EMD Gas Shales Committee

EMD's Gas Shales Committee Mid-Year Report

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As of: November 18, 2010

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Committee Activities

Introduction

It is a pleasure to present this report from the EMD Gas Shales Technical 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 gas, oil, or condensate are produced reflects the recently expanded mission of the EMD Gas Shale 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 and the hydrocarbons produced from them. An updated version of this report is expected in April, 2011.

This report is organized to include contributions from members of the EMD Gas Shales Advisory Committee on various shales (presented in alphabetical order by shale name or region) in North America as well as Europe. Additional sections of the report include valuable links, additional sources of information, gas shales and shale oil calendar of meetings to come.

Feel free to contact Neil Fishman, Chair, (nfishman@usgs.gov) with any questions.

Reports on various shales and regions:

Antrim Shale (Devonian), Michigan Basin

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 April, 2010 is approximately 11,375 with about 9,784 still online.

Total cumulative gas production reached 2.917 TCF by the end of April, 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 788 separate projects at the end of April, 2010. Cumulative production for the first 4 months of 2010 was 39,912,880 MCF of gas. That was a 2.9% decline from the first 4 months of 2009.

There were 33 operators with production at the end of April, 2010. There were 9,784 wells online at the end of April, 2010. There were 111 new wells drilled in 2009, and only 3 so far in the first 4 months of 2010. That is a 1.8% decrease in active wells from 2009 and an extraordinarily precipitous drop in new wells completed. Most of the production comes from a few operators. The top 10 operators produced 79.6% of the total Antrim gas in 2009.

Although some wells can initially produce up to 500 MCF/day, generally wells settle at less than 100 MCF/day. Play wide average production at the end of April, 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 April, 2010 the ratio was 1.52 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.

CO_2 is also an issue in the produced Antrim gas that is mostly of biogenic origin. Most wells begin with very low amounts of CO_2 in the produced gas; however, the percentage of CO_2 increases through time. Some projects that have a long production history may now exceed 30% CO_2 in the produced gas. The play wide average was just over 12.4% CO_2 in 2008.

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

Production and well data is available online at the Michigan Public Service Commission at:
http://www.cis.state.mi.us/mpsc/gas/prodrpts.htm
Various kinds of oil and gas information is also available at the Michigan Office of Geological Survey site at:
http://www.michigan.gov/deq/0,1607,7-135-3311_4111_4231---,00.html
Cores, samples and other kinds of data are available at the Michigan Geological Repository for Research and Education at Western Michigan University. That website is: http://wsh060.westhills.wmich.edu/MGRRE/index.shtml

Top 10 Operators:

Atlas Gas & Oil Company LLC	Muskegon Development Co.
Highmount Midwest Energy LLC	Trendwell Energy Corp.
Breitburn Operating Limited Partnership	Jordan Development Co. LLC
Terra Energy Ltd	Delta Oil Co. Inc.
Belden & Blake Corp. DBA Ward Lake Energy	OIL Energy Corp.

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 also 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

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 has 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 1950's and 1960's. 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 ft and was plugged back to a depth of 10,738 ft. 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 ft depth and in the upper Three Forks between 10,705 and 10,715 ft 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 ^{o} 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, 1964 after producing 57,840 bbls of oil.

Late in the 1970's, 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 up dip 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 ft. 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 MMBbls of oil have been recovered. The productive portions of the reservoir contains between 3 and 9 percent porosity with an average permeability of 0.04 md. A pressure gradient in the Bakken of 0.53 psi/ft indicates that the reservoir is overpressured. Laterals are routinely stimulated by a variety of sand-, gel- and water-fracturing methods. Initial production from these wells is between 200 and 1900 BOPD (Sonnenberg and Pramudito, 2009).

The Bakken middle member play moved across the line into North Dakota when Michael Johnson noted that wireline logs of the Bakken Formation along the eastern limb of the Williston Basin in Mountrail County, North Dakota resembled those from Elm Coulee. Even though the kerogen within the Bakken shales appeared immature and thus might not be generating oil, free oil in DSTs and some minor Bakken production encouraged Johnson to pursue a Bakken play in Mountrail County (Durham, 2009). In 2005, EOG Resources demonstrated with the #1-24H Nelson-Farms (SESE Sec. 24, T156N, R92W) that horizontal drilling coupled with large scale hydraulic fracture stimulation of the middle Bakken Formation could successfully tap significant oil reserves along the eastern flank of the Williston Basin. In the following year, EOG Resources drilled the #1-36 Parshall and #2-36 Parshall which resulted in wells with initial production rates in excess of 500 BOPD. Well stimulation of the early wells typically involved large single stage fracs using over 2 million pounds of propant 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 1.3 MMBbls of oil per month from 177 wells. Sanish Field, adjacent to Parshall, is producing just about 1 MMBbls of oil per month from 128 wells. This is up from 670 MBbls of oil per month from 95 wells reported in 2009.

Over 105 million bbls of oil have been recovered from the1,137 wells in the 81 middle Bakken producing fields put into service since 2004. The 231 horizontal wells drilled into the Three Forks Formation since 2006 have produced a total of 14 million bbls of oil. Currently there are 78 fields with Three Forks production. Sixteen wells have been completed in both the Bakken and Three Forks Formations. Half of these wells were drilled in 2010.

The North Dakota portion of the Williston Basin is extremely active with 140 rigs running. The top 10 producers in the play are:

1. EOG Resources (184 wells; up from 167)
2. Marathon Oil Company (150 wells; up from133 wells)
3. Hess Corporation (142 wells; up from141 wells)
4. Continental Resources, Inc. (129 wells; up from100 wells)
5. Whiting Oil and Gas Corporation (87 wells up from 69 wells)

6. XTO Energy Inc. (83 wells; up from 75 wells)
7. Burlington Resources Oil & Gas Company, LP. (78 wells; up from 72 wells)
8. Slawson Exploration Company, Inc. (47 wells up from 33 wells)
9. Petro-Hunt, LLC (36 wells up from 30 wells)
10. Encore Operating, L.P. (33 wells; up from 29 wells)

Additional Information:

The Bakken Source System was the focus of this past year's Williston Basin Petroleum Conference. The materials presented are available at the following link: http://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, Stephan H. Nordeng, 2010 Bakken Three Forks Core Workshop: Geologic Investigations 112.

Stephan H. Nordeng and Lynn D. Helms, 2010, Bakken Source System: Three Forks Formation Assessment.

Stephan H. Nordeng, Julie A. LeFever, Fred J. Anderson, Marron Bingle-Davis, and Eric H. Johnson, 2010, An examination of the factors that impact oil production from the middle member of the Bakken Formation in Mountrail County, North Dakota: Report of Investigation No. 109 Geologic Investigations No. 93

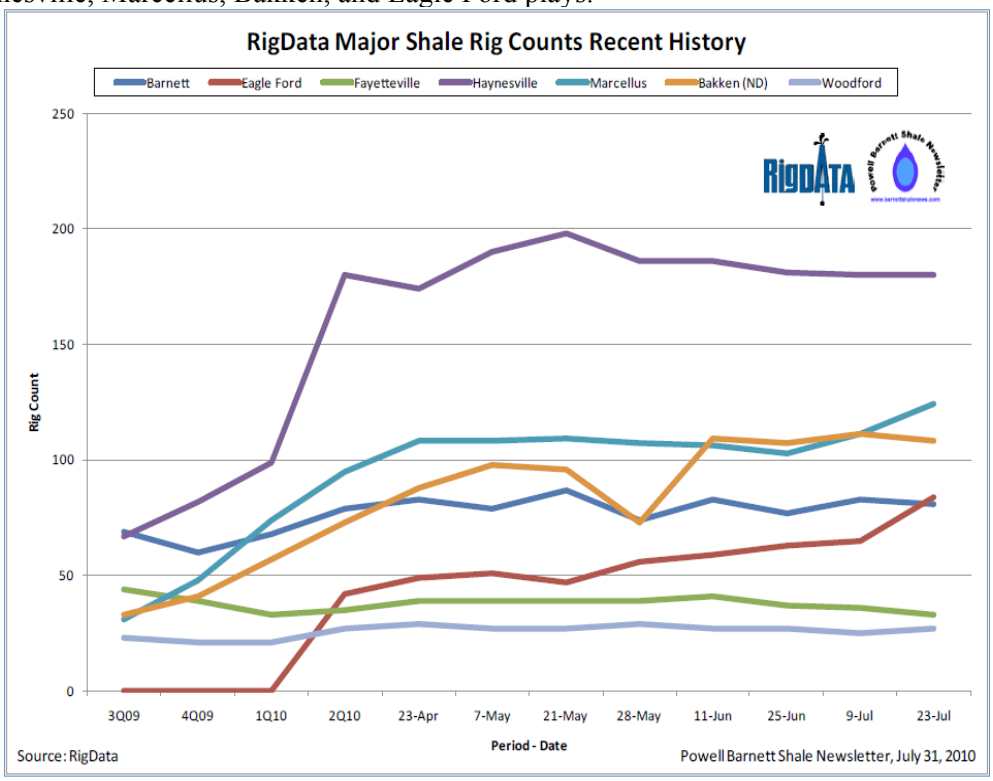
Sheet 1 - Stephan H. Nordeng and LeFever, J.A., 2010, Structural Transect of the Sanish and Parshall Fields, Bakken Formation, Mountrail County, North Dakota

Sheet 2 - Julie A. LeFever and Nordeng, S.H., 2010, Stratigraphic Transect of the Sanish and Parshall Fields, Bakken Formation, Mountrail County, North Dakota.

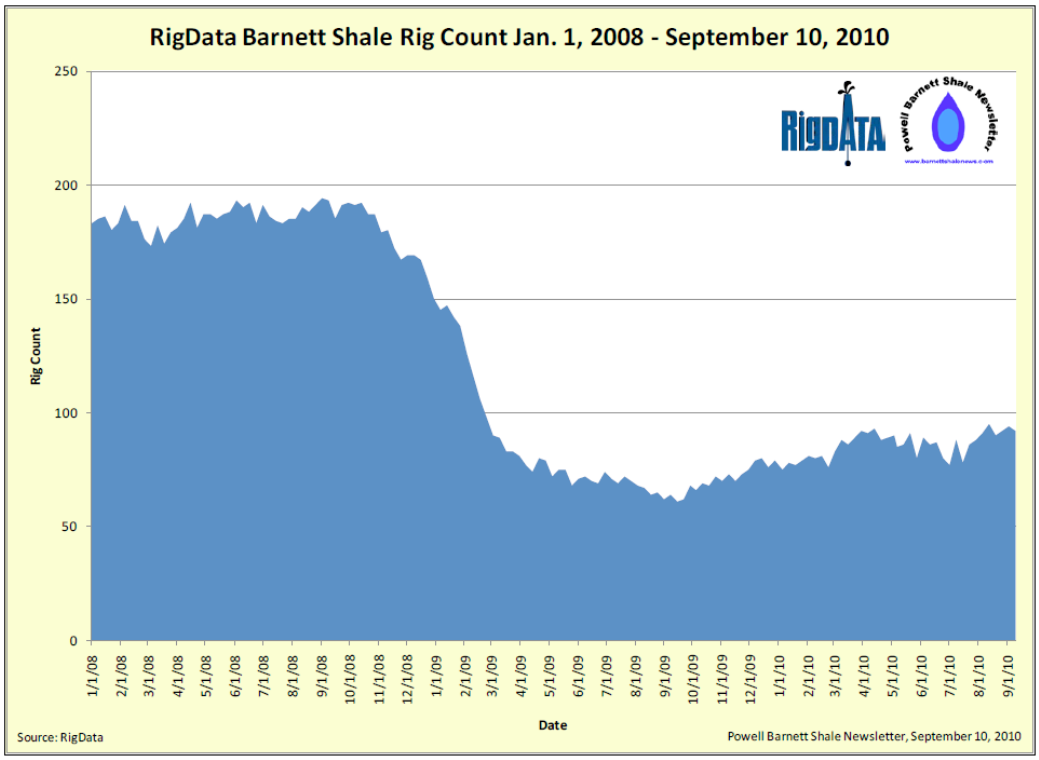
Barnett Shale (Mississippian), Fort Worth Basin

By Kent Bowker (Bowker Petroleum, LLC, The Woodlands, TX)

In terms of rig count, the Barnett was overtaken as the most active shale play in the US in the third quarter of 2009; it is now behind the Haynesville, Marcellus, Bakken, and Eagle Ford plays.



The Barnett rig count has been increasing steadily, but only slightly, since mid-September, 2009:



Of the some 90 rigs active in the play, fully one third are in Tarrant County. Operators continue to drill in the outlying areas of the play where the Barnett is less thermally mature (Palo Pinto, Montague counties, for example) but at a much lower rate that two years ago. By contrast, operators continue to be very active in counties with the best overall production (Tarrant County) and where they don't want to let leases expire.

The Texas Railroad Commission has recently added several new features to their website. These supplement the production and other information that their website has always provided:

http://lists.rrc.state.tx.us/mailman/listinfo/rules

This TRRC page permits users to subscribe to a new service that provides updates to all of the field rules in the state. Thanks to Gene Powell (http://www.barnettshalenews.com/) for permission to reprint the graphs used in this report.

Chattanooga Shale, (Devonian-Mississippian), Various Basins

By Kent Bowker (Bowker Petroleum, LLC, The Woodlands, TX)

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 the first half of 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, CNX Gas (now owned completely by CONSOL) 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 appears to be abandoned. CNX 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.

Eagle Ford Group (Cretaceous), Gulf Coast Basin

The Cretaceous (Cenomanian-Turonian) Eagle Ford Group, Gulf Coast Basin, comprises the Eagle Ford Shale and the up dip Woodbine Formation in Texas and the up dip 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 up dip 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 into East Texas and into 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 the general trend of the underlying Lower Cretaceous carbonate shelf edge.

The Eagle Ford disconformably overlies the Woodbine Group in Texas and the Tuscaloosa Group in Louisiana and is, in turn, disconformably overlain by the Austin Chalk (Dawson, 2000). The Eagle Ford, which contains a mixture of siliciclastic and carbonate lithologies and ranges to as much as 475 ft thick (Dawson, 2000), was deposited during a sea-level highstand associated with a global transgression (Hancock, 1993). Although the TOC content of shales in the Eagle Ford are variable, they range to as much as 8% (Liro and others, 1994; Dawson, 2000), with the organic matter being marine or mixed marine and terrestrial in origin (Liro and others, 1994).

