

EMD Gas Shales Committee



EMD Gas Shales Committee Annual Report - 2011

Neil S. Fishman, Chair

March 22, 2011

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INTRODUCTION

It is a pleasure to present this report from the EMD Gas Shales Committee. This report contains information about specific shales across North America and Europe from which hydrocarbons are currently being produced or shales that are of interest for hydrocarbon exploitation. The inclusion in this report of shales from which any hydrocarbon is produced reflects the expanded mission of the EMD Gas Shales 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 up-to-date on shales.

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

The leaders of this committee are interested in your feedback, so please feel free to contact us with your comments and suggestions. Feel free to contact Neil Fishman (nfishman@usgs.gov) with your thoughts.

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

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

The Michigan Basin Antrim Shale play is currently 24 years old, having begun the modern phase of development in 1987. The total number of producing wells drilled in the play through end of November, 2010 is approximately 11,415 with about 9,766 still online.

Total cumulative gas production reached 2.988 TCF by the end of November, 2010. 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 786 separate projects at the end of November, 2010. Cumulative production for the first 11 months of 2010 was 110,203,426 MCF of gas. That was a 4.3% decline from the first 11 months of 2009.

There were 31 operators with Antrim production at the end of November, 2010. There were 9,766 wells online at the end of November, 2010. There were 111 new wells drilled in 2009, and only 58 in 2010. That is a 48% decrease in active wells from 2009 and precipitous drop in new wells completed. Most of the production comes from a few operators. The top 10 operators produced 81.3% of the total Antrim gas in 2010.

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 November, 2010 was 33 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 and at the end of November, 2010 the ratio was 1.55 MCF/BBL. Play wide water ratios continue to increase relative to gas production as old wells decline in total gas and new wells start with high water cut.

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

Wells produce from depths as shallow as 350 feet to just over 3,000 feet, although the vast majority of wells are completed from 1,000 to 2,500 feet deep. Wells are typically drilled with water and an

attempt is made to keep the well in balance or slightly under-balanced. Wells are fraced with water and sand. Some wells are fraced using nitrogen or foam.

Production and well data are 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 are 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:

Atlas Gas & Oil Company LLC	Muskegon Development Co.
Linn Operating, Inc.	Trendwell Energy Corp.
Terra Energy Ltd	Jordan Development Co. LLC
Breitburn Operating Limited Partnership	Merit Energy Co.
Ward Lake Energy	Delta Oil Co., Inc.

Significant Trends – Production continues to decline as are the total number of active wells which show a decline for the first time. Daily production per well is also slightly declining this year. The number of horizontal completions is increasing, but still represents 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) (Bohrer and others, 2008) and the underlying Three Forks Formation contains an additional 2.1 BBbls (Nordeng and Helms, 2010).

Petroleum within the Bakken is properly considered a continuous petroleum accumulation for the following reasons:

- 1) The Bakken is a regionally extensive, organic-rich source rock;
- 2) The Bakken has a burial history that has resulted in temperatures sufficient to convert organic matter into petroleum;
- 3) The overlying and underlying rocks are sufficiently thick, widespread and impermeable so as to isolate the accumulation;
- 4) There are overlying and/or underlying rocks that are sufficiently permeable and porous to accumulate economic quantities of oil or gas. (i.e. Bakken Petroleum System which includes the

middle member of the Bakken Formation, Three Forks Formation, and the Lodgepole Formation; Price and LeFever, 1994); and,

- 5) Abnormally high formation pressures indicate that petroleum has been injected into these rocks and that the “charge” has not escaped through permeable zones, fractures or faults.

Petroleum accumulations, such as the Bakken, cover large areas with poorly defined margins. Virtually every study of the Bakken Petroleum System concludes that the resource is enormous with total in place volumes of oil that are in the range of 10s to 100s of billions of barrels.

Bakken development spans almost 60 years and is witness to several important advances in drilling, completion and stimulation techniques. Each of these advances has significantly increased the productive acreage and value of the formation. Of particular importance are the dual developments of precise directional drilling technologies that result in the modern horizontal well bore and advances in well stimulation technologies. The significance of this is that artificially fractured horizontal well bores open up much larger sections of an oil-bearing formation and by virtue of increasing the collection capacity of a single well allows for larger volumes of oil to be produced. This is especially important when attempting to produce oil from formations such as the Bakken and Three Forks in which matrix permeabilities are in the microdarcy range.

Oil production from the Bakken was first established on the Antelope Anticline in 1953 when Stanolind Oil and Gas Corp. drilled and completed the #1 Woodrow Starr (SWSE Sec. 21, T152N, R.94W). The well was drilled to a total depth of 12,460 feet, plugged back and cased to 10,675 feet. This well was perforated between 10,528 and 10,556 feet depth and stimulated with 4,900 pounds of sand and 120 bbls of crude oil. The well came on line on December 6, 1953 with an initial production (IP) of 536 barrels per day of 44° API gravity oil and 770 cubic feet of gas per barrel. Casing problems in the #1 Woodrow Starr forced the well to be plugged and abandoned after 55 months of production during which 279,254 barrels of oil and 108 barrels of water were produced. The majority of the 44 wells in Antelope Field were drilled during the 1950s and 1960s. Oil production from the first wells in the Antelope Field is restricted to structurally induced fracture systems. The recognition that pervasive fracture systems are a necessary component of a successful Bakken well became the dominant exploration model until the mid-1990s.

Between 1960 and 1975 production outside of the Antelope Field was established in a few wells. The Government 41X-5-1 well drilled by Shell Oil in 1961 in Billings County (NENE Sec. 5, T143N, R101W) demonstrated that oil production outside of the Antelope Field was possible. The Government 41X-5-1 was drilled to a total depth of 13,018 feet and was plugged back to a depth of 10,738 feet. A drill stem test of the lower Lodgepole, Bakken and Three Forks Formations recovered gas and heavily oil cut mud with shut in pressures of about 6,600 pounds per square inch (psi). The well was perforated in the upper Bakken shale between 10,682 and 10,692 feet depth and in the upper Three Forks between 10,705 and 10,715 feet depth. 4,000 gallons of acid were used to stimulate the well. The initial production rate was reported to be 136 barrels of 43.4° API gravity oil with a gas to oil ratio (GOR) of 1230 cubic feet of gas per barrel of oil. Seven months later the well was hydrofraced with 20,000 gallons of acid and 9,000 pounds of sand. Production following stimulation was reported to be 48 BOPD. The well was abandoned in August of 1964 after producing 57,840 bbls of oil.

Late in the 1970s, additional vertical production developed along the southwestern depositional limit of the Bakken Formation. Along this trend, known as the “Bakken Fairway”, only the upper Bakken is present. The “Fairway” is some 200 miles long and 30 miles wide and lies along the updip feather edge

of the upper shale. At least 26 fields were established along structural features over which the Bakken thinned and apparently fractured.

Drilling methods in the Bakken Fairway changed significantly in 1987 after Meridian Oil, Inc. drilled the first horizontal Bakken well. Meridian drilled and completed a vertical well in March 1986 for 217 BOPD. (#21-11 MOI-Elkhorn; NWSE Sec. 11, T143N, R102W). This well established the presence of a fracture trend that was exploited with the first horizontal well into the Bakken. A 2,600 foot. long lateral was drilled from the vertical well into an 8-foot-thick section of the upper Bakken shale. Initial production from the completed lateral was 258 BOPD and 299 MCF of gas (LeFever, 1991). Horizontal drilling along the Bakken Fairway peaked in 1992 before slowing late in the 1990s and essentially ending by 2000 (LeFever, 2000).

Development of the Elm Coulee Field in 1996 resulted from the first significant oil production from the middle member of the Bakken Formation. Production from the middle member was established in the Kelly/Prospector #2-33 Albin FLB following an unsuccessful test of the deeper Birdbear (Nisku) Formation. Subsequent porosity mapping outlined a northwest-southeast trending stratigraphic interval containing an unusually thick dolomitized carbonate shoal complex within the middle member. Horizontal wells drilled through this shoal complex in 2000 resulted in the discovery of the giant Elm Coulee Field in eastern Montana. As with the previous Bakken producing fields, production at Elm Coulee depends on fracturing but in this case the productive fractures are found in the middle member of the formation. Since its discovery, more than 600 horizontal wells have been drilled in the 450-square-mile field from which more than 94 MMBbbls 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 well (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 wells which resulted in 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 fracs have been replaced by multistage fracs that stimulate the lateral with about the same amount of material except that the frac is distributed over 10 to 30 or more separate stages. In a few instances, different laterals in the same well as well as laterals in adjacent wells are fraced at the same time. Whiting Oil has installed a microseismic array in the Sanish field in order to better visualize the real-time generation of induced fractures during stimulation.

Subsequent horizontal drilling in the Parshall Field coupled with staged fracture stimulation has resulted in several wells with IPs in excess of 2,000 BOPD. The Parshall field is currently producing about 1 MMBbbls of oil per month from 201 wells. Sanish Field, adjacent to Parshall, is producing just about 1.3 MMBbbls of oil per month from 188 wells.

Over 151.9 million bbls of oil have been recovered from the 1,529 wells in the 81 middle Bakken producing fields put into service since 2004. The 342 horizontal wells drilled into the Three Forks Formation since 2006 have produced a total of 22.6 million bbls of oil. Currently there are 107 fields with Three Forks production. Thirty-five wells have been completed in both the Bakken and Three Forks Formations. The majority of these wells were drilled in 2010.

The North Dakota portion of the Williston Basin is extremely active with 173 rigs running. The top 10 producers in the play are:

1. EOG Resources (267 wells; up from 184)
2. Whiting Oil and Gas Corporation (161 wells up from 87 wells)
3. Continental Resources, Inc. (210 wells; up from 129 wells)
4. Hess Corporation (172 wells; up from 142 wells)
5. Marathon Oil Company (177 wells; up from 150 wells)
6. Slawson Exploration Company, Inc. (73 wells up from 47 wells)
7. Burlington Resources Oil & Gas Company, LP. (92 wells; up from 78 wells)
8. XTO Energy Inc. (112 wells; up from 83 wells)
9. Murex Petroleum Corp. (40 wells)
10. Hunt, LLC (38 wells)

ADDITIONAL INFORMATION ON THE BAKKEN:

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://www.ndoil.org/?id=85&page=WBPC>

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

RECENT PUBLICATIONS:

Julie A. LeFever, Richard D. LeFever, and Stephan H. Nordeng, 2011, Cyclic Sedimentation Patterns of the Mississippian-Devonian Bakken Formation, North Dakota: NDGS Geological Investigation

Julie A. LeFever and Stephan H. Nordeng, 2010, Cyclic Sedimentation Patterns of the Mississippian-Devonian Bakken Formation, North Dakota: AAPG International Conference, Calgary, AB

Stephan H. Nordeng and Julie A. LeFever, 2010, Bakken Source System: Emphasis on the Three Forks: New Horizons Conference, SD School of Mines, Rapid City, SD

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

By Kent Bowker (Bowker Petroleum, LLC)

In late 2010, the US Energy Information Administration released a map and listing of the top 100 oil and gas fields by 2009 proved reserves (http://www.eia.gov/oil_gas/rpd/topfields.pdf). The Newark East (Barnett Shale) field came in at the top spot for gas fields. In addition, another Barnett field (Cleburne, West) also made the list. There are 14,886 gas wells in the Newark East Field, as of March, 2011, and over 2,800 permitted locations (<http://www.rrc.state.tx.us/data/fielddata/barnettshale.pdf>, accessed March 23, 2011). During 2010, gas production from the Newark East Field 1.8TCF, which accounts for about 28% of the gas produced in Texas:

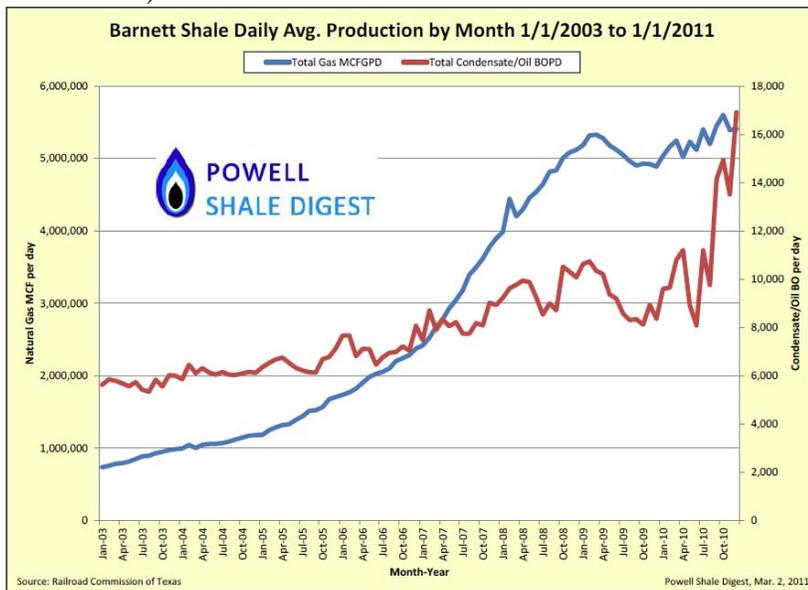
(<http://www.rrc.state.tx.us/data/fielddata/barnettshale.pdf>,

accessed March 23, 2011). More drilling permits were issued for the Barnett in the Newark East field in 2010 (2,157) than were issued in 2009 (1,755), but the number of drilling permits issued in 2010 is still much less than the 4,145 issued in 2008

(<http://www.rrc.state.tx.us/barnettshale/drillingpermitsissued1993-2010.pdf>,

accessed March 23, 2011).

The Powell Shale Digest (www.shaledigest.com) stated that cumulative Barnett production passed 9 TCF of gas in early January, 2011. Production from the Barnett is holding steady at 5.4 BCF/D, but the rate of oil/condensate increase from about 10,000 B/D in July 2010 to over 16,000 B/D in November 2010. This is a consequence of the price differential between gas and liquids, of course, so operators have increased activity in ‘wetter’ portions of the play (e.g., in Montague County located in the oil window).



(used with permission of Gene Powell)

Chattanooga Shale, (Devonian-Mississippian), various basins, U.S.

By Kent Bowker (Bowker Petroleum, LLC)

NORTHERN SHELF, BLACK WARRIOR BASIN, ALABAMA:

GeoMet's Chattanooga Shale program (they call it the Garden City Project) in Blount and Cullman counties in north-central Alabama (north shallow shelf of the Black Warrior Basin) continues to be on hold as GeoMet raises capital. No additional wells were drilled in 2009 or in 2010 on the 65,000 gross acres they have in the project. Currently, GeoMet had four wells producing in Blount County; since 2008 these wells have produced 82 MMCFG but they are all currently shut in. GeoMet continues to seek a 50% partner in the project.

CHATTANOOGA SHALE, NORTH-CENTRAL TENNESSEE (*Appalachian Basin*):

After being “excited” by initial results from their Chattanooga Shale program in Tennessee, CONSOL Energy (formally CNX Gas) has de-emphasized their position in the play in recent analyst presentations and press releases. The company’s previous plan to drill an additional 25 wells in the play in 2010 at a total cost of \$28MM never materialized. CONSOL reported year-end 2009 proved-developed reserves of 12 BCFG, proved-undeveloped of 29 BCFG, probable of 120 BCFG, and possible reserves of 640 BCFG associated with their 244,000 acres in the play; but these reserves were not mentioned in their year-end 2010 report, so it appears that CONSOL has at least temporarily abandoned this project.

