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SHALE-DEPOSITED NATURAL GAS: A REVIEW OF POTENTIAL

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Arnold Schwarzenegger, *Governor*

CALIFORNIA ENERGY COMMISSION

Leon D. Brathwaite
Principal Author

Ruben Tavares
Project Manager

Ivin Rhyne
Manager
ELECTRICITY ANALYSIS OFFICE

Sylvia Bender
Deputy Director
ELECTRICITY SUPPLY ANALYSIS DIVISION

Melissa Jones
Executive Director

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Picture on front cover courtesy of www.geology.com – Assessing the Marcellus shale formaton: drilling rig at natural gas wellsite.

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Abstract

This report explores the potential of shale-deposited natural gas and the associated environmental concerns arising from the development of this unconventional resource. Since the development of the north central Texas Barnett shale intensified in the mid-1990s, the natural gas industry has identified other deposits in the Lower 48 states and Canada. As a result, this report endeavors to answer the following questions:

- What are natural gas shale formations?
- What created their enhanced productivity?
- What are the technological innovations that have transformed the shales?
- Where are the gas shales located?
- What is the production history?
- What is the reserve potential?
- What is the potential for shale-deposited natural gas in Canada?
- What are the pertinent economic factors involved in the production and development of shale-deposited natural gas?
- What are the associated environmental concerns?

Keywords: Shale, formations, natural gas, economics, innovations, horizontal wells, reserves, environmental impacts.

Executive Summary

Technological innovations in exploration, drilling, and well stimulation (hydraulic fracturing) have transformed shale formations from marginal producers of natural gas to substantial contributors to the natural gas supply portfolio. In 2008, shale formations produced over 5,600 million cubic feet of natural gas per day (MMcf/d), a volume more than eight times their 1998 average of 656 million cubic feet per day. Natural gas from shale formations is increasing its share of the Lower 48 supply portfolio, growing from about 1 percent in 1998 to about 10 percent in 2008. Estimates of recoverable reserves from shale formations range from 267 to 842 trillion cubic feet of natural gas. At the current annual rate of U.S. consumption of 23 Tcf, shale production could add another 11 to 37 years to natural gas resources. Expected market prices determine the level of investments in shale formation drilling and development.

The development of shale formations raises several environmental concerns. First, shale formation development may pose an environmental risk to the groundwater supply of surrounding communities. Further, the carbon footprint of a single horizontal well far exceeds that of a typical single vertical well since the drilling process, the completion process, and the production stimulation process (hydraulic fracturing) require more carbon-based fuels, drilling mud, and water. Further, running the required equipment and pumps produces more emissions.

Developing equivalent amounts of natural gas resources requires two to three times more vertical wells than horizontal wells. The natural gas industry uses both well types to reach potential natural gas resources located thousands of feet beneath the Earth's surface, but each horizontal well recovers more natural gas on average than a vertical well. As a result, the overall carbon footprint (per cubic feet of natural gas) for the entire development of a shale formation may not differ from that of an equivalent-sized formation developed using vertical wells. As natural gas exploration and production companies develop shale resources, research will further illuminate the complete dimensions of the carbon footprint.

CHAPTER 1: Background

Introduction

In the last 20 years, technological innovations have eliminated the barriers that prevented the production of shale-deposited natural gas. As a result, production from shale formations[1] is satisfying demand requirements in all end-use sectors of the natural gas industry. Innovations in both drilling and well completion[2] transformed the shale deposits, which produced an average of 5,651 million cubic feet per day (MMcf/d) in 2008. Ten years earlier, shale production averaged 656 MMcf/d.[3]

The boom in natural gas from shale formations began in the mid-1990s. At that time, shale-deposited natural gas provided about 1 percent of the production in the Lower 48 states. By mid-2008, however, the shale production rose to occupy almost 10 percent of production from the Lower 48. The Natural Gas Supply Association believes that production from the shale formations "…could double in the next 10 years and provide one-quarter of the nation's natural gas supply."[4]

Geologic Characteristics of Shale Formations

Natural gas accumulates in three formations types: Limestone, sandstone, and shale. Before 1998, limestone and sandstone formations produced nearly all domestic supplies of natural gas. However, exploration and production (E&P) companies have long known about the vast quantities of natural gas in shale formations, black and brown fine-grained sedimentary rock material lying thousands of feet beneath the Earth's surface. These formations stretch over at least 23 states in the Lower 48 and can store natural gas in one of three methods:

- Free natural gas within natural micro-fractures
- Free natural gas within minute rock pores
- Adsorbed gas (methane molecules attached to organic material contained within solid matter).

[1] Formations are also called reservoirs or pools.

[2] The process by which natural gas producers transform drilled holes into productive wells.

[3] Lippman Consulting, Inc.

[4] News Release, Natural Gas Supply Association, October 8, 2008.

In Lower 48 shale formations[5], adsorbed gas can account for as little as 20 percent or as much as 85 percent of the total gas. This storage mechanism further complicates the extraction process. Though organic-rich and holding vast quantities of natural gas, shale formations functioned only as trapping and sealing rocks for the natural gas-bearing sandstone and carbonate reservoirs or pools. The geologic characteristics and composition of shale formations presented numerous challenges to E&P companies seeking new supply sources. Since shale formations include consolidated clay and silt-sized particles and its thin lamiae often break with irregular curving natural fractures, the possibility of production remained outside the industry's capabilities.

Until the development of the necessary technological innovations, the industry devoted its resources to extracting natural gas from conventional limestone and sandstone accumulations, since these formations exhibited the characteristics necessary for commercial production. The enormous potential of the shale formations, however, drove the industry to seek out the engineering innovations to tap the natural gas resources residing within these rocks.

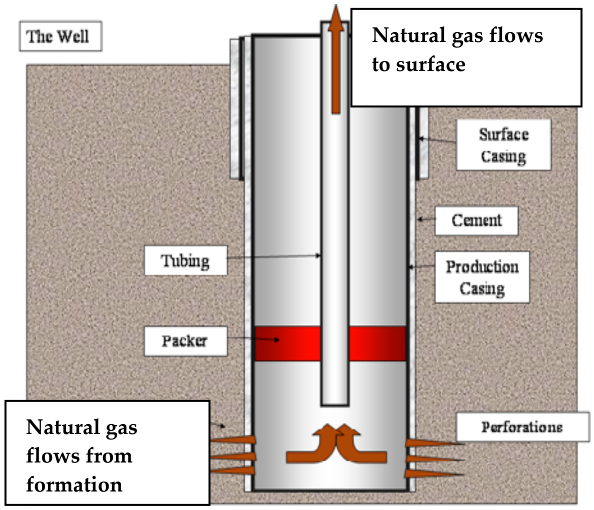
Production Requirements of Natural Gas

The economic production of natural gas from shale or any other rock formation requires three criteria:

- E&P companies must identify a rock formation containing a deposit large enough to incentivize investments.
- The rock formation must exhibit sufficient porosity to hold the natural gas.
- The rock formation must demonstrate sufficient effective permeability so that the natural gas can flow from within the formation to the wellbore (pictured in **Figure 1**) and then travel to the wellhead.

[5] Shale formations located in the the forty eight (48) states of the continental United States.

Figure 1: Simplified Schematic of a Wellbore



Source: Derived from Oil & Gas Journal and Natural Gas Supply Association

Production from shale formations pre-dates the current development activities; for more than 60 years, shale-deposited natural gas provided marginal production in the Appalachian and Illinois Basins. These formations, however, lacked sufficient effective permeability to facilitate large-scale economic or commercial flow of natural gas. As a result, before the technological breakthroughs, only the few shale formations with sufficient natural fractures produced limited quantities of natural gas.

CHAPTER 2: Technology Development

In his book *Basic Economics*, Thomas Sowell, an economist at the Hoover Institution, pointed out that "[how] much of any given natural resource is known to exist depends how much it *costs to know*."[6] The technological breakthroughs in the natural gas industry drove down the *costs to know* and thus boosted the development of shale formations.

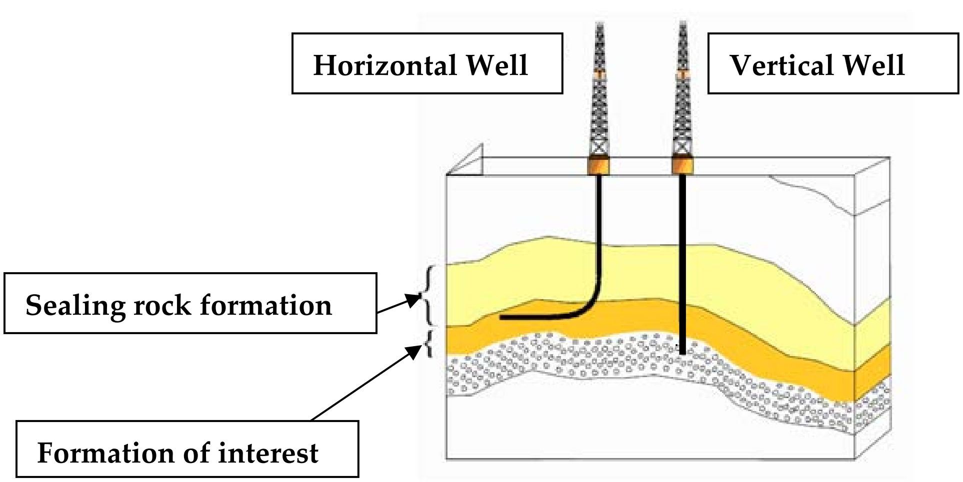
The enhanced productive capability of natural gas shales resulted from technological development in three areas:

- Exploration
- Drilling
- Well completion and stimulation

The exploration for natural gas deposits intensified with the development of three-dimensional and four dimensional seismic surveys. These new techniques allowed geologists and geophysicists to evaluate "chunks" of the Earth's subsurface rather than two-dimensional slices. This capability boosted the industry's ability to find natural gas deposits and to delineate the boundaries of identified deposits.

