Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale

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Lead Author Biographical Sketch

Dan Arthur is a founding member and the Managing Partner of ALL Consulting (www.all-llc.com). Mr. Arthur earned his bachelors degree in Petroleum Engineering from the University of Missouri-Rolla. He is a recognized authority on environmental issues pertaining to unconventional resource development and production. Mr. Arthur has served or is currently serving as the lead researcher on several significant projects involving unconventional resources; environmental considerations pertaining to shale gas development; produced water management and recycling; access to federal lands; and low impact natural gas and oil development. Has previously managed U.S. Department of Energy (DOE) funded research projects involving the development of best management practices utilizing GIS technologies for efficient environmental protection during unconventional resource Development and Production; research to develop a national primer on coal bed methane; research to develop a Handbook on the preparation and review of environmental documents for CBM development; and research with the Ground Water Protection Research Foundation (GWPRF) and funded by DOE and BLM involving analysis of produced water management alternatives and beneficial uses of coal bed methane produced water. Mr. Arthur has published many articles and reports and has made numerous presentations on environmental, energy, and technology issues.

Abstract

The issue of hydraulic fracturing has raised many concerns from the public as well as government officials. This paper will review the history and evolution of hydraulic fracturing, including environmental and regulatory considerations. Additionally, technical and environmental considerations will be presented applicable to hydraulic fracturing in the unconventional arena of gas shales with an emphasis on the Marcellus Shale of the Appalachians. Topics addressed in the paper will include discussion on why hydraulic fracturing is performed; the hydraulic fracturing process; applicable design and engineering aspects of well completions; geological considerations such as confinement of the fracturing process; potential risks to groundwater and underground sources of drinking water; and the use of hydraulic fracturing fluids and associated technical considerations.

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Introduction

Shale gas reservoir developments are a growing source of natural gas reserves across the United States. The successful model used for gas shale development in the Barnett Shale of the Fort Worth Basin is being expanded to other shale plays. The basis of the Barnett Shale completion model is the use of horizontal wells and hydraulic fracturing stimulations. One shale gas play that is currently in the early stages of development is the Marcellus Shale of the Appalachian Basin. The Marcellus Shale has the potential to be one of the largest natural gas plays in the United States and is the focus for the discussion in this paper. While the development of the Marcellus Shale is in the early stages, the use of horizontal well drilling and hydraulic fracturing appear to be key aspects of successfully developing this important natural gas resource. This paper is a review of the hydraulic fracture process, including a brief history of hydraulic fracturing as applied to shales and the activities associated with a hydraulic fracture treatment.

Unconventional development of energy resource plays, including coal beds, tight sands and shales has been a growing source of natural gas development in the United States. Since 1998 unconventional natural gas production has increased nearly 65%. This increase has resulted in unconventional production becoming an increasingly larger portion of total natural gas production, increasing from 28% in 1998 to 46% of total natural gas production in 2007[1]. One type of unconventional development that has gained attention and contributed to this increase is natural gas from shale formations. Gas production from gas shales is gaining attention throughout the United States and extends beyond the well known Barnett Shale in the Fort Worth Basin and Fayetteville Shale in the Arkoma Basin. Shale gas resources extend across the continental United States, offering abundant and available access to clean burning natural gas. Development of shale gas resources includes the shales in a variety of basins, including the Devonian shales in the Appalachian Basin; the Mowry shale in the Powder River Basin; the Mancos shale in the Uinta Basin; the Woodford shale in the Ardmore Basin; the Floyd/Neal shale play in the Black Warrior Basin; the Barnett shale in the Permian Basin; the New Albany shale in the Illinois Basin; the Pearsall shale in the Maverick Basin; the Chattanooga shale in Arkansas and Tennessee; the Hovenweep shale in the Paradox Basin; the Bend shale in the Palo Duro Basin; and the Barnett/Woodford shale plays in the Delaware and Marfa Basins[2].

One key shale gas play identified as having promise for future development is the Devonian Aged, Marcellus Shale of the Appalachians[2]. The development of the Marcellus has been made possible based on recent technological advances in two key technologies – horizontal drilling and hydraulic fracturing[3]. The technology of horizontal well completions was first adapted for shale gas development to provide increased wellbore exposure to the reservoir area while allowing for a reduced number of surface locations in the urban areas of the Ft. Worth Basin[4]. Barnett horizontal wells have laterals ranging from 1,500 to more than 5,000 feet and for these wells to be economically productive, they require hydraulic fracturing. Because of well configurations and other considerations, hydraulic fracturing procedures were adapted to the unique Barnett formation's needs[4]. Similar well completions and treatments are expected to be necessary for Marcellus Shale wells to be economically productive and to effectively and prudently manage the resource.

Shale gas plays are unconventional reservoirs because these formations contain oil- or gas-bearing rocks which have poor or limited natural permeability relative to the transmission of fluids to a wellbore[5]. As such, these resources require a means to increase their permeability through stimulation[5]. Hydraulic fracturing of unconventional plays has been tried in the judicial system due to expressed concerns that the technology had the potential for groundwater sources to be affected. In the coal bed play of the Black Warrior Basin of Alabama and the San Juan Basin of New Mexico and Colorado, this issue reached the 11th Circuit Court of Appeals and merited

[1] Navigant Consulting, Inc. 2008, *North American Natural Gas Supply Assessment*, Prepared for: American Clean Skies Foundation.
[2] David Brown. 2007. *From Sea to Shining Sea: If It's Shale, It's Probably in Play*. AAPG Explorer April 04 2007.
[3] H. Lee Matthews and Mark Malone. 2007. *Stimulation of Gas Shales: They're All the Same- Right?*. SPE 106070.
[4] R. Leonard, R. Woodroof, K. Bullard, M. Middlebrook, and R. Wilson. 2007. *Barnett Shale Completions: A Method for Assessing New Completion Strategies.* SPE 110809.
[5] David D. Cramer. *Stimulating Unconventional Reservoirs: Lessons Learned, Successful Practices, Areas for Improvement*. SPE 114172.

a court-imposed investigation by the U.S. Environmental Protection Agency (EPA) along with an additional investigation led by the Ground Water Protection Council[6]. One of the concerns identified dealt with the concerns that groundwater was impacted by hydraulic fracturing stimulations in the shallow coal bed methane formations because these shallow coal beds can also contain high quality water which is able to be treated to meet drinking water standards[6]. Unconventional gas shales resources are typically deeper than coal bed methane formations, have not traditionally been identified as sources for supplying drinking water, are not noted as containing treatable drinking water, and are often geologically isolated from drinking water aquifers by several thousand feet of other strata including other shale formations that act as aquitards. While hydraulic fracturing is a necessary aspect of gas shale development, the natural barriers present between productive shale formations and groundwater zones, in combination with the oil and gas regulations present in the regulating states provide levels of protection that ensure potential groundwater sources are protected.

America's Gas Shales

Gas shales are organic-rich shale formations that were previously believed to function as source rocks and seals for gas accumulating in the stratigraphically proximal sandstone and carbonate reservoirs of traditional onshore gas development[7]. Shale is a sedimentary rock that is predominantly comprised of consolidated clay and silt sized particles. Shales accumulate as muds in low-energy depositional environments such as tidal ponds and deep water basins where the fine-grained clay and silt particles fall out of suspension in these quiet waters. During the deposition of these sediments, there can also be deposition of organic matter in the form of algae, plant stems and leaves[8]. The compaction of the sheet-like clay particles results in thin laminae in part because the clay grains rotate to lie flat as a result of pressure from compaction. The thin layers that make up shale result in a rock that has limited permeability horizontally and extremely minimal permeability vertically; typical unfractured shales have permeabilities on the order of 0.01 to 0.00001 millidarcies[9]. The layering and fracturing of shales can be seen in outcrop and is reflective of the manner in which shales develop fractures both naturally and as a result of hydraulic fracturing (see photo). The photograph shows an outcrop of the Marcellus shale which reveals the natural bedding planes or layers of the shale and near vertical fractures that can cut across the natural bedding planes.