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

The Cretaceous (Cenomanian-Turonian) Eagle Ford Group, Gulf Coast Basin, comprises the Eagle Ford Shale and the updip Woodbine Formation in Texas and the updip Tuscaloosa Formation in Louisiana. The Eagle Ford Shale in southwestern Texas has been the target of several operators in the last two years. For many years considered only as the source for oil in Austin Chalk and updip Woodbine and Tuscaloosa clastic reservoirs, the Eagle Ford is now of widespread interest as a self-sourced and -reservoired shale gas and shale oil play. The Eagle Ford Shale trends across Texas from the Mexican border in South Texas east into East Texas and Louisiana, an area roughly 50 miles wide and 400 miles long. The Eagle Ford also produces condensate along the SW-NE trend of the current play that sits astride and just updip the general trend of the underlying Lower Cretaceous carbonate shelf edge.

The first of the Eagle Ford gas wells was drilled in 2008, and it flowed at a rate of 7.6 MCFG per day from a 3,200 foot lateral (first perforation 11,141 feet total vertical depth) with 10 frac stages. The wells that have been completed have initial potential similar to that of the discovery well; they then display a rapid decline in production similar to those in other shale plays. A total of 64 BCF of gas was produced from the Eagle Ford during 2010 (<http://www.rrc.state.tx.us/eagleford/eaglefordproduction.pdf>, accessed March 23, 2011). As for shale oil wells, recently-drilled wells have shown initial production rates of several hundreds of BOPD, and between January 2009 and October 2010, more than 2.5 MMBO was produced from the Eagle Ford in 2010 (Railroad Commission of Texas, <http://www.rrc.state.tx.us/eagleford/eagleford-oilproduction.pdf>, accessed March, 2011).

For the year 2010, there were 1,229 permitted

(http://www.rrc.state.tx.us/eagleford/eagleford_dp_issued_08-10.pdf, accessed March 23, 2011). In February, 2011, the number of permitted wells had increased to 1,132 (Railroad Commission of Texas, <http://www.rrc.state.tx.us/eagleford/images/EagleFordShalePlay201102-large.jpg>). 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 marl beds, with as much as 70% calcite and lesser amounts of quartz; clay content is relatively low (Durham, 2010). 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. The average well cost is between \$5 million to \$6 million dollars (Railroad Commission of Texas, <http://www.rrc.state.tx.us/eagleford/index.php>, accessed July, 2010). The current area of primary interest is where the Eagle Ford is in the oil window, or the wet gas window, due to market

return on liquid commodities. In the future, extensive development of the Eagle Ford in the gas window will be dependant on increased gas market prices. For more information on Eagle Ford production, please refer to the Texas Railroad Commission web link at <http://www.rrc.state.tx.us/eagleford/>.

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.

Early estimates have indicated that there are over 40 TCF of gas reserves in the Fayetteville Shale, although recent studies indicate that the Fayetteville contains an estimated mean undiscovered volume of 13.2 TCF of technically recoverable gas from the formation (Houseknecht and others, 2010). Also, smaller proved reserves of 9.07 TCF were reported to the Fayetteville Shale by the U.S. Energy Information Administration in 2010, which is based on data provided by operators on Form EIA-23. Estimated ultimate recovery (EUR) for a horizontal well is 2.9 BCF/well. Cumulative production of Fayetteville Shale by the end of 2010 has totaled 1,658,028,731 MCF from 3,064 wells. Annual production of Fayetteville Shale for 2010 is 775,527,728 MCF from 2,950 producing wells, about 50% increase compared with 2009 production. Initial production rates of horizontal wells have recently averaged about 2,800 MCF/day. For more Fayetteville Shale production information, please refer to the Arkansas Oil and Gas Commission (AOGC) web link at <http://www.aogc.state.ar.us/Fayproinfo.htm>.

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. As of February 2011, there are a total of 3,068 producing gas wells in the Fayetteville Shale play. Most of Fayetteville Shale wells are horizontal wells and have been fracture stimulated using slickwater or cross-linked gel fluids. Horizontal lateral lengths are continually increasing in Fayetteville Shale wells. Horizontal wells drilled from 2009 to 2010 averaged 4,720 feet in lateral length with some wells up to 7,000 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).

Southwestern Energy has been the largest player since 2004 when production started. It holds approximately 875,000 net acres in the play area and estimates 11 TCF of recoverable gas for its acreage position. Second-largest producer Chesapeake Energy leases about 487,000 net acres with about 9 TCF of recoverable gas. It announced on February 21, 2011 that it will sell all of the company's interests in leasehold and producing natural gas properties in the Fayetteville Shale play to BHP Billiton Petroleum, a wholly owned subsidiary of BHP Billiton Limited, for \$4.75 billion in cash. The deal is expected to close in the first half of 2011. Dated back to 2008, Chesapeake already sold approximately a 25% interest in Fayetteville assets to BP for \$1.9 billion. Petrohawk Energy, which includes subsidiaries of One Tec Operating LLC and KCS Resource Inc., announced on December 23, 2010 that it has completed the sale of its natural gas assets in the Fayetteville Shale to another active Fayetteville Shale producer XTO Energy Inc., a subsidiary of ExxonMobil, for \$575 million. In addition, Petrohawk has entered into a definitive agreement with XTO Energy to sell its midstream assets in the Fayetteville Shale for \$75 million. Other operators involved with Fayetteville Shale exploration and development ventures include:

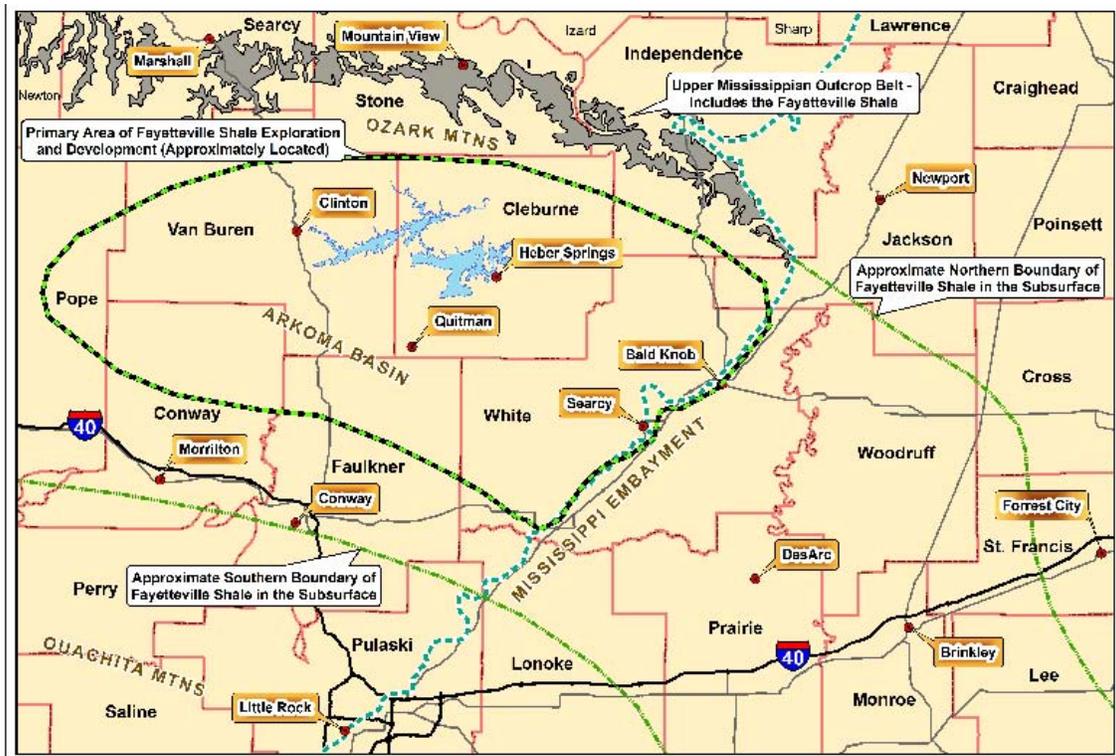


Figure 1. Primary area of Fayetteville Shale exploration and development in Arkansas.

The top three operators of the Fayetteville gas shale play as of February 2011 based on numbers of producing wells are as follows (Figure 2):

- 1) Seeco Inc. (an exploration subsidiary of Southwestern Energy) (1821 wells)
- 2) Chesapeake Operating Inc. (738 wells)
- 3) XTO Energy, Inc. (a subsidiary of ExxonMobil) (501 wells)

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

(1) The home page of the Arkansas Geological Survey (AGS) website is: <http://www.geology.arkansas.gov/home/index.htm> and the AGS Fayetteville Shale well location maps can be viewed at http://www.geology.arkansas.gov/home/fayetteville_play.htm. AGS updates these maps and associated well database (in Excel® format) online every two weeks.

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

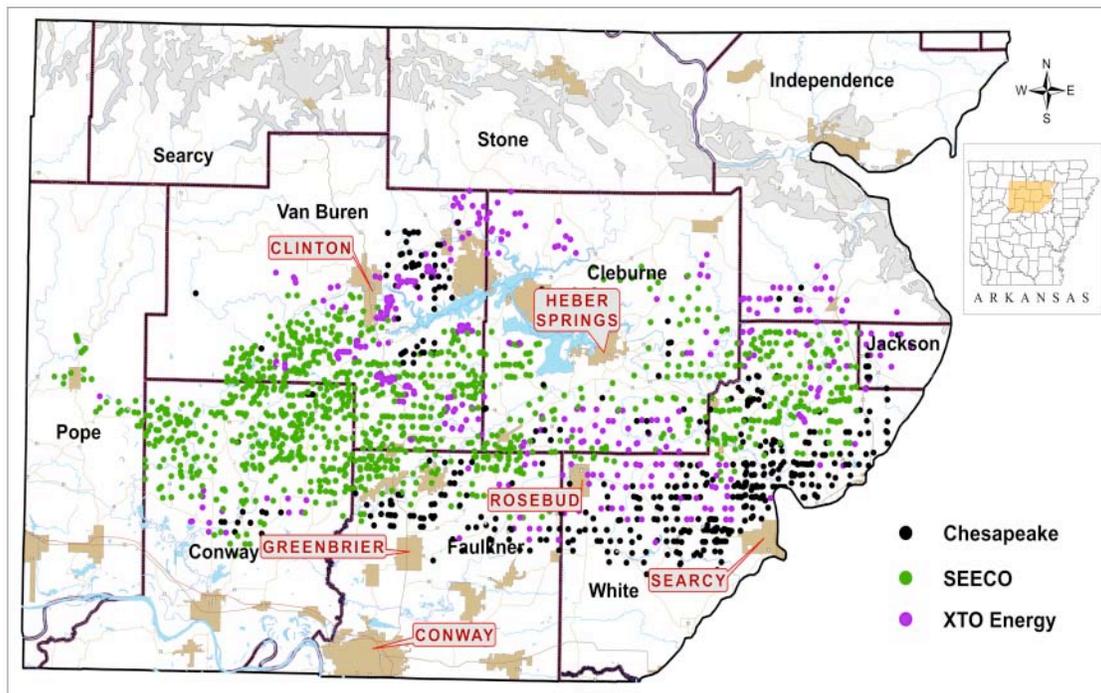


Figure 2. Location map of Fayetteville Shale producing wells by top 3 operators as of February, 2011.

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. AOGC imposed a six-month moratorium on new injection wells in the area that took effect in January to allow time to determine what relationship, if any, there is between the wastewater injection and the earthquakes. The quake intensified during the last two weeks of February, culminating in a 4.7-magnitude earthquake, the most powerful reported in Arkansas in 35 years, that struck near Greenbrier on February 27, 2011. AOGC held a special meeting on March 4 to issue an emergency order immediately shutting down all injection operations of two wells through the last day of the regularly scheduled hearing in March 2011. A recently discovered fault near the shut-down wells is nearly 7.5 miles long, which enables to generate a quake of around 6.0 in magnitude.

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

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

by Creties Jenkins (Degolyer and Macnaughton)

The Jurassic Haynesville Shale, and overlying Bossier Shale, generate thermogenic gas production from wells throughout the Texas-Louisiana-Mississippi Salt Basin in western Louisiana and eastern Texas (Fig. 1). Interest in the Haynesville/Bossier has been significant over the last few years, and as of November, 2010, 809 wells were producing gas, 132 were being drilled, and 288 wells were permitted but drilling had not begun. Of note is that the producing horizons are overpressured (0.7-0.9 psi/ft).

The Haynesville covers an area of approximately 9,000 square miles with an average thickness of 200 to 300 feet. The thickness and areal extent of the Haynesville has allowed operators to evaluate a wide variety of well spacings with companies now focusing on drilling six to eight wells per square mile, and each well was drilled with a 5,000 foot long horizontal component. Original gas-in-place is estimated to be 717 TCF and technically recoverable resources are estimated at 251 TCFG.

Initial production rates range from less than 3 to more than 24 MMCFG/day per well. Declines are very steep, exceeding 80% in the first year with estimated ultimate recoveries (EURs) ranging from 3 to more than 10 BCFG per well. Drilling and completion costs range from \$6-9 million per well and includes 12-15 fracture stages stimulated with slickwater and either ceramic or resin-coated proppant. Several companies operating in the Haynesville have been choking back new wells in an attempt to preserve fracture conductivity and reservoir permeability. This results in lower initial gas rates, but could translate into significantly higher ultimate recoveries per well if the technique proves successful over the long term. Additional information on the Haynesville can be found at the Louisiana Oil and Gas association (<http://loga.la/haynesville-shale-news/>, accessed March 14, 2011).

Gas Shale Basin	Barnett	Fayetteville	Haynesville	Marcellus	Woodford	Antrim	New Albany
Estimated Basin Area, square miles	5,000	9,000	9,000	95,000	11,000	12,000	43,500
Depth, ft	6,500 - 8,500 ⁶²	1,000 - 7,000 ⁶³	10,500 - 13,500 ⁶⁴	4,000 - 8,500 ⁶⁵	6,000 - 11,000 ⁶⁶	600 - 2,200 ⁶⁷	500 - 2,000 ⁶⁸
Net Thickness, ft	100 - 600 ⁶⁹	20 - 200 ⁷⁰	200 ⁷¹ - 300 ⁷²	50 - 200 ⁷³	120 - 220 ⁷⁴	70 - 120 ⁷⁵	50 - 100 ⁷⁶
Depth to Base of Treatable Water ⁷ , ft	~1200	~500 ⁹⁷	~400	~850	~400	~300	~400
Rock Column Thickness between Top of Pay and Bottom of Treatable Water, ft	5,300 - 7,300	500 - 6,500	10,100 - 13,100	2,125 - 7650	5,600 - 10,600	300 - 1,900	100 - 1,600
Total Organic Carbon, %	4.5 ⁹⁸	4.0 - 9.8 ⁹⁹	0.5 - 4.0 ¹⁰⁰	3 - 12 ¹⁰¹	1 - 14 ¹⁰²	1 - 20 ¹⁰³	1 - 25 ¹⁰⁴
Total Porosity, %	4 - 5 ¹⁰⁵	2 - 8 ¹⁰⁶	8 - 9 ¹⁰⁷	10 ¹⁰⁸	3 - 9 ¹⁰⁹	9 ¹¹⁰	10 - 14 ¹¹¹
Gas Content, scf/ton	300 - 350 ¹¹²	60 - 220 ¹¹³	100 - 330 ¹¹⁴	60 - 100 ¹¹⁵	200 - 300 ¹¹⁶	40 - 100 ¹¹⁷	40 - 80 ¹¹⁸
Water Production, Barrels water/day	N/A	N/A	N/A	N/A	N/A	5 - 500 ¹¹⁹	5 - 500 ¹²⁰
Well spacing, acres	60 - 160 ¹²¹	80 - 160	40 - 560 ¹²²	40 - 160 ¹²³	640 ¹²⁴	40 - 160 ¹²⁵	80 ¹²⁶
Original Gas-In-Place, tcf ¹²⁷	327	52	717	1,500	23	76	160
Technically Recoverable Resources, tcf ¹²⁸	44	41.6	251	262	11.4	20	19.2

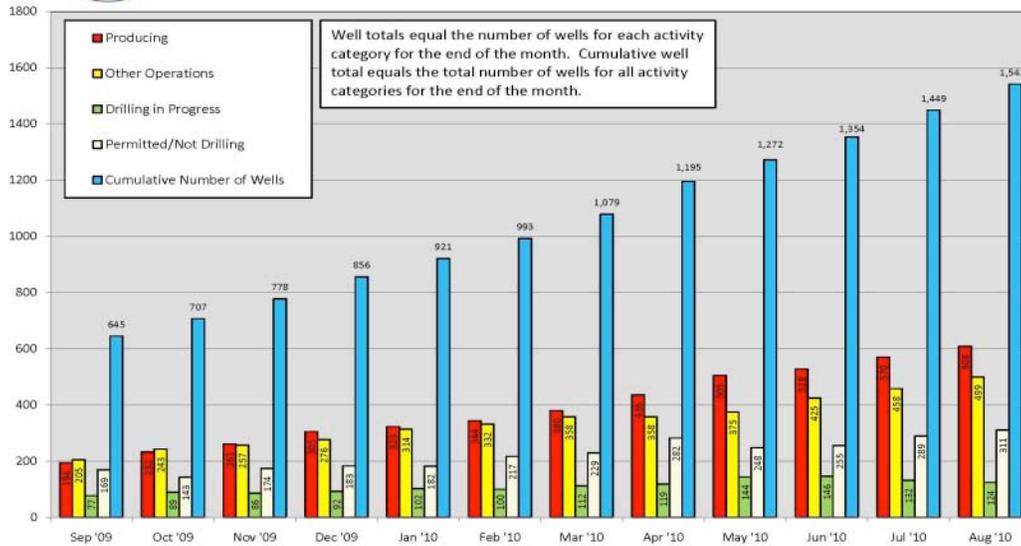
NOTE: Information presented in this table, such as Original Gas-in-Place and Technically Recoverable Resources, is presented for general comparative purposes only. The numbers provided are based on the sources shown and this research did not include a resource evaluation. Rather, publically available data was obtained from a variety of sources and is presented for general characterization and comparison. Resource estimates for any basin may vary greatly depending on individual company experience, data available at the time the estimate was performed, and other factors. Furthermore, these estimates are likely to change as production methods and technologies improve.