Improved drilling technology further transformed the productive capability of shale formations. Previous drilling activity involved the heavy reliance on vertical wells, limiting the wellbore exposure to the vertical footage that penetrated the formation of interest. **Figure 2** demonstrates a vertical well and a horizontal well.

Figure 2: Schematic of a Vertical Well and a Horizontal Well



Source: Online Oil & Gas Schematics

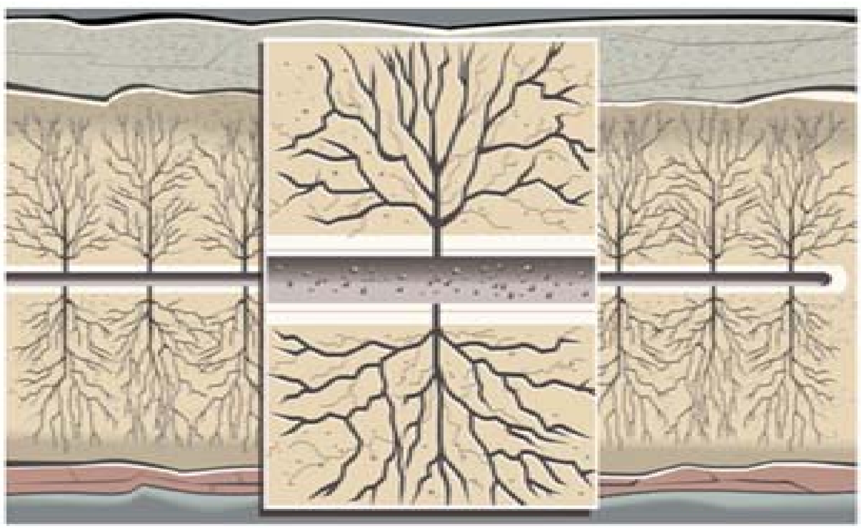
[6] Thomas Sowell, *Basic Economics*, Basic Books, 2007, p. 276 (emphasis added).

The advent of horizontal drilling, however, exposed 5 to 20 times more of the wellbore than did vertical wells. This exposure provided producers with greater opportunities to contact the productive formations, in this case the shales.

Technological innovations in well completion and stimulation further altered the productivity of the shale formations. Instead of single-zone well completions, natural gas producers now perforate[7] and stimulate multiple zones. The stimulation process, known as hydraulic fracturing, involves the pumping of a sand-laden viscous fluid, usually water, into the wellbore and into the formation. The operational pressure cracks open the rock formation, creating extensive artificial fractures.

After the sand settles from the fluid, the well operator retrieves the water by flowing it back to the surface through the wellbore. **Figure 3** demonstrates the creation of a network of artificial fractures after hydraulic fracturing. The schematic also displays the multi-zone result of fracturing.

Figure 3: Artifical Fractures Created by Hydraulic Fracturing



Source: Natural Gas Supply Association

These fractures, held open by sand or another proppant,[8] allow greater natural gas flow to the wellbore, and thus to the wellhead. In many instances, initial production may experience as much as a ten-fold increase after hydraulic fracturing. As a result of the technological developments in exploration, drilling, and completion, low effective permeability no longer prohibits production from shale formations.

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[7] A process by which well operators lower a gun into the wellbore and shoot holes into the formation though the well casing.

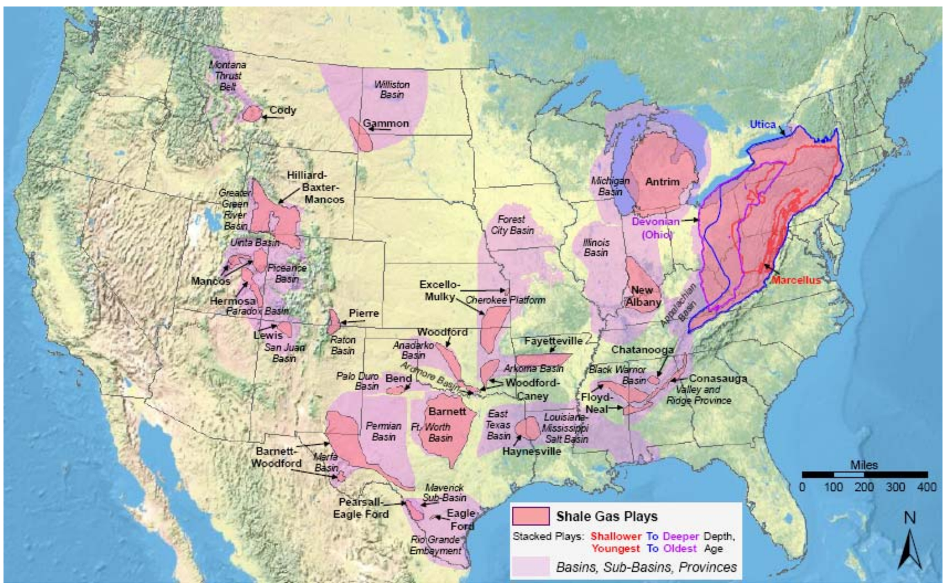
[8] Proppants are granular substances (sand grains, walnut shells, or other material) carried in suspension by a fracturing fluid that keep the cracks in the shale formation open after the well operator retrieves the fracturing fluid.

CHAPTER 3: Characteristics of Shale Formations

Location and Production History

Figure 4 displays the location of the major shale formations in the Lower 48. E&P geologists have identified shale formations in most areas of the country. The Pacific Coast[9] has yet to demonstrate any productive potential for natural gas from shale, even though the industry has identified two shale formations—the Monterey and the McClure—that appear to hold sufficient resources for commercial production[10].

Figure 4: Major Shale Formations in the Lower 48



Source: Energy Information Administration

Production Summary for Lower 48 States

Figure 5 summarizes the natural gas production from shale formations in the Lower 48. [11] The figure demonstrates the dominance of the Barnett shale, located in the Mid-Continent region. In 1998, the Eastern United States, the Antrim shale in particular, provided the majority of the shale production the Lower 48. However, by 2008, the Mid-Continent region,

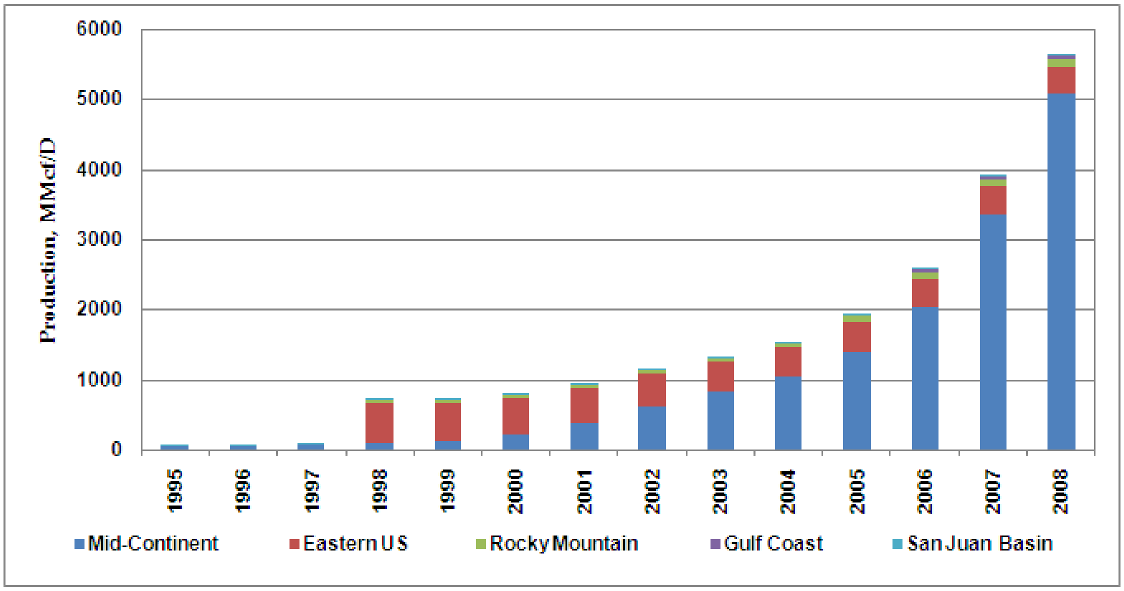
[9] California, Oregon, and Washington.