Photograph of Marcellus Shale Outcrop
Source: T. Engelder home page

The low natural permeability of shale has been a limiting factor to the production of gas shale resources[10]. Research from the 1980's documented the presence of natural gas in Devonian shales of the Appalachians identifying that the development of these resources had limited economic potential without supplemental reservoir stimulation to facilitate the flow of the gas to the wellbore[10,11]. Low reservoir permeability represents a key difference between shale and other gas reservoirs. For gas shales to be economically produced, the restrictions of low permeability must be overcome[12]. The combination of reduced economics and low permeability of gas shale formations historically caused

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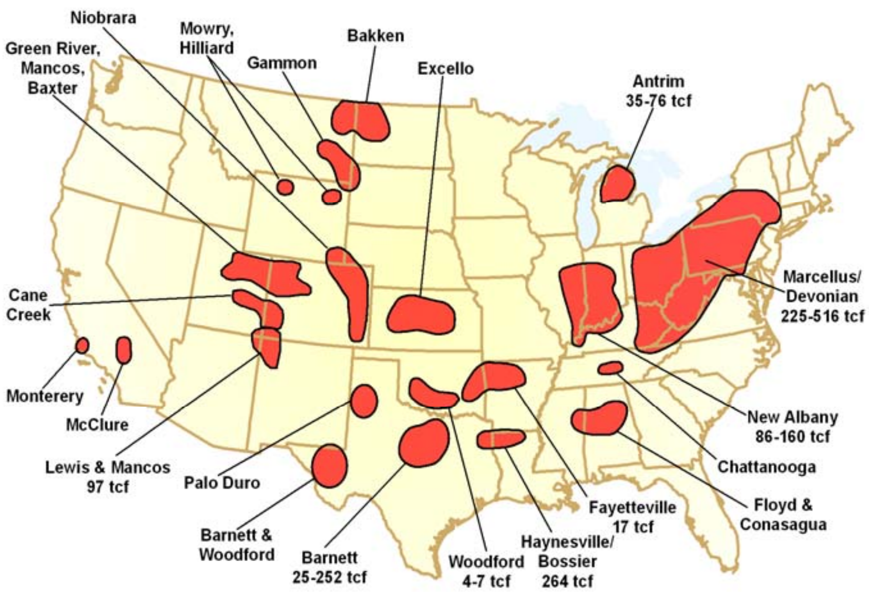
[6] Drilling Contractor, 2000. *Alabama Lawsuit Poses Threat to Hydraulic Fracturing Across US.* January/February 2000. pgs 42-43.
[7] Schlumberger 2005. *Shale Gas White Paper*. 05-OF299. October 2005, Schlumberger Marketing Communications.
[8] Richard Davis, Jr. 1992. *Depositional Systems: An Introduction to Sedimentology and Stratigraphy*. 2nd Edition. Prentice Hall. 604 pgs.
[9] R.A. Freeze and J.A. Cherry. 1979. *Groundwater*. Prentice Hall. 604pgs.
[10] S. Ameri, K. Aminian, J.A. Miller, D. Doricich, and A.B. Yost II. *A Systematic Approach for Economic Development of the Devonian Shale Gas Resources*. SPE 14504.
[11] D.E. Lancaster. *An Update on GRI's Comprehensive Study Well Program in the Devonian Shales of the Appalachian Basin*. SPE 19310.
[12] Halliburton Energy Services. 2008. *U.S. Shale Gas: An Unconventional Resource. Unconventional Challenges.* Halliburton White Paper

operators to by-pass these formations and focus on resources that required less investment and that had earlier financial return[13].

Shales are located across the United States, with those bearing natural gas at depths exceeding 12,000 feet (ft)[7]. Estimates of total natural gas resource potential for gas shales has been estimated to be from 500 to 1,000 Trillion cubic feet (Tcf)[12], with estimates increasing as additional wells are brought online and additional information is gathered. The distribution of gas shale formations in the continental United States with estimated reserves for those basins in which development is ongoing or evolving is shown in Figure 1. The natural gas present in the shale formations typically resides in one of three locations including: within the pore space of the shale, within natural fractures of the shale, and adsorbed on minerals or organic matter within the shale[14]. This gas has been identified as thermogenically sourced, as indicated by the lack of other liquid hydrocarbons[15]. The degree to which shale has been exposed to heat and pressure can be measured by the relative volumes of oil and natural gas; the most mature shales are comprised primarily of dry natural gas[15]. To date the gas shales which have been developed have occurred in three depth ranges, northern shallow gas shales are found between 250 to 2,000 ft in the Antrim Shale and New Albany Shale, eastern shales average between depths of 3,000 and 5,000 ft and southern shales are located between 2,000 and 6,000 feet[7], however new exploration activities are reaching depths of 12,000 ft[2].

Figure 1: Gas Shale Basins of the United States



The Barnett Shale has set the standard for gas shale development with production ramping up since the mid 1990's, when horizontal drilling and hydraulic fracturing technologies enabled the play to become economically viable[12]. The Barnett Shale play has experienced more than a 3000% growth rate between 1998 and 2007, and it has been estimated that the Fayetteville, Haynesville, Woodford, and Marcellus are expected to show similar growth as these plays move forward[1]. While the Barnett Shale technologies have continued to mature, petroleum industry innovators exported the lessons learned in the Fort Worth Basin to many other basins and many other shales[16], which has led to more recent development efforts in other shales.

Table 1 presents a comparison of the characteristics of select shale gas plays in the US. Table 1 is a summary of the characteristics for U.S. gas shale plays and provides several characteristics for comparison including; estimated reserves, play size, production volumes, depth to production zone, characteristics of the shales and estimated or known well spacing.

[13] M. Airhart. 2008. *The Barnett Shale Gas Boom: Igniting a Hunt for Unconventional Natural Gas Resources.* Geology.com article.
[14] Geology.com. 2008. *Marcellus Shale- Appalachian Basin Natural Gas Play: New research results surprise everyone on the potential of this well-known Devonian black shale.*
[15] John A. Harper. 2008. *The Marcellus Shale – An Old "New" Gas Reservoir in Pennsylvania*. In Pennsylvania Geology, Volume 28 Number 1. Published by the Bureau of Topographic and Geologic Survey, Pennsylvania Department of Conservation and Natural Resources.
[16] D.W. Walser and D.A. Pursell. 2007. *Making Mature Shale Gas Plays Commercial: Process vs. Natural Parameters*. SPE 110127

The data in Table 1 also shows the variations in depth of target formation with development potential. Review of the table shows that both the Haynesville and the Marcellus Shales have estimated maximum recoverable gas volumes six to eight times greater than the Barnett Shale. The Woodford and Haynesville Shales are predicted to have deeper average target depths than other shale plays. The shale plays show production intervals at depths considerably deeper than many other unconventional plays. A comparison of the estimated depth of the target zone and the base of treatable water data demonstrates that gas shale development is estimated to occur several thousand feet below treatable water zones in most of the gas shale basins. In analyzing the Fayetteville data, the shallowest shale gas play presented, it is important to understand that the Arkansas Oil and Gas Commission (AOGC) regulates the depth of protective casings (as do other state oil & gas regulatory agencies) based on field rules in order to protect groundwater resources[17]. These rules and regulations are not exclusive to Arkansas, rules regarding depth of casings in order to protect groundwater resources are part of every state oil and gas regulatory agencies rules. Based on the size of the Marcellus Play, the average target depth, estimated reserves, and the proximity to a large market for produced gas, the Marcellus is an appealing target which has a large potential upside for development[1] while also having significant natural isolation and confinement from treatable groundwater resources.

