Paper #2-27

NORTH AMERICAN OIL AND GAS PLAY TYPES

Prepared by the Onshore Operations Subgroup
of the
Operations & Environment Task Group

On September 15, 2011, The National Petroleum Council (NPC) in approving its report, *Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources*, also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the study's Task Groups and/or Subgroups. These Topic and White Papers were working documents that were part of the analyses that led to development of the summary results presented in the report's Executive Summary and Chapters.

These Topic and White Papers represent the views and conclusions of the authors. The National Petroleum Council has not endorsed or approved the statements and conclusions contained in these documents, but approved the publication of these materials as part of the study process.

The NPC believes that these papers will be of interest to the readers of the report and will help them better understand the results. These materials are being made available in the interest of transparency.

The attached paper is one of 57 such working documents used in the study analyses. Also included is a roster of the Subgroup that developed or submitted this paper. Appendix C of the final NPC report provides a complete list of the 57 Topic and White Papers and an abstract for each. The full papers can be viewed and downloaded from the report section of the NPC website (www.npc.org).

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I. Background

The following explanation of the development of onshore oil and natural gas resources is organized around what the industry refers to as 'play' types. This starts with the type of resource, geology and subsurface conditions that impact how the resource is obtained. Terms and concepts from geology, chemistry and economics are used. Explanations and illustrations are provided, and references to less technical resources may be helpful.

There are three key components to a subsurface system that will result in the accumulation of recoverable hydrocarbons in the earth a: source to generate hydrocarbons; reservoir to store the gas and or oil; and a seal or a trapping mechanism to hold the hydrocarbons in place.

The source largely determines the type of hydrocarbon that will be produced: oil, gas, or a mixture of both. The reservoir can be almost any rock type. Certain rock properties allow easier access to the oil and gas, such as sedimentary rocks with some naturally occurring porosity and permeability. The seal is a rock with very low permeability through which oil and natural gas cannot readily flow. The trap can be either stratigraphic, such as a pinchout, or some type of structural feature such as a fault or anticline.

The source and reservoir of the underground hydrocarbon accumulation impacts how and whether the petroleum can be extracted economically. "Conventional" deposits are oil and natural gas resources that exist in discrete deposits from which oil, gas, and natural gas liquids can be extracted, and these deposits have been historically produced.[1] "Unconventional" deposits are those in which the oil and natural gas resources exist in geographically extensive accumulations. Such deposits generally lack well-defined oil to water and gas to water contacts and include accumulations where the source and reservoir are the same. The term "self-sourcing" may be used when the rocks that now hold the oil are the same rocks that harbored the organic matter from which the oil was derived, such as some organically rich shales.[2]

Numerous areas in onshore North America exist with several play types in the same basin or even field. For example, the Powder River Basin, located in Wyoming and Montana has shallow coalbed natural gas (CBNG) and conventional oil and gas deeper in the basin (Figure 1).

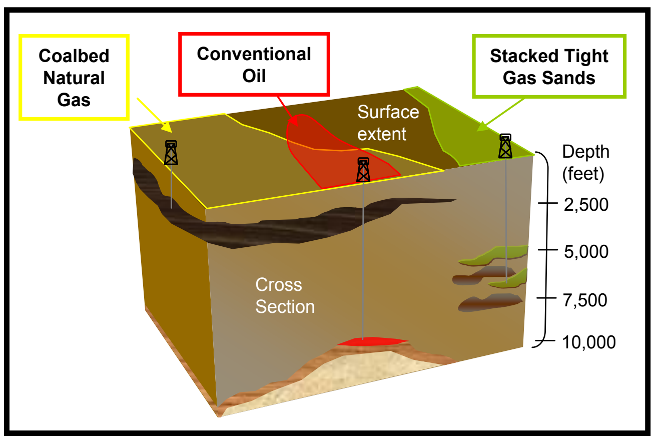

Figure 1: Hypothetical diagram of simplified view of three play types in the same area. Source: USGS Inventory of Onshore Federal Oil and Natural Gas Resources and Restrictions to Their Development (2008) ("EPCA Phase III Inventory") (p. 46).

The following is a description of various types of oil and gas plays seen throughout North America. Each of these plays and locations where the plays exist is unique,

[1] US Geological Survey (USGS). Energy Resources Program, *Conventional Petroleum Sources*. Accessed April 2011 at http://energy.cr.usgs.gov/oilgas/addoilgas/conventional.html

[2] USGS. Energy Resources Program, *Unconventional (Continuous) Petroleum Sources.* Accessed April 2011 at http://energy.cr.usgs.gov/oilgas/addoilgas/unconventional.html

requiring specific technologies to extract the fossil fuels. Often times, these technological advances and cost reduction measures can result in a reduced environmental footprint.[3]

II. Onshore Oil

A. Conventional Oil

Conventional oil is the term used when the oil exists in discrete deposits and can be accessed via the standard vertical well extraction methods. Historically, conventional oil accounted for a significant portion of North American crude. As conventional oil reserves are becoming scarcer, the industry is moving towards improved methods to extract conventional oil and unconventional oil.

Conventional or standard oil well extraction in North America has three phases of production: primary, secondary, and tertiary, or enhanced oil recovery (EOR).[4] These techniques are not always sequentially used. In typical initial production or primary recovery, the natural pressure of the reservoir, sometimes assisted by artificial or mechanical lift, is adequate to produce or remove approximately 10 percent of the oil. As the field ages and natural reservoir pressure drops, primary oil recovery ceases. Secondary recovery can increase the life of a field and achieve a 20 to 40 percent oil recovery rate. This phase involves injecting water or gas into the reservoir to increase the reservoir pressure and continue to drive the oil to the wellbore.

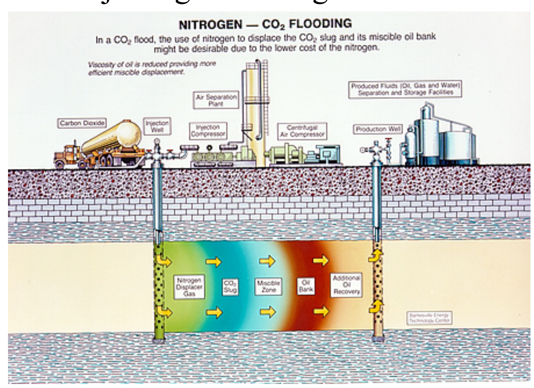

Figure 2: Illustration of the concept of EOR, where gas is pumped into the reservoir forcing oil to the production well. Source: DOE, NETL, at http://www.netl.doe.gov/technologies/oil-gas/EP_Technologies/ExplorationTechnologies/eordraw.html

Enhanced oil recovery (EOR) (illustrated in Figure 2) offers the potential ability to produce 30 to 60 percent or greater of the oil in place by increasing the mobility of the oil. Reducing the viscosity (the 'stickiness' or cohesive properties) allows the oil to flow more readily to the wellbore. EOR utilizes three main categories of technology: thermal, miscible (gas), and chemical. The difference between secondary recovery injection and EOR injection is that secondary occurs at ambient temperatures and EOR involves the addition of energy using mass and heat transfer. Commercial success with EOR has been variable due to the high costs associated with each of the three techniques and the unpredictable effectiveness.