Like 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, and a marl or carbonate content that allows artificial fracturing of the reservoir. 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).

Petrohawk drilled the first of the Eagle Ford wells in 2008, discovering in the process the Hawkville (Eagle Ford) Field in La Salle County, Texas. The discovery well flowed at a rate of 7.6 million cubic feet of gas 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.

Of particular note is that the Eagle Ford demonstrates relatively high gas production rates (Durham, 2010). Mineralogy of the Eagle Ford is somewhat different than other gas shales 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).

Much of the drilling activity in the Eagle Ford is currently centered in LaSalle and McMullen counties, although other counties with production or exploration interest include Bee, De Witt, Dimmitt, Karnes, Lavaca, Live Oak, Maverick, and Webb. The list of companies interested or active in this emerging play continues to grow and includes Anadarko, Apache, BP, Cabot, Chesapeake, ConocoPhillips, EOG, Murphy Oil, Petrohawk, Pioneer Natural Resources, Rosetta Resources, St. Mary Land and Exploration, Swift Energy, and TXCO.

During 2009 (January – August), more than 310 wells had been completed in the Eagle Ford and 415 have been permitted (The Tobin Monthly, http://news.p2es.com/newspage.aspx?cid=540&vid=44&gid=37). Production rates of 7.6-8.3 MMCFPD have been reported for some of Petrohawk's 16 producing wells (Durham, 2010), with some IP's being reported as high as 9 MMCFEPD (http://www.oilshalegas.com/eaglefordshale.html).

As of June 21, 2010, there have been 415 permitted and 137 completed wells (Railroad Commission of Texas, http://www.rrc.state.tx.us/eagleford/index.php, accessed July, 2010). The trend occurs at an average depth of 11,000 feet, and it is over-pressured (meaning wells drilled into this formation are expected to have high production rates).

References:

Dawson, W.C., 2000, Shale microfacies—Eagle Ford Group (Cenomanian-Turonian) North-Central TX outcrops and subsurface equivalents: Gulf Coast Association of Geological Societies Transactions, v. 50, p. 607-621.

Durham, L., 2010, Eagle Ford joins shale elite: American Association of Petroleum Geologists Explorer Magazine, January, 2010 edition, http://www.aapg.org/explorer/2010/01jan/eagleford0110.cfm

Hancock, J.M., 1993, Sea-level changes around the Cenomanian-Turonian boundary: Cretaceous Research, v. 14, p. 553-562.

Liro, L.M., W.C. Dawson, B.J. Katz, and V.D. Robison, 1994, Sequence stratigraphic elements and geochemical variability within a "condensed section"—Eagle Ford Group, east-central Texas: Gulf Coast Association of Geological Societies Transactions, v. 44, p. 393-402.

Texas Railroad Commission, July, 2010, http://www.rrc.state.tx.us/eagleford/index.php

Fayetteville Shale (Mississippian), Arkoma Basin

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).

Early estimates have indicated that there are over 40 Tcf of gas reserves in the Fayetteville Shale. Estimated ultimate recovery (EUR) for a horizontal well is 2.9 Bcf/well. As of June 2010, cumulative production of Fayetteville Shale has totaled 1,238,013,777 Mcf. The production of Fayetteville Shale for the first six months of 2010 is 353,961,143 Mcf. 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/Fayprodinfo.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 and 891 in 2009. As of August 2010 there are a total of 2,620 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 a major player since 2004 when production started. Chesapeake Energy and BP are also active in the Fayetteville play. BP acquired approximately a 25% interest in Chesapeake's Fayetteville assets for $1.9 billion in late 2008. Southwestern holds approximately 875,000 net acres in the play area and estimates 11 Tcf of recoverable gas for its acreage position. Chesapeake has about 600,000 net acres with about 9 Tcf of recoverable gas. Other operators involved with Fayetteville Shale exploration and development ventures include: XTO, One Tec, Petrohawk, KCS Resources, Hallwood Energy, Storm Cat Energy (USA) Operating, Edge Petroleum, Alta Operating and twelve other companies.

The top six operators of the Fayetteville gas shale play as of August 2010 based on numbers of producing wells are as follows (Figure 2):

1) Seeco Inc. (exploration subsidiary of Southwestern Energy) (1524 wells)
2) Chesapeake Operating Inc. (645 wells)
3) XTO Energy, Inc. (192 wells)
4) One Tec Operating, LLC (107 wells)
5) Petrohawk Operating Co. (70 wells)
6) KCS Resources (43 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

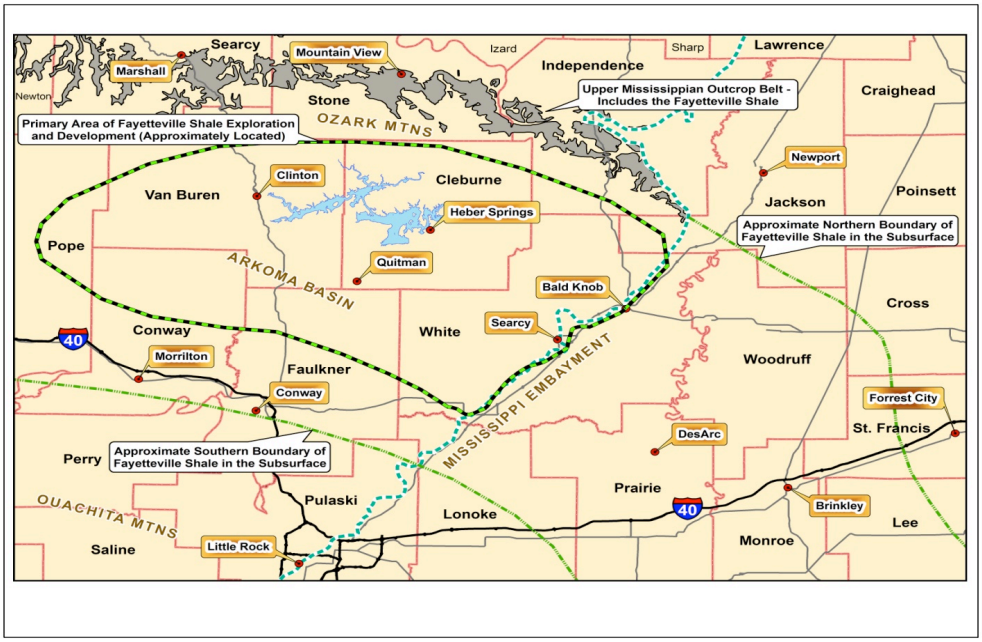


Figure 1. Primary area of the Fayetteville Shale exploration and development in Arkansas.

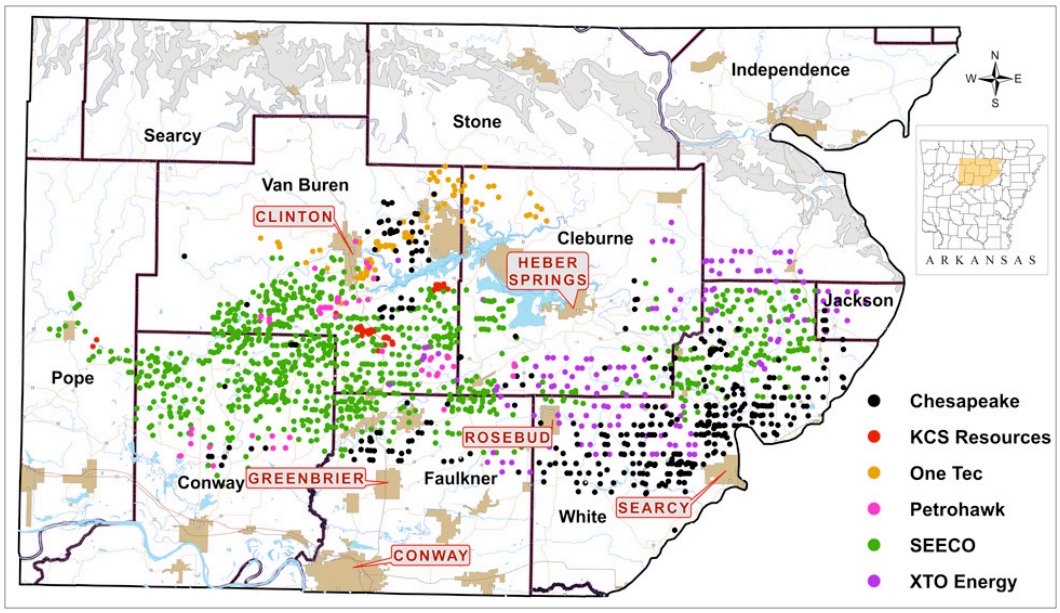


Figure 2. Location map of the Fayetteville Shale producing wells by top 6 operators as of August, 2010.

Gothic Shale (Pennsylvanian), Paradox Basin, SW Coloardo

By Laura L. Wray

In the southeast portion of the Paradox Basin in southwestern Colorado, an exploration play is underway to determine the economic feasibility of producing gas from the Pennsylvanian Gothic Shale. To date, Bill Barrett Corporation, the operator and a 55% leasehold owner of approximately 100,000 acres, with its partner, Williams Production RMT Company, have drilled and completed four vertical wells and nine horizontal wells to test this shale. The Gothic Shale/Mudstone is a transgressive/regressive black, organic-rich interval with significant amounts of detrital quartz and calcite, and lesser amounts of dolomite, pyrite, and clays. The clay fractions consist primarily of illite-mica with very minor amounts of chlorite. TOC values range up to 2% with transformation ratios of greater than 90%, indicating efficient conversion of the original TOC. Kerogen is predominantly Type II algal kerogen with very minor amounts of Type III terrigenous kerogen. Dry gas production in the northern four horizontal wells is contrasted with the wet gas and condensate production from the four southern wells. Btu values of the gas show this maturity variation also in the two groups of wells that are only 15 miles apart. However, vitrinite data is identical for the two sets of wells, thereby failing to confirm any variability in thermal maturity. More work is being done to better understand this discrepancy. Mass

spectroscopy and isotope data are surprisingly variable as well, suggesting a very complex history of thermal maturity and reservoir compartmentalization. Recent petrologic work has suggested that localized maturity trends may be caused by geothermal or magmatic processes.

The Paradox Basin of southwestern Colorado and southeastern Utah is an asymmetric, northwest-southeast trending basin, best known perhaps for the salt diapirs which intruded into late Pennsylvanian-Permian and Mesozoic sediments and have subsequently collapsed due to salt dissolution, creating northwest-southeast oriented valleys so characteristic of the Paradox Basin.

During the Pennsylvanian, thousands of feet of repetitive and reversing cycles consisting of evaporates (halite, anhydrite, and other associated salts), dolomites, black shales and/or shaly carbonates filled the basin. The deepest part of the basin existed along the eastern edge, proximal to the Uncompahgre Fault. Movement along this fault, thought by many to be reverse in nature, caused the Uncompahgre highlands to be uplifted to the east as the basin to the southwest subsided. Cyclic deposition in this evaporite basin resulted in thousands of feet of Pennsylvanian-age evaporates with interbedded clastics and carbonates. After the final halites were formed in the Desert Creek Formation, the overlying Gothic Shale was deposited in response to a major transgressive flooding event.

The Gothic "Shale" is more accurately described as a laminated, massive mudstone. It is not fissile in nature in the four conventional cores obtained by Bill Barrett and Williams, although the characteristic "poker chip" appearance is commonly seen in older cores taken in wells to the east of the exploration area and in recent cores taken in wells to the west in Utah.

The exploration wells, located in Dolores and Montezuma Counties, Colorado, have measurements of Poisson's Ratio and Young's Modulus that indicate significant brittleness. Efforts are now underway to create greater stimulated reservoir volumes in subsequent wells by adjusting the number of frac stages, increasing the volumes of slickwater and sand concentrations pumped, raising the injection rates, and modifying flow-back processes.

Gas production from the eight horizontal wells is quite variable and likely affected by different completion and flow-back procedures, as well as by the inherent heterogeneity of the formation. IPs have ranged from 200 MCFD to a high of 5.3 MMCFD. In all wells, frac water has dissolved salt to form brines with fluid weights of up to 10.5 pounds per gallon. As the hot brines cooled during flowback, salt precipitated in the wellbore at about 3000'. Continuous experimentation with drip string installations resulted in the successful mitigation of the salt precipitation problem. At first, it was thought that the frac fluids were dissolving the stratigraphically highest salts in the Akah Formation some 150 feet below the base of the Gothic. Surface and downhole microseimic monitoring showed clearly that microseisms occurred several hundred feet above and below the Gothic. Therefore, it was assumed that the microseisms below the Gothic must represent fluid movement that resulted in Akah salt dissolution. However, careful laboratory observations, identified with Scanning Electron Microscopy and with thin sections, revealed small halite crystals and salt-filled microfractures respectively. It appears that continuous experimentation with drip string installations has resulted in the successful mitigation of the salt precipitation problem.

The most recent well to be completed was fraced with huge volumes of water and sand per stage, and immediately after the frac was completed, a drip string was installed. The well produced 3.8 MMCFD initially and is declining as the load water is being recovered. Optimization of gas recoveries is ongoing to insure additional load recoveries and minimal problems associated with brine production.

Recent References:

The Pennsylvanian Gothic Shale Gas Resource Play of the Paradox Basin (AAPG Search and Discovery Article #90090©2009 AAPG Annual Convention and Exhibition, Denver, Colorado, June 7-10, 2009) By Peter G. Moreland, Bill Barrett Corp, Denver, CO., and Laura L. Wray, Williams Production Company, Denver, CO.

New production has been established from the Gothic Shale in the southeast portion of the Paradox Basin from the first two horizontal wells drilled in the shale. This frontier exploration project area is defined by numerous wells with gas shows in the Gothic Shale where the shale exhibits anomalous thickness. As part of this project, four vertical science wells cored the complete Gothic Shale section yielding good gas content and BTU values. The ensuing horizontal wells have initial production rates ranging from 3.1 to 5.7 MMCF/D with some associated condensate.