Table 1. Comparison of Data for the Active Gas Shales in the United States

Gas Shale Basin	Barnett	Marcellus	Fayetteville	Haynesville	Woodford	Lewis
Estimated Basin Area, square miles	5,000	95,000	9,000	9,000	11,000	10,000
Depth, ft	6500-8500[18]	4,000-8,500[12]	1,000-7,000[12]	10,500-13,500[12]	6,000-11,000[5]	3,000-6000[18]
Net Thickness, ft	100-600[18]	50-200[6]	20-200[18]	200[7]	120-220[5]	200-300[18]
Depth to Base of Treatable Water, ft#	~1200	~850	~500[17]	~400	~400	~2000
Total Organic Carbon, %	4.5[18]	3-12[11]	4.0-9.8[18]		1-14[10]	0.45-2.5[18]
Total Porosity, %	4-5[18]		2-8[18]			3.0-5.5[18]
Gas Content, scf/ton	300-350[18]		60-220[18]			15-45[18]
Water Production, Barrels water/day	0[18]					0[18]
Well spacing, Acres	60-160[18]	40-160[6]		40-560[6]	640[6]	80-320[18]
Gas-In-Place, Tcf	327[1]	1,500[1]	52[1]	717[1]	52[1]	61.4[1]
Reserves, Tcf	44[1]	262[1], 500[20]	41.6[1]	251[1]	11.4[1]	20[1]
Est. Gas Production, mcf/day/well	338[19]	3,100[20]	530[19]	625-1800[13]	415[19]	100-200[12]

mcf = thousands of cubic feet of gas.
NOTE: Data derived from various sources and research analysis. Information from some basins was unable to be identified and confirmed at the time of this paper and has been left blank.
- for the Depth to base of treatable water data, the data was based on depth of casing information if the state's oil and gas agency did not specifically report BTW values in their data base.

[17] Arkansas Oil and Gas Commission. 2008. Field Rules and Rule B-15.
[18] Hayden, J., and Pursell, D. 2005. *The Barnett Shale. Visitor's Guide to the Hottest Gas Play in the US.* October 2005.
[19] Williams, P. American Clean Skies. *A Vast Ocean of Natural Gas.* Summer 2008. P 44-50.

The Marcellus Shale

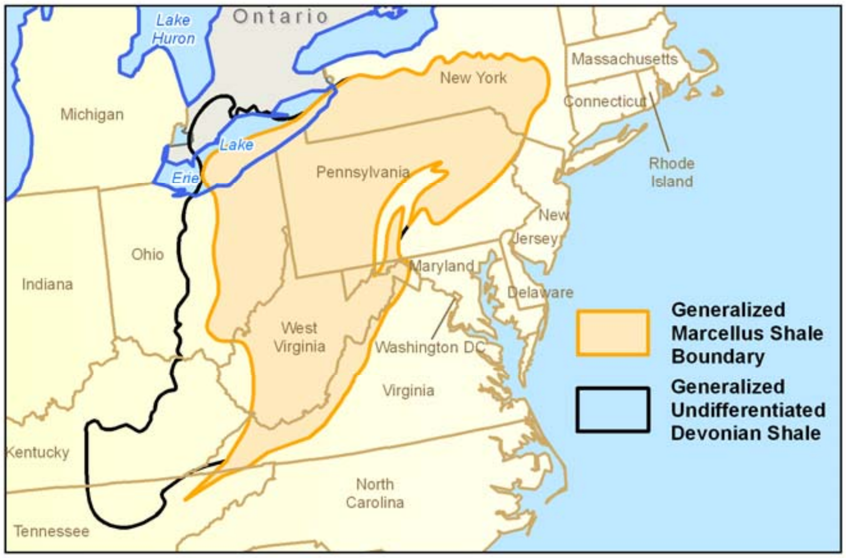


Figure 2: Marcellus Shale Distribution in the Appalachian Basin
Source: ALL Consulting, 2008

Devonian Shale was the producing formation of the first natural gas well drilled in the United States in 1821[15]. Devonian shales in the Appalachian Basin have a long history of low productivity and long well life which has limited the extent to which these sources of natural gas have been developed to date[15]. The Marcellus Shale extends from its northern reaches in west central New York on a northeast to southwest trend down into Pennsylvania, Ohio, and West Virginia; with minor portions of the eastern side of the basin extending into Maryland and Virginia (Figure 2).

The Marcellus Shale is a highly organic black shale that was deposited when a shallow continental seaway existed in the area that now makes up the eastern United States west of the Appalachian Mountains[20]. The interior seaway was a result of the African Plate (at the time part of the continent of Gondwana) and the North American plate (at the time part of the continent of Laurentia) colliding approximately 380 million years ago. The Marcellus Shale was deposited in a deep trough basin (below the pycnocline, a layer in water bodies below which a density difference prevents water from overturning and bringing oxygen to the lower portions of the water) located between the rise of the Cincinnati Arch and the collision boundary of the two plates[20]. This collision created a deep basin in which minimal clastic sediment deposition (from rivers and streams) occurred[20]. This depositional environment is analogous to the Black Sea of Europe, where a lack of fresh water flow from rivers prevents the deposition of significant quantities of clastic sediments. The deposition of large quantities of organic matter below the pycnocline and the subsequent thrust faulting that resulted from the continued collision of the two continental plates resulted in a rapid burial process for the organic matter that proved to be the source materials for the natural gas present in this black shale[20]. The rapid burial of the Marcellus, a result of continued sedimentation and thrust faulting, eventually resulted in the sediments surpassing the temperature and pressure of the oil window leading to the formation of large quantities natural gas entrained in the shales porosity[20]. The subsequent uplift and erosion of the Marcellus Formation has resulted in the natural formation of vertically orientated joints (or fractures)[20].

The Stratigraphic Column presented in Figure 3 is representative of the southwestern portion of New York State but provides a general reference to the composition of the overlying formations that were deposited after the Marcellus Shale. The strata overlying the Marcellus Shale in other portions of the Appalachians where Marcellus Shale is present are likely to be of similar composition. Directly overlying the Marcellus Shale are other Hamilton Group units of the middle Devonian, and the upper Devonian sequence, which is a section of geologic materials that are predominantly comprised of siltstones and shales. In the parts of the basin where the Marcellus is sufficiently deep to be a target for shale gas development, the upper Devonian strata would represent a thick section of geologic materials which would act as a barrier to upward migration of fluids.

[20] T. Engelder and G.G. Lash. *Marcellus Shale Play's Vast Resource Potential Creating Stir in Appalachia.* in The American Oil & Gas Reporter. May 2008.

Figure 3: General Stratigraphic Column of Southwestern New York State.