Mcf = thousands of cubic feet of gas
 scf = standard cubic feet of gas
 tcf = trillions of cubic feet of gas
 # = For the Depth to base of treatable water data, the data was based on depth data from state oil and gas agencies and state geological survey data.
 N/A = Data not available

For additional Haynesville information, visit these websites:
<http://geology.com/articles/haynesville-shale.shtml>
<http://oilshalegas.com/haynesvilleshale.html>
<http://loga.la/haynesville-shale-news/>



Number of Haynesville Shale Wells by Month



Maquoketa and New Albany Shales, Illinois Basin, U.S.

By Rick Sumner (Countrymark Energy Resources, LLC)

MAQUOKETA SHALE:

In contrast to the reported activity in the Ordovician Utica Shale in Michigan and the Appalachian areas in the last decade, the Ordovician Maquoketa Shale (Utica equivalent) of the Illinois Basin has received little if any industry attention. Some specific information on the Maquoketa follows:

- The Maquoketa Shale varies in thickness from approximately 200 feet in far-northwestern Indiana to over 900 feet in far eastern Indiana and the basal organic-rich unit, the Scales member, varies from roughly 150 feet in northwestern Indiana to over 300 feet in southwestern and eastern Indiana (Gray, 1972).
- Published data indicate that the dark shales of the Maquoketa have a range of Total Organic Carbon (TOC) from 2% to 12% (Gray, 1972; Autry et al, 1987).
- Bitumen ratios, Rock-Eval pyrolysis and illite crystallinity data indicate that the Maquoketa has reached a higher level of thermal maturity than either the New Albany or Antrim shales (Guthrie, 1989).
- Twenty small gas fields are listed in the files of the Indiana Geological Survey as having produced gas from Ordovician rocks younger than the Trenton Limestone, which include the Scales and the limey Ft. Atkinson members of the Maquoketa and the Ordovician Lexington Limestone that interfingers laterally with the shales of the Maquoketa in southeasternmost Indiana (Gutstadt, 1958; Gray, 1972).

In summary, the Maquoketa appears to be a thick, organic-rich shale that has reached thermal maturity in parts of the basin; as such, the Ordovician Maquoketa Shale of the Illinois Basin may have some potential as an unconventional shale gas target.

NEW ALBANY SHALE:

There has been virtually no additional shale gas drilling in the Illinois Basin since the EMD Gas Shales Committee 2011 Mid-Year Report of November, 2010. It is likely that low gas prices have stalled additional shale gas activity in the basin, with fewer than 10 new wells drilled since late 2010. The following information on the New Albany and Maquoketa Shales is repeated from the 2011 Mid-Year Report.

The New Albany Shale play in the Illinois Basin has manifested into two separate plays; one a shallow (<1,500 feet true vertical depth) vertical play, primarily concentrated along the eastern basin rim, and the other a deeper (1,500-3,000 feet tvd) horizontal play concentrated in southwestern Indiana and western Kentucky. The shallow vertical play has largely been concentrated in areas where the shale has historically produced in Harrison County, Indiana and Meade County, Kentucky, both areas where the shale has been produced for more than 100 years (Hassenmueller and Comer, 1994). Wells in this vertical play typically average 75-150 MCF/D but individual wells have been brought on at more than 1MMCF/D. Likewise, the results of early New Albany Shale drilling in the deeper horizontal play have been mixed with individual well tests running upwards of 7 MMCF/D but wells on production making in the range of 150-300 MCF/D on average. The current activity in both of these plays is focused on development drilling on existing projects. Breitburn Operating, LP continues to be an active player in the vertical play. In the horizontal play Atlas Energy Indiana, LLC and El Paso E&P Co., LLP both continue to develop existing projects in Knox, Daviess, Greene and Dubois counties in Indiana. On the Kentucky side CNX Gas Co., LLC are drilling on their projects in Meade and McLean counties.

The companies mentioned above along with others continue to hold large shale acreage positions in the Illinois Basin but New Albany Shale drilling activity in the basin has continued to decline from its peak in 2005-07. Nevertheless, the State of Indiana has issued 62 New Albany permits thus far in 2010, while Kentucky has issued less than a dozen New Albany permits in the Illinois Basin portion of that state thus far in 2010. Illinois has not issued any New Albany Shale permits this year.

Sources of information for New Albany and Maquoketa Shales:

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

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

The Marcellus Shale of the Appalachian Basin, according to the Energy Information Administration (EIA), is the most areally extensive shale play in the U.S., covering 95,000 square miles (http://www.eia.gov/oil_gas/rpd/shale_gas.pdf). The EIA also shows the gross thickness of the Marcellus Shale increases to the northeast, with the thickest area located in northeastern Pennsylvania (http://www.eia.gov/oil_gas/rpd/shaleusa5.pdf). 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 (Cardott and others, 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, 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). Horizontal drilling and induced fractures provide the porosity and permeability which allow for commercial production of natural gas from this formation. “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 water and used hydraulic fracturing water, called “flow-back” water, are being addressed with a variety of approaches including recycling and reuse of hydraulic fracturing water.

MARYLAND:

In 2009, Samson Investment Company submitted applications to drill 3 wells in Garrett County, and one well in Allegany County that would target the Marcellus Shale. At this time, none of the permits have been approved by the Maryland Department of the Environment (MDE). There is no production from the Marcellus Shale in Maryland.

NEW YORK:

As of July, 2010, there were 27 wells with Marcellus Shale listed as the producing formation, but only 16 had reported production of 56.1 billion cubic feet of gas in the previous 12 months. There was no reported oil production. Between 2005 and 2009, 21 wells were drilled targeting the Marcellus Shale. These wells were drilled by Talisman Energy, EOG Resources, Quest Eastern Resource, Eastern American Energy, Chesapeake Appalachia, Petroleum Development Corp., Norse Energy Corp, U.S. Energy Development, Fortuna Energy, and MegaEnergy Operating. The governor of New York has ordered the NY Department of Environmental Conservation (DEC) to publish a Revised Draft Supplemental Generic Environmental Impact Statement (SGEIS) by June 1, 2011, that will be subject to a public comment period, and afterward, to make recommendations for regulatory changes. In the

meantime, there is essentially a moratorium on horizontal drilling and high-volume hydraulic fracturing of the Marcellus Shale and other low permeability reservoirs in New York.

OHIO:

As of February, 2011, 76 drilling permits were issued for wells targeting the Marcellus Shale, 9 of which were for horizontal wells. To date, 44 vertical wells and 2 horizontal wells have been drilled into the Marcellus. The Ohio Department of Natural Resources reported that as much as 215 million cubic feet of gas, 3,092 barrels of oil, and 45,305 barrels of water were produced from 41 wells in the Marcellus Shale between 2006 and 2009. There are currently about 30 wells producing from the Marcellus Shale in easternmost Ohio.

PENNSYLVANIA:

Between July, 2009, and June, 2010, over 194 billion cubic feet (BCF) of gas, 187,856 barrels of condensate, and 453,378 barrels of oil were produced from about 850 active wells in the Marcellus Shale. Almost 360 of those wells were horizontal wells. As of October 2010, the Pennsylvania Department of Environmental Protection (DEP) had approved over 4500 active permits in about 35 counties. As of June 30, 2010, 67 Marcellus operators had submitted production reports, and 7 operators had not. Between July, 2009, and June, 2010, Range Resources, Chesapeake Appalachia, Talisman Energy, Cabot Oil & Gas, Atlas Resources, and East Resources were the largest producers, each with production over 10 BCF of gas.

VIRGINIA:

In 2009, Carrizo Oil & Gas, Inc. submitted an application to drill a well in Rockingham County targeting the Marcellus Shale. County and local officials have refused to issue a special-use permit needed for the well, so the company is no longer actively pursuing the drilling permit. There is commingled gas production from the Marcellus Shale in southwest Virginia, but the quantity is unknown.

WEST VIRGINIA:

The West Virginia Geological and Economic Survey (WVGES) identified almost 400 wells permitted in 2009 which were targeting the Marcellus Shale, whereas by October, 2010, there had been 112 permits granted to drill to the Marcellus. All but 15 of the permits in 2010 were for horizontal wells. As of October, 2010, production of about 4 billion cubic feet for 2006, over 8 billion cubic feet for 2007, and almost 15 billion cubic feet for 2008 can be attributed to wells with Marcellus Shale reported as at least one of the pays. Total production from these 1200 wells for 2005-2008 is over 27.7 billion cubic feet of gas. The Marcellus Shale was completed in many earlier vertical wells along with shallower shales and sandstones. If wells with the Marcellus Shale listed as the only pay zone are examined, the cumulative production from 2005 to 2008 was about 3.9 billion cubic feet of gas. Based on volume, the major producers include Chesapeake Appalachia, Columbia Natural Resources, Cabot Oil & Gas, Hall Drilling, Eastern American Energy, and New River Energy. In April, 2010, Dominion announced it planned to expand processing and fractionation capacity for natural gas and natural gas liquids that are produced from the Marcellus Shale in West Virginia, Ohio and Pennsylvania (OGJ Newsletter, 2010).

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/oil_gas/rpd/shaleusa5.pdf

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

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

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

<http://www.mgs.md.gov/geo/marcellus.html>

[http://www.mde.state.md.us/programs/Land/mining/Non%20Coal%20Mining/Pages/Programs/LandPrograms/Minin
g/mog/naturalgas.aspx](http://www.mde.state.md.us/programs/Land/mining/Non%20Coal%20Mining/Pages/Programs/LandPrograms/Minin
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<http://www.dec.ny.gov/energy/46288.html>
<http://www.dec.ny.gov/energy/36159.html>
<http://www.dec.ny.gov/energy/30438.html>
http://www.dec.ny.gov/docs/materials_minerals_pdf/GWPCMarcellus.pdf
<http://www.ohiodnr.com/mineral/oil/tabid/10371/Default.aspx>
<http://www.ohiodnr.com/oil/shale/tabid/23174/Default.aspx>
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<http://www.dcnr.state.pa.us/topogeo/pub/pageolmag/pdfs/v38n1.pdf>
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Monterey Formation (Miocene), Various California Basins, U.S.

by Margaret A. Keller (U.S. Geological Survey), originally presented in Annual Report, 4/2010

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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Neal/Floyd Shale (Mississippian), Black Warrior Basin, U.S.

by Kent A. Bowker (Bowker Petroleum, LLC)

Currently, there is no drilling activity in the Neal Shale play in the basin. Most of the acreage positions that were put together 5 to 6 years ago are starting to expire.

In the Chattanooga Shale play in the southern portion of the basin, Energen Resources has decided to completely write off their holdings of 221,000 gross acres; and, in addition, they have written off their 344,000 acres in the Conasauga trend. The announcement was made on September 17, 2010, about two months after the company performed a fracture stimulation on a horizontal Chattanooga well in southern Tuscaloosa County. This frac job appears to be the company's last activity in the play.

Also in central Alabama, in July/August Hillwood Energy (Dallas) and their partner Endeavour International Corporation drilled and cased a 10,713-ft vertical wildcat Greene County. This well is on strike with a previous Chattanooga test drilled several years ago by EOG Resources which test gas from Devonian shales before being plugged. Hillwood is currently evaluating the well (Tate 9-4 #1).

UTAH SHALES, U.S.

by Thomas C. Chidsey, Jr., Craig D. Morgan, and Robert Resselar (Utah Geological Survey); Lauren Birgenheier (EGI, University of Utah); S. Robert Bereskin (Bereskin and Associates, Inc.); and Steven Schamel (GeoX Consulting Inc.)

UINTA BASIN MANCOS SHALE PLAY:

Overview:

The Upper Cretaceous Mancos Shale is an emerging shale-gas play in the Uinta Basin of eastern Utah. Compared to established shale gas plays, like the Barnett, the Mancos is geologically distinct in that it is an extremely thick (averaging 4,000 ft) package of various shale lithotypes with varying organic content. Most of the Mancos is organically lean, but it contains richer condensed sections and gas shows are common throughout.

The Mancos Shale was deposited in the foreland basin of the Sevier orogeny, on the western margin of the Western Interior Seaway. The Mancos consists mostly of offshore marine mudstone that grades westward into coarser clastic rocks shed from the orogenic belt. The Mancos displays an overall progradational stacking pattern moving from west to east, illustrating the progressive shallowing and filling of the seaway. In detail, however, higher frequency changes in accommodation and sediment supply caused significant variations in sedimentary composition and texture. For example, at least five depositional sequences have been identified in the lower 650 ft of the Mancos alone (Anderson and Harris, 2006). Higher in the Mancos, the Prairie Canyon (Mancos B) Member is a heterolithic siltstone to sandstone, whose origin and correlations are poorly known. Understanding the distribution of the subunits within the Mancos and the resultant variations in reservoir properties poses a major challenge to shale-gas exploration.

Schamel (2006) listed four members of the Mancos with shale-gas reservoir potential. From top to base, these are the Prairie Canyon Member, the Lower Blue Gate Shale Member, the Juana Lopez Member, and the Tropic-Tununk Shale. The potential shale-gas members are up to 1,500 ft thick, have 2% to 5% porosity, and contain some overpressured zones.

Anderson and Harris (2006) reported a TOC range of 0.44 to 4.32%, and an average of 1.23% for the lower Mancos in the southeastern Uinta Basin. These values seem consistent with other recent reports (e.g., Schamel, 2006; Fisher, 2007). In the southeastern Uinta Basin, vitrinite reflectance ranges from

0.60% to 1.76% at the top of the Mancos, and from 0.70% to 3.6% at the base (Nuccio and Roberts, 2003).

Key regional fracture directions are northwest-southeast and north northeast-south southwest, with minor fracture sets trending east-west. However, localized deformation within the basin introduces additional local fracture orientations that add complexity to these patterns.