The Gothic Shale represents the maximum flooding surface for the third cycle of the Paradox Member of the Pennsylvanian Hermosa Formation and is found across the entire basin. The thickest Gothic Shale section is located in the southeastern and eastern portions of the basin and may represent the associated prodelta of the Silverton Delta. Elevated

terrigenous quartz percentages are observed in the shale from XRD data in the distal and central portions of the prodelta where the marine environment dominates the lithology. This portion of the prodelta is where the two horizontal wells are located that have a Type II kerogen source. On the proximal side of the prodelta, the shale has a larger terrigenous influence where the source will most likely have blend of Type II and Type III kerogens.

The gas shale revolution has spurred a wave of new thinking, drilling and completion technologies and a realization that giant gas fields are still undiscovered.

Bereskin, S.R. and J. McLennan, 2008, Hydrocarbon potential of Pennsylvanian black shale reservoirs, Paradox Basin, southeastern Utah: Utah Geological Survey Open-File Report 534, 56p.

Schamel, Steven, 2009, Shale gas potential of the Paradox Basin, Colorado and Utah, *in* Houston, W.S., L.L. Wray, and P.G. Moreland, eds, The Paradox Basin revisited – new developments in petroleum systems and basin analysis: RMAG Special Publication (CD), 825p. Updated Second Edition will be published in May 2010.

Haynesville/Bossier Shale (Jurassic), Texas and Louisiana

By Creties Jenkins (Degolyer & MacNaughton, Dallas, TX), originally included in 2010 Annual Report, 4/2010

The Haynesville Shale is located in western Louisiana and eastern Texas at depths ranging from 10,500 to 13,500 feet. It is an overpressured (0.7-0.9 psi/ft) Upper Jurassic-age shale bounded by the Cotton Valley Group sandstones above and Smackover limestones below. The Haynesville is overlain in the southeast portion of the play by the Bossier Shale which appears to be comparable to the Haynesville in terms of thickness and petrophysical properties, and is currently being tested by a few horizontal wells.

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 spacing intervals ranging from 40 to 560 acres per well. Original gas-in-place is estimated to be 717 TCF and technically recoverable resources are estimated at 251 TCF. A comparison of the Haynesville to other shale gas plays is shown in the table below (*Reference: Modern Shale Gas Development in the United States: A Primer; U.S. Dept. of Energy; April 2009*).

3-D seismic data have become increasingly important as operators try to quantify structural/stratigraphic complexities (faults, anticlines, thickness variations) as well as rock property variations (geomechanical and petrophysical properties) to steer wells into the best rock and understand their performance variability. Chesapeake, for example, is currently acquiring over 1,200 square miles of 3-D seismic data that will be available for use in 2010.

The biggest operators in the Haynesville, based on acreage position, are Chesapeake, Devon, EnCana, EOG Resources, Exco Resources, Forest Oil, Petrohawk, XTO Energy, and Plains Exploration and Production. As of September 3, 2009, there were 185 producing wells, 183 wells waiting on completion, 74 wells being drilled, and 167 wells permitted but not yet drilled.

Initial production rates range from less than 3 to more than 24 MMCFPD. Declines are very steep, exceeding 80% in the first year with estimated ultimate recoveries (EURs) ranging from 3 to 10 BCF per well. Drilling and completion costs range from 6-9 MM$ per well assuming lateral lengths of 4,500 feet, 12-15 fracture stimulation stages per well, and light sand fracture stimulations using either ceramic or resin-coated propant.

The rate-of-return in the play is highly-dependent upon gas price and EUR. At a $5 NYMEX gas price, a 4.5 BCF well will have a rate of return of less than 10%, whereas a 8.5 BCF well will have a return of nearly 50% (*Reference: Chesapeake's 2009 Institutional Investor and Analyst Meeting, October 14, 2009*) . At the present time, it is difficult to predict per well EURs because the most mature wells have only been on production for 1.5 years. The average EUR will depend in large part on whether reservoir permeability decreases with time and whether fracture conductivity diminishes as the well is produced.

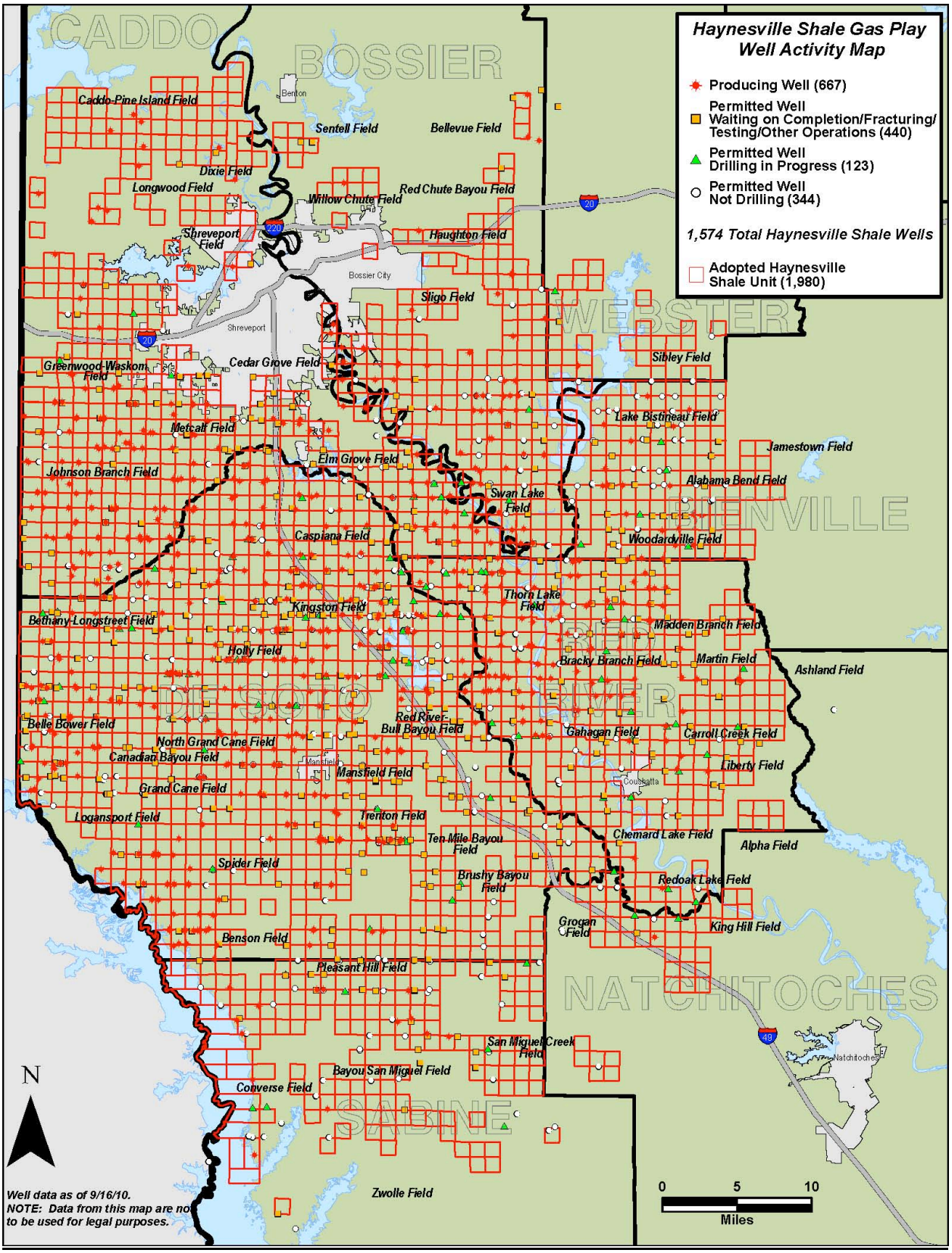
Additional information on the Haynesville can be found at these websites:

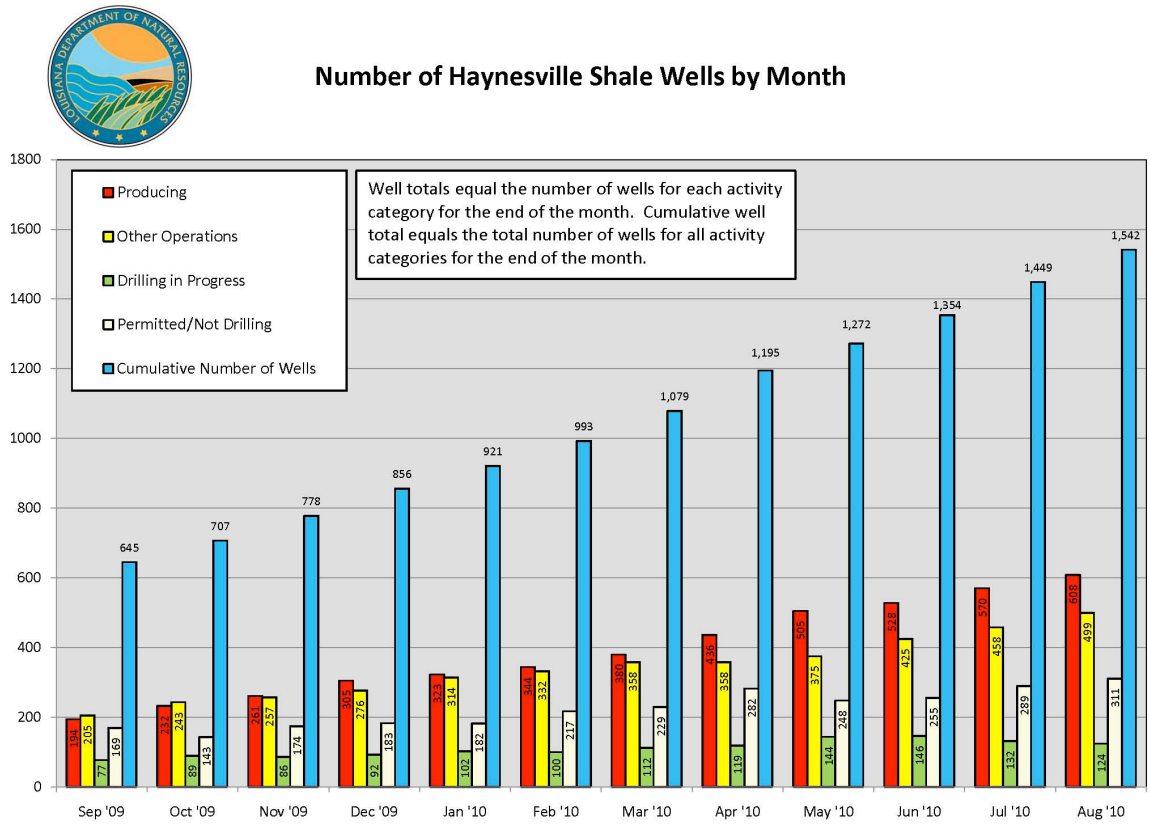
http://geology.com/articles/haynesville-shale.shtml
http://oilshalegas.com/haynesvilleshale.html
http://loga.la/haynesville-shale-news/

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[82]	1,000 - 7,000[83]	10,500 - 13,500[84]	4,000 - 8,500[85]	6,000 - 11,000[86]	600 - 2,200[87]	500 - 2,000[88]
Net Thickness, ft	100 - 600[89]	20 - 200[90]	200[91] - 300[92]	50 - 200[93]	120 - 220[94]	70 - 120[95]	50 - 100[96]
Depth to Base of Treatable Water[#], 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


Haynesville Shale Gas Play
Well Activity Map
Producing Well (667)
Permitted Well Waiting on Completion/Fracturing/ Testing/Other Operations (440)
Permitted Well Drilling in Progress (123)
Permitted Well Not Drilling (344)
1,574 Total Haynesville Shale Wells
Adopted Haynesville Shale Unit (1,980)
CADDO
BOSSIER
WEBSTER
CLAIBORNE
DE SOTO
RED RIVER
NATCHITOCHES
SABINE
Caddo-Pine Island Field
Sentell Field
Bellevue Field
Dixie Field
Longwood Field
Willow Chute Field
Red Chute Bayou Field
Shreveport Field
Haughton Field
Sligo Field
Sibley Field
Greenwood-Waskom Field
Cedar Grove Field
Lake Bistineau Field
Metcalf Field
Jamestown Field
Elm Grove Field
Johnson Branch Field
Alabama Bend Field
Swan Lake Field
Caspiana Field
Woodardville Field
Thorn Lake Field
Kingston Field
Bethany-Longstreet Field
Madden Branch Field
Holly Field
Bracky Branch Field
Martin Field
Ashland Field
Belle Bower Field
Red River-Bull Bayou Field
Gahagan Field
Carroll Creek Field
North Grand Cane Field
Canadian Bayou Field
Liberty Field
Mansfield Field
Grand Cane Field
Logansport Field
Trenton Field
Chemard Lake Field
Ten Mile Bayou Field
Alpha Field
Spider Field
Brushy Bayou Field
Redoak Lake Field
Grogan Field
King Hill Field
Benson Field
Pleasant Hill Field
San Miguel Creek Field
Bayou San Miguel Field
Converse Field
Zwolle Field
Benton
Bossier City
Shreveport
Mansfield
Coushatta
Natchitoches
N
0 5 10
Miles
Well data as of 9/16/10.
NOTE: Data from this map are not to be used for legal purposes.



Maquoketa and New Albany Shales, Illinois Basin

By Rick Sumner (Countrymark Energy Resources, LLC)

<u>Maquoketa Shale:</u>

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 southeastern 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

The New Albany Shale play in the Illinois basin has manifested into two separate plays; one a shallow (<1,500' true vertical depth) vertical play, primarily concentrated along the eastern basin rim, and the other a deeper (1,500-3,000' 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 75-150MCF/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 7MMCF/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 (In. Dept. Nat. Rsc.; Scout Check), while Kentucky has issued less than a dozen New Albany permits in the Illinois Basin portion of that state thus far in 2010 (Ky. Dept. Mines & Minerals.; Scout Check). Illinois has not issued any New Albany Shale permits this year (Ill. Dept. Nat. Rsc.; Scout Check).

Sources of information for New Albany and Maquoketa Shales:

Autry, A., Crockett, J.E., Dickerson, D.R., Oltz, D.F., Seyler, B.J., and Warren, R., 1987, *Source rock screening studies of Ordovician Maquoketa shale in western Illinois:* AAPG (American Association of Petroleum Geologists) Bulletin; Vol/Issue: 71:9.