[10] Both shale formations are located in California.

[11] Lippman Consulting, Inc., provided the production data in this section. The 2008 value reflects an estimate based upon first and second quarter production information.

fueled by the growth in the Barnett, dominated shale production in the Lower 48. Natural gas from shale now provides almost 10 percent of Lower 48 production.

Figure 5: Lower 48 Shale Natural Gas Production



Source: Lippman Consulting Inc.

Further, production of natural gas from shale formations has occupied increasing portions of the total unconventional production (tight gas, shale gas, and coal-bed methane). According to Energy Information Administration (EIA), unconventional production from all sources exceeded 16,000 MMcf/d in 2002, with natural gas from shale formations accounting for about 10 percent of the total. Five years later, unconventional production climbed to more than 25,000 MMcf/d, with shale formations comprising about 13 percent of total. Industry observers expect the 2008 figures to show an even larger share for natural gas from shale formations.[12]

Regional Shale Development

An evaluation of activities in the shale formations will break the Lower 48 into five regions:

- Mid-Continent
- Eastern United States
- Rocky Mountain
- Gulf Coast

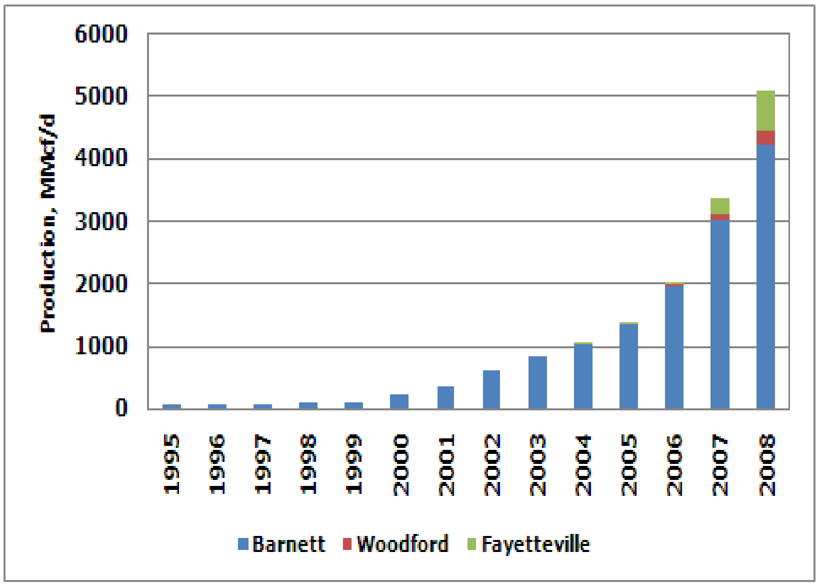
[12] EIA has not yet released its 2008 production figures, and Lippman Consulting does not list a separate unconventional (tight gas, coal-bed methane, and shale) category.

- San Juan Basin

Mid-Continent[13]

In the Mid-Continent region, E&P companies are developing three shale formations: The Barnett shale, the Woodford shale, and the Fayetteville shale. **Figure 6** shows the production from shale formations in the Mid-Continent region.

Figure 6: Mid-Continent Shale Natural Gas Production



Source: Lippman Consulting Inc., 2008 est.

Barnett Shale

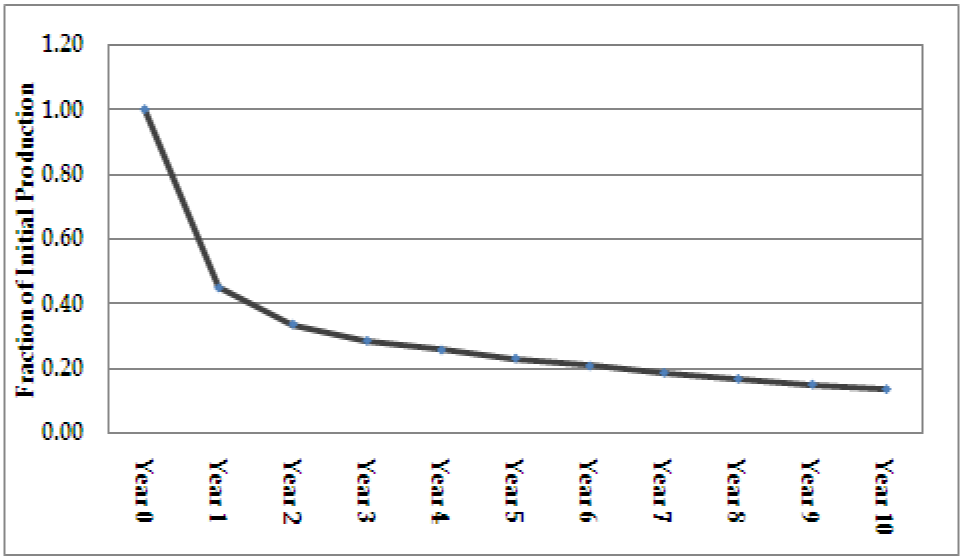
The Barnett shale, located in Texas, dominates the production in the Mid-Continent region, and its development surpasses all other known shale formations. Covering more than 5,000 square miles at a depth of 6,500 to 8,500 feet, the shale ranges in net vertical thickness from 100 to 600 feet. This shale first produced significant quantities of natural gas in the mid-1990s. By 2007, production averaged 3,028 MMcf/d and climbed to 4,241 MMcf/d by the second quarter of 2008. To date, the Barnett shale contributes about 75 percent of all Lower 48 shale production. As a result, the history of the Barnett's production provides insight into the behavior of wells drilled into shale formations in the Lower 48.

The Barnett's decline profile typifies that of tight (low effective permeability), fractured formations, that is, rapid decline in the first year, followed by a slowing of the decline rate. **Figure 7,** truncated after 10 years, demonstrates a representative production profile of the Barnett shale. Other Lower 48 shale formations, as a result of their similar geologic characteristics, will approximate this decline profile. Upon completion of the hydraulic

[13] States: Arkansas, Kansas, Oklahoma, and Texas (District 7B, District 9, and District 10).

fracturing process, low permeability formations, such as shales, release an initial "burst" of energy, resulting in a high initial production dominated by the formation's free gas[14]. A simultaneous large pressure drop occurs. As the pressure decline rate slows, the production rate also declines, but at a lower rate. The volume of slow releasing adsorbed gas overtakes that of free gas. As a result, wells drilled into shale formations may produce for periods exceeding 20 years.

Figure 7: Typical Production Decline Profile



Source: Derived from Pickering Energy Partners, Inc. Partners, Inc., *The Barnett Shale: Visitors Guide to the Hottest Gas Play in the U.S.*, 2005

Woodford Shale

The Woodford shale, located in Oklahoma at a depth between 6,000 and 11,000 feet, covers an estimated 11,000 square miles. The net vertical thickness of this rock formation varies between 120 and 220 feet. This shale first produced significant quantities of natural gas in 2004. Production reached 206 MMcf/d in 2008, more than doubling its 2007 annual average.

Fayetteville Shale

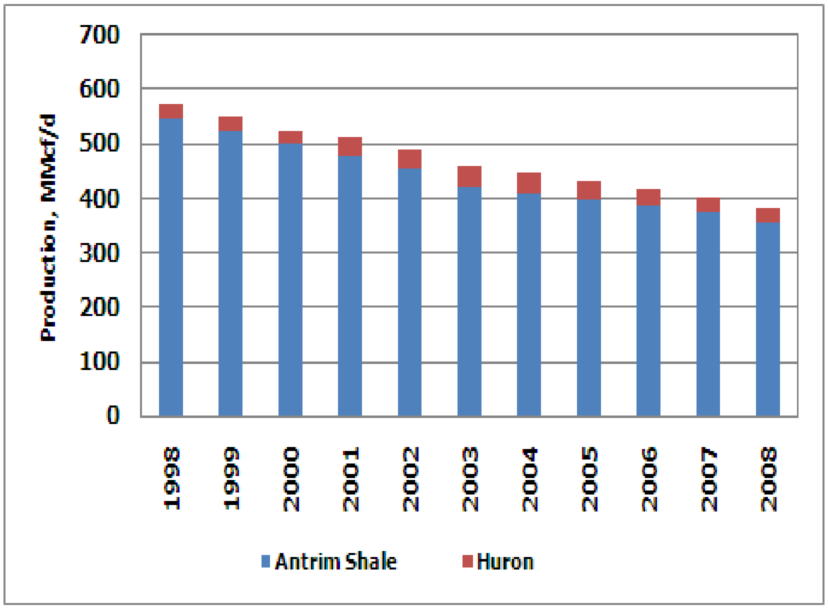
The Fayetteville shale, located in Arkansas at a depth between 1,000 and 7,000 feet, covers an estimated 9,000 square miles. The net vertical thickness of this rock formation varies between 20 and 200 feet. This shale first produced significant quantities of natural gas in 2005. Production reached 639 MMcf/d in 2008, more than three times its 2007 annual average.