Mancos gas in place and recoverable reserves are poorly understood, and the exact extent of the play has not been defined, due to the limited amount of exploration and production. Estimated in-place gas is reportedly between 280 and 350 BCF/mi², with a projected estimated ultimate recovery of 5% to 15% of in-place gas. Initial flow rates range from 1000 to 2000 MCFPD. For wells in the northeastern Uinta Basin, QEP Resources estimate 3 to 6 BCFG recoverable, and initial potentials of 5 MMCFGPD have been reported. Not surprisingly, recovery will vary widely throughout different areas of the basin.

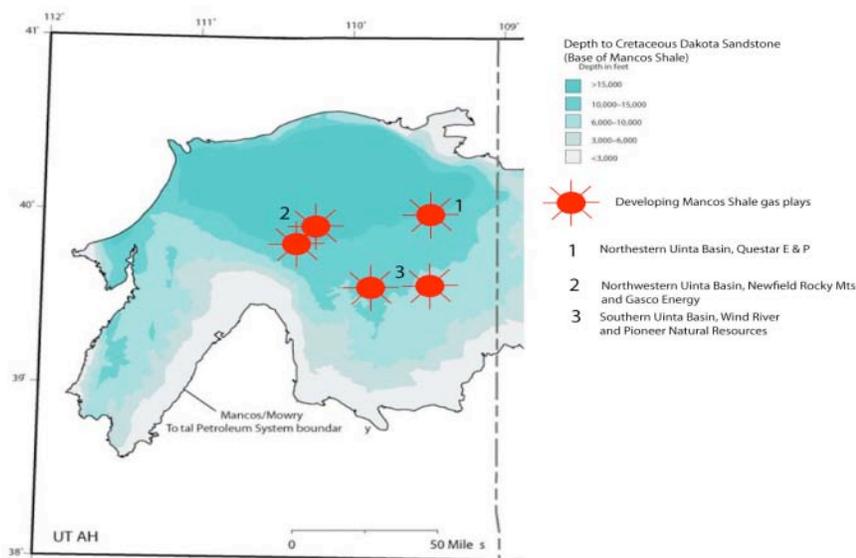
Activity:

Although entrepreneurs have recognized the productive potential for many years, there are several reasons that the Mancos Shale is viewed as a promising, emerging shale gas play in the Uinta Basin. First, historical production from sandstone-dominated and heterolithic (interbedded and interlaminated sandstone and mudrock) intervals, such as the Prairie Canyon Member (formerly Mancos B), has been economical. Secondly, production from other mud-dominated Mancos intervals is now proven within portions of the Uinta Basin.

The Utah Division of Oil, Gas, and Mining (DOG M) has identified 36 fields with producing or potential natural gas reservoirs in the Mancos Shale. In spite of this, the emerging Mancos Shale gas play only has a few completions scattered over the Uinta Basin. Most Mancos completions are commingled with gas production from overlying and underlying sandstone reservoirs. The majority of Mancos gas production to date has come from conventionally completed vertical wells in the sandier facies like the Prairie Canyon and Juana Lopez Members.

Little horizontal drilling has been attempted because specific horizontal targets within the thick Mancos have not been identified. The first horizontal well in the Mancos—XTO Energy's HCU 1-30F—was completed very recently (late 2010) and most of the well data are still confidential. The well was drilled in the Natural Buttes field and the first production data on the DOGM Web site were 11,457 MCF gas and 288 barrels of oil during six days in October 2010. In addition, Gasco Production Co. received drilling permits in May 2010 for two horizontal tests of Mancos zones: the 42-17H-11-15 Gate Canyon Federal and 32-22H-11-15 Gate Canyon Federal wells (sections 17 and 22, T. 11 S., R. 15 E., respectively, Duchesne County on the southwestern flank of the Uinta Basin).

Current production from the Mancos Shale in the Uinta Basin is modest, but increasing as a result of recent drilling campaigns, led by several companies including Questar E&P, Wind River Resources, Newfield, and Gasco. For instance, in the northeastern Uinta Basin, Questar has drilled over 50 deep wells in the Mancos during 2007-2008, which have significantly increased Mancos production. In the northwestern Uinta Basin, Newfield has completed six and Gasco has completed 18 deep Mancos wells. Wind River Resources and Pioneer Natural Resources have completed several wells in the Mancos in southern Uinta Basin. In July 2010, Bill Barrett Corp. agreed to a drilling plan with the Southern Utah Wilderness Alliance to develop gas resources, including the Mancos, in the West Tavaputs area east of the Book Cliffs in the southern Uinta Basin. This plan has now received federal approval from the Bureau of Land Management. Barrett holds 44,700 gross acres in the area.



Primary areas of emerging Mancos Shale gas production. Depth to Cretaceous Dakota Sandstone from Roberts, 2003.

New Research:

The Utah Geological Survey has been awarded funding from the Research Partnership to Secure Energy for America (RPSEA) to evaluate the resource potential and best practices for the Uinta Basin Mancos Shale gas play. To accomplish this, the project will:

1. Characterize the geology (sedimentology; stratigraphy; organic, stable isotope, and inorganic geochemistry; natural fracture analysis; and geophysical and 3-D seismic analysis) of the Mancos Shale in the Uinta Basin in order to identify premium target zones and determine the resource potential.

2. Define the geologic parameters, currently poorly understood, that determine various geomechanical properties (e.g., brittleness, “fracability”). These parameters will be used to predict regions of brittleness and shale gas prospectivity, from an engineering perspective.

3. Establish best drilling, completion, and production techniques for specific targeted intervals based on their rock properties.

The geologic and engineering evaluation will use public and proprietary datasets; well logs, core, cuttings; geochemical data; 3-D seismic information; and production data. This project will produce a GIS-based integrated geologic characterization of the Mancos Shale along with drilling, completion, and stimulation method recommendations. The investigation will quantify and potentially lower the economic risk of exploration and development in the Mancos Shale gas play, encouraging larger-scale, commercial production. To integrate the geologic and engineering disciplines, the project team includes specialists in sedimentary geology, geochemistry, geomechanics, production engineering, petrophysical log evaluation, seismic evaluation, reservoir simulation, and hydraulic fracturing. Project team members have been assembled from the Utah Geological Survey; the University of Utah’s Energy & Geoscience Institute, Geology and Geophysics Department, and Chemical Engineering Department; and Halliburton Energy Services. QEP Resources, Gasco Energy, Wind River Resources, and Pioneer Natural Resources, will participate in the project by donating data. Many other Uinta Basin gas producers will participate as Advisory Board members, and may contribute data as the project progresses.

For information about this ongoing project including available posters (in pdf), deliverables, etc., refer to the Utah Geological Survey's project Webpage http://geology.utah.gov/emp/shalegas/Cret_shalegas/index.htm.

RECENT PRESENTATIONS:

“Depositional Controls on the Organic-Rich Juana Lopez Member of the Mancos Shale, Southeastern Uinta Basin, Utah,” by Donna Anderson, June 15, 2010, at the AAPG Rocky Mountain Section Meeting in Durango, CO.

“The Mancos Shale: Lithotyping and Play Characterization in a Cretaceous Mixed Sandstone-Mudstone System,” by Mary Milner and S. Robert Bereskin, June 15, 2010, at the AAPG Rocky Mountain Section Meeting in Durango, CO.

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CENTRAL UTAH MISSISSIPPIAN/PENNSYLVANIAN SHALE GAS PLAY:

Overview:

Paleozoic shales 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 and Mississippian Delle Phosphatic shales of central Utah. The Manning Canyon Shale 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. The Delle Phosphatic Shale is a member of the Chainman Shale, Deseret Limestone, and Little Flat Formation. The Delle is composed of interbedded organic-rich phosphatic shale, siltstone, and limestone deposited in a starved basin at the foot of the Paleozoic carbonate ramp. The member is typically 100 to 200 ft thick.

Although the organic content of some of these shales is partially known, the reservoir quality and the basic rock mechanic data so important to successful completions are virtually unknown. In addition, the distribution and thickness of these rocks are poorly mapped and the vertical succession and regional correlation of the Manning Canyon and Delle Phosphatic has not been interpreted in a sequence

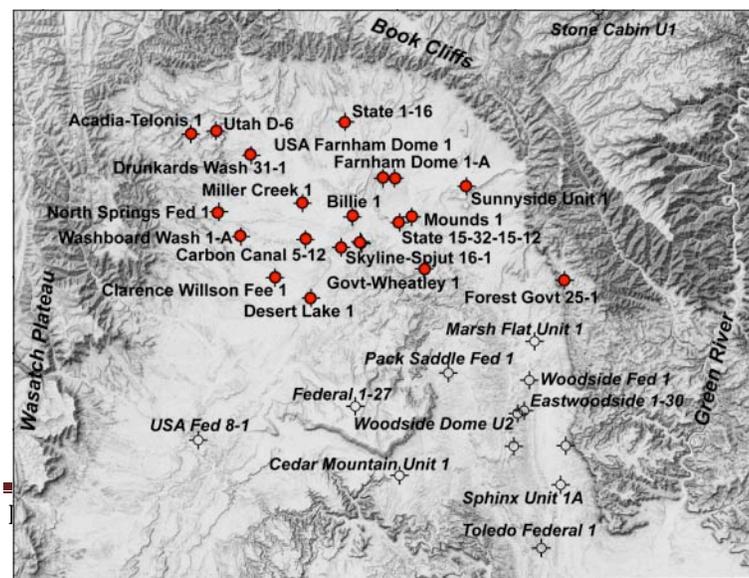
stratigraphic framework. The burial history of the Manning Canyon and Delle Phosphatic appears complex and probably varies widely from deep burial in the Permian Oquirrh Basin (>10,000 ft of overlying Pennsylvanian and Permian strata) to shallower burial along the Paleozoic shelf of central Utah. There are no published studies of the best completion practices for the Manning Canyon and Delle Phosphatic shales. Exploratory efforts are just beginning to target this frontier gas shale play.

Activity:

No new drilling activity targeting the Manning Canyon Shale occurred in 2010. In 2008, Bill Barrett Corporation and its partner ConocoPhillips continued to acquire leasehold acreage in a 58,000-acre area named “Hook” targeting the Manning Canyon Shale. Barrett (50% working interest with ConocoPhillips) drilled the 15-32-15-12 State well (section 32, T. 15 S., R. 12 E., Carbon County) to a total depth 7,585 ft in the Hook prospect targeting the Manning Canyon Shale. The Manning Canyon consisted of 589 ft of shale over a total formation thickness of 816 ft, 422 ft of which was cored. The well analysis indicated good gas shows and high gas contents from core samples. In May 2009, the company completed a horizontal well with a 3,700-foot horizontal lateral offsetting the vertical well in the same section. The State 16H-32 was reported to have flowed natural gas at a subcommercial rate from an interval below 8,000 ft and completed as a dry hole. The Utah Division of Oil, Gas, and Mining approved Barrett’s request to drill a second horizontal well in the section. The company plans on drilling the 8E-32-15-12 Federal well with a longer section and using improved completion techniques based on the information acquired from their first horizontal well. In addition, Barrett has locations staked for two additional Manning Canyon wells in Carbon and Emery Counties within its Hook prospect area. Both locations have potential spud dates in 2010. The company also plans to conduct a 3-D seismic program in the area covering 142 mi². The program is still under review by the Bureau of Land Management.

West of the Hook area, Shell Western Exploration & Production, Inc. drilled and cored the Manning Canyon Shale in the 5-12 Carbon Canal well (section 12, T. 16 S., R. 10 E., Emery County). The well is reported as a gas discovery with an initial flow rate of 468 MCFGPD and 1,750 bbls of water daily. Production is from three hydraulically fractured Manning Canyon 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 has staked two additional 9,400 ft wells to test potential Paleozoic shale gas reservoirs 3.5 mi southwest and 6 mi west-northwest in Emery and Carbon Counties, respectively.

Within the same area as Barrett is exploring, Genesis Petroleum U.S. has announced plans to reenter a former Triassic Moenkopi Formation producer at Grassy Trail Creek field and drill 7,200 ft to the Precambrian. The 2-43X State (section 2, T. 16 S., R. 12 E., Emery County) will evaluate the Manning Canyon and other Mississippian units.



Manning Canyon Shale well penetrations, northern San Rafael Swell area.

New Research:

Under the direction of the Utah Geological Survey and with project funding provided by RPSEA, research is being conducted on well cuttings, cores, and outcrops to define specific Manning Canyon play areas. For example, at the north end of the San Rafael Swell in central Utah, the 22 exploration wells that fully penetrate the Manning Canyon Shale, two of which were drilled in 2008, define a 600-mi² 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 Uncompaghere uplift to the northeast and the Emery arch to the south. RockEval geochemistry 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 are in the 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.

The most complete exposed section (1,544 ft thick) of Manning Canyon is in Soldier Creek Canyon in the Oquirrh Mountains of north-central Utah. These rocks, particularly the carbonates, show various depositional environments, which can be used to better understand the Manning Canyon regionally and its potential for hydrocarbon generation. The shale/claystone units are: (1) black to shades of gray, (2) calcareous or non-calcareous, and (3) non-fossiliferous or contain plant and other fossil fragments (brachiopods). These units are often interbedded with thin, non-fossiliferous limestone beds. Palynomorphs indicate a middle to late Chesterian age, and depositional environments include: (1) lower coastal plain, (2) marsh to restricted bay, and (3) open shelf. The limestone units are calcareous to shaly or silty (quartz) mudstone and vary from thinly laminated to thick bedded or massive; some display cross-bedding while others are bioturbated. Carbonate fabrics include skeletal grainstones through wackestones, and microbial (stromatolitic and thrombolitic) lime mudstones. These carbonates often contain a variety of marine fossils, such as brachiopods, bryozoans, crinoids, benthic forams, corals, trilobite carapaces, bivalve molluscs, sponge spicules, and ostracodes, while some units are non-fossiliferous. Non-skeletal grains consist of intraclasts, coated grains, detrital quartz, and peloids. Depositional environments include: (1) shallow, low to moderate energy subtidal, (2) salinity-restricted platform interior, (3) moderate energy, open marine platform, (4) quiet (below wave and storm base), deep, low-oxygenated water and (5) high-energy, nearshore terrigenous settings. Sandstone units consist of fine-grained, subangular to subrounded quartz grains with mild metamorphic overprints. They vary from poor to well sorted, contain clay, and are medium to massive bedded with cross-beds. These units represent an upper shoreface environment.

For information about this ongoing project including available posters (in pdf), deliverables, etc., refer to the Utah Geological Survey's project Webpage http://geology.utah.gov/emp/shalegas/paleo_shalegas/index.htm.

Recent Presentations:

“Manning Canyon Shale: Utah's Newest Shale Gas Resource,” by Steve Schamel and Jeffrey Quick, April 14, 2010, at the AAPG annual convention in New Orleans, Louisiana.

“Burial Histories of Mississippian Potential Source and Shale-Gas Reservoir Rocks, Central and Western Utah,” by Robert Ressetar, June 15, 2010, at the AAPG Rocky Mountain Section Meeting in Durango, Colorado.

“Manning Canyon Shale: An Emerging Shale Gas Resource” by Steve Schamel and Jeffrey Quick, June 15, 2010, at the AAPG Rocky Mountain Section Meeting in Durango, Colorado.

Paradox Basin Pennsylvanian Shale Gas Play

Overview:

In the Paradox Basin of southeastern Utah and southwestern Colorado, cyclic shale units in the Pennsylvanian Paradox Formation consist of thinly interbedded, black, organic-rich marine shale; dolomitic siltstone; dolomite; and anhydrite. They generally range in thickness between 25 and 50 ft. These units contain TOC as high as 15% with type III and mixed type II-III kerogen, are naturally fractured (usually on the crest of anticlinal closures), and are typically often overpressured. They are the source rocks for the oil produced in the basin. In the Utah part of the Paradox Basin, exploratory efforts are just beginning to target some of these shales for gas; many in environmentally sensitive areas. The Colorado part of the basin has seen considerable success, particularly for the Gothic shale zone, using horizontal drilling.