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Gray, H. H., 1972, *Lithostratigraphy of the Maquoketa Group (Ordovician) in Indiana*: Indiana Department of Natural Resources, Geological Survey Special Report No. 7.

Graese, A.M., 1991, *Facies analysis of the Ordovician Maquoketa Group and adjacent strata in Kane County, northern Illinois*: Illinois Department of Energy and Natural resources, State Geological Survey Division Circular No. 547.

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Guthrie, J., 1989, *Organic geochemistry and correlation of Paleozoic source rocks and Trenton crude oils in Indiana*: AAPG (American Association of Petroleum Geologists) Bulletin ; Vol/Issue: 73:8.

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Hassenmueller, N.R., and Comer, J.B., 1994, Gas potential of the New Albany Shale (Devonian and Mississippian) in the Illinois basin: Gas Research Institute Topical Report, GRI-92/0391.

Illinois Department of Natural Resources, Division of Oil and Gas, Springfield, IL

Indiana Department of Natural Resources, Division of Oil and Gas, Indianapolis, IN

Commonwealth of Kentucky Department of Mines and Minerals, Division of Oil and Gas, Frankfurt, KY

The Scout Check Report, LLC, Evansville, IN

Marcellus Shale (Devonian), Appalachian Basin

By Cathy Enomoto (U.S. Geological Survey)

Interest in the Marcellus Shale remains strong. The EIA Marcellus Shale map is available at http://www.eia.doe.gov/oil_gas/rpd/shaleusa5.pdf. At the 2010 AAPG Annual Convention and Exhibition, held in New Orleans, LA in April, there were 14 technical sessions with themes of depositional models, stratigraphy, geochemistry, petrophysics, production techniques and resource assessment methods of mudstones and shale gas. Of the 48 presentations on shale gas, at least 10 presentations were on the Marcellus Shale. Issues with water supply sources for large volume fracturing, disposal of produced-water and used hydraulic fracturing-water, and pipeline capacity are being addressed with a variety of approaches including new infrastructure construction to handle increased demands, and 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. There is no production from the Marcellus Shale in Maryland.

New York: In 2009, there were 27 wells with Marcellus Shale listed as the producing formation. From 2003 to 2009, gas production from the Marcellus increased from almost 3.3 million cubic feet to over 56 million cubic feet, with the maximum production in 2008 at 64 million cubic feet. There has been no liquid hydrocarbon production reported. The producers with the highest volume in 2009 included Quest Eastern Resource, Fortuna Energy, and EOG Resources. The NY Department of Environmental Conservation (DEC) is preparing new requirements for well permits for gas well development using high-volume hydraulic fracturing. In the meantime, there is essentially a moratorium on Marcellus Shale well permitting in New York. According to the DEC, only one new well was completed in the Marcellus Shale in 2009, and none have been completed in 2010.

Ohio: In 2009, 68 drilling permits were issued for wells targeting Devonian shale, including 13 issued for Marcellus Shale. The Ohio Department of Natural Resources reported that as much as 200.02 million cubic feet of gas, 2,784 barrels of oil, and 40,425 barrels of water were produced from the Marcellus Shale between 2006 and 2009.

Pennsylvania: During the first 8 months of 2010, 2,046 Marcellus wells were permitted, and 822 were drilled. 1,771 of the permitted wells were planned as horizontal wells. Pennsylvania Governor Rendell approved Senate Bill 297 on March 22, 2010 which establishes Marcellus Shale production reporting requirements (including the status of each well and production data for the preceding calendar year). Instead of the previous law requiring the Pennsylvania Department of Environmental Protection to keep these records confidential for five years, the new amendment will require DEP to release these reports to the public on their Web site after only six months. Oil and gas production through the end of 2008 became available in May. From 2004 to 2008, over 6.8 billion cubic feet of gas and 19,500 barrels of liquid hydrocarbons were produced from the Marcellus Shale. Production was reported for 146 wells in 2008 by Range Resources, Atlas Resources, and Williams Production.

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 identified more than 2,800 wells permitted through 2009 which may be targeting the Marcellus Shale. The permits for some wells specifically list the Marcellus as the target formation, while others list "Devonian shale". Preliminary production of about 3.5 billion cubic feet for 2006, 7.7 billion cubic feet for 2007, and 13.6 billion cubic feet for 2008 can be attributed to wells with Marcellus Shale reported as a pay. Total production from the Marcellus for 2005-2008 is over 24.8 billion cubic feet of gas from nearly 900 wells. The Marcellus Shale was completed in many wells along with shallower shales and sandstones. Based on volume, the major producers include Chesapeake Appalachia, Columbia Natural Resources, Cabot Oil & Gas, Hall Drilling, Eastern American Energy, and New River Energy.

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

http://www.wvgs.wvnet.edu/www/datastat/devshales.htm
http://www.wvgs.wvnet.edu/www/datastat/WVGES_GeologyMarcellusShale.pdf
http://www.mgs.md.gov/geo/marcellus.html
http://www.mde.maryland.gov/Programs/LandPrograms/mining/MOG/naturalgas.asp
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.dcnr.state.pa.us/topogeo/pub/pageolmag/pdfs/v38n1.pdf
http://www.dcnr.state.pa.us/topogeo/oilandgas/index.aspx
http://www.dep.state.pa.us/dep/deputate/minres/oilgas/oilgas.htm

Monterey Formation (Miocene), Various California Basins

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 past more than 100

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 mainly 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. 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) seem to fit some of the criteria for a shale gas play.

The Monterey Formation is notable for and primarily recognized due to 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 their 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, within the past 3 decades the Monterey Formation has become better known for self sourcing of 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 from Monterey sourced systems) have been hypothesized to originate from 2 generally different type II kerogens – 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.

References:

Behl, R. J., 1999, Since Bramlette (1946): The Miocene Monterey Formation of California revisited, *in* E.M. Moores, D. Sloan, and D.L. Stout, eds., Classic Cordilleran concepts: A view from California: Boulder, Colorado, Geological Society of America Special Paper 338.

Isaacs, C. M., 2001, Depositional framework of the Monterey Formation, California, *in* C.M. Isaacs, and J. Rullkötter, eds., The Monterey Formation: From rocks to molecules: New York, Columbia University Press, p. 1-30.

Isaacs, C. M., and J. Rullkötter, eds., 2001, The Monterey Formation: From rocks to molecules: New York, Columbia University Press, 553 p.

Neal/Floyd Shale (Mississippian), Black Warrior Basin

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, Various Basins

By Thomas Chidsey, (Utah Geological Survey),
Craig Morgan (Utah Geological Survey),
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. Existing gas production in the Uinta Basin could be greatly enhanced by the addition of recoverable gas reserves in the

Mancos Shale (from new drills or bypassed gas). As compared to established shale gas plays, like the Barnett, the Mancos is geologically distinct in that it is an extremely thick package of various shale lithotypes with varying organic content. Most of the Mancos is organically lean, with some richer condensed sections; gas shows are common throughout.

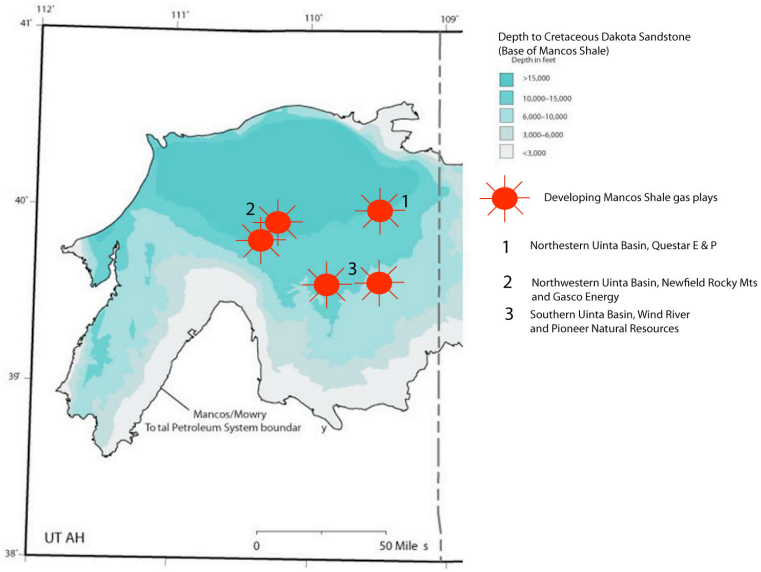
The Mancos Shale was deposited on the margin of an epeiric (shallow, continental interior) seaway with the Sevier orogenic belt to the west. It is a mud-dominated succession and generally interpreted as marine mudrock deposited in the offshore realm. The margins of the foreland basin experienced variable amounts of clastic-influence, as accommodation (tectonics and sea level) and sediment supply varied through time. Through its deposition, the Mancos displays a progradational (moving basinward) stacking pattern moving from west to east, illustrating the progressive shallowing and filling of the seaway in which it was deposited. 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.

The Mancos Shale consists of interbedded claystone, siltstone, and very fine-grained sandstone. It is up to 3,500 ft thick and overpressured in some areas. Thickness of potential shale-gas members (Prairie Canyon and Tununk Shale) of the Mancos ranges up to 1,500 ft with 2% to 5% porosity. Vitrinite reflectance at the top of the Mancos ranges from 0.65% to 1.50%; total organic carbon (TOC) is 1-2 % with type II to mixed type II-III kerogen. Estimated in-place gas is reportedly between 280 and 350 BCF/mi^2, with a projected estimated ultimate recovery (EUR) of 5% to 15% of in-place gas. Initial flow rates range from 1,000 to 2,000 MCFPD. Exact extent of the play has not been defined.

Recent smaller-scale studies funded by the Utah Geological Survey have indicated the potential of the Mancos Shale. Schamel (2005, 2006) discussed shale gas potential throughout the state and identified gas shows in the Mancos throughout the Uinta Basin. Longman and Koepsell (2005) discussed the stratigraphy and fractures in the upper Mancos in northern Uinta Basin. Anderson and Harris (2006) conducted a detailed sequence stratigraphic and geochemical study of the lower Mancos outcrops in the southern Uinta Basin, identifying several organic-rich condensed sections and mapped key horizons in the eastern Uinta Basin.

Mancos gas in place and recoverable reserves are poorly understood due to the limited amount of exploration and production. Questar E&P estimate 3 to 6 BCFG recoverable for wells in northeastern Uinta Basin while initial potentials of 5 MMCFGPD have been reported from wells in northeastern Uinta Basin. 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.



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

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. All Mancos Shale completions are in vertical drill holes; horizontal drilling has not been attempted because specific horizontal targets within the thick Mancos have not been identified. Drilling and completion programs are designed to accommodate all of the highly heterogeneous reservoirs. However, Gasco Production Co. has received drilling permits (May 2010) for the first two horizontal tests of Mancos zones in Utah: 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 49 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.

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 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, Uinta Basin, in order to identify premium target zones, and determine the resource potential.
2) Define the geologic parameters that determine various geomechanical properties (i.e. brittleness, "fracability"). These relationships are currently poorly understood. Use defined relevant geologic parameters to predict regions of brittleness ("fracability") and Mancos shale gas prospectivity, from an engineering perspective.
3) Establish best drilling, completion, and production techniques for specific targeted intervals based on their rock properties.

Geologic and engineering evaluation will use public and proprietary datasets; well logs, core, well 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 provide integration of geologic and engineering disciplines, the project team includes sedimentary geology, geochemistry, geomechanics, production engineering, petrophysical log evaluation, seismic evaluation, reservoir simulation, and hydraulic fracturing specialists. 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. Questar Exploration & Production, 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, many of whom may contribute data as the project progresses.

Recent Presentations:

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

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

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Longman, M. and R. Koepsell, 2005, "Defining and characterizing Mesaverde and Mancos sandstone reservoirs based on interpretation of formation microimager (FMI) logs, eastern Uinta Basin, Utah": Utah Geological Survey Open-file Report 458, DVD.

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Schamel, S., 2005, Shale-gas reservoirs of Utah: survey of an unexploited potential energy resource: Utah Geological Survey Open-file Report 461, 114 p.

Schamel, S., 2006, Shale gas reservoirs of Utah: assessment of previously underdeveloped gas discoveries: Utah Geological Survey Open-file Report 499, 84 p.

Central Utah Mississippian/Pennsylvanian Shale Gas Play

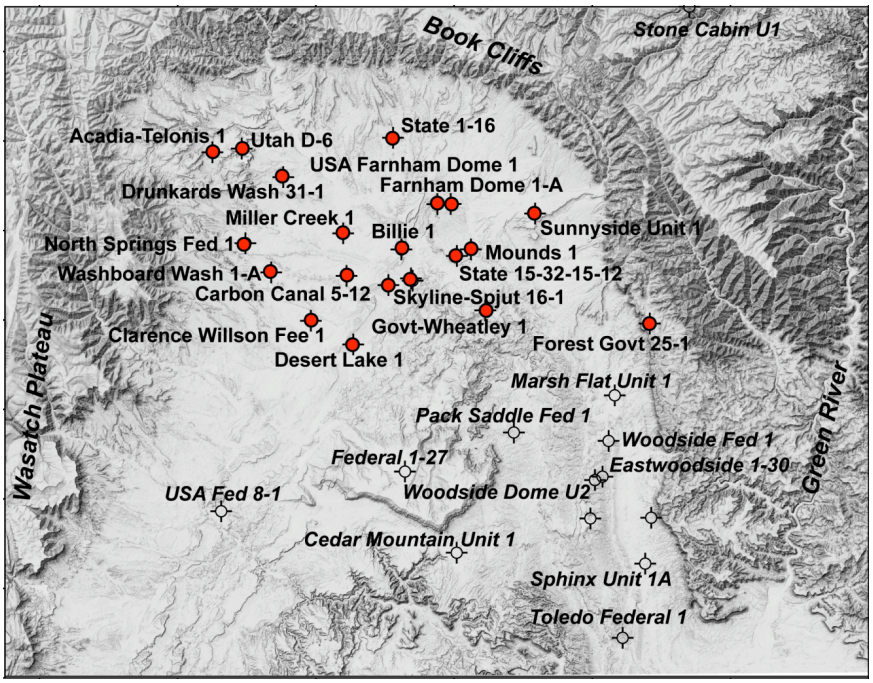
Overview: Paleozoic shales in the Colorado Plateau and eastern Basin and Range Provinces have long been known for their potential as source rocks for hydrocarbons that have migrated into other formations but have not been considered as in-situ gas reservoirs. These include the Mississippian/Pennsylvanian 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 basic rock mechanic data so important to successful completions are virtually unknown. In addition, distribution and thickness of these rocks are poorly mapped and the vertical succession and regional correlation of the Manning Canyon and Delle Phosphatic have 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 has 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 mi^2. 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.



