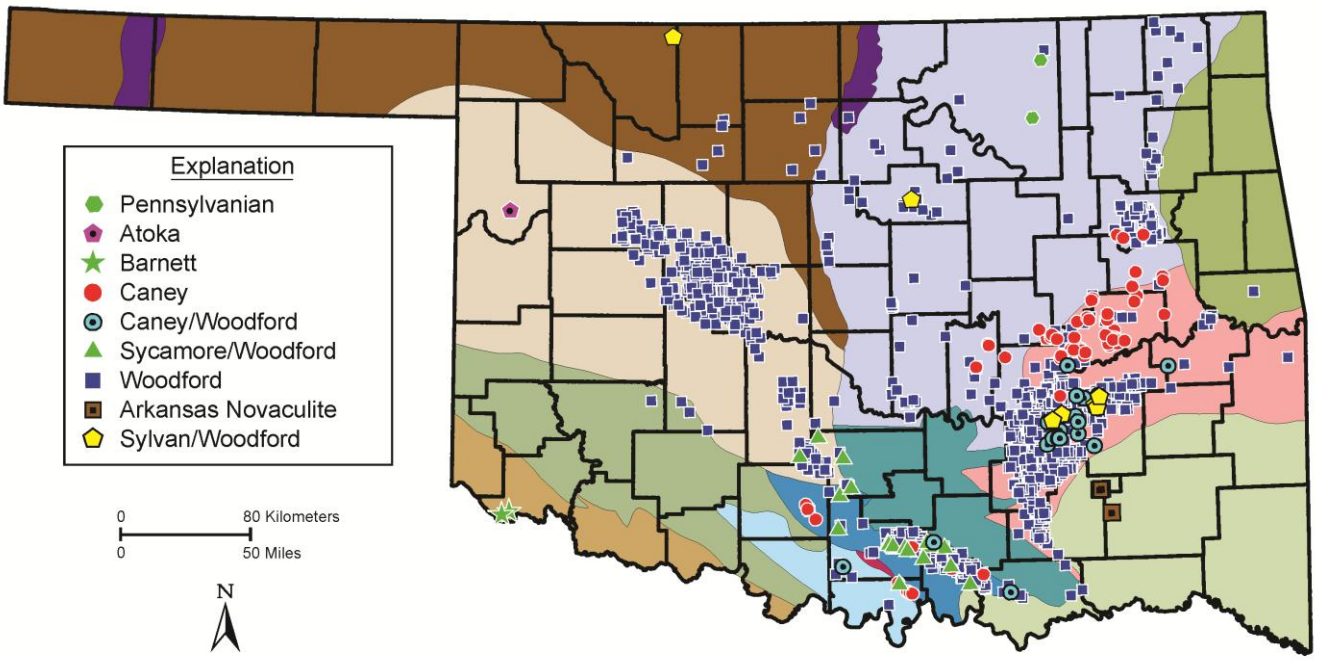


Figure 1. Map showing Oklahoma shale gas and oil well completions (1939–2012) on a geologic provinces map of Oklahoma.

The annual peak of 534 wells occurred in 2008 (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 2010–2012, 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. Figure 5 shows the same data with 2012 as the prominent layer.

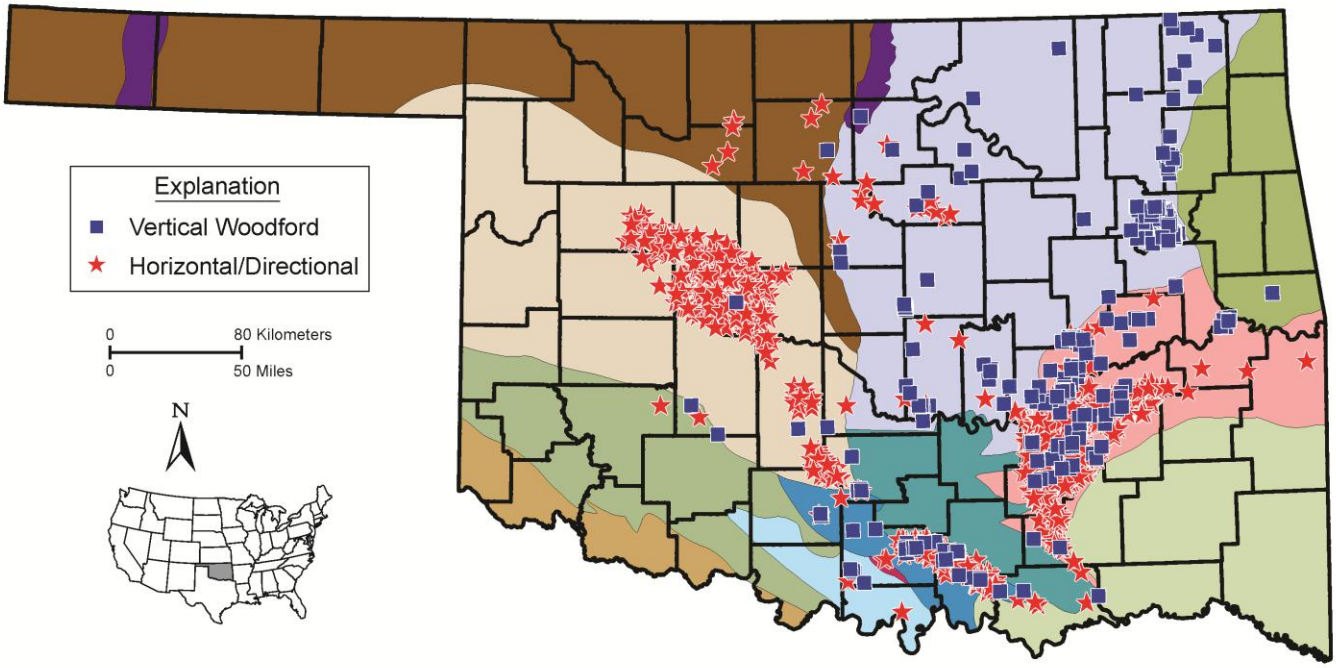


Figure 2. Map showing 2,641 Woodford Shale-only gas and oil well completions (2004–2012) on a geologic provinces map of Oklahoma.

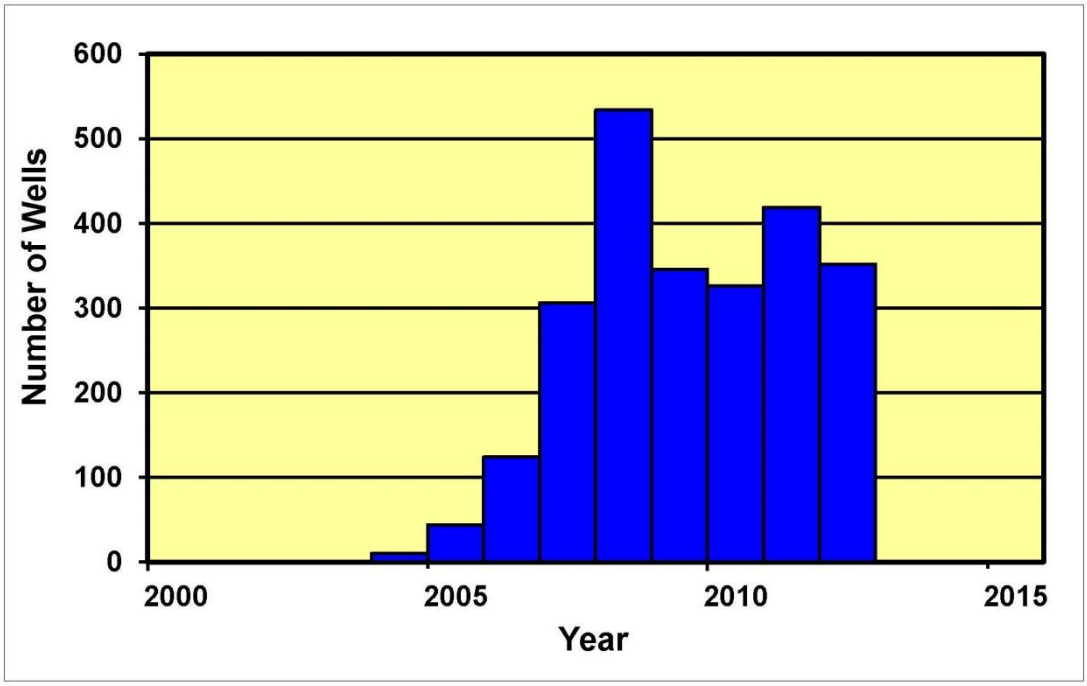


Figure 3. Histogram showing numbers of Woodford Shale-only well completions, 2004–2012.

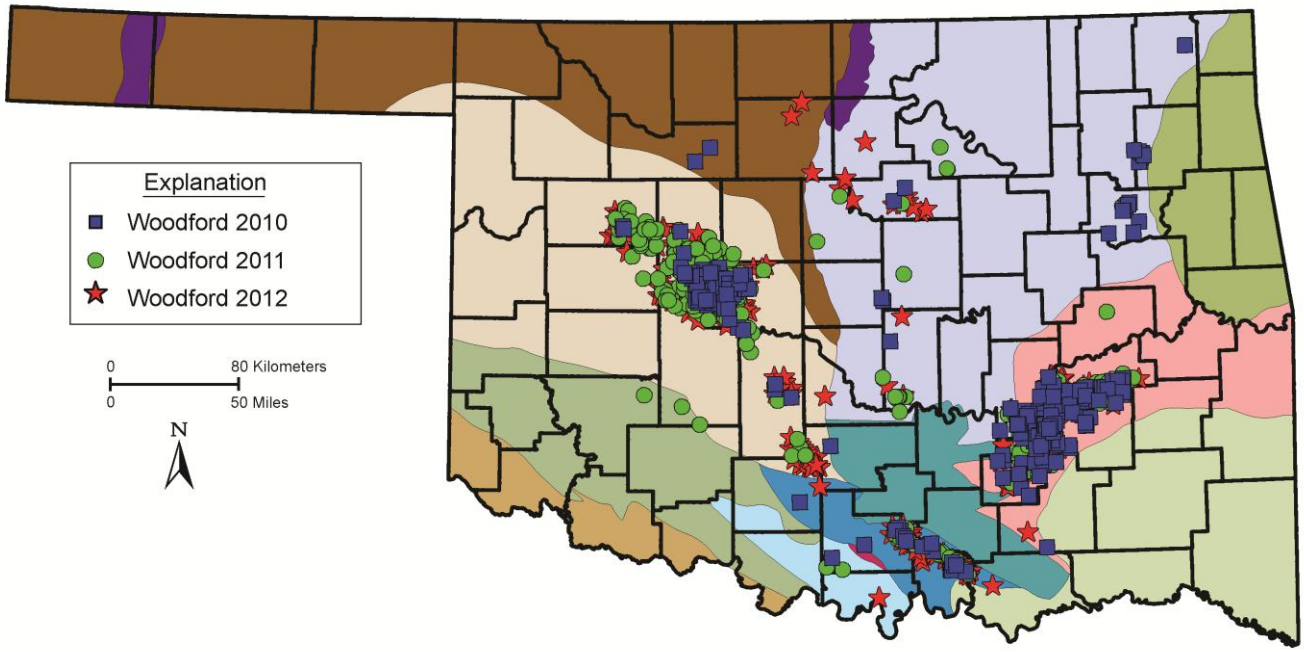


Figure 4. Map showing Woodford Shale-only gas and oil well completions (2010-2012) on a geologic provinces map of Oklahoma.

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 condensate production up to @1.67% VRo (Figure 6);
2) Anadarko Basin ("Cana" and "SCOOP" plays) in western Oklahoma with thermogenic methane production at thermal maturities from 1.1% to >1.6% VRo and condensate production at thermal maturities up to @1.5% VRo (Figure 7);
3) Ardmore Basin in southern Oklahoma with oil, condensate, and thermogenic methane production at thermal maturities in the oil window (<1.4% VRo) (Figure 8);
4) Wagoner County (Cherokee Platform, northeast Oklahoma) with biogenic and thermogenic methane production at thermal maturities <1.2% VRo.

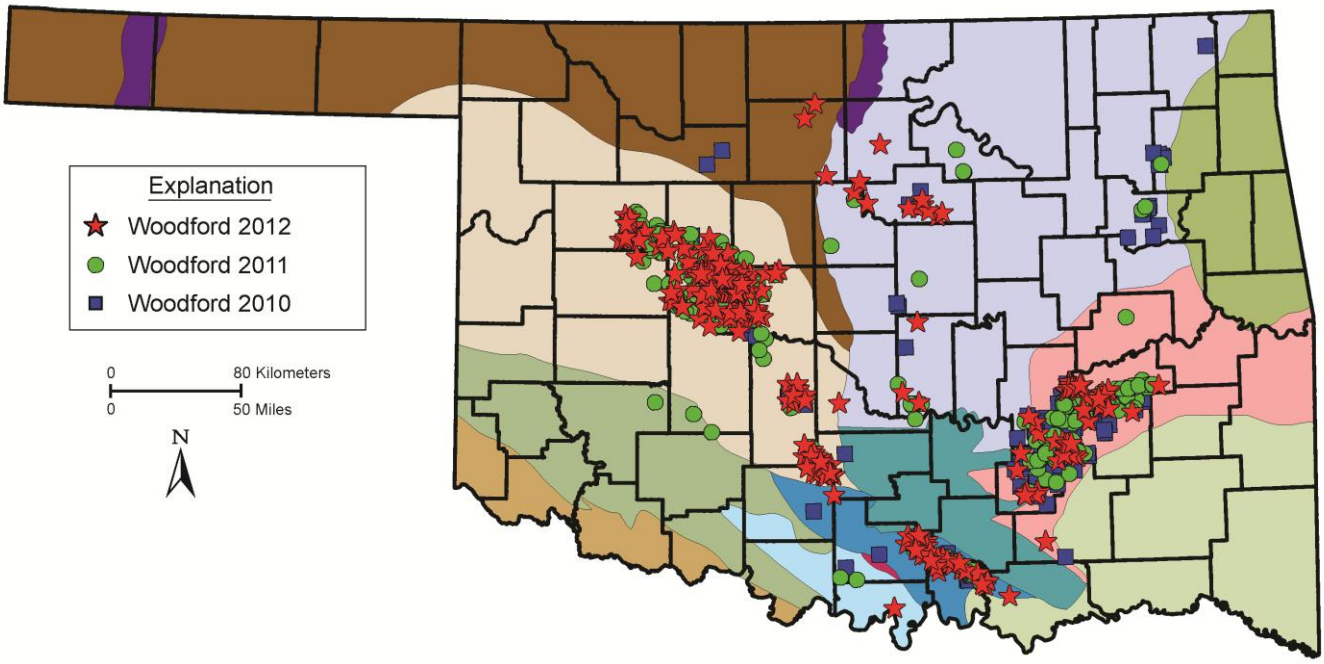


Figure 5. Map showing Woodford Shale-only gas and oil well completions (2012-2010) on a geologic provinces map of Oklahoma.

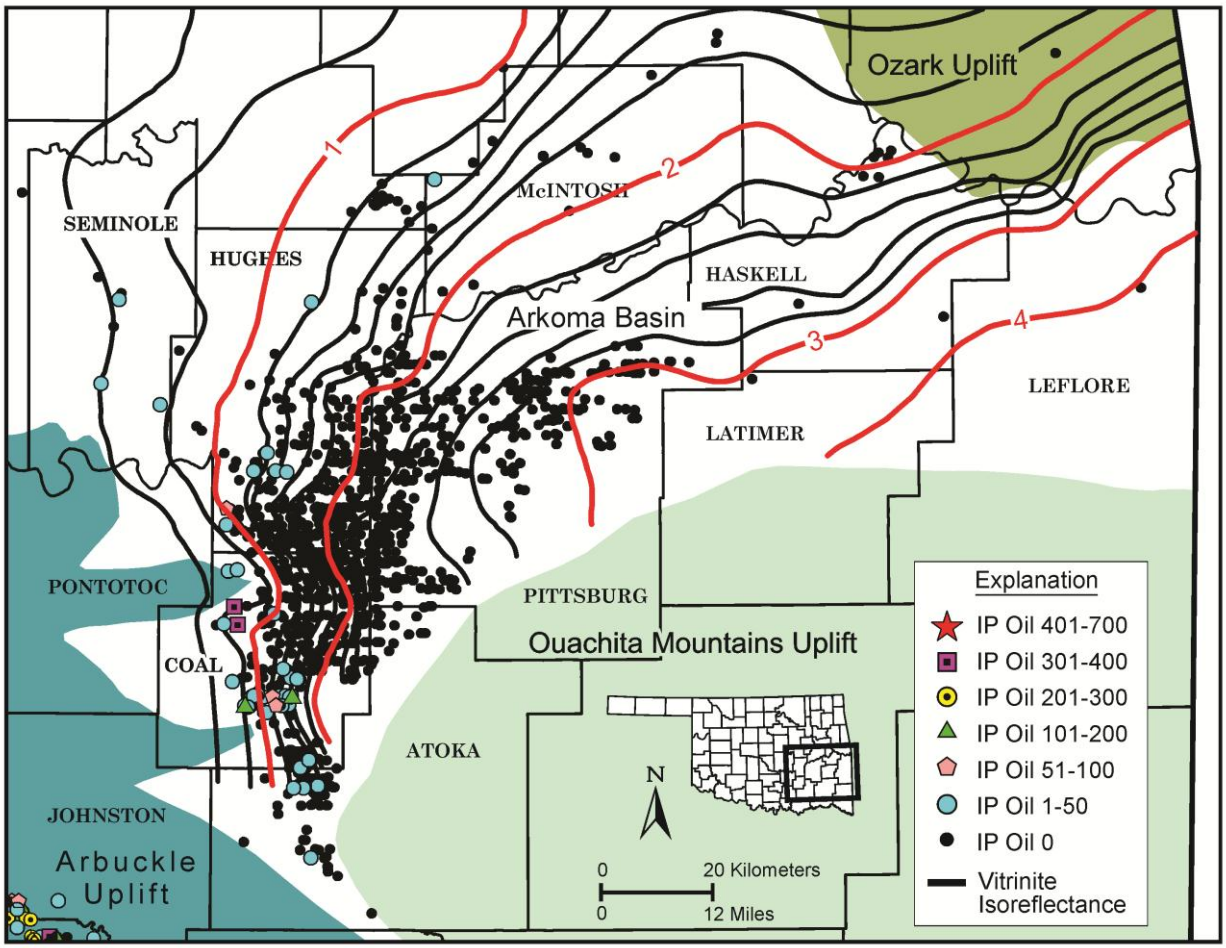


Figure 6. Map showing Woodford Shale-only gas and oil well completions (2004-2012) in the Arkoma Basin of eastern Oklahoma (modified from Cardott, 2012).

Cardott, B.J., 2012, Thermal maturity of Woodford Shale gas and oil plays, Oklahoma, USA: International Journal of Coal Geology, v. 103, p. 109-119. http://www.sciencedirect.com/science/article/pii/S0166516212001632

Of 26 operators active during 2012, the top nine operators (for number of wells drilled during 2012) are:

(1) Devon Energy Production Co. LP (96)
(2) XTO Energy (64)
(3) Continental Resources (48)
(4) Cimarex Energy (47)
(5) Petroquest Energy (30)
(6) Marathon Oil (29)
(7) Newfield Exploration Mid-Continent Inc. (23)
(8) Jones Energy Limited (17)
(9) BP America Production Company (16)

For additional information, visit the Oklahoma Geological Survey web site (http://www.ogs.ou.edu/level3-oilgas.php).

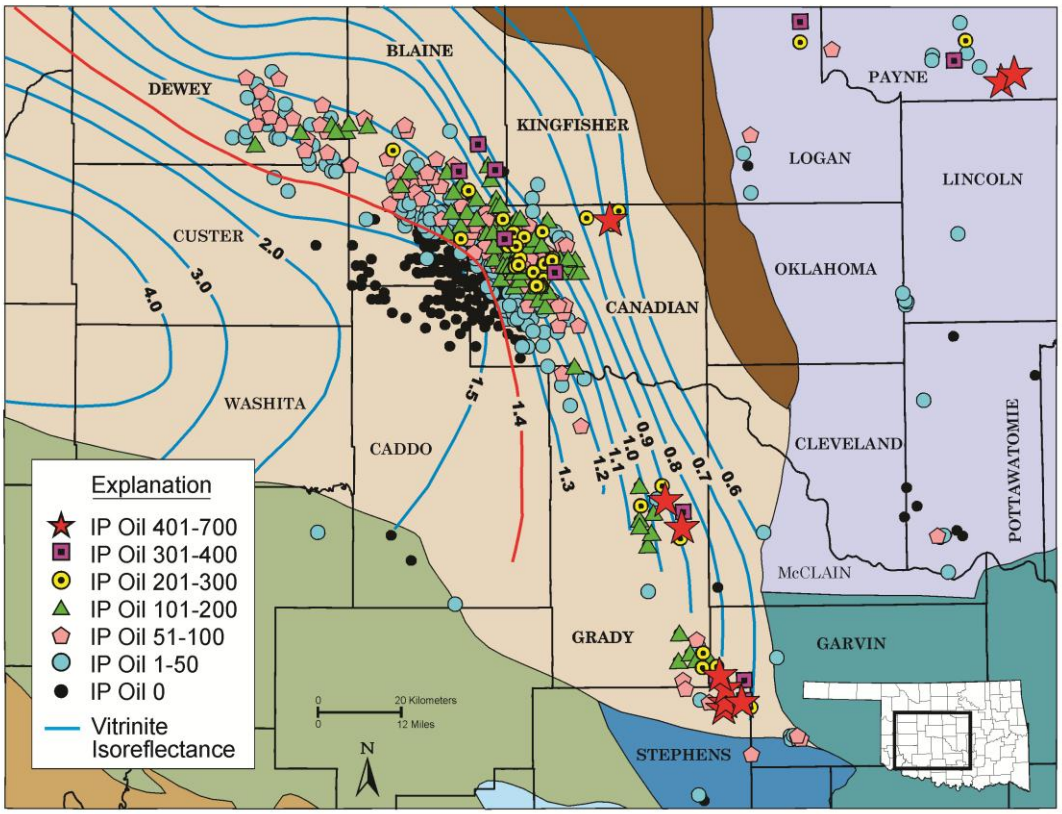


Figure 7. Map showing Woodford Shale-only gas and oil well completions (2004-2012) in the Anadarko Basin of western Oklahoma (modified from Cardott, 2012).