Period		Group	Unit		Lithology
Penn		Pottsville	Olean		Quartz Pebble
Miss		Pocono	Knapp		Conglomerate and Sandstone Quartz Pebble, Conglomerate, Sandstone, and Minor Shale
Devonian	Upper	Conewango			Shale and Sandstone Scattered Conglomerates
		Conneaut	Chadakoin		Shale and Sandstone Scattered Conglomerates
		Candadaway	Undifferentiated Perrysburg	•◦ •◦	Shale and Siltstone Minor Sandstone
		West Falls	Java Nunda Rhinestreet	•◦ •◦	Shale and Siltstone Minor Sandstone
		Sonyea	Middlesex	◦	Shale and Siltstone
		Genesee			Shale with Minor Siltstone and Limestone
	Middle		Tully	◦	Limestone with minor Siltstone and Sandstone
		Hamilton	Moscow Ludlowville Skaneateles Marcellus	◦	Shale with minor Sandstone and Conglomerate
			Onondaga	•◦	Limestone
	Lower	Tristates	Oriskany	◦	Sandstone
		Helderberg	Manlius Rondout		Limestone and Dolostone
Silurian	Upper		Akron	•◦	Dolostone
		Salina	Camillus Syracuse Vernon		Shale, Siltstone, Anhydrite, and Halite
		Lockport	Lockport	◦	Limestone and Dolostone
		Clinton	Rochester Irondequoit		Shale and Sandstone
	Lower		Sodus Retnules Thorold		Limestone and Dolostone
		Medina	Grimsby Whirlpool	◦ ◦	Sandstone and Shale Quartz Sandstone
Ordovician	Upper		Queenston Oswego Lorraine Utica	◦ ◦	Shale and Siltstone With Minor Sandstone
	Middle	Trenton- Black River	Trenton Black River	◦	Limestone and Minor Dolostone
	Lower	Beekmantown	Tribes Hill Chuctanunda		Limestone
Cambrian	Upper		Little Falls Galway (Theresa) Potsdam	◦ ◦	Quartz Sandstone and Dolostone; Sandstone and Sandy Dolostone; Conglomerate Base
Pre-Cambrian			Gneiss, Marble, Quartzite, etc …		Metamorphic and Igneous Rocks

Source: New York GEIS, 1992 ◦ - gas productive • - oil productive

The extraction of natural gas from shallow gas shale has been occurring in parts of the northeastern United States since the early 1800's[21] . By the turn of the 20th Century, development of shallow natural gas wells along the shoreline of Lake Erie was common place, with a well located on nearly every property or business in the area. In some cases, these wells were used for years to supply lighting or heat to properties[15]. However, many of these early wells were never able to produce a marketable quantity of natural gas; consequently researchers from agencies such as the Gas Research Institute (GRI) and the U.S. Department of Energy (DOE) have been searching

[21] NY DEC Division of Mineral Resources. 1992. *Final Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program.*

for means to effectively produce economic volumes of natural gas from the Appalachian Devonian shale for years[11].

The states of New York, Pennsylvania and Ohio each contain potential Marcellus Shale production; these are also states that rank in the top 10 in energy consumption in the United States based on data from the Energy Information Administration (EIA)[22]. These states contain some of the most densely populated areas in the United States, some of which have had historical power distribution issues with rolling blackouts and other energy crisis. New York City Mayor Michael R Bloomberg has recently proposed the addition of windmill farms to bridges and skyscrapers across the city to help generate additional power [23]. Local production of natural gas which could also be used to generate electricity could help meet New York City's energy needs.

In the two decades of Barnett Shale development, the science of shale gas production has grown to embrace sophisticated horizontal drilling and multi-stage hydraulic fracturing practices which help to make shale gas development successful[16]. The financial success and completion techniques of the Barnett Shale have developed to the point where analogous shale gas plays are similarly being explored and tested by various operators[16].

A renewed interest in the Marcellus Shale was initiated in 2003 when Range Resources-Appalachia, LLC drilled the first "new" Marcellus well in recent years and began experimenting with the techniques used in the Barnett. This effort resulted in reported production in Pennsylvania from the Marcellus in 2005[15]. Since 2005, the expansion of Marcellus shale development has continued in Pennsylvania and the Appalachian Basin. Development is increasing rapidly to the extent that Pennsylvania has experienced a nearly 25% increase in Applications for Permits to Drill, most of which are attributed to interest in developing Marcellus shale wells[15]. In Pennsylvania the number of Marcellus wells had reached an estimated 450 wells in February of 2008[15]. Development in other Appalachian states has been slower. For instance, the New York Department of Environmental Conservation (DEC) has less than 38 completed wells with the Marcellus formation as the target production zone in their current database[24]. One aspect which may facilitate a more rapid rate of development of the Marcellus shale is the proximity of the play to major markets in the northeastern United States. Development of the Marcellus Shale has

Figure 4: Horizontal and Vertical Well Completions
Source: John Perez, Copyright ©, 2008

[22] Energy Information Administration. Consumption, Price and Expenditure Estimates US State Rankings, 2005.
[23] NY Times Article. August 20, 2008. Bloomberg Offers Windmill Power Plan.
[24] NY DEC, Searchable On-Line Database. http://www.dec.ny.gov/cfmx/extapps/GasOil/ September 02, 2008.

potential to occur near some of the largest population centers of the eastern United States including New York City, Pittsburgh, and Philadelphia. This production of natural gas could help to facilitate meeting the energy needs of these major metropolitan areas. One operator with current production in Pennsylvania noted that the company receives a premium price to NYMEX from production in the Appalachians, while the company faces discounted rates from its production in the Rockies[2].

Current development practices in the Marcellus shale involve the drilling of both horizontal and vertical wells[15]. Regardless of the preferred well orientation, Marcellus shale well completions require formation stimulation, typically in the form of hydraulic fracturing to produce economic volumes of natural gas[25]. Further, based on development in other gas shales, it is likely that horizontal well drilling will become the preferred method of drilling for gas development from the Marcellus Shale.

From a historic perspective, horizontally drilled wells were first drilled in Texas in the 1930's[15]. The technology has been continuously improved and developed; and by the 1980's, horizontal drilling has become a standard industry practice[15]. In the Appalachians, through mid-2008, wells completed in the Marcellus formation have predominantly been vertically completed, but current permitting activity is showing an increasing trend in the numbers of horizontal well permit applications[15]. Based on discussions with industry in the area, it appears that there will continue to be a combination of both vertical and horizontal wells developed in the Marcellus, although horizontal wells are expected to become the predominant well drilling and completion for this play.

There are a wide range of factors that influence the choice between a vertical or horizontal well. While vertical wells may require less capital investment on a per well basis, production is less economical and overall development could require 4 or more vertical wells compared to one horizontal well or 16 separate well pads for vertical wells compared to only one multi-well pad using horizontal well technology. When assessing capital investments between vertical and horizontal wells, a vertical well may cost as much as $800,000 (excluding pad and infrastructure) compared to a horizontal well that can cost in the range of $2.5 million or more per well (excluding pad and infrastructure)[26].

Figure 4 illustrates the differences between horizontal and vertical shale well completions. The figure shows how a horizontal well completion provides greater wellbore exposure to the foundation in comparison to a vertical well. For the Marcellus Shale, a vertical well may only be exposed to as little as 50 ft of formation while a horizontal well may be developed with a lateral wellbore extending a length of 2,000 to 6,000 ft within the 50 to 300 ft thick formation as depicted in Figure 4[15]. The increase in reservoir exposure represents one advantage horizontal wells have over vertical wells. Other advantages of horizontal wells include reduced surface disturbances resulting from well pads, roads, and pipeline. Additionally, several horizontal wells can be placed on multi-well pads for a less intrusive impact to the surrounding area, the decrease in area can also change the impacts from noise, traffic, and result in visual changes to the landscape. Horizontal wells have also been used in many areas of the country to access natural gas resources in instances not possible using a vertical well due to existing infrastructure, buildings, environmentally sensitive areas, or other surface conflicts.