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-mi^2 potential shale gas-play area. Average depth to the top of the formation is 7,470 ft. In the play area the formation is up to 1,200 ft thick, of which approximately two-thirds is dark gray carbonaceous shale and argillaceous limestone. Associated intercalated lithologies include limestone and varicolored fine-grained sandstone and siltstone. Strata appear to alternate between marginal marine and non-marine. Integrated analysis of well cuttings, limited core, and well logs permit identification of the stratigraphic relationships between potential gas pay and non-pay intervals. In central Utah the formation was deposited in a shallow structural depression on the craton margin between the incipient Uncompaghre uplift to the northeast and the Emery arch to the south. 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.

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/index.htm.

Recent Presentations:

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

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

Schamel, S. and J. Quick, 2010, "Manning Canyon Shale: An Emerging Shale Gas Resource", June 15, 2010, at the AAPG Rocky Mountain Section Meeting in Durango, Colorado.

Paradox Basin Pennsylvanian Shale-Gas Play

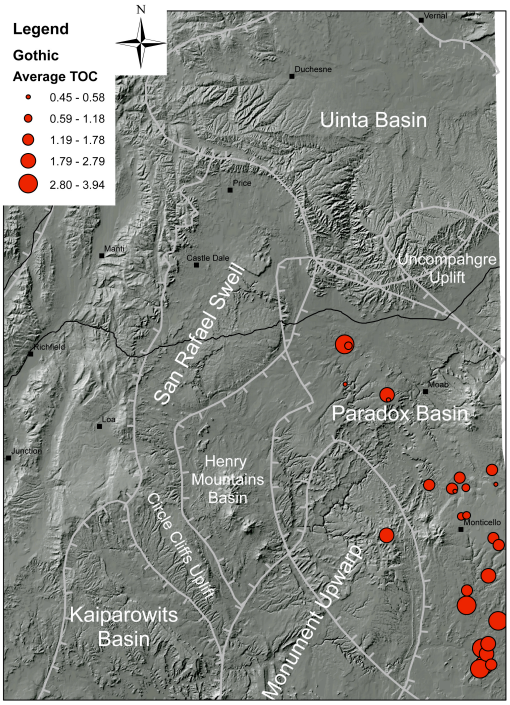
Overview: In the Paradox Basin of southeastern Utah and southwestern Colorado, cyclic shale units in the Pennsylvanian Paradox Formation consist of thinly interbedded, black, organic-rich marine shale; dolomitic siltstone; dolomite; and anhydrite. They generally range in thickness between 25 and 50 ft. 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: CrownQuest Operating LLC continues to evaluate the drilling results and conduct workovers in former dry holes on the Hovenweep, Gothic, and Chimney Rock shale zones of the Paradox Formation. 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 May 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 May 1, 2010, was 343.4 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 May 1, 2010, was 35.8 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 mi^2, where the company has about 140,000 net undeveloped acres.

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/cm^3 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/index.htm.

Recent Presentations:

Bereskin, S. R., *et al.,* 2010, "Pennsylvanian Organic Mudstone Reservoir Characteristics from the Paradox Basin, Southeastern Utah," June 15, 2010, at the AAPG Rocky Mountain Section Meeting in Durango, CO.

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

Moreland, P., 2010, "The Pennsylvanian Gothic Shale, Possibly the New Gas Shale Resource Play from the Paradox Basin," June 15, 2010, at the AAPG Rocky Mountain Section Meeting in Durango, CO.
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_Apr_2010.pdf, accessed August 9, 2010.

Wasatch Plateau Blue Gate and Tununk Shale Members, Cretaceous Mancos Shale

Overview: On the Wasatch Plateau in central Utah, potential shale gas reservoirs include the Blue Gate and Tununk Shale Members of the 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 has 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

By Rich Nyahay, NYSERDA, NY

Overview: The Ordovician Utica, Dolgeville, and Flat Creek are the Formations of interest. These shales and interbeded limestones range in TOC from 1- 5% in the dry gas window. They cover an area from Mohawk Valley south to the 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 1000 feet.

Current: In June 2010, Norse Energy Corp USA has received two permits to drill Utica wells in New York, the Aarismoa 1(1API 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 70mcf/d over a test period of 24 days. No production to date has come from the Utica.

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 CO_2 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 CO_2 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 CO_2 injection;
4) describing economic constraints to CO_2 sequestration;
5) assessing 'advanced' approaches to development; and
6) developing an independent, basin-wide assessment of the CO_2 storage potential in NY gas shale.

Norse is completing a cableless 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. 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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Woodford Shale (Late Devonian-Upper Mississippian), Anadarko & Arkoma Basins

By Brian Cardott (Oklahoma Geological Survey)

As of September 15, 2010, there were a total of 1,525 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 Anadarko Basin shelf in western Oklahoma and an oil play in the Ardmore Basin in southern Oklahoma.

Of a total of 1,186 horizontal Woodford Shale gas wells from 2005-2010, initial potential gas rates ranged from 3 to 12,097 thousand cubic feet of gas per day (MCFGPD; average of 2,777 MCFGPD from 1,159 wells) and lateral lengths of 10 to 10,195 ft (average of 3,403 ft from 1,178 wells). Cumulative production from 1,285 Woodford Shale-only wells drilled from 2004-2010 is 683 BCF gas and 2,303,403 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 24 operators active in calendar year 2010, the top ten operators (for number of wells drilled during 2010):

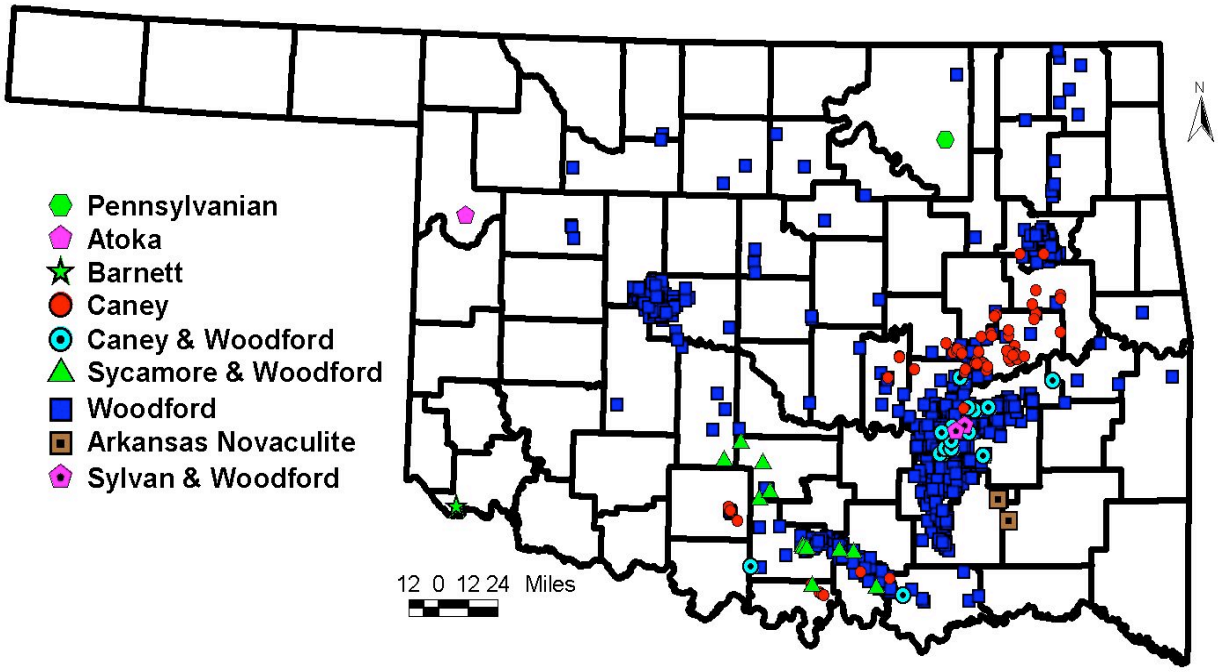
1) Newfield Exploration Mid-Continent Inc.

2) Devon Energy Production Co. LP
3) BP America Production Company
4) Cimarex Energy
5) XTO Energy
6) WCT Operating
7) Continental Resources
8) Petroquest Energy
9) Antero Resources
10) Cholla Petroleum

Caney Shale (Mississippian) gas-well completions dropped from 24 Caney-only wells in 2004 to 3 Woodford & Caney commingled wells in 2009 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 MCFGPD at 7,966 ft TVD).

There are four Woodford gas shale 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 1.1% 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 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.

Oklahoma Gas Shale Well Completions (1939 to 2010)

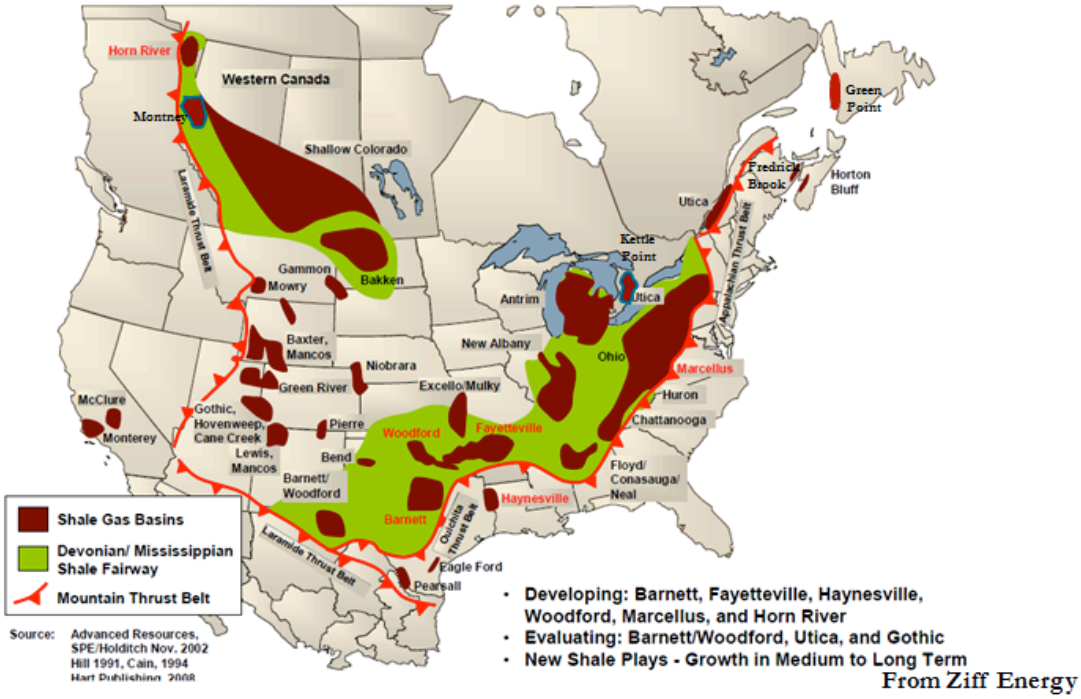


Canadian Shales

By Jock McCracken (Egret Consulting)

Shale gas production in Canada is now more than two years old after the announcement of new discoveries at the beginning of 2008. Therefore, the state of development for the shale plays still range from speculative to exploratory to emerging with only two giant plays in N.E. B.C. being considered developing and under increasing production. In most cases, the majority of these wells are still confidential, unless announced by the operator, so production numbers are unknown.

Two significant wells were drilled and tested the in the St. Lawrence Lowlands of Québec and New Brunswick. These could be a game changer in these plays. So far there is action and\or interest in 9 provinces of Canada out of the 10. Our smallest province of Prince Edward Island is our last holdout.



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 the 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.

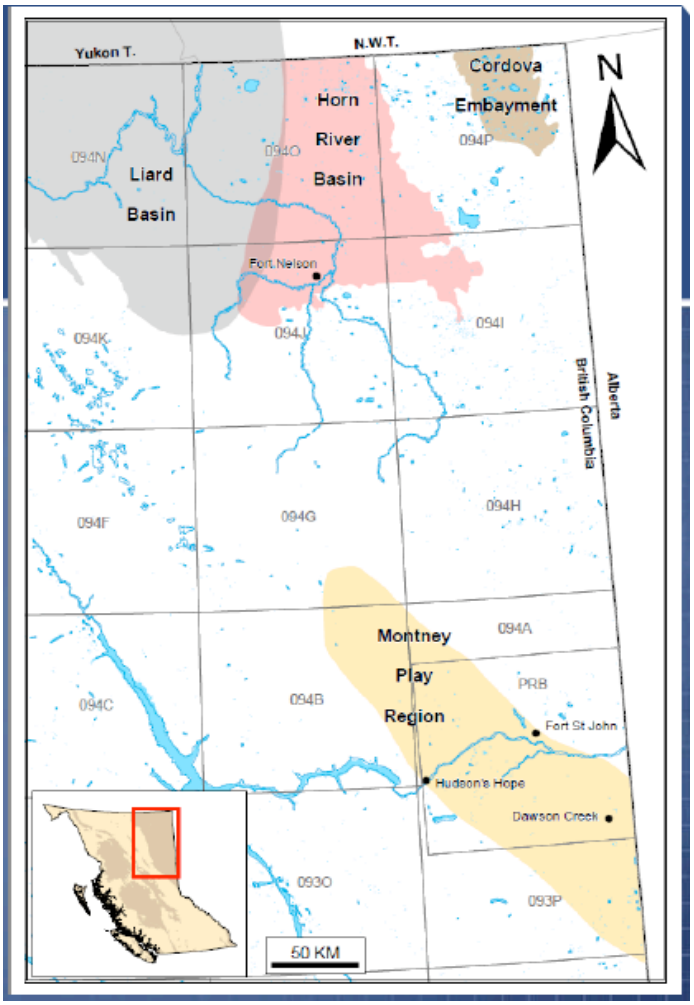
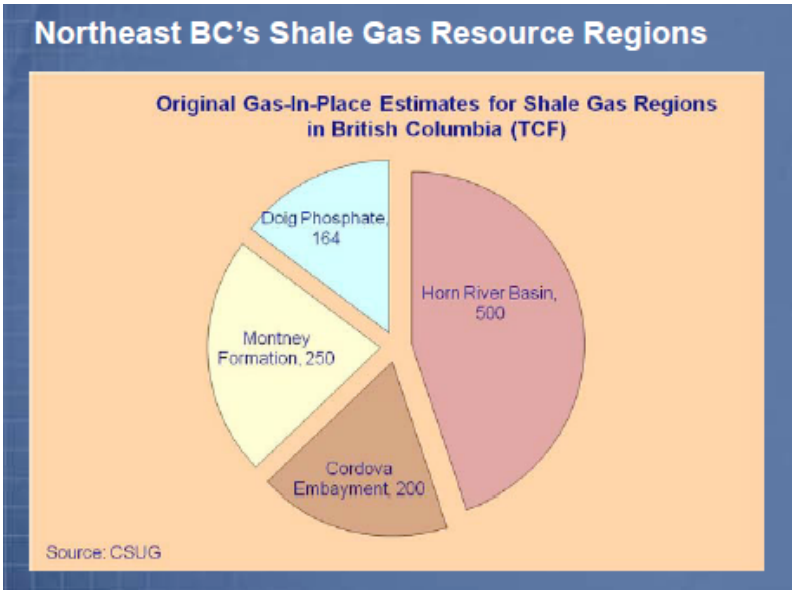