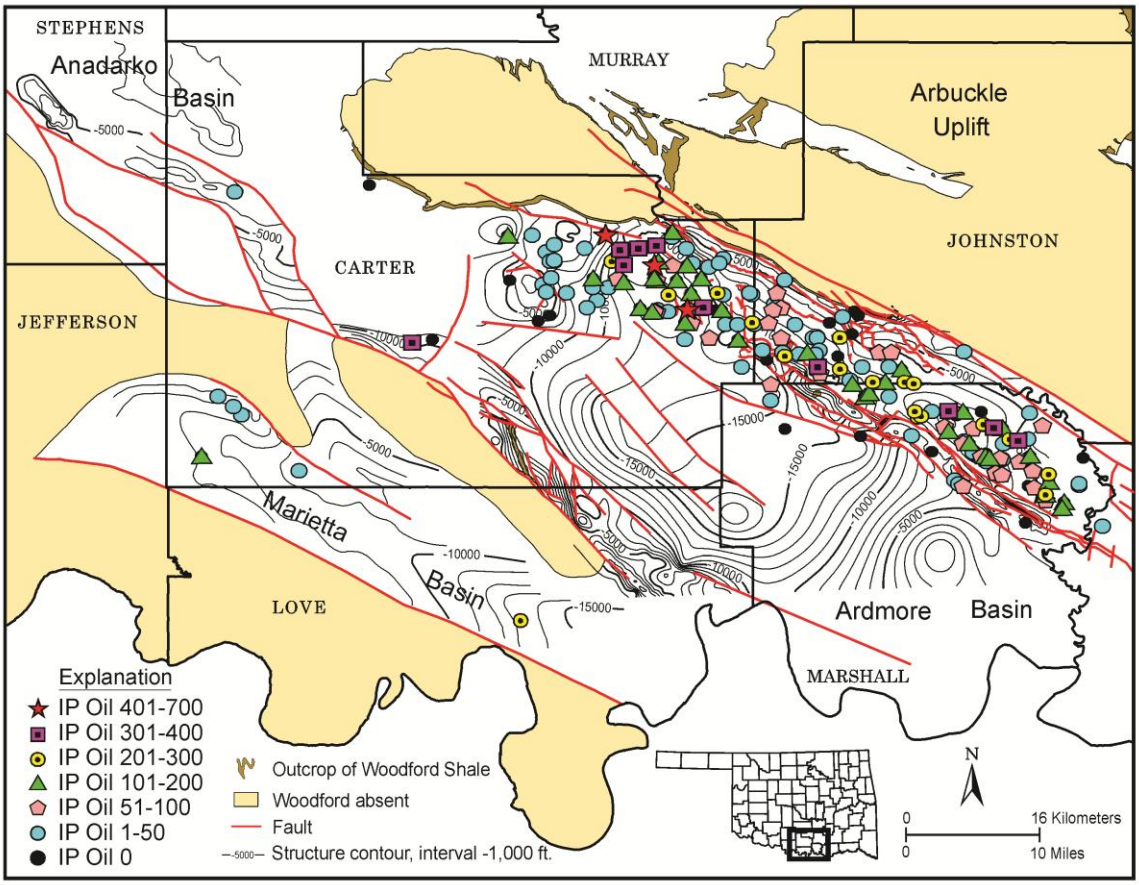


Figure 8. Map showing Woodford Shale-only gas and oil well completions (2004-2012) in the Ardmore Basin of southern Oklahoma (modified from Cardott, 2012).

Canadian Shales

By Jock McCracken (Egret Consulting)

Even though Canada has an abundance of conventional oil and natural gas, unconventional gas, liquids and oil 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 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 more than 16,000,000,000 cubic feet (450,000,000 m3) per day of gas in 2000. It also has huge reserves of coal. Of the provinces and territories within the WCSB, Alberta has most of the oil and gas reserves and almost all of the oil sands.

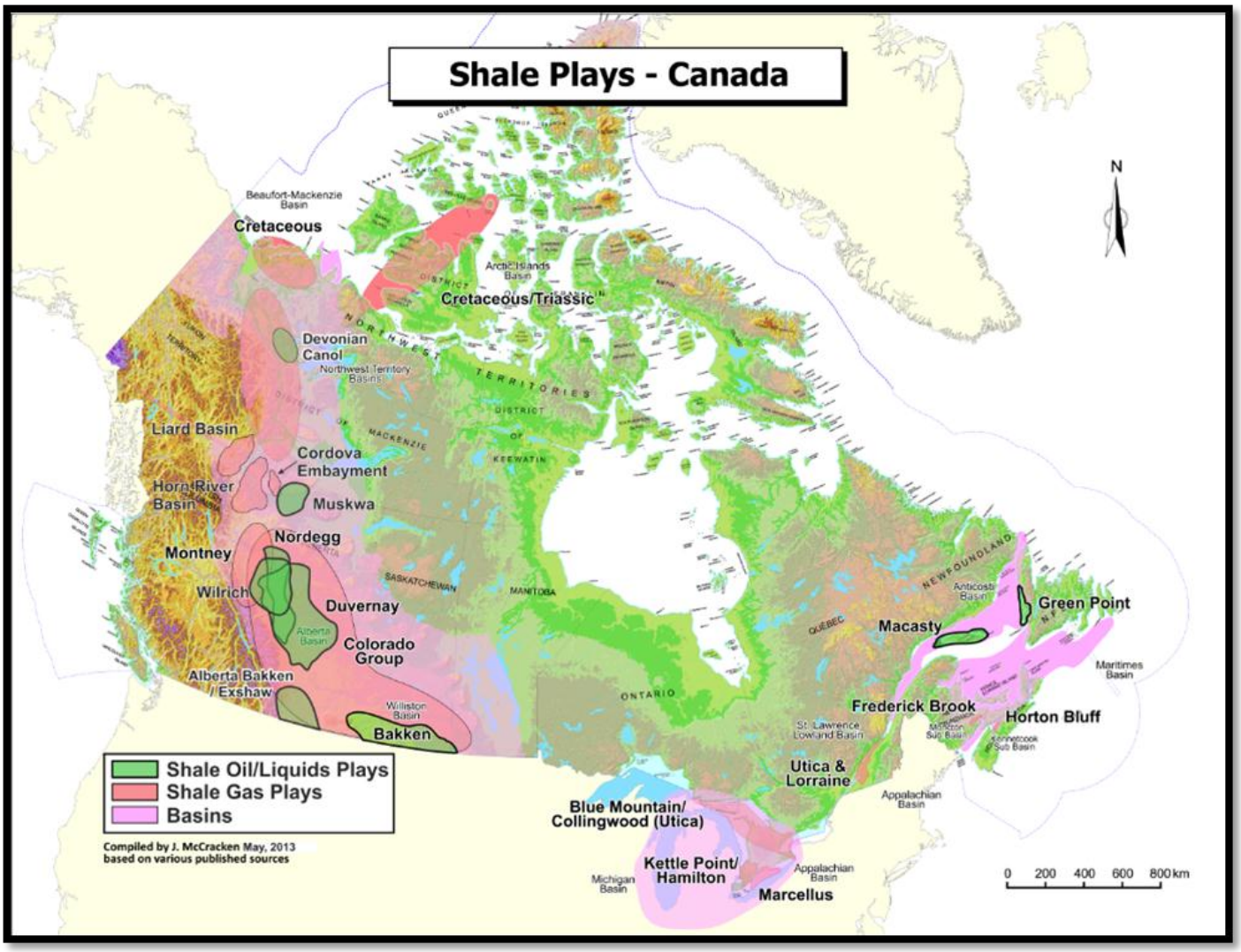
Shale gas production in Canada is five years old after the announcement of new discoveries at the beginning of 2008. About 25% of Canada's natural gas is coming from unconventional. The state of development for the shale plays range from speculative to exploratory to emerging with only two giant gas plays, Horn River and Montney, in N.E. B.C. being considered developing and under increasing production. In most cases, the majority of these wells are still confidential so more recent production numbers are unknown. 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 gas prices operators have been focusing exploration and production into the liquids-rich hydrocarbons, if possible within their areas.

This very prolific hydrocarbon basin has seen a flood of new activity exploring for the tight oil in the silts and shales Recently there have been some new exciting discoveries in Alberta within the liquids-focused Duvernay and Alberta Bakken. The Bakken oil play in Saskatchewan and Manitoba is still one of the hottest plays in Western Canada. Significant shale gas wells have been drilled and tested in the St. Lawrence Lowlands of Québec but a government freeze on fracking because of about environmental concerns will slow down any future exploration and production. The positive announcements out of New Brunswick have been tempered by recent disappointing results and low gas prices. 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 of their first wells into a possible oil-bearing shale section.

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. These concerns, especially in Provinces where there is limited oil and gas exploration and production, are being with by greater transparency and self-imposed industry guidelines.
http://www.capp.ca/aboutUs/mediaCentre/NewsReleases/Pages/GuidingPrinciplesforHyraulicFracturing.aspx

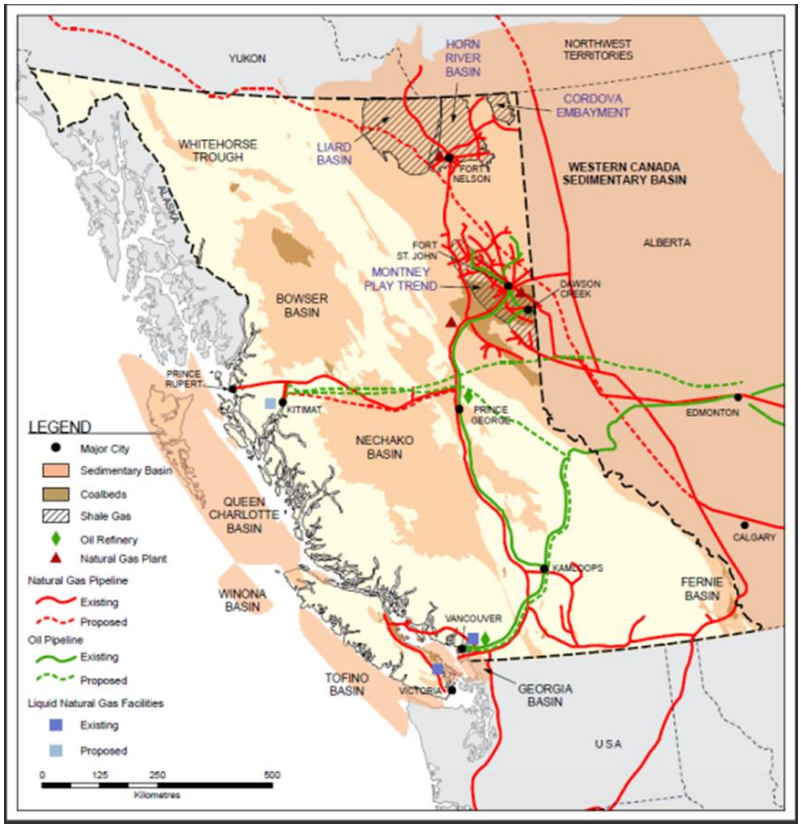
http://www.capp.ca/getdoc.aspx?DocId=210903&DT=NTV

A number of provincial governments are reviewing these practices (Quebec, Nova Scotia and New Brunswick) as well as updated their regulations (Alberta). 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.
http://www.montrealgazette.com/business/rules+practices+ease+fracking+concerns/6361034/story.html

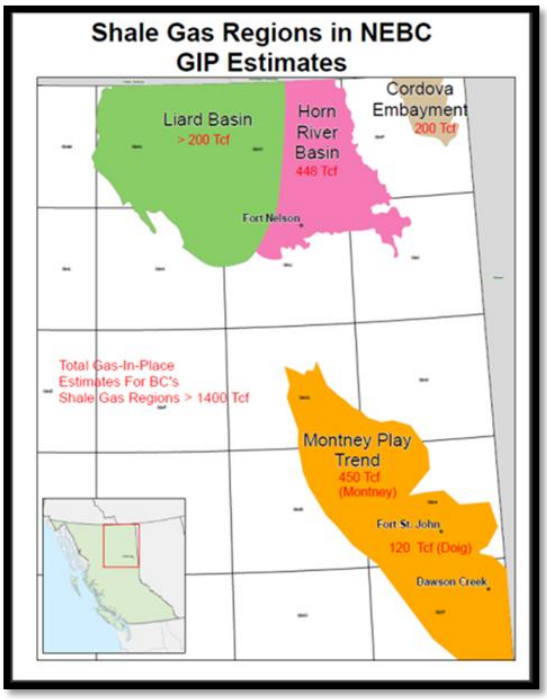


NORTHEAST BRITISH COLUMBIA

Shale gas interest has dominated the sale of petroleum and natural gas (PNG) rights from the province in the last five years with the Horn River Basin, the Cordova Embayment and the Montney Play trend generating the most interest. Recently the Liard Basin or Beaver River Area has come on to the radar screen with most of the basin almost entirely licensed. BC's total oil and gas revenue in 2011 was $731.3 million. Land sale bonuses for these NE BC areas accounted $4.6 billion since the record year in 2008. The bonuses of $223 million were reduced in 2011 since available land has been taken up but in 2012 the amount collected is just $17-million in three auctions, putting it on pace for its worst year of exploration land sales in nearly two decades. http://m.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/thrill-gone-for-bc-gas-exploration-rights/article576459/?service=mobile



These Cretaceous to Devonian British Columbia shales are estimated to have the capacity to hold over 1,400 TCF of gas in place with 78 trillion cubic feet (TCF) of marketable gas. The chart below shows this activity in the NE B.C. The steep decline in 2009 reflects the economic downturn and the low gas price but despite this, activity is still proceeding.



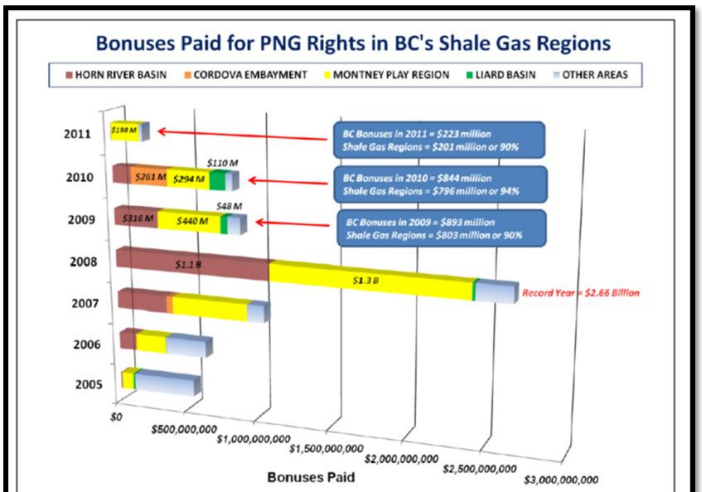
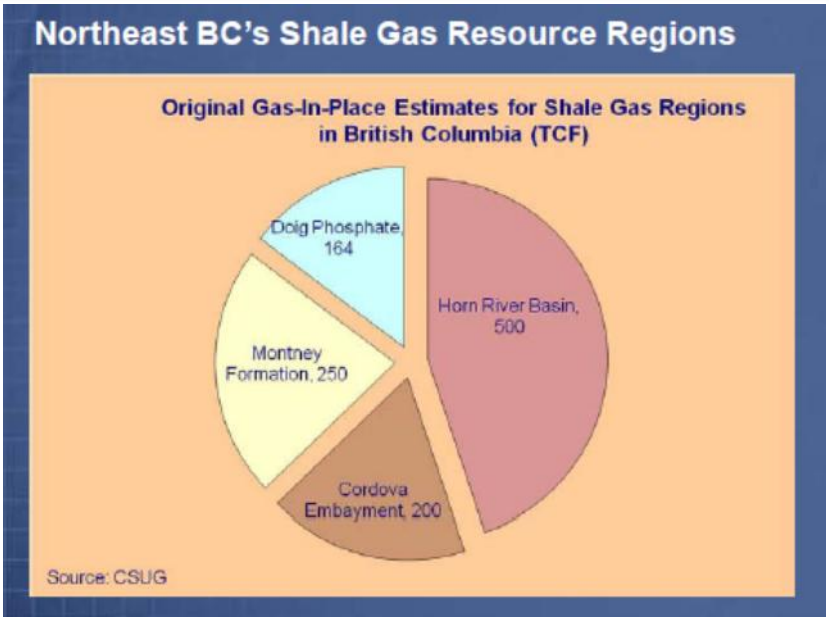


Figure 2. Bonuses collected over the last six years from the sale of British Columbia's Crown petroleum and natural rights in the province's shale gas regions. In 2010, British Columbia saw a total of $844 million collected in bonuses with 94 per cent amassed from shale gas interest. The Montney play region accounted for almost 89 per cent of the land sale bonus total in 2011.

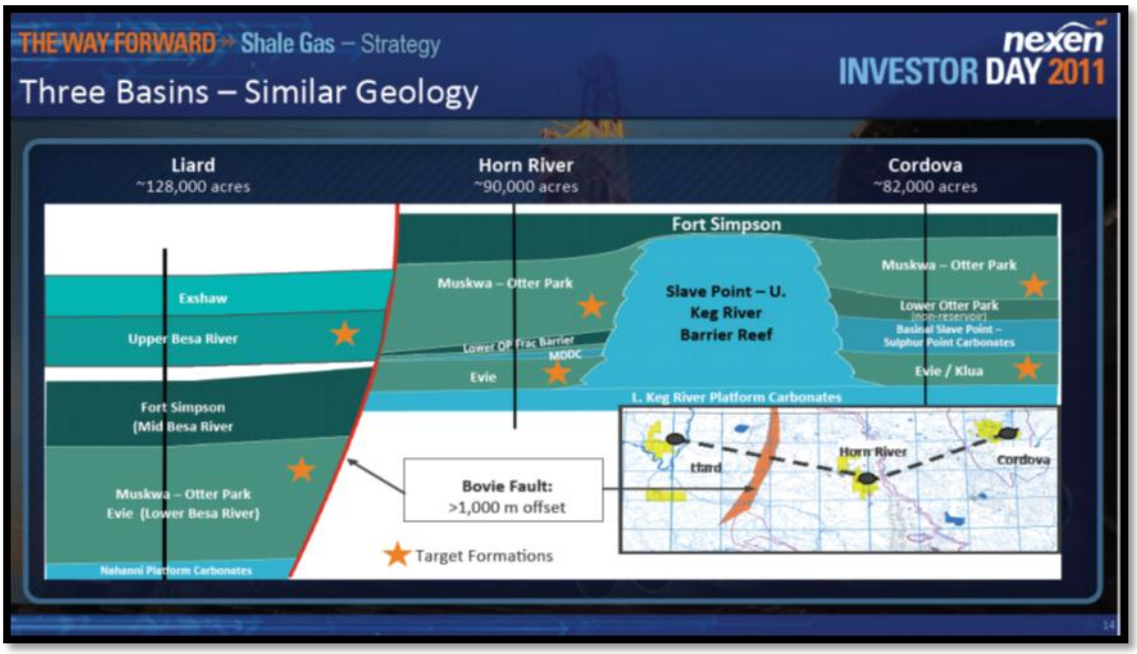
TABLE 1. POTENTIAL SHALE GAS FORMATIONS IN NORTHEAST BRITISH COLUMBIA

PROSPECTIVE HORIZONS

	Formations	Description	Depth	Average Thickness	Total Organic Carbon	Gas in Place
LOWER CRETACEOUS	Wilrich and Buckinghorse shales	Potential interbedded sand/siltstone	800 to 1,200 metres	100 metres	2.3%	60 Bcf per section
JURASSIC	Nordegg and Fernie shales	Recognized source rocks	1,200 to 2,500 metres	Up to 30 m organic rich section	up to 14%	>20 Bcf per section
TRIASSIC	Doig, Doig Phosphate and Montney	Montney turbidites may increase permeability Phosphate units have high TOC and are excellent source rocks	1,200 to 3,000 metres	300 to 500 metres	0.5 to >10%	10 to 110 Bcf per section
DEVONIAN	Exshaw, Besa River, Fort Simpson and Muskwa	Exshaw and Muskwa are widely distributed organic shales Fort Simpson and Besa River are thick basin-filling shales	1,800 to 3,500 metres	Huge thicknesses are common with some high TOC intervals	0.5 to >10%	10 to 100 Bcf per section



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. Recent government reports state that the Horn River production is, at year-end 2010, was approximately 392 MMCFD from 98 producing wells increasing from roughly 80 MMCFD at the end of 2009. The current production estimate of 500 MMCF/D is from a total of 160 producing shale gas wells. The following eleven operators form the Horn River Producers Group, which is a co-operative endeavor set up to share ideas and reduce the footprint: Apache, ConocoPhillips, Devon, EnCana, EOG Resources, Imperial Oil, Nexen, Pengrowth, Suncor, Quicksilver and Stone Mountain. There are another 15 companies working this area including SMR Oil and Gas, Taqa North, Storm Gas Resources, Canadian Natural Resources, Ramshorn Canada, Husky Oil and Delphi to mention a few.