Thermal recovery, most widely used in California, involves the introduction of heat through steam or other methods to decrease the viscosity of the oil. Miscible recovery uses natural gas, nitrogen, or carbon dioxide to lower the viscosity of the oil by mixing the oil and introduced gas. Using carbon dioxide with miscible recovery results in the potential environmental benefit of

[3] See, generally, U.S. Department of Energy (DOE), Office of Fossil Energy, 1999. *Environmental Benefits of Advanced Oil and Gas Exploration and Production Technology.* DOE-FE-0385. Washington, DC. Accessed April 2011 at http://fossil.energy.gov/programs/oilgas/publications/environ_benefits/Environmental_Benefits_Report.html.
[4] DOE, National Energy Technology Laboratory (NETL), Exploration & Production Technologies, Improved Recovery - Enhanced Oil Recovery. Accessed April 2011 at http://www.netl.doe.gov/technologies/oil-gas/EP_Technologies/ImprovedRecovery/EnhancedOilRecovery/eor.html

carbon sequestration and the life of an oil field is extended.[5] For example, carbon dioxide produced by human activities, such as industrial sources at which carbon dioxide is a by-product (i.e., fossil fuel power plants), might be used for flooding in reservoirs.[6]

Chemical injection lowers the surface tension of the oil in the reservoir, increasing the ability to flow. This relatively rare technique injects long chained polymers or surfactants as the injection material. The use of EOR has greatly increased the potential for extraction from many oil fields in North America. Continued advances in technology show promise for enhanced recovery.

B. Unconventional

Unconventional oil refers to the different petroleum accumulations that require additional techniques beyond standard oil well drilling and recovery techniques to extract the oil. Classes of unconventional oil include very heavy oil such as bitumen found in oil sands and shale oil.

Heavy oil types tend to have significantly higher viscosities and API gravities below 22.3 degrees, some existing in a semi-solid natural form.[7] (American Petroleum Institute [API] gravity is used to express the relative density of the oil. The higher API gravity indicates lighter oil and the lower API gravity indicates heavier oil.) These heavier oils may also have higher concentrations of sulfur and metals such as vanadium and nickel. This leads to heavy oil being more challenging to extract, transport, and process into marketable products.

Some unconventional oils are not heavy, such as that found in oil shale (kerogen) and tight oil. Because these oils are produced from low permeability formations, unconventional methods are necessary. Areas for both EOR and unconventional reservoirs in the United States are shown in Figure 3.

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[5] USGS. Energy Resources Program, *Geologic CO2 Sequestration Research at the USGS, Helpful Definitions*. Accessed April 2011 at http://energy.er.usgs.gov/health_environment/co2_sequestration/co2_definitions.html

[6] DOE, U.S. Energy Information Administration (EIA). *Assumptions to the Annual Energy Outlook 2010, Oil and Gas Supply Module.* Report #: DOE/EIA-0554(2010). Release date: April 9, 2010. Accessed April 2011 at http://www.eia.doe.gov/oiaf/aeo/assumption/oil_gas.html.

[7] Meyer, R.F., Attanasi, E.D., and Freeman, P.A., 2007, Heavy oil and natural bitumen resources in geological basins of the world: U.S. Geological Survey Open-File Report 2007-1084, at p.1. Accessed April 2011 at http://pubs.usgs.gov/of/2007/1084/.

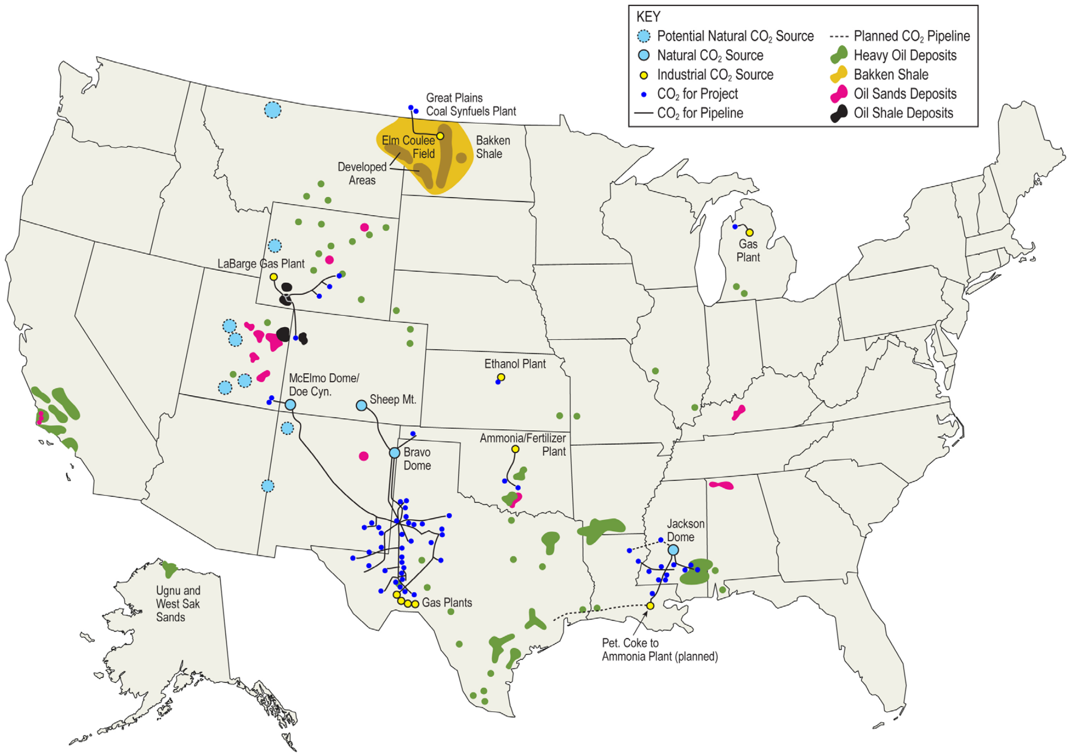

Figure 3. The current carbon dioxide EOR infrastructure, areas of development, and domestic oil resources in unconventional reservoirs, including the fractured Bakken shale of the Williston Basin. Source: DOE, National Energy Technology Laboratory, *Unconventional Fossil Energy Resource Program, Program Fact Sheet*, April 2011, www.netl.doe.gov/publications/factsheets/program/Prog100.pdf.