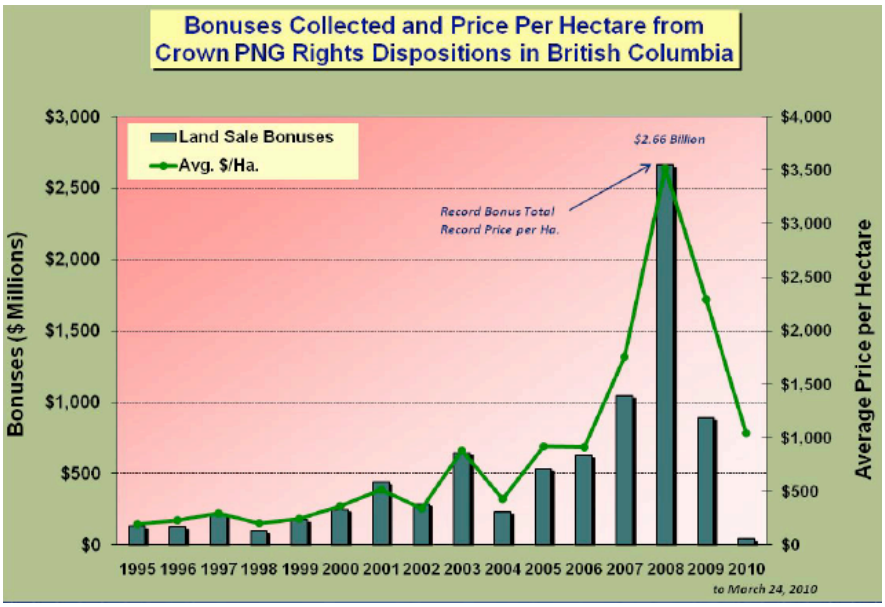
TABLE 1. POTENTIAL SHALE GAS FORMATIONS IN NORTHEAST BRITISH COLUMBIA

PROSPECTIVE HORIZONS

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



The chart below shows this activity iyn 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

The Horn y capacity of 2.2 Bcf per day 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 per day 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.

Cordova embayment is now picking up in the drilling phase after most parcels purchased privately by land brokers, mostly in 2007. 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 drilling two horizontals with both of them on extended tests. Penn West just announced a $850 mm 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 with this trend now 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, 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. The horizontal section are up to 2400m long with up to 14 fracs per well. They believe they have an estimated 70 Tcf of gas in place in their trend. Shell with 174 well rig releases since 2005 now has holding of 243,000 hectares in the prime Montney fairway. In November of 2009 they reported production of 100 MMcf/d from their Sunset-Groundbirch

complex. ARC Energy trust is another dominant player in the Dawson Creek area recently achieving a record average production of 52 MMcf/d. Twenty-two horizontal wells were drilled in 2009 with significant progress made toward completion of their 60 MMcf/d Dawson phase one gas plant. In 2010 they will be drilling 3 vertical and 30 horizontal wells.

Murphy has concentrated their efforts in the Tupper area and is now producing at 95 MMcf per day with the average IP at 7 MMcf/d. Progress Energy Resources Corp has one of the largest land base in the area with 233,000 hectares. The graph below shows the well production in the Montney.

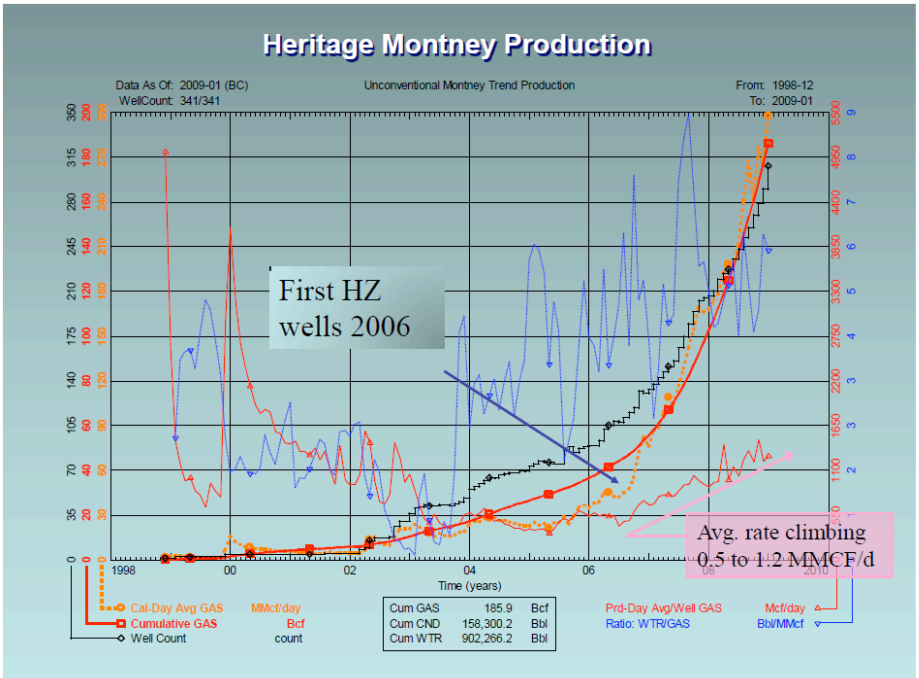


Figure 13. Chart displaying area gas production and total number of producing wells from the Heritage Montney. Horizontal drilling technology along with new and improved completion techniques are key factors in the increasing production profile from these areas. Data from Hayes (2009).

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 63,000 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.

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

B.C Shale information link: There is a wealth of data on this website.
http://www.empr.gov.bc.ca/OG/oilandgas/petroleumgeology/UnconventionalOilAndGas/Pages/Shale.aspx

Unconventional gas forum presentations from 2010 and 2009
http://www.empr.gov.bc.ca/OG/oilandgas/petroleumgeology/UnconventionalOilAndGas/Pages/default.aspx

Alberta Shale Gas

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. The shale gas intervals are normally co-mingled so numbers are difficult to grasp for the shales. Stealth Ventures announced their shale gas project in the Wildmere region of eastern Alberta as commercial within the Colorado Group, a mixture of biogenic gas-charged shales with silts and sand laminae.

They are negotiating to down space to 8 wells per section.

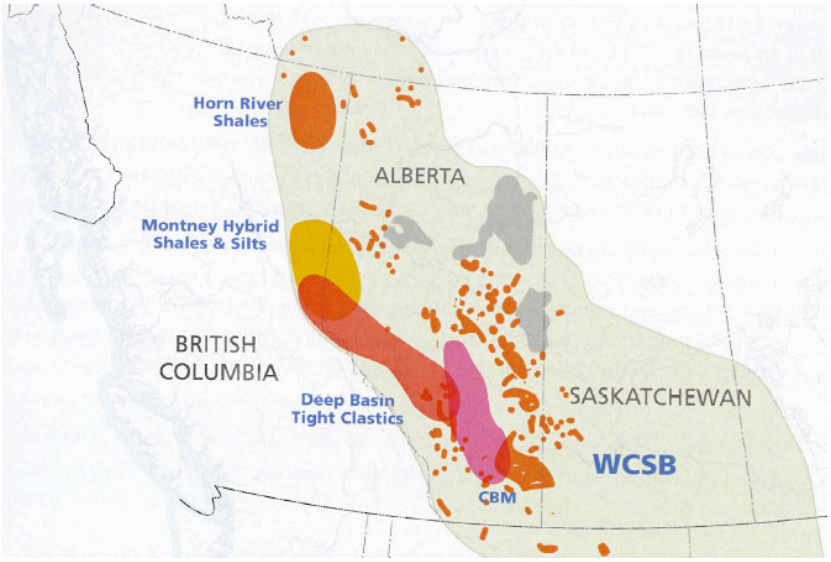
Lower Jurassic Nordegg (Gordondale), West Central Alberta

Anglo Canadian Oil Corp. is currently playing the potential of the Nordegg Member which is a source rock of basinal shales, silts and carbonates that is the regional source rock for the area. They feel that the Nordegg Member contains a huge amount of oil and has the potential to replicate the Bakken shale play in Saskatchewan. They are currently drilling a horizontal well to test this play. 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.

Mooncor is exploring for this play. They have re-entered a well and tested about one MMcf/d from a12-25 meter thick shale. Large land sale bids of $384 million at the end of 2009 triggered some speculation that the above shale may have been the target. The rather small foot print may hold 25 Trillion cu ft but infrastructure costs should be minimal since this area is just west of Edmonton.



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.
AGS Shale Gas Section: http://www.ags.gov.ab.ca/energy/shale-gas/shale-gas.html
AGS Reports: http://www.ags.gov.ab.ca/publications/pubs.aspx?tkey=shale%20gas
AGS Conference Papers and posters: http://www.ags.gov.ab.ca/conferences/geology-poster-ppt.html
Alberta Duvernay/Muskwa and Montney Formations Shale Analysis poster by the ERCB and Alberta Geological Survey: http://www.ags.gov.ab.ca/conferences/shale_gas_cspg_2009_poster.pdf

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

Saskatchewan
Cretaceous Colorado Group – biogenic gas

Central Saskatchewan

In Saskatchewan, the exploration focus has been primarily on two types of biogenic shale gas potential within the Upper Cretaceous. The first type is a hybrid shale gas play along the Saskatchewan–Alberta border, where thin laminae of sand and silt lie within the shales of the Upper Colorado Group. Other intervals within the Colorado Group that were once lumped and dismissed as 'non-productive shale' are also now being re-evaluated. The second type of play currently being evaluated is the Colorado shale gas play in the eastern half of the province. These highly organic shales have been the focus of exploration in the past, prior to World War II, when gas seeps were reported near the towns of Kamsack and Hudson Bay. Several wells near Kamsack produced from the early 1930s to late 1940s with total gas production of 168 MMcf. From 2001 to September 2008, 59 new wells, licensed for gas, were drilled in the Hudson Bay and Kamsack areas.

There are still no major commercial discoveries and not much news out of Saskatchewan this year as a result of the lower gas price and the economy. There are however around 13 wells in SW Saskatchewan that under production from the Colorado shales.

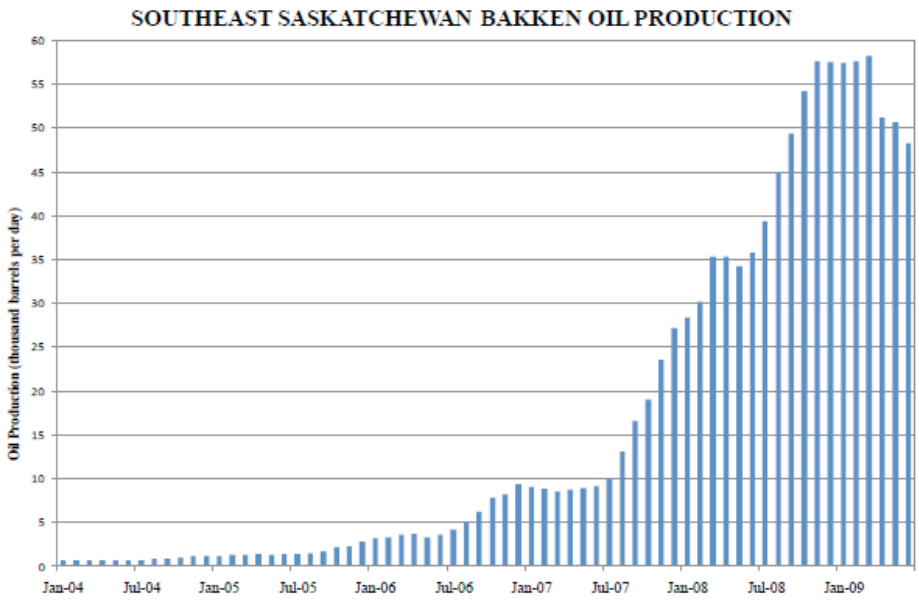
Between 2004 and 2008 more than 50 test wells were drilled for shale gas in all areas in the province, including Watrous, Moose Jaw, Strasbourg, Foam Lake, Smeaton, Shell Lake and Big River but no commercial discoveries have been announced. Some players are still operating, but at reduced or no activity, see:
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.

Mississippian Bakken

Saskatchewan is also reaping the benefits of the boom in horizontal and fracturing techniques drilling, especially in the Bakken.