The companies with the most acreage are Encana, 260,000 ac, ExxonMobil, 250,000 ac, Apache, 289,000 ac, EOG, 157,000 ac, Quicksilver, 127,000 ac, Devon, 100,000 ac, Nexen, 88,000 ac, and Taqa North, 31,500 ac. (Hart E&P May 2011) It is said that the entire Horn River has marketable gas at 78 TCF. http://www.energy-pedia.com/news/canada/new-150721. The five companies with the most drilling, as of end of 2011, are Apache, Encana, Nexen, EOG, Imperial Oil, Devon and Quicksilver. Apache has been the most active since 2003. Their production is 90 MMCFD as of Jun 2012 with the production from 70 wells on 7 pads. Their net recoverable resource is 9.2 TCF and net production is 90 MMCF/D. Apache has up to 16 wells on a pad. Encana has drilled 88 shale wells since 2003. Their current production is 95 MMCFD. They lead the way with multiple fracture stimulations of up to 28 per well as well as the longest laterals of up to 3 kilometres long. Their forecast average production from this basin is expected to 600 MMCFD? by 2014 (it may have been revised). Encana and Apache have entered into a partnership sourcing fracing water from the Mississippian Debolt Formation. Encana and Kogas Canada Ltd., a subsidiary of Korea Gas Corporation (KOGAS), have entered into a three-year exploration and production agreement with the first well pad expecting gas production this summer. EOG completed 11 wells in 2010 but planning minimal drilling after that to hold the acreage. They recently drilled three wells testing and producing the Evie member at 16-22 MMCFD

Nexen, which was recently purchased by CNOOC Limited of China, is expecting production to be 200 MMCF/D by 2013. By the 3rd quarter of 2011, they fractured and completed and brought on stream gas from their 9 well pad. With the completion of this pad they expect to ramp up production to 50 MMCFD. They have another pad with 18 wells coming on stream in late 2012. Their previously announced shale gas joint venture with INPEX Gas British Columbia Ltd. (IGBC) closed in August. Nexen have 128,000 acres of highly prospective shale gas lands in the Liard basin, with between 5 and 23 TCF of unrisked prospective resource. Devon with 174,000 acres has the potential to produce

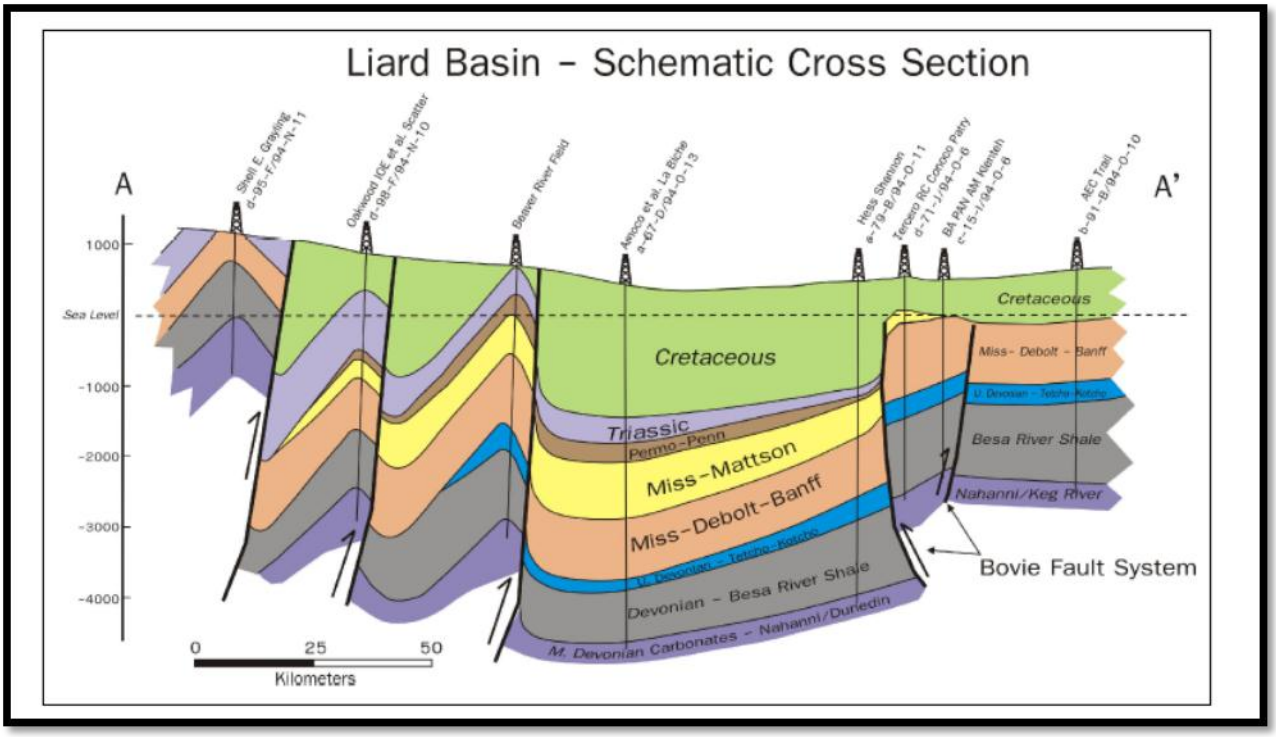
up to 700 MMCFD based on its good land position and in the thickest part of the Basin. Eight producing horizontal wells are producing.

ExxonMobil and its 50% partner Imperial Oil have been encouraged by their 10 plus wells over their large 320,000 acre position. They are therefore setting up a multi-well horizontal pad pilot development in one of their areas. Production began on schedule from an eight-horizontal-well pad in August 2012 to assess productivity and improve development costs. Imperial continues to evaluate information from the pilot phase to determine long-term plans for the development.

Quicksilver drilled 11 horizontal wells in 2011. They have 20 horizontals drilled. Four of their wells are under production with one of them producing an average of 10 MMCFD since production was brought on in Oct of 2010. The eight well from one pad have an estimated production capacity in excess of 150 million cubic feet of gas per day. Production has been curtailed because of flow limitations, but individual wells tested between 20 million to 30 million cubic feet per day.

They were also planning to drill an oil-rich horizontal leg into a section considered to be "Exshaw/Bakken zone" within the Horn River area. No news on that yet.

The Laird Basin, which contains 3 million acres and a thick 5 kilometres of section from the Cambrian to the Upper Cretaceous, remains relatively unexplored but Houston-based independent Apache Corp., which has aggregated a large acreage position, calls the Lower Besa River first 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



In the Besa River, original natural gas in place is 170-500 bcf/sq mile, and Apache said it has identified 48 tcf of dry sales gas from 210 tcf of net gas in place on its acreage (OGJ Online, June 14, 2012). 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

Apache said the D-34-K well, one of three it has drilled and hooked to a pipeline, is believed to be the world's highest-flowing shale gas resource test. D-34-K flowed 21.3 MMCFD on a 30-day initial potential test from a 2,900-ft. lateral at 12,600 ft. true vertical depth after six frac stages. Cumulative production was 3.1 BCF in 12 months, and the company looks for estimated ultimate

recovery of 17.9 BCF of gas. 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.

Another company in the Laird Basin is Transeuro Energy where they are proceeding to develop the pre-existing Beaver River gas field. They are continuing to develop this field with the hopes that the surrounding shales are feeding these reservoirs. Currently they are producing 2.7MMCFD. They plan to drill 6 more wells to target 14 horizons. Nexen and Paramount have acreage positions in this basin.

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. Nexen, Penn West Trust and Canadian Natural Resources Ltd. have operations in this category with Nexen having drilled one vertical and one horizontal and Penn West Exploration planning 15 to 20 appraisal wells this year. Penn West just announced an $850 million Joint Venture with Mitsubishi to help develop their property in this area. To October 2011, five wells have recorded approximately 2.0 Bcf of gas production from shale gas zones in the Cordova Embayment. The producing wells were drilled by CNRL and Penn West Exploration Ltd.

Recently, EnCana entered into an agreement with Enbridge Inc. for the sale of its majority stake at the Cabin Gas Plant in Horn River Basin for approximately $220 million. Phase 1 of the development will have 400 MMCFD of natural gas processing capacity. The plant is currently under construction and is expected to be in-service in the Sept 2012. Phase 2 will add an additional 400 MMCFD of capacity and has been sanctioned by producers and has received regulatory approval. The Phase 2 plant is expected to be ready for service in the third quarter 2014. Devon also has an interest in this facility. Enbridge Inc. is shelving the nearly complete Phase 1 of its $1.15-billion Cabin gas processing plant project in B.C. until natural gas markets recovers. The first 400-million-cubic-feet-per-day phase is nearing completion, but the expected volumes of gas from the Horn River Basin of northeastern B.C. have not materialized as explorers forego investment. It is unclear when the project will be on the go again. http://www.calgaryherald.com/Business/846719/story.html#ixzz2BIpz8dlX

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 2.4 BCFD. TransCanada Corp. has filed an application for an Alberta pipeline extension subject to regulatory approvals, the approximate $310 million project is expected to be operational early in second quarter 2012 with commitments for contracted gas rising to approximately 540 MMCFD by 2014.

The Asian gas market is being targeted by up to six joint venture export groups with the building of LNG terminals in Kitimat, Prince Rupert and Grassy Point BC, 643 kilometers north of Vancouver. Shell Canada Ltd. (TSX:SHC) was the first one out of the gate to send its plans for review to build a $4-billion pipeline and liquefied natural-gas export terminal to federal and provincial environmental regulatory agencies.

Shell's plans, which are now among at least a half-dozen proposed B.C. LNG developments, include building a natural-gas pipeline from northeastern B.C. to Kitimat, where the liquefied gas will be loaded onto tankers and shipped to Asia. The construction for the project is expected to start in 2015 with a completion date of 2019 or 2020. The LNG Canada project is a venture between Shell and affiliates of Asian companies Mitsubishi Corp., Korea Gas Corp., and PetroChina Investment Ltd.

The other projects and partners are: Kitimat: Kitimat LNG: Chevron and Apache, Douglas Channel LNG: Haisla First Nation and LNG Partners from Houston. Prince Rupert: Pacific Northwest LNG Terminal: Petronas owned Progress Energy and BG Group PLC. Grassy Point is being marketed

by the B.C government as another location. Exxon Mobil Corp and Nexen, AltaGas Ltd and Talisman/Sasol have also been pursuing LNG projects as well.

http://www.calgaryherald.com/business/energy-resources/Shell+submits+Kitimat+project+plans/8190707/story.html?__lsa=ffb3-424d#ixzz2RoTsGwaI

http://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/british-columbias-potential-lng-terminals/article8956483/

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

The Montney is a tight gas/shale gas play and producing at approximately 1.38 BCFD at the end of October 2011. 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 main Montney players in order of rig utilization are Shell Canada Ltd, Murphy Oil Co. Ltd, Talisman Energy Ltd., Encana Corp., Progress Energy Ltd., ARC Resources Ltd., Canadian Natural Resources Ltd, Tourmaline Oil Corp., Crew Energy Inc., Painted Pony Petroleum Ltd., Canbriam Energy Inc., Huron Energy Corp. as well as, at least, another 23 operators. This report will just cover the most active players.

Shell Canada Limited keeps expanding their program in the Sunset Prairie-Groundbirch area where they have only tapped into 5% of their resource estimate of 8 TCF for the area. Shell's Groundbirch venture currently includes five natural gas processing plants, over 230 wells and 900+ kilometres of pipeline which are producing over 200 million standard cubic feet of raw gas per day as of mid-2012.The heart of this tight gas formation lies in a wide layer of siltstone, sandstone and shale some 8,200 to 9,800 feet below ground, and the producing zone is approximately 500 feet thick Groundbirch is still being explored, so the current drilling program includes a mix of single and multiple well pads. Eventually, most of the wells will be drilled on pads containing up to 26 wells, with two such pads for every three square miles of land.

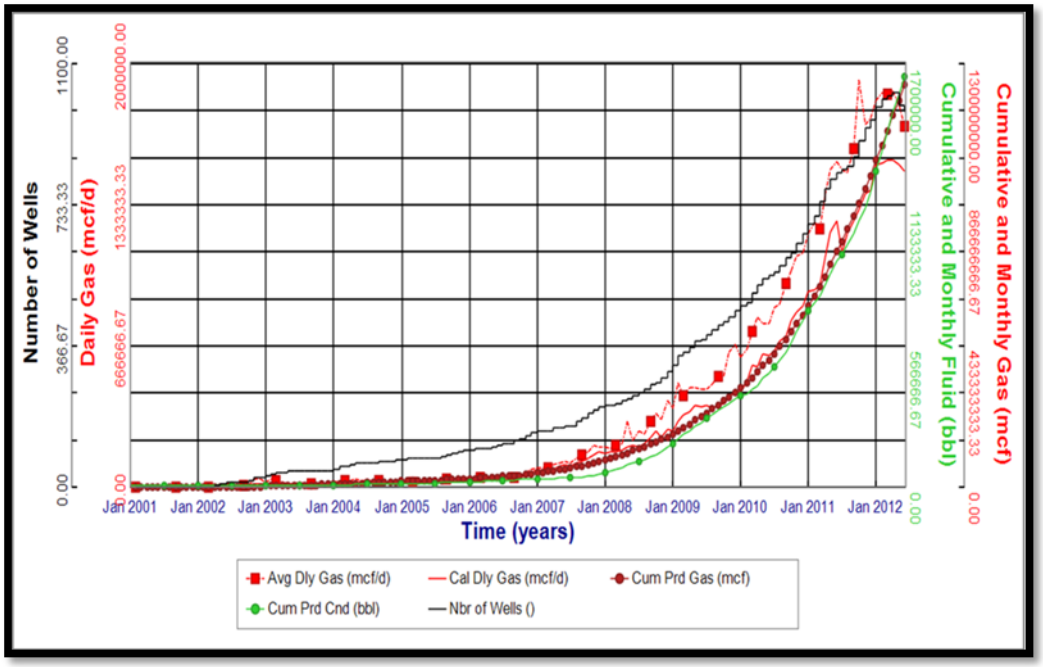
Murphy Oil Corporation, in their Tupper Creek Area, has now reached a production level of over 250 MMCFD. They have almost 145,000 net acres in the Montney Trend and drilled 60 wells last year. Their Tupper West gas plant has the capacity of 180 MMCFD with the current production of 150 MMCFD from 59 wells. Recently, because of price, they have curtailed production and reduced spending. ARC Resources Ltd. has now increased their daily production to 235 MMCFD and 1,800 barrels per day of liquids. They have stated that they could sustain rates of up to 800 MMCFD and 17,000 BPD of liquids for a period of 10 years based on their resource portfolio. The first two of three 60 MMCFD gas plants are on stream at full capacity. Some of their wells are producing 30 to 200 barrels per/MMCF. Another recent well of theirs is producing 4.7 MMCFD from a 100 metre section in the Upper Montney. The total BC Montney 2012 Q2 production was 240 MMCF/D with Dawson contributing approximately 167 MMCF/D.

Encana, one of the biggest players with 482 rig releases since 2005, drilled 90 wells in 2009 with 8 to10 wells per section, 62 wells in 2010, 43 in 2011 and 70 wells in 2012. The horizontal section are up to 2400m long with up to 17 fracs per well with some recent IP at 10 MMCFD. They believe they have an estimated 70 TCF of gas in place in their trend. Their Montney, Cutbank Ridge area was producing at the end of 2011 at 548 MMCFD with their current forecast for 2014 at 600 MMCFD. They have advanced their resource hub design to a new level with 8-12 wells per hub, 100-200 completions per hub, up to 17 stages per well, laterals of 650-100 ft., horizontals of 6500-10,000 ft. and completions every 450 ft. They have announce one well with a 8,935 ft lateral, 12 frac and an IP of 19 MMCF/D. Their completion costs have been reduced by approximately 60% in the last 5 years. They recently announced 40% sale of some of their acreage in the area to Mitsubishi Corp.

This play keeps expanding both aerially and stratigraphically as operators are searching for the more liquids-rich sections. Two other operators are partnering up with other international players

where Progress Energy Resources Corp. created 50/50 partnership with the Malaysian PETRONAS and Talisman Energy Inc. partnered up with South Africa's Sasol Ltd. Other companies have reported liquid yields per MMCF of 20 BBL (Terra Energy Inc.), 30 BBL (Canadian Spirit Resources Inc.), 35 to 50 BBL (Tourmaline Oil Corp.), and 60 to 85 BBL Crew Energy Inc.) A very extreme gas rate of 24.5 MMCFD was announced by Painted Pony Petroleum Ltd.

The graph below shows the well production in the Montney from the Adams, 2012 report.



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.

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

http://hornrivernews.com/

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

Adams, C. (2012): Summary of shale gas activity in northeast British Columbia 2011, BC Ministry of Energy and Mines, pages 1-19.

http://www.empr.gov.bc.ca/Mining/Geoscience/PublicationsCatalogue/OilGas/OGReports/Documents/2012/Summary%20of%20Shale%20Gas%20Activity%20in%20NEBC%202011%20Version%20HQ.pdf

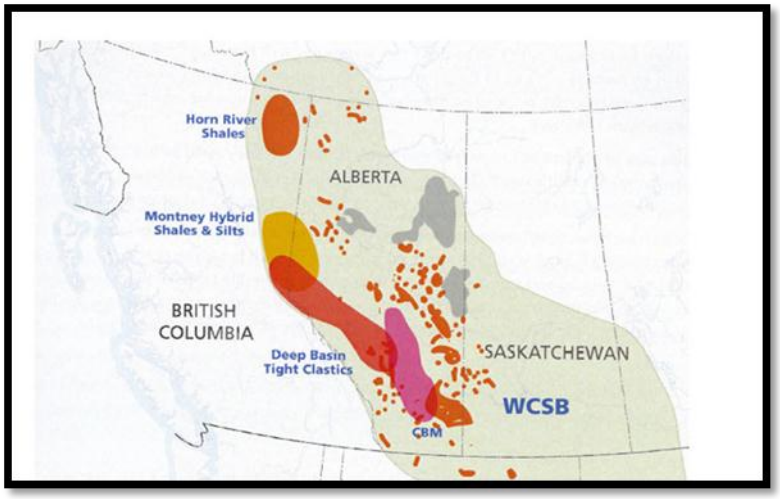
BC MEM/NEB Report, May 2011: Ultimate Potential for Unconventional Natural Gas in Northeastern British Columbia's Horn River Basin

http://www.em.gov.bc.ca/OG/Documents/HornRiverEMA_2.pdf
http://www.aapg.org/explorer/2010/10oct/regsec1010.cfm
Geoscience BC
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

ALBERTA

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 25,400 M3/D (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 27,000 M3/D (170,000 BBL/D) to conventional light oil production by 2014. In Saskatchewan, tight oil production in the first quarter of 2011 was 14,300 M3/D (90,000 BBL/D), while Manitoba, reached 4 000 M3/D (25,000 BBL/D). Companies have so

far identified just over 80 million M3 (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 21,000 M3/D (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.

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.

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

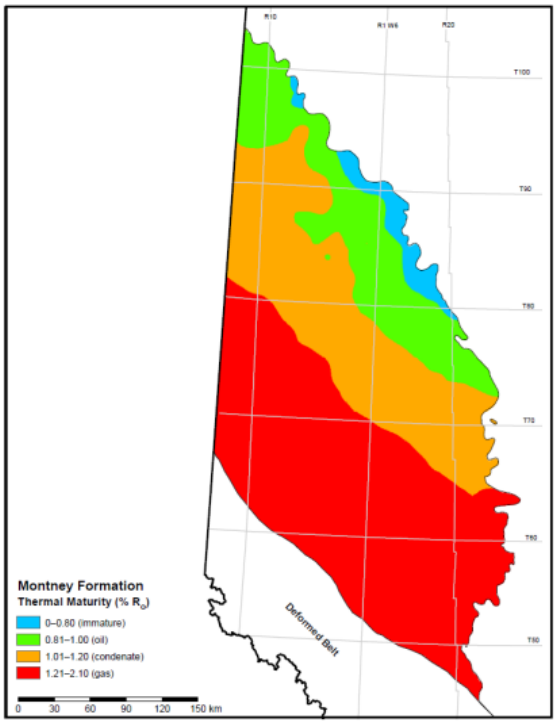


Figure 2.3.7. Thermal maturity map of the Montney Formation.