Activity:

No new drilling activity targeting the Paradox Formation shales occurred in 2010. CrownQuest Operating LLC completed evaluating drilling results and workovers in former dry holes on the Hovenweep, Gothic, and Chimney Rock shale zones of the Paradox. They reported the completion of the 1-21X Anteater State (section 21, T. 34 S., R. 26 E., San Juan County) initially flowing 329 MCFGPD from the Paradox Formation; cumulative production as of November 1, 2010, was 10.9 MMCFG (Utah Division of Oil, Gas, and Mining, 2010). CrownQuest also confirmed the discovery of Horsehead Point field with the completion of the 1-32 Chanticleer State (section 32, T. 34 S., R. 26 E., San Juan County) from the Paradox. Cumulative production from Horsehead Point field as of November 1, 2010, was 393.4 MMCFG (Utah Division of Oil, Gas, and Mining, 2010). Finally, CrownQuest reported completion of the 1-16 Explorer State (section 16, T. 34 S., R. 25 E., San Juan County) as another gas discovery in the Paradox; cumulative production as of November 1, 2010, was 40.2 MMCFG (Utah Division of Oil, Gas, and Mining, 2010). Few details have been released on these wells. On the Colorado side of the Paradox Basin, Bill Barrett Corporation continues its extensive, successful horizontal drilling exploration and development program for the Gothic and Hovenweep shales in what the company has named the “Yellow Jacket” and “Green Jacket” areas, respectively. The estimated Gothic and Hovenweep shale thickness in these areas ranges from 80 to 150 ft at depths between 5,500 and 7,500 ft. The shale zones are composed of 36% quartz, 44% carbonate, and 15% clay. They are over pressured at 0.52 to 0.59 psi/ft. Barrett estimates gross in-place reserves are 50 BCF/section. The Yellow Jacket area covers 1,850 mi², where the company has about 140,000 net undeveloped acres (Peter G. Moreland, Bill Barrett Corporation, verbal communication, June 15, 2010).

New Research:

Under the direction of the Utah Geological Survey, as part of the same RPSEA-funded project mentioned above, research is being conducted on Hovenweep, Gothic, and

Chimney Rock shales to better understand the gas potential in the Utah part of the Paradox Basin. Extensive examination of numerous cores has revealed several important parameters about these shales: (1) most shales are organic mudstones containing significant amounts of silt, pyrite, and calcareous (and some phosphatic) fossil debris; (2) TOC values are comparatively modest (1-5%) compared to other Paleozoic shales elsewhere; (3) all maturity values obtained from these southeastern Utah cores fall within the oil (or oil-gas) window; and (4) core-measured porosity (2-3%), and permeability values are also low compared to other Paleozoic mudrocks. The bounding and interbedded carbonate units are silty or muddy dolostones, in many cases possessing modest amounts of conventional intercrystalline and microvugular pore space. This porosity has largely been unrecognized or minimized because most openhole density logs are run on a 2.71 g/cm³ matrix density. These dolostones, as well as some shales, are also beset by numerous subvertical fractures, both filled and partially filled, mainly by calcite. Therefore, it is highly probable that this gas production is derived not only from the shales themselves, but also from the associated carbonates and from the natural fractures. Thus, this shale play is likely an intermixed series of reservoir types, all of which could produce upon successful stimulation.

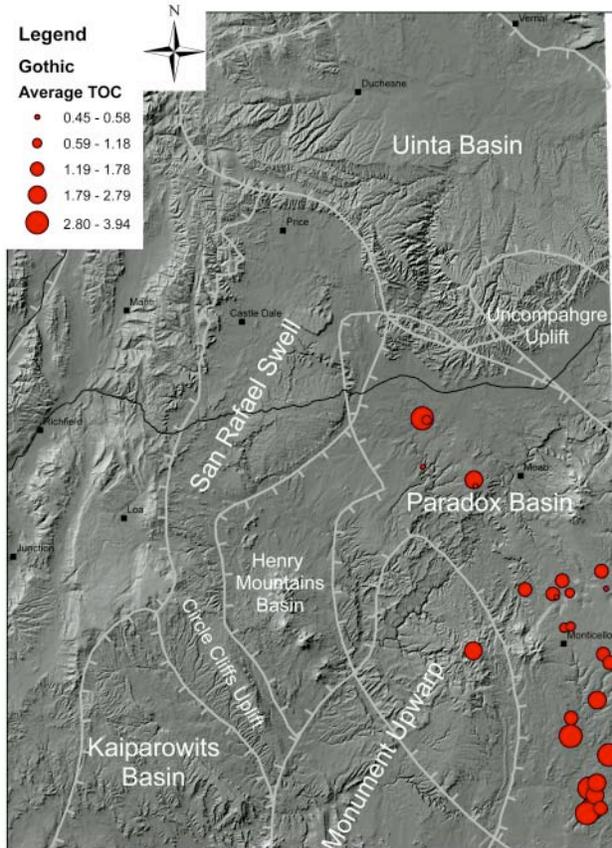
Triaxial compression laboratory data were used to assess the potential for storing energy and the manner in which energy is released on failure. These data are indications of the potential for brittle reservoir behavior and suggest opportunities for defining sweet spots with fracturing. Energy-based inferences of preferentially fractured zones could be useful in designing directional drilling and optimized stimulation programs.

For information about this ongoing project including available posters (in pdf), deliverables, etc., refer to the Utah Geological Survey's project Webpage http://geology.utah.gov/emp/shalegas/paleo_shalegas/index.htm.

RECENT PRESENTATIONS:

“Pennsylvanian Organic Mudstone Reservoir Characteristics from the Paradox Basin, Southeastern Utah,” by S. Robert Bereskin, Thomas C. Chidsey, Jr., John McLennan, and Tarn Bereskin, June 15, 2010, at the AAPG Rocky Mountain Section Meeting in Durango, CO.

“Revisiting the Shale-Gas and Shale-Oil Resources of the Paradox Basin, Colorado and Utah,” by Steve Schamel, June 14, 2010, at the AAPG Rocky Mountain Section Meeting in Durango, CO.



Total organic carbon (TOC) in the Gothic shale of the Pennsylvanian Paradox Formation, Utah

“The Pennsylvanian Gothic Shale, Possibly the New Gas Shale Resource Play from the Paradox Basin,” by Peter Moreland, June 15, 2010, at the AAPG Rocky Mountain Section Meeting in Durango, CO.

REFERENCE CITED:

Utah Division of Oil, Gas, and Mining, 2010, Oil and gas production report, April: Online, <https://fs.ogm.utah.gov/pub/Oil&Gas/Publications/Reports/Prod/Field/Fld_Oct_2010.pdf>, accessed February 23, 2011.

WASATCH PLATEAU BLUE GATE & TUNUNK SHALE MEMBERS, MANCOS SHALE

Overview:

On the Wasatch Plateau in central Utah, potential shale gas reservoirs include the Blue Gate and Tununk Shale Members of the Cretaceous Mancos Shale. The Blue Gate contains an upper high-TOC interval with dense, non-fissile, dark gray claystone and scattered, light gray silt laminae and bivalve fragments. The Tununk consists of dark gray calcareous mudstone with interbeds of silt to very fine sand

laminae containing silt-filled burrows. The extent and resource potential of this frontier play are unknown.

Activity:

No new drilling activity targeting the Manning Canyon Shale occurred in 2010. In the fall of 2009, Liberty Pioneer Energy Sources staked the 10-17 Skyline Unit (section 17, T. 14 S., R. 6 E., Sanpete County), a 7,550 ft test of the Tununk Shale on the western Wasatch Plateau. Liberty Pioneer drilled a 8,750-ft Tununk test, the 8-7 Skyline Unit (section 7, T. 15 S., R. 6 E., Sanpete County); no details have been released. The company also has a 7,250-ft Tununk test, the 14-28 Skyline Unit (section 28, T. 14 S., R. 6 E., Sanpete County). Liberty Pioneer acquired the prospects from XTO in 2009 (XTO took over the prospects from Dominion E&D in 2007).

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

By Rich Nyahay

OVERVIEW:

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

CURRENT:

In June 2010, Norse Energy Corp USA has received two permits to drill Utica wells in New York, the Aarismoa 1(API No. 31-017-26464-00-00) in the town of Preston, Chenango County and the Byler 1 (API No. 31-053-26465-00-01) in the town of Lebanon, Madison County. No spud dates have yet to be reported. This activity was to be phase one of a four phase program to be initiated by Norse Energy Corp USA to test and develop production in the Utica Formation during the upcoming year. Norse Energy Corp USA estimates to have 2.5 TCF of resources in the Utica on their 180,000 acres of land.

Gastem USA's Ross #1(API No. 31-077-23783-00-00) well that was drilled in October 2009, and fraced in November 2009, in the town of Maryland, Otsego County remains the most recent activity. The modest vertical frac in one of the three members which comprise the Utica produced a sustained rate of more than 70 MCF/D over a test period of 24 days. No production to date has come from the Utica.

Recent Utica tests in eastern Ohio and western Pennsylvania are encouraging. Consol Energy drilled an unstimulated vertical test in Belmont County, Ohio that flowed at 1.5 million cubic feet per day. Range Resources drilled a successful horizontal test in the Utica in Butler County, Pennsylvania. Range also plans to drill another horizontal Utica test in Beaver County, PA projected to 14,837 feet. Chesapeake pulled a permit for a horizontal Utica test in Beaver County, PA that is projected to be drilled to a depth of 14,776 feet. East Resources is also planning a Utica test in Lawrence County, Pennsylvania. (Williams, 2011).

RESEARCH:

Research is being performed on well cuttings and cores from the Utica in the New York State Museum collection under the direction of Taury Smith, State Oil & Gas Geologist, to determine the TOC and carbonate content. Currently 45 wells with cuttings and one core have been analysed. Some results have been released and can be found in the Pittsburgh Association of Petroleum Geologists Publications

website(<http://www.papgrocks.org/publications.htm>) This study is being supported by NYSERDA and companies who subscribe for data from this study.

NYSERDA is also sponsoring the Shale Enhanced Recovery Program and a study to determine if CO₂ can be trapped by shale when injected into it thereby displacing the methane for increased recovery from the shale. Advanced Resources International is: 1) characterizing the geology of the Utica and Marcellus shales in New York; 2) collecting new data related to CO₂ storage and natural gas production from new shale wells in NY; 3) creating a reservoir model for each shale formation and model reservoirs for both natural gas production and CO₂ injection; 4) describing economic constraints to CO₂ sequestration; 5) assessing 'advanced' approaches to development; 6) developing an independent, basin-wide assessment of the CO₂ storage potential in NY gas shale.

Norse is completing a cable less 3D seismic survey on 38,000 acres to indentify several high graded prospects in Chenango County, New York

WEB SITES:

<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 800 page draft Supplemental Generic Environmental Impact Statement.

ISSUES:

No permits have been issued for horizontal drilling and high-volume hydraulic fracturing to develop the Marcellus Shale or the Utica Shale in New York. The Department has released the draft Supplemental Generic Environmental Impact Statement on September 30, 2009 for horizontal drilling and high-volume hydraulic fracturing to develop the Marcellus Shale and all associated shales. The sixty day comment period for all stake holders was extended until December 31, 2009. Four public comment meetings were held in various areas throughout the southern tier of the State. The NYDEC are now reading and sorting the comments to come out with a new Supplemental Generic Environmental Impact Statement before the start of the New Year. On August 4, 2010 the New York State Senate passed a bill by a vote of 48-9 in favor of a moratorium on permits to be issued for all high volume hydraulic fracturing of Utica and Marcellus wells in New York State until May 15, 2011. In order for the bill to be law the New York Assembly must pass it and the Governor must sign it. The New York State Assembly is supposed to reconvene sometime in September.

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- Williams, P., 2011, Unlocking the Utica: Oil and Gas Investor, Feb. 17-18, 2011, p. 13.

Woodford Shale (Late Devonian-Early Mississippian), Anadarko, Arkoma, and Ardmore Basins, U.S.

by Brian Cardott (Oklahoma Geological Survey).

As of March 1, 2011, there were a total of 1,635 Woodford Shale-only well completions (excluding wells commingled with Caney or Sylvan shales) in Oklahoma since 2004 (first application of advanced completion technology). The play has expanded from mainly a thermogenic methane play in the western Arkoma Basin in eastern Oklahoma to include a condensate play in the western Arkoma Basin, a condensate play in the Anadarko Basin shelf in western Oklahoma, and an oil play in the Ardmore Basin in southern Oklahoma. Of a total of 1,286 horizontal Woodford Shale gas wells from 2005 to February 2011, initial potential gas rates ranged from 3 to 12,097 thousand cubic feet of gas per day (MCF/D; average of 2,813 MCF/D from 1,257 wells) and lateral lengths of 10 to 10,195 feet (average of 3,483 feet from 1,278 wells). Cumulative production from 1,429 Woodford Shale-only wells drilled from 2004-2011 is 773 BCF gas and 2,936,228 BBLs oil/condensate. A gas shale completions database, lists of references, maps, and several presentations are available on the OGS web site (<http://www.ogs.ou.edu/level3-oilgas.php>).

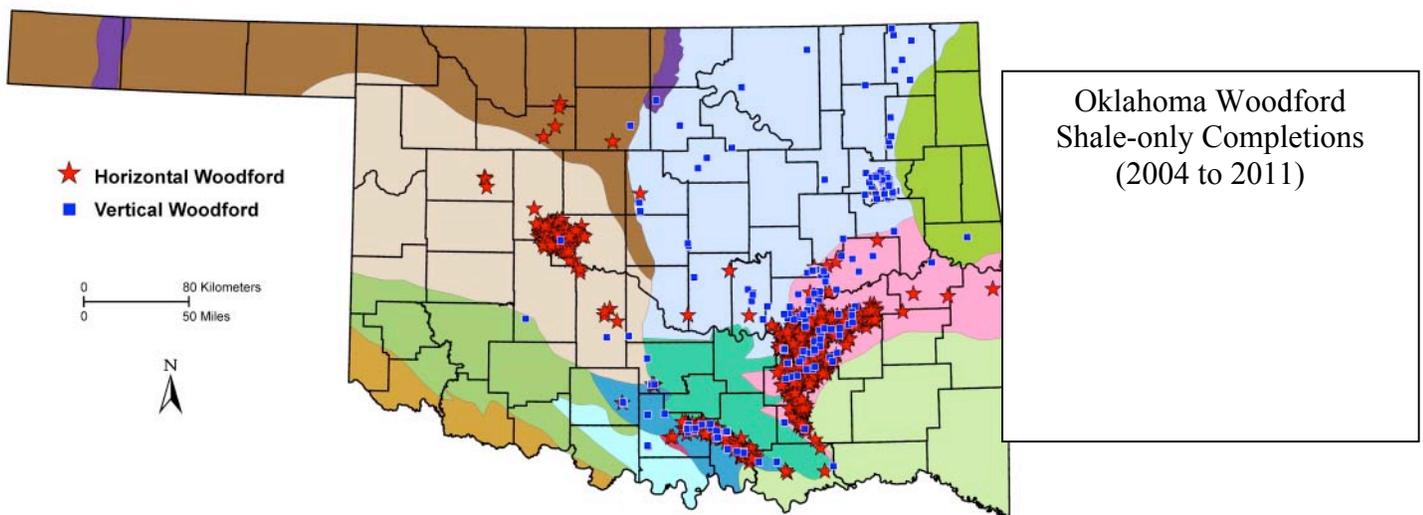
The latest Woodford Gas Shale Plays presentation (Application of vitrinite reflectance to four Woodford gas-shale plays in Oklahoma) at the 2010 SIPES annual meeting is available at <http://www.ogs.ou.edu/oilgaspres.php>. Of 33 operators drilling gas-shale wells in Oklahoma in calendar year 2010, the top ten operators (by number of wells drilled during 2010) are as follows:

- (1) Devon Energy Production Co. LP (70 wells)
- (2) Newfield Exploration Mid-Continent Inc. (54 wells)
- (3) Cimarex Energy (33 wells)
- (4) XTO Energy (32 wells)
- (5) BP America Production Company (24 wells)
- (6) Petroquest Energy (11 wells)
- (7) Continental Resources (9 wells)
- (8) WCT Operating (7 wells)
- (9) Antero Resources (5 wells)
- (10) Kaiser-Francis Oil Company (5 wells)

Caney Shale (Mississippian) gas-well completions dropped from 24 Caney-only wells in 2004 to 4 Woodford & Caney commingled wells in 2010 due to problems completing the clay-rich shale. Several companies have given up looking at less damaging completion fluids for Caney Shale wells.