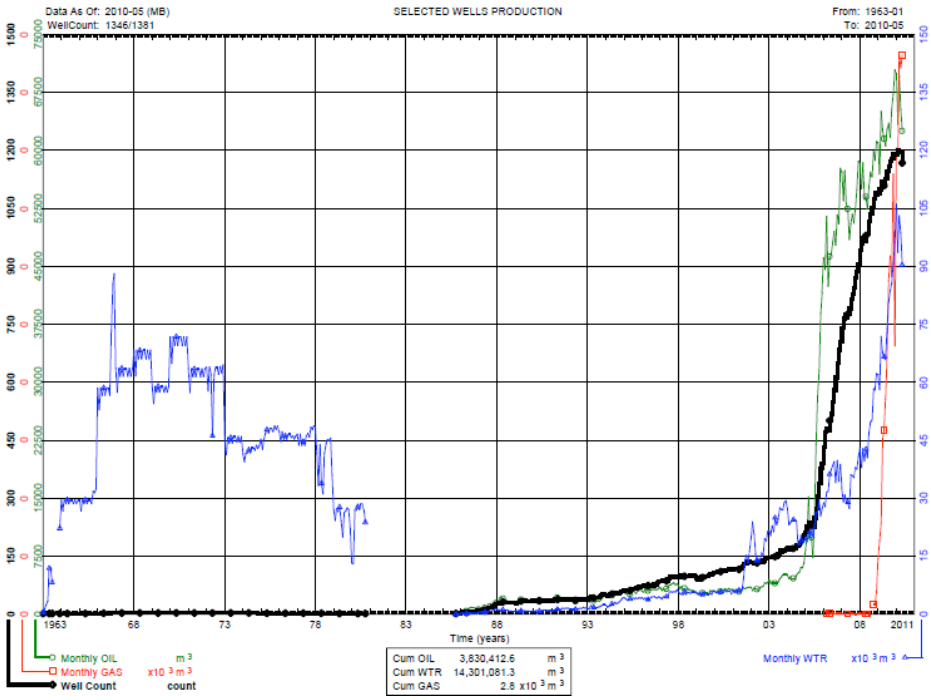
Saskatchewan Government energy and resources is the regulator:
http://www.er.gov.sk.ca/Default.aspx?DN=4c585c56-193a-485a-91fd-7c49f0104a60

Manitoba
Cretaceous Colorado Group

There is the potential of shale gas in Manitoba, but no activity. 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

Mississippian Bakken

Manitoba has the Bakken play within its borders and has experienced a rapid rise in its well count and production.



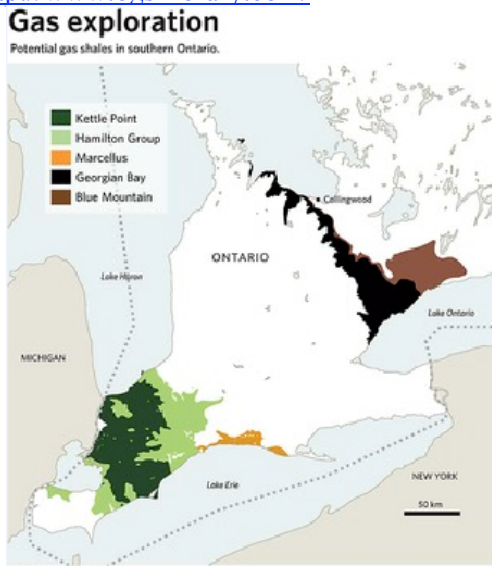
The Manitoba oil and gas is the regulatory agency. http://www.gov.mb.ca/stem/petroleum/index.html

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 no wells have 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 earlier this year to assess the shale gas potential of the Kettle Point Formation. The results will take several months to acquire. They have just released a request for proposals to drill two more stratigraphic test wells latter this year, this time to test the Collingwood-Blue Mountain.

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 bright light in Canadian shale exploration in 2008 was in Quebec, within a 300 km by 100 km fairway between Montreal and Quebec. Both Forest Oil Corporation and their partners and Talisman and their partners have drilled about 11 wells to evaluate both the Lorraine (up to 6,500 ft thick) and the Utica (300 to 1,000 ft thick). Talisman with their partners and a 771,000 acre land position has drilled 6 vertical wells with tested rates at from 300 to 900 Mcf/d. In 2009 and 2010 they drilled or will be drilling three horizontals which are 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 ft thick within the gas window. Canbrian, 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. Initial rates were over 12 MMcf/d. During the test, the well flowed natural gas at an average rate of over 6 MMcf/d.

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

Ordovician Macasty Shale

Petrolia and Corridor recently drilled the oil prone Macasty Shale as a secondary target on Anticosti Island in the St. Lawrence Seaway. No results to date.

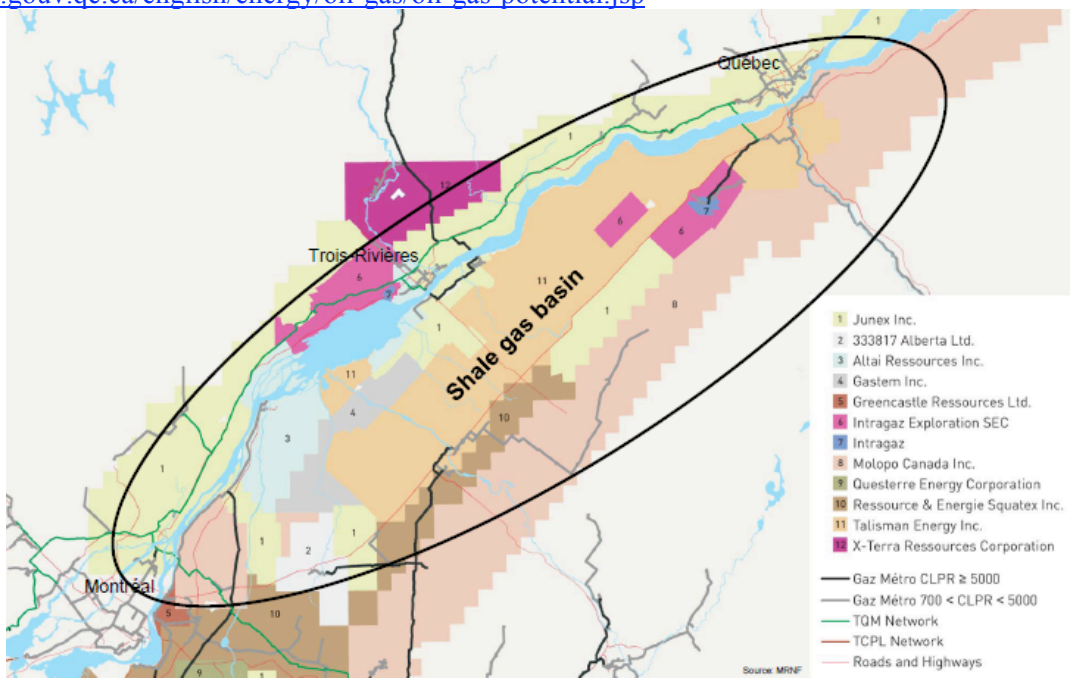
Quebec's natural gas royalty, which currently is 12.5%, has been described as attractive by some of the players. As well, shale gas plays in the province's St. Lawrence Lowlands enjoy another advantage in being close to the northeast U.S. gas market.

Recently there has been some concern about the environmental effects of fracturing so the government is planning on conducting public hearings on the subject:
http://www.cbc.ca/canada/montreal/story/2010/08/29/que-shale-gas.html

Quebec Shale Conference 2010 and 2009:

The *Association pétrolière et gazière du Québec (*Quebec Oil and Gas Association):
http://www.apgq-qoga.com/html/en/conference_2010.php can download the talks:
http://www.apgq-qoga.com/html/en/conference_2009.php

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

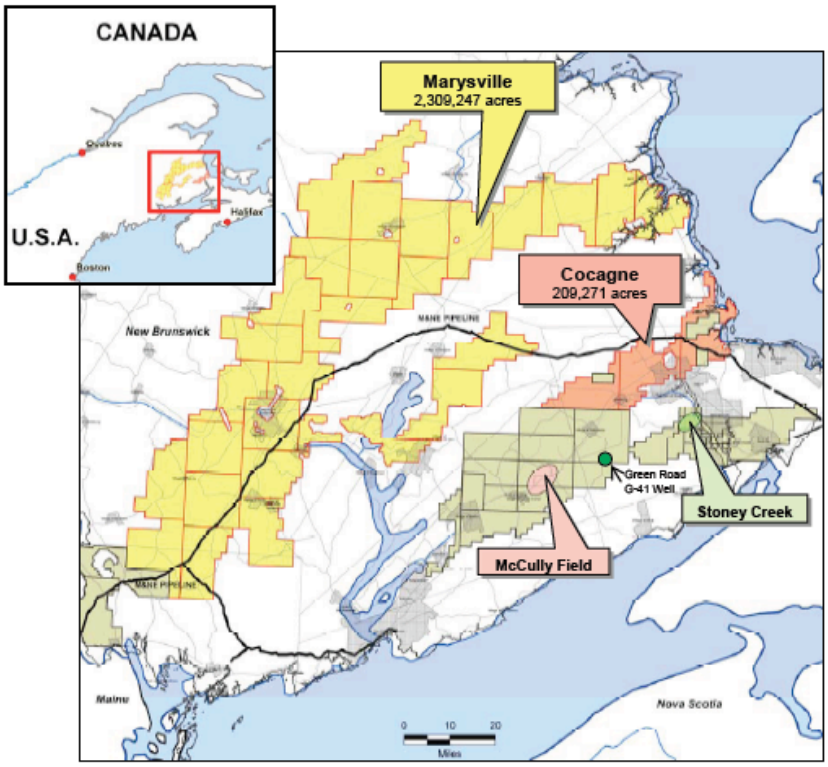
New Brunswick
Lower Mississippian Fredrick Brook Shale
Moncton Basin

There have been some recent exciting developments for New Brunswick shale gas. The Fredrick Brook shale was being tested by Corridor at the Green Road G-41 well in Nov 2009. Two zones were tested with a propane fracture. The lower black shale interval flowed with rates of 0.43 MMscfd while the upper silty/sandy shale zone tested at initial peak rates of 11.7 MMscf/d and a final rate of 3.0 MMscf/d.

Corridor also announced the farm out of 116,018 acres this shale-potential land to Apache. Currently Apache is drilling their second well with plans on casing a 1000 foot horizontal section for multi zone fracturing and testing: 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 non conventional resources of the Mississippian Horton Group.



"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

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

Triangle Petroleum has been working on this block since May 2007 with 2D and 3D seismic programs and 5 vertical exploration wells. Since then these wells have experimented on various fracture treatments with no success 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. One well will be needed to be drilled by April 2011. In 2009 they conducted a 30 km 2D seismic program to try to pinpoint areas with structure for future shale targets. Currently there has been no work this year as they are looking for partners.

The 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

Shoal Point Energy and its partners in 2008 encountered about 500 m of shale with siltstone stingers with high gas and oil shows through the Ordovician Green Point Formation west of Stephenville, Newfoundland. This shale has been studied in outcrop by the Canadian Geological Survey and is summarized in Hamblin (2006). The geochemistry indicates that this zone is in oil window. The companies are planning further testing of the oil-in-shale concept in Oct 2010.

The Newfoundland Department of Natural Resources is the regulator for the province:
http://www.nr.gov.nl.ca/mines&en/oil/

Societies, Conferences and Courses

Canadian Society for Unconventional Gas (CSUG):
http://www.csug.ca/

Canadian Unconventional Resources and International Petroleum Conference
19-21 October 2010, BMO Center at Stampede Park:
Calgary, Alberta, Canada
http://www.spe.org/events/curipc/2010/

Presentations:
http://www.csug.ca/index.php?option=com_content&task=view&id=72&Itemid=118

Videos:
http://www.csug.ca/index.php?option=com_content&task=view&id=55&Itemid=55

CSPG:
http://www.cspg.org/

Joint Annual Convention, 2011 CSPG CSEG CWLS Convention Calgary May 9-13, 2011:
www.geoconvention.org

Shale Gas Critical Fundamentals, Techniques and Tools for Exploration Analysis
Calgary October 27, 2010

Key References and Information on Canadian Shales:

Dixon, J, 2009: The Lower Triassic Shale member of the Montney Formation in the subsurface of northeast British Columbia; Geological Survey of Canada, Open File 6274, 9 p. + 10 figures + 5 appendices

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

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European Shales

By Dan Jarvie, Worldwide Geochemistry (danjarvie@wwgeochem.com) originally presented in Annual Report, 4/2010

Introduction

Activity in Europe has increased dramatically with extensive acreage positions being staked by a number of international independents. Of course the US Majors have contributed to the push here making their own deals or partnerships with groups that have leasehold positions. As reported previously, ExxonMobil and Shell are active individually and as partnerships in Germany and Sweden. ConocoPhillips, Chevron, and Marathon have also staked positions with the most notable to date being in Poland.

Almost all of the activity has been for shale-gas resources with little consideration of shale-oil, although Toreador Resources has shown shale-oil potential in the Paris Basin. Drilling activity will extend over a broader geographic territory in 2010 with wells staked to drill in Germany, Poland, Sweden, and England.

Limitations for doing business in Europe are worth noting in addition to an environmental persona comparable to New York or California. Costs are certainly higher due to limited rigs and services. The limited drilling activity to date has constrained the availability of services as it is difficult to establish a critical mass of business activity at this point in European shale resource plays. Once discoveries are announced, and they will be forthcoming, drilling activity will increase rapidly but not likely until 2011-2012. At such time the limited number of rigs available for drilling in Europe will continue to be an issue. At the present time it is my understanding that there are about 50 rigs available in all of Europe.

An excellent and as comprehensive review of European shale resource potential was reported in E&P by Ken Chew of IHS. Readers are referred to this article dated March 1, 2010 as it was a major source of information for this report:

Chew, K., 2010, The shale frenzy comes to Europe: Hart Energy Publishing, E&P, v. 83, no. 3, p. 35-39.

Exploration Activity:

The following is a report by country drawn from a variety of public sources:

Austria

OMV is investigating the Upper Jurassic Mikulov Marl in the Deep Vienna Basin (Chew, 2010). This locale may also include the Lower Jurassic Posidonia Shale. The Mikulov Marl is over 1,500 m thick with TOC values ranging from 0.20% to 10% (Reuters).