1. Oil Sands, Tar Sands, Heavy Oil

Oil sands, bituminous sands, or tar sands (herein "oil sands"), are a type of bitumen deposit. The sands are naturally occurring mixtures of sand, clay, water, and an extremely dense and viscous form of petroleum called bitumen. They are found in large amounts in many countries throughout the world, and Alberta, Canada, claims "the largest concentration of oil sands in the world."[8]

Oil sands reserves have only recently been considered part of the world's oil reserves, as higher oil prices and new technology enable them to be profitably extracted and upgraded to usable products. Oil sands are often referred to as one of the unconventional oils or crude bitumen, in order to distinguish the bitumen extracted from oil sands from the free-flowing hydrocarbon mixtures known as crude oil traditionally produced from oil wells.

In general, oil sands projects are more costly than conventional crude oil projects and analysts estimate that the production of synthetic crude is only economically viable with relatively high crude oil prices. The oil sands industry is heavily reliant upon water and natural gas, which is

[8] Government of Alberta. Alberta's Oil Sands: Opportunity. Balance. March 2008. ISBN 978-07785-7348-7. Accessed April 2011 at http://www.environment.alberta.ca/documents/Oil_Sands_Opportunity_Balance.pdf.

necessary in both the extraction of bitumen from oil sands and the upgrading of bitumen to synthetic oil.[9]

Extraction is conducted using unconventional methods because extra-heavy oil and bitumen flow very slowly, if at all, toward producing wells under normal reservoir conditions. Open pit (strip mining) is used when the reserves are close to the surface. The mined oil sands are processed to separate the oil from the sand. The oil is made to flow into wells by in-situ (in place) techniques for deeper deposits, which reduce the viscosity by injecting steam, solvents, or hot air into the underground sands. Both of these processes currently use more water and require larger amounts of energy (such as natural gas) than typical conventional oil extraction (although many conventional oil fields also require large amounts of water and energy to achieve good rates of production).[10]

Additional energy is necessary after extracting the oil from the sand to process or "upgrade" the heavy crude feedstock before it is fit for conventional refineries. Oil sands projects will either process the product on-site or have it processed off-site.

Carbon rejection is a method used to heat the bitumen to a very high temperature, resulting in the release of the lighter gases and liquids and the production of petroleum coke from the heavier materials. The liquids become "synthetic crude" (similar to kerosene or diesel) and the petroleum coke (similar to coal) can be used as a fuel.[11]

Hydrocracking and hydrotreating are other upgrading methods that use catalysts, hydrogen generated from natural gas, and high pressure and temperature. A hydrocracker uses hydrogen and a catalyst to remove impurities and 'cracks' or breaks the long hydrocarbon chains. A hydrotreater uses additional catalyst and hydrogen to further upgrade the oil, improve properties, and possibly remove impurities.[12]

Figure 4: Locations of the Alberta oil sands. Source: Alberta's Oil Sands, 2008.

Canada, specifically the Western Canada Sedimentary Basin in northern Alberta (Figure 4), is currently the only area in North America with commercial producers of synthetic crude oil from bitumen deposits.[13] The main deposits are located in three areas in Alberta: Athabasca, Peace River, and Cold Lake. Mining and in situ processes are used. The deposits at Cold Lake have

[9] DOE, EIA. Country Analysis Briefs, Canada, April 2011, accessed April 2011 at http://www.eia.doe.gov/countries/cab.cfm?fips=CA
[10] Ibid.
[11] This technique is used at Suncor Energy, accessed April 2011 at http://www.suncor.com/en/about/2510.aspx.
[12] This technique is illustrated by Bechtel and its Canadian subsidiary, Bantrel. Accessed April 2011 at http://www.bechtel.com/assets/files/PDF/DetailDesign.pdf.
[13] World Energy Council. 2007. *Survey of Energy Resources 2007*. p. 600: Ch. 4, Natural Bitumen and Extra-Heavy Oil. Accessed April 2011 at http://www.worldenergy.org/publications/survey_of_energy_resources_2007/natural_bitumen_and_extraheavy_oil/654.asp

been developed using cyclic steam stimulation, which involves injecting steam into the reservoir to heat the formation. The injection wells are then converted to production wells until additional heat is required and the process repeats.

2. Oil Shale

Dyni (2006) defines oil shale as, "a fine-grained sedimentary rock containing organic matter that yields substantial amounts of oil and combustible gas upon destructive distillation."[14] Destructive distillation, or retorting, is a process that uses heat to decompose the organic matter in the shale producing hydrocarbon liquids and gases.[15] This need for additional pyrolysis (chemical decomposition of a substance by heat) is the main difference between oil sands and oil shales; oil sands already have the product hydrocarbons, whereas oil shales have the ingredients, known as kerogen, to be heated to make the desired hydrocarbons.

The economic potential of oil shale is largely controlled by the depth of the deposit. It can be developed via open pit or conventional mining or by in situ methods if it is near enough to the surface. Additional economic factors come into play for commercial development, such as the yield of oil from the formation, the current price of petroleum, transportation access, and workforce availability. The U.S. Geological Survey has used a lower limit of shale oil yield of about 40 liters of shale oil per metric ton of rock (40 l/t) for classification of Federal oil-shale lands.[16]

Oil shale resources in North America are highly variable in composition and much of the supply remains to be further evaluated. A number of deposits have been discovered in Canada as shown in Figure 5. The greatest potential at this time comes from the Albert Formation in New Brunswick, with an average production of 100 l/t of oil and for use in co-combustion of coal for electricity generation.[17]

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[14] Dyni, J. R., 2006, Geology and Resources of Some World Oil-Shale Deposits: United States Geological Survey Scientific Investigations Report 2005-5294, 42 p. Accessed April 2011 at: http://pubs.usgs.gov/sir/2005/5294/pdf/sir5294_508.pdf.
[15] Ibid.
[16] Ibid.
[17] Ibid. at 10.

Source: Energy Information Administration based on data from various published studies.
Updated: March 21, 2011

Figure 5. Shale Gas and Oil Plays, North America. Source: DOE, EIA, at http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm

Oil shales in the United States are found throughout the east in the Devonian through Mississippian black shales and Pennsylvanian aged shales in association with coal, as well as in the Green River Formation found in Colorado, Utah, and Wyoming. Other deposits exist throughout the west and Alaska.

For the eastern black shales in the central and eastern parts of the United States (Figure 5), hydroretorting is necessary to achieve high enough oil yields due to the high abundance of aromatic hydrocarbons (hydrogen and carbon arranged in ring shaped molecules). The main potentially productive areas for this shale based on organic content and depth to allow open pit mining are concentrated in Kentucky, Ohio, Indiana, and Tennessee, with additional resources found in Alabama, Illinois, Michigan, and Missouri.