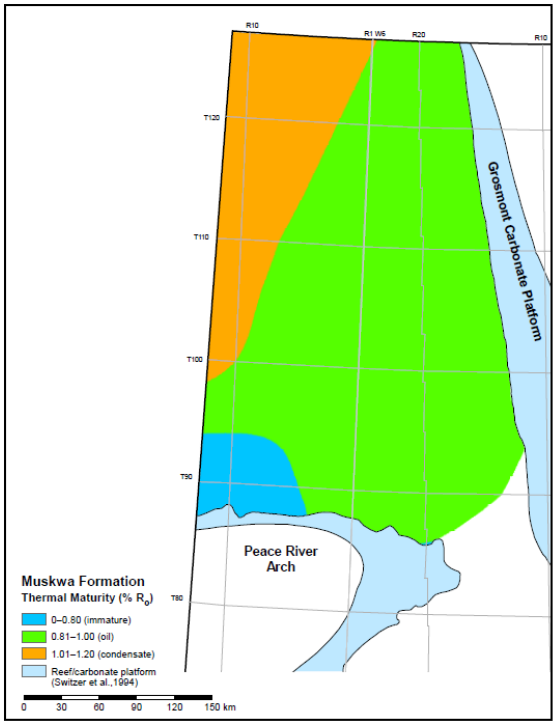


Figure 2.2.6. Thermal maturity map of the Muskwa Formation.

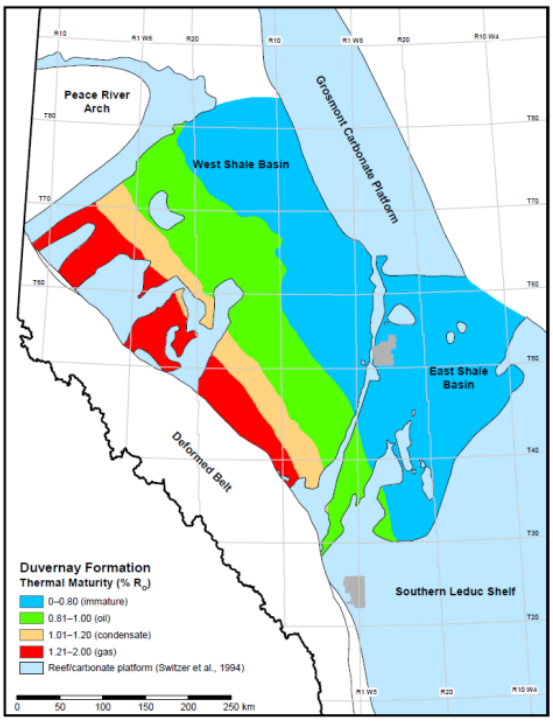


Figure 2.1.7. Thermal maturity map of the Duvernay Formation.

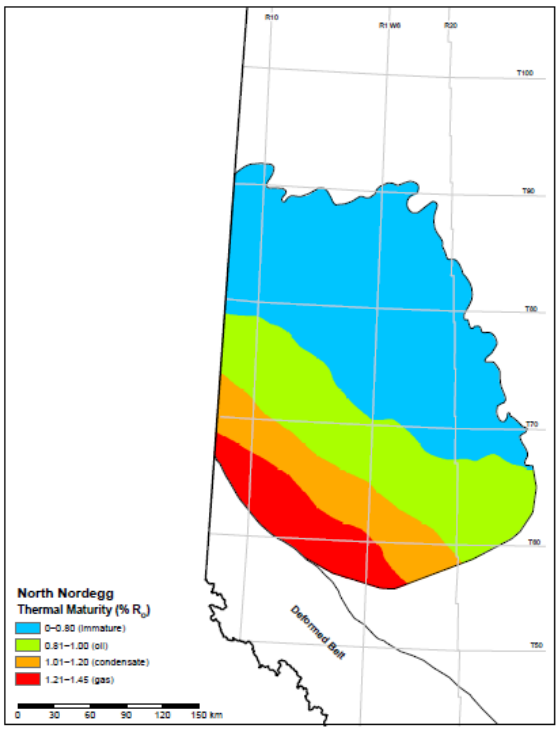


Figure 2.5.7. Thermal maturity map of the north Nordegg.

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 feel that the Nordegg Member contains a huge amount of oil. They are drilled a horizontal well to test this play producing limited liquids. There have been tests in this play area of 147 BOPD. There are others in this play but information is tight: Penn West, Quatro, Athabasca Oil Sands, 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.
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. 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.
https://bmo.can.idrsite.com/Login%20Page%20Document%20Library/ADLibrary/Presentations/BMO%20Duvernay%20DUG%20June%202012.pdf

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, ConocoPhillips, Husky, Athabasca, Chevron, Trilogy, Shell, Talisman, Yoho, Taqa North amongst others. Encana has accumulated a 460,000 acre position in this play. They announced that their two wells produced 2 to 5 MMCFD and 158 to 390 bbl per day respectively. They announced one well with a good liquid rate at 2.4 MMCF/D, 1632 BBL of Cond/D (709 BBL per MMCF).They have accumulated a 460,000 acre position in this play. They have 5 wells planned for the first half of 2012. Their well costs are $12 million with a EUR per well at 3 – 6 BCF and 350 – 600 MBBL over a lateral length: 3,500 – 6,500 feet and at a TVD of 8,300 – 13,000 feet. They are getting 159 to 320 bbl per MMCF. They are planning 20 wells in 2013. They are expecting 50 to 60 ^{o}API condensate. Talisman has drilled and released five wells in to this play and has reported one of the highest liquids ratio from one of them. They spent $510 million in June increasing their footprint to 347,000 acres. Two wells currently producing and expect 4-5 wells on production by end of 2012.

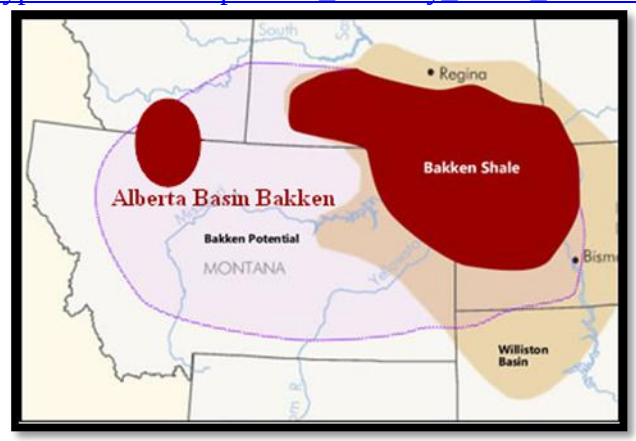
Late Devonian and Early Mississippian Alberta Bakken – Exshaw Southern Alberta

The Alberta Bakken (Exshaw) is another emerging tight oil resource play in SW Alberta to NW Montana consisting of three zones, Big Valley / Steller Carbonates, Bakken /Exshaw dolomitic siltstones and Banff carbonates. 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 late last year, 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, Murphy, Argosy, Nexen, Bowood/Legacy, Rosetta and Newfield are some of the companies involved. Crescent Point Energy has 1,000,000 acres, 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 has 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. See Zaitlin 2011.

http://www.calgaryherald.com/business/DeeThree+raises+Alberta+Bakken/7089513/story.html#ixzz2BIMcQPb3

http://www.primarypetroleum.com/pdf/PIE_Industry_News_2011-03-10.pdf



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. In this province, 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.

There are still no major commercial discoveries and not much news out of Saskatchewan this year as a result of the lower gas price and the economy. There are however around 13 wells in SW Saskatchewan that under production from the Colorado shales. 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. Some players are still operating, but at reduced or no activity. http://www2.canada.com/reginaleaderpost/news/business_agriculture/story.html?id=c41a6b5b-b892-40cc-8cb4-902156681111&k=18412

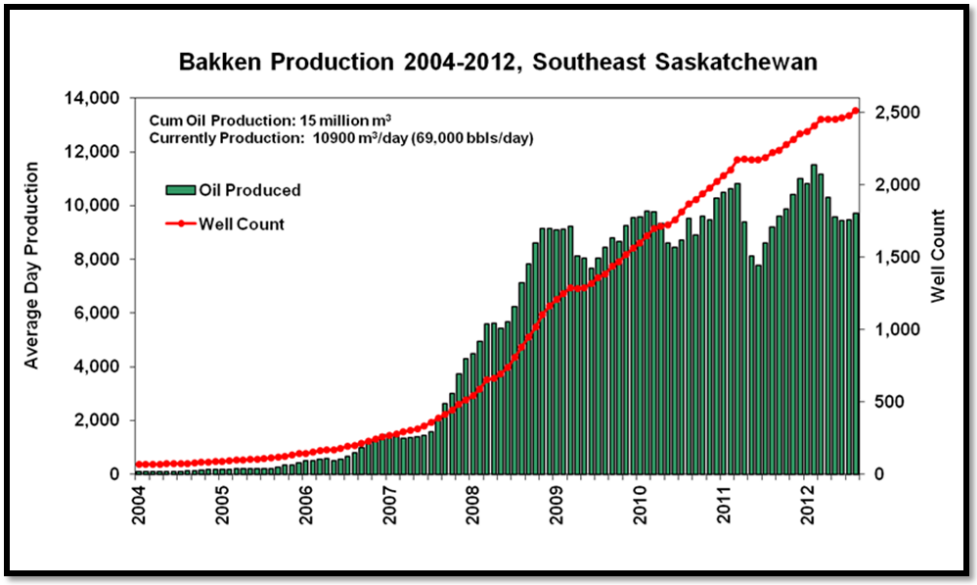
PanTerra Resource Corp. have drilled and cased thirty-six wells within their more than one million acres of land. They feel they have 3 TCF of recoverable gas. They had been coring, logging and fracture stimulating but no rates have been announced to date. Because of the low gas prices they have put 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. Nordic announced recently that survey work has now commenced for a five-well drilling program on the Company's land in Preeceville. Nordic believes that with new drilling technology available, it will be successful in unlocking the enormous reserves of shale and natural gas. After drilling two unsuccessful wells they will be returning in the fall for another well. It is unclear whether this play is unconventional or conventional or both with both gas and oil as their targets.

Recently Questerre announced a Pasquia Hills program. They acquired 100% interest in over 100,000 acres at Crown land sales with a 2-year work program. Situated in one of Canada's largest oil shale deposits with plans of a 2012-2013 work program to include core holes and trenching to assess potential. 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 oil. Drilled 10 wells this winter 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. Ten more wells to be drilled beginning fall 2012 and then integrate core data and develop resource estimate by early 2013. Xtra Energy Corp. announced today that it has entered into a Letter of Intent with two corporations which own a 55% working interest in the Pasquia Hills oil shale permit SHP00008.

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 69,000 BOPD at the end of 2012 with a cumulative production of 15 MM M3 or 94 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 players in this zone. One of the two bigger players are Crescent Point with 704,000 net acres, 3,800 drilling locations, 198 wells to be drilled in 2012 and 4.6 Billion BOIP. They plan to drill 163 wells in 2013. Currently they are producing at 42,000 BPD. PetroBakken is the other one with 275,200 net acres, 979 producing wells, 700 net drilling locations and about 19,000 BPD.



Saskatchewan Government energy and resources is the regulator.
http://www.er.gov.sk.ca/Default.aspx?DN=4c585c56-193a-485a-91fd-7c49f0104a60
http://www.wbpc.ca/assets/File/2011%20Presentations/Tuesday/Nickel%20wbpc%2011%20Bakken%20Talk.pdf

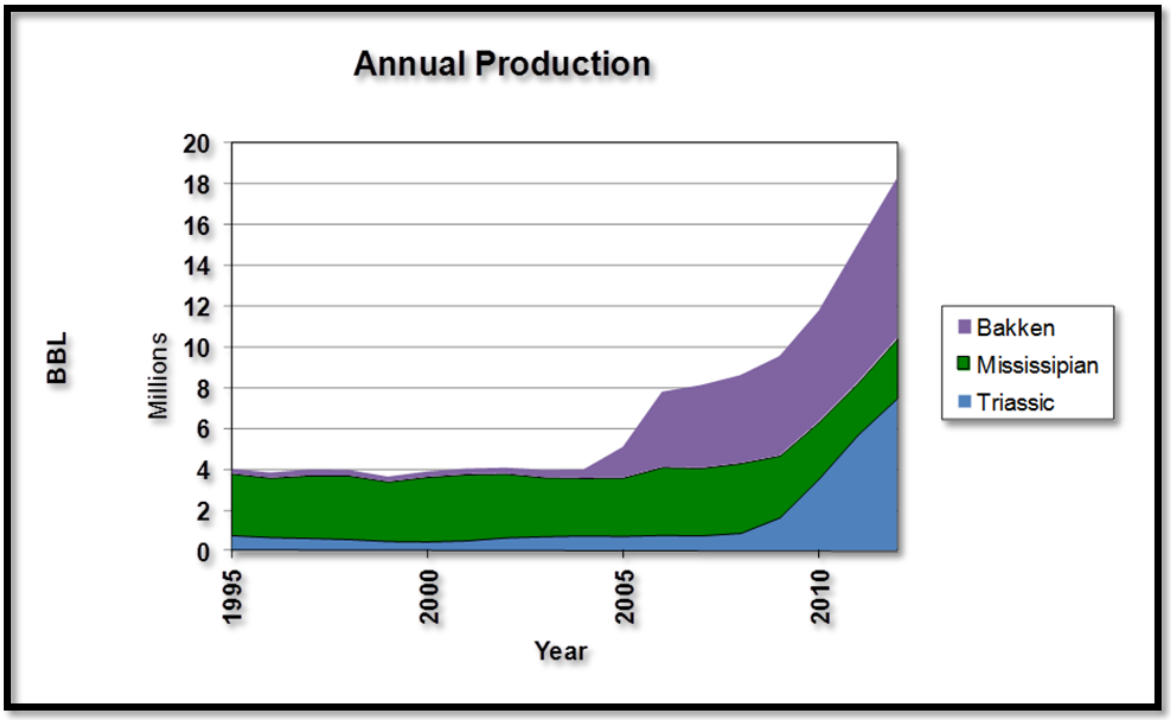
MANITOBA

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 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

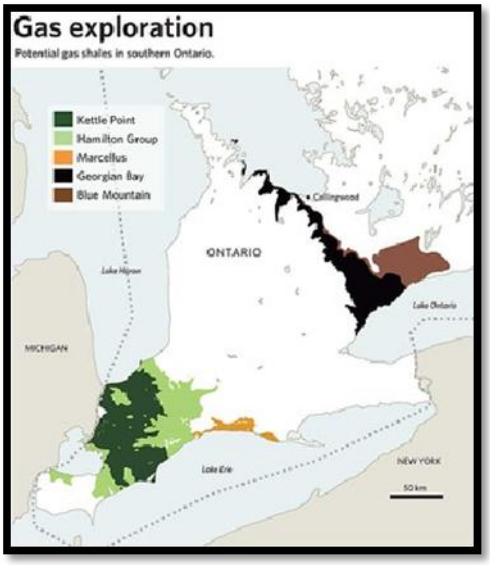
ONTARIO
Upper Devonian Kettle Point Shale (Antrim Shale Equivalent)
Middle Devonian Marcellus Shale
Upper Ordovician Blue Mountain and Collingwood Shale (Utica Equivalent)

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. Mooncor has just locked up about 23,000 acres of shale gas potential.

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.

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. On March 8 2011, the Quebec Provincial Government effectively declared a temporary moratorium on the use of chemical fracturing during shale gas drilling pending a full environment assessment audit http://www.bape.gouv.qc.ca/sections/rapports/publications/bape273.pdf in French only. As well, no new wells will be drilled without local approval. This review conducted by a 11 person committee could take up to 30 months. The government had previously awarded permits for 29 drilling sites where fracking has taken place on 18 locations.

A year ago, when Quebec Environment Minister Pierre Arcand announced the $7-million Strategic Environmental Assessment (SEA) on shale gas, he said it was in part to reassure the public that shale gas development will not go ahead in Quebec unless it is determined to be safe. But a year into that process, opposition remains as fierce as ever. The committee's final report is to be submitted to the government by November 2013. It is now estimated it might be complete in 2014.

http://www.montrealgazette.com/technology/year+later+opposition+shale+exploration+still+fierce/6327547/story.html#ixzz1qkV4IfFA

Less than 24 hours after being sworn in, Quebec's new natural resources minister has shut the door nearly definitively on shale gas exploration and commercialization in the province. http://business.financialpost.com/2012/09/20/quebec-hints-at-long-term-shale-gas-ban-citing-ecological-risks/

As of February 2013 Quebec announced a moratorium on shale gas development in the St. Lawrence Valley until after the above review is complete. Talisman has suspended shale gas exploration here. 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. 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

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

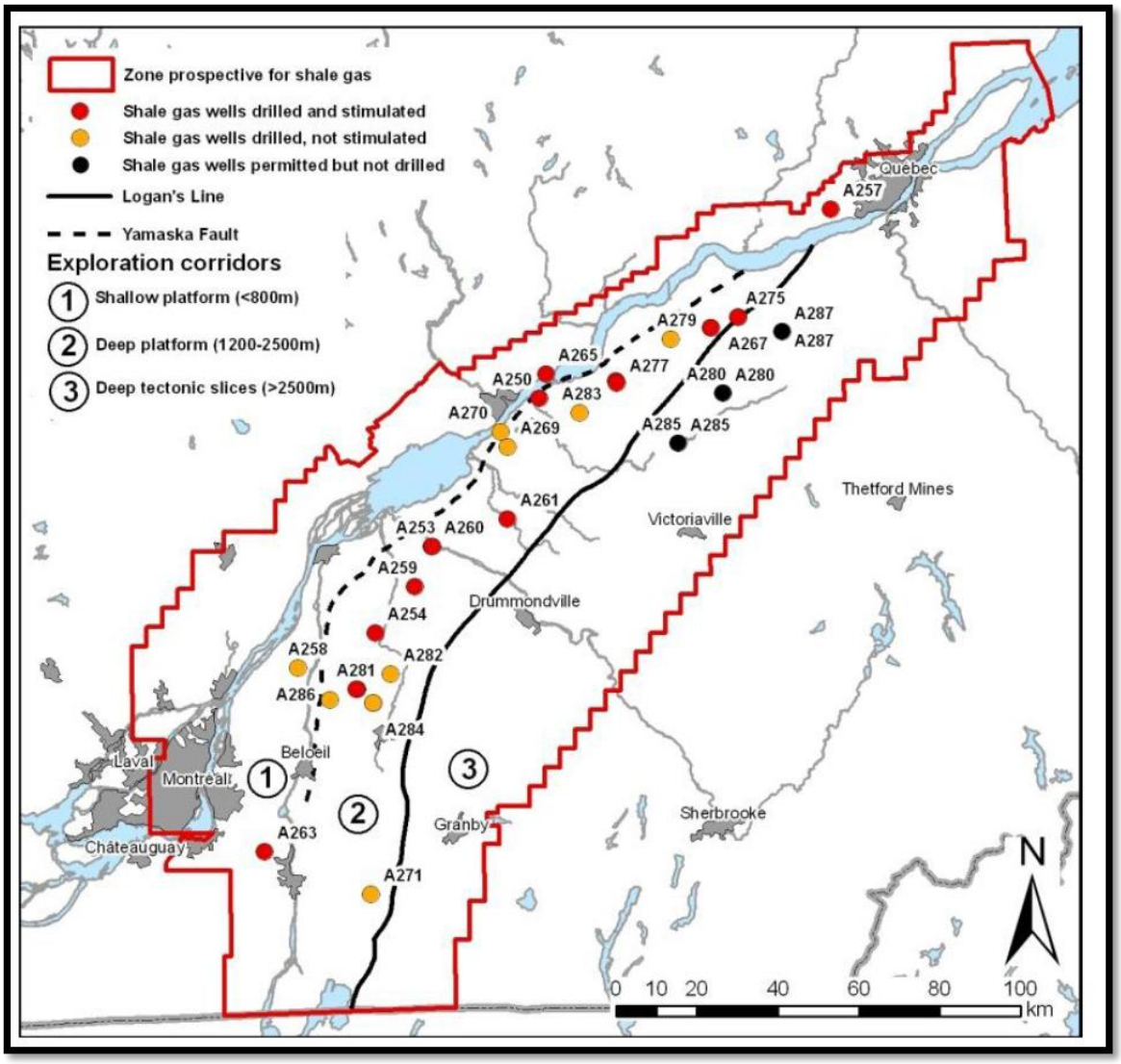
Utica Emerges in Quebec Shale Play Extends to Canada by Susan Eaton
http://www.aapg.org/explorer/2010/01jan/shale0110.cfm

Shale gas plays in the province's St. Lawrence Lowlands enjoy another advantage in being close to the northeast U.S. gas market. The *Association pétrolière et gazière du Québec (*Quebec Oil and Gas Association) APGQ/QOGA membership : Altai Resources Inc., Canadian Forest Oil, Canadian Quantum, Canbriam, Dessau (Associate member), Gastem, Intragaz, Junex, Molopo, Questerre, Roche (Associate member), SNC-Lavalin (Associate member) and Talisman Energy Inc.