Hydraulic Fracturing

In addition to horizontal drilling, the other technology key to facilitating economical recovery of natural gas from shale is hydraulic fracturing. Hydraulic fracturing is a formation stimulation practice used in the industry to create additional permeability in a producing formation to allow gas to flow more easily toward the wellbore for purposes of production[27]. Hydraulic fracturing can be used to overcome natural barriers to the flow of fluids to the wellbore. Barriers may include naturally low permeability common in shale formations or reduced permeability resulting from near wellbore damage during drilling activities[27]. The process of hydraulic fracturing

[25] A.R. Jennings Jr. and W.G. Darden. 1979. *Gas Well Stimulation in the Eastern United States.* SPE 7914.
[26] Marshall Miller & Associates.Inc. *Marcellus Shale*. Presented to: Fireside Pumpers in Bradford, PA.
[27] Veatch, Ralph W. Jr.; Zissis A. Moschovidis; and C. Robert Fast, *An Overview of Hydraulic Fracturing.* in Recent Advances in Hydraulic Fracturing, Edited by John L Gidley, Stephen A. Holditch, Dale E. Nierode, and Ralph W, Veatch Jr. Society of Petroleum Engineers, Henry L Doherty Series Monograph Volume 12.

has been used in the Appalachia area since the early 1960s[15]. While aspects of hydraulic fracturing have been changing (mostly changes in the additives and propping agents) and maturing, this technology is utilized by the industry to increase the necessary production to support an ever increasing demand for energy. Modern formation stimulation practices have become more complex and the process has developed into a sophisticated, engineered process in which production companies work to design a hydraulic fracturing treatment to emplace fracture networks in specific areas[28]. Hydraulic fracture treatments are not a haphazard process but are designed to specific conditions of the target formation (thickness of shale, rock fracturing characteristics, etc.) to optimize the development of a network of fractures. Understanding the in-situ conditions present in the reservoir and their dynamics is critical to successful stimulations. Hydraulic fracturing designs are constantly being refined to optimize fracture networking and to maximize gas production, while ensuring that fracture development is confined to the target formation for both horizontal and vertical shale gas wells[28].

Initial hydraulic fracture treatments for new plays are designed based on past experience and data collected on the specific character of the formation to be fractured. Engineers and Geologists evaluate data from geophysical logs and core samples and correlate data from other wells and other formations which may have similar characteristics. Data are often incorporated into one of the many computer models the natural gas industry has specifically developed for analysis and design of hydraulic fracturing.

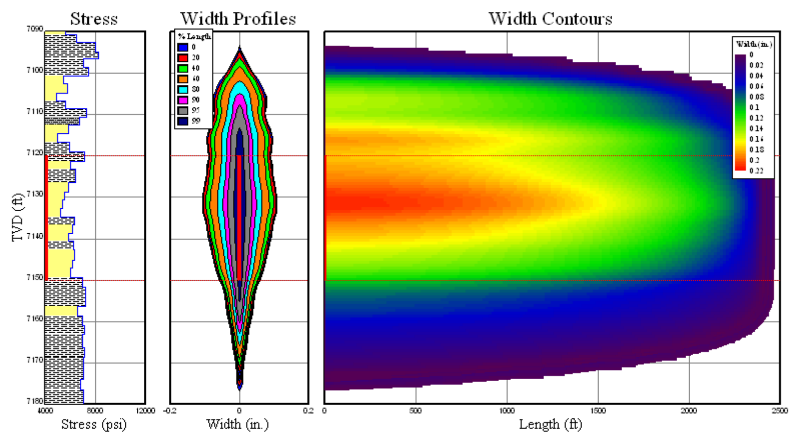


Figure 5: Example Output of a Hydraulic Fracture Stimulation Model.
Source: Chesapeake Energy Corporation.

Fracture Design

Fracture design can incorporate many state-of-the-art and sophisticated procedures to accomplish an effective, economic and highly successful fracture job. Some of these techniques include pre- and post-simulation, geologic studies using microseismic fracture mapping, and additional data collection that is used to refine future stimulations.

A computer simulation of the geologic model can be used to evaluate hydraulic fracturing designs via a simulator[29]. Using a simulator can help to economically plan and design a simulation treatment helping to manage costs and effectiveness of the stimulation. A simulator is used to predicted three-dimensional fracture geometry (Figure 5), integrated acid fracturing solutions, or to reverse engineer design stages for specific characteristics[28]. Hydraulic fracturing modeling programs allow geologists and engineers to modify the design of a hydraulic fracture treatment and evaluate the height, length and orientation of potential fracture development prior to initiation of the actual fracture treatment (Figure 5)[30]. These simulators also allow the engineers to use the data gathered during a fracture stimulation to evaluate the effectiveness and success of the fracture job performed. From these data and analyses the hydraulic fracturing design engineers can better predict and perform more effective fracture jobs in the future.

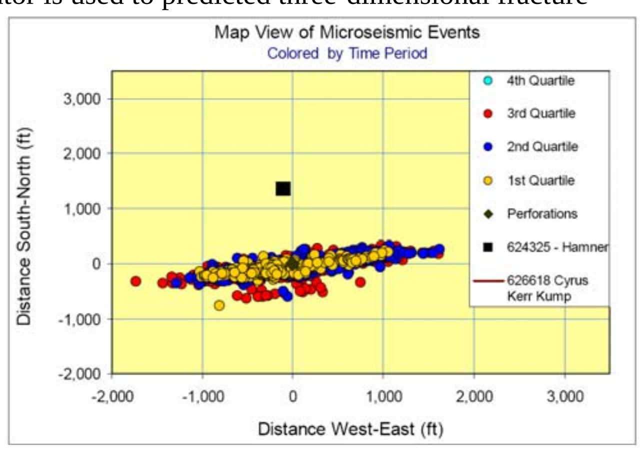


Figure 6: Mapping of Microseismic Events
Source: Oilfield Service Company

[28] C. Boyer, J. Kieshchnick, and R Lewis. 2006. Producing Gas from Its Source. In Oilfield Review Autumn 2006. pgs 36-49.
[29] Meyer & Associates, Inc. *User's Guide for the **M**eyer **Frac**turing Simulators. Sixth Edition.*
[30] Schlumberger Fracturing Services PowerSTIM webpage. www.slb.com. September 2, 2008.

Modeling programs also allow designers to modify plans as additional data are collected relative to the specific target formation[29]. The use of models allows designers to make advances in the design of hydraulic fracturing operations to develop more efficient ways to create additional flow-paths to the wellbores.

Additional advances in hydraulic fracturing design target analysis of hydraulic fracture treatments through technologies such as microseismic fracture mapping (Figure 6) and tilt measurements[22]. These technologies can be used to define the success and orientation of the fractures created, thus providing the engineers the ability to manage the resource through intelligent placement of additional wells to take advantage of the natural conditions of the reservoir and expected fracture results in new wells.

The refinement of the hydraulic fracture process that occurs as operators collect more resource specific data, helps to create a more optimized fracture pattern within the target formation to increase gas production and ensure that the fractures do not grow out of the formation which may reduce production[32]. Not only is fracture growth outside of the target formation discouraged relative to the potential of reduced production by production of fluids from non-productive zones, creating fracture size outside of the productive interval is more expensive and less cost beneficial to the well's economics.

Fracturing Fluids and Additives

The current practice for hydraulic fracture treatments of gas shale reservoirs are commonly sequenced events which can require thousands of barrels of water-based fracturing fluids mixed with proppant materials to be pumped in a controlled and monitored manner into the target shale formation above fracture pressure[21].