A large area under Wyoming, Colorado, and Utah (Figures 5 and 6), known as the organic rich Green River Formation, is now the largest known shale oil deposit in the world.[18] Historical development of this resource has included several attempts at underground mining and in-situ retorts, and current development includes testing of a proprietary in-situ technique by Shell and

[18] Ibid, at 33.

other companies.[19] This resource is also unique due to the associated and valuable mineral deposits of nahcolite and dawsonite, valuable for soda ash and aluminum.[20] The oil shale of Colorado has been studied and is understood in greater detail than that of Utah and Wyoming; however, the resource in Utah is known to be very shallow, a potential key for commercial development. Wyoming has less continuous deposits of the oil shale making development in the area more arduous; however, incredibly large quantities of the shale do exist.[21]

The interest in development of oil shale continues.[22] "In Colorado alone, the total resource reaches one trillion barrels, of which one-quarter to perhaps as much as one-third may be recoverable with mining and processing techniques available today."[23] The Department of Energy (DOE) has reported that: "America's total oil shale resources could exceed 6 trillion barrels of oil equivalent. However, most of the shale is in deposits of insufficient thickness or richness to access and produce economically."[24] The DOE also cautions that "because the in-situ process is still at the experimental stage, and because the underground mining and surface retorting process is unlikely to be environmentally acceptable, the oil shale liquids production projections should be considered highly uncertain."[25]

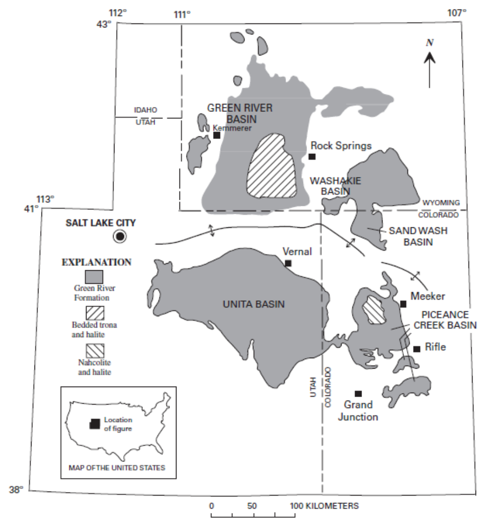

Figure 6: Areas underlain by the Green River Formation in Colorado, Utah, and Wyoming, United States from Dyni, 2006. Figure 16, p.28.

3. Tight Oil

Tight oil fields may have some conventional characteristics and produce light crude but are unconventional in the sense that the porosity and permeability are too low to produce the oil without stimulation.

Two examples of successful tight oil fields are the Bakken in North Dakota and Montana, and the Eagle Ford in South Texas (Figure 7). Oil companies discovered these fields decades ago, but recent advances in technologies such as horizontal drilling and hydraulic fracturing (use of liquids to create fractures in rocks), have made tight oil accumulations economic to drill and produce. As with other unconventional play types, the challenges faced and techniques applied can be unique to each field or even parts of each field, and best practices are continually evolving.

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[19] Ibid, at 27 - 29.
[20] Ibid. at 29.
[21] Ibid.
[22] U.S. Geological Survey Oil Shale Assessment Team, 2010, Oil shale resources of the Uinta Basin, Utah and Colorado: U.S. Geological Survey Digital Data Series DDS–69–BB, 7 chapters, pages variable. Accessed April 2011 at http://pubs.usgs.gov/dds/dds-069/dds-069-bb/
[23] Dyni. p 33.
[24] DOE, Office of Petroleum Reserves. *Strategic Unconventional Fuels, Fact Sheet: U.S. Oil Shale Resources*. Accessed April 2011 at http://fossil.energy.gov/programs/reserves/npr/Oil_Shale_Resource_Fact_Sheet.pdf.
[25] DOE, EIA. *Assumptions to the Annual Energy Outlook 2010, Oil and Gas Supply Module.* Report #:DOE/EIA-0554(2010). Release date: April 9, 2010. Accessed April 2011 at http://www.eia.doe.gov/oiaf/aeo/assumption/oil_gas.html.

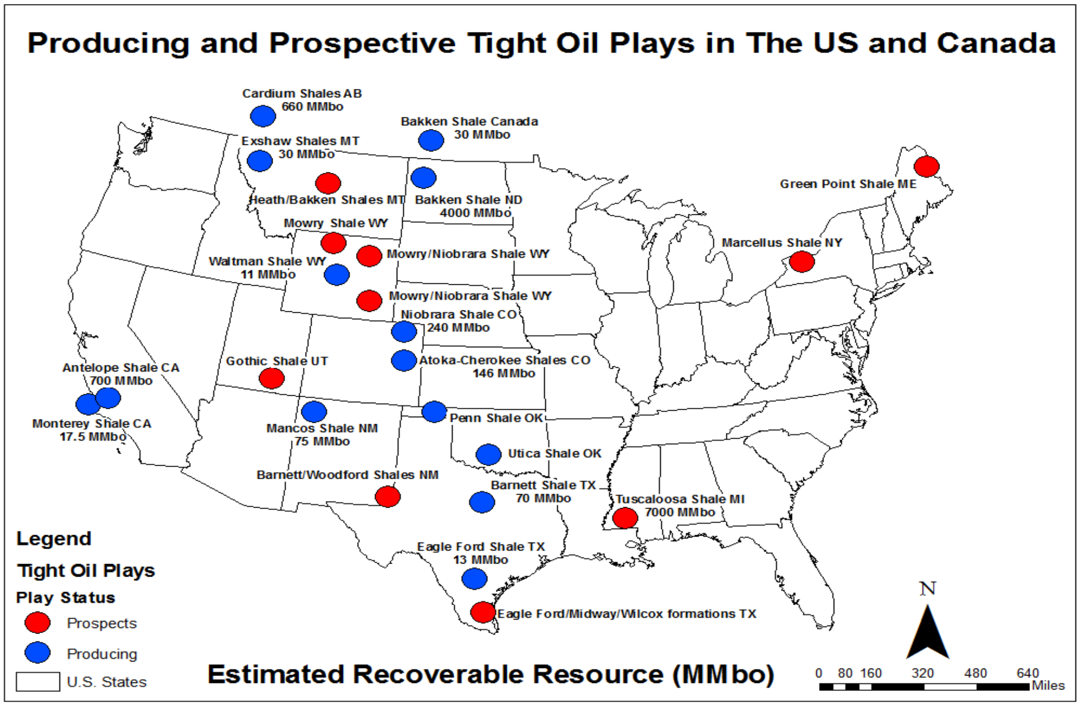

Figure 7: Tight oil plays in North America (source: Unconventional Oil Group, NPC).