Quebec Shale Conference 2010 and 2009
http://www.apgq-qoga.com/en/
http://www.apgq-qoga.com/en/2011/07/20/qoga-annual-conference/
http://www.apgq-qoga.com/wp-content/uploads/2012/09/Programme-APGQ-2012-HR.pdf

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

The Lower Mississippian Fredrick Brook Shale in the Moncton Basin has 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 fracing 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 are 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. The Province of New Brunswick has recently issued recommendations for new proposed environmental requirements which allow for the exploration and development of oil and gas in New Brunswick. Corridor is working with the government and other stakeholders to ensure best practices are followed and oil and gas activities can be completed in a safe and responsible manner. Details of their play can be found at

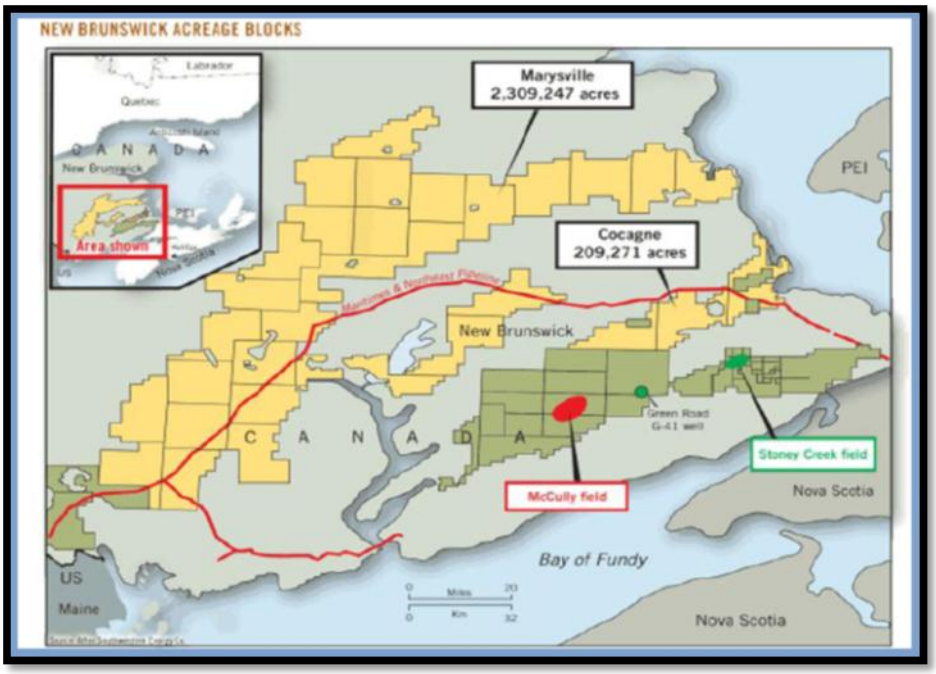
http://www.corridor.ca/documents/CorridorOverviewMemorandumUpdateFB.pdf

Contact Exploration and PetroWorth Resources are 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). In consultation with the New Brunswick Department of Natural Resources and other key government officials, SWN Resources Canada will defer there planned 2012 exploration program until 2013 to provide additional time for public engagement and completion of the permitting process. Just recently they have applied to the government for a one year extension on their permits with the plans for a further 130 miles of 2D seismic with the plans of future drilling.

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.

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

As announced by Pieridae, 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.



"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
Update on Fracking
Energy and Mines Minister Craig Leonard is promising to review two new reports on the shale gas industry before the provincial government acts on any of their recommendations.
http://www2.gnb.ca/content/dam/gnb/Corporate/pdf/ShaleGas/en/ExecSummary.pdf

In February 2013, New Brunswick released their new rules for industry by pushed ahead with dozens of new regulations governing shale gas exploration. In bringing forward 97 new rules that will cover the oil and gas industry's practices, the government said it's striking a balance between environmental protection and the economic potential that fracking for shale gas represents.

http://www2.gnb.ca/content/dam/gnb/Corporate/pdf/ShaleGas/en/RulesforIndustry.pdf

NOVA SCOTIA

Upper Devonian/Lower Mississippian Horton Bluff

Kennetcook Basin

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.

The Government is appointing an internal committee of officials from the Departments of Energy and Environment to examine the environmental issues associated with hydraulic fracturing in

shale gas formations and make recommendations on any additional required regulatory measures was to be finished in early 2012 but now has been extended to 2014.
http://www.gov.ns.ca/nse/pollutionprevention/docs/Hydraulic.Fracturing.Web.Update-2012.07.pdf
http://www.cbc.ca/news/canada/nova-scotia/story/2012/04/17/ns-fracking-decision-delay.html

There are currently no applications for hydraulic fracturing of shales in Nova Scotia and none are anticipated soon until this review is complete. 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), working closely with industry, has recently undertaken the task of trying to understand the resource potential. GIP or "size of the prize" is determined by the shales' gas generating potential, the mineralogy which may dictate the fracing techniques and lead into the engineering solutions that need to be achieved through the drilling and piloting phase to reach commercial producabilty. Good seismic coverage (2-D and 3-D data) and well control is available to help define the shale's reservoir quality or "sweet-spots". Seismic interpretation linked to well data has given an understanding of the depositional system and structural evolution of the basin which then can be linked to predicted production variability. To date five wells have been drilled and two successful wells have shown volumes of gas to surface post completion and stimulation. The analogous shale reservoirs to the north (in New Brunswick) are currently in the evaluation pilot phase for scalable production by Apache Canada and attractive tight sands within the same formation are producing at approximately 25 mmcf/day through vertical wellbore at the McCully gas field.

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 1000 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 reentry of the previous well bore, sidetracking and testing. These plans were unsuccessful and discontinued because of severe formation damage. The company has recently locked up contiguous blocks of land of about 720,00 acres to the north stretching more than 160 km. Just recently Black Spruce Exploration made an agreement to drill up to 12 wells in this play over the entire length of this play.
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/

TERRITORIES

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 which stretches across Montana, North Dakota, Saskatchewan and Manitoba. 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://www.calgaryherald.com/Northwest+Territories+play+Bakken/6955053/story.html#ixzz2BHTUev77

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

MGM in partnership with Shell, who farmed in, were the first to announce the results of drilling into 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. 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. They plan to test them this year. They have built an all weather road into the drill site. Meanwhile, ConocoPhillips drilled two wells on its lone license in the Canol shale this winter and is planning to drill two horizontal wells in the winter of 2013-2014.
http://www.albertaoilmagazine.com/2013/03/mgm-energy-releases-underwhelming-results-for-canol-shale-well/

The Enbridge Norman Wells to Alberta pipeline runs through the area flowing 40,000 barrels of oil per day. The Norman Wells oil field discovered in the 1920s, has been in decline for decade and the pipeline is running at 33% capacity.

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

Currently, the Yukon Geological Survey is 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, Eflow Energy and partners are planning to exploit the Devonian/Mississippian shales near the Kotaneelee conventional field which has declining production. A sales gas pipeline exists to Ft. Nelson.

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/about/organization/organization-structure/geological-survey-of-canada/9590
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
October 9 & 10, 2013 Calgary TELUS Convention Centre
120 - 9th Avenue SE, Calgary
Note that they have technical luncheons for members.
http://www.csur.com/events/technical-conference
Canadian Society of Petroleum Geologists (CSPG)
Note the CSPG has technical luncheons throughout the year.
http://www.cspg.org/
GeoConvention 2013: Integration: Calgary TELUS Convention Centre, May 6 – 10, 2013
http://www.geoconvention.com/
CSPG Courses
http://www.cspg.org/CSPG/Education/Education_Week/CSPG/ConEd/Courses_By_Event.aspx?hkey=aa56013f-7c87-4cfd-af15-8aa5c9cece60

Other Meetings

CI Energy Group's 9th Annual Shale Oil and Gas Symposium, Jan 29-30 2013 Hyatt Regency Hotel Calgary, Alberta

http://www.shalegassymposium.com/

Unconventional Gas Technical Forum – Victoria, B.C.

The Ministry of Energy and Mines, in collaboration with the B.C. Oil and Gas Commission, is proud to host the 6th B.C. Unconventional Gas Technical Forum on April 2–3, 2012 at the Victoria Conference Centre http://www.empr.gov.bc.ca/OG/oilandgas/petroleumgeology/UnconventionalGas/Pages/default.aspx

7th B.C Unconventional Gas Technical Forum, June 17 and 18, 2013 at the Victoria Conference Centre in Victoria.

Canadian Business Conferences – 3rd Annual Tight Oil Canada 2013 June 24 to 26, 2013, Calgary http://www.tight-oil-canada-2013.com/

Exploration, Mining and Petroleum New Brunswick 2013, Delta Hotel Fredericton, November 3 to 5. http://www.gnb.ca/0078/minerals/Exmin_Home-e.aspx

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Adams, C., 2012, Summary of shale gas activity in northeast British Columbia 2011: BC Ministry of Energy and Mines, pages 1-19. http://www.empr.gov.bc.ca/Mining/Geoscience/PublicationsCatalogue/OilGas/OGReports/Documents/2012/Summary%20of%20Shale%20Gas%20Activity%20in%20NEBC%202011%20Web.pdf

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

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Beaton, A.P., Pawlowicz, J.G., Anderson, S.D.A., Berhane, H. and Rokosh, C.D. (2010): Organic petrography of the Duvernay and Muskwa formations in Alberta: shale gas data release; Energy Resources Conservation Board, ERCB/AGS Open File Report 2010-06, 147 p. http://www.ags.gov.ab.ca/publications/OFR/PDF/OFR_2010_06.PDF

Béland Otis, Catherine, Carter, Terry and Fortner, Lee, 2011, Preliminary Results of a Shale Gas Assessment Project in Ontario, Canada: Search and Discovery Article #50390

Béland Otis, C. 2012, Preliminary results: potential Ordovician shale gas units in southern Ontario; in Summary of Field Work and Other Activities 2012, Ontario Geological Survey, Open File Report 6280, p.29-1 to 29-12. http://www.geologyontario.mndm.gov.on.ca/mndmfiles/pub/data/imaging/ofr6280//OFR6280.pdf

Carter, Fortner and Béland-Otis, 2009, Ordovician and Devonian Black Shales and Shale Gas in Southwestern Ontario, Canada. http://www.ogsrlibrary.com/downloads/Ontario_Shale_Gas_OPI_2009_Nov11.pdf

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Chalmers G.R.L and Bustin R.M., 2012, Light volatile liquid and gas shale reservoir potential of the Cretaceous Shaftesbury Formation in northeastern British Columbia, Canada: AAPG Bulletin, v. 96, no. 7, pp. 1333–1367.

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Shale Gas/Shale Oil in Europe

By Ken Chew

1. Summary of the five months November 2012 – March 2013

Europe remains relatively unexplored for shale gas and, especially, shale liquids. In total some 77 shale gas specific exploration and appraisal wells have been drilled, including horizontal legs from vertical wells. Twelve (12) of these wells were shallow biogenic gas tests drilled by mineral exploration equipment. Significant exploration activity since November 2012 has been limited to Poland, where 5 shale gas exploration wells were spudded. Two shale oil exploration wells were also spudded in Poland. The five months from November 2012 have once again seen more action in the political / environmental sphere than in exploration activity. There has, however, been a subtle shift in opinion. At grassroots level, opposition to hydraulic fracturing and shale oil and gas exploration in general remains strong. But at a European and national political level, one can detect a desire to permit and even encourage exploration.

Partly this is because technical experts have challenged the reports of environmental authorities and partly because of a desire for more energy independence. But a number of 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.

Moratoria on some or all aspects of shale gas exploration and production remain in place in Bulgaria, Czech Republic, France and Netherlands, plus certain administrative regions in Germany, Spain and Switzerland, while proposed new environmental legislation has led OMV to abandon its plans for shale gas exploration in Austria. The moratorium in Romania has been terminated.

The decision by ExxonMobil to withdraw from its six licences in Poland, considered to be the most prospective European country for shale gas, has also had the effect of downgrading expectations in some quarters. Talisman ahs also announced that it is evaluating its options in Poland.

2. 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 five countries, with most wells being drilled from 2010 onwards. As a consequence, little is known about Europe's ultimate potential.

<u>Resources</u>

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 10 countries (excluding Ukraine) at 2,390 Tcf with a combined technically recoverable resource of 582 Tcf (U.S. EIA, 2011). Nevertheless, 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.

Sweden.

To give three examples which indicate the caution that must be exercised when using the data, the EIA report provides an estimated technically recoverable resource of 41 Tcf for Sweden's Alum Shale, which Shell's recent three wells found to have a very limited content of natural gas which it was not possible to produce.

Poland.

A second noteworthy example is in Poland where the EIA report estimated the risked technically-recoverable resource for the combined Baltic Depression, Danish-Polish Marginal Trough and East European Platform Margin at 187 Tcf while a study published in March 2012 by the Polish Geological Survey, in conjunction with the USGS, placed estimated recoverable resources in the range 12 – 27 Tcf. In July 2012 the USGS published its own estimate of technically-recoverable resources which it placed in the range 0 – 4 Tcf with a mean estimate of 1.35 Tcf. In the face of such disparities, today's estimates for undrilled or virtually undrilled provinces are effectively meaningless. The Polish Geological Institute will not produce a new estimate until it can incorporate results from horizontal wells. This revision is not expected before 2014 at the earliest.

United Kingdom.

By way of contrast, the Midland Valley of Scotland, where Europe's first certification of recoverable shale gas resources has taken place, is considered by the EIA report to be non-prospective. 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. The BGS is scheduled to produce a revised estimate for the Bowland Shale in the Craven Basin during 2013.

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.

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.

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. 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).

Given the potential size of the in-place resource it is not surprising that investigations have been proposed in at least sixteen countries. Company interest extends from super-majors, such as ExxonMobil and Shell, through majors (Chevron; ConocoPhillips; Eni; Total) and major independents (e.g. Marathon; 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).

2.1 Major shale gas plays in Europe

There are three potentially major regional shale gas plays in Europe plus a number of others with more restricted distribution.

2.1.1 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. 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.

BasGas (now Hutton Energy) has 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. The remaining Lower Paleozoic plays occur on or adjacent to the Baltica terrane. 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. 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, 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. Total and Nordsøfonden will now review the City Council's decision.

Sweden.

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 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). 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 Östergötland, 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. The Alum Shale at this location occurs at shallow depth and is thermally immature but the 50'-80' thick shale has high TOC contents of up to 20%. It is therefore considered to be an analogue 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. Gas flows are known from water wells and seeps in the area and flow rates 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 processing concession, valid until 2033.

Four companies own a total of 20 licences in the Östergötland Lower Paleozoic Basin. In April 2012, Gripen Gas, the largest licence holder, 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. Gripen 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 and it is expected that a first shale gas exploration well will be drilled in the latter half of 2013 or early 2014. Further north, AB Igrene has 18 concessions with Alum 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. Gripen Gas also has five (5) concessions in the Baltic Depression on the island of Öland.

Poland.

Further to the southeast, in Poland, the main Lower Paleozoic target is Silurian-age graptolitic shale, with the Upper Cambrian to Upper Ordovician a secondary target. 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. To date, this play has been the most sought after in Europe. Some 36 concessions have been awarded in the Baltic Depression, of which 7, operated by LOTOS Petrobaltic, are offshore in the Baltic Sea and 29 lie onshore in the Gdansk Depression. Six of the most easterly concessions, such as the four held by Wisent Oil & Gas, are considered to be more prospective for shale liquids than for shale gas. Another 40 concessions have been awarded in the Danish-Polish Marginal Trough and 15 on the East European Platform Margin, northeast of the Marginal Trough. Three of these awards (1 – Marginal Trough; 2- Platform Margin) have since been relinquished by ExxonMobil.

Baltic Depression.

Thirteen different companies are active in the onshore Gdansk Depression including Conoco, Eni and Talisman plus a number of small niche players and the Polish state company, PGNiG. 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, Lebien LE-1 (Lębork concession) and Legowo LE-1 (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. A 3,300' horizontal leg drilled in a second Lebien 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 2011 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 subsequent test in early November 2012 flowed at rates of up to 780 mscf/d, averaging 550 mscf/d. 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 new Cambrian prospective interval which was then redrilled with a 1,650' horizontal leg (12,610' MD) because of hole stability issues. A 7-stage gel frac test was suspended after 5 days during which flow declined from 60-90 mscfd to 18 mscfd. On retest in summer 2012 the well produced at a rate of 90 mscfd after 20 days of flow. Lane's initial seismic and drilling programme on its six Gdansk Depression concessions has been funded by ConocoPhillips (see *4.3 Ownership Transactions: Farm-ins*). 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 and preparations are now under way to stimulate the Cambrian section. 2-3 vertical wells are planned on the Lane – Conoco acreage in 2013. 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 the table 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)

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. 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 is now awaited. 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.

San Leon has announced a proposed pilot development programme for the Gdansk West concession. 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. It is unclear, however, on what basis this project will proceed as Talisman has announced that it is currently evaluating its options in Poland.

A promising gas flow was also reported by PGNiG from a single-stage frac test of the Silurian / Ordovician at 9,500' 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. A second test was subsequently conducted at 9,200'. A horizontal well (Lubocino-2H) was spudded in August 2012. Fracture testing was coming to an end in March 2013. The company plans to drill Lubocino-3H in 2013. PGNiG also spudded a vertical well, Opalino-2, in the same concession in September 2012, with a targeted depth of 10,000'. Gas flows were reported from the Cambrian at around that depth. PGNiG has indicated that it may start production from the area in 2014. In March 2013 the company spudded Wysin-1, its first well on the Stara Kiszewa concession, some 20 miles southeast of Gdansk. 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. A further three wells are planned in this exploration campaign. San Leon / Hutton plan a vertical well on the South Prabuty concession in 2013. An interesting feature revealed by sampling and gas shows from the three Lane Energy, three Saponis and two San Leon / Talisman well locations 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, and a vertical frac test is planned from this sandstone in Q4 2013 with four horizontal wells to follow if successful.

Danish-Polish Marginal Trough & East European Platform Margin.

There are 52 currently valid concessions covering the Platform Margin and Marginal Trough, the most prominent participants being Chevron, Marathon, Polish state company PGNiG, and PKN Orlen, another Polish company. 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 has 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 and drill a further well, while relinquishing the other. Despite the disappointing results from the ExxonMobil wells, the East European Platform Margin and Danish-Polish Marginal Trough are still the focus of current drilling activity, with 4 wells spudded in the past five months. 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 10-stage fracture operation and production test is scheduled for April 2013. 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 will be frac tested after Syczn-OU2K. In July 2012, Orlen spudded the first well to be drilled in the Warsaw Trough of the Danish-Polish Marginal Trough. Goździk-OU1 in the Garwolin concession had a target depth of approximately 13,000'. Chevron also commenced its Lublin Trough programme in Q4-2011 with a well in the Grabowiec concession at Lesniowice, spudded on 31st October. 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.

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. Two or three wells will now be selected for hydraulic fracturing.

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 has reported that a 1,650' horizontal leg was drilled in this well. 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.

Dart Energy has published a "best estimate" of 9.485 Tcf in place in its Milejow concession, where a seismic programme was carried out in Q3 2011. As part of its restructuring, Dart is looking to joint-venture, farm out or sell its Polish asset.

General

The Polish Treasury Ministry is said to be targeting commercial production from at least one pad by late 2014 or early 2015. It is assumed that the initial production of 20 – 30 million cf/d will come from the Lower Paleozoic play. PGNiG has indicated that it would like to provide local supply from its Lubocino well in the second half of 2012.

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. In May 2012 local oil producer Minijos Nafta spudded a Cambrian sandstone oil exploration well, Skomantai-1, on its existing acreage which was also intended to test the Ordovician and Silurian shales for unconventional hydrocarbons. Core samples have been sent abroad for analysis with results expected at end 2012 or early in 2013. Chevron plans 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 has been delayed until Parliament amends laws to strengthen environmental regulations – expected in May 2013.

Romania.

Chevron has acquired a concession (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. Prior to the introduction of a shale gas drilling moratorium, the first well in a multi-well drilling programme had been planned for late 2012. Following the expiry of the moratorium, Chevron is moving ahead with seismic exploration and the permitting required for drilling.

2.1.2 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 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.

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. Some of BNK Petroleum's eight concessions are also targeting Carboniferous shale gas, as are Wintershall's Rhineland and Ruhr concessions and Dart Energy's Saxon I West and Saxon II concessions. Dart reports 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. As part of its restructuring, Dart is looking to joint-venture, farm out or sell its German assets. BNK has announced that it intends to relinquish five of its eight German concessions, retaining the three concessions (Adler; Falke; Falke South) in North Rhine – Westphalia's Munsterland Basin, which appear to have primarily Carboniferous potential.

Ireland (Republic of Ireland & Northern Ireland).

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 levels of thermal maturity so the issue here may be whether it is over-mature for gas but 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. 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.

Netherlands.

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 2014 as a result of permitting delays and the need to await an independent study (scheduled for mid-2013)

commissioned by the Dutch Ministry of Economic Affairs, Innovation and Agriculture on the risks associated with unconventional gas drilling and production.

Poland.

Lane Energy, the 3Legs Resources subsidiary, has interests in the Fore-Sudetic Monocline in southwest Poland but unlike the Gdansk area, this activity is not funded by ConocoPhillips. On 6th August 2012 Lane announced that it will relinquish one of its three concessions (Dabie-Laski). It is seeking to monetise its other two concessions in the area so as to focus on the Baltic Basin. San Leon has also acquired some concessions covering this play, as have PKN Orlen, Silurian Sp. (Petrolinvest.S.A.), Strzelecki Energia (Hutton Energy) and Eco Energy. Although all 18 of the remaining valid Fore-Sudetic Monocline concessions are considered to have some shale gas prospectivity, some are also being investigated for their conventional oil and gas prospects.

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. 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'. In the first instance, testing will focus on the deeper of the tight sandstone intervals. 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 will perform a DFIT on Siciny-2 in May 2013 followed by a two-stage vertical frac in early June. Subject to the execution of a further binding agreement, completion of the DFIT and hydraulic fracturing phase shall give Halliburton the option to earn up to a 25% working interest in the Carboniferous and deeper sections within the Concessions by fully funding two vertical exploration wells, including full technical evaluation with core, DFIT, and vertical hydraulic fracturing if technically warranted.