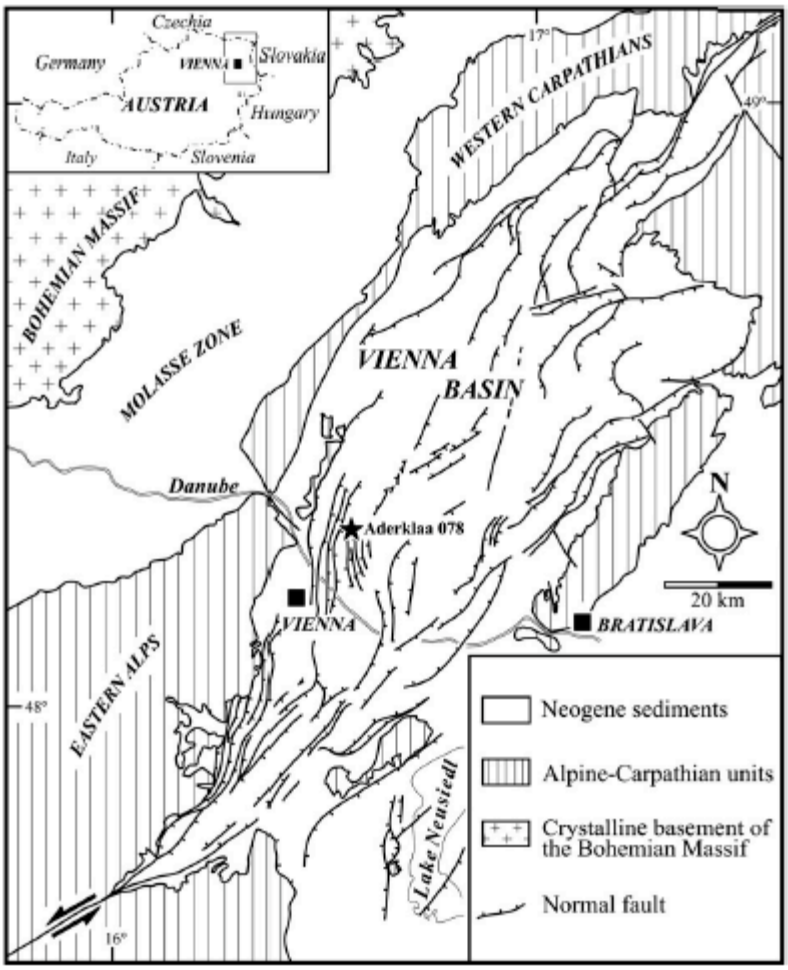


Fig. 1. Regional geological map and the position of the well Aderklaa-78 (adapted from Wagreich and Schmid, 2002).

Reference: Gier et al., 2008, *Marine and Petroleum Geol*., 25, pp 681-695.

Denmark

The proposed borehole for Alum Shale is planned in association with the GASH project with considerable science investment ranging beyond drilling costs to an expanded range of analysis ranging from mud gas logging to gas contents and beyond. Drilling is expected to commence in May, 2010.

France

Toreador has 649,000 acres under lease in the Paris Basin and hopes to reach an JV agreement in the coming weeks, which would result in the first test for shale-oil production in the basin. It was also recently announced that Eurenergy Resource Corp. has been awarded 1.3 million acres in the East Paris Basin of France (see also Eurenergy, UK).

In eastern France and western Switzerland in the Languedoc area, the Stephanian-Autunian Lodeve Basin is being evaluated for the Lower Permian Autunian Shale, which is a lacustrine source rock. Celtique Petroleum has conventional production in this area with potential for unconventional shale plays in the Autunian Shale. Other lease awards in the Languedoc area will apparently be announced in April 2010.

No additional news has been reported on the activity in southern France that involves Total and Devon Energy.

Germany

ExxonMobil Petroleum Germany (EMPG) has completed drilling its first three shale resource wells in the Lower Saxony Basin and a fourth well, the Niedernwohren-1, will be drilled in the near term future. They have drilled and cored the Damme 2, 2A, and 3 wells and also the Oppenwehe-1 and Schlahe-1 wells. No results have been announced on any of these wells to date. EMPG has a 10 well program planned according to previous reports in the WSJ. There is thought to

be shale resource potential in the Berriasian Wealden Shale and the Upper Jurassic Posidonian Shale according to Chew (2010).

Chew (2010) also reports shale resource potential in the Upper Devonian Kellwasser Shale in northern Germany. North of the Swiss border into Germany in the Bodensee Trough, Parkyn Energy has licenses with a likely shale resource play in Permian lacustrine shale (Chew, 2010).

Chew (2010) also states that ExxonMobil and Shell in some fashion will be examining the shale resource potential of the Visean shale in eastern Germany and the Namurian shale in the west.

Hungary
ExxonMobil and MOL have decided not to continue any further drilling in the Mako Trough in southeastern Hungary.

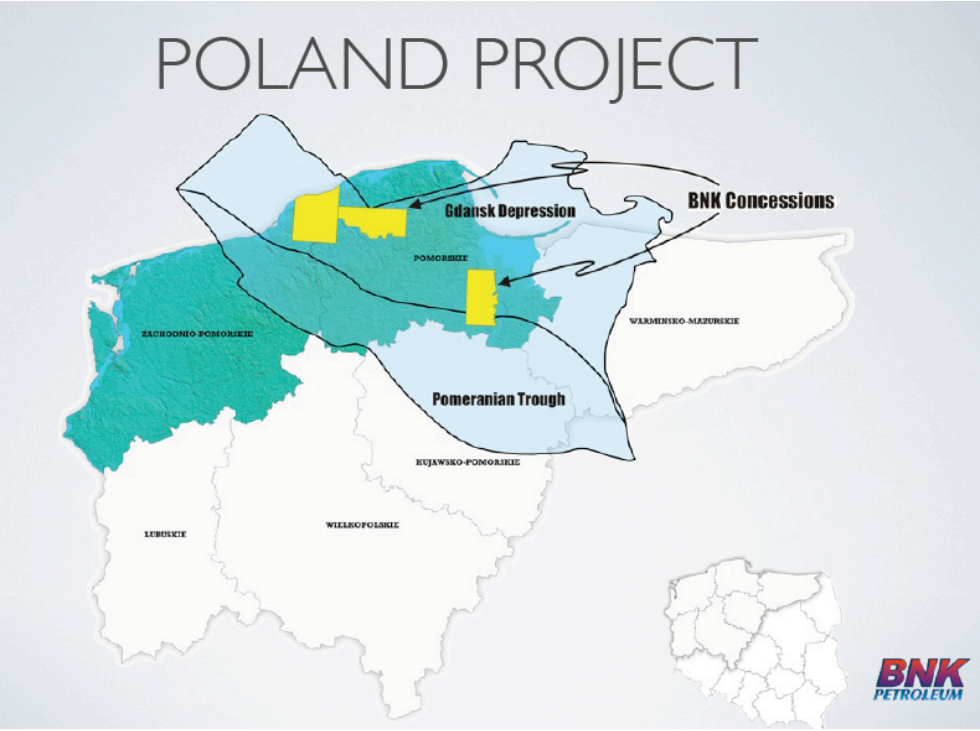
The Netherlands
In the Anglo-Dutch Basin, Cuadrilla Resources has obtained a license and appears to be chasing the shale resource potential of the Namurian Epen Formation.

Poland
The total number of concessions granted in Poland for shale-gas potential now totals 30 according to Reuters news service. Poland has very favorable fiscal terms for E&P with royalties less than 5% and corporate tax rate of 19%. It is expected that Lane Energy will operate the first well to test the Lower Paleozoic in Poland (Chew, 2010). The well will be located in the Gdansk Depression with funding provided by ConocoPhillips with targets in the Silurian and Ordovician (Chew, 2010).

Talisman Energy has announced a joint venture with San Leon Energy subsidiary, Oculis Investments SP, for exploration for shale gas in the Baltic Basin onshore Poland (O&GJ, Jan. 29, 2010). As such Talisman has paid Oculis 1.5 million euros and will pay 60% of the cost for a seismic program. Talisman will drill one well in each of Oculis' three concessions with an additional three wells if initial well results are encouraging. Talisman will have a 60% interest in each concession; however, this would be reduced to 30% if Talisman does not drill the optional wells (Scandinavian Oil-Gas Magazine, March 4, 2010).

Chevron Polska E&P has been granted a concession in southeastern Poland near the city of Zamosc. Under the terms of the concession, they will have 5 years to explore shale gas opportunities in the area covering ca. 800 sq km. It is reported that Chevron only expects to assess the possibility of developing this into a shale gas field.

A range of companies have acquired concessions in Poland. According to O&G Journal (Jan. 29, 2010), Marathon has acquired interests in Poland. Others such as LNG Energy have three concession areas in Poland totaling 88,000 acres with focus on Silurian and Ordovician shales. EurEnergy has also obtained concessions in Poland (Reuters). BNK has also obtained concessions in Poland for 720,000 acres. The following two cut and paste graphics show BNK Concessions in Poland as well as general rock characteristics that they have reported:



- Polish Project
  - 3 concessions
  - ~720,000 acres, with an 80% working interest
    - Total Organic Carbon > 2%
    - Thermal maturities. Ro's of 1.2 - 2.5 (Vitrinite reflectance)
    - Hundreds of meters of potentially productive interval
    - Highly siliceous, brittle rock
    - No major water bearing or structural complications
    - Nearby infrastructure
  - Further Core analysis scheduled for 2009, drilling planned for 2010
  - Entertaining partnerships for exploration phase

Romania
No known new activity in shale resource plays although shales are present and producing gas in Romania. These are likely biogenic plays.

Sweden
Shell is drilling the first of three wells in the Alum Shale. The Lovestad A3-1 well will test the shale resource potential of the Cambro-Ordovician Alum Shale. A drill depth of 1,007 m is planned (Chew, 2010).

Switzerland
An agreement between Ascent Resource and Schuepbach Energy was made for an option to pursue Jurassic shale exploration in Switzerland. Schuepbach has a concession in the Canton of Fribourg adjoining Ascent's concession in the Canton of Vaud. Ascent holds 90% of the Canton of Vaud concession with 10% held by SEAG of Switzerland.

The agreement specifies that Schuepbach will earn 75% interest in shales if the first well is drilled in the Canton of Vaud, and a 25% interest if the first well is drilled in Canton of Fribourg.

Ukraine
EuroGas Ukraine acquired three unconventional gas concessions in the Donbas Basin; however, it is not clear whether these are shale-gas, CBM, or both. They are reported to have increased activity in the Lublin Basin in western Ukraine

and perhaps into Poland (O&GJ, Jan. 29, 2010). Their total acreage in unconventional gas (shale gas and CBM) is now 512 sq km (O&GJ, Jan. 29, 2010).

Shell is also reported to be assessing shale-gas opportunities in Ukraine (O&GJ, Jan. 29, 2010).

United Kingdom
In the Cheshire Basin Cuadrilla Resources plans to spud the Preese Hall #1 well in March 2010 targeting the Namurian age Bowland Shale, on trend with the same age target cited in the Anglo-Dutch Basin (see The Netherlands) (Chew, 2010).

In the Weald Basin there is reported potential for L. Jurassic shale (Chew, 2010). EurEnergy Resources has announced plans to drill for shale gas in the Weald Basin where it holds 123,000 acres (Reuters).

IGAS, a UK exploration company, has acquired shale-gas licenses in northern England (O&GJ, Jan. 29, 2010), presumably in the Cheshire Basin. They also have about 2,000 sq km of shale gas potential in North Wales at Point of Ayr. A recent report suggests about 3,823 BCF of gas in place (Feb, 2010). The Holywell Shale averages about 2.1% TOC and is upwards of 250 m thick in locations.

Other Exploration News
Realm Energy in collaboration with Halliburton Consulting is evaluating numerous shale resource plays in Europe and expects to make applications in a variety of basins (O&GJ, Jan. 29, 2010). Similarly, BNK has announced a new concession (300,000 acres) but has not disclosed the country. This concession brings BNK's land position to approximately 1.4 million acres under license in Europe.

European Meetings Referencing Shale Resource Plays:

AAPG Europe Region Annual Conference and Exhibition, 17-19 October, 2010, Ukranian House, Kiev, Ukraine (www.aapg.org/kiev).

The Geological Society, The Geology of Unconventional Gas Plays, 4-7 October 2010, Burlington House, Piccadilly, London (www.geolsoc.org.uk/petroleum).

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 Geoscience 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.gfzpotsdam.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)

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*
  - *Oil and Gas Investor*
  - *Oil and Gas Journal*
  - *Hart's E & P*
  - *AAPG 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/)

Gas Shales and Shale Oil Calendar, Oct. 1, 2010-May 31, 2011

- **October 5-6, 2010: Developing Unconventional Gas Eagle Ford**, Hart Energy, San Antonio, TX. http://www.dugeagleford.com/
- **October 5-6, 2010: The Geology of Unconventional Gas Plays**, The Geological Society, London, http://www.geolsoc.org.uk/gsl/groups/specialist/petroleum/page6673.html
- **October 5-7, 2010: Unconventional Gas International Conference & Exhibition**, Fort Worth, TX. http://www.unconventionalgas.net
- **October 10-12, 2010: Organic "shales" of the Gulf Coast—Controls on reservoir quality and producibility,** GCAGS/GCSSEPM meeting, San Antonio, TX. http://www.gcags.org/
- **October 17-19, 2010: AAPG European Region Annual Conference, Unconventional Exploration Session**, Kiev, Ukraine**.** http://www.aapg.org/kiev/
- **October 19-21, 2010: Canadian Unconventional Resources and International Petroleum Conference**, The Canadian Society for Unconventional Gas (CSUG) and the Society of Petroleum Engineers (SPE), BMO Center at Stampede Park, Calgary, Alberta, Canada. http://www.spe.org/events/curipc/2010/
- **November 3-4, 2010: Hart's Developing Unconventional Gas Conference (DUGeast), Marcellus and More: Appalachian Shales**, Pittsburgh, PA http://www.dugeast.com/
- **December 2-3, 2010: The Energy Forum: Unconventional East 2010**, Pittsburgh, PA. http://www.theenergyforum.com/AI_1209/main.asp
- **December 5-10, 2010: Hedberg Research Conference on Critical Assessment of Shale Resource Plays**, Austin, TX. http://www.aapg.org/education/hedberg/austin/
- **March 22, 2011:** 2nd Annual Marcellus Midstream Conference & Exhibition, Pittsburgh, PA. http://www.marcellusmidstream.com/
- **April 10-13, 2011:** AAPG Annual Convention and Exhibition, Houston, TX. http://www.aapg.org/houston2011/
- **April 18-20, 2011:** 6th Annual Developing Unconventional Gas Conference & Exhibition, Fort Worth, TX. http://www.dugconference.com
- **May 24-25, 2011:** 2nd Annual Developing Unconventional Oil Conference & Exhibition, Denver, CO. http://www.hartduo.com