[14] Natural gas stored within the shale's natural micro-fractures and minute rock pores.

Eastern United States[15]

In the Eastern United States, E&P companies have identified four major deposits of natural gas in shale formations: The Antrim shale, the Huron shale, New Albany shale, and the Marcellus shale. **Figure 8** displays the shale natural gas production in the Eastern United States. This region has been declining since 1998. However, the natural gas industry expects a reversal with the development of the Marcellus shale.

Figure 8: Eastern U.S. Shale Natural Gas Production



Source: Lippman Consulting, Inc.

Antrim Shale

The Antrim shale, located in northern half of the Lower Peninsula of Michigan at a depth of 600 to 2,200 feet, covers an estimated 12,000 square miles and produces more than 90 percent of the shale natural gas in the Eastern region. This shallow late Devonian[16] formation with a net vertical thickness that varies between 20 and 200 feet, this shale has been supplying natural gas in small quantities since the 1940s. However, the 1980s and 1990s technological innovations transformed the Antrim shale from marginal to major supplier of natural gas.

Production from this shale peaked in 1998, reaching 547 MMcf/d. **Figure 8** shows the decline observed from the Antrim shale. By the second quarter of 2008, the Antrim shale averaged 351 MMcf/d, less than its 2007 average of 370 MMcf/d.

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[15] States: New York, Pennsylvania, Virginia, West Virginia, Ohio. Michigan, Kentucky, Alabama (onshore), and Florida (onshore).

[16] A geologic period and system of rock formations deposited about 400 million years ago.

Huron Shale

The Huron shale, at a depth between 1,000 and 7,000 feet, stretches across portions of West Virginia, Ohio, and Northeast Kentucky. Most development and production in the Huron are occurring in West Virginia. The vertical thickness of this rock formation varies between 200 and 2,000 feet. Since peaking in 2004 with average production of 39 MMcf/d, the Huron shale averaged 27 MMcf/d in 2008.

New Albany Shale

At a vertical depth of 500 to 2,000 feet, the New Albany shale, located in the Illinois basin, stretches across portions of Indiana, Illinois, and Kentucky. This shale formation has produced small quantities of natural gas since 1858. The net vertical thickness of the New Albany varies between 50 and 100 feet. Development is ongoing, and production data, as it becomes available, will determine the potential and limits of this formation.

Marcellus Shale

Industry observers project that the Marcellus shale will become the largest natural gas producer from shale formations in the Lower 48. At depths that vary between 4,000 and 8,500, this shale stretches over more than 95,000 square miles, reaching into portions of four eastern U.S. states: Southern New York, Western Pennsylvania, Eastern Ohio, and West Virginia.

Before the current boom, the Marcellus shale produced small quantities of natural gas for many years. However, the renewed interest in shale natural gas revealed vast quantities of deposits in this shale. The first horizontal wells drilled into the Marcellus shale tested at flow rates that exceeded 6.0 MMcf/d, and drilling operators are still delineating the boundaries of this shale formation.

Rocky Mountains[17]

In the Rocky Mountains, the natural gas industry has identified four major deposits of natural gas in shale formations: The Bakken Shale, the Baxter Shale, the Pierre Shale, and the Mancos Shale. Unconventional production in this region is growing as natural gas producers continue to expand their drilling activities.

Bakken Shale

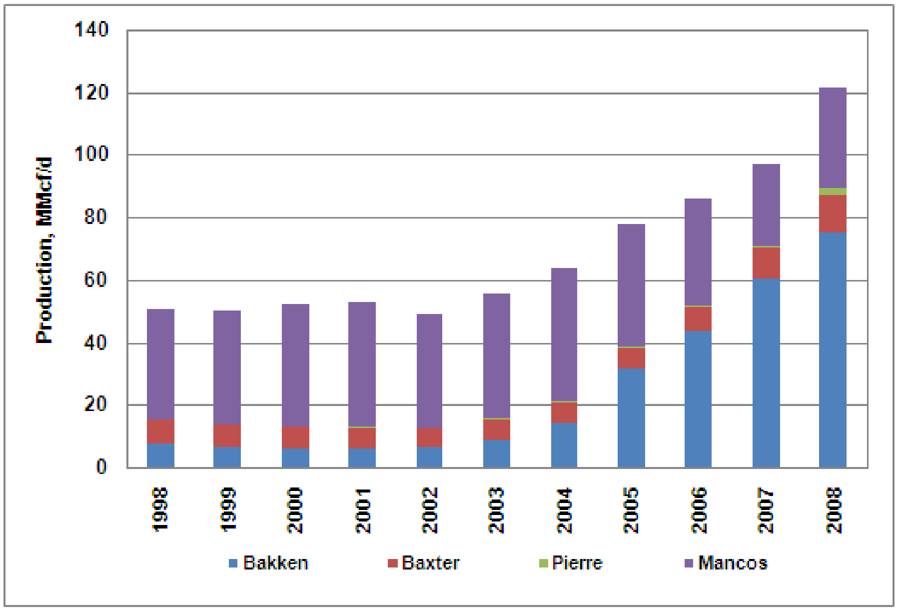
The Bakken shale, located in the Williston Basin, straddles the Montana-North Dakota border and produces natural gas in both states. At a depth of more than 10,000 feet, this rock formation varies in vertical thickness between 8 and 20 feet. In the last three years, production from the Bakken exhibited rapid expansion, dwarfing that of other shales in the

[17] States: Montana, Wyoming, Utah, Northern Colorado, North Dakota, Arizona, Nevada, Nebraska, and South Dakota.

Rocky Mountains. In the second quarter of 2008, production from the Bakken averaged 75.3 MMcf/d, far exceeding its 2004 average of 14.3 MMcf/d.

Figure 9 displays the shale natural gas production in the Rocky Mountains.

Figure 9: Rocky Mountains Shale Natural Gas Production



Source: Lippman Consulting, Inc.

Mancos Shale

The Mancos shale, the second largest producer of shale-deposited natural gas in the Rocky Mountains, straddles the Colorado-Utah border. At depths in some wells of more than 13,000 feet, this shale peaked in the first quarter of 2003 at 44.8 MMcf/d of natural gas. By the second quarter of 2008, production from this shale averaged 32 MMcf/d.

Baxter Shale

The Baxter shale, located in Wyoming at a depth exceeding 11,000 feet, produced about 8 MMcf/d in 1998. However, this shale averaged 11.9 MMcf/d in 2008. Its net vertical thickness surpasses 2,500 feet in some locations. Industry operators are still delineating the extent of this shale.

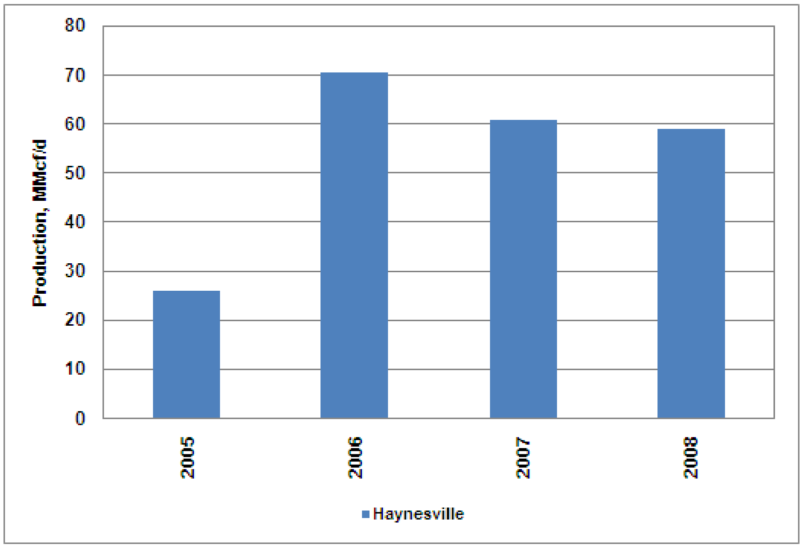
Pierre Shale

The Pierre Shale, located in Colorado, produced 2 MMcf/d in 2008. Drilling operators are still developing this rock formation, which lies at depths that vary between 2,500 and 5,000 feet, and will not know its full potential until more wells provide greater information about its limits.

Gulf Coast[18]

In the Gulf Coast region, the E&P companies have identified two major deposits of natural gas in shale formations: The Haynesville/Bossier Shale and Pearsall-Eagleford Shale. **Figure 10** displays the shale natural gas production in the Gulf of Mexico region.

Figure 10: Gulf Coast Shale Natural Gas Production



Source: Lippman Consulting, Inc.

Haynesville Shale

The Haynesville shale, located at a depth that exceeds 11,000 feet, straddles the Texas–Louisiana border, and almost 70 percent of its production comes from wells located in Texas. The shale's net vertical thickness varies between 200 and 270 feet. The first significant production from the Haynesville began in 2005 when it averaged 26.2 MMcf/d. Production rose to 70 MMcf/d in 2006, but declined to 59.1 MMcf/d in 2008.