III. Onshore Natural Gas Resources

A. Conventional Natural Gas Resources

In conventional natural gas deposits, similar to conventional oil, the hydrocarbons originate from proximal organic-rich source beds, such as shale. The gases then migrate into either structural or stratigraphic traps, which are sealed by low-permeability shales, mudstones or salt. (Figure 8.) The gas remains trapped in these discrete accumulations of sandstone or carbonate reservoirs, both of which have interconnected pore networks, readily allowing gas flow to the wellbore.[26]

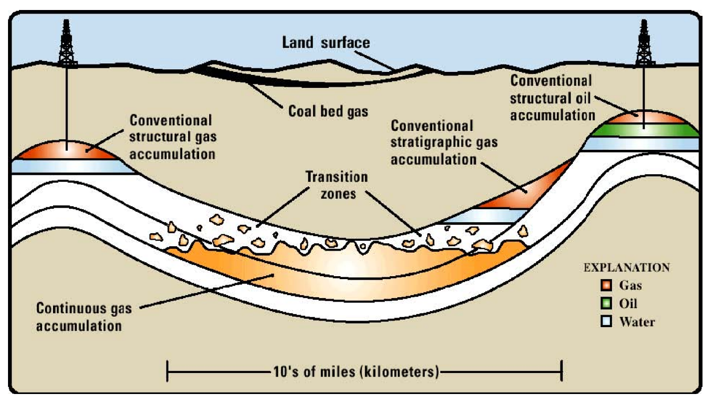

Figure 8: Types of onshore natural gas plays. Source: USGS Inventory of Onshore Federal Oil and Natural Gas Resources and Restrictions to Their Development (2008) ("EPCA Phase III Inventory") (p. 46).

[26] Ground Water Protection Council and ALL Consulting. 2009. Modern Shale Gas Development in the United States: A Primer. p. 66, Prepared for the DOE Office of Fossil Energy and National Energy Technology Laboratory (NETL). April 2009. at p. 15. Accessed April 2011 at http://www.netl.doe.gov/technologies/oil-gas/publications/epreports/shale_gas_primer_2009.pdf

Due to the ease of access and high porosity and permeability, conventional gas resources typically require a lower number of wells to economically access the resource, which is often held in small pockets within the stratigraphy. "Most natural gas is produced from conventional gas accumulations by drilling a well into the reservoir rock, casing the well with pipe, perforating the pipe to allow the gas to flow into the wellbore, placing a string of tubing inside the casing, and then extracting the gas up the tubing, sometimes with the aid of a pumping system. In some cases, natural gas flows freely up the tubing without the aid of a pumping system, because of high pressure in the reservoir. Natural gas flows from the reservoir rock into the well and up the tubing, as long as the pressure at the bottom of the well is lower than the pressure in the reservoir."[27]

B. Unconventional Natural Gas Resources

Unconventional[28] gas reservoirs are those which require different techniques to get the gas to flow. Many reservoirs lack the matrix permeability that connects the pore of the rock together, which is characteristic to conventional accumulations, greatly reducing the ability for gas to flow. Induced fracturing or permeability must occur in order to produce these reservoirs. This additional challenge for production requires advancements in technology that can reduce the economics of the project. With the recent advancements in stimulation techniques, such as hydraulic fracturing (use of liquids to create fractures in rocks), these reservoirs are becoming key resource plays in North America.[29]

The unique geologic character of unconventional gas resources often results in these accumulations being laterally extensive with continuous play deposits in high volumes (Figure 8). "The total in-place gas volume is commonly large and the overall recovery factor is relatively low. Although truly dry holes cannot be drilled within the boundaries of the accumulation, it is very possible to drill wells that are not economic."[30] Recent developments in technology and practices allow for reductions in cost and environmental footprint[31] although considerable environmental impacts remain. The degree of variability in unconventional natural gas resources is described below by the play types: tight gas, coalbed natural gas, shale gas, and gas hydrates.

1. Tight Gas

Tight gas production comes from conventional reservoir rock types, such as sandstone and less often carbonates. The reservoirs are regionally extensive over tens of thousands of acres and

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[27] DOE, National Energy Technology Laboratory (NETL). 2011. Energy Resource Potential of Methane Hydrate. p. 24. at p. 12. Accessed April 2011 at http://www.netl.doe.gov/technologies/oil-gas/publications/Hydrates/2011Reports/MH_Primer2011.pdf

[28] May also be called continuous reservoirs because of the geographically extensive accumulation. USGS. Energy Resources Program, *Unconventional (Continuous) Petroleum Sources.* Accessed April 2011 at http://energy.cr.usgs.gov/oilgas/addoilgas/unconventional.html. See, also, Natural Gas Suppliers Association. NaturalGas.org, *Unconventional Natural Gas Resources*. Accessed April 2011 at http://www.naturalgas.org/overview/unconvent_ng_resource.asp

[29] William A. Ambrose, Eric C. Potter, and Romulo Briceno, “An 'Unconventional' Future for Natural Gas in the United States,” *Geotimes*, February 2008, Accessed April 2011 at http://www.agiweb.org/geotimes/feb08/article.html?id=feature_gas.html.

[30] Schmoker, J. W., "Resource–assessment perspectives for unconventional gas systems," *AAPG Bulletin*, 86, no. 11 (2002): 1993-1999. DOI: 10.1306/61EEDDDC-173E-11D7-8645000102C1865D.

[31] DOE. Modern Shale Gas Development in the United States: A Primer, at p 11. Accessed April 2011 at http://www.netl.doe.gov/technologies/oil-gas/publications/epreports/shale_gas_primer_2009.pdf.

have very low porosity. The gas is sourced externally to the reservoir and migrates into the rock over time.[32] These systems can range from a single reservoir that is laterally extensive to stacked reservoirs thousands of feet thick. There are accepted values for porosity and permeability for classification as a tight gas reservoir. The term has been adopted to cover any reservoir with low permeability requiring special completions techniques to stimulate production.[33,34] Tight gas reservoirs are commonly so impermeable that fractures, either natural or those that are intentionally induced in the well-completion process or both, are necessary to boost producibility.[35] Stimulation techniques often involve hydraulic fracturing, without which, these reservoirs are not likely to produce economically. Tight-gas drilling programs are under way in the Appalachian Basin, Rocky Mountain basins into Canada, and eastern and southern Texas (Figure 9).

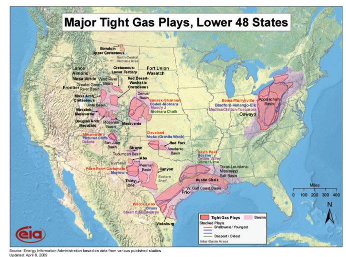

Figure 9: Major tight gas plays in the lower 48 states with the basins in light pink and play boundaries in rose. The plays are further distinguished by age in areas with multiple producing formations. Source: DOE, Energy Information Administration, last updated June, 2010. http://www.eia.gov/oil_gas/rpd/tight_gas.jpg

Due to extreme heterogeneity of both geology and surficial environmental setting in tight gas accumulations, different drilling and completion techniques are used in different areas. For example, stacked lenticular (shaped like a lentil or biconvex lens) sandstones as seen in Jonah Field of the Green River Basin, are accessed using vertical wells with stimulation on as many reservoir levels as possible. This is in part due to the small size and limited lateral extent of each individual sand body. The Department of Energy Multiwell Experiment in the Piceance Basin of Colorado in the 1980s is a well documented and analyzed experiment of vertical and slant wells with natural and stimulated fractures. For example, the slant well contacted 65 natural fractures in two cored intervals.[36] In the environmental framework, this type of information is important because drilling the appropriate wellbore design allows optimum contact with the producing formation, avoiding infill drilling and a larger footprint.