United Kingdom.

England.

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 Mississippian to Lower Pennsylvanian) 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.

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'. The rig then moved to a third location in the area, which represented a substantial step-out from the locations of the first two wells. Becconsall-1, 15 km south of Preese Hall-1, spudded on 16th August 2011. 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'. 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 is 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. A full Environmental Impact Assessment will also be conducted. Cuadrilla is also installing surface seismic monitoring equipment at 156 locations surrounding the Anna's Road site. 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 is 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. 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%. Porosity ranges from 1 – 6% and silica / carbonate content is high with less than 50% clay.

On 4th November 2011, IGas Energy spudded a joint coal seam gas / shale gas exploration well in the Rossendale Basin (Cheshire Basin) on PEDL 190 south of the River Mersey opposite Liverpool. The 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. 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. 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 is one of the companies rumoured to have been in discussions with IGas. Dart Energy has 11 licences in the Cheshire and Stafford basins. Netherlands Sewell & Associates (NSAI) has 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 Sub-basin, where it is a known source rock for oil and gas. By September 2014 eCorp is scheduled to drill one vertical well in the Gainsborough Trough area to test the Bowland Shale and to a depth of 14,750', or to sufficient depth to test the Dinantian shale. Dart Energy has bought into this acreage through its acquisition of Greenpark Energy's unconventional gas assets (see *4.2 Licence Acquisitions: United Kingdom*). In total, Dart's (NSAI) best estimate of Original Gas in Place for 7 of its 13 licences east of the Pennines is 32.4 Tcf net to Dart (47.6 Tcf gross). On PEDL 252 on the southern margin of the Wales – Brabant High near Woodnesborough in Kent (north of the Kent Coalfield), Coastal Oil & Gas 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 has identified 1.14 Tcf of 2P contingent resources of gas in place in the Bowland Shale equivalent on its acreage in North Wales. 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. In August / September 2011, U.K. Methane (a company with similar management to Coastal Oil & Gas) 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 indicates 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 are estimated to contain 3.6 Tcf gas in place with a gross resource of 0.5 Tcf. Dart Energy owns 100% of the Namurian prospect but BG retains a 51% interest in the Visean prospect. Shale gas exploration of PEDL 133 is still at an early stage while the company focuses on the start-up of coal seam gas production from the licence.

United Kingdom - General.

In October 2012 it was announced that the DECC has commissioned the BGS to provide a better estimate of the Bowland Shale resource. Study of the prospectivity of other shales will be considered after this report is published (estimated publication date towards end 2012).

On 30th October 2012 an Energy minister said that he had requested more information from Cuadrilla regarding its proposed management processes for fracking operations. Once the response has been received and appropriate regulation is in place to ensure the safe conduct of exploitation operations, the minister will look at a timetable for a new UK shale gas licensing round.

2.1.3 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 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 exploratory tests of the Lower Jurassic play have taken place in Germany where ExxonMobil drilled wells between 2008 and 2011.

Germany.

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 3,600' horizontal leg (Z14b) within the Posidonia Shale from well Z14 in the Bahrenborstel Upper Permian Zechstein carbonate sour gas field. The well may be drilled in 2013. BNK Petroleum (eight concessions) and Realm Energy, a wholly-owned subsidiary of San Leon (one concession) have also announced the Posidonia Shale as a target. BNK has announced that it intends to relinquish five of its eight German concessions, retaining only the three concessions (Adler; Falke; Falke South) in North Rhine – Westphalia's Munsterland Basin where the Posidonia Shale is a possible target.

2.1.4 Other plays with shale gas potential

Austria.

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. 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.

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 Landguedoc-Provence Basin, one of which also incorporated part of the Lodève Basin. Total was awarded the Montélimar permit. The Schuepbach and Total permits have since been cancelled (see *5. Above-ground issues: France*). A number of other companies have also applied for permits in Languedoc-Provence, many of them overlapping. Realm (San Leon) has identified Stephanian-Autunian potential in the Bresse-Valence Basin, where it has 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. 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. In the Bodensee Trough, north of the Swiss-German border, Parkyn Energy, another 3Legs Resources subsidiary, has taken out two licences in which the principal prospect appears to be lacustrine shale of Permian age. The company has applied for extensions to these licences but is investigating options to monetise them as its focus is the Baltic Basin in Poland.

Hungary.

The shale gas exploration situation in Hungary is unclear. 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 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. 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 cfg/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 should commence before end-2011. Cuadrilla has 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.

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. 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.

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 have 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 are believed to be shale of Silurian to Lower Devonian age (Tandarei Formation) and Middle Jurassic age (Bals Formation). Sterling Resources / Transatlantic Petroleum are reprocessing 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. 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. A moratorium was imposed on shale gas exploration in May 2012 but that has now been lifted. Chevron is proceeding with seismic exploration and acquiring the necessary authorisations for drilling.

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 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 has submitted five Environmental Impact Assessments on its Sedano and Urraca concessions as part of the exploratory drilling permitting process and plans to drill in Q1 2014, pending permitting. In the Ebro Basin, San Leon's six pending awards are primarily targeting organic-rich Paleozoic shales (Ordovocian; Silurian; Carboniferous) but Eocene shale is also a target.

Switzerland.

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.

2.2 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.

3. 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'. Toreador Resources (now ZaZa Energy Corp.) has 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 will 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 has scheduled a three (3) vertical well drilling program for 2013 but it is unclear whether this will test the Liassic play.

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*).

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. 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.

Germany.

Outcrop work by BNK Petroleum has 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 acreage the Posidonia Shale will fall within the oil window and have potential for tight shale oil. BNK has announced that it intends to relinquish five of its eight German concessions, retaining only the three concessions (Adler; Falke; Falke South) in North Rhine – Westphalia's Munsterland Basin, where the Posidonia Shale is a possible target.

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 Mcfg/d declined to 63 bo/d and 137 Mcfg/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.

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 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 but after data analysis it was decided not to conduct the planned frac test. Wisent then spudded Babiak-1 on the Lidzbark Warmiński concession in March. Planned TD is 7,875' and after logging a horizontal sidetrack is planned with subsequent frac testing. 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 considers 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.

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 in Q2 2013.

United Kingdom.

Cuadrilla Resources plans to investigate 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 1,800' at this location. 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.

4. 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.

4.1 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. Eden Energy Ltd. has spun out Eden Energy (UK) into a new entity, Adamo Energy (UK) Ltd. Adamo has an unrisked (P90) gross shale gas in place resource of 34.2 Tcf (17.1 Tcf net to Adamo) in 7 licences in South Wales. 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.

4.2 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.

4.3 Farm-ins

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 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.

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 is understood that Chevron's primary interest in the licence is in shale exploration.

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 to be divested into a separate Polish legal entity, which would be a wholly-owned subsidiary of 3Legs Resources. ConocoPhillips has opted not to acquire a 70% interest in the three eastern concessions. 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 is currently evaluating its options in Poland. 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 remains operator. The one concession excluded from the farm-outs is 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 will acquire a 49% interest while ExxonMobil retains 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 has indicated that it will become 100% owner and operator of the Chelm concession on the East European Platform Margin. ExxonMobil previously held 51% of the concession and was operator. Unconfirmed reports suggested that Polish independent PKN Orlen was at one time in discussions with Encana with a view to exchanging an interest in some of Encana's North American shale gas acreage for access to PKN Orlen's Polish shale gas concessions. Orlen has seven shale gas concessions in Poland plus one with tight gas potential. It has also been reported that Italian major Eni was considering taking an interest in LOTOS Petrobaltic's seven offshore shale gas concessions.

4.4 Relinquishments

Poland.

After the transfer of two concessions to PKN Orlen and surrendering its 51% interest in another to its partner, Total SA, ExxonMobil has relinquished its other three Polish concessions, one in the Danish-Polish Marginal Trough and two on the East European Platform Margin. Lane Energy (3Legs Resources) has relinquished one concession in the Fore-Sudetic Monocline but retains another two in the basin. BNK Petroleum has announced that it intends to relinquish five of its eight German concessions, retaining the three concessions in North Rhine – Westphalia's Munsterland Basin. Some of the licences to be surrendered contained primarily conventional prospects.

5. Above-ground issues

There are a number of issues that face most gas 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 and Germany. 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.

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.

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 Commission 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 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

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 announced a moratorium on shale gas exploration in the Czech Republic until 30th June 2014.

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 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.

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 allow hydraulic fracturing to resume, subject to strict controls (e.g. limited to areas where water resources will not be impacted). 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.

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 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 has commissioned an independent study (scheduled for completion in July 2013) 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. Until the outcome of this study is known, no drilling for shale gas is allowed and no further exploration licences for unconventional gas will be awarded by the Ministry.

At the beginning of April 2013 it was reported that 33 of some 400 local authorities had declared their opposition to shale gas production.

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 Economis*t 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 is expected that new regulations on shale gas extraction will 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 will form a part of the new regulatory environment. Companies will 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.

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.

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 the United Kingdom and

some examples are given below. 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. 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.

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 has 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.

Background comment. 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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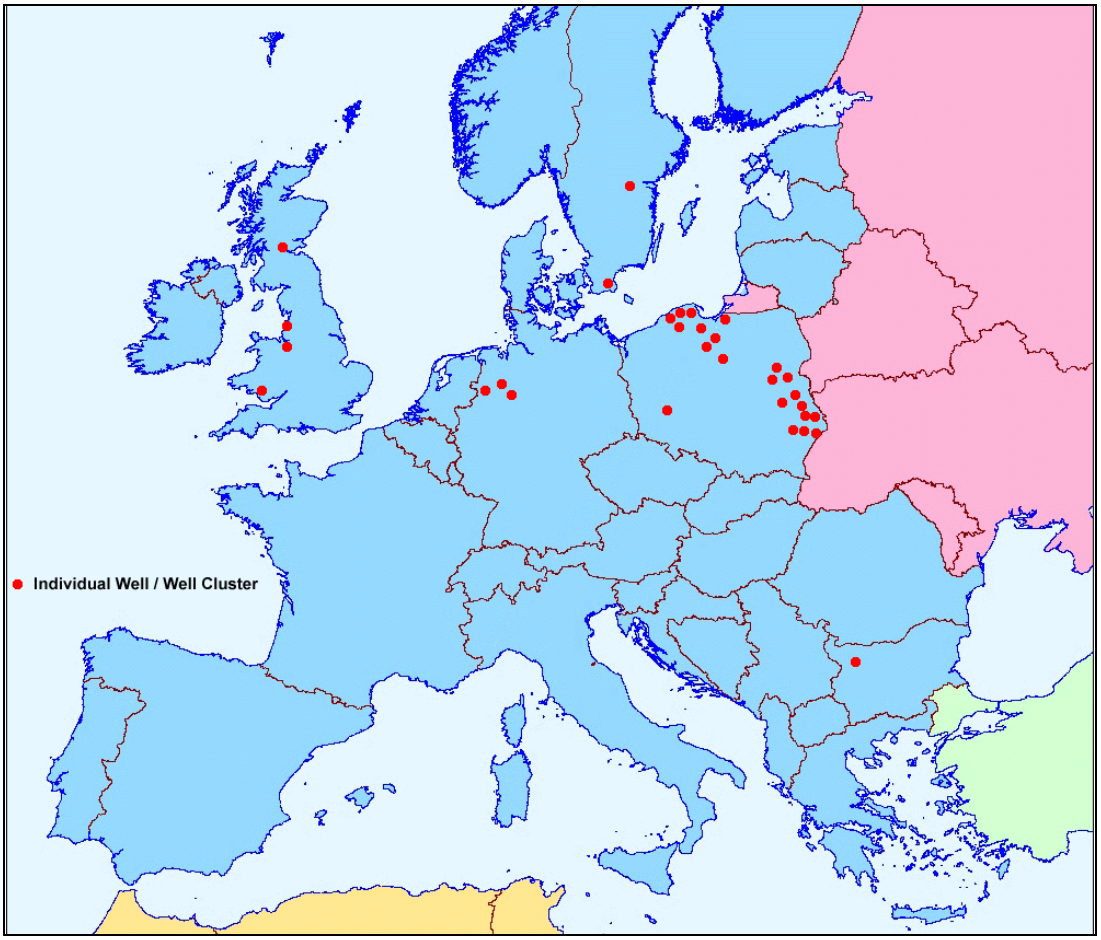
Appendix 1

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
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		5,280		3	Wealden	
Northw est German Basin	Low er Saxony Basin	Minden	Oppenw ehe	1	ExxonMobil	Jun-08		8,730			Wealden, Posidonia	
Northw est German Basin	Low er Saxony Basin	Schaumberg	Niedernw öhren	1	ExxonMobil	2009		3,394			Wealden	
Northw est German Basin	Low er Saxony Basin	Scholen-Barenburg II	Schlahe	1	ExxonMobil	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	Slaw no	Wytow no	S1	Saponis Investments	Dec-10	14-Feb-11	11,750			Low Paleozoic	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	gas show s: C1 - C3
Baltic Depression	Gdansk Depression	Starogard	Starogard	S1	Saponis Investments	16-Jul-11	Sep-11	11,560			Low Paleozoic	gas show s: C1 - C5
Baltic Depression	Gdansk Depression	Lebork	Łebień	LE-1	Lane Energy (3Legs)	Mid Jun-10	28-Jul @ TD	10,120		1; DFIT	Low Paleozoic	gas
Baltic Depression	Gdansk Depression	Lebork	Łebień	LE-2H	Lane Energy (3Legs)	10-May-11	Jun-11		Y	13	Low Paleozoic	gas show s
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	Lebork	Strzeszew o	LE-1	Lane Energy (3Legs)	04-Oct-12	Early Dec-12	10,040			Low Paleozoic	
Baltic Depression	Gdansk Depression	Gdansk-W	Lew ino	1G-2	Talisman Energy Polska	26-Sep-11	17-Nov-11	11,800			Low Paleozoic	C1+ small C2-C5
Baltic Depression	Gdansk Depression	Braniew o	Rogity	1	Talisman Energy Polska	12-Dec-11	14-Feb-12	9,147			Low Paleozoic	C1-nC8
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				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	11,500		2	Low Paleozoic	promising gas flow . No H2S and low N2. Heavier hydrocarbons
Baltic Depression	Gdansk Depression	Wejherow o	Lubocino	2H	PGNiG	Aug-12	Nov-12		Y	Y	Low Paleozoic	
Baltic Depression	Gdansk Depression	Wejherow o	Opalino	2	PGNiG	Sep-12	Dec-12				Low Paleozoic	flow ed gas
Baltic Depression	Gdansk Depression	Stara Kiszew a	Wysin	1		Mar-13						
Baltic Depression	Gdansk Depression	Wejherow o	Kochanow o	1	PGNiG							

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. Either number indicates China's shale resource is comparable with US's 862 TCF recoverable shale gas resource.

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).

China has investigated shale gas and shale oil for 5 years. By the end of February, 2013, 2D seismic data covering 9000 km^2 and 3D seismic data covering 800 km^2 were acquired, and 81 shale gas wells (including shallow parameter wells) targeting marine, lacustrine and transitional (coastal swamp setting associated with coal) shales were drilled so far by the PetroChina, Sinopec, CNOOC, Yanchang Petroleum, 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. So far, almost half of drilled shale wells have good shale gas and shale oil show. Among 20 hirizontal wells, several wells were reported very successful based on test results rate of over 100,000 cubic meters daily production. The highest rate from well Yang201-H2 in Luzhu, Sichuan was reported to produce at 430,000 cubic meters per day. 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. 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.

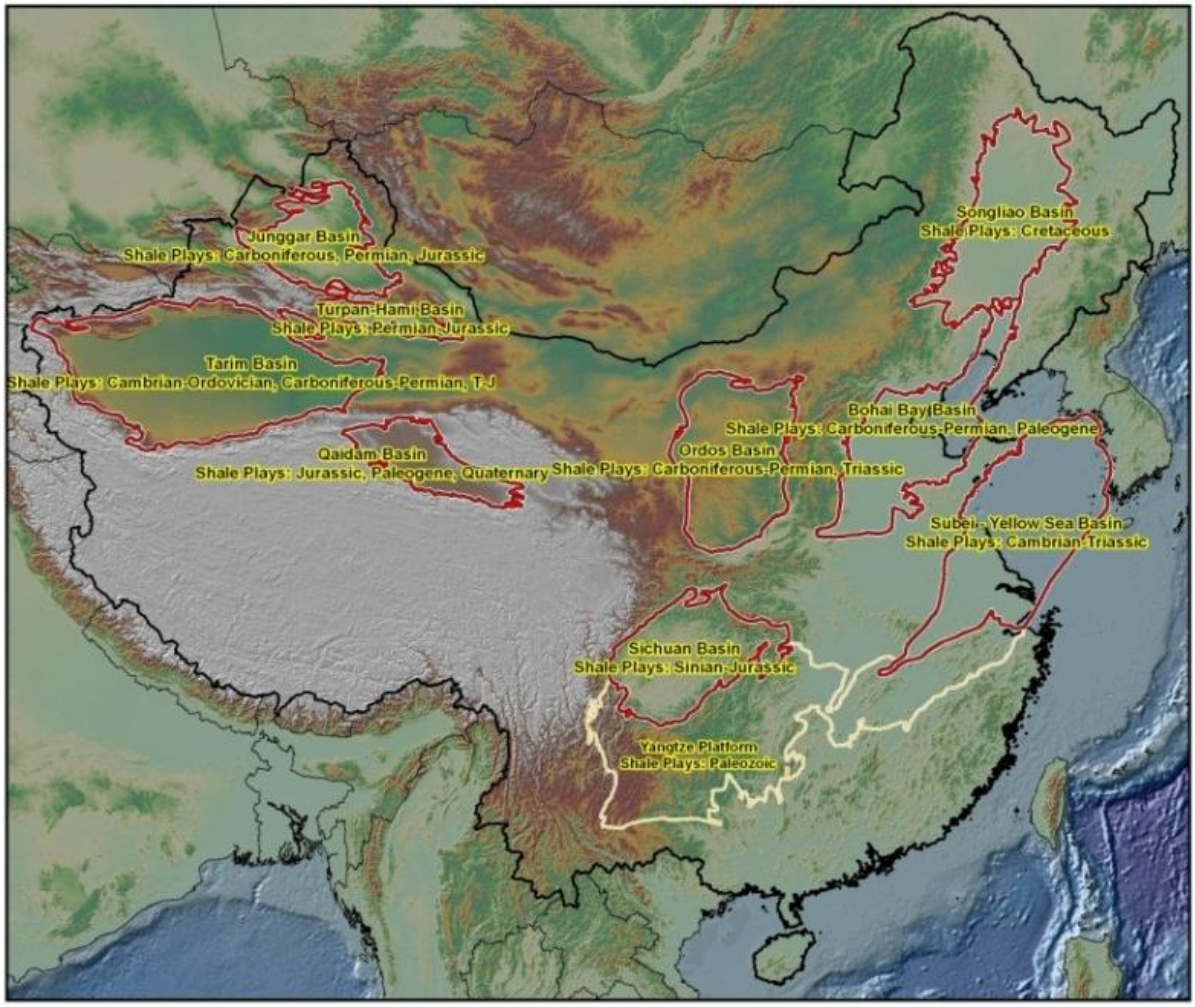


Fig. 1. Distribution of potential major China shale gas and shale oil plays. Scale is about 800 miles in width.