At this time, the Haynesville is undergoing major development. The initial well tests in this formation showed higher potential than the Barnett shale. Since the Haynesville shale extends over a larger geographic area and estimates of its original gas-in-place[19] surpasses that of the Barnett by a factor of more than two, industry observers expect that this formation will surpass the Barnett shale in future productive capability.

Pearsall-Eagleford Shale

The Pearsall-Eagleford shale, located in south Texas at a depth of more than 11,500 feet, demonstrated significant potential with the initial production testing of four wells, three horizontal and one vertical. The horizontal wells flowed at rates of 0.8 MMcf/d, 1.1 MMcf/d,

[18] States: Louisiana and South Texas.

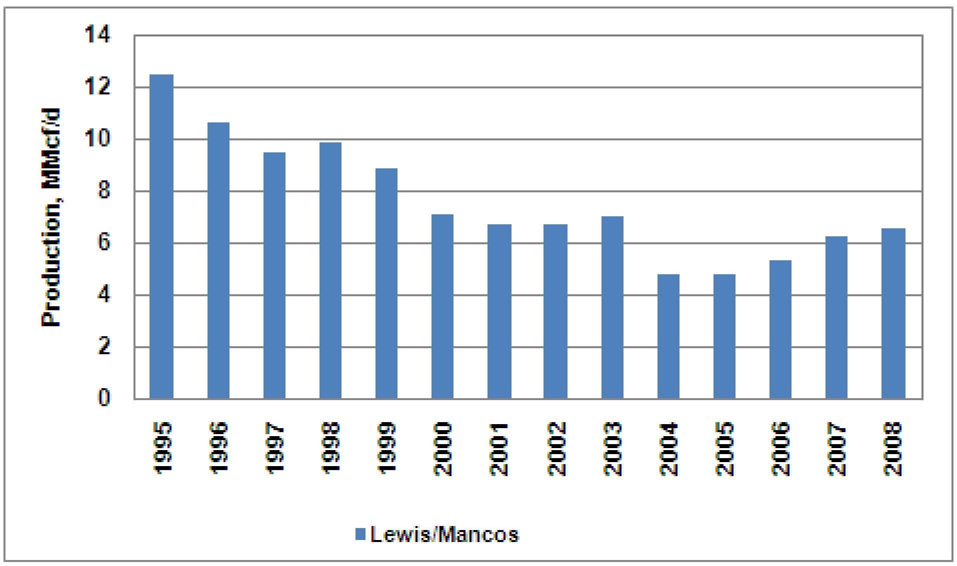
[19] The original total volume of natural gas contained in the shale formation.

and 3.8 MMcf/d. The vertical well, on the other hand, flowed at a rate of 0.5 MMcf/d without fracturing stimulation. Natural gas producers have not yet mapped the boundary of this shale deposit. The net thickness of the Pearsall-Eagleford shale varies between 600 and 1,000 feet.

San Juan Basin[20]

In the San Juan Basin region, the natural gas industry has identified two major deposits of natural gas in shale formations: The Lewis Shale and the Mancos Shale. **Figure 11** displays the shale natural gas production in the San Juan Basin region.

Figure 11: San Juan Basin Region Shale Natural Gas Production



Source: Lippman Consulting, Inc.

Lewis/Mancos Shale

In the San Juan Basin, the geologic characteristics of Lewis and Mancos shales do not differ. As a result, producers in the region do not distinguish the development of these shales. The Lewis/Mancos shale covers about 10,000 square miles at a depth of 3,000 to 6,000 feet. Net vertical thickness varies between 200 and 300 feet. In 1995, this shale averaged about 13 MMcf/d. However, production sank to about 7 MMcf/d in 2008. Drilling and development activities continue the delineation of this shale.

[20] States: The region surrounding the San Juan Basin that stretches into New Mexico and Southern Colorado.

Other Lower 48 Shales

Geologists have identified other shale formations containing producible natural gas. However, only limited drilling and development activities, if any, have occurred in these shale formations, which include:

- Monterey and McClure in California,
- Floyd in Mississippi and Alabama,
- Conasauga in Alabama,
- Gammon in Montana and Wyoming,
- Barnett in the Delaware Basin,
- Niobrara in Wyoming and Colorado.

As a result, years may pass before the natural gas industry knows the full potential of these formations.

Canadian Shale Formations

Development of shale formations in Canada lags that of the Lower 48. However, the natural gas industry in Canada has identified and tested five formations:

- Horton Bluff, Utica, and Lorraine in Eastern Canada,
- Muskwa shale of the Horn River Basin in northeast British Columbia~~,~~
- Montney shale in the Western Canadian Sedimentary Basin (British Columbia).

Drilling operators and producers have tested two shale formations:

Utica Shale

In Eastern Canada, drilling operators drilled and tested one well. This well, completed in the Utica shale, flowed at a rate of 1 MMcf/d in an initial test.

Montney Shale

Three wells penetrated the Montney shale located in British Columbia. Initial production tests from these well exhibited flow rates of 8.8 MMcf/d, 6.1 MMcf/d, and 5.3 MMcf/d.

The encouraging results from these initial tests have motivated further development of the Canadian shale formations.

CHAPTER 4: Uncertainties in Shale Development

Introduction

The major factors affecting the development of the natural gas from shale formations fall into three categories:

- Economics of shale development
- Reserve potential
- Potential environmental impacts

Uncertainties surrounding each factor thus produce inexact estimates of future production and recoverable reserve potential.

Uncertainty: Economics of Shale Development

> Horizontal drilling and hydraulic fracturing are unlocking the continent's bountiful gas shale plays[21] one by one, leading to a seismic shift in production economics -- and prices will never be the same.[22]

Prices, current and expected, play a crucial role in the development of shale-deposited natural gas. Expected prices and their associated present values drive investments in exploration, development, and production. In turn, these activities expand knowledge about shale formations, increasing the current estimates of recoverable natural gas reserves and strengthening confidence in those estimates.[23] The determination of present value distills a future stream of revenues or costs into a single current-dollar value. Many predictions about ultimate depletion, arising from confusions about the present value concept, litter the history of natural gas development. Economist Thomas Sowell of the Hoover Institution, noted:

> Present value profoundly affects the discovery and use of [natural gas] resources. There may be enough [natural gas] underground to last centuries, but its present value determines how much [natural gas] will

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[21] A gas shale play is the extent of a shale formation bearing natural gas.

[22] Peter Tertzakian, chief energy economist, ARC Financial Corp; reported in *Natural Gas Intelligence*, April 27, 2009.

[23] The next section will explore estimates of recoverable reserve potential for shale formations.

> repay what it costs anyone to discover it at any given time –- and that may be no more than enough [natural gas] to last for a dozen or so years. A failure to understand this basic economic reality has, for many years, led to numerous and widely publicized false predictions that we were "running out" of [natural gas, oil], coal, or some other natural resource.[24]

Using an appropriate interest rate, natural gas producers/investors determine the present value of *all costs* to find and develop natural gas and the present value of *all revenues* emanating from the investment. This process leads to the equation:

Expected Net Present Value (NPV) = Present Value of the Revenues – Present Value of the Costs

Investors always seek out positive expected NPV projects.

As stated earlier in this paper, Sowell pointed out "[how] much of any given natural resource is known to exist depends how much it *costs to know*."[25] The development of the shale formations exemplifies this phenomenon. Before the mid 1990s, natural gas drillers and producers ignored shale formations because, at that time and at that level of technology, the present value of the *costs to know* exceeded the present value of expected revenues, creating a negative expected NPV.

Technological innovations have decreased the *costs to know* about shale-deposited natural gas, and development of shale formation exploded. In the Barnett shale, for example, the finding and development (F&D) cost in a vertical well equals about $1.71 per thousand cubic feet (Mcf), whereas in a horizontal well, the F&D cost varies between $1.06 and $1.34/Mcf.[26]

The industry's heavy reliance on horizontal wells to access shale formations establishes a linkage between prices and rig count. In 1998, exploration and production (E&P) companies drilled 78 vertical and 2 horizontal wells into the Barnett shale. A decade later, more than 2,700 horizontal wells penetrated this formation[27] compared to only 108 vertical wells.

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[24] Thomas Sowell, *Basic Economics*, Basic Books, 2007, p. 275.