The first Barnett Shale horizontal well in Oklahoma was completed by GLB Exploration in Jackson County in southwest Oklahoma in April 2010 (initial potential of 1,100 MCF/D at 7,966 feet TVD).

There are four Woodford shale gas, condensate, and oil plays in Oklahoma: 1) western Arkoma Basin in eastern Oklahoma, with thermogenic methane production at thermal maturities from <1% to >3% vitrinite reflectance (VRo) and condensate production to @1.67% VRo; 2) Anadarko Basin shelf (“Cana” play) in western Oklahoma, with thermogenic methane at thermal maturities from @0.9% to 1.6% VRo and condensate production up to @1.4% VRo; 3) Ardmore Basin in southern Oklahoma, with oil and thermogenic methane production from thermal maturities in the oil window (<1.2% VRo); and 4) Wagoner County (northeast Oklahoma), with biogenic and thermogenic methane production from thermal maturities <1.2% VRo. Presentations from the July 2010 “New Perspectives on Shales” Conference are available at <http://www.ogs.ou.edu/level3-meetingsPRES2010.php>.



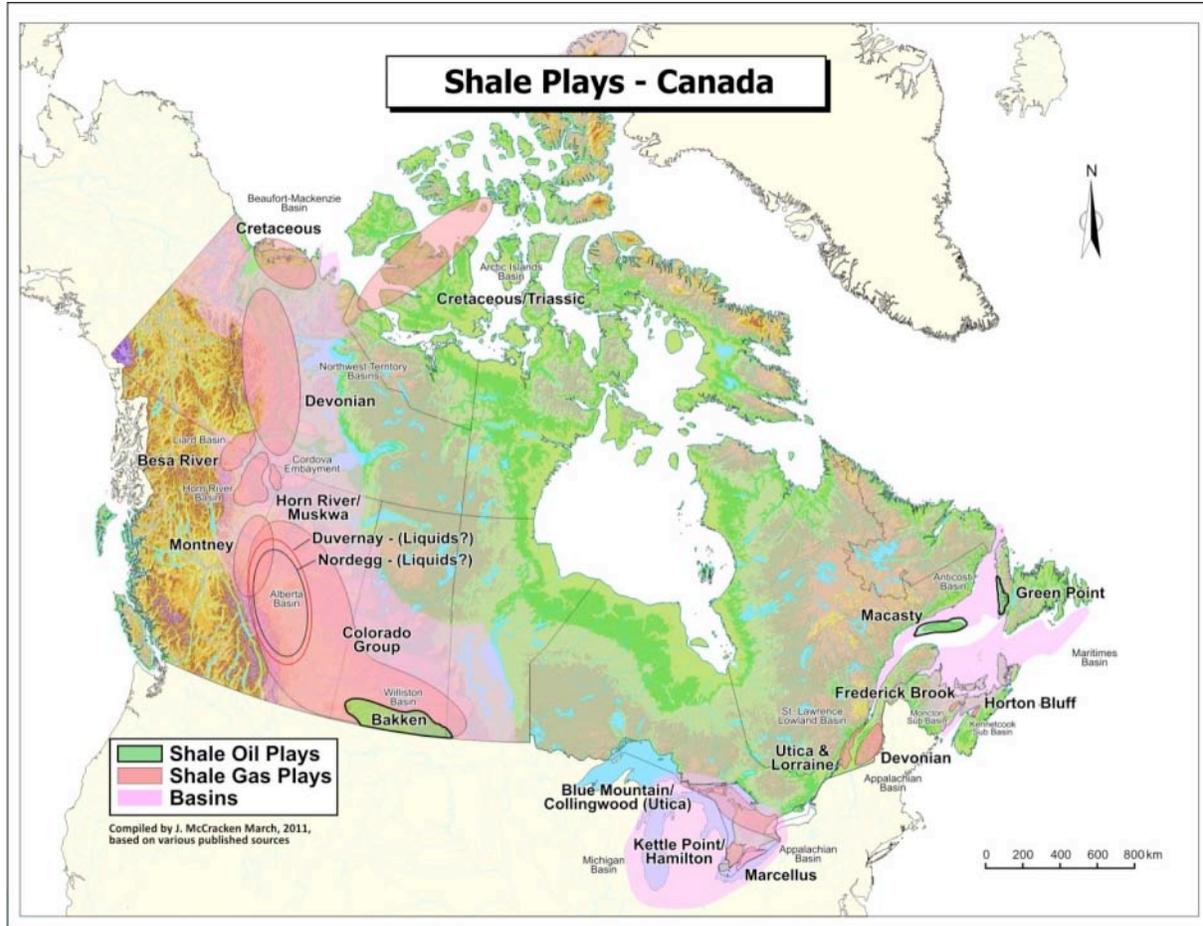
Canadian Shales

By Jock McCracken (Egret Consulting)

Shale gas production in Canada is now more than three years old after the announcement of new discoveries at the beginning of 2008. The state of development for the shale plays range from speculative to exploratory to emerging with only two giant plays in northeast British Columbia being considered developing and under increasing production. In most cases, the majority of these wells are still confidential so production numbers are unknown. Typically, production numbers from government websites are up to one year behind. Other numbers and statistics can be gathered from press releases and presentations from the companies mentioned in this report.

Significant shale gas wells were drilled and tested in the St. Lawrence Lowlands of Québec but a government freeze on fracking because of environmental concerns will slow down any future production. The positive announcements out of New Brunswick have been tempered by recent disappointing results.

The Bakken shale oil play in Saskatchewan and Manitoba is still one of the hottest plays in Western Canada. To date there is exploration activity in 9 provinces of Canada out of the 10 with Prince Edward Island being the exception.



NORTHEAST BRITISH COLUMBIA

Shale gas interest has dominated the sale of petroleum and natural gas (PNG) rights from the province in the last four 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 between July 2009 and end of that year. Land sales for these NE BC areas accounted for \$893 million in bonuses with the shale gas areas being about 90% of the total. The PNG rights sales for the Montney Play, encompassing the southern Fort St. John region accounted for \$437 million and the Horn River Basin accounted for \$321 million during that period. These Triassic to Devonian British Columbia shales are estimated to have the capacity to hold 250 to 1,000 trillion cubic feet (TCF) of original gas-in-place.

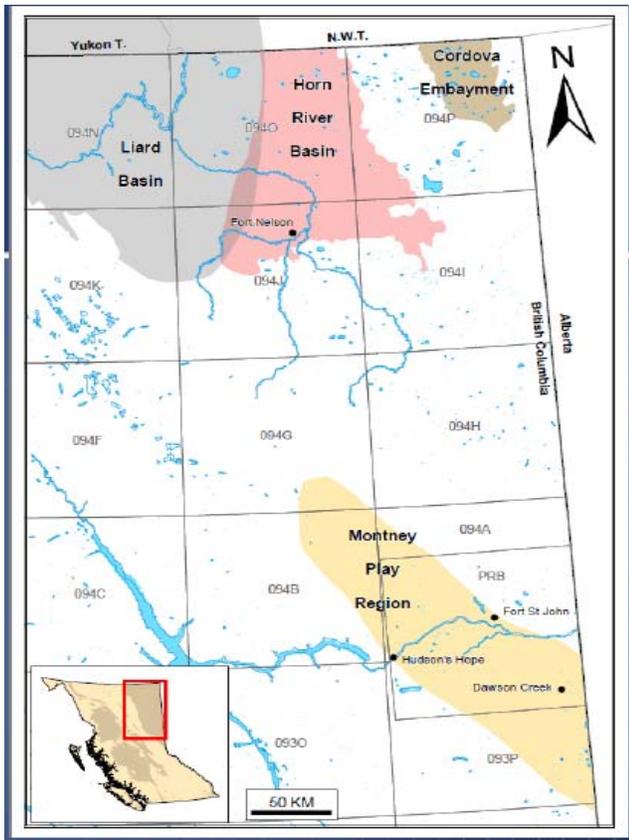
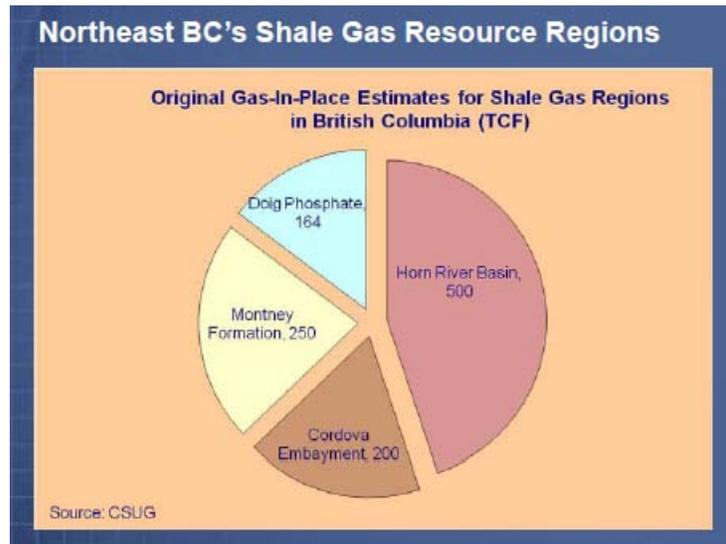
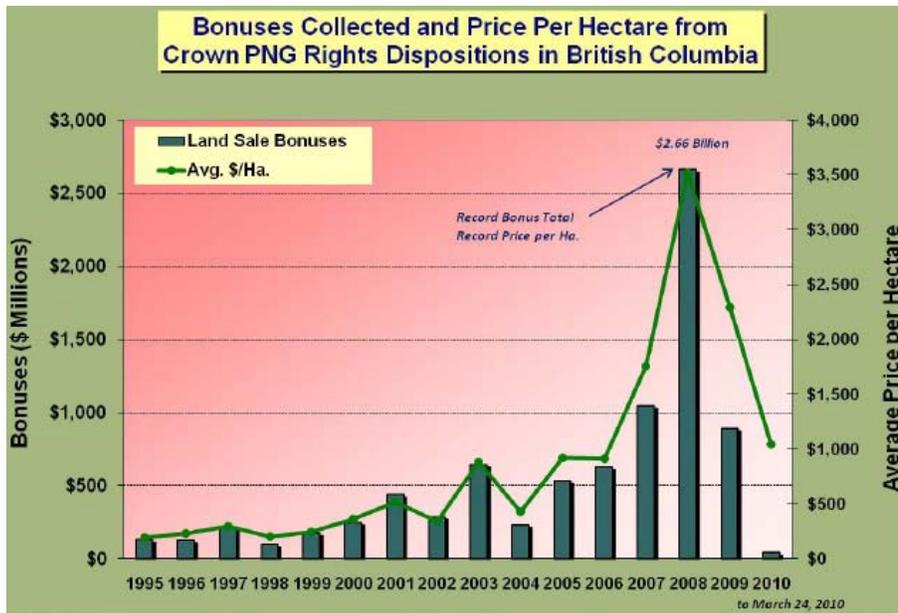


TABLE 1. POTENTIAL SHALE GAS FORMATIONS IN NORTHEAST BRITISH COLUMBIA

PROSPECTIVE HORIZONS						
	Formations	Description	Depth	Average Thickness	Total Organic Carbon	Gas in Place
LOWER CRETACEOUS	Willich and Buckinghorse shales	Potential Interbedded sand/siltstone	800 to 1,200 metres	100 metres	2.3%	60 Bcf per section
JURASSIC	Nordeg 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	Dolg, Dolg 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



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.



Devonian Muskwa Shale, Horn River Basin, Cordova Embayment and the Liard Basin

Of these very far north basins the Horn River has the most activity. There are some reports that Horn River production is now at approximately 80 MMCF/D at the end of 2009. Government numbers are not published yet because of the confidentiality in this relatively young play.

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: Encana Corporation, Apache Canada, Devon Canada Corporation, EOG Resources Inc., Nexen Inc., Quicksilver Resources Inc., Stone Mountain Resources Ltd., Imperial Oil Limited-ExxonMobil Canada Limited, ConocoPhillips, Suncor Energy and PenGrowth Energy Trust. Other companies working this area are Taqa North, SMR Oil and Gas Ltd, Storm Exploration Inc., Ramshorn Canada Ltd., Great Plains Exploration among others.

Encana and its joint venture partner, Apache, are the two most active players in this play with 134 wells drilled since 2003. Together they operate about 7 pads with up to 16 to 20 wells per pad. Encana has indicated plans of drilling another 21 net wells in 2010. Their recent wells have reported rates of 8-12 MMCF/D (30 day average) with up to 28 fracture stimulations per well. Lateral lengths are 1,600 to 3,000 m. The well depth average is about 9,000 feet with an estimated 150 - 270 BCFE per section of gas-in-place. Encana's current production is 20 MMCF/D but could rise to 100 MMCF/D by the end of 2010 and up to 500 MMCF/D by 2014. Encana and Kogas Canada Ltd., a subsidiary of Korea Gas Corporation (KOGAS), have entered into a three-year exploration and production agreement. Investment is planned in three, one-year phases as defined by distinct farm-out agreements for each block of land. Encana is operator. Encana also signed a memorandum of understanding with state-owned China National Petroleum Corporation (CNPC) to negotiate a joint venture to develop Encana's Horn River and Montney shale-gas properties in northern British Columbia.

Apache with 17 net wells in 2010 is moving to full scale production by 2011-2012. They have made 27 net completions and have 22 net producers this year. EOG has drilled 12 horizontals in the first half of 2010 with completions during the second half. They consider the rock quality of the Horn River Shales better than the Barnett. Devon's acreage is in the thickest part of the basin. They plan minimal drilling

this year to hold the acreage. Nexen, as well as all the other operators, have made great advancements in driving down the drilling, completion and production costs. They plan to have an 8 well pad under production at an estimated 50 MMCF/D/d in 2011, a 9 well pad on stream in late 2011 and an 18 well pad on stream for 2012. Quicksilver has plans to test the oil-leg of the Late Devonian and Early Mississippian Exshaw Formation in 2011 at approximately 4,000 feet, where they have encountered oil shales in each of the four offset wells drilled to date.

Encana is working on its Cabin Lake processing facility, located 60 km north of Fort Nelson which should have a capacity of 800 MMCF/D by 2012 and a final processing capability of 2.4 BCF/D. Spectra Energy Corp. which has 2,800 km of pipeline in B.C. and transportation capacity of 2.2 BCF/D is working on infrastructure efficiency. A new Fort Nelson North processing plant will accommodate increased production with initial contract volume of 55 MMCF/D. This facility will be processing 250 MMCF/D by 2012. 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 MMCF/D by 2014.

The Asian market is being targeted by Apache and EOG with the building of an LNG terminal in Kitimat, BC to be opened in 2014. This terminal will be fed by the proposed 300 mile (463km) Pacific Trail Pipeline coming from N.E. B.C.