2. Coalbed Natural Gas

Coalbed natural gas (CBNG) or coalbed methane is natural gas that is produced from coal zones, often the source and reservoir of the gas. Coalbed methane can be created through two distinct pathways. There is a bacterial or biogenic pathway where anaerobic bacteria reduces carbon dioxide to form methane at low temperatures. There is also thermogenic where the natural heat and pressure within the earth convert organic matter from coal into gas. The biogenic process

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[32] Ibid., at p 15.
[33] Moslow, T. F., "Evaluating Tight Gas Reservoirs," *in* D. Morton-Thompson and A. M. Woods, eds., Development Geology Reference Manual: AAPG Methods in Exploration Series, No. 10, pp. 321-325. (1992)
[34] Law, B. E., "Basin-centered gas systems," *AAPG Bulletin*, 86, no. 11(2002): 1891-1919. DOI: 10.1306/61EEDDB4-173E-11D7-8645000102C1865D.
[35] Ambrose, et al., "An 'Unconventional' Future for Natural Gas in the United States." Accessed April 2011 at http://www.agiweb.org/geotimes/feb08/article.html?id=feature_gas.html.
[36] Philip H. Nelson, **A** Review of the Multiwell Experiment, Williams Fork and Iles Formations, Garfield County, Colorado, Chapter 15, at p 20, in USGS, National Assessment of Oil and Gas Project: *Petroleum Systems and Geologic Assessment of Oil and Gas in the Uinta-Piceance Province, Utah and Colorado,* Compiled by USGS Uinta-Piceance Assessment Team, U.S. Geological Survey Digital Data Series 69-B (2003)**.** Accessed April 2011 at http://pubs.usgs.gov/dds/dds-069/dds-069-b/REPORTS/Chapter_15.pdf.

allows the accumulations to occur very shallow, with maximum depths of four thousand feet, and the gas is composed mostly of methane with some carbon dioxide and nitrogen. Thermogenic CBNG is formed deeper in the earth, thousands of feet below the surface, and contains methane as well as heavier hydrocarbons and potentially hydrogen sulfide.[37] Thermogenic gas can also migrate into shallow coal beds, adding to the self-sourced gas stored within those shallow coals.[38]

Coalbed methane can be recovered from underground mines before, during, or after mining operations. Significant volumes of CBNG are extracted from "unminable" coal seams that are relatively deep or thin, of poor or inconsistent quality, or represent difficult mining conditions. Ninety percent of the US coal resource is unminable but represents a vast potential source of natural gas.[39]

The shallow coal beds where CBNG occurs are completely permeated by water. The water pressure holds the gas in the reservoir and the gas occurs adsorbed onto the grain surfaces of the coal or as a free phase in the water. In order to desorb the gas from the coal, the water must be removed, reducing the pressure and allowing the gas to move within the coal matrix to the wellbore.[40] Production of water dominates shallow CBNG wells until the pressure in the coal is reduced below saturation, allowing gas to readily move. At this point, gas production begins and water production declines, a process that typically takes several months.[41] Understanding this driver for production was essential in the successful development of CBNG plays.[42]

Some of the most prolific CBNG basins are located in the western United States. The Appalachian basin, Illinois basin, and some areas of Alaska and Canada[43] also have notable accumulations.[44] (Figure 10).

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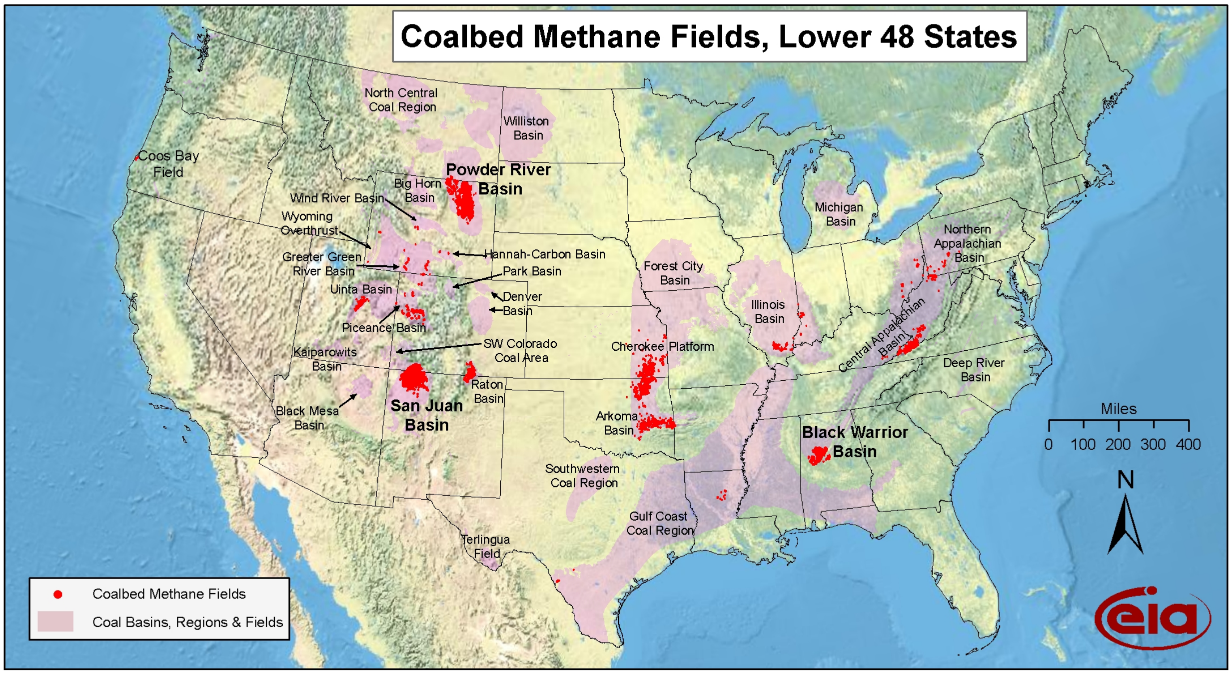
[37] DOE, National Energy Technology Laboratory (NETL). *Future Supply and Emerging Resources, Coal Bed Natural Gas.* Accessed April 2011 at http://www.netl.doe.gov/technologies/oil-gas/futuresupply/coalbedng/coalbed_ng.html.
[38] Rice, D. D., 1993, Composition and origins of coalbed gas, *in* B. E. Law and D. D. Rice, eds., Hydrocarbons from coal: AAPG Studies in Geology 38, p. 159-184.
[39] DOE, NETL. *Coal Bed Natural Gas.*
[40] DOE, EIA. *Coalbed Methane Basics.* Accessed April 2011 at http://www.eia.doe.gov/emeu/finance/sptopics/majors/coalbox.html.
[41] Ayers, W. B., "Coalbed gas systems, resources, and production and a review of contrasting cases from the San Juan and Powder River Basins," *AAPG Bulletin,* 86, no. 11(2002): 1853-1890. DOI: 10.1306/61EEDDAA-173E-11D7-8645000102C1865D.
[42] National Petroleum Council. (2007) Topic Paper #29, *Unconventional Gas Reservoirs - Tight Gas, Coal Seams and Shales*. Accessed April 2011 at http://www.npc.org/Study_Topic_Papers/29-TTG-Unconventional-Gas.pdf.
[43] Alberta Geological Survey. *Coal Zones with CBM Potential in the Alberta Plains.* Accessed April 2011 at http://www.ags.gov.ab.ca/energy/cbm/coal-zones.html
[44] DOE, NETL. *Coal Bed Natural Gas*. Additional maps indicating US coalbed methane locations are also available from the DOE, EIA at http://www.eia.doe.gov/oil_gas/rpd/cbmusa1.pdf and http://www.eia.gov/oil_gas/rpd/cbmusa2.pdf.