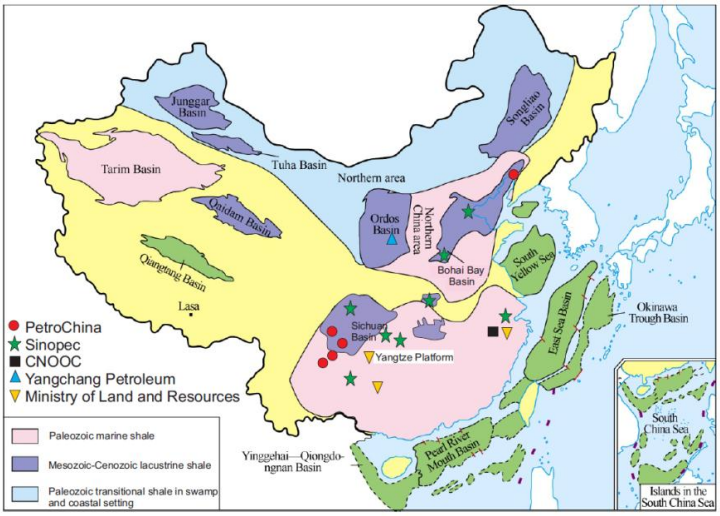


Fig.2 The shale exploration activities in China

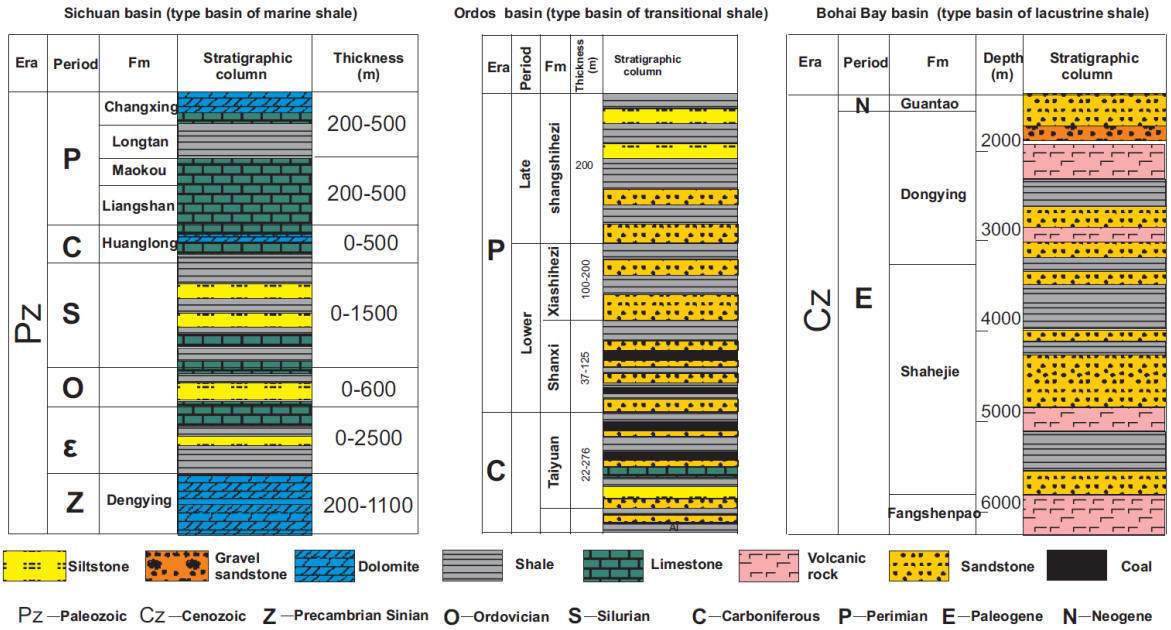


Fig. 3 Three kinds of potential shales (marine, lacustrine and transitional/coastal setting) and their type basins

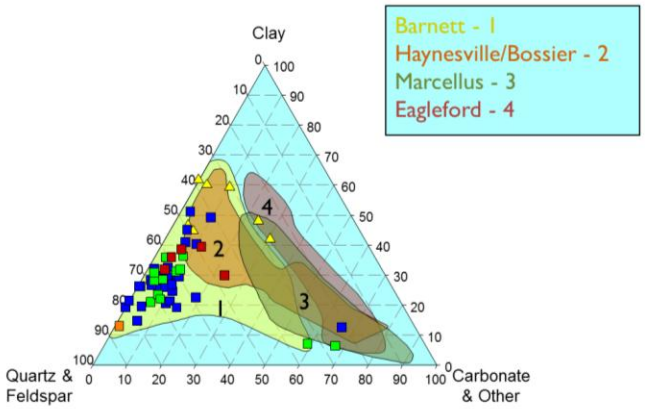


Fig.4 Ternary diagram for mineralogy of marine shale (square legend) and lacustrine shale (triangle legend) in China and its comparison with mineralogy of typical US shales.

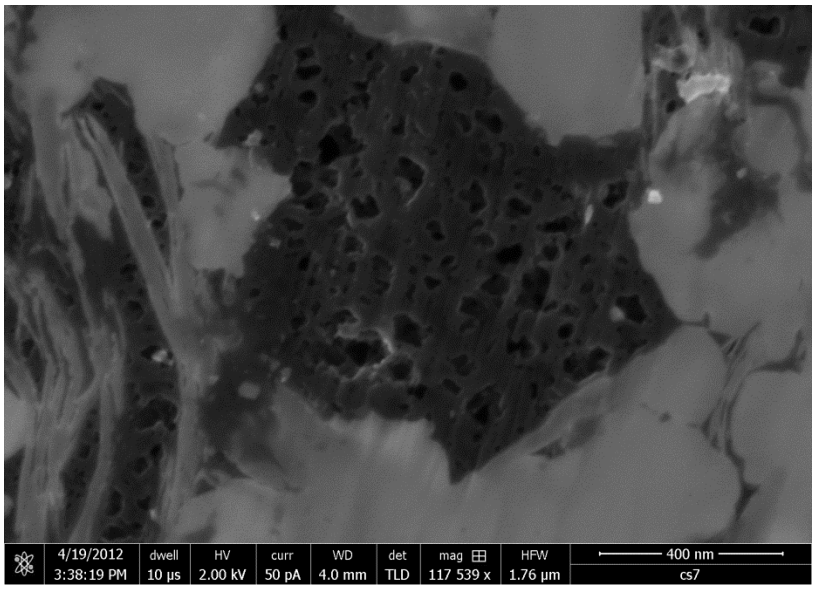


Fig.5 SEM of ion polished sample showing intra-organic nano-pores of a marine shale Sichuan Basin, China

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.

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 bidding blocks located at the margin or outside conventional oil and gas producing basins disappointed many companies. With the speeding 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.

Since technologies will continue advancing and China has ambitious goals to develop shale resources, e.g., low volume fracking fluid technology and new water treatment to recycle water in the future will help shale to be fracked in dessert setting, and several pilot development projects (e.g. demonstration areas in Changning-Weiyuan in Sichuan, Fuling in Chongqing and Zhaotong in Yunan) have been started. China vast shale resources are expected to be extracted.

Southeast Asia

By Jeff Aldrich, with assistance from Dylan Mair, Joe Dumesnil, and Chandra Triandra (Dart Energy, LLC., Singapore)

2012 will mark the year that Asia took the first substantial steps towards the shale gas future that most have been predicting. The first commercial gas well began production in the Cooper Basin in Australia and there were both vertical and horizontal pilot tests in multiple basins in both Australia and China. The great land rush of 2011 in Australia peaked in 2012 with most of the prospective shale basins now licenced and Indonesia has 64 Joint Study Agreement applications submitted on Shale Gas as a precursor to converting them to Exploration PSCs. China announced, delayed and now looks to hold the 2nd Shale Gas bid round with twenty licences spread over three basins. Even New Zealand has licenced blocks for shale gas and has a pilot well completed. At the AAPG ICE in Singapore JAPEX announced a potential game changer with a shale oil test on Japan's West Coast with encouraging flow rates. Only India seemed to take steps backward by the government announcing delays in shale gas legislation of up to an additional 12 months before the start of a new bid round, although it does have a shale gas pilot project underway (see below).

Country	# Shale Wells Permitted	# Vertical Wells Drilled	# Vertical wells fracced	# Hrz wells drilled	Vert well flow rates	Horz well flow rates
Australia	6+ planned	Est. 17 of 21	Confirmed 4 completed	Est. 4 of 21	See below	See below
China	Unknown	40	Assume most	26	See below	See below
Indonesia	No contracts, only 64 JSAs					
India	Applications for 3V, 1H	5		0	See below	See below
Japan	Unknown	12	0 (not yet)	0	unknown	unknown
Other=New Zealand	Unknown	1			unknown	unknown

Data supplied by IHS with modifications from industry sources

There have been around 11 dual target wells that have targeted shale and CBM. From what I can tell all of these have had cores acquired from the shales, but no testing has been undertaken. I think these are all vertical / near-vertical.

Australia

Reported Gas Flow Rates by IHS

Content	Gas Per Day scf
gas	446000 (1 of 5 DSTs)
gas	2100000
gas	200000 *
gas	2000000
gas	2600000
Gas	1350000
Gas	50000 - 100000 (most positive flow)

* To frac November 2012. Others listed here were fracced.

Cooper Basin

Commercial shale gas production has begun in Australia with Santos announcing its Moomba-191 shale gas well in the Cooper Basin had been connected to the eastern states' gas grid. The other participants are Beach Energy (20 per cent) and Origin Energy (13 per cent). Moomba-191 is a dedicated shale well that flowed gas at stabilised rates of 2.6 million cubic feet per day (MMcfd) with a peak rate of 3MMcfd from the Roseneath, Epilson and Murteree shales. Santos said the well was only 350 metres from the existing pipeline network and eight kilometres from Moomba's gas processing plant, enabling it to be brought on line quickly. Further drilling is planned for the area, including an ongoing vertical well appraisal program and Santos' first horizontal shale well planned for 2013.

While other companies have established flow rates from their unconventional gas wells, with Beach Energy flowing 2 million cubic feet of gas per day from both its Holdfast-1 and Encounter-1 wells, none have yet established concrete plans to put the wells into production.

In a global study the US Energy Information Administration estimated that "technically recoverable" shale gas resources in Australia could be as high as 396 trillion cubic feet (tcf) and Geoscience Australia has produced a similar estimate. This is significantly larger than the estimated 235 tcf of discovered and undiscovered CSG in Australia, according to Geoscience Australia.

Perth Basin

While much of the activity is occurring in the Cooper Basin with companies such as Senex Energy, Drillsearch with QGC, and Orca Energy drilling unconventional wells, considerable attention is also focused on the Perth Basin where fracture stimulation and testing efforts have yielded encouraging

early results. Norwest Energy has enjoyed early gas flow rates of up to 777,000 cubic feet of gas per day from testing of the High Cliff Sandstone, a secondary target at its Arrowsmith-2 well, and has also started flowing gas from the primary target Irwin River Coal Measures, following successful separate fracs of the intervals. This will be followed by fraccing of the other primary target, the Lower Carynginia and Middle Carynginia shales, as well as the secondary objective Kockatea Shale.

AWE Limited, which is sharing the fracture stimulation equipment with Norwest, has also flowed gas from the Middle Carynginia and Upper Carynginia shales at its Woodada Deep-1 well though flow results are not available as yet. Meanwhile, Empire Oil & Gas has flagged that it may explore the 24Tcf of in place unconventional gas that RPS Energy Services believes could be contained within the Lower Cattamarra Coal Measures in EP 389.

Southern Georgina Basin

Over in the Northern Territory, unconventional gas exploration activity in the Southern Georgina Basin looks set to pick up considerably with the entry of Norwegian state oil major Statoil. With potential spending of up to US$210 million under its farm-in agreement with Canada's PetroFrontier , the deal is also larger than previous foreign investments into Australian shale and tight oil plays. Statoil has flagged that it could drill between 10 and 20 wells by 2017, giving Baraka Energy & Resources, which while not a direct participant in the farm-in, exposure to its upside through its undiluted 25% stakes in EP 127 and EP 128, both of which are covered by the agreement.

Fraccing of the MacIntyre-2H in EP 127 as well as PetroFrontier's 100% owned Baldwin-2Hst1 and Owen-3H is expected to begin soon, giving the partners more information about how the target Arthur Creek Formation shales compares to North America's highly productive Bakken Shale.

Canning Basin

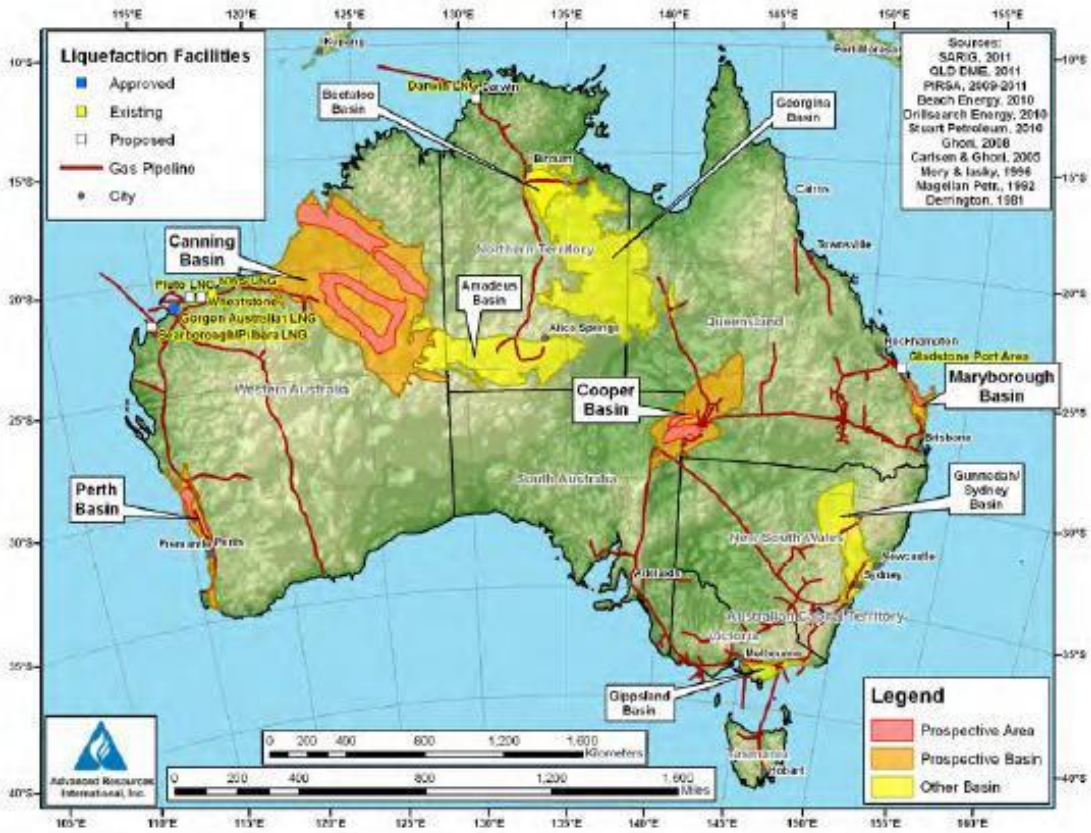
Unconventional gas exploration in the Canning Basin has also picked up with Buru Energy finding signs that its Yulleroo gas accumulation is part of a basin centred gas accumulation that offers better gas recoverability and lower costs than traditional unconventional gas plays. New Standard Energy is poised to drill the first of an initial three well program with ConocoPhillips to establish the hydrocarbon prospectivity of the Goldwyer Shale. The Goldwyer Shale is believed to have attractive economic parameters that are similar to the North American Bakken and the Eagle Ford shales.

Key Petroleum will also start exploration activity under its Canning Basin focus with its participation in the upcoming Cyrene-1 exploration well. Operator Buru Energy will spud the well, which targets conventional Willara Formation shallow oil play that could hold 5 million barrels of recoverable oil and the unconventional Goldwyer Shale, after it completes the Ungani North-1 well. A core will be cut from the Goldwyer to assess its unconventional oil potential.

Galilee Basin

In Queensland, Exoma Energy and Chinese major CNOOC are involved in an aggressive 22 well drilling program to appraise the coal seam gas, conventional oil and shale oil and gas resources in their acreage, which covers 27,000 square kilometres. These include seven shale exploration wells to collect further shale geological and geochemical data on the Toolebuc shale, which covers about 20,000 square kilometres. Early exploration had indicated the Toolebuc shale could hold more than 3 million barrels of oil equivalent of in place oil and gas per square kilometre.

[Information and reporting from Interactive Investors Website]



China

<u>China Horizontal Well Flow Rates</u>: data sourced for 8 wells. Data from IHS

Content	Oil Per Day bbl	Gas Per Day scf
oil	168	
gas		388000
gas		5296000
gas		
oil, gas & cond *	240 (condensate)	284000
oil	4	
oil	106	
Gas **		14800000

* This well targeted a silty limestone, called “Shiping-Shilongchang-Si-2-1H”.
** This was a Production Test, others were Drill Stem Tests.

In its 12th Five-Year Plan (2011-2015), China set the goal of producing 229.5 billion cubic feet (6.5 billion cubic meters) of shale gas by 2015; the United States produced about 30 times more shale gas in 2011. But while the U.S. shale gas revolution amounted to roughly a seven-fold increase in production in the past five years, China's aim is to ramp up shale production at least ten-fold between 2015 and 2020.

In China, where coal now generates 80 percent of electricity, there is great potential to curb greenhouse gas emissions by substituting natural gas. A preliminary EIA assessment of world shale reserves last year indicated that China has the world's largest "technically recoverable" resources—with an estimated 1,275 trillion cubic feet (36 trillion cubic meters). That's 20 percent of world resources, and far more than the 862 trillion cubic feet (24 trillion cubic meters) in estimated U.S. shale gas stores

China Vertical Well Flow Rates: data sourced for 10 wells, all DSTs.

Content	Oil Per Day bbl	Gas Per Day scf
oil	27	
oil	16	
gas		5900
gas		529000
gas		380000
2nd test of well above		*600000*
oil	313	
gas		2100000
oil	990	
gas		17900000

It is doubtful that China can achieve the stated targets, given challenging environmental conditions more difficult than those for shale gas development in North America and the current lack of 'players'. To facilitate this transformation state-owned China National Offshore Oil Corporation (CNOOC) entered into a joint venture with U.S. shale gas leader Chesapeake Energy two years ago, in a move experts viewed as a bid to gain access to expertise. In January, Sinopec, China's number two oil company purchased a one-third stake in several new ventures of industry pioneer Devon Energy for $900 million and commitment to cover $1.6 billion of future drilling costs. In March, Shell* signed the first shale gas production-sharing agreement ever in China, with state-owned China National Petroleum Corporation (CNPC), also known as PetroChina. ExxonMobil, BP, Chevron, and the French company Total also have embarked on shale gas partnerships in China. On June 9, state-owned oil giant Sinopec started drilling the first of nine planned shale gas wells in Chongqing, expecting by year's end to produce 11 billion to 18 billion cubic feet (300 to 500 million cubic meters) of natural gas—about the amount China consumes in a single day. Several state

agencies have drilled test wells for shale or other unconventional hydrocarbons in most basins but hold the data as state secrets.

Experts say Sichuan Province and the Tarim Basin in Xinjiang Province in the northwest hold promising marine deposits. Five other areas identified by the EIA as potential shale plays in China, including Inner Mongolia's Ordos Basin and parts of northern China, are more likely to hold non-marine deposits. Other attributes of China's shale might pose additional challenges. It's believed that many of the deposits are mixed with a high percentage of clay. In addition, shale in Sichuan is 1.2 to 3.7 miles (2 to 6 kilometers) below ground. On the higher end, that's deeper than many of the U.S. deposits, and the mountainous terrain above ground increases the difficulty and cost of drilling.

Sichuan Basin

Two of the four blocks offered in the first shale gas bid round were signed. Sinopec plans to invest CNY591.1 million to explore the Nanchuan block, while Henan Provincial Coal Seam Gas will spend CNY247.6 million to develop the Xiushan block.

In 2011, CNPC accelerated the building of demonstration zones of shale gas production at Weiyuan-Changning in Sichuan and Zhaotong in Yunnan drilling:

- Four vertical wells
- Four horizontal wells

Five of them were fractured out of which the Wei 201-H1 well produced 1.77 million cubic meters of natural gas in 150 days and became the first completed horizontal well that began to produce shale gas.

On June 2011, Shell and CNPC signed a Global Alliance Agreement to jointly pursue opportunities internationally and in China including a well manufacturing joint venture (50% CNPC and 50% Shell). With this joint venture Shell and CNPC intend to develop a highly automated well manufacturing system that could boost the efficiency of drilling and completing onshore wells using drilling optimization technologies. On March 2012, Shell and CNPC signed a product sharing contracts (PSC) for the exploration, development and production in the Fushun-Yongchuan shale gas block in the Sichuan Basin, China. Covering approximately 3,500 square kilometers, this PSC is the first ever signed in China for shale gas.

Sichuan total reserves in place are estimated to 11 tcm of gas.

PetroChina holds access rights to 131 blocks in Sichuan where:

- 113 gas fields were discovered
- Containing 813 bcm of gas proven reserves
- Supplying 14 gas plants
- Producing 15 bcm/y of natural gas

Unfortunately most of these gas fields are maturing and should deplete now by 1 bcm/y.

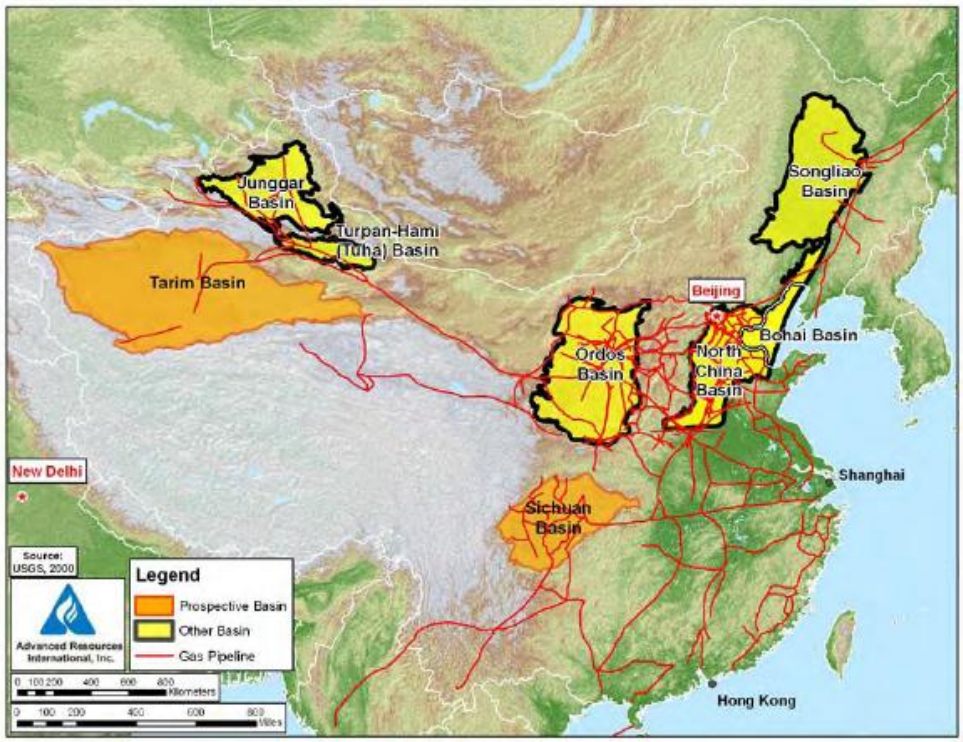
To stop spiraling down the Sichuan gas production,PetroChina is planning to double its capital expenditure to $6 billion in order to develop the local shale gas available over the next 5 to 8 years.