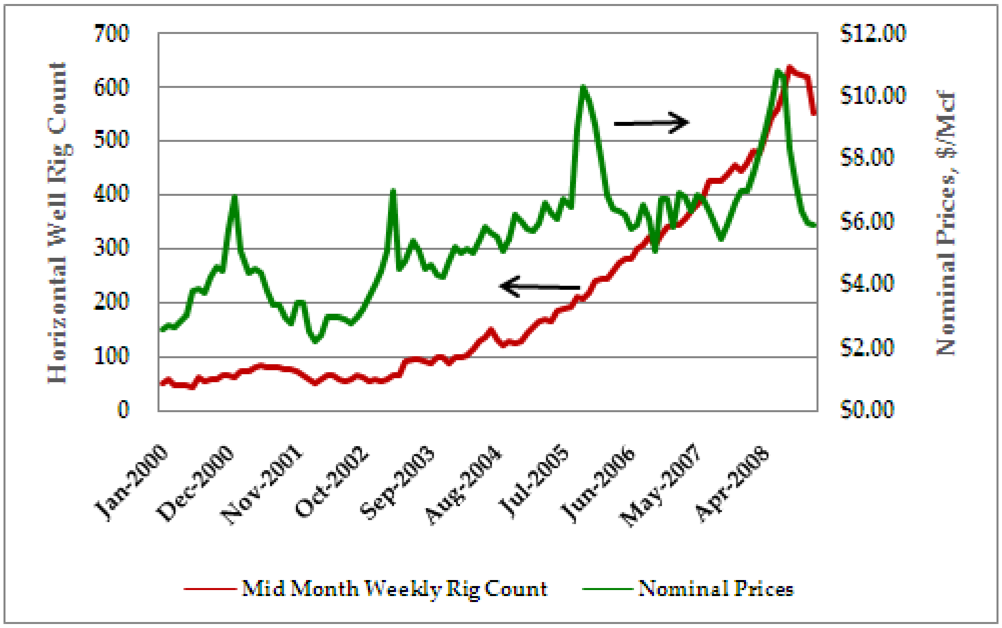
[25] Thomas Sowell, *Basic Economics*, Basic Books, 2007, p. 276, (emphasis added).

[26] Pickering Energy Partners, Inc., *The Barnett Shale: Visitors Guide to the Hottest Gas Play in the U.S.*, 2005.

[27] *Powell Barnett Shale Newsletter*, 01/11/2009.

Figure 12 explores the relationship between level of investment (as represented by the horizontal rig count) and prices (as represented by Henry Hub spot prices).

Figure 12: Horizontal Well Rig Count and Spot Prices



Source: Baker Hughes and Energy Information Administration

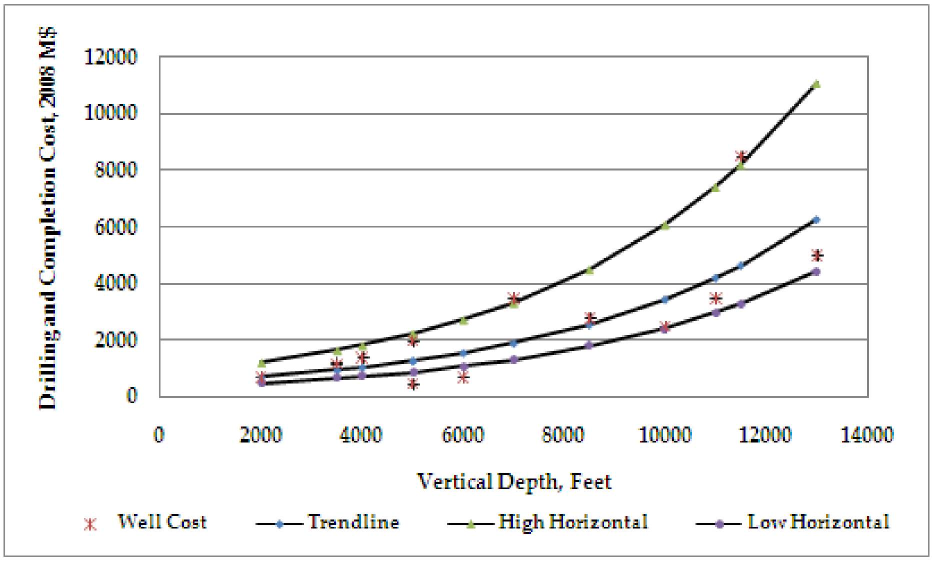
In general, the graph shows that investments, the *costs to know*, rise and fall with prices. The present decline in natural gas prices is forcing cutbacks in scheduled drilling programs. In August 2008, with prices hovering around $11.00/Mcf, the weekly horizontal rig count climbed over 600. As prices plunged in late 2008 and early 2009, the horizontal rig count dropped to less than 450.

The actual cost to drill and complete a horizontal well in a shale formation depends on two important variables:

- Total vertical depth
- Horizontal (lateral) length

While the geologic composition of the formations lying above the shale could add to the overall cost, the two variables account for the vast majority. **Figure 13** provides a *preliminary estimate* of drilling and completion cost per well, not including dry hole cost and seismic surveying cost, for shale formations in the Lower 48. A more complete data set will allow greater segregation of the three lines into horizontal-length cost estimations. As a first approximation, the low line should apply at horizontal length below 750 feet, the trend line at length between 750 and 2,000 feet, and the high line above 2,000 feet.

Figure 13: Drilling and Completion Cost per Well in the Lower 48



Source: Energy Commission Staff; cost data from *Oil & Gas Journal* (various issues) and from U.S. Shale Gas Brief (Phasis Consulting)

The present value of all costs, along with the present value of all revenues, determines the expected profitability, or lack thereof, of developing the various shale formations. Information derived from drilling programs generates the recoverable reserve estimates.

However, the tightening of credit markets has also affected drilling activities in the natural gas industry. Natural Gas Intelligence reported that "…energy industry spending and drilling activity contracted in North America during the first three months of 2009."[28] Further, in the same report, Baker Hughes Inc., a well-known oil services contractor, added that the current market condition is "… characterized by lower natural gas and oil prices, scarce commercial credit, ample natural gas supplies and reduced natural gas demand." [29]

Uncertainty: Reserve Potential

Table 1 summarizes the recoverable reserve[30] potential of shale formations and their associated depths. The estimates listed in **Table 1** emanate from various sources, which may raise issues of consistency in method of determination. Further, the recent and continuing development of most shale formations limits the data necessary for evaluation. As such, total estimated reserves equaled 799.2 Tcf. This number reflects a composite of current and

[28] *Natural Gas Intelligence*, April 29, 2009.

[29] Ibid.

[30] The amount of natural gas that producers, using available technology, expect to extract from a formation.

“best available “estimates and does not discount the high degree of uncertainty surrounding this stated value.

Few industry observers doubt the enormity of the original gas-in-place (OGIP)[31] for shale formations. Estimates of OGIP exceed 3,000 Tcf. However, assessments of recovery (extraction) rates produce a wide range of values.

As such, the recoverable reserves listed in Table 1 differ from Navigant Consulting Inc’s (NCI) technical recoverable estimate[32] of 274 Tcf and the Energy Information Administration’s estimate[33] of 267 Tcf. The Federal Energy Regulatory Commission (FERC), in its March 2009 *Natural Gas Market National Overview*, estimated 742 Tcf. The NCI study, however, did note that the “maximum reported” recoverable reserve estimate equaled 842 Tcf.

The major differences arise from reserve estimates of two shale formations: The Marcellus and the Haynesville. For example, the NCI study estimated 34.2 Tcf for the Marcellus shale, while the FERC listed 262 Tcf and Professor Terry Engelder, geoscientist at Penn State University, listed 392 Tcf.

[31] The total volume of natural gas present in shale formations, which differs from and exceeds the total expected to be extracted.

[32] *North American Natural Gas Supply Assessment*, Navigant Consulting, prepared for American Clean Skies Foundation, July 2008.

[33] Energy Information Administration, *Annual Energy Outlook 2009*.

Table 1: Estimated Recoverable Reserves for Lower 48 Shale Formations

Natural Gas Shale Formations in the Lower 48		
Shale Formation	Approximate Vertical Depth, feet	Approximate Recoverable Reserves, Tcf
Barnett	6500 - 8500	44.0
Wordford	6000 - 11000	11.4
Fayetteville	1000 - 7000	41.6
Antrim	600 - 2200	20.0
Huron	1000 - 7000	N/A
Marcellus	4000 - 8500	392.0
New Albany	500 - 2000	19.2
Bakken	>10000	N/A
Baxter	>11000	N/A
Pierre	2500 - 5000	N/A
Mancos	>13000	N/A
Haynesville/Bossier	>11000	251.0
Pearsall-Eagleford	>11500	N/A
Lewis/Mancos	3000 - 6000	20.0
Total		799.2

Sources: Various [34]

While production from the shales is exploding, the full delineation of the formations is lagging since only *more drilling* can provide the necessary critical information. This creates great uncertainty in estimating recoverable reserves. The progression of development will shed new light on the boundaries of the shale formations, generating more precise estimations.

Uncertainty: Potential Environmental Impacts

The shift to a greater reliance on horizontal, rather than vertical, wells in the development of shale formations elevated the issue of potential environmental impacts. Regulatory agencies and environmental groups highlighted these issues in the past. However, in the last 10 years, the increased activities in shale formations place greater focus on the potential

[34] Source: Energy Information Administration; Navigant Consulting; *Oil and Gas Journal* (various issues); Arthur, J. Daniel, et al., *Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale*, 2008; Arthur, J. Daniel and Bobbi Jo Coughlin, *Evaluating the Environmental Implications of Hydraulic Fracturing in Shale Gas Reservoirs,* 2008; and Terry Engelder, Ph.D., Professor of Geoscience, Penn State University

environmental impacts, which can occur in any of five venues: surface preparation, drilling and completion, production and clean-up, transmission and distribution, and consumption.