Source: Energy Information Administration based on data from USGS and various published studies
Updated: April 8, 2009

Figure 10. Coalbed Methane Fields, Lower 48. Source: DOE, EIA, at http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm

Initial CBNG completions were done as contingency targets in unsuccessful deeper targets starting more than 70 years ago in the eastern and 40 years ago in the western basins. The potential of this resource was steadily uncovered through research pertaining to methane removal in coal mining operations and government research grants. Unique aspects of CBNG are the significant quantity of water, treatment of co-produced carbon dioxide, and gas compression, required from the very low production pressures.[45]

Vertical and horizontal wells, including multi-laterals, are used to develop CBNG resources. For the most part, the quality of a seam cleat system (high-conductivity flow paths) will dictate the type of well completion and stimulation employed. In high-permeability settings, gas flow enhancement may not be required. In other situations, hydraulic fracturing and cavitation stimulations are used. The cavitation method involves enlarging the original wellbore and linking the wellbore with the cleat system within one or more coal seams. In all cases, water initially must be pumped out of the coals (dewatering) in order to reduce the reservoir pressure and allow the methane to desorb.[46]

Several completion technologies have been evaluated including open hole cavity completion, open hole completion, and the most common cased hole single- or multi-seam completion. The open hole cavity completion resulted in significant increases in production from wells in a specific overpressured fairway in the San Juan basin, but has not worked outside of this area.

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[45] Ayers, "Coalbed gas systems."
[46] DOE, NETL. *Coal Bed Natural Gas*.

Cased hole single or multi-seam completions involve hydraulic fracturing. In CBNG, no proppants (sand or other particles to prop the fractures open) are used, it is only the injection of water into the coal, a process that may result in fracturing of the coal, but predominantly acts to clean out the coal to allow the gas to flow to the wellbore.[47]

The need for safe and efficient wastewater disposal during production can be a significant cost factor for producing CBNG due to the dewatering process that takes place prior to gas production. Wells in the deeper part (total depth >2,000 ft) of the Powder River basin can produce up to 1,000 barrels of water per day in initial dewatering (typical wells outside of the deep area produce between 200-500 barrels per day). Wells in the San Juan basin typically produce between 100-300 barrels of water per day in the initial dewatering. This water can be more expensive to dispose of due to the use of injection wells, compared to surface disposal in the Powder River basin.[48]

Treatment (if necessary), surface discharge or subsurface injection of CBNG waste water[49] is subject to federal and state regulations, including the Clean Water Act, the Safe Drinking Water Act, and the Resource Conservation and Recovery Act. Subsurface injection requires compatibility studies of the proposed injection formation and the water that is injected. Surface discharge must meet daily effluent limits on constituents. The cost of handling coproduced CBNG water can vary from a few cents per barrel to more than a dollar per barrel. The volumes of water produced and cost of handling could prohibit development of the resource.[50]

Production of CBNG can result in substituting clean-burning methane for dirtier fuels and using coalbed methane as a fuel rather than venting it into the atmosphere as a result of coal mining activities (methane is 21 times more potent a greenhouse gas than is carbon dioxide).[51]

3. Shale Gas

Shale gas is produced from low permeability shale formations that are the reservoir and source of the gas. Subtle trapping mechanisms typically hold the gas, allowing large areas to be gas saturated, such as seen in the Appalachian Basin (Figure 5). Shale gas production is controlled in part by the amount of gas generated by the shale, retention of this gas, presence of fractures, and the mechanical properties of the rock. The storage of the gas can greatly affect the speed and efficiency of production. The percentage of gas recovered by current production methods in

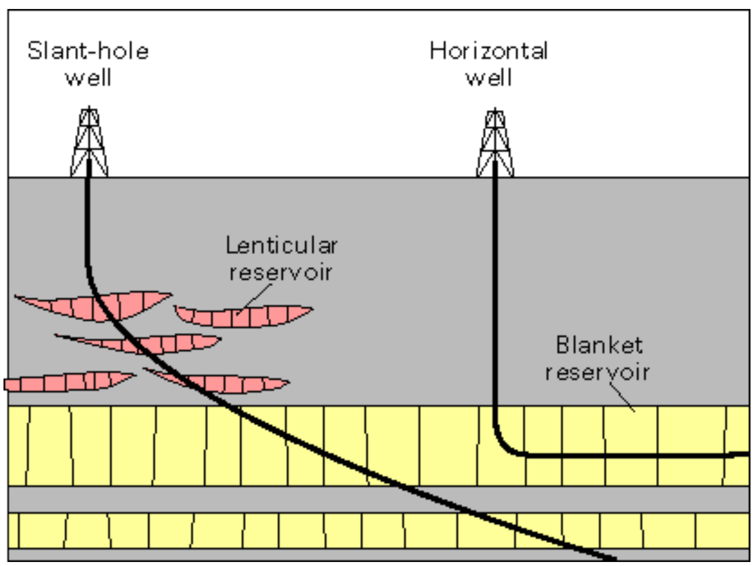
[47] Colmenares, L.B., and M.D. Zoback, "Hydraulic fracturing and wellbore completion of coalbed methane wells in the Powder River Basin, Wyoming: Implications for water and gas production," *AAPG Bulletin*, 91, no. 1 (2007): 51-67. DOI: 10.1306/07180605154.
[48] Ayers, "Coalbed gas systems."
[49] DOE, EIA. *Coalbed Methane Basics.* Accessed April 2011 at http://www.eia.doe.gov/emeu/finance/sptopics/majors/coalbox.html
[50] USGS. *Water Produced with Coal-Bed Methane.* Fact Sheet FS-156-00, November 2000. Accessed April 2011 at http://pubs.usgs.gov/fs/fs-0156-00/fs-0156-00.pdf.
[51] DOE, EIA. *Coalbed Methane Basics.*

shale gas reservoirs is low[52, 53] with some reporting production of less than 15 percent of the estimated gas in place.[54]