To boost its local shale gas exploration and production the Government of the Sichuan Province is establishing a joint venture with CNPC (PetroChina) and some private companies. In this Sichuan Changning Natural Gas Development joint venture, the Sichuan Government will take a share, but PetroChina will hold the majority stake and will be the operator, while the invited private companies will have minority stakes. The mission of this Sichuan Changning Natural Gas Development joint venture will be to implement the ongoing exploration of the Weiyuan-Changning area running with

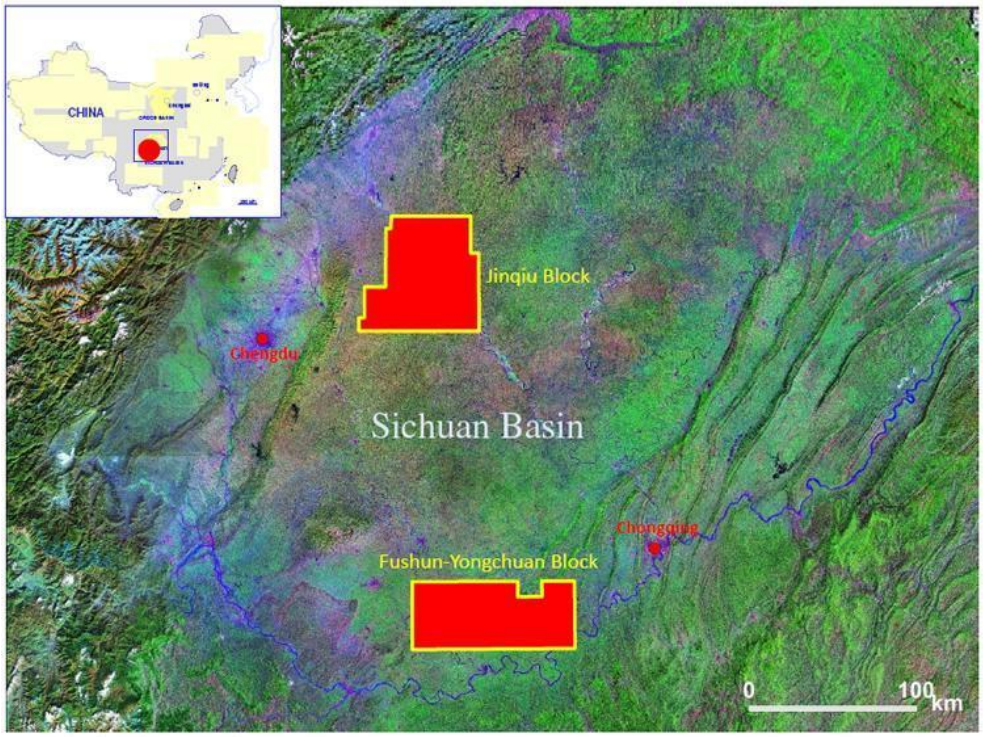
seven experimental wells producing each one 10,000 to 100,000 cm/d. The Weiyuan-Changning holds about 300 bcm shale gas reserves and should be able to produce 2 bcm/y ofnatural gas in 2015.

FIGURE 2

China's key shale basins and natural gas pipeline system



Source: http://www.eia.gov/analysis/studies/worldshalegas/pdf/fullreport.pdf.



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http://www.2b1stconsulting.com/petrochina-to-invest-6-billion-to-develop-sichuan-shale-gas/

Involvement of foreign investment

In the latest Foreign Investment Catalogue promulgated in 2012[6], the exploration and exploitation of shale gas was categorized as "*encouraged industry*" for joint ventures, separate from "natural gas". The reclassification of shale gas represents a significant change in the way foreign investors can select potential Chinese partners for the joint venture. Prior to the Announcement, only certain state-owned oil and gas companies (i.e. CNPC, Sinopec and CNOOC) were permitted to cooperate with foreign energy companies to explore and produce natural gas (as well as shale gas) in China[7]. As a result, foreign energy companies were only allowed to cooperate with those companies. However, since the Announcement which reclassifies shale gas as a new mining resource, the previous cooperation limitation will no longer apply. However, the requirements for the international cooperation remain unclear.

In this regard, the Shale Gas Plan outlines the necessary approval requirements with the general principle that international cooperation in exporting and exploiting shale gas between Chinese enterprises and foreign investors shall first obtain approval from the MLR, NDRC and State Council. Whilst details on the approval procedure and qualifications remain unspecified, these are expected to be further clarified.

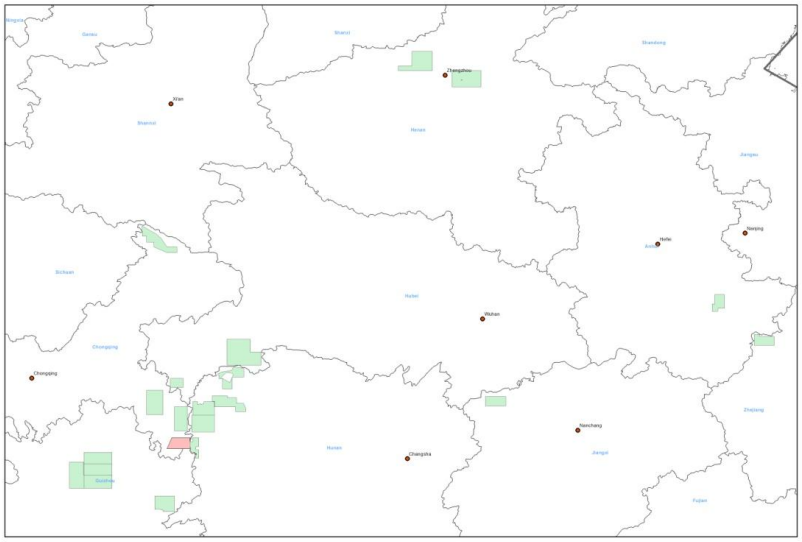
Financial preferential treatments

To boost the development of shale gas industry, the Shale Gas Plan also indicates a number of possible preferential financial treatments, which are expected to be implemented in detail. These include:

- Subsidies for the exploration and exploitation of shale gas;
- Reduction of and/or exemption from the usage fees for Mining Rights;
- Exemption from customs duties on imported machines and equipment (including relevant technologies) that cannot be manufactured by domestic companies; and

- Other measures, including a market price mechanism for shale gas and priority for land use approval.

http://www.infoclient.gide.com/newsletters/en/china/index.php?option=com_content&view=article&id=210:shale-gas-new-category-new-prospects&catid=59:may-2012&Itemid=54



Twenty 2nd round Shale gas bid blocks plus the Henen Xiushan Shale Gas Block (red) from the first round) Map supplied by Dart International Energy

INDIA

In 2010 ONGC working with Schlumberger began a four well shale gas pilot project, two in the Raniganj sub-basin in West Bengal and two in the North Karanpura sub-basin in Jharkhand. One confirmed gas flow, another confirmed drilled (result unreported), project understood to be completed. The data below is the additional Dholka 19 well which was fracced.

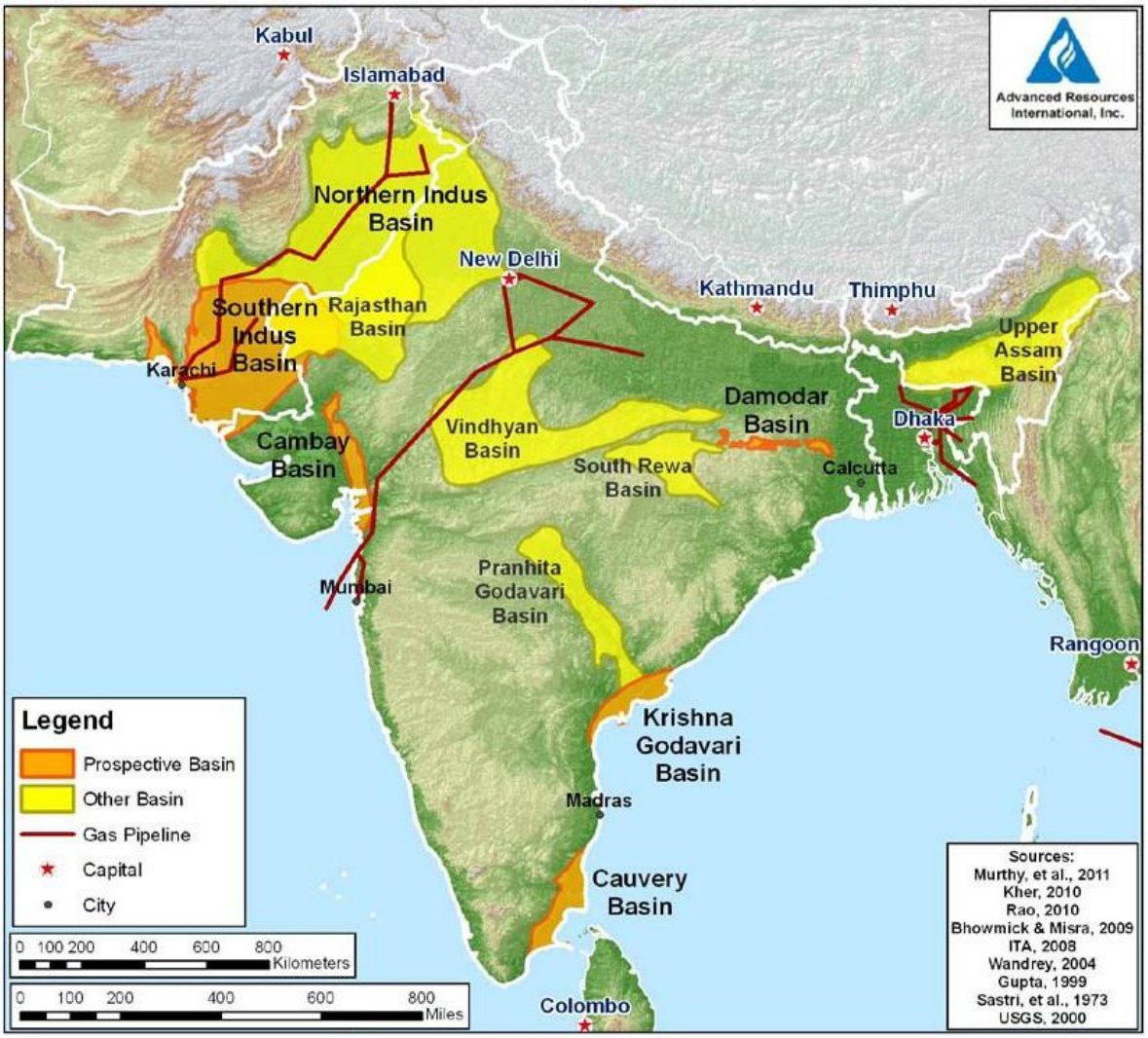
Content	Oil Per Day bbl	Gas Per Day scf
Oil and gas	12	17600

An India shale gas round is planned for late 2013, no other plans expected until then.

Indonesia

There is much anticipation about the shale gas potential of Indonesia and much uncertainty about how the legislation will be applied. The Ministry announced early in 2012 that it would review and change the terms for Shale Gas under the PSC contract and up to 64 Joint Study Agreements, normally a precursor to PSC contracts have been submitted various companies. According to the Migas website from the 64 applications, 5 JSAs have been finalized, 2 JSAs are ongoing, 29 JSA are in the process of approval, 24 JSAs are being process and 4 JSAs are rejected. To date no wells are known to have been spudded. To date

there has not been clarity on the proposed legislation with concerns raised over potential overlapping claims from existing conventional PSCs.

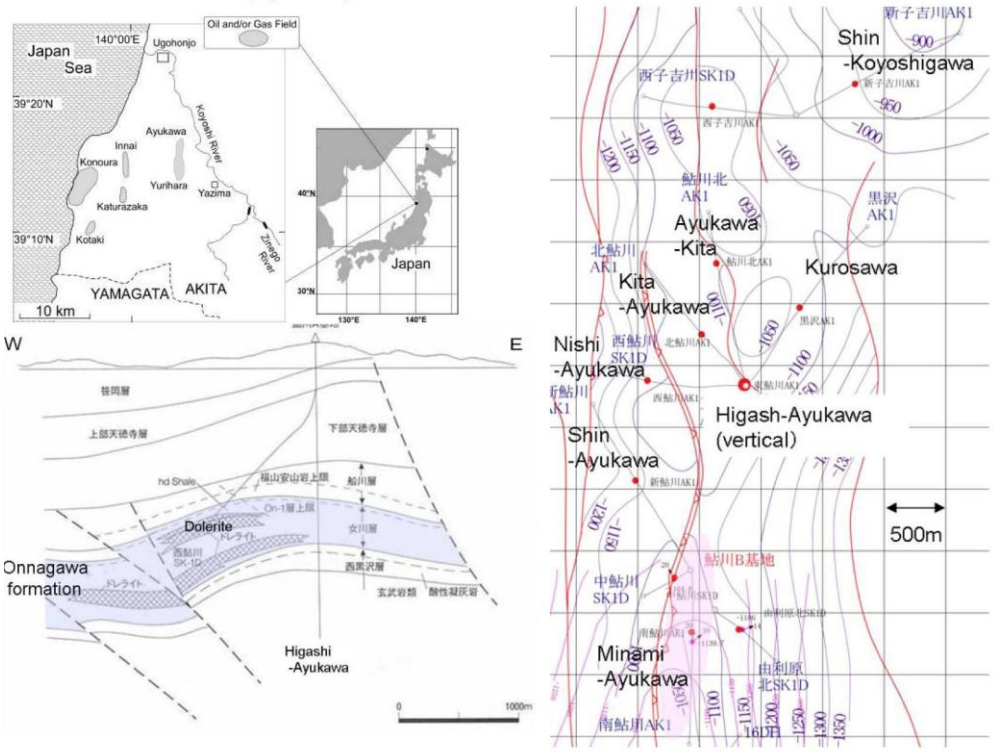


Japan

Japan Petroleum Exploration Co. on Wednesday extracted shale oil for the first time in Japan, from the Ayukawa oil and gas field in Yurihonjo, Akita Prefecture.

JAPEX, started test drilling for shale oil with an acidization of the shale layers 1,800 meters below the surface. JAPEX confirmed the presence of shale oil after collecting and analyzing the liquid. JAPEX plans to examine whether full-fledged shale oil production is possible based on data from the test drilling. Total shale oil deposits in the prefecture are estimated at 100 million barrels, equivalent to about 10 percent of the nation's annual oil consumption.

Shale Oil Potential in Neogene Siliceous Shales of Japan*



http://www.searchanddiscovery.com/documents/2012/80256yokoi/ndx_yokoi.pdf

Satoru Yokoi[1], Amane Waseda[1], and Takashi Tsuji[1]

Search and Discovery Article #80256 (2012)*

Posted September 24, 2012

We have proposed a hydrocarbon trap model in the Monterey-like bio-siliceous shale Onnagawa Formation. The trap is associated with diagenetic transformation of silica mineral from opal-CT to quartz, and across the boundary, the overlying opal-CT porcelanite layer forms a seal and underlying clay-poor quartzose porcelanite forms a reservoir (Tsuji et al 2012 in this poster session, Figure 1). The Onnagawa Formation is the main source rock in Japan, particularly in the Akita Basin, with high potential. It averages 500 m thick and has a total organic carbon (TOC) ranging from 2% up to 5%, and HI of 500.

New Zealand

Exploratory drilling has resumed in New Zealand's nonproducing East Coast basin after a long hiatus. New Zealand Energy Corp. deepened the Ranui-1 well, drilled to a total depth of 1,134 m by a previous operator, on the 100% owned Ranui permit. Initial drilling encountered 224 m of prospective Whangai shale, but the well did not reach the base of the shale. Upon reentry, NZEC cored as many as four Whangai shale intervals and drilled through the base of Whangai into conventional reservoir sands to a planned 1,500 m. The company ran a full suite of open hole logs.

The company is analyzing core from two other test holes drilled in late 2011 on its 100% owned Castlepoint permit. The Orui core hole, TD 125 m, and Te Mai core hole, TD 195 m, cored and tested the Waipawa and Whangai shales. The two shales source more than 300 oil and gas seeps in the basin.

http://www.ogj.com/articles/2012/01/new-zealand-east-coast-basin-shale-pursuit-resumes.html

Comparison of Characteristics of New Zeland Shales

Table 3. Key Properties of Potential Shale Plays, New Zealand (with speculation about wells)

Basin	Waipawa North	Waipawa ECB	Whangai ECB	Taranaki-Turi
Depth, m	300	300-1800	400-2000	3000-4000
Net Thickness, m	15	17	400	200
TOC %	6-12%	3.6%	.56%	2%
Maturity Ro	?	.32-.37	.65	.44-.52
Gas Content, SCF/ton		25-100	10-40	25-200
Pressure, MPa	2.7	2.7-10.4	3-12	12-20
Well Cost, NZ$	$1,100,000	$1,100,000-$3,600,000	$1,500,000 $5,500,000	$6,000,000-$12,000,000
Water Prod, LWPD	1,000-30,000	1,000-30,000	0	0
Reserves, PJ per well	.3	.3-1.0	1	1
Cost, NZ$/GJ	$3.67	$3.60-$3.70	$5.00-$5.50	$6.00-$12.00
Gas Price, NZ$/GJ	$6.00	$6.00	$6.00	$6
Gas Type	Biogenic	Biogenic	Mixed	Thermogenic

Data from King and Thrasher, 1996; Lowery, 1988; Sproule/GNS 2007;
Pressure assumed to be hydrostatic
Gas content estimated from Langmiur isotherm at hydrostatic pressure; gas reserves from gas content, TOC value, depth, thickness, analogy to shale gas in the US

RESOURCE DEVELOPMENT TECHNOLOGY LLC

http://www.nzpam.govt.nz/cms/pdf-library/petroleum-conferences-1/2008-conference-proceedings/presentations/g-twombly

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

2013

May 13-14, 2013: 3rd Annual Bakken & Three Forks Completions Congress 2013, Denver, CO. American Business Conferences. http://www.bakken-three-forks-completions-congress.com/

May 15-16, 2013: Tight and Shale Gas Summit, Istanbul, Turkey. Active Communications International. http://v11.vuturevx.com/exchange-sites/Whitmore%20Group/59/events-pdfs-eu/eug2-mktg-agenda.pdf

May 18, 2013: Basic Tools for Shale Exploration, Pittsburgh, PA. AAPG 2013 Annual Conference & Exhibition.

May 18-19, 2013: Integrating Data from Source-Rock and Reservoir Fluid Samples to Evaluate Oil/Gas-Shale Resources Across the E&P Lifecycle, Pittsburgh, PA. AAPG 2013 Annual Conference & Exhibition.

May 19-22, 2013: AAPG 2013 Annual Conference & Exhibition, Pittsburgh, PA. http://www.aapg.org/pittsburgh2013/

May 23, 2013: Application of Maturation/Organic Facies, Geochemistry, and Petroleum System Modeling for the Shale Gas/Shale Oil Resource Evaluation, Pittsburgh, PA. AAPG 2013 Annual Conference & Exhibition.

May 29-31, 2013: Developing Unconventionals (DUG Bakken and Niobrara), Denver, CO. Hart Energy. http://www.dugbakken.com

May 29-30, 2013: 2nd Annual Tight Oil Reservoirs California, Monterey & Surrounding Sediments 2013, Bakersfield, CA. American Business Conferences. http://www.tight-oil-monterey-california-2013.com/

July 16-17, 2013: Geomechanics and Reservoir Characterization of Carbonates and Shales, AAPG Geosciences Technology Workshop, Baltimore, MD. http://www.aapg.org/gtw/2013/baltimore/index.cfm

August 6-7, 2013: Reservoir Compartmentalization and Connectivity: Multiple Methods for Shales, Carbonates, Deepwater, AAPG Geosciences Technology Workshop, Houston, TX. http://www.aapg.org/gtw/2013/houston/index.cfm

August 12-14, 2013: Unconventional Resources Technology Conference, SPE, AAPG, and SEG, Denver, CO. http://www.urtec.org/

August 27-29, 2013: Developing Unconventional Gas (DUG Australia), Brisbane, QLD, Australia. http://www.dugaustralia.com/

August 28-30, 2013: Shale Energy Technology Conference, Houston, TX. World Oil ShaleTech. http://www.cvent.com/events/shaletech-conference/event-summary-b1d5e7ef56f14bce92d42be8035be004.aspx

September 17-19, 2013: Developing Unconventionals (DUG Eagle Ford), San Antonio, TX. http://www.dugeagleford.com/

September 22-24, 2013: AAPG–Rocky Mountain Section Annual Meeting, Salt Lake City, UT. http://www.rmsaapg2013.com/

November 3-5, 2013: Hydrocarbon Charge Considerations in Liquid-Rich Unconventional Petroleum Systems, AAPG Geosciences Technology Workshop, Vancouver, BC, Canada. http://www.aapg.org/gtw/2013/vancouver/index.cfm

November 12-13, 2013: Reservoir Quality in Unconventionals, AAPG Geosciences Technology Workshop, Austin, TX. http://www.aapg.org/gtw/2013/austin/index.cfm

November 13-15, 2013: Developing Unconventionals (DUG East), Pittsburgh, PA. http://www.dugeast.com/