The Beaver River or Liard Basin area has had some activity by Questerre Energy and Transeuro. One of the wells is flowing at a facilities constrained rate of around 5 MMCF/D from the Mississippian Mattson carbonate which is in direct communication with the surrounding shales. They hope to see evidence that the gas from the surrounding shale will contribute to the production. Thick shales exist in the region but more work needs to be done to properly assess these intervals.

Nexen have 128,000 acres of highly prospective shale gas lands in the Liard Basin, with between 5 and 23 TCF of unrisks prospective resource.

The Cordova Embayment area, 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.

Triassic Doig and Montney, Dawson Creek Area

The Montney is a tight gas/shale gas play producing at approximately 472 MMCF/D at the end of 2009. The primary zones are the Upper and Lower Montney. The major facies include fine-grained shoreface, shelf siltstone to shale, fine-grained sandstone turbidites, and organic rich phosphatic shale. The Doig has potential but the Montney has been the focus. The main Montney players are ARC Energy Trust, Encana Corporation, Murphy Oil Corporation, Storm Exploration, Shell Canada Ltd., Progress Energy Resources, Talisman Energy and Strategic partnership with Sasol on Montney Shale – Farrell Creek Development, Terra Energy and Crew Energy. There are numerous other operators as well.

Encana is by far the biggest player with 482 rig releases since 2005. They drilled 90 wells in 2009 with 8 to 10 wells per section and 40 wells in 2010. The horizontal section are up to 2400m long with up to 14 fracs per well with some recent IP at 10 MMCF/D. They believe they have an estimated 70 TCF of gas in place in their trend. Their current forecast for 2014 is 600 MMCF/D Their gas plant at Steeprock

has a current capacity of 140 MMCF/D with a forecast 200 MMCF/D in 2011. Shell with 174 well rig releases since 2005 now has holding of 210,000 net acres in the prime Montney fairway. In October 2010 they reported production of 170 MMCF/D from their Groundbirch complex. They anticipate to drill up to 280 wells per year in 2014 from the current 100 wells per year. ARC Energy Trust is another dominant player in the Dawson Creek area recently achieving an average production of 110 MMCF/D at the end of 2010 with a production forecast of 165 MMCF/D at the end of 2011. They just brought on stream in 2010 a 60 MMCF/D gas plant with two more to follow by 2014. In 2011 they will be drilling 14 wells. Murphy has concentrated their efforts in the Tupper West area and is now producing at 85 MMCF/D with 2011 year-end exit rates projected to be over 120 MMCF/D through their recently opened gas plant. Progress Energy Ltd. has amassed approximately 900,000 net acres of land within the commercially productive Montney fairway which represents one of largest land positions among all North American natural gas resource players. The graph below shows the Montney well production.

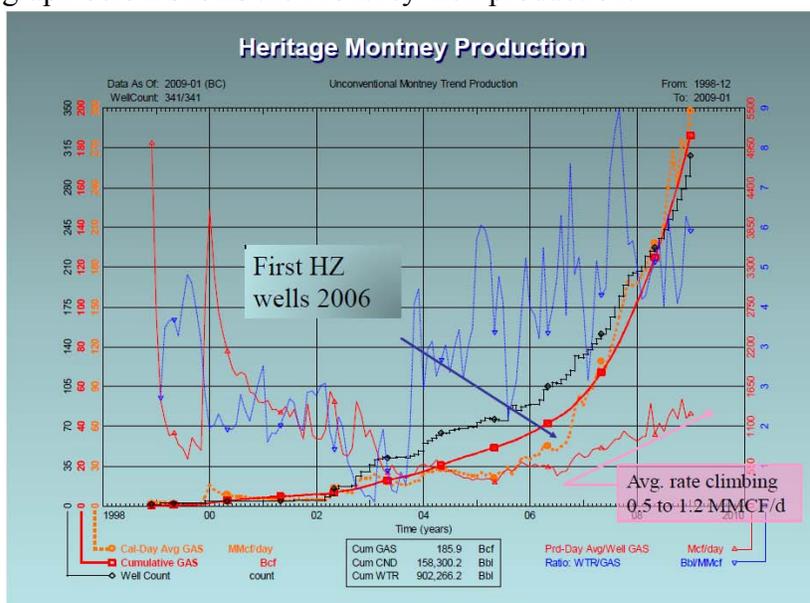


Figure 13. Chart displaying area gas production and total number of producing wells from the Heritage Montney. Horizontal drilling technology along with new and improved completion techniques are key factors in the increasing production profile from these areas. Data from Hayes (2009).

Lower Cretaceous – Gething and Buckinghorse.

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 74,000 net acres of Buckinghorse potential with 3 wells on production and 2 more wells planned this year. Canadian Spirit is another player in the area, mostly with experimental schemes, on the Gething. No production volumes reported yet.

The following link 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>

ALBERTA

Estimates of shale gas within the Western Canada Sedimentary Basin (see map below) vary from 86 TCF to 1000 TCF. While there is a huge potential in Alberta, commercial shale gas production is at early stages but additional new plays have suddenly begun to emerge.

Alberta has extensive experience in the development of energy resources and has a strong regulatory framework already in place. Shale gas 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.

It is predicted that about two to eight shale wells will be drilled per section to effectively produce shale gas in Alberta. There can be multiple zones of potential in Alberta within a shale gas play, both from conventional and unconventional gas production. This could result either in commingling of gas zones or more than two to eight wells per section being drilled, subject to Energy Resources Conservation Board regulations

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 commingled 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.

Lower Jurassic Nordegg (Gordondale), West Central Alberta

Anglo Canadian Oil Corp. is currently 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. Undoubtedly there are others in this play.

Devonian Duvernay/ Muskwa Shales, Western Alberta

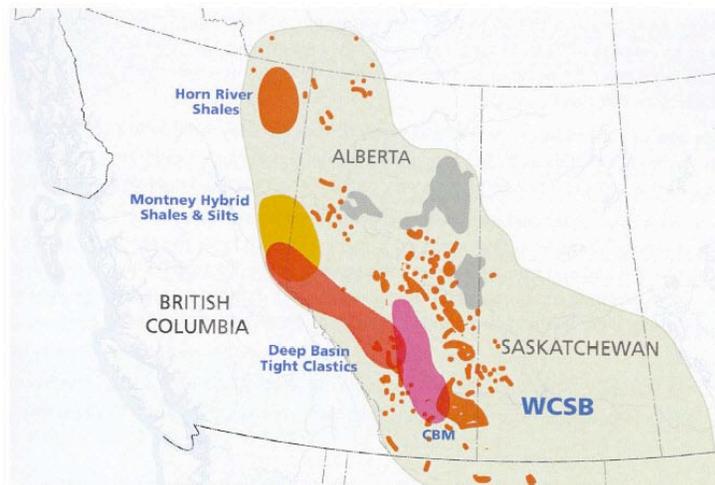
The Duvernay is the stratigraphic equivalent to the Muskwa in N.E. B.C. Trilogy Energy has successfully tested a horizontal well in the Kaybob area with a 1,700 m lateral at 2 MMCF/D with 75 BBL per MMCF. They are drilling a second horizontal.

Mooncor is exploring for this play. They have re-entered a well and tested about one MMCF/D from a 12-25 m thick shale. They recently announced that they are retrieving 75 BBL /MMCF gas. Large land sale bids of \$384 million at the end of 2009 triggered some speculation that the above shale may have been the target despite its 4000 m depth. The rather small foot print may hold 25 TCF but infrastructure costs should be minimal since this area is just west of Edmonton.

Late Devonian and Early Mississippian Alberta Bakken – Exshaw, Southern Alberta

This play gained momentum south of the border in Montana and has recently emerged into Alberta. There is a rush to get a position. There are a number of companies in this play. Crescent Point Energy has 1,000,000 acres, drilled three wells with 14 wells planned for 2011. No numbers have been published yet.

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>

The Alberta Government Royalty regime changes can be found at this site

http://www.energy.gov.ab.ca/About_Us/1525.asp

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. The AGS Shale Gas Section website is accessible through the following URL:

<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>

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 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 southwest Saskatchewan that are 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.

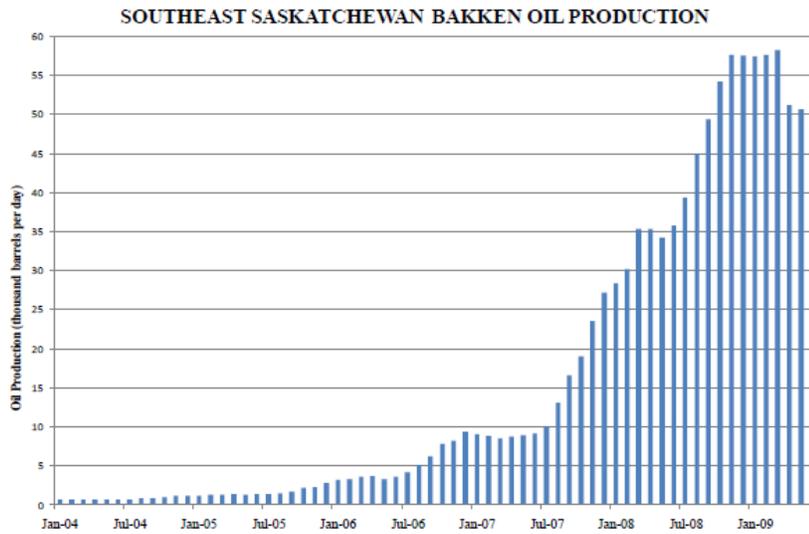
http://www2.canada.com/reginaleaderpost/news/business_agriculture/story.html?id=c41a6b5b-b892-40cc-8cb4-902156681111&k=18412

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

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.

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 BO/D in 2005 to about 50 to 60,000 BO/D at the beginning of 2010. The Bakken production comes from the siltstone and sandstone beds within the shales (Kreis, L.K. and Costa, A. 2005) The Bakken wells tend to be highly productive at 200 BO/D producing a light sweet crude oil with a 41 API gravity.



Saskatchewan Government Energy and Resources is the regulator.

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

MANITOBA

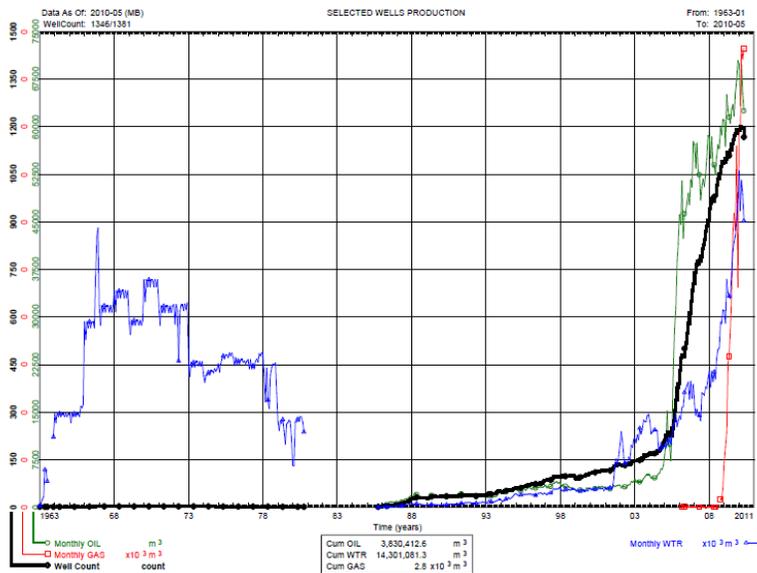
Cretaceous Colorado Group

There is shale gas potential 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

Upper Devonian-Lower Mississippian Bakken

The production of oil from the Bakken, which began in the mid-1980's, continues, with about 14,700 BO/D from the formation, a tenfold increase since 2005.



Manitoba Innovation, Energy and Mines is the regulatory agency and information can be obtained from their website using the URL <http://www.gov.mb.ca/stem/petroleum/index.html>

ONTARIO

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

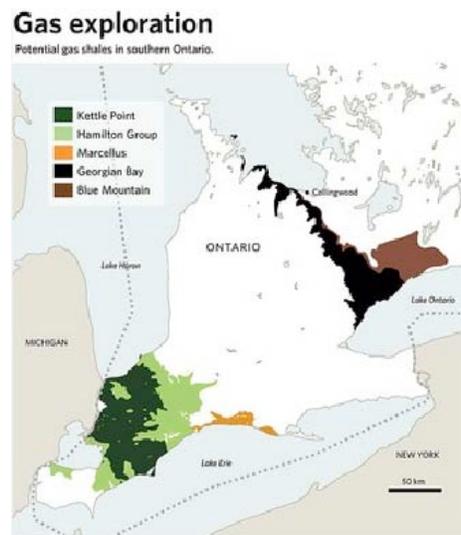
Exploitation of these shales has been very quiet with only a few operators discussing the evaluation of these shale targets. These shales are mostly considered secondary targets but only one well has been drilled to test these zones to date. Mooncor has just locked up about 23,000 acres of shale gas 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.

The Ministry of Natural Resources of Ontario is the regulator.

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

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



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 stricter 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 process could take up to 30 months. The government had previously awarded permits for 29 drilling sites where fracing has taken place on 18 locations.

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 feet 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 MCF/D. In 2009 and 2010 they drilled or will be drilling five horizontals which were currently being evaluated. Forest, after drilling two vertical wells with production rates up to 1 MMCF/D and three horizontals, is waiting for the rock work and the analysis before proceeding further. The horizontals rates range from 100 to 800 MCF/D 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 feet thick within the gas window. Cambrian, Gastem, Junex, Questerre and Altai are among the other interest holders in this play.

Questerre Energy Corporation recently 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 MMCF/D.

http://www.questerre.com/assets/files/PDF/101121_QEC_Presentation-Update.pdf

Upper Ordovician Macasty Shale

The Upper Ordovician Macasty Shale (Utica Equivalent) drilled by Corridor and Petroliia 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.

<http://www.corridor.ca/investors/documents/March2011TechnicalPresentationonAnticostiIsland.pdf>

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

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

Quebec's natural gas royalty, which currently is 12.5%, has been described as attractive by some of the players. As well, shale gas plays in the province's St. Lawrence Lowlands enjoy another advantage in being close to the northeast U.S. gas market.

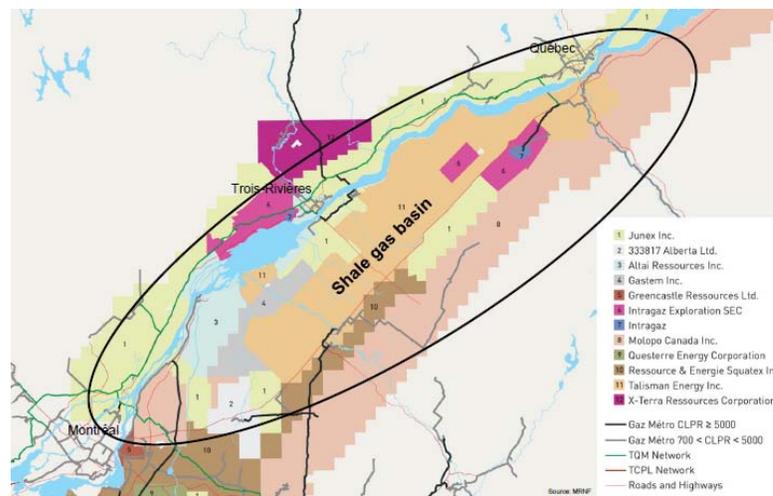
Quebec Shale Conference 2010 and 2009

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

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

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

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



Quebec Shale Gas Area

NEW BRUNSWICK

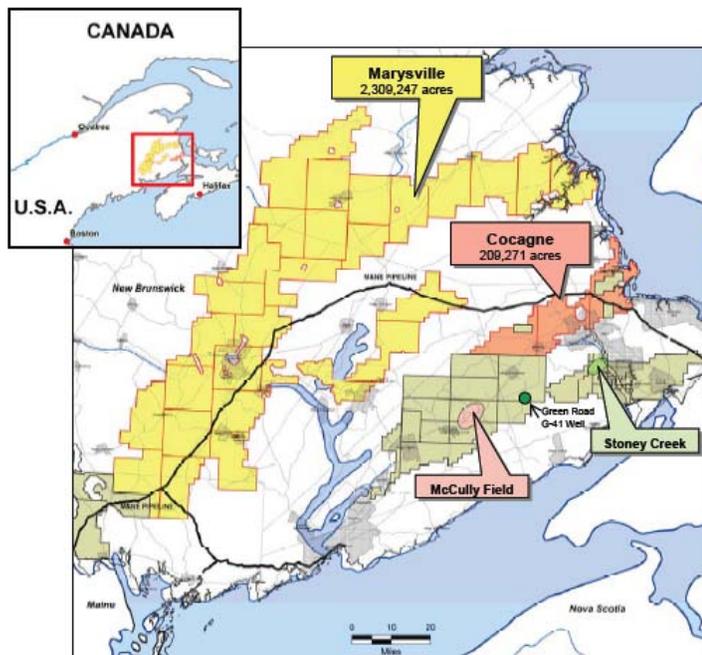
Lower Mississippian Fredrick Brook Shale, Moncton Basin

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 MMCF/D, whereas the upper silty/sandy shale zone of the formation tested at initial peak rates of 11.7 MMCF/D with a final rate of 3.0 MMCF/D. 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. They are currently assessing the results of this early stage exploration.