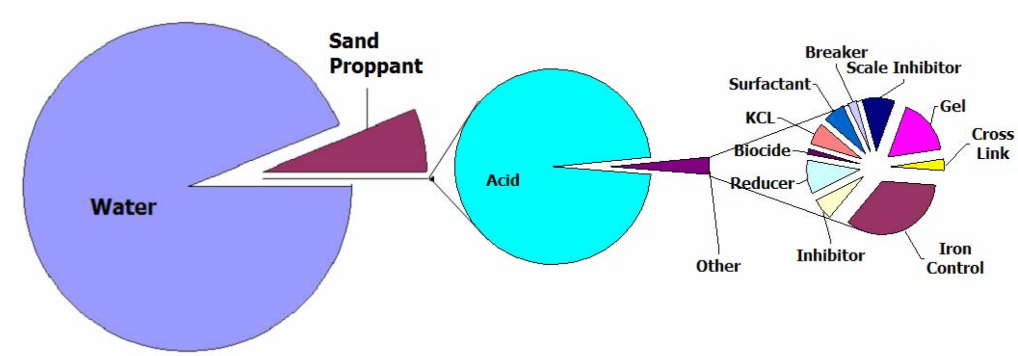


Figure 7: Volumetric Composition of a Fracture Fluid
Source: Compiled Data from Multiple Sources

The fracturing fluids used for fracturing gas shale include a variety of additive components, each with an engineered purpose to facilitate the production of gas[31]. The fluids currently being used for fracture treatments in the Marcellus Shale are water based or mixed slickwater fracturing fluids. Slickwater fracturing fluids are water-based fluids mixed with friction reducing additives, primarily potassium chloride.[15]. Water is the principal component of slickwater based fracturing fluids; however, other additives are included to perform specific actions, such as the addition of friction reducers which allows a fracturing fluid and proppant to be pumped to the target zone at a higher rate and reduced pressure than by using water alone. In addition to friction reducers, other additives include biocides to prevent micro-organism growth and reduce bio-fouling of fractures. Oxygen scavengers and other stabilizers which

Closed system hydraulic fracturing of a vertical well (PA)
Source: ALL Consulting, September 2008

[31] Schlumberger Fracturing Services Page of Schlumberger website, www.slb.com September 2, 2008.

prevent corrosion of metal pipes, and acids which are used to remove drilling mud damage within the area near wellbore are also common either in fracturing fluids or as part of the fracture treatment[30].

Figure 7 is a pie chart showing a relational breakdown of the volumes used for additives in a hypothetical 2,500,000 gallon fracture treatment which would be a similar size to a Marcellus Shale horizontal well treatment. The chart shows water as the primary component in comparison to the other additives that comprise the total of all fracturing fluids used for an individual fracturing event (Figure 7). Table 2 provides a summary of the additives, their main compounds and some of the other common uses for the main compounds of the additives in day-to-day life. Table 2 reveals that while there are a variety of different additives used in fracturing fluids, these additives are items that people encounter in their daily lives. Because the make-up of each fracturing fluid varies to meet specific needs for a well, it is not possible to provide a single amount or volume present in each additive. However, based on the volume of water that is used in making a fracturing fluid as seen in Figure 7, the concentration of these additives is diluted considerably when considered on an overall volumetric basis. Service companies are also working to develop even more environmentally friendly fluids, including the use of hydrochloric acids which more easily break down into simple salts[32].

Table 2: Fracturing Fluid Additives, Main Compounds and Common Uses.

Additive Type	Main Compound	Common Use of Main Compound
Acid	Hydrochloric acid or muriatic acid	Swimming pool chemical and cleaner
Biocide	Glutaraldehyde	Cold sterilant in health care industry
Breaker	Sodium Chloride	Food preservative
Corrosion inhibitor	N,n-dimethyl formamide	Used as a crystallization medium in Pharmaceutical Industry
Friction Reducer	Petroleum distillate	Cosmetics including hair, make-up, nail and skin products
Gel	Guar gum or hydroxyethyl cellulose	Thickener used in cosmetics, sauces and salad dressings.
Iron Control	2-hydroxy-1,2,3-propanetricaboxylic acid	Citric Acid it is used to remove lime deposits Lemon Juice ~7% Citric Acid
Oxygen scavenger	Ammonium bisulfite	Used in cosmetics
Proppant	Silica, quartz sand	Play Sand
Scale inhibitor	Ethylene glycol	Automotive antifreeze and de-icing agent

Table 3 presents an example of a single stage hydraulic fracture treatment. The data in Table 3 presents a generalized treatment design for what might be considered as a typical well completed in the Marcellus Shale – although practices are quickly advancing and can be substantially different than what is presented. The fracture treatment design shown in Table 3 is a single stage treatment that is typical of what may performed on a vertical Marcellus Shale well or a single stage on a horizontal well. This treatment differs from a horizontal well treatment primarily because it is only a single stage treatment. Horizontal wells in the Marcellus Shale may be treated using 4 or more stages to fracture the perforated interval of the well.

Figure 4 (above) presents a schematic representation of the differences between a four stage horizontal fracture treatment and a single stage vertical hydraulic fracturing treatment. While the sequence of events that occur within each stage of a fracture treatment are similar for both horizontal and vertical wells in the Marcellus Shale, horizontal well completions require multiple stages because it is not typically possible to maintain pressures sufficient to induce fractures over the complete length of a lateral leg that can be several thousand feet in length[33]. Further, staging fracture treatments allows the fracturing process to be performed in a much more controlled manner.

[32] Joel Parshall. *Barnett Shale Showcases Tight-gas Development.* Journal of Petroleum Technology.
[33] A.A. Ketter, J.L. Daniels, J.R. Heinze, and G. Waters. *A Field Study Optimizing Completion Strategies for Fracture Initiation in Barnett Shale Horizontal Wells.* SPE 103232.

Table 3: Example of a Single Stage of a Sequenced Hydraulic Fracture Treatment				
Stage	Volume (gallons)	Rate (gal/min)	Fluid Type	Proppant Size
Acid	5,000	500	15% HCl acid	none
Pad	100,000	3,000	slickwater	none
Prop 0.1	50,000	3,000	slickwater	100 Mesh
Prop 0.3	50,000	3,000	slickwater	100 Mesh
Prop 0.5	40,000	3,000	slickwater	100 Mesh
Prop 0.75	40,000	3,000	slickwater	100 Mesh
Prop 1	40,000	3,000	slickwater	100 Mesh
Prop 2	30,000	3,000	slickwater	100 Mesh
Prop 3	30,000	3,000	slickwater	100 Mesh
Prop 0.25	20,000	3,000	slickwater	40/70
Prop 0.5	20,000	3,000	slickwater	40/70
Prop 0.75	20,000	3,000	slickwater	40/70
Prop 1	20,000	3,000	slickwater	40/70
Prop 2	20,000	3,000	slickwater	40/70
Prop 3	20,000	3,000	slickwater	40/70
Prop 4	10,000	3,000	slickwater	40/70
Prop 5	10,000	3,000	slickwater	40/70
Flush	13,000	3,000	slickwater	none
Volumes are presented in gallons (42 gals = one barrel, 5,000 gals = ~120 bbls). Rates are expressed in gals/minute, 42 gals/minute = 1 bbl/min, 500 gal/min = ~12 bbls/min. Flush volumes are based on the total volume of open borehole, therefore as each stage is completed the volume of flush decreases as the volume of borehole is decreased.				

Before operators or services companies perform a hydraulic fracture treatment of a well (vertical or horizontal), a series of tests are performed to ensure that the well, well equipment and hydraulic fracturing equipment is in proper working order and will hold up to the operational pressures of the fracture treatment. The testing of well equipment starts with the testing of casings and cements during the drilling and well construction process and the testing continues with pressure testing of hydraulic fracturing equipment throughout the fracture treatment process[15]. It should be noted that minimum construction requirements are typically required and are regulated by state oil and gas regulatory agencies to assure that a well is protective of resources and safe for operation.