As such, the development of natural gas in shale formations has raised three general environmental concerns:

- Surface disturbance
- Greenhouse gas emissions
- Potential leakage into the groundwater

Surface Disturbance

The surface preparation before drilling any well, vertical or horizontal, may create environmental stress in some sensitive areas. Some environmentalists, including the Wilderness Society, believe that, in many cases, the cost of the environmental harm exceeds the value of the extracted resources. As a result, the potential impact on wildlife habitat and wilderness areas has led to moratoriums on drilling in the Rocky Mountains and other sensitive areas of the Lower 48.

Drilling operations in permitted areas do impact the environment, and some states, including New York and Pennsylvania, have issued restoration requirement rules. The Wilderness Society believes that "[a] more accurate estimate of economically recoverable gas should include a full accounting of all the hidden, nonmarket costs, including the *costs associated with erosion*, *declining water and air quality*, and *loss of wildlife habitat*." [35]

The Natural Gas Supply Association, on the other hand, points out that the industry, by using new technologies, is addressing some of the environmental impacts. Smaller rigs decrease surface disturbance, and horizontal and directional drilling allows greater flexibility in rig placement.[36] The shift to horizontal drilling lessens the surface disturbance by requiring fewer wells to recover an equivalent amount of resource. According to the National Energy Board of Canada, "[t]he land-use footprint [of shale natural gas development] does not appear to be of significant concern beyond conventional operations, despite higher well densities, because advances in drilling technology allow for ten or more horizontal wells to be drilled from the same wellsite."[37]

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[35] Pete Morton, Ph.D. et al, *Energy and Western Wildlands: A GIS Analysis of Economically Recoverable Oil and Gas*, 2002 (emphasis added).

[36] Natural Gas Supply Association, www.naturalgas.org.

[37] National Energy Board (Canada), *A Primer for Understanding Canadian Shale Gas*, November 2009.

Greenhouse Gas Emissions

As a result of combustion, natural gas produces about 19 percent of the carbon dioxide, [38] a greenhouse gas (GHG), in the United States.[39] Most emissions occur during the consumption of this fossil-based fuel. **Table 2** shows the emissions from natural gas. When compared with other fossil-based fuels, natural gas produces the lowest GHG emissions.[40]

Table 2: Emissions from the Combustion of Fossil-based Fuels

Emissions from Fossil-based Fuels, Pounds per MMbtu						
	Carbon Dioxide	Carbon Monoxide	Nitrogen Oxides	Sulfur Dioxide	Particulates	Mercury
Natural Gas	117	0.040	0.092	0.001	0.007	0.000
Crude Oil	164	0.033	0.448	1.122	0.084	0.000
Coal	208	0.208	0.457	2.591	2.744	0.000
Note: 1 cubic feet of natural gas = 1,031 Btus of natural gas						

Source: Energy Information Administration

On a *per* MMBtu basis, total emissions from natural gas produced from shale formations differ little from that of natural gas from conventional sources.

The leakage of methane, a GHG and the main component of natural gas, into the atmosphere also raises environmental concerns. The Energy Information Administration says that methane emissions from all sources account for about 1 percent of total U.S. greenhouse gas emissions, but about 9 percent of the "greenhouse gas emissions based on global warming potential."[41] Methane can leak at any stage of the entire process leading to consumption.

Normally, field production, gathering and cleaning, separation of water or oil from associated gas, and the extraction of natural gas liquids reduce gross natural gas production by about 6 to 10 percent. In addition, transmission and distribution consume another 3 to 8 percent, further reducing the gross natural gas volume. As a result, only about 85 to 90 percent of the gross production in the United States reaches end users. However, whether the natural gas flows from a vertical well or from a horizontal well, the process leading to consumption does not vary.

A further examination of the carbon footprint on a *per-well* basis may generate an apparent contradictory result. The carbon footprint of a horizontal well far exceeds that of a typical

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[38] Emissions from energy and industry.

[39]Energy Information Administration, *Emissions of Greenhouse Gases Report*, 2008.

[40] In Table 2, only carbon dioxide (CO_2) and Nitrogen Oxides (NO_X) are greenhouse gases.

[41] An indicator of the carbon dioxide equivalent.

vertical well since the drilling process, the completion process, and the production stimulation process (hydraulic fracturing) require more carbon-based fuels, more drilling mud, and more water. Further, running the required equipment and pumps produces more emissions.

On the other hand, developing equivalent amounts of natural gas resources requires two to three times more vertical wells than horizontal wells, for example, extracting 20,000 MMcf of natural gas may require 10 horizontal wells, but 25 to 30 vertical wells. The natural gas industry uses both well types to reach potential natural gas resources located thousands of feet beneath the Earth's surface, but each horizontal well recovers more natural gas on average than a vertical well. As a result, the overall carbon footprint for the entire development of a shale formation may not differ from that of an equivalent-sized formation developed using vertical wells.

While the extraction of natural gas impacts the environment, a study commissioned by the United States Department of Energy (Office of Fossil Fuels) concluded that "[t]he use of horizontal drilling has not introduced *new* environmental concerns (emphasis added)."[42] However, the National Energy Board of Canada indicated that "…the potential growth in CO_2 emissions from shale gas"[43] development needs further investigation and, if necessary, mitigation action. The US Environmental Protection Agency is considering the development of a regulatory framework for a category of injection wells that will facilitate the sequestration of CO_2.

Potential Leakage into the Groundwater and Associated Water Issues

The potential contamination of groundwater raises another environmental concern. A typical multi-stage hydraulic fracturing treatment requires between two and four million gallons of fresh water treated with chemicals, sometimes called slickwater, that facilitate both the suspension of the proppant (sand, most times) and the lubrication of the conveying mediums. In the development of an entire field, the amount of water injected into a shale formation could reach into the hundreds of millions of gallons.[44] Although field operators retrieve most of the injected water upon completion of the hydraulic fracturing stimulation, a significant quantity of water and chemicals remain within the formation.

Development of several shale formations, for example, the Barnett shale near Fort Worth, Texas, is occurring near major population centers. As a result, some environmentalists claim

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[42] United States Department of Energy (Office of Fossil Fuels), National Energy Technology Laboratory, *Modern Shale Gas Development in the United States: A Primer*, April 2009.

[43] National Energy Board (Canada), *A Primer for Understanding Canadian Shale Gas*, November 2009.

[44] The volume of water used in the development of natural gas from shale formations raises other environmental concerns, including the consumption of large water quantities and recovered water disposal.

that potential leakage of chemicals used in the hydraulic fracturing process pose a health and safety risk and are calling for stricter regulation.

The natural gas industry responds to the concern by pointing out that “the chemical injections [into the shale formations] are happening thousands of feet below the surface, whereas groundwater is usually just hundreds of feet deep.”[45]

Some states, including New York, have issued regulatory requirements for “responsible development” of shale formations[46]. These regulations include guidelines for the use and disposal of water, the protection of groundwater, and the use of chemicals. Further, the regulatory requirements[47] include:

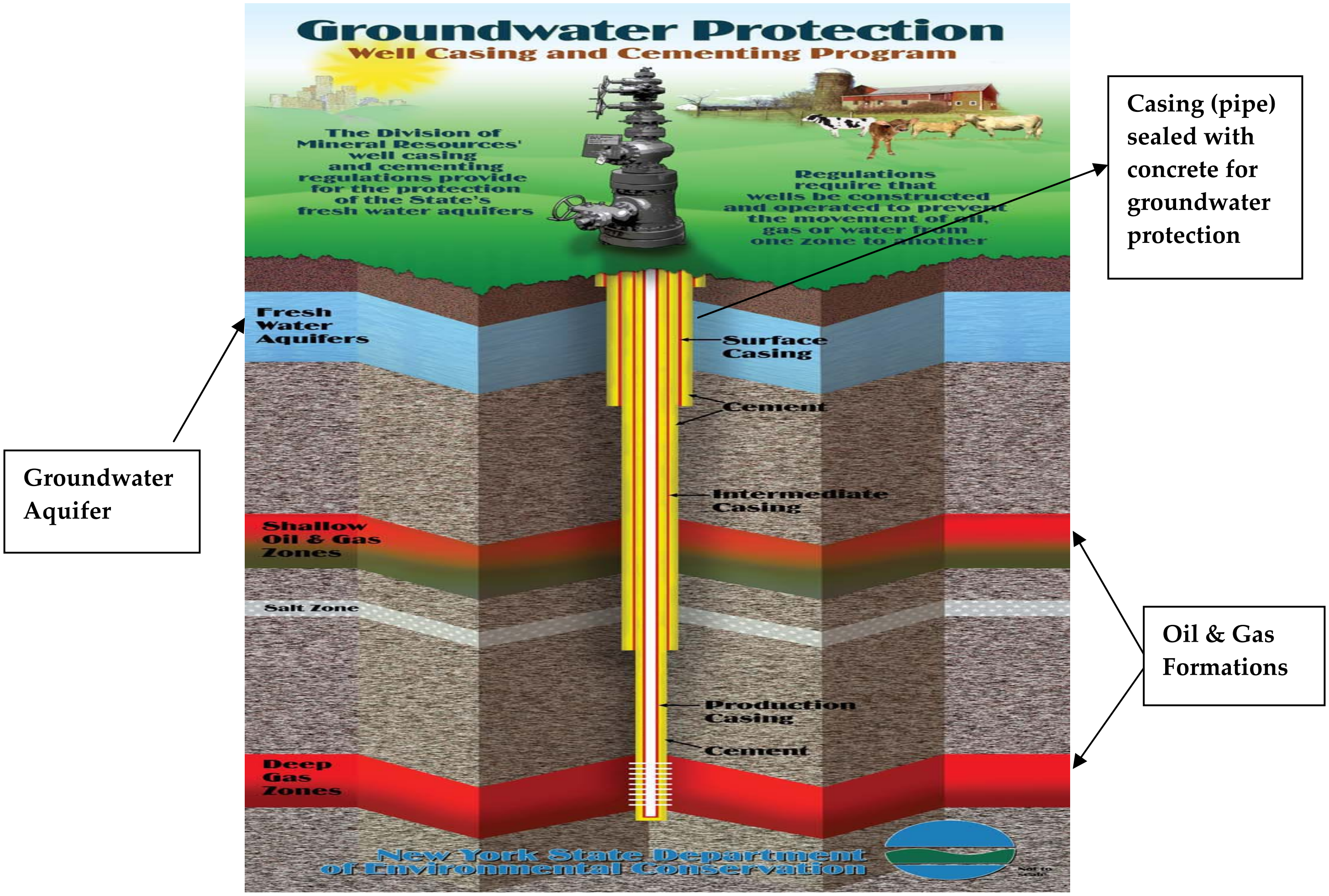
- Review of each drilling application for environmental compliance
- Complete environmental assessment of all proposed oil or gas wells that are within 2000 feet of municipal water wells
- Strict review of the well design to ensure groundwater protection. **Figure 14** displays a typical well design
- On-site inspection of drilling operations
- Enforcement of strict restoration rules when drilling ends