<http://www.apachecorp.com/Operations/Canada/index.aspx>

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 nonconventional resources of the Mississippian Horton Group. Currently they have conducted airborne magnetic, gravity and geochemical surveys with plans for 2D seismic surveys and then the first well in 2012.



“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

<http://www.gnb.ca/0078/Promo/ShaleGas/Exploration-e.asp>

New Brunswick Presentation

http://energy.ihs.com/NR/rdonlyres/2AE1999D-5D81-4B30-8405-94854EEDD6CB/0/7New_Brunswick_DeptSteven_Hinds.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 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.

Additional exploration elsewhere in the province is underway on the Horton Bluff, although no additional information is currently available.

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 thermogenic shale gas and oil 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). A well drilled in 2008 by Shoal Point Energy and partners encountered about 500 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 is underway by the same companies as of Jan 2011.

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

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

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Shale Gas/Shale Oil in Europe

By Ken Chew

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 Germany in 2008 and since then exploratory drilling has been limited to four countries. As a consequence, little is known about Europe's ultimate potential.

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. 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. 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.

Given the potential size of the in-place resource it is not surprising that investigations are currently under way in at least fifteen 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 and coal seam gas explorers who may have some shale gas potential on their acreage.

MAJOR SHALE GAS PLAYS IN EUROPE

There are three potentially major regional shale gas plays in Europe plus a number of others with local potential.

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.

In Denmark and Sweden the principal target is the kerogenous Alum Shale of Middle Cambrian to Early Ordovician (Tremadoc) age. Licences have been applied for / awarded over the Fennoscandian Border Zone and Norwegian-Danish Basin onshore *Denmark*. On 28th November 2009 Shell spudded the first well in a three-well test program in *Sweden's* Colonussänkan permit (Fennoscandian Border Zone, southern Sweden). Lövestad A3-1, Oderup C4-1 and Hedeberga B2- 1 ranged in depth from 2,457 feet to 3,133 feet.

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 feet of Silurian section may be present.

To date, this play has been the most sought after in Europe. Some 26 concessions have been awarded in the Gdansk Depression, another 27 in the Danish-Polish Marginal Trough and 11 on the East European Platform Margin, northeast of the Marginal Trough.

Ten different companies or consortia are active in the Gdansk Depression including a number of small niche players, but of the 38 concessions on the Platform Margin and Marginal Trough, 29 are held by one of ExxonMobil, Chevron, Marathon or PGNiG, the Polish state company.

The first tests of the Polish Lower Paleozoic are now under way. Between June and October 2010, Lane Energy (a subsidiary of 3Legs Resources) drilled two vertical wells, Lebien LE1 (Lębork concession) and Legowo LE1 (Cedry Wielkie concession) in the Gdansk Depression. The wells have been suspended pending fracture testing. Lane's initial seismic and drilling program on its six Gdansk Depression concessions is being funded by ConocoPhillips, giving the latter the option to earn up to 70% interest in the concessions. The group plans to drill and test one horizontal and two vertical wells in 2011.

The same drilling contractor, NAFTA Pila, then spudded Wytowno S1 (Slawno concession, Gdansk Depression) in December 2010 on behalf of Saponis (BNK; RAG; Sorgenia; LNG Energy). The US\$ 6 million well reached TD at 11,745 feet in mid-February 2011. The well encountered gas shows in a 1,475 feet Middle to Upper Silurian section and over a 725 feet Cambrian, Ordovician and Lower Silurian section. The strongest shows were recorded in the Ordovician interval (220 feet). The well will be fracture tested once well results have been analysed, probably in Q2-2011. Saponis also plans to drill a well on each of its other two concessions (Starogard; Slupsk) in 2011. The Slupsk well (Lebork S1) will be spudded once the casing has been run and cemented in Wytowno S1.

San Leon / Talisman plan a 3 vertical well program in the Gdansk Depression commencing in Q3 2011.

The first well in the Podlasie Depression of the East European Platform Margin, Siennica 1, should be spudded by ExxonMobil in February 2011. The company plans to farm out some of its 100% interest in its four concessions in this area but will retain operatorship.

The first wells in the Danish-Polish marginal Trough (Lublin Trough) should also be drilled in 2011 by PKN Orlen and Chevron (Q4 2011). Marathon also plans to drill at least one well in Q4 2011 though it has not indicated which area it will test.

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 and the Fore-Sudetic Monocline (Northeast German-Polish Basin) in southwest Poland. The age of the most prospective shales appears to young westwards from the Viséan (Middle Mississippian) Kulm facies of southwest Poland 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 and the Clare Shale in western Ireland. Visean (Middle Mississippian) shale may also be prospective in Scotland and northwest Ireland.

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. San Leon has also acquired some concessions in this play. On behalf of the Polish state company, PGNiG, Halliburton frac tested an Upper Carboniferous shale in the Lublin Trough in July 2010 but the flow rates are said to have been lower than expected.

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.

In the *Netherlands*, Cuadrilla Resources has been awarded a license 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) Epen Formation shale is the primary target in this location. Drilling of the first well is now planned for 2012 as a result of additional drilling planned on Cuadrilla's UK Bowland Shale acreage (below).

Cuadrilla Resources, through its Bowland Resources subsidiary, also has interests in the Cheshire Basin in northwest *England*. Spudded in August 2010, the company's Preese Hall 1 well targeted the Namurian (Upper Mississippian to Lower Pennsylvanian) Bowland Shale. Drilled to a depth of 9,100 feet, the well encountered over 4,000 feet of shale containing both vertical and horizontal fractures and which produced "substantial gas flows". The well was due to be frac tested in January 2011. The rig has moved to drill a second well at Grange Hill 1 (spudded 15 January 2011). On the basis of results to date, Cuadrilla's drilling plans have been modified to bring forward two further Bowland Shale wells. A preliminary estimate of reserves should be known by end 2011. Preese Hall 1 is the first known test of the Carboniferous shale gas play in Europe.

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.

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 the Midland Valley of *Scotland*, Composite Energy has established an estimated gas-in-place of 0.3 to 4.0 TCF in the Namurian (Upper Mississippian to Lower Pennsylvanian) Black Metals Member (Limestone Coal Formation) of the Kincardine Basin at depths of 1,000 feet to 4,000 feet. Composite has estimated from regional data that the deeper Visean (Middle Mississippian) shales of the Lawmuir and Lower Limestone formations may contain between 7.4 and 11.6 TCF. On 28th February 2011 Australia's Dart Energy announced that it will acquire the 90% of Composite that it does not already own. Composite owns 100% of the Namurian prospect but BG has a 50% interest in the Visean prospect.

Enegi Oil has taken out an option 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. 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 Benbulbin shales, both of which yielded strong gas shows in wells drilled in the mid-1980s.

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.

In *Germany* ExxonMobil commenced shale gas exploratory drilling in 2008 in the Lower Saxony Basin, drilling Damme 2/2A 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. At least some of these wells are known to have been frac tested and Posidonia Shale is presumed 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. The well is planned to have a 1,600' horizontal leg.

Other plays with shale gas potential

In *Austria* OMV is investigating the potential of the Upper Jurassic Mikulov Formation in the Deep Vienna Basin. The company estimates that the formation contains 200 – 3—TCF of gas in place of which 15 tcf may be recoverable. The target occurs at depths greater than 14,700 feet and a temperature of 160° C.

Permo-Carboniferous basins in *France's* Languedoc such as the Stephanian-Autunian (Upper Pennsylvanian – Lower Permian) Lodève Basin may have some potential in bituminous Autunian (Lower Permian) shale. Schuepbach Energy has been awarded two permits in the Landguedoc-Provence Basin, one of which also incorporates part of the Lodève Basin. Total has been awarded the Montelimar permit. A number of other companies have also applied for permits in Languedoc-Provence, many of them overlapping. 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).

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. 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 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.” 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 feet gross gas-bearing interval in an interbedded Karpatian (Lower Miocene) sequence of siltstone, shale and sandstone below 10,000 feet. The two lowest zones were fractured and are believed to have produced gas-condensate. RAG and its new partner, Cuadrilla Resources, have announced a refrac operation for April 2011, but without indicating whether this is a shale gas play.

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 *Romania* Chevron has acquired a number of licenses in the south of the country, along the Bulgarian border, and has also applied for a license on the Bulgarian side of the border. The targets are believed to be shales of Silurian and Early to Middle Jurassic age.

In *Spain* applications that are presumed to be for shale gas exploration have been submitted in the Pyrenean Foothills (Cuadrilla Resources) and the Campo de Gibraltar (Schuepbach Energy / Vancast).

In addition to the Lower Jurassic Posidonia Shale, Schuepbach is also targeting the Aalenian (Middle Jurassic) Opalinuston in *Switzerland’s* Molasse Basin.

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. 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.

Hydraulic fracturing of shale gas reservoirs

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. There has been opposition to Shell’s drilling in southern Sweden, ExxonMobil has been questioned about its shale gas exploration activities in Lower Saxony and in the UK the parliamentary Energy Committee is undertaking a shale gas investigation.

The only concrete action, however, has taken place in France where the government has suspended shale gas drilling pending a progress report on the environmental consequences of shale exploitation, due on 15th April 2011. Companies have further undertaken not to fracture shale wells until after completion of the final report on May 31st 2011. It is understood that the government may allow an extension to the duration of existing permits in view of the suspension.

SHALE OIL IN EUROPE

In *France’s* Paris Basin, Toreador Resources is investigating the fractured shale oil potential of a Liassic (Lower Jurassic) analogue to the Bakken Formation of the Williston Basin. The Liassic section is similar to the Bakken Formation in that the bituminous shales also contain a middle calcareous member

(Banc de Roc). Shows have 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 whereby each partner will hold a 50% interest in Paris Basin unconventional oil exploration and production.

There are four Liassic targets in the basin: Schistes Carton (Toarcian); Banc de Roc (Pliensbachian); Amaltheus Shale (Pliensbachian); Sinemurian-Hettangian Shale.

Toreador / Hess had planned to drill six wells in 2011, at least two of them horizontal, but as a result of the recently announced French government study into the economic, social and environmental impact of shale gas and shale oil drilling, the partners have voluntarily agreed to suspend the four-well vertical drilling program until after the interim report is published in mid-April.

In 2010 Vermilion Energy fracture tested two vertical wells in the Toarcian Schistes Carton, producing 32 - 38° oil from both wells. These wells are currently believed to be producing about 63 BBL/D. Vermilion plans 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.

Realm Energy, although focused on shale gas, may also have some shale oil potential on the permits for which it has applied in the Paris Basin.

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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](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://www.warlick.net/>)
- **Hydraulic Fracturing**
 - <http://www.strongerinc.org/>

Gas Shales and Shale Oil Calendar

April 5-6, 2011: B.C. Unconventional Gas Technical Forum 2011, Victoria, B.C.

<http://www.empr.gov.bc.ca/OG/oilandgas/petroleumgeology/UnconventionalGas/Pages/default.aspx>

April 6-8, 2011: Shale Gas Eastern Europe 2011, C5 Group, Warsaw, Poland. <http://www.c5-online.com/SGEE.htm>

April 10-13, 2011: AAPG Annual Convention and Exhibition, Houston, TX. <http://www.aapg.org/houston2011/>

April 13-14, 2011: Shale Gas Water Management, Marcellus Initiative 2011, American Business Conferences, Pittsburgh, PA. <http://www.shale-gas-water-management-2011.com/>

April 18-20, 2011: 6th Annual Developing Unconventional Gas Conference & Exhibition, Fort Worth, TX. <http://www.dugconference.com>

April 19-20, 2011: RPSEA Unconventional Gas Conference 2011: Technological Keys to Unlocking Additional Reserves, Denver, CO. <http://www.rpsea.org/en/cev/342>

April 27-29, 2011: Montney/Horn River Infrastructure Finance & Development Summit, Calgary, Alberta, CA. Infocast. <http://www.infocastinc.com/index.php/conference/montney>

May 1-3, 2011: Nineteenth Williston Basin Petroleum Conference 2011, Regina, Saskatchewan. <http://www.wbpc.ca/>

May 9-11, 2011: Canadian Society of Petroleum Geologists Annual Convention, Calgary, AB. <http://www.geoconvention.com>

May 17-18, 2011: Northeast Shale Gas Symposium, American Conference Institute, Pittsburgh, PA. <http://www.canadianinstitute.com/NEShaleGas.htm>

May 23-25, 2011: Success in the Marcellus and Utica Shales: Case Studies and New Developments, AAPG Geoscience Technology Workshop, Baltimore, MD. <http://www.aapg.org/gtw/MarcellusUticaShale/index.cfm>

May 24-25, 2011: 2nd Annual Developing Unconventional Oil Conference & Exhibition, Denver, CO. <http://www.hartduo.com/>

June 25-29, 2011: AAPG Rocky Mountain Section, Cheyenne, WY (sessions on Niobrara, fractured shale plays, unconventional plays) http://www.rms-aapg.org/2011_meeting

July 31-Aug. 4, 2011: TSOP-CSCOP Joint Meeting, Halifax, NS (sessions on shale gas evaluation) <http://www.tsop.org/2011Halifax>

August 2-4, 2011: U.S. Shale Plays, AAPG Geoscience Technology Workshop, Ft. Worth, TX <http://www.aapg.org/gtw/USShale/index.cfm>

August 30-September 1, 2011: Unconventional Resources: Where Finance and Technology Meet. Unconventional Oil and Gas International. San Antonio, TX. <http://www.unconventionaloilgas.com>

September 24-28, 2011: AAPG Eastern Section Meeting, (sessions on eastern shale gas, new developments in unconventional gas reservoirs), Washington, D.C.

September 28-30, 2011: West Texas Geological Society Fall Symposium, Midland, TX

October 11-12, 2011: International Shale Plays, AAPG Geoscience Technology Workshop, Houston, TX.
<http://www.aapg.org/gtw/IntlShalePlays/index.cfm>

October 23-26, 2011: AAPG-International Conventional and Exhibition, Milan, Italy (sessions on North American and European shales and other unconventional plays) <http://www.aapg.org/milan2011/>

November 15-17, 2011: The Canadian Unconventional Resources Conference—a joint meeting of the Canadian Society for Unconventional Gas and the Society of Petroleum Engineers, Calgary, AB.
<http://www.spe.org/events/curc/2011/index.php>