After the testing of treatment equipment and well equipment has been completed, the hydraulic fracture treatment of a well can begin. The first sequence in the hydraulic fracture treatment stage is initiated with the pumping of an acid treatment. This acid treatment helps to clean the near wellbore area permeability which is lost as a result of the drilling process and drilling muds. The acid treatment can also initiate the fracturing process. The next sequence after the acid treatment is a slickwater pad. The slickwater pad is a volume of fracturing fluid large enough in volume to effectively fill the wellbore and open the formation area with slickwater for friction reduction purposes. The slickwater pad helps to facilitate the flow and placement of the proppant sequences further into the fracture network. After the slickwater pad is the first proppant sequence which combines a large volume of water with fine mesh sand at a low concentration of 0.1 pounds per gallon (lbm/gal). As shown in Table 3, each subsequent sequence in the stage increases the concentration of proppant. In the example single stage treatment, there are seven sequences of fine proppant in which the volume of fluids pumped are decreased incrementally from 50,000 gallons (gals) to 30,000 gals. This fine grained proppant is used because the finer particle size is capable of being carried deeper into the developed fractures[5]. The fine proppant stages are followed by eight stages of a more course proppant with volumes from 20,000 gals to 10,000 gals. After the completion of the final sequence of the coarse proppant, the well and equipment is flushed with a volume of freshwater sufficient to flush the excess proppants from the equipment and the wellbore.

Hydraulic fracturing stimulations are monitored continuously by operators and the service companies to evaluate and document the events of the hydraulic fracturing treatments (see photo to right). The monitoring of the fracture treatment includes tracking every aspect of the process from the wellhead and downhole pressures, to pumping rates, density of the fracturing fluid slurry, tracking the volumes for each additive (from the acid, to the slickwater lubricant and friction reducer), tracking volumes of water, and ensuring that equipment is functioning properly. For the 12,000 bbl fracture treatment of a vertical Marcellus Shale well in Pennsylvania shown in the photo on page 11, there were between 30-35 people on site monitoring the entire stimulation.

Monitoring Fracturing Activities (Fayetteville Shale)
Source: ALL Consulting, 2008

Marcellus Shale Development and the Environment

Horizontal and Vertical Well Completions

Operators developing the Marcellus Shale are currently using both horizontal and vertical wells to extract the natural gas present in the shale. The low natural permeability of shale requires vertical wells to be developed at closer spacing intervals than conventional gas reservoirs to effectively manage the resource; this can result in initial development of vertical wells at spacing intervals of 40 acres or less to efficiently drain the gas resources from the tight shale reservoirs[32]. If the formation characteristics of Marcellus Shale allow for similar development patterns as seen in the Barnett Shale of the Ft. Worth Basin, shale gas operators who are able to successfully incorporate horizontal wells into the development of the Marcellus can reduce the number of wells needed to developing this resource. In addition, one can significantly reduce the overall number of well pads, access roads, pipeline routes, and production facilities required, thus minimizing forest fragmentation, impacts to public and overall environmental footprint. Devon Energy Corporation reports that incorporating the development of horizontal wells into the development of the Barnett Shale allowed the company to replace 3 or 4 vertical wells with a single horizontal[31]. While it is too early in the development of the Marcellus to determine the final spacing that operators will use to efficiently drain the gas resource over the lifetime of the play, assumptions can be made based on information from other gas shale basins that there will be less surface disturbance using horizontal well technology over vertical well technology.

Table 1 includes data on the well spacing for several shale gas basins including the Marcellus; and based on these data, assumptions can be made regarding the level of disturbance or number of wells that would be drilled using horizontal techniques in comparison to vertical well completions. The spacing for vertical well completions in the Marcellus are predicted to start on 40 acre spacing, while horizontal wells are predicted to be spaced at intervals closer to 160 acres. Applying these predicted well spacing units to a standard 640 acre (1 square mile) section of land a total of 16 vertical wells per square mile would be needed. Whereas the same square mile of resource could drilled and produced by as few as 4 or 6 horizontal wells from a single multi-well drilling pad. Development of horizontal wells and multi-well pads not only reduces surface area disturbances by reducing the total number of drilling and well pad sites, but also results in fewer roadways being needed and combined utility corridors.

Water Availability, Fluid Handling, and Disposal

The Appalachian area receives approximately 10 inches more precipitation per year than the average for the continental United States[34]. The average annual precipitation that falls in the Marcellus shale area is approximately 43 inches (Figure 8) and is evenly distributed over the course of the year. This precipitation over the Marcellus Shale Boundary production area (estimated to be between 54,000 square miles and 95,000 sq. mi) results in between 710,000,000,000 and 1,250,000,000,000 gallons of water input into the Marcellus Shale area annually from precipitation. In comparison to other shale plays, there is substantially more available water in this region than many others, making the area ideal for shale gas development.

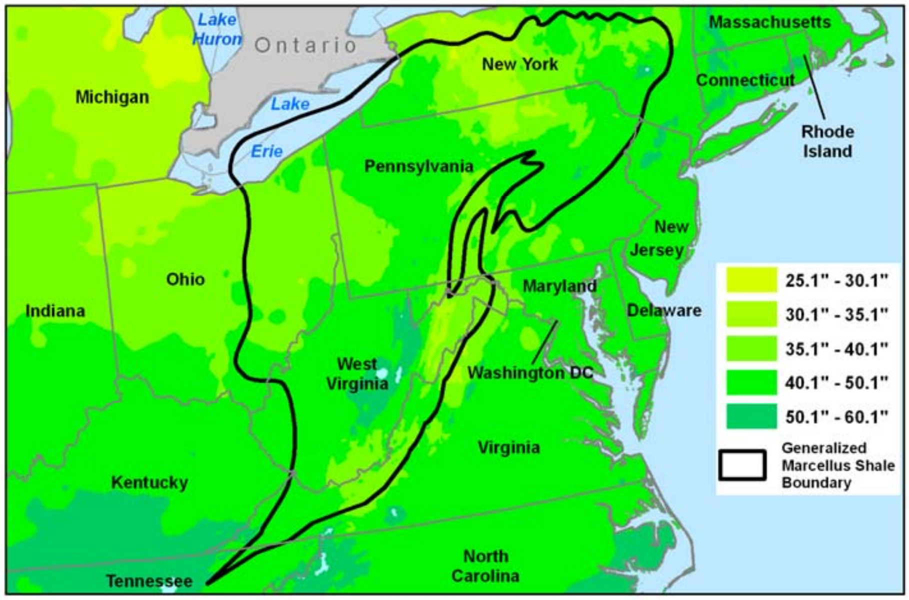


Figure 8: Average Annual Rainfall in the Area of the Marcellus Shale Play
Source: NOAA

Groundwater

Geological materials can act as natural barriers that provide protection to groundwater zones. The stratigraphic column in Figure 3 for part of the Marcellus Shale play area shows that there are multiple siltstone and shale formations (the Hamilton Group and upper Devonian formations) overlying the Marcellus[6]. Shale is a natural barrier to the vertical migration of fluids and is documented as confining layers to vertical migration of oil and gas. The multiple shale zones present between the Marcellus Shale and shallow groundwater zones in much of the development area provides protection of groundwater resources from the hydraulic fracture treatments used to develop the Marcellus Shale. In some parts of the Marcellus Shale production area there is as much as 7,000 ft of sedimentary rock strata, including thousands of vertical feet of shale, between the Marcellus and the shallow groundwater system in parts of the Appalachian Basin. Additionally, each shale has a varied physical character such that the propagation of fractures across multiple shale zones is unlikely. In the designing of fracture treatments, it is beneficial to have a zone with differing physical properties outside the target zone as the interface of the target and bounding formation can act as a transition zone where the direction of fracture propagation can be altered[13]. This can be used to help manage fracture growth during the fracturing job.