[45] “Natural gas vs. contaminated water,”CNNMoney.com, Quote from Phani Gadde, a gas supply analyst at the energy consultancy Wood Mackenzie, July 28, 2008.

[46] Department of Environmental Conservation, New York State, *Final Scope for Draft Supplemental Generic Environmental Impact Statement on Oil, Gas and Solution Mining Regulatory Program*, 1992.

[47] See previous footnote.

Figure 14: Typical Well Design for Protecting Groundwater



Source: Department of Conservation, New York State

Pennsylvania has also instituted rules governing the extraction of natural gas from shale formations. Kathleen McGinty, the state's Department of Environmental Protection Secretary, noted that "…developing our energy resources cannot come at the expense of our environmental resources - - our water, our land and our ecosystems." McGinty further stated that "…these rules are in place to protect our natural treasures and we will not compromise on them."[48] In 2008, the department's inspectors ordered the partial shutdown of two drilling sites after discovering violations of state regulations.[49]

Other states have also developed regulatory framework for the protection of groundwater resources. The US Department of Energy examined this issue and concluded that "[s]tates,

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[48] Kathleen McGinty, Secretary of Pennsylvania's Department of Environmental Protection, speaking at a department-sponsored summit, June 2008.

[49] Environmental News Service, June 16, 2008.

local governments, and shale gas operators seek to manage produced water in a way that protects surface and ground water resources and, if possible, reduces future demands for freshwater. By pursuing the pollution prevention hierarchy of "Reduce, Re-use, and Recycle" these groups are examining both traditional and innovative approaches to managing shale gas produced water. This water is currently managed through a variety of mechanisms, including underground injection, treatment and discharge, and recycling."[50] For example, in some areas where shale development has surpassed infancy, "…pipelines have been constructed to transport produced water to injection well disposal sites. This minimizes trucking the water and the resultant traffic, exhaust emissions, and wear on local roads. Injection disposal wells are permitted under the federal Safe Drinking Water Act (SDWA), Underground Injection Control (UIC) program (or in the case of state primacy, under equivalent state programs), a stringently permitted and monitored process with many environmental safeguards in place."[51]

However, Amy Mall, a policy analyst for the Natural Resources Defense Council, added that "… natural gas is important and we don't have any interest in shutting down the operations…[but] all the right policies might not be in place."[52] As the development of shale natural gas proceeds, new information will illuminate the strengths and weaknesses of current policies and the regulatory framework will evolve to meet public safety requirements.

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[50] United States Department of Energy (Office of Fossil Fuels), National Energy Technology Laboratory, *Modern Shale Gas Development in the United States: A Primer*, April 2009.

[51] Ibid

[52]"Natural gas vs. contaminated water," CNNMoney.com, Quote from Amy Mall, policy analyst, Natural Resources Defense Council, July 28, 2008.

CHAPTER 5: Major Findings and Issues

Major Findings

- Technological innovations in exploration, drilling, and well stimulation (hydraulic fracturing) have transformed shale formations from marginal producers of natural gas to substantial contributors to the natural gas supply portfolio.
- In 2008, shale formations produced over 5,600 MMcf/d, a volume more than eight times their 1998 average of 656 MMcf/d.
- Natural gas from shale formations is increasing its share of the Lower 48 supply portfolio, rising from about 1 percent in 1998 to about 10 percent in 2008.
- Estimates of recoverable reserves from Lower 48 shale formations range from 267 to 842 trillion cubic feet of natural gas (Tcf), but the current infancy of shale development creates a high degree of uncertainty in the estimations. At the current annual rate of U.S. consumption of 23 Tcf, shale production could add another 11 to 37 years to natural gas resources.
- Expected market prices determine the level of investments in shale formation drilling and development.
- Shale formation development may pose an environmental risk to the groundwater supply of surrounding communities.
- The carbon footprint of a horizontal well far exceeds that of a typical vertical well since the drilling process, the completion process, and the production stimulation process (hydraulic fracturing) require more carbon-based fuels, more drilling mud, and more water. Further, running the required equipment and pumps produces more emissions.
- Developing equivalent amounts of natural gas resources requires two to three times more vertical wells than horizontal wells. The natural gas industry uses both well types to reach potential natural gas resources located thousands of feet beneath the Earth's surface, but each horizontal well recovers more natural gas on average than a vertical well. As a result, the overall carbon footprint for the entire development of a shale formation may not differ from that of an equivalent-sized formation developed using vertical wells.

Glossary of Terms

Adsorbed gas	Methane molecules attached to organic material contained within solid matter.
Bcf	Billion cubic feet.
Carbon footprint	The total set of GHG (greenhouse gas) emissions caused directly and indirectly by an individual, organization, event, or product.
Casing	Pipe set with cement in the hole in the earth.
Coal-bed methane (CBM)	Natural gas from coal deposits.
Drilling	The process of boring a hole in the earth to find and remove subsurface fluids such as oil and natural gas.
E&P	Exploration and Production.
EIA	Energy Information Administration.
Environmental impact	Adverse effect upon natural ambient conditions.
FERC	Federal Energy Regulatory Commission.
Formation	A bed or rock deposit composed, in whole, of substantially the same kind of rock; also called reservoir or pool.
Groundwater	Water in the earth's subsurface used for human activities, including drink.
Henry Hub	Located in Southern Louisiana, it is a major pricing point in the Lower 48.
Horizontal well	A hole at first drilled vertically and then horizontally for a significant distance (500 feet or more).
Hydraulic fracturing	The forcing into a formation of a proppant-laden liquid under high pressure to crack open the formation, thus creating passages for oil and natural gas to flow through and into the wellbore.
MMcf /d	Million cubic feet per day.
Net Present Value	The process of finding the current-date value of a stream of cash-flows occurring in multi-periods. Present value of revenues minus present value of costs gives the net present value.

Original gas-in-place	The total initial volume (both recoverable and non-recoverable) of oil and/or natural gas in-place in a rock formation.
Permeability	The ability of a fluid (such as oil or natural gas) to flow within the interconnected pore network of a porous medium (such as a rock formation).
Porosity	The condition of a rock formation by which it contains many pores that can store hydrocarbons.
Production decline profile	A chart demonstrating the depletion of a producing well.
Proppant	A granular substance (sand grains, walnut shells, or other material) carried in suspension by a fracturing fluid that keep the cracks in the shale formation open after the well operator retrieves the fracturing fluid.
Recoverable reserves	The unproduced but recoverable oil and/or natural gas in-place in a formation.
Rig count	The number of drilling rigs actively punching holes in the earth.
Shale	A fine-grained sedimentary rock whose original constituents were clay minerals or mud.
Shale gas	Natural gas produced from shale formations.
Stimulation	The process of using methods and practices to make a well more productive.
Tcf	Trillion cubic feet.
Tight gas	Natural gas from very low permeability rock formations.
Unconventional production	Natural gas from tight formations or from coal deposits or from shale formations.
Well	A hole in the earth caused by the process of drilling.
Well completion	The activities and methods necessary to prepare a well for the production of oil and natural gas.
Wellbore	The hole made by drilling. It may be cased, i.e., pipe set by cement within the hole.