Shale gas is one of the most rapidly expanding play types in onshore North America. This rock was formerly seen as only a source and a seal. As new technologies are developed and refined, shale gas plays once believed to have limited economic viability are now being re-evaluated. Estimates of the accessible shale gas resource are likely to increase over time as new data become available from additional drilling, experience is gained in producing shale gas, understanding of the resource characteristics increases, and recovery technologies improve.[55]

Each gas shale basin is different and has a unique set of exploration criteria and operational challenges. Shale gas wells may be drilled either vertically or horizontally and most are hydraulically fractured to stimulate production. The wells can be similar to other conventional and unconventional wells in terms of depth, production rate, and drilling. The combination of sequenced hydraulic fracture treatments and horizontal well completions was key in facilitating the expansion of shale gas development.

Horizontal drilling allows more exposure to a formation than a vertical well (Figure 11). Fewer wells are required since each well accesses more potential pay zone. This reduces the surface footprint and environmental impacts, although impacts remain. Multi-well pads have also decreased the surface footprint and cost associated with rig moves and transportation for shale gas production.



52 Curtis, K.B, "Fractured shale-gas systems," *AAPG Bulletin*, 86, no. 11 (2002): 1921-1938. DOI: 10.1306/61EEDDBE-173E-11D7-8645000102C1865D
53 DOE. Modern Shale Gas Development in the United States: A Primer, at p.17, Exhibit 11: Comparison of Data for the Gas Shales in the United States. Accessed April 2011 at http://www.netl.doe.gov/technologies/oil-gas/publications/epreports/shale_gas_primer_2009.pdf.
54 Ambrose, et al., "An 'Unconventional' Future for Natural Gas in the United States," Accessed April 2011 at http://www.agiweb.org/geotimes/feb08/article.html?id=feature_gas.html.
55 DOE. Modern Shale Gas Development in the United States: A Primer, at p 16. Accessed April 2011 at http://www.netl.doe.gov/technologies/oil-gas/publications/epreports/shale_gas_primer_2009.pdf.

Figure 11. Deviated well drilling involves drilling horizontal and slant-hole wells to better intersect vertical fractures in tight formations. Source: USGS, Energy Resource Surveys Program, *Describing Petroleum Reservoirs of the Future.* USGS Fact Sheet FS-020-97. Accessed April 2011 at http://energy.usgs.gov/factsheets/Petroleum/reservoir.html

Hydraulic fracturing overcomes the naturally low permeability seen in shales and creates pathways for the natural gas to flow to the wellbore. Many types of hydraulic fracturing exist, as necessitated by the variability seen in the shales and numerous techniques have been applied. The fracturing may be done in stages, involving different fluids and additives, and a variety of planned and engineered processes.[56]

There are greater quantities of water used in and waste water generated from the hydraulic fracturing process. The Marcellus Shale has reported three million gallons of water per hydraulic fracturing treatment. Disposal of the water after the hydraulic fracturing may be done by reinjecting the fluid into the ground, treatment in waste water treatment plants, or evaporation of the water and disposal of the solids. Each of these methods has its difficulties and regulatory requirements.[57]

Currently, the most active shales include the Barnett, Haynesville/Bossier, Antrim, Fayetteville, Marcellus, and New Albany (Figure 5). The basic development concepts of the gas shale basins are similar, but there are significant variations in the requirements of each area. This can necessitate unique technological approaches to the processes. Operators have overcome these operational challenges by identifying and solving problems in a pay specific approach and understanding that each reservoir is unique and requires specific exploration and development approaches. [58]

For example, the New Albany Shale development was based on success seen in the Antrim Shale. This approach worked in the Indiana portion of the basin where the New Albany was shallow and produced significant quantities of water. Upon moving into the Kentucky section of the shale, operators discovered the best practices were similar to the Ohio Shale in the Appalachian basin, which produces less water and is deeper.

3.2.4 Gas Hydrates

Naturally occurring gas hydrates, or methane hydrate, is another type of unconventional gas found onshore in arctic regions. This resource has been detected in many regions of the Arctic, including the Mackenzie River delta in Canada's Northwest Territories and the north slope of Alaska.[59] A gas hydrate is a crystalline solid. The building blocks consist of a gas molecule such as methane, surrounded by a cage of water molecules. It is stable in association with permafrost in the polar regions.[60]

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[56]Ibid at p 56-64.
[57] Soeder, D.J., and Kappel, W.M., 2009, Water resources and natural gas production from the Marcellus Shale: U.S. Geological Survey Fact Sheet 2009–3032, 6 p. Accessed April 2011 at http://pubs.usgs.gov/fs/2009/3032/.
[58] DOE. Modern Shale Gas Development in the United States: A Primer. at pp. 3, 7-10.

[59] USGS, Woods Hole Science Center, Gas Hydrate Studies, http://woodshole.er.usgs.gov/project-pages/hydrates/index.html

[60] Ibid.

The industry is interested in methane hydrates due to the current resource estimates. Significant research is occurring to better understand where and how to produce it. The National Energy Technology Laboratory methane hydrate primer summarizes recent developments.[61] Methane is the main ingredient in natural gas, and it is now believed that "methane hydrate deposits hold immense volumes of methane, primarily stored in sediments of the Earth's outer continental margins and polar regions. The total amount of carbon stored in these deposits amounts to many thousands of gigatons and far exceeds the quantity of carbon that currently resides in the atmosphere. In addition, methane is itself a potent greenhouse gas, remaining in the atmosphere for about a decade before it is converted to carbon dioxide."[62]

"Significant scientific work must be completed before methane hydrate can be considered a producible natural gas resource. Critical tasks include identifying sites that are suitable for methane hydrate production testing and validating reservoir quality and well performance through extended field testing. Such testing must demonstrate that methane can be produced safely from hydrate deposits, at commercial rates, over extended time periods, and with minimal environmental impacts."[63]

[61] DOE, NETL. 2011. *Energy Resource Potential of Methane Hydrate*, p. 24. Accessed April 2011 at http://www.netl.doe.gov/technologies/oil-gas/publications/Hydrates/2011Reports/MH_Primer2011.pdf
[62] Ibid. at 11.
[63] Ibid. at 13.