In additional to the natural protection of groundwater provided by the distance between producing shale gas formations and potentially usable groundwater sources, there are protection factors built into state required well completion procedures. The casing and cementing programs that state oil and gas agencies require provide protection of groundwater resources. The casing and cement programs required by oil and gas agencies are designed to ensure that drilling and construction of a gas well protects potential sources of drinking water. Therefore, it is typical for state oil and gas agencies to require operators to include casing and cementing details for proposed well completions when the operator files an Application for Permit to Drill (APD). An APD typically details the size, weight, and pressure rating of each type of steel casing that will be installed during the completion of a well. APD's also include details pertaining to how steel casings are cemented into place to further prevent unintended flow of injected or produced fluids from occurring outside of the casing string.

Analysis of the protection provided by casings and cements was presented in a series of reports and papers prepared for the American Petroleum Institute[35] in the 1980s[36]. These investigations evaluated the level of

[34] National Oceanic and Atmospheric Administration. 2005 Annual Summary.
[35] Michie & Associates. 1988. *Oil and Gas Water Injection Well Corrosion.* prepared for the American Petroleum Institute. 32 pgs.

corrosion that occurred in Class II injection wells. Class II injection wells are used for the routine injection of water associated with oil and gas production. The research resulted in the development of a method of calculating the likely probability (or risk) that fluids injected into Class II injection wells could result in a discharge of fluids that could reach an Underground Source of Drinking Water (USDW). This research started by evaluating data for oil and gas producing basins to determine if there were formations present that were reported to cause corrosion of well casings. The United States was divided into 50 basins, and each basin was ranked by its potential to have a casing leak resulting from such corrosion. The Appalachian Basin was ranked as having a minor potential for corrosion because there were only a minor number of instances of casing corrosion reported by oil and gas agencies.

The analysis performed was then limited to those basins in which there was a possibility of casing corrosion[36]. The Appalachian Basin was not analyzed in detail because the risk of casing failure was considered so low. For those basins where analyses were carried forward, risk probability analysis provided an upper bound for the probability of the fracturing fluids reaching an underground source of drinking water. Based on the values calculated, a modern horizontal well completion in which 100% of the USDWs are protected by properly installed surface casings (and for geologic basins with a reasonable likelihood of corrosion), the probability that fluids injected at depth could reach a USDW would be between 2×10^{-5} (one well in 200,000) and 2×10^{-8} (one well in 200,000,000) if these wells were operated as injection wells. This analysis does not account for the fact that gas shale wells are not operated as injection wells, a gas producing well is operated at a reduced pressure, would be exposed to lesser volumes of water flowing through the production tubing, and would only be exposed to the pumping of fluids into the well during fracture stimulations. Based on the analysis performed for API, the Appalachian Basin was not identified as having a reasonable likelihood of corrosion so the risk probability is likely lower than the value presented above.

The API study also included an analysis of wells which have been in operation for numerous years, accounting for what is likely many variations in applied technologies and regulations. As such, a calculation of the probability of fracture fluids reaching groundwater would have an even lower probability for newly constructed wells than the calculations conducted by API; perhaps by as much as two to three orders of magnitude. The API report also makes one other important conclusion relative to the probability of the contamination of a USDW when it stated that "…for injected water to reach a USDW in the 19 identified basins of concern [the 19 basins from the API study did not include the Appalachian Basin], a number of independent events must occur at the same time and go UNDETECTED (emphasis added) [by the Operator and regulators]. These events include simultaneous leaks in the [production] tubing, production casing, [intermediate casing], and the surface casing coupled with the unlikely occurrence of water moving long distances up the borehole past salt water aquifers to reach a USDW." As indicated by the analysis conducted by API, the potential for groundwater to be impacted by injection is low. It is expected that the probability for groundwater to be impacted by the pumping of fluids during hydraulic fracture treatments of newly installed wells when a high level of monitoring is being performed would be even less than the 2×10^{-8} calculated in the API research.

Surface Water

The potential for hydraulic fracturing and Marcellus Shale development activities to impact surface water has been reduced by operator and service company practices over recent years. The migration toward the use of water-based slickwater fracturing fluids has reduced the number of additives used in fracturing fluids in comparison to a cross-linked gel. Service companies who perform hydraulic fracturing stimulation work for operators are also working to design systems which allow fracturing fluids to be contained within closed systems which have been designed to keep all additives, fracturing fluids, mixing equipment and flow-back water within a storage tank, service truck or flowline[21].

[36] Michie & Associates. 1989. *Evaluation of Injection Well Risk Management Potential in the Williston Basin.* Prepared for Underground Injection Practices Council Research Foundation. 79 pgs.

Service companies and operators try to ensure that spills do not occur during a fracturing job; however, if a spill did occur operators act to contain the spill because fluids lost to a spill must be replaced and this increases the cost of the fracture treatment. Operators also have reporting responsibilities which are typically addressed in state oil and gas regulations which require operators to report all spills of additives or produced water to the state oil and gas agency, which can potentially cause delays while the agency assesses the size of the spill and completes the appropriate paperwork and other agency requirements related to documenting the spill. The operator also has the responsibility to remediate the spill including the removal and remediation of contaminated soils, which adds another cost to the project.

Disposal

Operators developing the Marcellus Shale are evaluating safe and economic practices for the disposal of produced waters from the drilling and fracture treating of wells. Flow-back and produced water from hydraulic fracturing events are being contained in enclosed fluid capture systems to reduce their exposure to the environment and the potential for spills to occur. Operators are using a variety of containment tanks and storage trucks to reduce the potential for exposure of fluids to the environment during the transport of chemicals to disposal locations away from the well pad. Many Marcellus operators in states like New York are actively researching options where Class II disposal wells and municipal and industrial treatment facilities can be used to manage flow-back water.

The disposal of flow-back and produced water is evolving in the Appalachians. The volumes of water that are being produced as flow-back water is likely going to require a number of options for disposal that may include municipal or industrial water treatment facilities, Class II injection wells, and the recycling of flow-back water.

Conclusions

The Marcellus Shale of the Appalachian Basin is a potential source for 50 Tcf or more of technically recoverable natural gas[20]. In a time when national energy dialogue has focused on finding alternatives to our reliance on foreign oil, the natural gas resources of the Marcellus Shale presents an opportunity to move toward a domestic source for some of our future energy needs. The history of shale gas development including the success of Barnett Shale has demonstrated the economic potential of shale gas through the use of horizontal well completions and hydraulic fracturing techniques.

Hydraulic fracturing and horizontal well completions appear to be effective for development of natural gas from the Marcellus Shale, although development is still early and there have only been a few wells drilled to-date. However, it is reasonable to conclude that horizontal well completions combined with hydraulic fracturing will provide the best opportunity for producing economic volumes of natural gas from the Marcellus Shale. Advances are being made in the design of hydraulic fracturing programs to develop more efficient ways to create additional flow-paths to the wellbores; and these advances are targeting extensive design and analysis of hydraulic fracture treatments including simulators, microseismic fracture mapping and tilt measurements[22]. The refinement of the hydraulic fracture process that will occur as operators collect more resource-specific data will help to create a more optimized fracture pattern within the target formation, resulting in increased gas production and ensuring that the fractures do not grow out of the formation. Production economics directly hinge on improving gas production by optimizing fracture development and ensuring the propagation of fractures is contained or limited to the target formation and ensuring fractures do not extend into surrounding wet formations.

The potential for impacts to surface water and groundwater from development of the Marcellus shale are expected to be minimal because of the regulatory requirements from state oil and gas agencies involved and the practices operators are implementing to ensure fluids are contained. In evaluating the risk of fluids migrating up to reach groundwater; the depositional environment of the Marcellus Shale that produced a thick blanket of Devonian-aged shales above the Marcellus should also be considered as this thick sequence of overlying shales act as series of confining layers to prevent the vertical migration of fracturing fluids toward groundwater systems.